Oil & Natural Gas Technology

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Final Report

Field Testing of Environmentally Friendly Drilling System

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TITLE PAGE

Title: **Field Testing of Environmentally Friendly Drilling System**

Final Report: **Environmentally Friendly Drilling**

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To: **Project Manager DOE**

The Harold Vance Department of Petroleum Engineering has been the lead contractor for the subject project. The enclosed report provides a compilation of the reports published during the time funded by DOE. These hard copy reports attached can be found on the Final Report web site at http://sites.google.com/site/environmentallyfriendlyep/

DISCLAIMER

ABSTRACT
The Environmentally Friendly Drilling Program (EFD)
Project Final Reports

The Environmentally Friendly Drilling (EFD) program addresses new low-impact technology that reduces the footprint of drilling activities, integrates light weight drilling rigs with reduced emission engine packages, addresses on-site waste management, optimizes the systems to fit the needs of a specific development sites and provides stewardship of the environment. In addition, the program includes industry, the public, environmental organizations, and elected officials in a collaboration that addresses concerns on development of unconventional natural gas resources in environmentally sensitive areas. The EFD program provides the fundamentals to result in greater access, reasonable regulatory controls, lower development cost and reduction of the environmental footprint associated with operations for unconventional natural gas. Industry Sponsors have supported the program with significant financial and technical support.

This final report compendium is organized into segments corresponding directly with the DOE approved scope of work for the term 2005 – 2009 (10 Sections). Each specific project is defined by (a) its goals, (b) its deliverable, and (c) its future direction. A web site has been established that contains all of these detailed engineering reports produced with their efforts. This site can be accessed at:

http://sites.google.com/a/pe.tamu.edu/efd-2005-2009---sponsors-site/

Goals of Program

The goals of the project are to 1) identify critical enabling technologies for a prototype low-impact drilling system, 2) test the prototype systems in field laboratories, and 3) demonstrate the advanced technology to show how these practices would benefit the environment.

Background Leading to the Development of “Environmentally Friendly Drilling”

With the support of the U.S. National Energy Technology Laboratory of the DOE and other industry sponsors from GPRI, we have worked to identify and develop environmentally friendly drilling (EFD) systems that incorporate current and new drilling technology. These new systems will be designed to be compatible with environmentally sensitive or currently off-limits areas such as Federal lands in the Western United States and the wetlands and marshes of the Gulf Coast. Funding from the U.S. DOE have been augmented by industry funding (both cash and in-kind).

Scope of Work

The EFD program is intended to showcase new technology that the O&G industry is developing to reduce the impact of operations on the environment. The prime effort of the members is to integrate the various technologies into a cost effective system. To accomplish this, the EFD members have created a systematic list of Tasks based on the Scope of Work agreed to by our funding agencies and sponsors.

The scope of work for the project includes 15 Tasks. These are listed below.

Task 1 Research Management Development
Task 2 Technology Status Assessment
Task 3 Prelim. Economic, Market, and Environmental"
Task 4 Planning Prototype Development
Task 5 Specialized Operations Studies
Task 6 Mobilize Equipment to Test Site (Arrange transport, Deploy to Pecos, Arrange storage)
Task 7 Test System Components
Task 8 Analyze Performance
Task 9 Additional Studies
Task 10 Phase I Final Report
Task 11 Prepare Full-Scale Engineering System Design
Task 12 Combine Selected Components into Integrated System for Test Site 1
Task 13 Site 2 Studies marsh-like environments & Coastal Margins
Task 14 Update Economic Analysis and Finalize Project Field Testing
Task 15 Report for Phase 2.

Deliverables.

The deliverables for the project are contained in 10 Report or Sections.

- Report 1: Background and Technical Approach
- Report 2: EFD Technology Assessment; circa 2005
- Report 3: EFD Systems Design
- Report 4: Advanced Drilling Technology: Low Impact Rigs
- Report 5: Low Impact Access: Reduced Surface Environmental Footprint
- Report 6: Waste Management: Produced Brine and Mud Pit Reduction
- Report 7: Outreach Activity, Public Acceptance, & Technology Assimilation
- Report 8: An EFD Scorecard for Operations
- Report 9: Presentations and Briefings

- Report 10: Publications

The Reports represent the work performed under the Texas A&M TEES contract and DOE contract DE-FC26-05NT42658.

TABLE OF CONTENT

Publications

Executive Summary

Web content found at

http://sites.google.com/a/pe.tamu.edu/efd-2005-2009---sponsors-site/home/chapter-4-advanced-drilling-technology-low-impact-rigs

Goals and Objectives of the Project

Environmental issues are a significant part of every energy industry endeavor whether exploiting new natural gas resources in Western U.S., or extending field development in coastal areas of the U.S. creating a new, dual engineering and environmental research program. The long range goal of the program is to reduce the footprint of O&G exploration and production operations. Our specific goals have been to design a drilling system that can operate in environmentally sensitive areas with little or no impact.

The long range goal of the EFD program is the integration of currently known but unproven or novel technology to develop drilling systems that will have very limited environmental impact and enable moderate to deep drilling and production operations and activity.

The specific objectives of the DOE Environmental Drilling Systems Project:

(1) To identify new technology that can reduce or eliminate the impact of drilling operations on environmentally sensitive areas

(2) To design an EFD system using most promising technology

(3) To include environmental stakeholders in designs

The petroleum industry may be well equipped to demonstrate its economic contribution and the benefits it brings to society through energy, chemicals, and other products, and through wealth generation and employment creation. However, the key challenge for the industry is how to satisfy energy demand, while safeguarding the environment. This is especially challenging in the restricted areas of the U.S. in the arid/semi-arid deserts and coastal inland wetlands of the U.S. where these ecologies are very sensitive to disruptive activity but have significant value to society.

The information contained in this report is the foundation to develop a Best Available Technology for E&P in sensitive areas within the lower 48 states of the U.S. and is part of the Environmentally Friendly Drilling Project awarded to GPRI and Noble Corporation by the U.S. Department of energy in October 2005. The concept of the project is to integrate currently known but unproven or novel technology into a drilling process or system and enable moderate to deep drilling and production operations with very limited (preferably no) environmental impact through the lifecycle of a well and field development.

List of Tasks: Accomplishments

EFD Technology Assessment

In the last decade substantial technology has been transferred from the premium offshore drilling industry to increase the safety, efficiency, and lower the environmental impact of land drilling rigs. Substantially more technology is available to develop zero discharge on land operations and reduce the impact of land drilling rigs. And substantially more technology is available to develop zero discharge on land operations and reduce emission and location impact to the ecology both onshore and offshore.

1. Transportation equipment and/or methods that are used in or developed for other sensitive areas and do not require building of conventional roads but carry heavy loads with little or no permanent damage to the soils, vegetation, or animals that inhabit the sensitive or off-limits areas. Road-less or disappearing road concept(s) would be of interest. Low ground pressure equipment e.g., Hover craft, Rolligons. Temporary roads construction methods and materials

2. Drilling Equipment and Methodologies: new smaller modular rig designs, automation, and pipe handling equipment to reduce the environmental footprint also reduce downtime for rig moves improving the economics and safety issues. Pad Drilling using horizontal, multilateral drilling and or extended reach drilling not only for multiple completions in gas reservoirs but also for production and gathering lines and disposal systems.

3. Zero Pad concept and issues related to onshore platform concept low impact ecological footprint (reduced land usage). Improve drilling equipment efficiency and methodology to reduce green house gas emissions i.e., zero discharge concepts. Bring lessons learned offshore and economically apply onshore. Low ecological footprint.

4. Waste management during drilling and production operations life cycle. Capture all waste and runoff (waste management) during drilling, and completion operations (e.g., arctic platform) and no waste generated concept. Individually many of these concepts have been developed to varying degrees, the key objective is the synergistic incorporation of a number of current and emerging technologies into a single clean drilling/production system with no or very limited impact. The ultimate deliverable would be to define the best available technology and a prototype demonstration of a sustainable life cycle system to access sensitive areas for the exploration and exploitation of natural gas primarily in the lower 48 continental states and marshes of the U.S.

5. Rig Technology: A plethora of patents exist on technology associated with modular and mobile oil well drilling. Some have been utilized as proposed most seem to have aspects of past and present techniques. Though this technology assessment was not an exhaustive search, what is presented is to define the state of the art for land drilling operations. Most descriptions of modular land rig processes use methods to assemble the components on small and fewer roadable loads then easily assemble these roadable packages and elevate the modular rig platforms without use of cranes and gin pole trucks.

7. Low impact access processes: Moving equipment, supplies, and people to and from a drilling site at the right time can be logistically complex. Add the restriction that there must be no or limited impact to the environment, and complexity is magnified significantly. Protecting cryptobiotic soils in the west and southwest and inland and coastal wetlands will be challenging. However, implementing combinations of current large transport and temporary road technology could make this objective achievable.

Environmentally Friendly Systems Design

The Program is taking a systems approach to the integration of currently known but unproven or novel technology in order to develop drilling systems that will have very limited environmental impact and enable moderate to deep drilling and production operations and activity with reduced overall environmental impact. The drilling process is considered a complex activity composed of a set of processes interrelated by purpose, sequence, and time. The systems themselves are made up of sub systems. The rig and the surface equipment is a complex subsystem of the drilling process. The subsystem includes the drilling control system, drilling machine, pipe handling, blow-out-preventer (BOP) and handling system, mud supply, and mud return. Though defined for the offshore jack up design environment, many of the concepts have transitioned to the onshore rig design.

The focus of the research effort has been the drilling systems and operations, recognizing that there is a need to also consider other oil and gas systems and operations. Environmentally Friendly Exploration and Production scorecards could be developed, as a minimum, for:

- Exploration
- Drilling
- Completion
- Processing
- Refining
- Transportation
- Distribution
- Field Development
- Field Operations

An EFD scorecard for drilling systems and operations was selected as the first scorecard to be developed due to the ease at which a boundary can be established around the time and location for the systems and operations. The objective of the EFD scorecard is to have a methodology that is meaningful, simple and easy to implement and understand. Five attributes were identified as meaningful to evaluate: site (soil/sediment), water, air, biodiversity and societal issues. Each attribute could have several layers or sub-attributes. As an example, within biodiversity, the potential threat to wildlife due to proximity or timing of operations could be assessed and minimized. Drilling activities have the potential risk of temporarily interfering with wildlife. The risk can be mitigated through proper planning and monitoring of operations. The EFD scorecard has two point levels. First are the prerequisites – those items that must be done. Secondly are optional credits – those items that are considered best practices, going beyond minimum operating requirements. These concepts are described more completely in the body of the report.

Application of Membrane Filtration Technologies to Drilling Wastes

The Waste Water Management section of the EFD program funded a renewed look at dealing with the issue of waste management and re-use particularly with regards to produced water and water based drilling wastes, developing solutions that would possibly reduce the size of reserve pits needed in drilling operations and achieve significant waste volume reduction through the extraction of water from drilling wastes encouraging reuse of the extracted water in drilling operations and the concentration of suspended solids.

The EFD is investigating the use of membrane-filtration technologies in the aforementioned aim of waste volume reduction and water extraction from drilling wastes. The investigation involves processing actual drilling wastes using various membrane types and configurations in developing solutions to challenges facing membranes particularly fouling. We are investigating the ability of these membranes to effectively remove the suspended solids from waste streams and refine the waste to levels where they could be used in drilling operations or sent for further treatment such as desalination. Our aim is to develop a mobile treatment unit made of a suitable membrane system that could be deployed to drilling sites to be used as an onsite option aimed at recycle or re-use of water resources.

Texas A&M has an on-going project to look at various membrane-filtration technologies with water based oilfield wastes and coupling this with our prior development of field deployed technologies in developing a cost efficient membrane filtration system for field application. We show in this report how membranes have been used in the filtration of actual solids laden field supplied water based muds and a solids simulated laboratory water based mud, highlighting the compatibility of membrane systems with water based muds.

In light of the evolving stringent regulatory standards and in demonstrating good stewardship of the environment, the Oil and Gas industry is expected to be active in reducing the footprint of its various activities on the environment and in showing optimal use of resources. This approach to dealing with drilling wastes confers the two-fold advantage of optimal use of water resources through re-cycle and the reduction of the footprint of drilling operations well within reasonable economic costs by saving significant waste treatment, hauling and freshwater costs.

A comprehensive study based on the research program of Dr Olassaun Olatubi is described in this report.

Advanced Drilling Technology: Low Impact Rigs

This segment of the overall EFD program sought to identify systems using new technology such as light weight drilling rigs compatible with smaller well pad locations to reduce the footprint of drilling activities. A number of studies were conducted. The first study evaluated the industry's new generation of light weight rigs that require smaller well pads or could be utilized with modular platforms to reduce well site size while retaining the capability of drilling greater than 10,000 ft. The next effort was to ascertain if a modular platform design previously used in the Arctic on the North Slope could be adapted to use in coastal margins and/or desert ecosystems drilling operations. Later in the program the EFD team incorporated the technology developed within the Microhole Technology program funded by DOE and managed by Roy Long.

Two of our industry sponsors – Huisman and National Oilwell Varco (NOV) manufacture rigs and have supported our project. This report incorporates information from meetings with these sponsors, plus other companies who build and operate rigs including Helmerich & Payne, Nabors Drilling and Xtreme Coil Drilling. The evolution of rigs in the drilling industry is evident as other companies are introducing new smaller footprint rigs including Schramm, Honghua America, MD Cowen (DC Electric super single), Pioneer Drilling, IDM Quicksilver and others. These companies and others are building the next generation small, efficient rigs. The features include:

- Minimized rig-up/down time
- Compact well site footprint
- Reduced environmental impact
- Smaller crew size

- Lower transport cost
- Fast, efficient pipe handling
- Minimized accident exposure
- Smaller equipment size
- Reduced transport loads by as much as two thirds
- Smaller access road requirement,
- AC driven – Minimized hydraulics, reduced emissions
- Meet the majority of drilling conditions

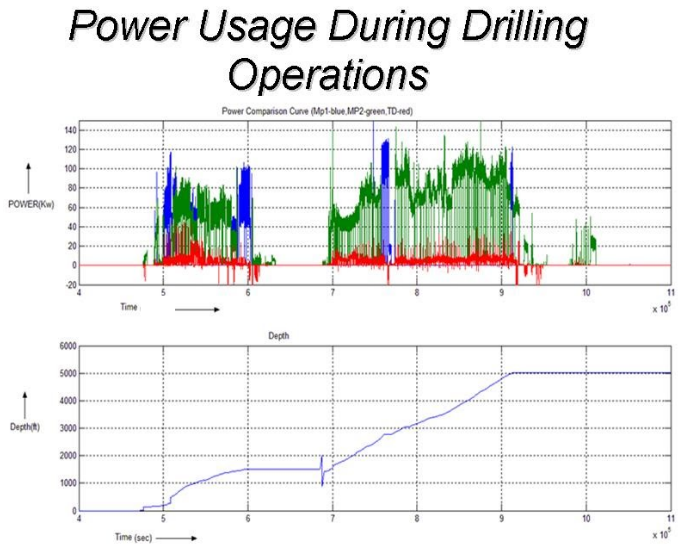
Also important is the transportability of the new types of rigs, so they can get in, drill the well and get out as fast as possible. The rigs are modular so the access roads can be smaller, with less environmental impact, and it takes fewer people to assemble the rigs. The name "super single" is associated with many of these rigs. This means that the mast is much shorter because the rigs only use a single strand of drill pipe, and thus not as visible. This also allows the rigs to be more portable. The automation design used on these rigs makes this practical and does not compromise the drilling speed. Improvements to the drilling process include AC driven power, so the rigs are much quieter. It also reduces much of the hydraulics that potentially poses a threat of leaks. Some rigs are designed to use power from the power grid when it is available; this can also reduce the noise and need for additional generators.

Other improvements include better environmentally acceptable drilling fluids and fluids handling, managed pressure and underbalanced drilling and new bit designs; all designed to improve the drilling process, making it more efficient, safer with less impact on the environment. So even with a higher day rate associated with a more modern drilling system, the well construction can cost less in many cases (per completed well) than drilling with conventional rigs. When horizontal drilling is applied, the total field development cost is less than drilling several vertical wells in the same area, especially when adding the cost of well site, associated mobilization cost of the rigs, operating costs associated with roads, infrastructure, and production facilities.

The EFD program also studied the feasibility of incorporating alternate sources of energy in drilling operations including solar, wind, fuel cell technology, and connecting to the grid. The most promising technology, grid drilling, was studied in detail and an engineering design was created for a power transmission link (up to 2 miles) to provide prime power to the rig as an alternate to diesel/generator packages.

The goal of this project is to determine the feasibility of adopting technology to reduce the size of the power generating equipment and to provide "peak loading" energy through the use of new energy generating and energy storage devices.

This project is part of a larger **Proposed GPRI/Crisman Study** to develop theoretically and empirically an energy inventory of the drilling process from a rig perspective. There are a number of current technologies that can be used to ***partially*** provide power to a rig and reduce fuel consumption and emissions. These need to be evaluated technically and economically to determine the feasibility of application to a drilling rig (e.g., diesel additives, types of fuels (gas, dual fuel system, synthetic fuels etc, wind energy, solar cells, fuel cells, power management, and gas turbine generators). Together with these technologies, new energy storage technology (specifically energy storage compatible with drilling operations) will be required



Depth and Individual Power Consumption

Milestones Met

This program has developed an environmentally friendly drilling system and in addition developed an environmental scorecard. The EFD program's Scorecard and its Systems Design were developed to determine the tradeoffs associated with implementing low impact drilling technology in environmentally sensitive areas. The scorecard assesses drilling operations and technologies with respect to air, site, water, and biodiversity issues. Low environmental impact operations reduce the environmental footprint of operations by the adoption of new methods to use in (1) getting materials to and from the rig site (site access), (2) reducing the rig site area, (3) using alternative drilling rig power management systems, and (4) adopting waste management at the rig site.

Finally the effort at technology transfer and interactions with the public has addressed an understanding of the social impacts associated with this immense unconventional energy development. Theodori used key informant interview data collected in two Barnett Shale counties to investigate the reported positive and negative outcomes of unconventional energy development, as well as the similarities and differences in perceptions between respondents from each of the study counties. He discusses practical applications and future research implications of our findings.

List of Accomplishments

2005 -2008
Accomplishments

1. Technology Assessment Reports on current practices.
2. An engineering design and mathematical model to incorporate disparate low impact technology into one optimal EFD system for developing resources
3. Integration of a modular, light weight, top drive casing drilling rig into a low impact drilling system design
4. Establishment of a waste management system at the rig site for mud pit cleanup, desalination, and for water reuse at the rig site.

5. Establishment of a program to supply alternate power for rigs
6. A survey report on the Impact of O&G Activities on Environmentally Sensitive Environments.
7. Establishment of a “Disappearing Roads” competition for engineering students across the U.S (to encourage innovative collaborative problem solving).
8. Development of public survey instruments to support introduction of new EFD programs into the community
9. Established partnership among landowners, operators, service companies and environmental organizations to review and discuss low impact technologies.
10. Development of an EFD scorecard methodology to measure tradeoffs between oil and gas activities and environmental / societal issues.

The goal of the EFD Program has been to further advance the knowledge and development of environmentally friendly oil and gas activities. The program enables a dialogue between the energy industry, environmental organizations and appropriate government agencies and legislators.
The program is dedicated to the development and integration of low-impact technology and systems for unconventional natural gas resources. To reduce the environmental footprint of operations, the program will incorporate new methods in (1) logistics (site access), (2) rig/site area, (3) alternative power options, and (4) waste management. The program is a partnership of the Houston Advanced Research Center, Texas A&M University, Sam Houston State University, University of Arkansas, the University of Colorado, West Virginia University and TerraPlatforms, L.L.C.
The program provides a comprehensive technology transfer effort that includes outreach to industry, NGO's, government officials and the general public. In addition, a scorecard system is being developed to recognize those companies who employ the most applicable technologies and systems that minimize the environmental tradeoffs of oil and gas operations in sensitive ecosystems.

Web Sites

1. Master Site: www.efdsystems.com
2. Link to A&M Low Impact Access to Well Sites: http://sites.google.com/a/pe.tamu.edu/low-impact-access/
3. Link to A&M Optimization of Surface Site Selection for O&G Operations : http://sites.google.com/a/pe.tamu.edu/optimization-models-for-surfaceplacement-of-o-g-drill-sites/
3. Link to A&M Alternate Rig Power Options: http://sites.google.com/a/pe.tamu.edu/gpri-alternate-rig-power-study/
4. Link to A&M Oil Field Brine Desalination and Mud Pit Cleanup: http://www.GPRIDesigns.com
5. Link to Systems Engineering Design of Complex Low Impact Wells: http://sites.google.com/a/pe.tamu.edu/environmentally-friendly-drilling/Home/efd-systems-engineering
6. Public Perception and Acceptance of New Technology : http://sites.google.com/a/pe.tamu.edu/environmentally-friendly-drilling/Home/public-perception-and-acceptance-of-new-technology
7. EFD Alliance http://sites.google.com/a/pe.tamu.edu/efd-alliance/

Environmental Friendly Drilling Systems

Volume 1

Background and Technical Approach

This Introduction and Overview represents Volume 1 in the compilation of work accomplished during the years 2005 through 2008.

This section represents work done as part of the Statement of Work - Task 1 Research Management Plan.

Goals and Objectives of the Project

Environmental issues are a significant part of every energy industry endeavor whether exploiting new natural gas resources in Western U.S., or extending field development in coastal areas of the U.S. creating a new, dual engineering and environmental research program. The long range goal of the program is to reduce the footprint of O&G exploration and production operations. Our specific goals have been to design a drilling system that can operate in environmentally sensitive areas with little or no impact.

Program Goals & Objectives

The long range goal of the EFD program is the integration of currently known but unproven or novel technology to develop drilling systems that will have very limited environmental impact and enable moderate to deep drilling and production operations and activity**.**

The specific objectives of the DOE Environmental Drilling Systems Project:

(1) to identify new technology that can reduce or eliminate the impact of drilling operations on environmentally sensitive areas.

(2) To design an EFD system using most promising technology

(3) To include environmental stakeholders in designs

Methodology

Large scale oil and gas production operations have been criticized as creating an undesirable footprint, especially in environmentally sensitive areas. Present day O&G operations to explore or develop oil and gas reserves are being held up in many areas based on the continuation of the historical operating practices for building drill sites. Even as the industry modifies its standard operating practices, being more aware of the environmental criteria and the associated regulations evolved, as in Alaska, access roads, well sites, and operations activity, for various oilfield operations are raised as barriers to oil and gas development.

Accordingly, if the corridors to well sites, and the well sites themselves are minimized, and the technology to accomplish this can be incorporated into emerging low impact technology currently being developed by the O&G industry, the result should be an "environmentally friendly" drilling system, one that can be used to explore for and produce oil and gas with greater acceptance by the general public and stakeholder interests

Project Organization

Project Management

The Project Manager for the EFD Program (2005-2009) was David Burnett, Director of Technology GPRI, Department of Petroleum /engineering Texas AM University. His Deputy Project Managers have been Tom Williams, formerly of Noble Technology Services and Rich Haut of the Houston Advanced Research Center (HARC). Administrative tasks were be the responsibility of Ms. Connie Conaway. The Project Manager had overall responsibility of the Project to meet deliverables stated in the SOW and to meet schedule deadlines. Project Manager's involvement in each of the major Tasks of the project is listed in a MS Project "Resource Assessment Report". An organization chart is shown in Table 1

Advisory Committee and Task Working Groups

The Advisory Committee was made up of O&G industry representatives and GPRI members who are sponsoring the project. The Chair of each Task Working group also served on the Advisory Committee as did the Department of Energy Project Manager.

Five Task Working Groups were been created. These groups or committees represented the interests of our EFD sponsors, reflecting the needs of those stakeholders with interests in preserving desert ecosystems and fragile coastal margins, and those responsible for the development of O&G natural resources. The EFD Advisory Committee (or Council) was made up of GPRI sponsors and TWG Chairs. The Organization Chart and the Task Working Groups are shown in Table 1 and Table 2.

Table 1 EFD Organization

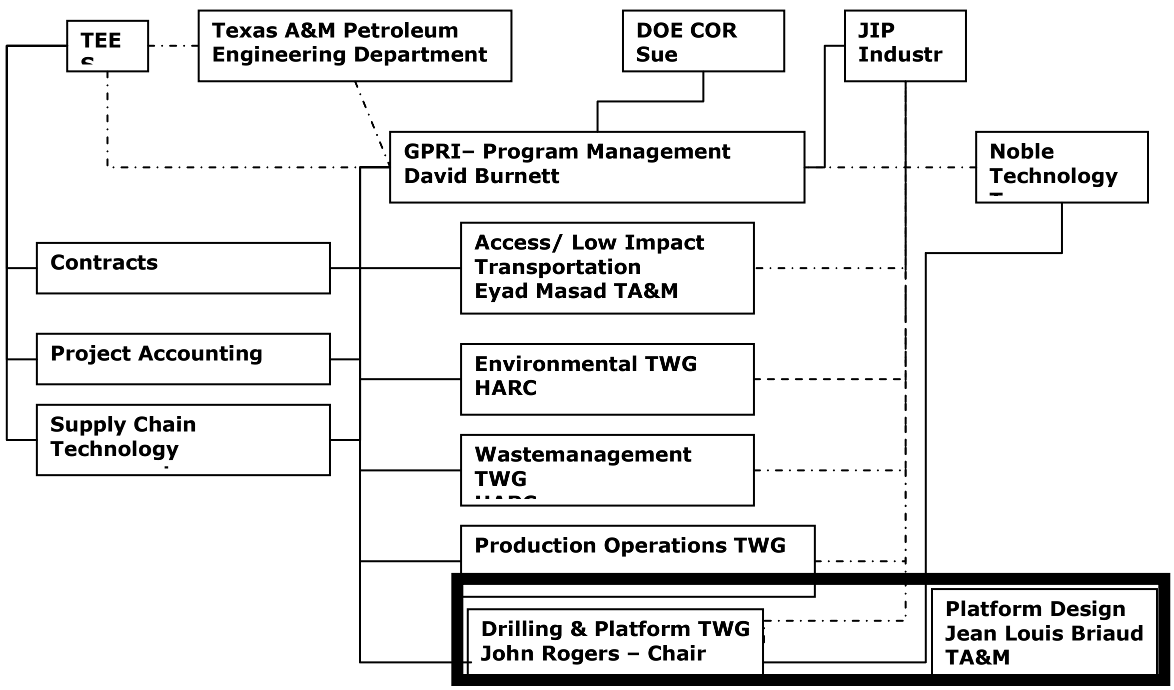


Table 2 Task Working Groups

Task Working Group	Current Members
1. Drilling/Platform TWG	Noble Technology Services*
	Anadarko Petroleum*
	Huismann
	National Oil Well Varco
	A&M Civil Eng.
	*
2. Waste Management TWG	HARC*
	BP
	Chevron
	Derrick Equipment
	Halliburton*
	MI SWACO
	PTTC

	Shell
	Statoil*
	TAMU
	s
	*
3. Access TWG	TAMU Civil Engineering*
	Halliburton
	Hovertrans
	Rolligon
	Texas Transportation Institute
	American Society of Civil Engineers (DR contest sponsor)
4. Environmental TWG	HARC*
	TAMU CESU (National Park Service)
	Padre Island National Seashore
	Nature Conservancy (invited)
	TAMU Park Recreation and Tourism Dept.
	TAMU Rangeland Ecology Management
5. Technology Acceptance & Assimilation TWG	TAMU Park Recreation and Tourism – Rural Sociology*****
	Texas Water Resources Institute
	Petroleum Technology Transfer Institute
	DOE NETL*
6. Production Operations TWG	TAMU Petroleum Engineering*****
* Denotes Industry Advisory Board Member	

Administrative Structure

Overall responsibility for the project was with Texas A&M PE - GPRI. The administrative organization, Texas Engineering Experiment Station (TEES), served as the formal contractor with the DOE, managing accounting, contracts, and intellectual (P) issues. The Top level work breakdown structure is shown in Table 3.

Project managers were chosen for two of the key areas. Mr. John Rogers of Noble Technology Services managed technical issues related to the Drilling and Platform technology development. The information describing these Task Working Groups was developed by him. Dr. Rich Haut of HARC was responsible for the Waste Management TWG and has provided the information in this review and

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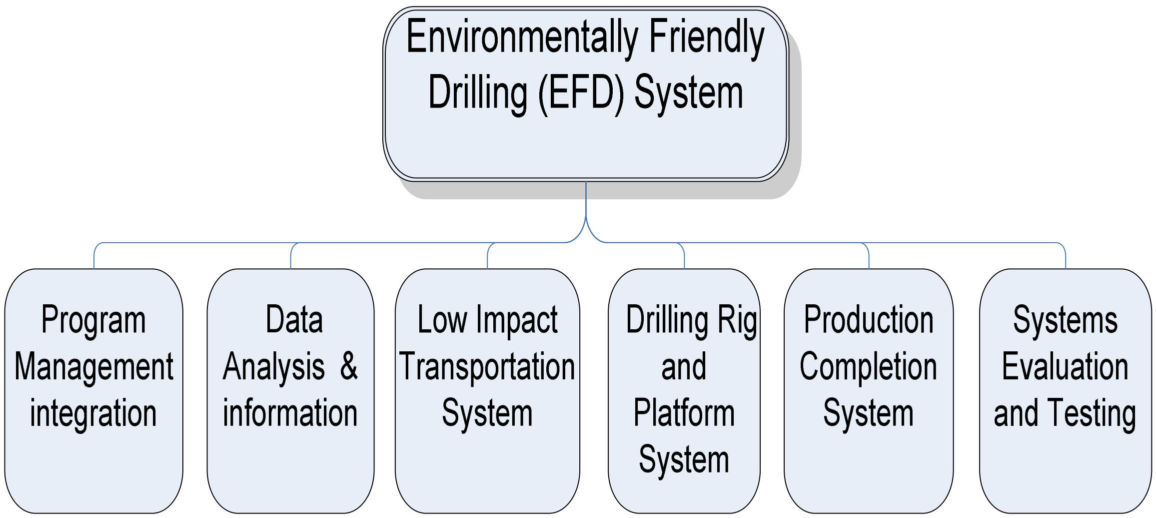
assessment relating to those concepts and practices to be incorporated into an EFD system. The Access TWG (Low Impact Transportation Systems) had several key individuals, but no Group Chair was selected. The Waste Management TWG and a Production TWG were established as separate entities early in the program.

Table 3 Top Level Work Breakdown Structure



Environmental Friendly Drilling Systems -

Industry information

Almost without exception, stakeholders from the environmental sector have said that fragmentation of the habitat is the most damaging effect of O&G drilling activities. Environmental fragmentation stems from both access roads T/F well sites, the well sites themselves, and the infrastructure developed for O&G production. These concerns are voiced both by those in the West (desert ecosystems) and those on the coastal margins.

Environmental Effects of O&G activity

Environmental issues are a significant component of every energy industry endeavor, whether developing deep water reserves in the Gulf of Mexico, exploiting new natural gas resources in Western New York, or extending field development in coastal areas of the U.S. Individually, many O&G operators and service companies are employing new ways to comply with environmental guidelines in their areas of operations. Collectively however, little has been done to identify new technology that may offer ways to reduce or eliminate the impact of operations. The Texas A&M partnership plans to identify ways to reduce the impact of O&G activity on the environment.

The EFD project focused on two types of environmentally sensitive environments, a desert ecosystem and a coastal margin. Two Task Working Groups were established to address environmental issues, the Environmental TWG and the Acceptance and Assimilation TWG. The goals of the Environmental TWG were to assess the impact of current O&G activity and to find a way to measure the effect of new low impact technology as it is developed. For guidelines, the Environmental TWG had access to the Environmental Impact Statement (EIS) for the Jonah Field in Wyoming for Rocky Mountain desert like environments and the Padre Island National Seashore Environmental Guidelines set up for that sensitive coastal area. In addition representatives of the Environmental TWG participated in the effort of the Access TWG to establish a low impact transportation system to and from rig sites.

Societal Issues Related to O&G activity

The Assimilation and Acceptance Task Working Group (AAT) was and continues to be an integral part of the EFD program. It is led by Dr. Gene Theodori an Associate Professor in Rural Sociology at Sam Houston State University. Its goals were;

1. To provide technical input related to EFD. The AAT works with citizen groups (stakeholders) to measure the societal dimensions of energy development in environmentally sensitive areas.

2. To work in cooperation with other TWGs. Community impact issues are defined and discussed and the implications incorporated into engineering program planning..

Theodori worked with citizens and community leaders in Johnson County Texas to evaluate the impact of the Barnett Shale development. He took the “lessons learned” from polling residents in North Texas to the Gulf Coast where he has assessed the importance of low impact drilling in the Padre Island National Seashore Park.

Identification of Key Technology –Primary Topics

Introduction

A systems approach was used to identify critical technology to integrate into a low impact operations. It has been clear from literature review, industry experience and stakeholder input that certain technologies are key. The five areas that were chosen to incorporate into a low impact well design are described in the following sections.

Drilling Rigs – Low Impact

A detailed review of rig technology, well construction technology has been prepared for the WMTWG by Rogers, as part of the Technology Assessment Report contained in Volume 2 of this compendium. Technology has allowed the industry to contact almost 60 times the volume of subsurface rock material that could be accessed in 1970 while occupying only one third the surface areai (Figure 1). The drilling and production process can be unobtrusive and more efficient if the state of the art technologies are used concurrently on the same well. Roger's Technology Assessment Report reviews the current state of the art of drilling technology and documents how the current surface rig technology with modern drilling methods can lower the surface impact safely and economically.

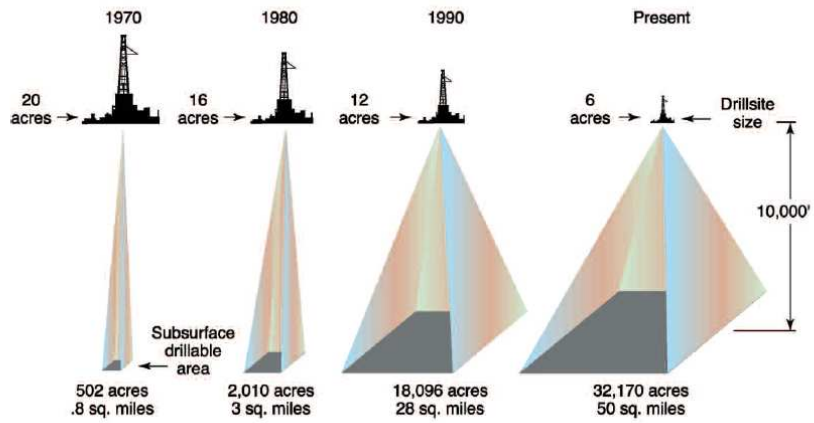


Figure 1: Shrinking the Surface Footprint -- Expanding the subsurface Contact Area (after Harrison[i])

Reducing Footprint of Well Sites- Platform Technology

In 2003, Anadarko Petroleum Corporation in conjunction with Maurer Technology and the Department of Energy (DOE), installed and operated a reusable modular platform for drilling operations on Alaska's North Slope (DOE project DE-FC26-01NT41331). Anadarko contributed the sections of the onshore platform and this technology to TAMU to employ in additional testing and demonstrations of the new technology in other environmentally sensitive areas, including coastal wetlands and fragile high desert ranges. Field application of the new platform clearly demonstrated the ability to dramatically decrease the footprint and environmental effects of drilling operations in ecologically sensitive areas. This project also showed that a system could be installed "road-less" without any adverse impact on the tundra, and that a zero-discharge facility could be operated safely. This rig concept also incorporates a number of offshore designs which have application to on-shore operations. These platforms will have the capability for drilling a number of directional wells from one surface site.

Low impact Site Access

One key objective of the EFD program is to bring environmentalists into a dialog with engineers responsible for low impact drilling system designs. Part of this involves accessing the actual drilling area, and the environmental and technical challenges associated with such access.

Preliminary meetings of the EFD team with NGO groups were conducted to define and highlight the complexity of concerns from all stakeholders. The consensus was that roads were of great concern as the biggest 'risk' to the protection of environmentally sensitive areas and especially the U.S. National Park Lands.

Conventionally, roads are constructed to access drill sites, and given that distances from the nearest paved highway can be significant, the building of a road may have many more times a rig site's impact in terms of area of disturbed landscape. Roads may vary in aerial coverage from a few to over a hundred acres, depending on the drilling site. The effects of access routes are described in detail elsewhere, but putting in a road has a multitude of impacts. For example, roads:

- Disturb natural watersheds.
- Remove vegetation coverage.
- Change the topography and soil structure
- Remove natural habitat for wildlife.
- Provide a barrier to movement and spread of plants and animals.
- Affect animal behavior.
- Provide further access to sensitive areas off the main highway.
- Pose a visual disturbance to the landscape.

After operations have been completed or suspended, the roads are frequently 'remediated'. This removal is intended to allow both the recovery of the lands to a pre-use condition so as to minimize additional access. What timeframe does it take for natural habitats to recover? Padre Islands Park personnel have remediation measures to allow roads to return to 'pre-use' conditions, but experience has shown that such efforts pose difficulty, highlighting the complexity of potential long term consequences of oil and gas operations.

Is a road really necessary- what about other forms of transport could be considered? What would be the impacts of other ways of shifting materials, equipment and personnel on and off site? What is the engineering practicality of alternative access methods than the current road approach?

Faced with the importance of reducing or eliminating access roads to a well site, the team created the idea of a "disappearing road, one that would "go away" after a period of time or even not be a road at all. From the concept came the idea of a challenge to civil engineers – to design a disappearing road.

Disappearing Roads – Nationwide Scholastic Competition

The aim of the program has been to create "Disappearing Roads" or "road less" transportation techniques for the oil and gas industry for access to oil and gas drill sites in environmentally sensitive areas. The program has three main objectives; (1) to form a nationwide scholastic competition to create the concept of "Disappearing Roads" (DR), (2) to create a research program to identify new concepts in "road less" transportation techniques usable in the oil and gas drilling operations, and (3) to compile a Handbook of Best DR Practices for O&G Operations bringing together environmental interests with engineering teams in a common effort to address low impact oil and gas operations in environmentally sensitive areas.

The DR program also creates an educational tool to teach young engineers and scientists how to incorporate sound environmental practices into engineering projects they may work on in their upcoming careers.

It is the long term goal of this Texas A&M University led program to help the oil and gas industry develop the capability reduce or eliminate well site access roads that create a major negative environmental impact in oil and gas drilling operations**.**

Waste Management

Low impact development of petroleum resources requires appropriate management of all waste streams generated over the entire life cycle of a development beginning with initial planning of projects and operations right through to decommissioning and site restoration. Quality waste management approach is crucial to achieve this goal. The principle aim of waste management is to ensure that waste does not contaminate the environment at such a rate or in such a form or quantity as to overload natural assimilative processes and cause pollution. Eliminating or minimizing waste generation is crucial, not only to reduce environmental liabilities but also operational cost.

E&P waste-management has evolved beyond the traditional drill cuttings and excess drilling fluids during drilling and work over operations. Though these comprise the vast majority of the wastes other materials include contaminated water, material and chemical packaging, emissions such as carbon dioxide, scrap metals, fuel, lubricants and other oils as well as the usual human and industrial wastes associated with E&P operations[1]. Application of computer models is new tool to help manage solids control, wastes, and liability issues from a drilling project

A detailed review of current waste management technology was prepared for the Waste Management TWG by Haut. This report is the basis of the work described in Volume 4 of this final compendium.

There are two other sources of information relating to waste management in the oil field. Argonne National Laboratories is maintaining a web site defining waste management at http://web.ead.anl.gov/dwm/ Second, the Texas Railroad

[1] Browning, K and S. Seaton: "Drilling Waste management: Case Histories Demonstrate That Effective Drilling Waste Management Can Reduce Overall Well-Construction Costs," SPE paper 96775 presented at the 2005 SPE Drilling Conference 9-12 October, Dallas, Texas

Commission information on Texas environmental compliance issues can be found at http://www.rrc.state.tx.us/divisions/og/key-programs/p2links.htm

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Environmental Friendly Drilling Systems

Report 2

EFD Technology Assessment; circa 2005

The report enclosed contains a Technology Assessment of the state of the industry circa 2005. The Assessment was prepared by Dr. John Rogers whose studies formed the basis of our work planned during the years 2005 through 2008.

This section represents work done as part of the Statement of Work - Task 2 Technology Assessment

In the last decade substantial technology has been transferred from the premium offshore drilling industry to increase the safety, efficiency, and lower the environmental impact of land drilling rigs. Substantially more technology is available to develop zero discharge on land operations and reduce the impact of land drilling rigs. Substantially more technology is available to develop zero discharge on land operations and reduce emission and location impact to the ecology both onshore and offshore.

This compilation focuses on the "State of the Art" in the E&P industry in the dawning of the age of shale gas development.

Assessments of Technologies for Environmentally Friendly Drilling Project:
Land-Based Operations

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1. Executive Summary

The petroleum industry may be well equipped to demonstrate its economic contribution and the benefits it brings to society through energy, chemicals, and other products, and through wealth generation and employment creation. However, the key challenge for the industry is how to satisfy energy demand, while safeguarding the environment. This is especially challenging in the restricted areas of the U.S. in the arid/semi-arid deserts and coastal inland wetlands of the U.S. where these ecologies are very sensitive to disruptive activity but have significant value to society.

The information contained in this report is the foundation to develop a Best Available Technology for E&P in sensitive areas within the lower 48 states of the U.S. and is part of the Environmentally Friendly Drilling Project awarded to GPRI and Noble Corporation by the U.S. Department of energy in October 2005. The concept of the project is to integrate currently known but unproven or novel technology into a drilling process or system and enable moderate to deep drilling and production operations with very limited (preferably no) environmental impact through the lifecycle of a well and field development. Technologies include

1. Transportation equipment and/or methods that are used in or developed for other sensitive areas and do not require building of conventional roads but carry heavy loads with little or no permanent damage to the soils, vegetation, or animals that inhabit the sensitive or off-limits areas. Road-less or disappearing road concept(s). Low ground pressure equipment e.g., Hover craft, rolligans. Temporary roads construction methods and materials

2. Drilling Equipment and Methodologies: new smaller modular rig designs, automation, and pipe handling equipment to reduce the environmental footprint also reduce downtime for rig moves improving the economics and safety issues. Pad Drilling using horizontal, multilateral drilling and or extended reach drilling not only for multiple completions in gas reservoirs but also for production and gathering lines and disposal systems.

3. "Zero Pad" concept and issues related to onshore platform concept low impact ecological footprint (reduced land usage). Improve drilling equipment efficiency and methodology to reduce green house gas emissions i.e., zero discharge concepts. Bring lessons learned offshore and economically apply onshore. Low ecological footprint.

4. Wastemangement during drilling and production operations life cycle. Capture all waste and runoff (wastemanagement) during drilling, and completion operations (e.g., arctic platform) and no waste generated concept.

Individually many of these concepts have been developed to varying degrees, the key objective is the synergistic incorporation of a number of current and emerging technologies into a single clean drilling/production system with no or very limited impact. The ultimate deliverable would be to define the best available technology and a "prototype" demonstration of a sustainable life cycle system to access sensitive areas for the exploration and exploitation of natural gas primarily in the lower 48 continental states and marshes of the U.S.

Rig Technology: A plethora of patents exist on technology associated with modular and mobile oil well drilling. Some have been utilized as proposed most seem to have aspects of past and present techniques. Though this technology assessment was not an exhaustive search, what is presented is to define the state of the art for land drilling operations. Most descriptions of modular land rig processes use methods to assemble the components on small and fewer roadable loads then easily assemble these roadable packages and elevate the modular rig platforms without use of cranes and gin pole trucks.

Substantial improvements in operational performance, safety, and employee productivity evolved from modular rig designs in the late 90's. Much of the newer innovative rig designs in the last decade have evolved from the necessity of reducing costs of drilling and the evolution of modular land drilling rigs. These highly mobile, automatic and semi-automatic—robotic— rigs emphasize safety of the rig workers and the environment, and reduce the number of rig workers. Innovative designs have emerged worldwide not only from U.S. suppliers of rigs but also from European and Asian manufacturers of rigs. The majority of the technology is captured in the examples discussed. Additionally, Nabors, Pioneer and a number of smaller drilling contractors are buying new builds from overseas for use in the U.S. and also use outside of the U.S.

A review of the current rig technology is presented. Mobile and modular drilling rigs have historically been the Holy Grail in the drilling industry, especially for land drilling operations. Substantial improvement in operational performance, safety, and employed productivity evolved from when modular rigs were finally accepted by the industry in 2006. The acceptance of self elevating substructures, automation, and environmental considerations took nearly 40 years when one of the first self elevating Rigs was disclosed by Lee C Moore in 1966. Helmerich and Payne initiated the acceptance by introducing its flex rigs beginning in 1996. Most land based new builds have reduced the number of people necessary on a drilling rig and substantially automated the drilling process with pipehandling equipment, iron roughnecks, digital controls from the drillers doghouse and substantially reduced the footprint.

New modular rig designs and automation has changed the job specifications of personnel and training requirements of working on a drilling rig. Activities can be monitored in real time and performance prediction can be made and workflow procedures adjusted to create more efficient operations. Maintenance personnel will be able to detect problems that affect the "health of the system" and diagnose predictive measures to schedule downtime outside of critical activities.

Many discussions in the literature have been presented and some conferences held around the theme of "the rig of the future". However little discussions have been raised as to how to power the rig or make the rig more efficient and environmentally friendly and still maintain the reliability and robustness of oversizing the prime movers yet operating them substantially below efficient design conditions. Drilling rigs are sized for peak power needs. Conventional rigs usually use internal combustion engines sufficient to mechanically drive pumps, drawworks, and rotary table directly through mechanical compounding or drive a generator and use electric motors distributed throughout the rig to drive the other drilling rig components. The latter is more prevalent in the current market though the former is still used on older rigs that have not been refurbished. New build rigs are primarily equipped with AC generating capability. Older electric rigs use(d) DC capability. AC motors have been found to be more efficient in heavy load applications and much more controllable and can provide a concept to capture wasted power through regenerative techniques.

Electrical power up to 5 MW is needed for land rigs and over 30MW for some offshore rigs. Conventional internal combustion engines (ICs) and turbines and post combustion technology such as selective catalytic reactors to reduce emissions are reviewed. Unconventional power (wind, solar, fuel cell) generation is also reviewed. These unconventional methods can supplement diesel as a power generating source especially in remote locations. Hybrid wind systems have been shown to save 18% to over 25% fuel savings and displace significant greenhouse gas emissions. Rigs however are very temporary and the power generation needs to be very portable, robust, and safe. Constructing a portable unconventional power supplement to ICs or CTs may not be technically or economically practical for drilling operations. Power recovery and management utilizing regenerative techniques along with electrical energy storage systems using modern composite flywheels, capacitor banks, or even fuel cell concepts could be useful in reducing diesel fuel consumption and resulting in reduced emissions in restricted or nonattainment areas. Types of fuels (natural gas, biofuels, synfuels and oils etc) and additives are also discussed as to effectively increase efficiency and reducing emissions as compared to mineral oil diesel. Biodiesel has lower energy content and thus uses slightly more volume of biodiesel when compared to #2 diesels. However the biodiesel does not contain sulfur and reduces sulfur oxides in the exhaust.

Turbines can deliver the same power as and IC engine in a smaller package (footprint). The electrical efficiency is not significantly better than the diesel or gas IC unless a combined heat process (CHP) is utilized. A CHP will add additional cost and design considerations and could swell the footprint but the efficiency and reduction in emissions would significantly improve.

The US EPA has generated a new regulatory program to reduce emissions from future non-road diesel engines by integrating engine and fuel controls as a system to gain the greatest emission reductions. All new engines and installations will be required to meet the new requirements and is phased in over 20 year time period that began 1996. The 1998 nonroad engine regulations are structured as a 3-tiered progression depending on horsepower rating -- each tier becoming more stringent. Engines between 49-99 hp have to comply with tier 2 regulations in 2007. Engines 100-751 hp will have to comply with Tier 3 and engines larger than 751-hp will continue at tier 2 until 2011. Engines greater than 3,000 horsepower will remain at Tier 1 until their Tier 4 requirements become effective in 2011. Additionally EPA is adopting a limit to decrease the allowable level of sulfur in non-road diesel fuel by more than 99 percent.

Zero Pad Concepts: An elevated modular mobile platform is to be demonstrated for application in the lower United States. The objective is to drill in sensitive areas without disturbing the ground surface as in conventional land drilling operations and perhaps extend the drilling cycle time in the arctic. The system consists of aluminum, or other light-weight material, modules approximately 12.5 ft wide and 50 ft long. Modules need not be in those dimensions, but should be light enough to be transported to a drilling location by aircraft, land vehicles, sleds, boats, barges, or the like. Additionally, the modules may be configured to float and to be towed on water to the drilling site.

Wastemanagement: Eliminating or minimizing waste generation is crucial not only to reduce environmental liabilities but also operational cost. Wastemanagement portion of this project is directed at reduction, reusing, recycling and recovering and disposing in that order. Drilling smaller holes where applicable reduces cuttings volume. Biotreating using vermicomposting (worms) to remediate cuttings, converting them into a compost material that is useful as a soil enhancer. This method has been suggested to be a preferred method compared to thermal treatment of the cuttings.

Thermal treatment of cuttings generally requires substantial equipment as well as energy consumption and consequently additional emissions. Costs for thermal treatment range from $75 to $150/ton. Thermal treatment are grouped into two categories – 1) incineration to destroy the hydrocarbons at very high temperatures and 2) thermal desorption in which heat is applied to the wastes to vaporize volatile components without incinerating the soil.

Cuttings injection is a waste disposal technique where drill cuttings and other oilfield wastes are slurred by being milled and sheared/mixed with water. The mixture is then disposed of in a dedicated well or through the open annulus of a previous well into a non producible formation.

Containment of stormwater or washwater can be accomplished on today's rigs by containment equipment to affect a zero discharge.

Low impact access process: Moving equipment, supplies, and people to and from a drilling site at the right time can be logistically complex. Add the restriction that there must be no or limited impact to the environment, and complexity is magnified significantly. Protecting cryptobiotic soils in the west and southwest and inland and coastal wetlands will be challenging. However, implementing combinations of current large transport and temporary road technology could make this objective achievable.

"Artificial" or temporary roads and drilling sites to minimize impact can be achieved by using a nonwoven geotextile and laying a strong but light synthetic mat such as the Durabase made by Composite Materials. This material supports heavy loads and can distribute the load more evenly. If used in conjunction with the rolligon trucks or a hovercraft the sensitive soils can be protected from compaction and erosion. Temporary bridging techniques as well as temporary roads technology developed for the military can also be used with little effect on the ecology if properly applied.

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2. Background

The primary goal of sustainable development is to make certain that the world of the future is a suitable place for us and our children. It is concerned with responsibly meeting the demands of today, without jeopardizing opportunities for the next generation. In short, sustainable development is to give back (or leave behind) more than we take.

State legislation and internal management vision have directed operators' focus toward safety and environmental protection. Worker protection legislation in most industrial nations, in particular the European Community, has set new standards based on other onshore industries.

Environmental conservation is now firmly on the public agenda in the form of government policies and strategies. It also strongly influences the private sector and business. The petroleum industry is, in general, well equipped to demonstrate its economic contribution and the benefits it brings to society through energy, chemicals, and other products, and through wealth generation and employment creation. However, the key challenge for the oil and gas industry is to satisfy energy demand while safeguarding the environment. This represents a key change in focus from simply improving a company's economic performance, to now considering environmental, health and safety issues and impacts. This change raises a number of challenges for the industry[1] including:

- Contribution of air emissions to potential global climate change
- Local impacts from operations and from using products
- Conservation of biodiversity
- Internalization of environmental costs
- Acting in a socially responsible manner
- Transparency and openness in communication and decision-making

Corporations must be prepared to demonstrate that they are governed by their declared values and principles when they address these challenges.

2.1 Value and Motivation

When comparing locations in the US of arid ecosystems (Figure 1) and natural gas deposits (Figure 2), one can deduce that most regions with delicate soils and coastal wetlands are in the same areas as significant natural gas deposits. Access to indigenous resources is essential for reaching our full supply potential. New discoveries in mature North American basins represent the largest component of the future supply outlook, including potential contributions from imports and Alaska (Figure 3).[2] The ability to protect and responsibly use these natural resources is the definition of Sustainable Development.

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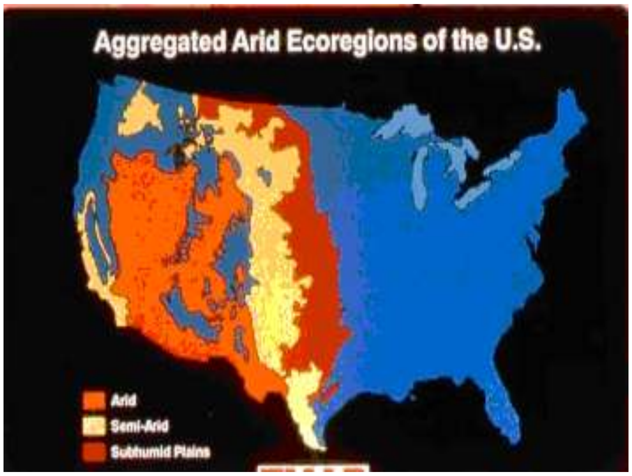

Figure 1: Arid ecosystems in the United States where crusts are found (USGS)

Figure 2: Super-Region Technical Resources (TCF) (2003 NPC Report)

Figure 3: Lower-48 Technical Resource Impacted by Access Restrictions

2.1.1 Arid and Semi-Arid Deserts

The bare soil in arid and semi-arid deserts supports a "biological crust." These soil crusts are commonly found in these same types of environments throughout the world, and are a complex, living community. Exact composition varies from place to place, but a soil crust can include algae, bacteria, lichens, mosses, fungi, liverworts, and especially, cyanobacteria—organisms formerly referred to as blue-green algae. Above-ground crust thickness can exceed 10 cm.

Cryptobiotic soil crusts play important ecological roles in the arid Southwest. Areas in the US where crusts are a prominent feature of the landscape include the Great Basin, Colorado Plateau, Sonoran Desert, and the inner Columbia Basin. Crusts are also found in agricultural areas, native prairies, and Alaska. In the cold deserts of the Colorado Plateau region (parts of Utah, Arizona, Colorado, and New Mexico), these crusts are extraordinarily well-developed, often representing over 70% of the living ground cover.[3]

Cryptobiotic crusts increase the stability of otherwise easily eroded soils, increase water infiltration in regions that receive little precipitation, and increase fertility in soils often limited in essential nutrients such as nitrogen and carbon. Soil crusts form in dry climates where other plants, grasses, shrubs, and trees may be scarce. They play a very important role in the ecosystem. Soil crusts prevent erosion by acting as a sponge to retain precious rainwater and make the soil more fertile. But soil crusts are fragile. A footstep can kill the micro-organisms and initiate erosion. Soil crusts have been damaged by cattle, hikers, or off-road vehicles. And recovery is slow.

The Mojave Desert is an arid region of southeastern California and portions of Nevada, Arizona, and Utah, occupying more than 25,000 square miles. General Patton sent troops to practice maneuvers in the Mojave Desert 60 years ago. In some places the tank tracks still look fresh, and some experts estimate that it may take 1000 years for the soil crust to recover.[4]

2.1.2 Tidal Wetlands, Marshes, and Swamps

Long regarded as wastelands, wetlands are now recognized as important features in the landscape that provide numerous beneficial services for people and for fish and wildlife. Some of these services, or functions, include protecting and improving water quality, providing fish and wildlife habitats, storing floodwaters, and maintaining surface water flow during dry periods. These beneficial services, considered valuable to societies worldwide, are the result of the inherent and unique natural characteristics of wetlands.[5]

Wetlands found in the US fall into four general categories: marshes, swamps, bogs, and fens. Marshes are wetlands dominated by soft-stemmed vegetation, while swamps contain mostly woody plants. Bogs are freshwater wetlands, often formed in old glacial lakes, characterized by spongy peat deposits, evergreen trees and shrubs, and a floor covered by a thick carpet of sphagnum moss. Fens are freshwater peat-forming wetlands covered mostly by grasses, sedges, reeds, and wildflowers.

Although wetlands are often wet, it might not be wet year-round. In fact, some of the most important wetlands are only seasonally wet. Wetlands are the link between the land and water. They are transition zones where the flow of water, the cycling of nutrients, and the energy of the sun meet to produce a unique ecosystem characterized by hydrology, soils, and vegetation—making these areas very important features of a watershed. Using a watershed-based approach to wetland protection ensures that the entire system, including land, air, and water resources, is protected.

Drilling in a marsh creates a unique set of difficulties. The land is frequently insufficient to support trucks, which prevents equipment from being driven to the site. Even if the soils can support trucks, the soils and ecology could be severely damaged. Also, water in the marsh is too shallow to allow equipment to be floated to the drill site, and the cost is too high and equipment too heavy for all necessary equipment to be transported by helicopter or other aircraft. The solution most frequently employed is to dig canals in the marsh to create water deep enough to float in drilling equipment. In addition to the other difficulties discussed below, this is a substantial expense in marsh drilling.

Probably the most significant disadvantage to the use of canals is that they provide a direct passage for saltwater to enter the marsh, with the environmentally disastrous results of destroying wildlife habitat and barriers to flooding during storms. For this reason, regulations have been passed in the US restricting canals in the remaining coastal marshes. This creates critical transportation challenges for drilling in marshes, which may preclude drilling some wells altogether.

Similar difficulties can arise in other sensitive environments such as Arctic tundra or any other location where canals or roads may prove harmful. A semi-arid desert has very delicate ecology that does not recover very quickly if damaged. Effects of disturbances in a semi-arid landscape can often be seen for years.

2.2 EFD Project – Sustainability in E&P Operations

The US Department of Energy awarded GPRI (Global Petroleum Research Institute) at Texas A&M University and Noble Drilling a financial assistance partnership to create an engineering and environmental research project. A Joint Industry Partnership (JIP) was organized to fund the cost share required by DOE and to form partnerships with industry for support, guidance, and direction for the project.

The purpose of the award is to integrate current and new technology into a field demonstrable drilling system for compatibility with ecologically sensitive, restricted access, off-limits areas (e.g., Otero Basins of New Mexico, Wetlands of Louisiana, East Texas and Mississippi Coasts, and Rocky Mountain areas etc.). The concept is to integrate currently known but unproven or novel technology into a drilling process or system to enable moderate (TVD of 10,000 to 15,000 ft) to deep (TVD of 15,000 to 20,000 ft) drilling and production operations for hydrocarbons with very limited environmental impact though the lifecycle of a well and field development. Four main subsystems and work-flow product areas have been identified for the program thus far. These may be adjusted and others incorporated as defined by the industry advisory board (participants), Project Management and DOE.

1. Transportation equipment or methods that were developed for other sensitive areas and do not require building of roads but allow carrying heavy loads with little or no permanent damage to the soils, vegetation, or animals that inhabit the sensitive or off-limits areas in the lower 48 continental states of the US. Roadless or disappearing road concept(s).

2. Drilling Equipment and Methodologies: Pad drilling using horizontal, multilateral drilling and/or extended-reach drilling not only for multiple completions in gas reservoirs, but also for production and gathering lines and disposal systems. “Zero pad” concept and issues related to onshore platform concept with low impact ecological footprint (reduced land usage). Capture all waste and runoff (waste management) during drilling and completion operations (e.g., arctic platform). Improve drilling equipment efficiency and methodology to reduce greenhouse gas emissions, i.e., zero-discharge concepts. Bring lessons learned offshore to onshore.

3. Production Completions Systems: Disposal systems subsurface or other for mitigation of fluids such as produced water. U-tube concept of trenchless production gathering systems(s). Waste management during drilling and production operations life cycle. Low ecological footprint.

4. Studies related to environmental management in E&P operations. Research on public perception of impacts from oil and gas explorations in ecologically sensitive or protected area. Ecological impacts of pre- and post-E&P operations. Review regulations and potential impact of technology demonstration on regulations and access to targeted sensitive areas.

Individually, several of these concepts have been developed to varying degrees. The key objective is synergistic incorporation of a number of current and emerging technologies into a single, clean drilling/production system with no or very limited impact. The ultimate deliverable will be to define the best available technology and a prototype demonstration of a sustainable life-cycle system to access sensitive areas for the exploration and exploitation of natural gas primarily in the lower 48 continental states and marshes of the US

About 55% of the wells drilled on US land are to depths ranging from 8,000 to 18,000 ft[6]. This project targets safe and environmentally responsible drilling and production in moderate (10,000 to 15,000 ft) to deep (15,000 to 20,000 ft) resources in ecologically sensitive areas of the US The project is targeted for the US lower 48 states but is applicable worldwide.

The bottom line is to:

1. Define the Best Available Technology (system) for sustainable drilling in specific areas
2. Demonstrate that technology is sufficiently available to economically develop oil & gas resources while protecting the environment (sustainable E&P development can be achieved)
3. Encourage sustainable access to environmentally sensitive areas that are currently off-limits or restricted for hydrocarbon development.

This assessment reviews the state of the art for drilling rigs and equipment, impact mitigation of heavy haul equipment (transportation logistics), waste management as a system during drilling, and well construction methods that impact life cycle production operations. Included in the rig assessment is a review of current unconventional methods to power drilling and production operations with fewer emissions and by using less diesel fuel through developed technologies of wind, solar, regenerative braking energy capture, fuel cell, and energy storage concepts.

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3. Rig Technology to Minimize Drilling Ecological Impact

Drilling is a complex activity composed of a set of processes interrelated by purpose, sequence, and time. In the mid 1980's, Millheim[7] defined drilling as a complex interaction of five subsystems: (1) geology; (2) drilling rig; (3) wellbore; (4) mud system (chemistry of the mud); and (5) drill string. Pedersen and Essendrop[8] defined the drilling system (Millheim's rig subsystem) as comprised of six subsystems: (1) drilling control system, (2) drilling machine, (3) pipe handling, (4) blow-out-preventer (BOP) and handling system, (5) mud supply, and (6) mud return[9]. Though these subsystems specifically described the offshore jack up environment, many of the concepts have transitioned to onshore rig design and have helped safely mitigate ecological impact in active areas.

Technology has allowed the industry to contact almost 60 times the volume of subsurface rock material that could be accessed in 1970, while occupying only one-third the surface area[10] (Figure 4). Drilling and production can be unobtrusive and more efficient if state-of-the-art technologies are used concurrently on the same well. In the following sections, current drilling technology is reviewed as well as how modern drilling methods can lower surface impact safely and economically.

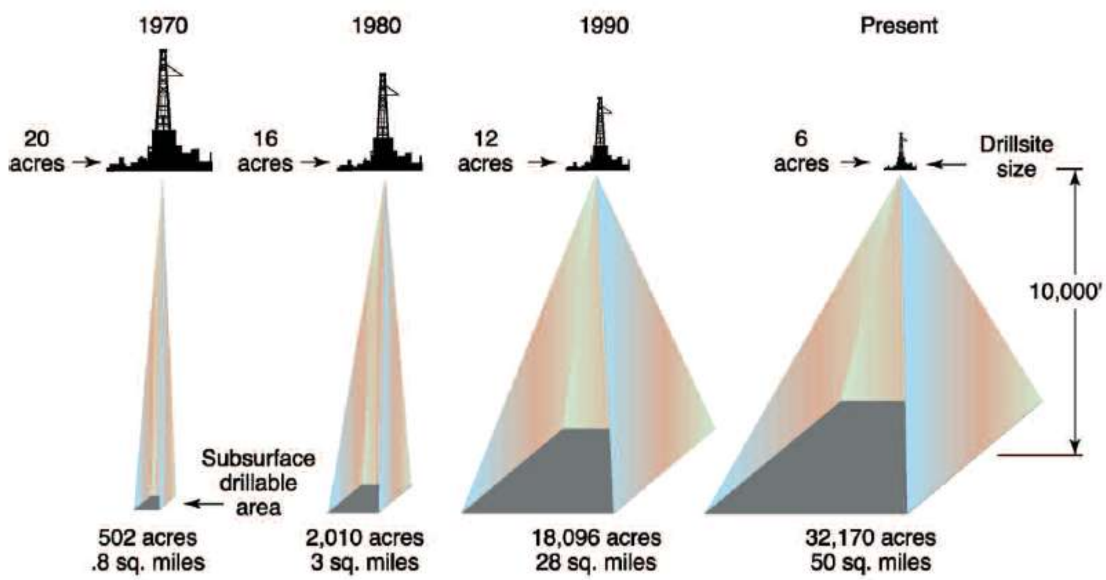

Figure 4: Shrinking the surface footprint – expanding the subsurface contact area (after Harrison[10])

3.1 Modified Conventional Rigs

The need for more compact, safer, more efficient, flexible drilling rigs for land operations has been noted for a considerable time. A semi-automatic hydraulic rig was built as far back as the mid 1960s by Hycalog Inc.[11] (developed in the late 1950s). Automation of drilling as a system was proposed in 1967 by Automatic Drilling Machine Inc. to overcome the exodus of most of the land rig qualified personnel to offshore, foreign drilling and more desirable industries with better working conditions[12]. Automation was suggested as an approach to permit an increase in the application of engineering to drilling operations through the use of computer control and to increase safety and require fewer personnel.

Successful technology developments since the late 1970s through the early 1990s focused primarily on improvements to increase ROP, improve performance of downhole tools; reduce hole/casing size drilling programs, and lower the cost of drilling. Most (if not all) of these technologies could be handled by existing rigs[13]. Actual efficiency and effectiveness of the overall well construction process integrating the surface equipment required to drill and construct a well were not typically addressed or emphasized.

Offshore environmental and safety requirements spurred the offshore drilling industry to develop substantial technology that evolved into more automated, efficient, and safe operations and showed economic benefits to both operators and contractors. Though there has been a trend toward larger drilling rigs offshore to work in deeper water depths, there is also a trend to reduce weight, evolve more efficient operations, and use smaller rigs where possible. One significant offshore evolution was the development of the ultra-deepwater rig with dual rotaries to reduce costs – the Discoverer Enterprise developed by Transocean under contract from Amoco in the late 1990s[14]. Another concept was to use aluminum risers to extend depth capacity of existing rigs and platforms. This has increased efficiency significantly.

In the last decade substantial technology has been transferred from the premium offshore drilling industry to increase safety, efficiency, and lower environmental impact of land drilling rigs. Substantially more technology can be applied to develop zero-discharge systems and to reduce emission and reduce the impact to the ecology in both onshore and offshore operations.

Much of the newest innovative rig designs in the last decade have evolved from the necessity of reducing costs of drilling and the evolution of modular land drilling rigs and adapting technology previously used in premium drilling arenas. These highly mobile, automatic and semi-automatic (robotic) rigs emphasize safety of the rig workers and the environment, and reduce the number of rig workers. Innovative designs have emerged worldwide not only from US suppliers of rigs but also from European and Asian rig manufacturers.

Early North Slope drilling rigs were designed around a wheeled substructure/mast module and skid rail mounted support module. As hydraulic technology matured, subsequent designs were based on one or two large modules as a "unitized rig"[15].

The industry realized in the last decade that development of "marginal" fields is not cost-effective with large, cumbersome rigs of 1950s vintage. This was obvious to the operators of the Alaskan North Slope fields where the "Prudhoe Bay" style rigs would not be sustainable in the smaller fields [15]. Operators realized that the rigs had to be smaller, lighter, safer, and capable of constructing wells cheaper than what conventional drilling rigs can deliver. This is not only true in the once premium fields of Alaska, but is even more evident in the continental US

In 1997, BP Milne Point Management initiated an internal study and design effort to research concepts, and propose a design that could deliver a step-change in cost savings for drilling smaller field in the Alaska province. Several design tenets were set to steer the effort[15]:

- Safety and Environment – using automation and other means, the rig had to provide a safer and cleaner work environment
- Deliver significant Cost Savings
- Weight and Mobility – to facilitate rig moves across thawed gravel roads, narrow bridges, and frozen tundra, the rig had to be light and extremely mobile
- Compact Layout – due to financial and environmental costs of gravel pads, the rig had to work on narrow (<15 ft) well centers and have a very small foot print

After conceptual and engineering design phases, a light, automated drilling design was proposed and constructed. Major features of the design were

- Caterpillar Mobile Tracs for ease of mobility. These were heavy-duty rubber tracks developed for use in Antarctica by NSF. The track system distributes the 60,000-lb gross vehicle weight to 10 psi at full load.
- Hydraulic driven drawworks, top drive, and mud pumps
- Automated pipe handling with horizontal setback. Horizontal set back allowed substantial lightening of the substructure and mast.
- 1,000,000 lb hook load capability
- Three light, compact, 1500 hp, quintuplex pumps with radial piston hydraulic motors
- Stainless steel mud tanks with rounded corners fully enclosed
- Triple-option power supply for diesel, highline, or diesel/highline combination
- Automation and control system based on programmable logic control
- Two 2500 hp diesel engines
- Modular layout – the rig is laid out in six modules
  - Drill Module – composed of substructure, mast, drilling equipment, and corresponding trailer. Mounted on 160 pneumatic tires with hydraulic steering system.
  - Solids Control Module – contains all solids control equipment and six open top, stainless steel mud tanks
  - BHA Module – parked beside the drill module trailer, used for storing, making up, and working on BHAs
  - Power Module – houses generator sets, hydraulic power unit (HPU), and upper level electrical control room
  - Pump Module – contains three mud pumps, mixing hoppers, cement mixer, pallet storage
  - Volume Tank Module – houses six closed top stainless steel tanks, and centrifugal charge pumps

3.1.1 Mobile Drilling Rigs

Conventional 1950s-vintage drilling rigs (many modified versions are still being deployed in 2006) are moved after laying down the pipe (which can require eight hours or more) by removing all floor equipment (tongs, valves, rotary chains, hand rails etc), dissembling working and setback floors, laying the derrick over with the drawworks, unstringing the drawworks, removing the drawworks, motors, compounds, removing rotary tables, substructure supports, and unpinning the derrick (not necessarily in that order). Additionally, all substructure beams and supports that are pinned to form various box-like "pony" steel structure supports, are unpinned with sledgehammers with considerable labor. Pumps are disconnected from the standpipe, compound drive sheaves (usually V-belts), mud charge pumps, and mud tanks (pits). Prior to this the pits must be cleaned and fluids pumped into large reserve pits. All solids and gas handling equipment near the pits, including surge tank and gas separator, well flowline, shale shaker, desander, desilter, centrifuge, mud mixing station etc., had to be disabled and removed. All dog houses, generators etc. had to be unhooked and readied for moving.

Obviously, moving a conventional rig is a substantial task. It is laborious, time consuming, dangerous, and costly. Additionally, large trucks with ramps were required to attain the elevation to remove the floor equipment etc. In the late 1970s cranes and forklifts were employed to accomplish rig up and rig down, which added speed and safety but also additional cost. A typical move required a number of very heavy truckloads—as many as 40 in some cases. A move could take as long as a week and possibly more, especially in harsh weather environments.

Mobile and modular drilling rigs have historically been the Holy Grail in the drilling industry, especially for land drilling operations. Trailer mounted cable tool and rotary rigs (both pole and telescoping derricks) were and are used but have primarily been limited to shallow targets. The evolution of larger, deeper modular concepts can be traced back to the first jackknife rig replacing the old standard type rigs that took days to build just the derrick.

Historically, risky techniques and methods were employed by rig tool pushers and rig supervisors to reduce RU/RD time as much as possible. In West Texas and Eastern New Mexico in the 1970s, small doubles were moved with a winch truck at each corner that elevated the substructure approximately one foot and moved to another location a short distance away with the derrick standing (no motors on the floor). At that time, leaving a mast standing and "skidding the rig" was not considered good practice; but, a short move, spud, and surface pipe set could be completed in less than 36 hours.

Land drillers started designing and building modular, highly mobile drilling rigs to move deeper rated drilling rigs in the late 1990s.[16] Santa Fe International, a former Dallas-based company, used a variety of rig designs to achieve extraordinary gains in drilling efficiency both on- and offshore in 1998. In harsh desert and geology in Kuwait, Santa Fe integrated desert drilling rig moving systems to increase efficiency on rigs rated for 10,000 to 30,000 ft.

- Integral-wheel complex designed by Dreco Energy Services Inc. was first used in Kuwait in about 1991. Rigs were moved with masts standing. Three six wheel drive trucks were used with the 30 ft substructure supported by four sets of dual tires 36–40 inches wide and 8–10 ft tall. The independent steering mechanism allowed sharp turns and positioning. Power was supplied using a hydraulic power unit for steering.
- A skid-beam system was used to pin the substructure to the integral-wheel complex and then jack the rig up with derrick still standing. The skid-beam system saved 4–5 days in moving.
- Telescoping derrick and hydraulic cylinders were used to scope the upper section of the mast down into the base and lay the derrick down on a trailer.

Historical Patents Associated with Mobile Modular Drilling Rig Designs

Modular rig concepts have been used in the offshore drilling industry for a considerable time. Offshore, a modular rig may be used either as a second platform rig, or to replace existing platform derrick equipment sets on mature fields with limited drilling programs. These same concepts and technology continue to be transferred to the onshore drilling community.

Historically, the drawworks, rotary table floor, and setback floor have the same relative elevation. As wells became deeper and masts and substructures of rigs became taller, reassembling the engine supports and placement of the engines, drawworks, and setback floor become more dangerous and expensive, requiring very steep and costly truck ramps or cranes.

A plethora of patents exist on technology associated with modular and mobile oil well drilling. Some have been utilized as proposed. Most seem to combine aspects of both past and present techniques. Described below, though not an exhaustive search, is a definition of the state of the art for land drilling operations. A few patents are described of modular land rig processes as a whole and not individual parts or how to elevate modular rig platforms without the use of cranes and gin pole trucks. There are many similarities in the concepts from these patents and the current state of the art. It is also worth noting that integration of the concepts of modular mobile drilling rigs into the industry took nearly 30 years (e.g., 1966 to the mid 1990s) and nearly 40 years (2006) to receive acceptance and value by the industry.

Patent 3,228,151 – Lee C More Assembly of Rig at Ground Level (1966)

Lee C. More Company through Woolslayer and Jenkins disclosed in US patent 3,228,151 a drilling apparatus for deep oil wells to assemble the substructure and mast near ground level (see Figure 5). The drawworks, power units, and rotary table are mounted on the substructure before it is raised, and the

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required flooring is laid on the substructure and in the mast before erection. Consequently none of these tasks need to be done after the floor erection when it is much more difficult, dangerous, and costly. Ramps are unnecessary and the derrick is pivoted to the substructure. As the mast is raised it may carry with it to the top of the substructure a built-in floor that will overlie the substructure and is shaped to straddle the rotary table and register with floor section. No gin pole is necessary for raising the mast. All power to raise the substructure first may come from the drawworks, screw jacks, or hydraulic rams or other means. The mast is raised once the drawworks and floor are raised and secured. The mast may also be raised by the power of the drawworks, hydraulics, or other means.

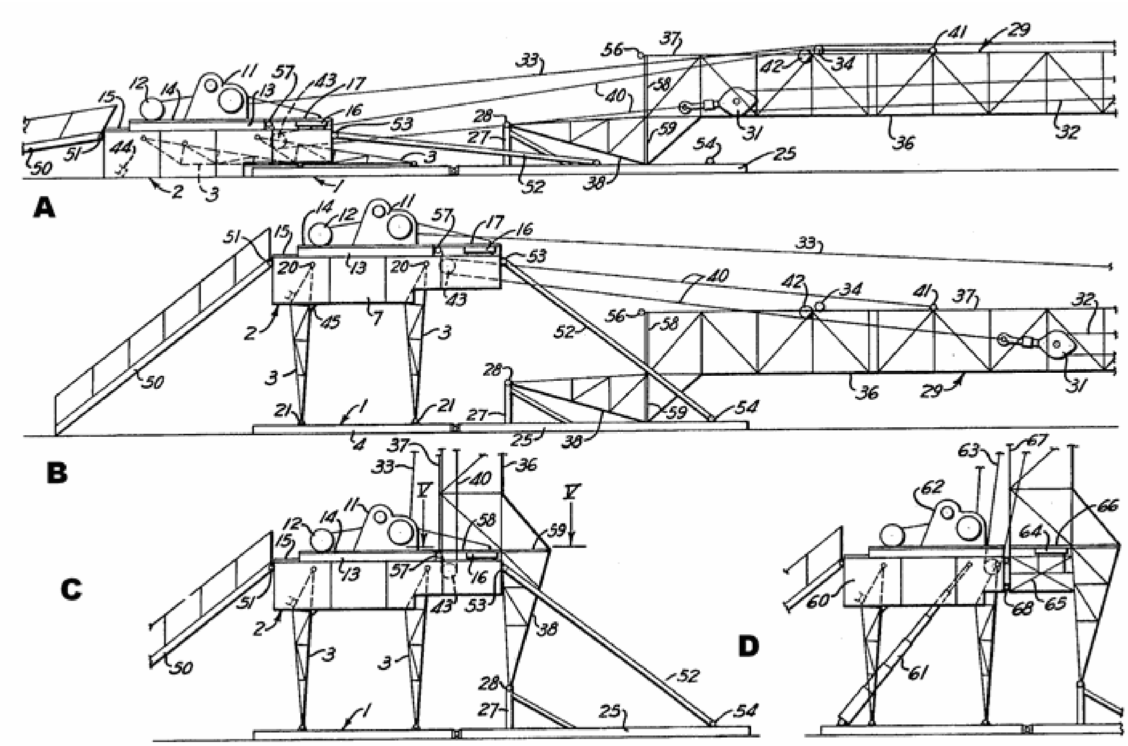

Figure 5: Lee C. Moore Company Patent 3,228,151 illustrating scissor-type elevating concept. Similar to current concepts

Patent 3,483,933 – Pivoting Mast and Floor from Low Profile (1969)

Patent 3,483,933 issued to Dyer et al. and assigned to Dresser Industries in 1969 disclosed the concept of pivoting the mast from a low profile base (low to the ground) and elevating the mast to the vertical using a gin pole with the drawworks at or near ground level. A catworks unit (a lighter component) was then winched in place on the elevated floor and the set back floor pivoted into place (see Figure 6).

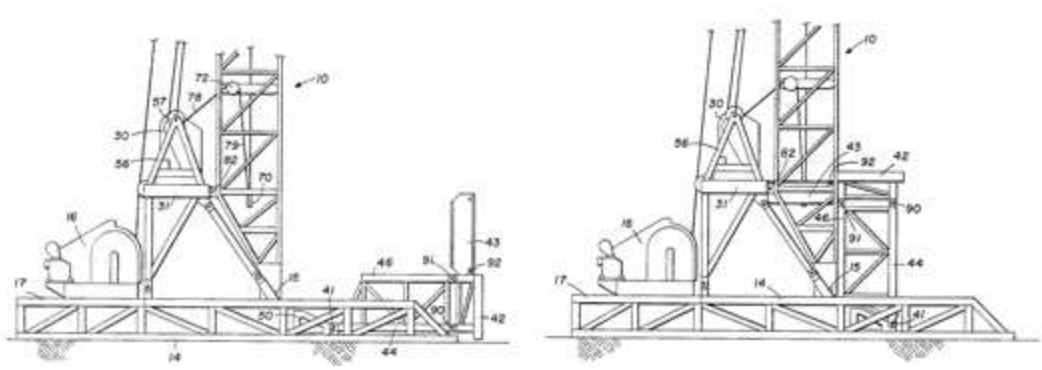

Figure 6: Patent 3,483,833 illustrating drawworks at lower elevation than work floor

Patent 3,803,780 – Folding Pole for High Floor Mast (1974)

Donally illustrated a method assigned to Lee C. Moore Company for assembling the mast at low elevation and with specially designed and disclosed gin pole or "A" frame, erect the mast and provide an oil well derrick substructure in which a hinged mast is provided with a high working floor. Once the derrick is in the vertical position, the drawworks, which is mounted on a support at a low level during the raising of the mast, is elevated to a position behind the working floor with the rig blocks and pinned in place. The lower potion of the mast is below the working floor.

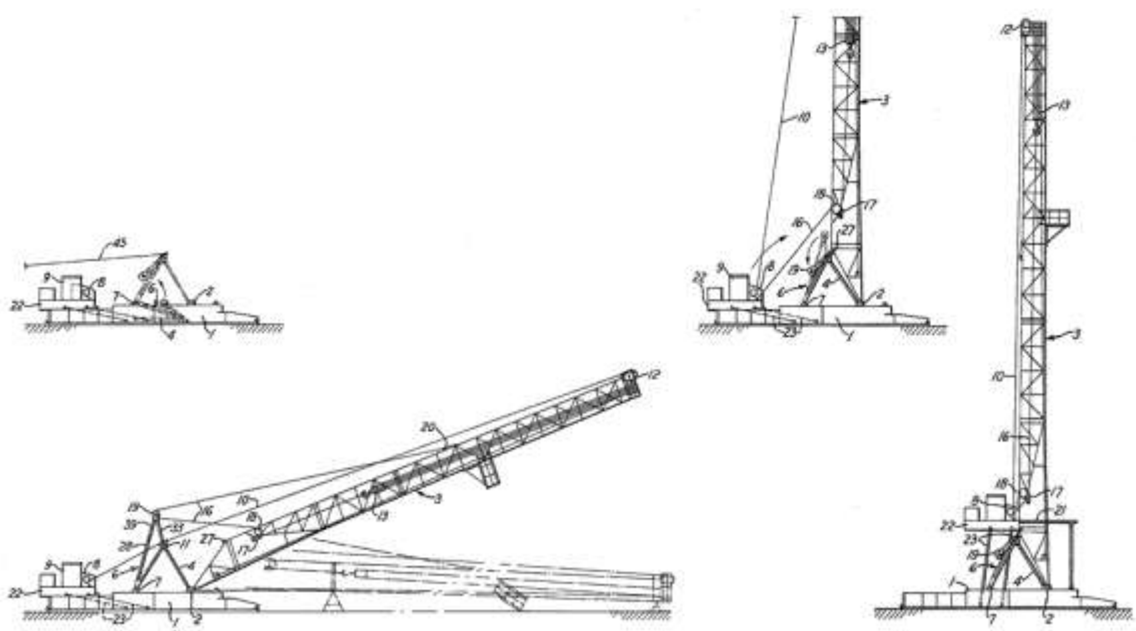

Figure 7: Lee C. Moore/Donnally Patent 3803780 Folding Pole for High Floor Mast

Patent 4,024,924 – Drilling Rig with Independent Table Structure and Patent 4,009,544 – Drilling Rig with Improved Mast Support Structure (1977)

Parker Drilling Company disclosed through Houck (inventor) a rig where a working floor can be assembled at a lower (ground height) and then raised to the required height either before or after the mast is raised vertically (a scissor action) by a system of cables and sheaves. The mast is assembled low to the ground and attached to a base plate on the ground and not as an integral part of working floor where the substructure typically supports the floor and the derrick.

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Patent 4,135,340 – Modular Drill Rig Erection System (1979)

This particular system elevates the floors and mast using a "strong back" or "A" frame and gin pole concepts with a series of sheaves, cables and single horizontal hydraulic cylinders or linkages (Figure 8). The concept is to assemble the drawworks, derrick, and floors at ground level and raise them to an elevated position using a "sling shot" concept. Once the floor and drawworks platform are in an elevated position, the derrick "A" frame or gin pole is assembled and the derrick raised using the drawworks. The derrick is then pinned in place to the "A" frame. The concept appears to be self contained without the need for cranes and truck setup ramps etc.

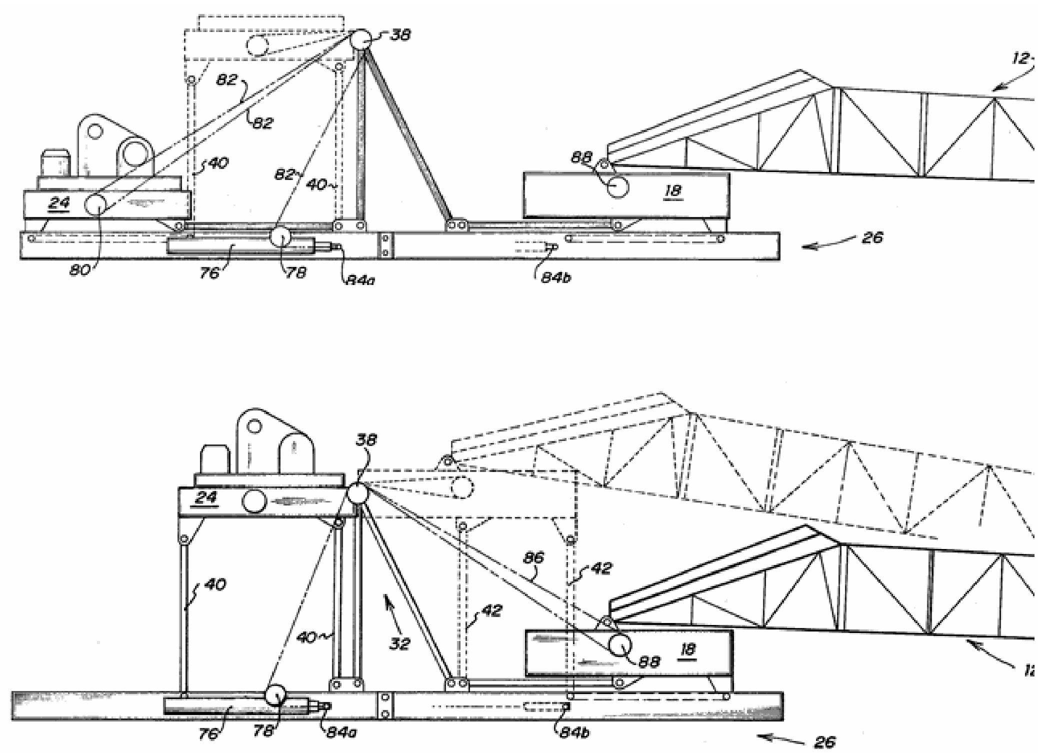

Figure 8: Patent 4,135,340 Modular Drill Rig Erection System (1979)

Patent 4,375,241 – Drilling Installation for Oil Drilling Operations (1983)

Gallon disclosed a method to install all equipment on a platform at ground level and raise the drawworks, engines, derrick etc. to a suitable elevation using uprights and a suitable system, such as a rack-and-pinion device (not shown in the patent). The pinions on the platform are driven by a reduction unit and mesh with a rack on the uprights. When it has been raised to the high position, the platform may be wedged to the uprights, and further held in position by means of struts suitably installed between the base and platform. Opposite ends of the uprights are contained in a suitably designed base to provide sufficient structural support and rigidity.

Patent 4,899,832 – Modular Well Drilling Apparatus and Methods (1990)

This patent proposes to reduce erection time by having compact modular components mounted on trailers or skids for easy rig set-up rig and is fully automated and self-monitoring. The drilling unit provides a rigid frame support for the crown sheaves, top drive drilling system, mechanical pipe handler, power, slips, master bushing, automatic tensioner, hydraulic locks and monkey arm and is transported to the well site on a trailer pulled by a truck tractor. The unit uses typical pipe handling and top drive components commercially available from other vendors (e.g., Varco, BJ etc). Pipe handling is unusual though not novel in that it places the entire drill pipe inventory vertical (Figure 9). This is similar to the DrillMec hydraulic rig construction concept though the patent does not stipulate the type of power used.

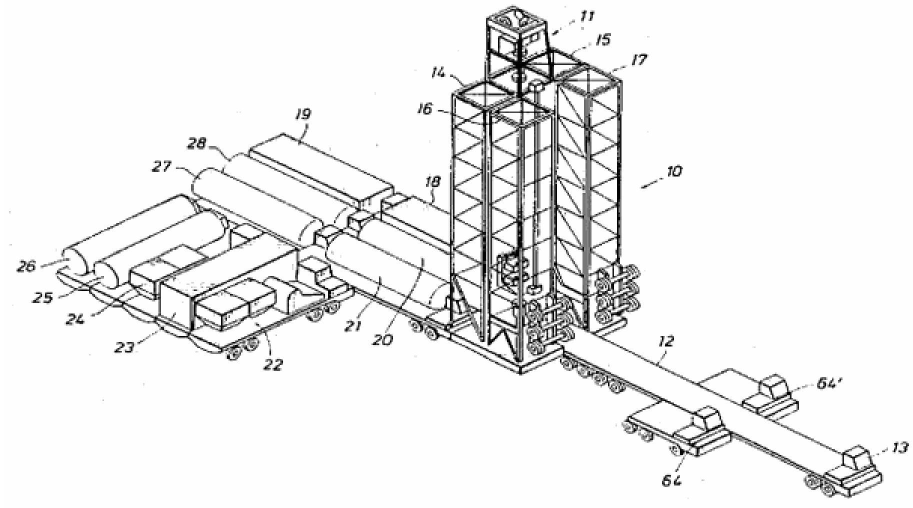

Figure 9: Patent 4,899,832

Patent 6,634,436 – Modular Well Drilling Apparatus and Methods (2003)

This patent is assigned to National Oilwell and appears to be the patent behind the Ideal commercial rigs described below. Their objective was to develop a mobile land rig that was self sufficient and capable of being transported, erected, and disassembled without auxiliary equipment. Thus, cranes and large gin-pole trucks would not be needed. The substructure is self elevating (telescoping) and has structural integrity to withstand winds and forces incumbent on the mast structure. (See Ideal Rig below.)

Patent 6,848,515 – Modular Drilling Rig Substructure (2005)

Assigned to Helmerich & Payne, this patent is a self-elevating substructure using hydraulics. The process allows transportation of the substructure without entirely dismantling it. It describes the modular drilling rig substructure that may be transported to and from a rig site with various drill floor equipment and hand rails remaining in place. The substructure is built to minimize liquid discharge during operations by providing an integrated containment and drainage system. This containment system does not have to be removed or dismantled during the move.

Patent Application 20040211598 – Fast Moving Drilling Rig (2004)

This patent application is published for National Oilwell and seems to be the disclosure behind the Rapid commercial rigs described below. The concept is to transport and assemble a drilling rig using specialized positioning pads integral to the side boxes of the drilling rig to facilitate the connection of the center drill floor of the drilling rig to the side boxes of the rig. Additionally a specialized positioning dolly and an adjustable fifth-wheel truck connection for transporting the mast to the drill site, assembling the mast sections together, and positioning the mast for connection to the drill floor of the rig are incorporated. The result is a unique drilling rig design and sequence for assembly that significantly reduces time required to transport the rig from location to location and to assemble the rig at the drill site (see Rapid Rig description below).

Patent 5,109,934 – Mobile Drilling Rig for Closely Spaced Well Centers (1992)

Sensitive environmental issues are a concern at Arctic locations such as the North Slope of Alaska. It is critical that wells and mobile equipment be installed and operated to minimize any danger or risk to the environment. Nabors industry was assigned patent 5,109,934 issued to Mochizuki in 1992 for a modular drilling apparatus having three units, each of which are fully enclosed, transportable and positionable for workover and completion of wells on 30-ft well centers without interfering with the operation of adjacent wells. Primarily for use in the Arctic environment, the equipment must be protected and includes the drilling rig itself, the mud equipment, and pipe storage and handling equipment. The first end of the drilling unit is positioned over a well with its central axis diagonal to the centerline of the wells and at a right angle to the pipe handler in the pipe shelter unit, the vertex of the right angle being at the well center. The mud unit is set back from the centerline of the wells, and is functionally connected to the second end of the drilling unit. The width of the drilling unit is greater than 50% of the clearance between adjacent well houses on each side of the well.

Patent 6,161,358 – Modular Mobile Drilling System (2000)

Mochizuki et al. in US patent 6,161,358 describe a modular mobile drilling system and method of use for land-based drilling operations on remote sites. Fixed support boxes are used in first and second rows and define a drilling zone. Platform support beams disposed from the first row to the second row support a platform for holding drilling equipment. An actuator associated with the platform and beams skids the support beams relative to the boxes to align the platform with predetermined positions in the drilling zone, allowing the drilling of multiple wells along the length of the support box rows. The drilling equipment can also skid laterally across the drilling platform to support drilling of multiple rows of wells in the drilling zone. The drilling platform is supported by some but not all of the support boxes, enabling modular transportation by helicopter of support boxes to a new remote drilling site, disassembly of the drilling platform at the existing site, reassembly of the drilling platform on the transported boxes at the new site, and then transportation of remaining boxes from the existing site to the new site to support new drilling operations. The box-on-box substructure and skiddable drilling platform enhance transportability by helicopter and assembly with minimal footprint and reduced assembly steps.

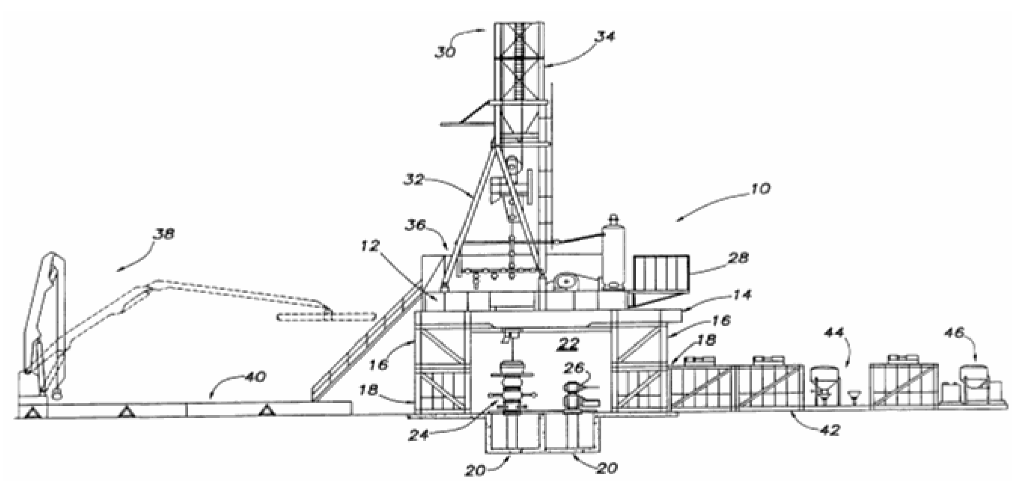

Figure 10: Modular rig concept Patent 6,161,358 (2000)

Paradigm Changes

H&P Flex Rigs

Substantial improvements in operational performance, safety and employee productivity evolved from modular rig designs in the late 1990s. In 1997 and 1998 Helmerich & Payne International Drilling Co. (H&P) built six new onshore rigs based on modular designs to do away with repetitive and labor-intensive work associated with onshore drilling operations[17]. These rigs allow rig personnel to concentrate on drilling activities and not labor activities that do not add value. They also incorporated top drives, a technology primarily used on offshore rigs up to now. In 2000/2001 H&P constructed 12 additional Flex rigs with additional technical modifications and improvements. In 2002 H&P initiated a new-build program of 32 Flex3 rigs[6].

By using critical path analysis techniques to evaluate labor drilling activities, H&P designed drilling rigs to eliminate non-value-adding activities during drilling and reduce flat time. The concepts and rig layouts were incorporated into IRI International Corporation's 1500 class rigs.

By rearranging the rig layout–i.e., SCR (silicon controlled rectifier) house, engines, water tank, and fuel tank to the mud-pit side (or "backyard") allows for easier access to the drawworks and subsequently the substructure and derrick can be moved more quickly and safely. A telescoping substructure eliminates the need for cranes and gin trucks to rig down and up. Eight inch clamps, located about five feet above the ground, are removed from the four substructure legs and hydraulic pistons in the legs are actuated and the substructure can be lowered or raised accordingly (Figure 11). The substructure splits in the middle for mobilization. The driller dog house is raised hydraulically on a parallelogram structure (Figure 12).

Figure 11: Flex Rig substructure support during instillation

Figure 12: Flex Rig Drillers Substructure Panal

Additionally, three advanced pipe movement and drilling control technologies were incorporated for safer and more-efficient control of the block during drilling, tripping, running casing, geosteering, and other drillstring movement activities. Integration of the brake system, block control system (BCS), and autodriller (AD) into the IRI 1500 series of rigs reduced the average rotating hours per well by 37% and reduced bits per well by 34%[18].

The mud system uses enclosed cylindrical skid-mounted, round-bottom tanks and electric mixers that eliminate "dead spots" in the drilling fluid. The substructure is designed to contain 100% of the drill-floor runoff which is collected at a containment point. This reduces labor required to constantly clean the rig and any impact to the environment due to that activity. An oil and lubrication system is incorporated to eliminate the need for motor oil and antifreeze and other motor fluid and lubricants to be hauled in buckets. This reduces the chance of contamination and accidental mixing, and allows better inventory control. Initially, the 1500 hp drawworks rig is complemented by a Varco hydraulic Kelly spinner, a Varco SSW-30 hydraulic pipe spinner, a crown-a-matic and hydraulic hoists replaced the air hoists and are man-rider certified. The foot print of the H&P/IRI 1500 series rig is 160 x 225 ft (36,200 ft^2) and enables rig up on small, environmentally sensitive locations.

The highly mobile rigs that H&P purchased in 1994 encouraged the company to subsequently continue modifications toward what it has called "Flex rigs" which primarily have the "flexibility" to drill economically over a rating of 8,000 to 18,000 feet, have high mobility during moves, large mud pumps, and create added value to the drilling process. FlexRigs move an average of 30 miles between wells in 2.5 days. Their mobility yields shorter well cycle times, greater productivity and more wells per year. An integrated drainage system and lubrication system protects the environment. More recent Flex Rigs can rig up in 24 hours compared to nearly four days or longer to move for a similar depth rig[19].

Figure 13: Flex Rig Lubrication Center

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Figure 14: Flex Rig Floor Run off Containment

Figure 15: Flex Rig Cylindrical Round Bottom Tanks

Figure 16: Flex Rig Drillers Control Unit

National Oilwell IDEAL and Rapid Rig

National Oilwell bought IRI International in March 2000, which redefined National Oilwell as a significant drilling rig design and equipment manufacturer onshore as well as offshore. Prior to the merger, National Oilwell focused more on offshore drilling, while IRI concentrated on land drilling.

National Oilwell IRI Designs

Pioneer Drilling Co. mobilized two IRI 1700E series rigs built by National Oilwell in August of 2001. Rated for 18,000 ft, the 1700 hp rig has a number of improvements to make it one of the most efficient rigs at that time[20]. The rig features AC drawworks and regenerative braking through the AC motor eliminating the need for an auxiliary brake enabling smaller footprint and less weight. AC drawwork rigs require fewer engines and thereby reduce maintenance requirements, increase fuel economy, and lower operating costs. National Oilwell's IRI mobile drilling rig design has been supplied to most of the recent new builds in the industry. The derrick and substructure have telescoping designs to increase modularity and ease of rig up thus reducing the number of loads required to move the rig.

The substructure has cylindrical legs, which telescope from 11 ft 4 inches to 22 feet, and is rated for 1,135,000 lb load capacity and can be moved in two loads compared to four to six loads for conventional substructures. The substructure is pinned together at ground level and raised to working position by hydraulic cylinders within the substructure legs. Diagonal supports are installed after raising the substructure.

The derrick is a 136-ft telescoping mast that is moved in one load, compared to three or four loads for conventional derricks. The derrick is telescoped to full height and pined prior to being raised. The mast is raised and positioned using two large hydraulic rams.

The mud system uses three Brandt LPC-40 shale shakers, developed for the North Sea, to provide high solids-control efficiency, and reduce drilling fluid, pump, and bit costs. The shale shakers sit on a skid that has a cantilever rig-up system eliminating the need for a crane (Figure 17). Mud pits are rectangular and have rounded bottoms to eliminate corners and sides that create dead spaces in conventional tanks.

Figure 17: National IRI Shaker System

Figure 18: National IRI Mobile rig

The driller occupies a single-seat, climate-controlled cabin near the rig floor where he controls the drawworks, rotary table, mud pumps, and rig power plants, using touch-screen computer controls and a joystick. The system employs programmable logic circuits and fiber optic cabling, to provide control to the rig as well as real-time data for analysis, rending, processing, and graphical display.

The IRI rig requires a smaller well location than conventional rigs with the capability. The rig can be moved in 20 loads, compared to 30 loads for a more conventional rig and requires no crane to rig up or rig down.

IDEAL Rig

In May 2004, National Oilwell announced its new 1,500-hp Ideal rig drilling system designed for the North American land rig market. The rigs were initially marketed with the option to add a BOP, top drive, and drill pipe. Conventional SCR rigs are capable of drilling to 18,000 ft and feature disc brakes, large mud pumps, advanced solids handling equipment, zero-discharge systems, and modern drilling controls. The footprint of the Ideal rig is 129 by 306 ft (39,474 ft^2 or 0.9 acres not including reserve pit).

The rigs can be moved in 27 loads, and assembly is intuitive and simpler than older conventional rigs and does not require a crane for Rig Module or Mud System Assembly. Additional features are:

- Traveling block, rotary table, and optional top drive remain mounted in mast and substructure during transportation and assembly
- Modular mud system reduces transportation time and rig up/down time
- Remotely controlled hydraulic raising system requires no generators and keeps operator at a safe distance
- Innovative pinning system (patent pending) makes structural connections safe and easy
- Drawworks is remotely controlled including KEMS (kinetic energy monitoring system) and block control features, and is mounted at ground level to maximize usable drill floor space
- Drawworks disk brake system provides maximum control with quiet operation
- Electrical system benefits from deployable booms to minimize connections to make easier hook-up and longer service life
- Industry-proven, advanced diesel power systems maximizes efficiency, performance, and reliability
- Available Smart Drilling Rig Information System enhances remote monitoring capability
- Standard DC/SCR power or optional AC power and controls
- Large capacity mud pumps can be expanded to two-motor drive for increased pumping capability

Procedures to erect the mast and substructure include:

1. A portable hydraulic system is connected to raise both the mast and substructure (without the need for generator power).
2. With the substructure in lowered position, the mast is pinned to the middle drill floor section.
3. To raise the mast, telescoping mast cylinders are pinned to the lower section of the mast and then telescoped.
4. With the mast in the vertical position and the raising cylinders still in place, mast support legs are swung out and pinned to the floor.
5. Mast raising cylinders are then disconnected and retracted.
6. With mast secured in the vertical position, telescoping hydraulic cylinders then raise the drill floor. Telescoping braces are extended when the floor is at ground level and retract as the substructure rises. Once completely raised, the braces bottom out and are secured with pins.

IDEAL Rig Modular Mud System

- **Engineered for Optimal Performance:**
  Following API recommendations, each pump is sized and routed to feed individual pieces of mud processing equipment. This increases mud system efficiency by: (1) ensuring that each piece of equipment is provided adequate feed rate and pressure; and (2) minimizing the possibility that a piece of equipment will be fed from the wrong compartment.
- **Designed to Reduce Settling:**
  Minimal piping within the tanks, proper agitator sizing and straightforward compartment configuration yields a mud system which reduces the likelihood of settling and helps maintain constant drilling fluid properties. These aspects will in turn reduce mud additive and disposal costs.
- **Simplified Maintenance:**
  Vertical centrifugal pumps allow easy access for repair and maintenance. All mud processing equipment provided with the mud system is rugged and requires minimal maintenance.

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- **Integrated Jetting System:**
  Vertical centrifugal pumps have run dry capability and pull fluid from sumps located on the tank floor. This allows an operator to jet the system without the need for expensive vacuum trucks, saving time and money.

Rapid Rig

In May 2006, National Oilwell Varco (NOV) began offering a smaller, fully automatic land drilling rig called “Rapid Rig”. This is a singles rig as it has pipe handling capability to rapidly pick up/lay down, make up/break out drill pipe and run casing and be able to mobilize/demobilize in approximately 8 hours. It uses Range II or III drill pipe. The Rapid rig is deployed with a single forklift and requires no cranes or gin pole trucks and is capable of moving in 16 highway-legal transport loads. The automated rig floor and pipe-handling systems allow operation by a three person crew. The rig floor has an iron roughneck and stabbing guide, automated pipe slips, AC drawworks rated at 1000 hp and gear driven with regenerative dynamic braking system, and top drive controlled from a climate controlled driller’s cabin on the mud pit side.

The foot print of the Rapid Rig is 185 ft by 98 ft (Figure 19). The rig is rated for approximately 11,000 ft and has a hook load rating of 500,000 lb. The pipe handling system has a weight limit of 6,000 lb with drill pipe capacity of 5.5 inch Range III and drill collar capacity of 8 inch Range II and casing capacity of up to 13⅜ inches.

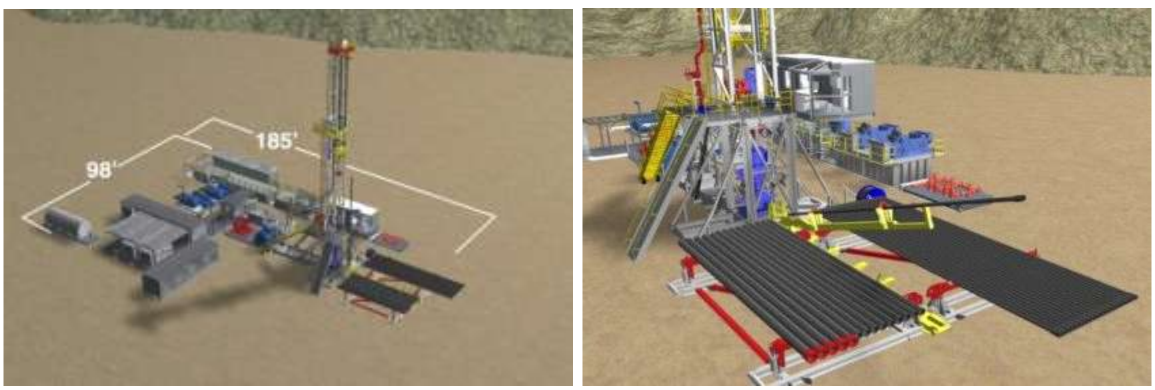

Figure 19 : NOV Rapid Rig foot print and pipe handling concept

Table 1: NOV Rapid and Ideal Rig Typical Specifications

	Rapid Rig	**Ideal Rig**
Mast Hook Load	250 tons (8 lines)	300 ton
Mast Height	80 ft (telescoping)	142 feet
Base Dimensions	7 ft x 5 ft	12 ft x 12 ft
Wind Rating	70 knot free standing	70 knot w/ full set back
		208 stands of 5.5 inch DP
		8 stands 8 inch DC
Rotary load Rating	250 tons	375 tons (w/ set back)
Drill floor height	20 ft	25 ft
Clear height under floor	17 ft	21 ft 8 inches
Drill Floor Dimensions	16 ft x 17 ft	32 ft x 32 ft
Substructure setback	N/A	250 ton slingshot

Drawworks Nominal Power	1000 hp	1500 hp
Braking System	Regenerative Dynamic Disk Parking/Emergency Brakes	Disc brakes, Ideal Auto Drilling and Brake control System (IABC)
Top Drive	350 HP, 20,000 ft-lb	Optional
	250 ton	
Pipe Handling System	6,000 lb range II and III 5½ pipe 8 inch collars and 13⅜ inch casing	Optional
Control/instrumentation	SDAQ	SDAQ
Mud System	620 bbl two tanks	620 bbl two tanks
	3-panel linear motion shale shaker,	2 – 4-panel high G shale shaker, 1000 GPM
	Atmospheric Degasser	Degasser
	Two Cone Desander	Desander, Desilter
Mud Pumps	2-1000 HP Triplex AC electric Motor Driven	2-1600 HP Triplex AC electric Motor Driven
Power Generation	2- 1350 BHP, 1800 RPM 1750 kVA	3- 1350 BHP, 1800 RPM 1750 kVA
Hydraulic Power	Dual Driven System 70 GPM Diesel, 40 GPM Electric	Dual Driven System 70 GPM Diesel, 40 GPM Electric
Fuel Tanks	Diesel 190 bbl	400 bbl cylindrical
Water Tanks	400 bbl	400 bbl
Foot Print (NOV layout)	98 ft x105 ft	129 ft x 206 ft
	10,290 ft^2 (0.24 acres)	39,474 ft^2 (0.9 acres)

Nabors PACE Rig

Nabors Industries developed the Programmable AC Electric (PACE) rig and included upgrades to shorten the drilling cycle. The key feature of the PACE rig is the use of variable frequency AC drives and programmable logic control (PLC) technology. This gives the driller better control of the drawworks, top drive, mud pumps and every other significant piece of rig equipment.

Nabors developed the proprietary Commander Class Drawworks which is gear driven and has no chains or sprockets. Gear-driven drawworks developed by Germany's Wirth GMBH for use in the North Sea have shown significant advantages as enormous weight reductions and improved safety with regenerative braking using the drive motors, plus the integration of an anti-collision system[21]. Similar drawworks have been marketed by NOV and others.

The control system and drawworks along with regenerative braking provide a system that is lightweight, reliable and cost-effective, allowing faster moves, enhancing safety, better power distribution and greater torque and rate of penetration. AC-powered rigs have fewer electrical connections, more accurate speed control and torque, better motor efficiency and produce less noise and fewer emissions, and better power distribution.

Like offshore rigs and many advanced onshore rigs, Nabors PACE rigs have an advanced control center. All instrumentation is ergonomically available to the driller. This includes an auto-drill touch screen and driller console monitoring systems which are all housed in a control center. Data monitoring is integrated with equipment control through PLC technology and provides a system of checks and balances prior to operating any piece of equipment. Benefits of this technology are: fewer, less cumbersome electrical connections that ensure ease of rig up/ down. PLC technology also promotes improved motor and fuel efficiency, fewer emissions, enhanced power distribution and less electrical noise. Greater control of torque and rate of penetration results in faster, better holes[22].

Larger PACE rigs feature 3000-hp AC drawworks, three 1,600-hp pumps, and 7,500-psi mud circulation systems. Smaller PACE rigs can have telescoping derricks.

Table 2: Nabors PACE Rig Specifications[22]

	PACE 750	**PACE 1500**
Drawworks	750 HP/750 AC motor	1,500 HP/two-800 hp AC motors
Power Generation	3-Cat 3512B engines 1476-hp/Kato 1365 kW generator total 4,428 hp	3-Cat 3512B engines 1476-hp/Kato 1365 kW generator total 4,428 hp
MAST	Loadmaster 142 ft telescoping	Pyramid 142-ft three section
Substructure	Loadmaster 22-ft floor height 17 ft 10 inch under rotary table	Pyramid 30-ft floor height 26 ft under rotary table
Static Hook load	550,000 lb	1,000,000 lb
Set back capacity	300,000 lb	800,000 lb
Traveling Block	275 ton	500 ton
Top Drive	Canrig 6027 AC 275 ton	Canrig 1250 AC 500 ton
Rotary Table	27.5 in.	37.5 in
DP/collars	4.5 inch 100,000 overpull 6-in and 8-in collars 40,000 lb BHA weight	As required
Mud Pumps	2 @ 1600 hp	2 @ 1600 hp
Mud tank capacity	750 bbl (1 tank)	3 tanks total of 1500 bbl

Other Drilling Rig Manufacturers

There are a number of manufacturers developing modified modular and efficient drilling rig technology.

Drilling Rigs from China

GTS Drilling Services Inc as subsidiary of General Turbine Systems of Conroe, Texas, brought the first Chinese-made drilling rig to the US. GTS is operating it in the Piceance basin for independent Presco Inc., based in The Woodlands, Texas. The rig is an electric rig rated at 1300 hp and has a zero discharge mud system. Nabors Industries ordered 25 land rigs from China's HongHua. Most will be put into service outside the US.[23].

The three largest Chinese manufacturers are Baoji Oilfield Machinery Co. Ltd. (BOMCO), Chuanyo Guanghan HongHua Co. Ltd. (HongHua), and Lanzhou petrochemical machinery plant. BOMCO, based in Baoji, Shaanxi Province, is China's largest manufacturer of drilling equipment and rigs, larger than all national competitors combined. Founded in 1937 as the Baoji Petroleum Machinery Manufacturing Plant (BPMMP), the company was reorganized in 2002 under CNPC. The company offers mechanical and electric drive drilling rigs, derricks and substructures, wellhead equipment, mud pumps, pumping units, and solids control equipment. They offer 21 different rig designs, including AC-powered rigs, truck-mounted rigs and rigs for cluster drilling, slant hole drilling, and desert drilling, capable of drilling from 3,300 feet to 29,500 feet. BOMCO has shipped products to 42 different countries, including the US, Canada, and Mexico, as well as countries in South America, Africa, Europe, Middle East, Asia, Australia, and New Zealand.

HongHua is the second-largest rig builder in China. Based in Guanghan City, Sichuan Province, the company has built 150 rigs since 1997 and is now able to construct 50 rigs/year. HongHua's most powerful rig is a 2,600-hp design, but the 1,500–2,000 hp models are more popular[24].

IDM Quicksilver Drilling Systems

IDM Equipment, Ltd. evolved from a service and repair company into a supplier of complete drilling rigs and integrated systems. IDM's experience with drilling rigs and automation controls provides a capability to incorporate proven technology from other industries into modern drilling systems. IDM has developed a modular drilling system, the Quicksilver drilling system or QDS, similar to other modular, highly mobilized drilling systems[25].

Their design focuses on economic moves, safer operating parameters, reduced rig-up/rig-down time and utilization of technology. The QDS includes ability to demobilize and rig up on a new location within 100 miles in less than 48 hours. IDM incorporated several drilling systems on single skids which minimizes the number of components requiring disassembly; e.g., well control skid combines 80-bbl trip tank, 1000-gpm mud gas separator and 4-10M dual choke and kill manifold; self-contained diesel-powered HPU, rig HPU and brake water cooler (DC version) are all unitized on a single skid. Similar to other modular rigs, the QDS requires no cranes for rigging up or down. The mud tanks are round bottom but, unlike the cylindrical tanks of the H&P design, IDM uses rectangular tanks similar to the Ideal rig design. Similar to the PACE and H&P designs, the IDM system uses DC SCR and IDM AC VFD control systems to maximize efficiency in rig operations. The driller's cabin is climate controlled and contains modern touch screen technology controls and rig monitoring systems. The electronic driller provides automated control of weight on bit (WOB), rate of penetration (ROP), and rotary torque.

The substructure, mud boat (self elevating mud processing system is completely unitized with the shale shakers, vacuum degasser and desilter on a single skid), stairs, V-door and driller's cabin are all pinned together at ground level. After all major structural components are pinned, the drill floor and driller's cabin are hydraulically raised and secured from ground level. The mast is raised with hydraulic cylinders after the substructure is raised.

The QDS is constructed in location layouts from 125 by 250 ft down to 100 by 200 ft. The QDS is available with an optional skidding system for pad drilling applications and is available in drawworks ratings from 1000 hp to 1500 hp and depth rating of 14,400 ft with 5" drill pipe and about 1000 ft of 6.5 inch drill collars racking capability.

RDE

Rigs Derricks Etc. LLC was established in 2002 in Houston, Texas. RDE furnishes the domestic and international oil and gas industry with complete new and used workover and drilling packages. RDE supplies custom designed rig packages, derricks, mast, substructures, and accessories for all land and offshore environments[26].

RDE offers a new patented design referred to as the Cheetah. This design is for 500 to 1500 hp rigs and moves the mast, substructure and drawworks skid in three loads. It does not require rig-up cranes and uses a telescoping triple mast that accommodates a top drive. The Cheetah rig incorporates a unique concept: the derrick is not supported on the drilling floor and then raised as in most modular rig designs, rather the

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mast is supported at ground or zero level and the floor is raised by the derrick or hydraulically and then pined to the derrick. US patent application 2003/0121230 appears to disclose this or a similar technology.

Figure 20: RDE Modular Mobile Rig Design Concept

Bentec

Bentec GmbH Drilling & Oilfield Systems designs, manufactures and sells major mechanical and electrical components for land and offshore drilling rigs as well as workover rigs. In March 2004 Bentec celebrated its tenth anniversary and was formerly part of the German drilling contractor DEUTAG. Bentec has evolved as an independent business unit within the ABBOT Group PLC, Scotland as is KCS Deutag[27].

HR 5000 Cluster Slider™

The Bentec HR 5000, Cluster Slider™ is a 1500 hp drilling system for operating in harsh environments such as those found in Siberia. The system is designed to operate on cluster locations, with a full winterization package incorporated into the design. All direct drilling related subsystems are installed on a rail track, allowing fast skidding in one direction. The rig design incorporates not only modern and high performing items; particular focus was set on creating a safe and well protected work area. Components that require maintenance are easily accessible.

The skidding movement is predetermined in one direction on each location to match the pad layout and well head positions. Repositioning the drilling rig and its auxiliary components is fast and reduces overall time. Power for the rig can be from the main power lines, or self generated with generator sets. A single cable runs from the support system block to the SCR unit with step down transformers placed on the rail track. Hot air blowers on the rail track provide sufficient heat to cope with the extremes of the Siberian climate. The support system block can be heated either by an air heater or by the secondary disposed heat from the diesel engines. The rig contains a derrick with 320 mt (705,000 lb) hook load capacity and a foldable substructure. Additional equipment such as mud separation systems, tank systems, mud pumps, air compressors and heating system are installed on trolleys, winterized by isolated sandwich panels. Those trolleys move with the mast and substructure during rig skidding. The move from pad to pad requires a certain degree of disassembly, transportation and re-erection. The rig can move in a 40 km (25 mile) radius within 18 days.

T208

Bentec T208 is a 1500 hp land drilling rig for KCA Deutag/OMV and is in the final stages of construction. As soon as the rig-up and testing phase is finished, the rig will be transported to Austria, where it will be operating in the wider area of Vienna. The design of this rig was driven by stringent European emission- and noise regulations.

Slant Well Drilling

Precision Drilling developed with PanCanadian Petroleum Ltd. a slant drilling rig in the 1990s.[28,29] This concept was a revival of older methods of horizontal drilling most successfully employed in heavy oil drilling at shallow depths. Wells were spudded at an angle (usually 30–45°) and then aimed straight at the target. The concept was less expensive, faster and more productive than directional horizontal drilling. Slant drilling allowed shallow heavy oil deposits to be developed form one or several pad locations. Pad drilling emerged as a way to minimize environmental impact because it allows multiple-well access to larger areas and targets beneath sensitive areas, such as lakes and towns. This technique does not require downhole motors or MWD technology. Improvements to the technology and methodology of use reduced time and well costs up to 50% on heavy-oil pad projects. In 1993 the slant rig had a depth rating of 6600 ft. Currently, models are available to drill to 10,000 ft.

The success of the rig can be attributed to technology that controls critical functions, makes the work environment safer for rig crews, and improves equipment control. Combined with pad drilling, the slant concept offers fast and simple movement from site to site and the ability to perform more than one type of well drilling. The rig is fully mechanized to minimize manual labor; the rig's remote control features reduce the crew's exposure; and automation of pipe handling improves safety since most injuries occur while the crew is handling tubulars. Features include:

- Hydraulic tubular handling arm
- Hydraulic power wrenches for make-up and break-out of tubulars
- Hydraulic power wrench carrier
- Hydraulic tip drive
- Hydraulic BOP handler and hydraulic pull down
- Pneumatic tubular slips
- Hydraulic pipe tables for gravity indexing of tubulars and casings to and from the catwalk
- Hydraulic tubular kickers and indexer systems that index tubular from the catwalk individually into the tubular handling boom, or kick tubulars out of the handling boom and onto storage racks or tables.

The rig can drill vertical, deviated, and underbalanced wells to 9,000 ft. The rig uses programmable logic controls to monitor the position of the traveling blocks and employ a fail-safe disc break to control the block speed as it approaches the crown or nears the rig floor. The rig can be moved quickly because the rig lies down singles every trip. The rig requires only eight loads for well-to-well movements on a pad and can be moved 1 to 2 miles in four hours and is easily disassembled for highway transportation.

Figure 21: Precision Drilling Slant Singles Rig

Figure 22: Precision Drilling Pipe Handling

DrillMec – Hydraulic Rigs

As mentioned previously, a semi-automatic hydraulic rig was proposed in 1950 and built in the mid-1960s by Hycalog Inc.[11] The hydraulic systems were not well developed at that time and the rig was not accepted by industry.

Since 1995 a unique land-rig designed by the Italian company DrillMec (formerly SoilMec; a division of the Trevi Group) has offered a fully automatic hydraulic rig. Drillmec was formed in 2004 from Trevi Group's reorganization to focus on the oil, gas and water drilling markets while SoilMec focuses on ground engineering and equipment. Trevi Group has a history of foundation, geotechnical drilling, and tunneling technology.[30]

Drillmec manufactures derricks and offshore equipment, trailer-mounted mobile drilling rigs, conventional masted drilling rigs, and unique hydraulic drilling rigs. Most of the hydraulic and mobile drilling rigs are shallow depth capability less than 10,000 ft depth (with 5-inch drill pipe) using single, double and small triple conventional drilling rigs. The rigs are designed to work in a reduced footprint location to lower construction costs and reduce environmental impact (6375 ft^2; 0.15 acres) (Figure 23). The entire pipe inventory is placed in a vertical position for more efficient pipe handling (Figure 24). The trailer mounted hydraulic hoist rig incorporates many new concepts and innovative features, along with a high level of automation and safety allowing consistent reduction of the total drilling cost (by as much as 25%) and environmental impact associated with a drill field development. This design has been demonstrated in different terrains, weather conditions and applications worldwide.

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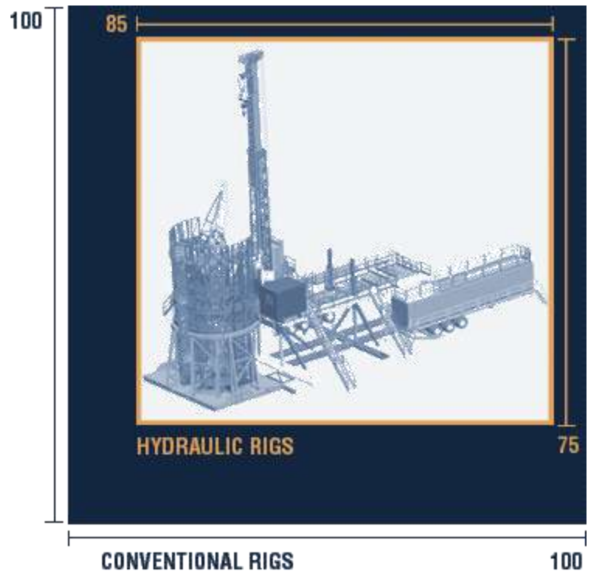

Figure 23: DrillMec Hydraulic Rig Foot Print


Figure 24: DrillMec Hydraulic Rig

The mud system has integrated mud control features so as to prevent mud leaks and spilling. Complete mud collecting ditches under the drill floor, mud pumps, substructure, tanks, and pipe vertical bins guarantee a dry location. Leaks are also prevented through pneumatic sealed coupling between bell nipple and connector pipe.

Features include:

- **Technology serving safety, environmental control and cost reduction.** The driller has full control of all the operations from the cabin (climate controlled if required). Automatic pipe handling system, automatic power tong, automatic slips, and mud systems and drilling parameters can be easily controlled by a single operator from the dog house.
- **HH Design covers two current rigs categories.** The HH Drilling Rig series covers the category of typical single, double and small triple conventional drilling rigs.
- **Ease and safe moving.** All loads are wheeled and self-erecting ensuring fast movement between locations and prevention of accidents during transportation.
- **Reduction in location size.** Layout of the rig and its reduced footprint require half the area required by a conventional rig of the same capacity.
- **Self erecting hydraulic telescopic mast.** Easy rig up and down operation are all hydraulic-controlled. Drill string operations are performed using movement of the hydraulic telescopic mast and the patented top drive traveling system from the center well to the mouse hole.
- **Pull down capability.** HH rigs have a pull down capability up to 40 tons, which gives big advantages in horizontal and/or UBD wells.
- **Complements down hole technology.** The entire hydraulic control of the drilling parameters means getting the maximum benefit from the innovative down-the-hole technologies with enhanced production in items of ROP.
- **Built-in top drive.** An integrated top drive allows back reaming, well control, and fine rotational control, automatic control in weight on bit, ROP and maximum torque.
- **Micro-control of torque and weight on bit.** As a consequence of all the function being hydraulically controlled, the rig has the built-in capability to micro adjust torque and weight-on-bit, resulting in more benefits to the drilling and core operators.
- **Range 3 drill pipe.** HH rigs are designed to work with Range 3 drill pipe, which facilitates horizontal drilling and allows one-third less connections and a corresponding reduction of tripping time.
- **Environmental control.** HH rigs are designed to avoid any spillage of fluid from the drill floor, mud tanks, mud pumps, generator and ancillary equipment. This allows the rig to provide drilling service in a dry location in accordance of the ISO 14000 rules with enhanced control on environmental pollution.
- **Noise pollution.** HH rigs are designed to work with a maximum 60 dB noise on the drilling box.
- **Power.** Four 700-kW Caterpillar sound-proof diesel electric generators and Siemens power control room power the hydraulics of the rig.

Hydraulic rigs are designed to address demanding technological requirements that characterize current onshore drilling activity. Focal points of the design are reduced weight and size, and enhanced automation to reduce crew size. Interdisciplinary cooperation between operator and contractor has made possible the development of an innovative drilling rig that performs economically and efficiently for drilling shallow and medium-depth wells. HH series rigs have been used in a wide variety of field conditions, from the desert of North Africa to Siberia. In September 2005 a US drilling company contracted to buy 25 hydraulic oil drilling rigs. Previously Cheyenne Drilling accepted delivery of a 220,000 lb hook load mobile hydraulic hoist rig (G-105) in June 2005 and has an order for another G-200.

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Table 3: DrillMec Hydraulic Drilling Rig Specifications

Model	static hook load lb (mt)	max pull down lb (mt)	rated input HP (kW)	top drive torque ft-lb (daN-m)	top drive stroke ft (m)	approx.mass lb (kg)
HH-100	200,000 (91)	44,000 (20)	540 (403)	26,035 (3530)	49 (15)	94,800 (43,000)
HH-102	220,000 (100)	44,000 (20)	560 (418)	26,035 (3530)	52 (16)	99,200 (45,000)
HH-150	300,000 (136)	44,000 (20)	700 (522)	26,035 (3530)	52 (16)	110,230 (50,000)
HH-200	400,000 (181)	44,000 (20)	1340 (1000)	26,035 (3530)	52 (16)	121,250 (55,000)
HH-200S	441,000 (200)	44,000 (20)	1340 (1000)	26,035 (3530)	52 (16)	132,280 (60,000)
HH-300	600,000 (272)	66,000 (30)	1542 (1150)	36,141 (4900)	52 (16)	198,420 (90,000)

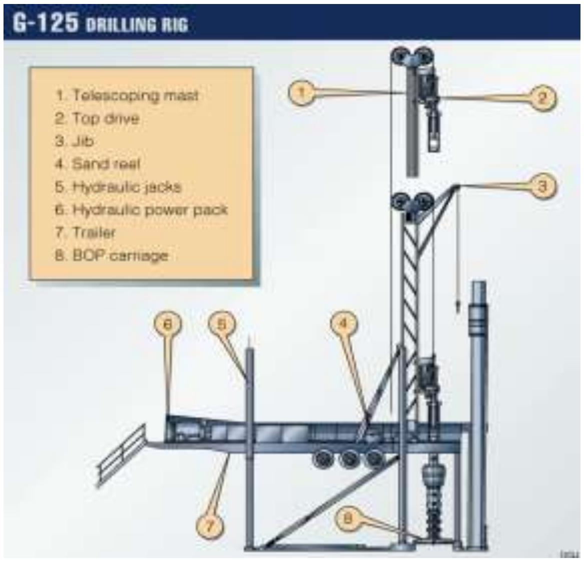

Figure 25: Schematic of DrillMec Operations (Courtesy of OGJ)

3.2 Casing While Drilling

Casing drilling is envisioned to eliminate the use of drill pipe as used in conventional rotary drilling. Instead, the drillstring consists of standard oil field casing that is used to simultaneously drill and case the well. Spinning the casing with a top drive rotates the drill bit. Furthermore, the casing does not have to be tripped for bit and bottom-hole assembly changes, as these are performed via wireline retrieval. Proponents of casing drilling claim that wireline retrieval of the bottom-hole assembly, which on average comprises 35% of the total time to drill a well, will be 5–10 times faster than conventional drill pipe tripping[34].

3.2.1 Huisman/Drillmar

Netherlands-based Huisman Special Lifting Equipment BV and Drillmar Inc. of Houston, through a technology development joint venture, have developed an innovative new rig concept: the LOC250 Land and Offshore Containerized 250 ton hook load rig. The LOC250 is designed to take advantage of emerging casing while drilling (CWD) technology to reduce costs as well as the environmental impact of drilling a well. The LOC250, first offered in October 2005, has a drilling depth capability of 5,500 m (18,000 ft) with 4½-in casing; 4,500 m (15,000 ft) with 7-in casing; and 3,500 m (11,500 ft) with 4½-in drill pipe. CWD is not the solution for all wells; therefore, the LOC250 was designed to drill with conventional drill pipe using the same automated pipe handling and tripping processes.

Two of the most important features of the LOC250 rig are its compact size and the fact that the entire rig can be broken down into 17 modules with the shape and the dimensions of standard ISO containers. Within 24 hours (including limited transportation time) and without cranes, a five-man crew with three trucks can demobilize the compact rig and rebuild it in another location. As standard container ships, trains and oilfield trucks can transport ISO containers rapidly and economically, the LOC250 rig can be used to drill wells anywhere in the world. This was achieved by designing the rig so that its load bearing components are either in the shape of, or can be pivoted, rotated, or connected into, an ISO container.

The LOC250 is equipped with a fully automated pipe handler, which enables highly efficient handling of both casing and drill pipe. When the pipe handler has upended the tubulars, they are taken over by elevators in the rig. A top drive is used to spin the tubulars in and to torque up the connections. Fully automated power slips are integrated within the rotary table. Capable of tripping drill pipe at 2000 ft/hr, the LOC250 is as efficient as existing conventional drill pipe drilling rigs and more efficient than other specially designed CWD rigs. The drill-pipe drilling and CWD processes (including pipe and casing handling) are fully controlled from the control room without personnel on the drill floor. As drill pipe handling is identical to casing handling and uses the same equipment, the same team can carry out both tasks. While a conventional pipe-drilling rig needs a crew of 10, the LOC250 requires only a five-man crew for operation.

Pipe and material handling cause almost 50% of the recorded accidents during well drilling. The fully automated pipe handling of the LOC250 obviates the need for personnel on the drill floor and thus reduces the potential for accidents. In addition, the simple rig-assembly process – smaller loads, less rig crew involvement and improved overview and visibility – effectively mitigates the risk for the crew and the potential for accidents and damage during rig moves.

The LOC250 has significantly less adverse impact on the environment when compared with older conventional rigs. Because drilling a well with the LOC250 requires less drilling time and lower mud pump pressures and flow rates, two 800-hp mud pumps are sufficient, compared with the three 1000-hp pumps required for conventional DP drilling. This means a 45% lower fuel consumption and a reduction in hydrocarbon emissions of up to 75%. Solid waste volumes are reduced by up to 30%, as the cascading shaker system provides drier cuttings. Mud and cement costs are reduced by 10 to 20%. Because the LOC250 has only a single 38-m (125 ft) mast, its silhouette does not impact significantly the horizon. The footprint of the LOC250, at 700 m^2 (7500 ft^2) is 75% smaller than the 3000 m^2 (32300 ft^2) required for a conventional rig.

Fidelity Exploration and Production of Texas has already taken delivery of one LOC250. Additionally, Huisman-Itrec is developing the JBF 10000 drilling "rig of the future," which is a compact, deepwater semisubmersible that has only 60% of the displacement of fifth-generation semisubs capable of 10,000 ft water depths. This will be a fully automated drill pipe handling system designed to run 135-ft pipe stands in a box mast drilling tower and features a zero-discharge fluid system[31] .

Table 4: Huisman LOC 250 General Specifications

Weight and dimensions				
Total transport weight	475	[mton]	524	[Shton]
Number of container units	17			
Containers for loose gear (40')	4	TBD		
Max. ISO dimensions				
Length	12.2	[m]	40	[ft]
Width	2438	[mm]	8	[ft]
Height standard	2590	[mm]	8' 6"	

Height high cube without gooseneck	2794	[mm]	9' 2"
Height high cube with gooseneck	2896	[mm]	9' 6"
Infield rig move	< 30	hours	

Figure 26: Huisman Itrec Rig in South Texas

Figure 27: Huisman Rig during Rig Up

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Figure 28: Huisman LOC 250 Drawing of Operations

3.2.2 Tesco[32]

Tesco pioneered the CWD concept and currently offers rigs from about 5000 to 13,000 ft capacity and depending on the rig can be moved in 6 to 12 truckloads. All equipment is in modules that are pulled to the location by regular oilfield trucks. The rigs do not require cranes or gin pole trucks to rig up.

All TESCO CASING DRILLING® rigs are hydraulic powered using proven mobile closed loop hydraulics. Unique to these rigs is an advanced power distribution system which distributes the hydraulic power to the three primary rig functions (mud pumps, top drive and drawworks) from common prime movers and hydraulic pumps.

TESCO-built rigs include top drive technology. All TESCO rigs are designed with the top drive permanently in the mast. Raising and lowering the mast takes place with the top drive in place. Tesco claims that this system makes the crews more efficient and results in fewer accidents. A self elevating substructure design allows elimination of rig mats, which improves the rig move load count and time/cost. Additionally a climate controlled driller control center and PLCs monitor every drilling function and routinely displays, alarms, and functions each step of the drilling process. Preset operational sequencing coupled with the pipe handling features provide semi or complete hands-free drilling.

The rig includes a driller operated pipe handling system designed specifically for CASING DRILLING®. Like the Huisman Rig, the TESCO rigs can also be used with drill pipe.

The system uses a catwalk mounted, hydraulic casing racks and hydraulic pipe trough that are set to direct up to 2,500 m (8,200 ft) of tubulars toward the power catwalk. An indexing system off of the catwalk frame (either side) loads single joints into the trough within the carrier. The carrier is moved and raised by hydraulic cylinders within the catwalk to the substructure level. The trough within the carrier is then extended, transporting the casing coupling to a predetermined point close to well center. As the top drive is rotating a single joint of casing is lifted toward the rig floor, a hydraulic elevator link tilt system attaches to the casing standing in the trough, the mud pump is stopped, slips set and the casing drive disengaged (does not screw into the casing). The top drive is raised along with the next joint of casing, the stabbing arm guides the lower end of the casing into the stump, the casing drive again engages the top of the casing and the top drive torques the lower connection. Drilling is resumed and another joint is loaded into the power catwalk. All of these functions are performed remotely by the driller in the isolated control center (hands free connections).

3.3 Coiled Tubing

Coiled tubing drilling (CTD) has been used on a commercial basis for several years, and can provide significant economic benefits when applied in the proper field setting. In addition to potential cost advantages, CTD can provide the following benefits[33]:

- Safe and efficient pressure control
- Faster tripping time (150+ ft/min)
- Smaller footprint and weight
- Faster rig up/rig down
- Reduced environment impact
- Less personnel
- High speed telemetry (optional)

Fueled by the buoyant demand for natural gas, CTD rigs have gone from an unproven concept to commanding approximately 25% of the Canadian drilling market in less than 10 years.

Figure 29: CTD Unit Mast and Substructure for CT Sizes through 5½ in.

CTD is ideal for underbalanced applications because of its inherent well control system. To date, most underbalanced CTD activity has been for re-entry operations, but new wells could also benefit from this approach. In addition, underbalanced "finishing" is a variation of underbalanced drilling used extensively in Canada and gaining acceptance in other areas. For finishing operations, a conventional rig is used to drill to the top of the reservoir and casing is run. From this point, CTD is used to drill into the reservoir underbalanced. This technique leverages the respective strengths of both drilling approaches. Conventional drilling can be faster (less expensive) in the large diameter, unproductive uphole drilling intervals, while underbalanced CTD is faster (less expensive) in the producing interval. CTD is also better suited to deal with the pressure/produced hydrocarbons from the productive interval. This is evolving to integrating the rotary rig and CT on one rig (see Section 3.3.2 on Hybrid Coil Tubing).

The use of CT instead of conventional drill pipe has been employed primarily in the drilling of shallow gas wells in Western Canada and Alaska[34] and more recently in eastern Kansas of the US. Initial results show penetration rates double that of conventional rig rates.

Blast Energy Services Inc. (formerly Verdisys Inc.) is building a new generation CTD rig that will use abrasive fluid jetting. Maxim TEP Inc. Woodlands uses the technology of Blast Energy Services to economically develop old reservoirs assumed depleted at shallow depths. The main functional system is CT to jet lateral “wagon wheel spoke” holes horizontally and to do so economically.

CTD is also evolving into a useful concept for multilateral drainage techniques for reservoirs. Typically used for heavy oil or shallow production operations, the use of multilateral production techniques is proving to be a technology that can help increase recovery factor considerably. Drilling methods such as multilateral CTD are evolving to address this challenge.

3.3.1 Deep CTD

Historically, CT has been used in an extension from other wellbores or through tubing primarily in Alaska. CTD has been used at depths greater than 17,000 ft but has been used for small diameter wells and not as a primary drilling mechanism. In Canada, CTD has been used in shallow wells and had considerable success in high penetration formations.

Until very recently deep CTD was not considered possible. Xtreme Coil Drilling Corp. claims to have five different rig design patents pending with an additional 11 patents pending addressing transport of CT that could drill to deeper depths. These designs are targeted at both the US and Canadian markets. Currently 65% of the wells in the US market are medium depth and will be drilled to 12,000 ft or shallower. Successful demonstration of Xtreme’s technology will open up the CTD market to 10,000 ft and deeper due to the ability to transport longer strings of CT. All rigs can drill with up to 4-in. CT.

There are, however, significant disadvantages to deep CTD:

- Rigs cost 20% more to build
- CT has a much shorter life cycle than drill pipe
- There are only two CT suppliers in the world, both in Houston
- CT can be more difficult to fish
- Directional drilling components need more development
- Rapid penetration rates can result in problems getting logs to bottom
- Due to high penetration rates operator needs to mud up wellbore earlier
- Mud systems need to be carefully monitored to achieve log to bottom consistency
- BHA assembly can also make a difference in logging

The US market is believed to be primed for CTD and the need to reduce finding costs for operators has become critical. Efficiency of drilling with CT will improve the economics of drilling prospects. Canadian experiences actually made uneconomic fields economic. Markets where PDC bits are effective will be a perfect start for CTD in US markets. These applications allow high penetration rates and fewer trips, reducing cycle life on CT. Larger CT sizes are allowing larger hole sizes to be drilled with considerably less pressure requirements. Concentrated improvements in directional drilling with CT should allow tremendous savings on wells being drilled with “S” curve wellbores. The US has a larger potential market for CTD beyond 7000 ft than does Canada.

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Shallow markets in Wyoming, Montana, Colorado, New Mexico, Texas, and California were tested in 1999–2000 by Plains Energy and Fleet Coil. These were very successful. ADT is drilling very successfully in the Eastern Colorado/ Kansas area. Deeper markets up to 10,000 ft will be tested in Colorado and Wyoming later in 2006. Once technology has been proven, it is planned to drill in additional increments, reaching 11,000 ft with CT by mid-2007. Top drive combination allows CTD rigs to drill virtually anywhere (Figure 30)[35].

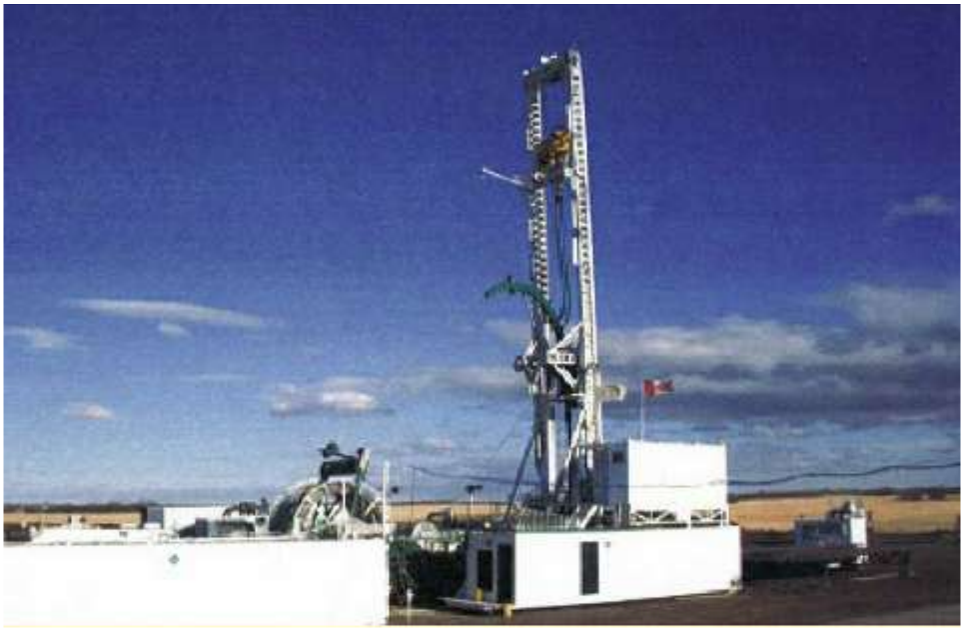

Figure 30: CTD unit with Top Drive

3.3.2 Hybrid Coiled Tubing

Combining CTD technology with a conventional jointed pipe workover capability represents the next step-change in providing low-cost reserves access solutions.[36] This approach can use a single rig where two normally would be required and operate in remote fields more economically than either alone.

In 2002, Trailblazer Drilling recognized the limitations of existing conventional and CTD technology in addressing various difficult drilling conditions. Trailblazer designed and patented next-generation hybrid units which have the capacity to operate with CT or with a conventional top drive off of the same rig. Conversion from CT to conventional drilling is accomplished in the field without any significant cost or downtime. These units also have the capacity to drill and pre-set casing. The capability of these rigs is approaching 12,000 ft.

3.4 Drilling Rig Automation

Phil Vollands of National Oilwell Varco stated in 2001 that the drilling industry has undergone three eras of technology evolution: mechanization, semi-automation, and local automation[37]. The 1970s saw the introduction of equipment such as power slips, iron roughnecks, and top drives that reduced labor on the rig floor. (However, much of the implementation was carried out in 1980's[38].) Introduced in the mid- to late 1970s for offshore operations,[39] piperacking and pipehandling systems were implemented in the 1980s and were extensions of the previous era and classified by Vollands as semi-automation. Human intervention was for control only. Primarily this technology was implemented in the premium offshore area, although in the late 1990s, this technology was being incorporated into newbuilt onshore rigs.

The 1990s was a transition and reconstruction period for the onshore oil and gas drilling industry and saw these component technologies start to be integrated and developed as whole drilling systems and include the entire rig. The uptake of this technology was more rapid offshore. Through this transition evolved a more mobile, modular, efficient, environmentally friendly, economic, and safe drilling system. Key to this evolution was development and integration of drilling rig automation technology and the programmable logic controller.

The kelly spinner replaced the infamous spinning chains, which were responsible for numerous injuries on the rig floor. Subsequently, the iron roughneck and automated pipe handling equipment are replacing the kelly spinner. More than 30% of the rig time is spent on drillstring tripping and casing and tubing handling and most accidents occur while handling tubulars. Acceleration of pipe handling and faster joint makeup can significantly reduce the total time needed to drill a well and the related costs[40]. Automation has reduced the number of people needed on the drilling floor, removed people away from potentially dangerous activities as well as the number of accidents especially in the dangerous activity of running casing. The introduction of stabberless pipe system in 1996 improved pipe running capability and reduced casing, tubing, or riser running times considerably without compromising safety[41].

Automated tubular handling systems designed into some onshore modular rigs consist of:

- Mechanized catwalk with V-door conveyor
- Mechanized pipe racking system
- Rotating iron roughneck
- Kelly spinner
- Rotating mouse hole
- Pneumatic racking board locking fingers
- Adjustable racking board

Automated drawworks using AC-powered motors that provide significantly more performance and have made possible hoisting mechanisms that require approximately half the space and weight with lower maintenance than traditional drawworks (see Section 3.1.1; PACE rigs). These drawworks incorporate a sophisticated braking system offering proportional control to improve drilling and tripping efficiency while increasing safety.

Electronic drillers to maximize the efficiency and safety of drilling and tripping operations were introduced. Monitoring drilling parameters and precisely controlling the drawworks, torque and rotation speed at the surface provides a constant control at the bit not previously available. Additionally the use of new automated directional drilling capability in the "Slider" coupled with greater control of drawworks surface capability and new braking techniques allow better control during horizontal drilling.

Top drive, drawworks and mud pump performance may be improved as remote monitoring allows technicians to track bearing wear, torque, input and output power, and oil temperature. Monitoring to detect component and equipment health is being developed within Noble Corporation.

Automation has changed the job specifications of personnel and training requirements of working on a drilling rig. Activities can be monitored in real time and performance predicted and workflow procedures adjusted to create more efficient operations. Maintenance personnel will be able to detect problems that affect the "health of the system" and diagnose predictive measures to schedule downtime outside of critical activities. Caterpillar Engines began putting smart chips in its engines to monitor wear in 2001[37].

3.5 Pumps

In 2001, the LeTourneau Ellis William Co. (Lewco) introduced one of the largest mud pumps built, the W-3000. At 3000 hp (over 2.2 MW), it has a working pressure of 7500 psi and maximum output of 1044 GPM (3954 l/min). These pumps are light (7400 lb) and are rated for helicopter lifts and have small footprints (10 ft by 4 ft (3 m by 1.2 m) over the pinion)[42]. The W-3000 pump has a unique inherently balanced crankshaft that minimizes vibration for reduced wear, quieter operation and longer life. Other life-extending features include triple-redundant lubrication and anti-friction roller bearings. Lewco expanded its range of services to include designing and producing balanced crankshafts to replace the worn crankshafts of mud pumps made by other companies.

National Oil Well introduced its Hex pumps in 2002. The new Hex Pump (Figure 31) technology uses six pistons together with an asymmetric cam, resulting in minimized pressure pulsations and flow ripples from the pump. Both measurements and theoretical calculations show that the pump provides a nearly constant steady flow, eliminating the need for pulsation dampeners. The 1500-hp pump was tested on a land rig in 2003, and operated concurrently with two triplex pumps on the rig to compare the performance of two different pump designs. The Hex Pump is an axial piston mud pump with six vertical pistons driven by two AC motors via a gear and a specially profiled cam. In contrast to crankshaft-driven triplex pumps, the Hex pump delivers a nearly pulsation free flow. The Hex 240 (2500-hp) pump uses two 1200-hp AC motors; maximum pump speed is 212 spm, delivering 1035 gpm at 7,500 psi. Major benefits claimed include: up to 45% smaller footprint and 35% less weight; less vibration and noise; more consistent plunger speed; and minimized output pulsation. The Hex Pump can replace two triplex pumps with an increase of 50% pumping capability installed in the same area. The pump effected a time savings due to better MWD readings (MWD data are less affected by the Hex pump).

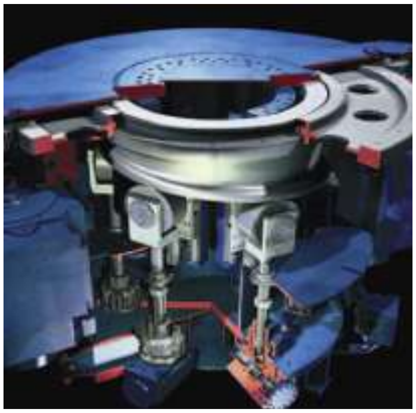

Figure 31: National Oilwell Hex Pump

Reduced power consumption is another benefit. At the same pumping capacity, instead of using three diesel generators when running the triplex pumps, only two generators where used when the Hex Pump was running, resulting in lower diesel consumption and lower operating cost for the rig (estimated between 10 and 30% for the land field test) [43]. However, this is related to increased power factor since the Hex Pump is using AC motors and the triplex pump was using DC motors[43].

3.6 Waste Management

Sustainable development of petroleum resources requires appropriate management of all waste streams generated over the entire life cycle of a development beginning with initial planning of projects and operations to decommissioning and site restoration. Quality waste management is crucial to achieve this goal. The principal aim of waste management is to ensure that waste does not contaminate the environment at such a rate or in a form or quantity as to overload natural assimilative processes and cause pollution. Eliminating or minimizing waste generation is crucial, not only to reduce environmental liabilities but also operational cost. Many disposal practices of the past are being questioned now. The cost of cleaning up many past hazardous waste sites will be high and a substantial part of these clean-up costs will be charged to industry under the polluter pay principle. As inadequate waste handling eventually leads to environmental damage and financial liabilities, systematic waste management through integrated environmental economics became a preferred approach in the up stream phase of the petroleum industry[44].

Historically, waste pits (reserve pits) were used at land rig sites. At the end of each well the wet cuttings were left to dry naturally and then bulldozed or covered with natural soil. More recently cuttings were dug out and trucked to landfill, where a significant cost is incurred as the cuttings were treated purely as waste material[45]. Current practice for operators onshore and offshore employs extensive fluids recovery and cuttings disposal methods. Often, because they want to be considered responsible guests by their host country, oil and gas operators impose even more stringent environmental regulations on their operations than those imposed by the host country.

E&P waste management has evolved to encompass more than drill cuttings and excess drilling fluids during drilling and workover operations. Though these comprise the vast majority of the wastes, other materials include contaminated water, material and chemical packaging, emissions such as carbon dioxide, scrap metals, fuel, lubricants and other oils as well as the usual human and industrial wastes associated with E&P operations[46]. Application of computer models is a new tool to help manage solids control, wastes, and liability issues from a drilling project[47].

Shell established a Rig Waste Reduction Pilot Project in 2001 to identify potential waste reduction strategies.[48] The preferential hierarchy they developed is: *reduce, reuse, recycle, recover and dispose*. The major of the total waste stream was found to be drilling discharges and non-hazardous oilfield waste. Mud use was reduced by 20% and mud component packaging was reduced by 90% through a combination of solids control efficiency, cuttings dryer technology and bulk mixing equipment. In addition, Shell implemented a sorting, compaction and recycling process for solid waste (consumables and trash) to reduce landfill disposal.

Schlumberger introduced a total waste management program to mitigate rising quantities of landfill waste.[49] Benefits included an overall improvement in general housekeeping that reduced health and safety exposure and a general increase in environmental awareness and concern.

Mobil implemented a waste management program for Hugoton field operations.[50] The waste management system decreased overall waste-related costs while improving compliance assurance and reducing potential liability. The key element was a mechanical solids-control system consisting of a semi-closed loop centrifuge flocculation dewatering process that removes solids for burial on location.

Waste management incorporates other aspects in addition to drilling fluids and cuttings. Air emissions and water runoff from the site should also be considered. With the increase in rig activity in the Rocky Mountain states, pollution from drilling rigs and other oil field related equipment has become a concern.[51] Wyoming’s Jonah Field near Pinedale is a concern where it is estimated that 3,100 wells will be added. EnCana tested a natural gas fired drill rig that reduces emissions by 90% compared to conventional diesel rigs.[52] EnCana is also evaluating the possibility of providing electrical service to the Jonah field to power drilling rigs with direct electrical power, thereby reducing emissions to negligible amounts.[53] A water runoff management program may be developed to control discharges of waste water to the environment.[54]

3.6.1 Drilling Fluids

Solids and Cuttings Management

API estimated that in 1995 about 150 million barrels of drilling waste were generated from onshore wells in the US alone. Operators have employed a variety of methods for managing these drilling wastes depending on state and federal regulations and how costly those options are for the well in question. Onshore operations have a wider range of options than offshore operations. These include land-spreading and land-farming, evaporation and burial onsite, underground injection, incineration and other thermal treatment, bioremediation and composting and reuse and recycling[55].

ChevronTexaco published 10 years of lessons learned concerning biotreating exploration and production wastes.[56] They have successfully implemented bioremediation in diverse climates and in remote locations. The most common biological treatment techniques in the exploration and production industry are composting and land treatment. Land-farming and composting have been successfully used for drilling wastes.[57]

A novel technique for effective drilling waste management is vermicomposting,[58] which uses worms to remediate the cuttings, converting them into a compost material that is useful as a soil enhancer. It was found that this technique not only cleans the cuttings but converts them into a valuable resource. For environmentally sensitive areas, this bioremediation technique may be applicable. It was found that the vermicompost technique, combined with environmentally friendly design of the drilling fluid, is by far the preferred treatment technique compared to thermal treatment of the cuttings.

Drill Cuttings Processing – Thermal Processes

The Drilling Waste Management Information System, developed by Argonne National Laboratory and industry partners ChevronTexaco and Marathon under the US DOE's Natural Gas & Oil Technology Partnership program, provides a summary of thermal treatment technologies.[59] Thermal technologies use high temperatures to reclaim or destroy hydrocarbon-contaminated material. Thermal treatment is efficient for destroying organics and reducing the volume and mobility of inorganics such as metals and salts.[60] After-treatment may be necessary for metals and salts. Waste streams high in hydrocarbons (typically 10 to 40%) like oil-based mud, are prime candidates for thermal treatment. Thermal treatment can be an interim process to reduce toxicity and volume and prepare a waste stream for further treatment or disposal (e.g., landfill, land farming, land spreading), or it can be a final treatment process resulting in inert solids, water, and recovered base fluids.

Costs for thermal treatment range from $75 to $150/ton, with labor a large component.[60] Currently, however, the rate in the UK is £140 ($250) per tonne for thermal desorption and disposal. Waste volumes from a single operator may not be high enough to justify continuous operation of a thermal treatment process, but contract operation of a centrally located facility that manages waste from multiple area operators may be cost-effective.

Thermal treatment technologies can be grouped into two categories.[59] The first group uses incineration (e.g., rotary kilns, cement kilns) to destroy hydrocarbons by heating them to very high temperatures in the presence of air. The second group uses thermal desorption where heat is applied directly or indirectly to the wastes to vaporize volatile and semivolatile components without incinerating the soil. In some thermal desorption technologies, off-gases are combusted, and in others, such as in thermal phase separation, gases are condensed and separated to recover heavier hydrocarbons. Thermal desorption technologies include indirect rotary kilns, hot oil processors, thermal phase separation, thermal distillation, thermal plasma volatilization, and modular thermal processors.

Various thermal processes have been patented.[61,62,63] A detailed summary of various thermal processes is presented in Appendix A.

Cuttings Injection

Cuttings injection is a waste disposal technique where drill cuttings and other oilfield wastes are slurried by being milled and sheared in the presence of water (usually seawater). The resulting slurry is then disposed by pumping it into a dedicated disposal well, or through the open annulus of a previous well into a fracture created at the casing shoe set in a suitable formation.

Drilling a dedicated injection well is sometimes ruled out in favor of an annular injection plan due to cost. More frequently, operators are deciding not to risk damaging their well and would rather drill a separate shallow injection well.

For single well programs or areas with specific logistical limitations (Cook Inlet), annular injection is the norm. However, for development drilling, a dedicated injection well (or two) is often used. For development drilling from a platform, the first well could be drilled with water-base fluids to an injection depth and then be used as the injection well for the balance of the wells to be drilled from the platform or pad. After all other wells are drilled, the annulus of one of the other wells can be used as the original injection well is drilled to TD and completed.

Operations are usually batch by nature and carried out at low pump rates (2.0–8.0 BPM). Typically the 13⅜ by 9⅝-in. annulus is selected as the disposal location. These types of operations have been carried out all over the world, with disposal into many different types of strata.

3.6.2 Stormwater Management

Drilling operations can produce large volumes of wastewater that contains sediment, mud and drilling additives. The proper handling, containment and disposal of the wastewater are important to mitigate potential harm to the environment.

Stormwater should contain only clean rainwater, not pollutants such as wastewater, sediment, mud, drilling additives or other pollutants. Only clean, non-contaminated stormwater should be allowed to flow directly into rivers, oceans and other waters.

Addressing potential stormwater pollution

- Improves awareness of the impact of well drilling on the environment
- Meets public expectations that drilling activities do not pollute
- Reduces environmental impacts
- Complies with legal and environmental responsibilities
- Provides a cleaner work environment and improves efficiency
- Increases long-term cost savings through increased efficiency and reduced costs.

Wastewater should be contained on site and disposed of away from any watercourse or wetland area. Wastewater can usually be contained by constructing a temporary reserve pit of adequate size, protected from stormwater by banks. The wastewater drained into the reserve pit can be disposed of by evaporation or hauled offsite to a suitable disposal location.

Capturing Runoff – Zero Discharge

Third Party Products – Spill Protechtion

Katch Kan™ introduced the Zero Spill project to the upstream oil and gas industry with the first two components of the Zero Spill System™ (ZSS) in 1994. As needs of the industry further developed, the ZSS became more fully involved and effective in controlling and redirecting drilling fluid. The technology enables drilling as a zero spill operation; directly avoiding environmental contamination. ZSS technology can be applied to drilling rigs, service rigs, wellheads, barge, and other offshore applications. These products can also be retrofit to older rigs.

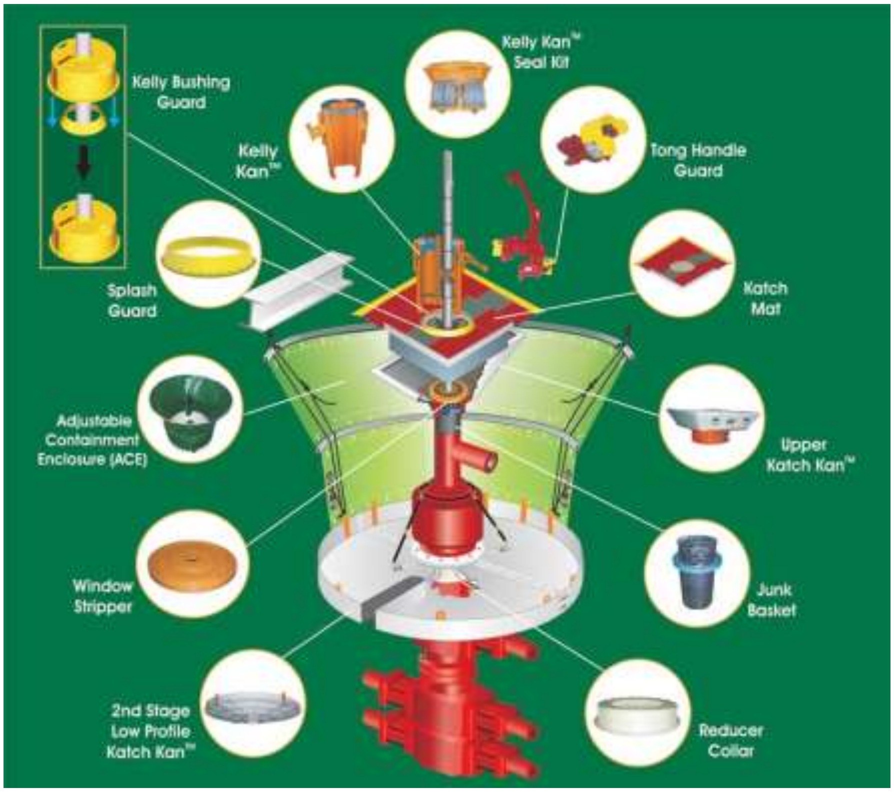

Figure 32: Katch Kan Products for Zero Spills

3.6.3 Emissions Control

Drilling operations involve the use of diesel engines for delivery/logistics of equipment, materials and supplies and for power generation at the drill site. There has been much advancement in reducing emissions from diesel engines. Diesel engines emit particulate matter (PM) and oxides of nitrogen (NOx) into the atmosphere, along with other toxic air pollutants. Health experts have concluded that pollutants emitted by diesel engines adversely affect human health and contribute to acid raid, ground-level ozone and reduced visibility. Studies have shown that exposure to diesel exhaust causes lung damage and respiratory problems and there is evidence that diesel emissions may cause cancer in humans.

Significant improvement in diesel emission levels, in both light- and heavy-duty engines, was achieved in the 1970 - 2000 period. PM, NO_x, and HC emissions were cut by one order of magnitude. Most of that progress was achieved by emission-conscious engine design, such as through changes in the combustion

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chamber design, improved fuel systems, implementation of low temperature charge air cooling, and special attention to lube oil consumption.

However, more progress was still required, as the NO_x and PM emissions from diesels remained higher than those from Spark Ignited (SI) engines. A new series of diesel emission regulations was developed with implementation dates around 2005-2010, which require the introduction of exhaust gas aftertreatment technologies in diesel engines, as well as fuel quality changes and additional engine improvements.

Table 5: Technology Emission Impacts

Technology	Emission Impact	Significance
Engine Design Technologies		
Fuel Injection System Charge Air System Combustion Chamber Electronic Control	~90% PM reduction, ~75% NO_x reduction, large reductions in HC/CO emissions achieved in the 1980-1990 timeframe	Combination of these engine design techniques was the major source of diesel emission reduction through the end of 1990s; Potential for further emission reductions in the future
Exhaust Gas Recirculation	30-50%+ NO_x reduction	Light-duty vehicles; Major heavy-duty engine applications from 2002 (USA)
Fuel, Oil & Additive Technologies		
Fuel & Lube Oil	Only limited direct emission impact in modern engines	Sulfur content remains the critical property due to its effect on catalytic aftertreatment technologies
Alternative Diesel Fuels	Variable, depending on fuel and emission	Short term: emission-driven niche markets; Long term: critical importance due to depletion of petroleum reserves
Fuel Additives	Small emission effect with modern engines and quality diesel fuels	Possible use to assist particulate filter regeneration
Water Addition	1% NO_x reduction for every 1% added water	Niche markets: marine and stationary engines; centrally fueled fleets (emulsions)
Exhaust Gas Aftertreatment		
Diesel Oxidation Catalyst	High reduction of HC/CO emissions; PM conversion depends on fuel sulfur, usually limited to maximum 20-30%	Widely used on Euro 2/3 cars and on 1994 and later heavy-duty urban bus engines in the U.S.; Will remain a component of future emission control systems
NO_x Adsorber Catalysts	~90% NO_x reduction potential	Potential future technology for light duty engines worldwide and for heavy-duty engines in the U.S. (2007/2010)
Urea-SCR Catalysts	~90% NO_x reduction	Future technology for Euro 5 heavy-duty diesel engines; Currently used in stationary engines and other niche markets
Diesel Particulate Filters	70-90%+ PM emission reduction	Expected widespread use for (heavier) Euro 4 cars and heavy-duty US2007 engines; Currently used in retrofit programs and voluntary diesel car applications
Lean NO_x Catalysts	NO_x reduction potential of ~10-20% in passive systems, up to 50% in active systems	Uncertain; NO_x reduction potential insufficient for long-term regulatory objectives
Plasma-Assisted Catalysts	NO_x reduction potential up to ~50%	Uncertain; NO_x reduction potential insufficient for long-term regulatory objectives

Table 6: Available Diesel Retrofit Technologies

Technology	Emissions Reductions			Fuel Requirements	Other Information
	HC	PM	NOx		
Diesel Oxidation Catalyst (DOC)	50–90%	25–50%	--	500 ppm sulfur	DOC's have an established record in the highway sector and are gaining in nonroad applications. Sulfur in fuel can

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					impede effectiveness of DOCs; therefore, the devices require fuels with low sulfur levels. Can be combined with other technologies for additional PM and or NOx reductions.
Diesel Particulate Filter (DPF)	50–95%	>85%	--	CB-DPF – ULSD; active, non-CB-DPF – 500 ppm	DPF's use either passive or active regeneration systems to oxidize the PM in filters. Passive filters require higher operating temperature to work properly. Filters require maintenance. Can be combined with NOx retrofit technologies.
Flow-through Filter (FTF)	50–95%	30–60%+	--	500 ppm sulfur	Filtration efficiency is lower than DPF, but is much less likely to plug under unfavorable conditions, such as high engine-out PM emissions and low exhaust temperatures.
Lean NOx Catalyst (LNC) with a DPF	--	>85%	5–30%	ULSD	Verified LNCs are always paired with a DPF or a DOC.
Selective Catalytic Reduction (SCR)	80%	20–30%	80%	500 ppm sulfur	Common in stationary applications. Require periodic refilling of an ammonia or urea tank. Often used with a DOC or DPF to reduce PM emissions.
Exhaust Gas Recirculation (EGR) with a DPF	--	>85%	40–50%	ULSD	Both low-pressure and high-pressure EGR systems exist, but low-pressure EGR is used for retrofit applications because it does not require engine modifications. Feasibility of low-pressure EGR is more of an issue with nonroad equipment than on-road equipment.
Closed Crankcase Ventilation (CCV)	--	5–10%	--	500 ppm	Usually paired with a DOC or DPF.

The array of emission control methods provides the designer with building blocks which need to be chosen and combined into the emission control system, which in turn is integrated with the engine to achieve a given emission target. A system approach is necessary to develop the clean emission diesel engine. There is no miraculous "plug-in" device available which could be installed on a particular engine and effectively clean emissions. An effective emission control strategy has to combine elements of engine design with the use of appropriate fuels and exhaust aftertreatment methods.

Selective catalytic reduction (SCR) of NO_x by nitrogen compounds, such as *ammonia* or *urea*—commonly referred to as simply "SCR"—has been developed for and well proven in large-scale industrial stationary applications. The SCR technology was first applied in thermal power plants in Japan in the late 1970s, followed by widespread application in Europe since the mid-1980s. In the USA, SCR systems were introduced for gas turbines in the 1990s, with increasing potential for NO_x control from coal-fired powerplants. In addition to coal-fired cogeneration plants and gas turbines, SCR applications also include plant and refinery heaters and boilers in the chemical processing industry, furnaces, coke ovens, as well as municipal waste plants and incinerators. The list of fuels used in these applications includes industrial gases, natural gas, crude oil, light, or heavy oil, and pulverized coal.[64]

SCR is the only proven catalyst technology capable of reducing diesel NO_x emissions to levels required by a number of future emission standards. Urea-SCR has been selected by a number of manufacturers as the technology of choice for meeting the Euro V (2008) and the JP 2005 NO_x limits—both equal to 2 g/kWh—for heavy-duty truck and bus engines. First commercial diesel truck applications were launched in 2004 by Nissan Diesel in Japan and by DaimlerChrysler in Europe.

SCR systems are also being developed in the USA in the context of the 2010 NO_x limit of 0.2 g/bhp-hr for heavy-duty engines, as well as the Tier 2 NO_x standards for light-duty vehicles.

The technologies and strategies being developed for the 2007/2010 heavy-duty highway diesel engine and Tier 4 nonroad diesel engine standards may be applicable stationary diesel engines provided adequate lead-time is given. The issue is to match the right technologies to the right applications. Reduction of emissions is influenced by the duty cycle of the engine.

DieselNet (www.dieselnet.com) provides current information about emission standards and regulations.

3.6.4 Flaring Control

Well Testing – Well testing enables valuable reservoir data to be obtained prior to making the financial commitments required for field development. During testing operations, although the operation may contribute a small fraction of total operational flaring for a large operator, the high visibility of the operation can attract attention. In the North Sea, produced water is cleaned to reduce oil contamination to levels as low as 20 ppm or less prior to discharge. In the Gulf of Mexico, produced oil has been conditioned to sale quality, pumped to tethered barges, and then sold. New, high efficiency burners are available to reduce NOx, CO and unburned hydrocarbon levels and to ensure that liquid fallout to the sea is eliminated.

Well Clean-up – Production facilities are typically not designed to handle the mix of drilling fluids, brines and solids that can be produced during initial well clean-up. It may be required to have a temporary facility on site, similar to a well test package, during well clean-up. Well clean-up fluids are difficult to burn as they usual contain much aqueous fluid such as completion brine. Surface equipment designs have evolved to handle well clean-up. Initial flows can be diverted to storage tanks and separators enabling a clean gas flare to be maintained. Produced fluids can then be disposed.

Gas Flaring and Venting – Gas flaring/venting from production facilities can be eliminated through the collection and recompression of vent gas from storage tanks and pipelines.

3.7 Power Generation

Drilling rigs are sized for peak power needs. During drilling operations all of the design power of a specific rig is rarely needed; roughly 25% power is needed the majority of the time. However, during hoisting a great deal of power is needed. Most of the large deepwater offshore rigs being built today need over 40,000 hp (30 MW). Many exceed 50,000 hp (37.3 MW). To put this into perspective, the average person in the US consumes roughly 13,000 kW-hr of energy each year (www.eia.doe.gov) (about 1.48 kW per person). Rig power then corresponds approximately to a 20,000 person community for these large rigs. A land rig operation would be roughly 10–20% of this capacity (4,000–8,000 hp; 3–6 MW).

Conventional rigs usually use internal combustion engines sufficient to mechanically drive pumps, drawworks, and rotary table directly through mechanical compounding or drive a generator and use electric motors distributed throughout the rig to drive the other drilling rig components. The latter is more prevalent in the current market though the former is still used on older rigs that have not been refurbished.

New build rigs are primarily equipped with AC generating capability. Older electric rigs used DC capability. AC motors have been found to be more efficient in heavy load applications and much more controllable.

3.7.1 Conventional Power Generation

Internal or Recipricating Combustion Engines

Reciprocating internal combustion engines are a widespread and widely known technology. A variety of stationary engine products are available for a range of power-generation applications and duty cycles, including standby and emergency power, peaking service, intermediate and base-load power, and combined heat and power (CHP). Reciprocating engines are available for electrical power generation applications using many different fuel sources in sizes ranging from a few kilowatts to many 10s of megawatts of power in individual applications.[91] Wartsila builds one of the largest specialty IC currently (2300 tons, 108,900 hp Total displacement of 1,556,002 cubic inches, and exceeds 50% thermal efficiency). IC engines are generally characterized as having:

- Low initial capital cost
- Proven reliability
- Strong maintenance support networks
- Rated output that is not impacted by higher ambient temperatures or elevations
- High partial load efficiency
- Heat recovery capabilities for combined heat and power
- No requirements for external inlet fuel compression

Diesel engines (compression ignition or Diesel cycle) have historically been the most popular type of reciprocating engine for drilling rig use; though, gas fueled spark ignition (SI) engines (Otto Cycle) have also been used. In the United States and other industrialized nations, diesel engines are increasingly restricted because of air emission concern. The emissions signature of natural gas SI engines has improved significantly in the past decade through better design and control of the combustion process and through the use of catalytic treatment of exhaust gases. Advanced lean-burn natural gas engines are available that produce untreated NOx levels as low as 50 ppmv at a 15% reference O_2 (dry basis).[91] Engines intended for industrial use are designed for durability and for a wide range of mechanical drive and electric power applications. Their sizes range from 20 kW to more than 7 MW, including industrialized truck engines in the 200 to 600 kW range and industrially applied marine and locomotive engines above 1 MW.

Depending on the engine and fuel quality, diesel engines produce 5 to 20 times as much NOx (on a ppmv basis) as lean-burn natural gas engines. Diesel engines also produce assorted heavy hydrocarbons and particulate emissions (PM). Common NOx control techniques include delayed fuel injection, exhaust gas recirculation, water injection, fuel-water emulsification, and compression ratio and turbocharger modifications – all designed to eliminate hot spots and reduce the flame temperature within the cylinder.

An increasing number of larger diesel engines are equipped with selective catalytic reduction (SCR) and oxidation catalyst systems for post-combustion emissions reduction.

Gas Turbines

Gas turbine generators (generally classed a Brayton thermodynamic cycle) or combustion turbines (CT) are an established technology in sizes from several hundred kilowatts up to several hundred MW. Though the equipment can be complex the process is fairly simple. Air is pulled through rotating and fixed blades in the compression turbine, raising both the pressure and temperature of the air. The compressed air is then forced into a combustion chamber where fuel is injected and ignited. Hot gases exiting the combustion chamber expand across rotating and fixed blades in the power turbine.

Gas turbines can be set up to burn natural gas, a variety of petroleum fuels or can have a dual-fuel configuration. Gas turbine emissions can be controlled to very low levels using water or steam injection, advanced dry combustion techniques, or exhaust treatment such as selective catalytic reduction (SCR). Maintenance costs per unit of power output are among the lowest of power generation technology options. Technical and economic improvements in small turbine technology are pushing the economic range into smaller sizes as well. Low maintenance and high-quality waste heat make gas turbines an excellent match for industrial or commercial CHP (combined heat power) applications larger than 5 MW. The CHP increases the thermal and electrical efficiency of the turbine process since high quality heat can be captured for additional generation or use. The key attributes of CTs include the following:

- Highly efficient when at or near full-load
- Produce very low air emissions compared to reciprocating engines
- Ideal for combined heat and power (CHP) or combined cycle applications
- High energy density (power to weight ratio) and smaller footprint than reciprocating engines
- Proven technology with wide range of currently available products and established service channels

Simple Cycle efficiencies for gas turbines available today range from 10 to 43%. CT design varies by manufacturer, but the fundamental principles remain the same and performance varies with factors that alter the mass of air flowing into the turbine. For example, net output power is reduced when there is an increase in atmospheric temperature or site elevation. Efficiency can be increased by decreasing inlet and outlet pressure losses, designing more efficient compressor or power turbines, and achieving higher combustion temperatures.

Small Industrial Turbines

As opposed to the large scale utility turbines that are generally 50MWe if not 100's of MWe power requirements the industrial turbines have smaller capacity but are basically the same design configuration. Aero-derivative turbine units are derived from jet propulsion engines utilized on commercial aircraft. Aero-derivative units are available with power output ranging from 300-52,000 kW. Typical applications include peaking and cogeneration projects. Because these turbines were originally optimized for aviation, these are designed to be light weight, reliable, efficient, and easily packaged. Aero-derivatives tend to have shorter intervals between overhauls than industrial CTs. Industrial units do not have the design constraints of aero-derived combustion turbines as they are designed from the bottom up for high efficiency and high reliability, with long periods of continuous operation between overhauls. Industrial turbines have a fundamentally different combustor design than aero-derivative machines. Power output for commercially available units range from a few hundred kW to over 50,000 kW. Industrial turbines are typically installed in CHP applications, but can be found in peaking capacities as well.

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Micro Turbines

Microturbines are small gas turbines that burn gaseous and liquid fuels to create a high-energy gas stream that turns an electrical generator. Today's microturbine technology is the result of development work in small stationary and automotive gas turbines, auxiliary power equipment, and turbochargers – much of which was pursued by the automotive industry beginning in the 1950s. Microturbines entered field-testing around 1997 and began initial commercial service in 1999-2000. The size range for microturbines (either commercially available or in development) is from 25 to 500 kilowatts (kW), while conventional gas turbine sizes range from 500 kW to more than 300 megawatts (MW).

Microturbines generally have marginally lower electrical efficiencies than similarly sized reciprocating engine generators. However, because of their design simplicity and relatively few moving parts, microturbines have the potential for simpler installation, higher reliability, reduced noise and vibration, lower maintenance requirements, and possibly lower capital costs compared to reciprocating engines. Microturbines have the potential for extremely low emissions. Most current microturbines operating on gaseous fuels feature lean premixed (dry low NOx, or DLN) combustor technology, which was developed relatively recently for gas turbines, but is not universally featured on larger gas turbines. Because microturbines are able to meet key emissions requirements with this or similar built-in technology, post-combustion emission control (aftertreatment) techniques are currently not needed.

Microturbines are very small combustion turbines that are currently offered in a size range of 30 kW to 250 kW. Microturbine technology has evolved from the technology used in automotive and truck turbochargers and auxiliary power units for airplanes and tanks. In the typical configuration, the turbine shaft, spinning at up to 100,000 rpm, drives a high-speed generator. The generator's high-frequency output is converted to the 60 Hz power used in the United States by sophisticated power electronics controls. Electrical efficiencies of 23-26% are achieved by employing a recuperator that transfers heat energy from the exhaust stream back into the combustion air stream.

Microturbines are compact and lightweight, with few moving parts. Many designs are air-cooled and some even use air bearings, thereby eliminating the cooling water and lube oil systems. Low-emission combustion systems, which provide emissions performance approaching that of larger gas turbines, are being demonstrated. Microturbines' potential for low emissions, reduced maintenance, and simplicity promises to make on-site generation much more competitive in the 30 to 300 kW size range characterized by commercial buildings or light industrial applications. Microturbines also have significantly lower emissions signatures (i.e., lower NOx and CO emissions) than reciprocating engines. Microturbine emissions can be up to eight times lower than diesel generators. In resource recovery applications, microturbines can burn waste gases that would otherwise be flared directly into the atmosphere.

Microturbines and larger gas turbines operate on the same thermodynamic cycle, known as the Brayton cycle. In this cycle, atmospheric air is compressed, heated at constant pressure, and then expanded, with the excess power produced by the expander (also called the turbine) consumed by the compressor used to generate electricity. The power produced by an expansion turbine and consumed by a compressor is proportional to the absolute temperature of the gas passing through those devices. The general trend in gas turbine advancement has been toward a combination of higher temperatures and pressures. However, microturbine inlet temperatures are generally limited to 1750ºF or below to enable the use of relatively inexpensive materials for the turbine wheel and recuperator. For recuperated turbines, the optimum pressure ratio for best efficiency is usually less than 4:1.

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The basic components of a microturbine are the compressor, turbine, generator, and recuperator. The heart of the microturbine is the compressor-turbine package, which is most commonly mounted on a single shaft along with the electric generator. The single shaft is supported by two (or more) high-speed bearings. Because single-shaft turbines have only one moving part, they have the potential for low maintenance and high reliability. There are also two-shaft versions of the microturbine, in which the turbine on the first shaft only drives the compressor while a second power turbine on a second shaft drives a gearbox and conventional electrical generator producing 60 Hz power. Moderate- to large-size gas turbines use multistage axial flow compressors and turbines, in which the gas flows parallel to the axis of the shaft and then is compressed and expanded in multiple stages. Most current microturbines are based on single-stage radial flow compressors and either single- or two-stage turbines. Radial flow turbomachinery can handle the very small volumetric flows of air and combustion products with higher component efficiency and with the simpler construction than axial flow components.

Recuperators are air to gas heat exchangers that use the hot turbine exhaust gas (typically around 1,200ºF) to preheat the compressed air (typically around 300-400ºF) before the compressed air goes into the combustor, thereby reducing the fuel needed to heat the compressed air to the design turbine inlet temperature. Microturbines require a recuperator to achieve the efficiency levels needed to be competitive in continuous duty service. Depending on microturbine operating parameters, recuperators can increase machine efficiency by as much as a factor of two. However, since there is increased pressure drop in both the compressed air and turbine exhaust sides of the recuperator, power output typically declines 10% to 15% on a recuperated turbine.

3.7.2 Regulatory Impacts on Rig Power (Stationary) Generation

EPA adopted a comprehensive national program to reduce emissions (see appendix B) from future non-road diesel engines by integrating engine and fuel controls as a system to gain the greatest emission reduction. To meet these emission standards, engine manufacturers will produce new engines with advanced emission-control technologies similar to those already expected for highway trucks and buses. Exhaust emissions from these engines will decrease by more than 90%. Because emission-control devices can be damaged by sulfur, EPA is also adopting a limit to decrease allowable levels of sulfur in non-road diesel fuel by more than 99%.

Mobile diesel engines used on drilling rigs and other industrial applications have been required to meet emissions standards for off-highway compression ignition sources since 1996. Specific emission standards for hazardous air pollutants (HAPS) for oxides of nitrogen, hydrocarbon, carbon monoxide, and particulate matter vary by engine power category and year, with each reduction referred to as a "tier" (Table 7).

Table 7: Timeline for New Source Performance Standards for Stationary Engines. Second number is emergency conditions emission allowance (after Brand and Iverson AOGR March 2006[65])

	Interim	Engine Manufacturer Certification									
kW (hp)	Apr-06	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
0-18 (0-24)	T1/T1	T2/T2	T4/T4								
19-36 (25-48)	T1/T1	T2/T2	T4/T4					T4/T4		T4/T4	
37-55 (49-74)	T1/T1	T2/T2	T3/T3				T4/T3 (0.3 g/kWh PM?)		T4/T3 (0.3 g/kWh PM?)		
56-74 (75-99)	T1/T1	T2/T2	T3/T3				T4/T3			T4/T3	
75-129 (100-173)	T1/T1	T3/T3					T4/T3			T4/T3	
130-560 (174-751)	T1/T1	T3/T3				T4/T3			T4/T3		
61-900 (752-1,207)	T1/T1	T2/T2				T4/T4				Power Gen: T4 (Nox &PM a/T)/T4	
-2237 (1,208-3,000)	T1/T1	T2/T2				power gen: T4 Nox A/T)/T2				Power Gen: T4	
>2237 (3,000)	T1/T1	T1/T1				other : T4i (non-A/T)/T4				(Nox &PM a/T)/T4	

EPA has assumed technologies for controlling HAPS from gas/diesel fueled engines are three way catalysts for rich burn engines and oxidation catalysts for lean burn engines as well as diesel engines.

Manufacturers currently offer products that meet various control levels established by pre-existing EPA non-road regulations. Compared to older engines, NO_x emissions from non-road diesel engines (commonly available for stationary use) have been reduced 77% and PM emissions have been reduced 85% to meet current advanced requirements.

Reducing oil consumption has been one of the primary ways that highway diesel engines have complied with the PM (particulate matter) standard since 1994. Reducing oil consumption not only decreases maintenance costs, but also VOF (volatile organic fractions) and PM emissions. Oil consumption through the combustion chamber can be reduced through improvements in piston ring design and through the use of valve stem seals. Piston rings can be designed to "scrape" oil from the cylinder liner surface back into the crankcase reducing the amount of oil consumed during combustion from the cylinder. Valve stem seals can be used to reduce oil leakage from the lubricated regions of the engines valve train into the intake and exhaust ports of the engine. Engine designs that incorporate these technologies have reduced VOF and PM emissions[66].

Other technologies suggested in the literature as well as the EPA "Nonroad diesel emissions standards" to reduce the HAPS are

- Charge Air Cooling or lowering the intake manifold temperature lowers peak temperature of combustion and thus NO_x emissions. Note that this can also increase specific power output of an engine.
- Fuel injection rate shaping and multiple injections
- Injection Timing Retard. Delaying fuel injection until the cylinder is moving down can reduce the NO_x emissions from a diesel engine. Cylinder temperature and pressure are lowered; however, hydrocarbons, carbon monoxide, PM and fuel consumption increase. This is a trade-off and may be changed through application of new technologies such as common rail fuel systems and exhaust gas recirculation.
- EGR (Exhaust Gas Recirculation) reintroduces or retains a fraction of the exhaust gases into the cylinder. This decreases NO_x formation by reducing thermal peak combustion temperature; reducing amount of oxygen available for formation of NO_x; and chemical dissociation effect of CO_2 and water which is endothermic.
- Induced Mixing Charge Motion
- Control of air-to-fuel ratio
- Flow through diesel oxidation catalyst reduces HC and PM emissions by oxidizing both gaseous (volatile) hydrocarbons and semi-volatile portions of PM. These components can also oxidize sulfur compounds in the diesel.

3.7.3 Fuel Types

Bi-fuels Concept

Natural-gas industrial engines have been used for several decades. Typically, large engines used in the oil and gas industry are fueled by diesel or other combustible fuels or gases (e.g., natural gas, propane or butane) normally as either a 100% diesel or 100% gas fuel source. In the early to mid 1980s, a bi-fuel system concept was introduced to reduce emissions by using two types of fuels simultaneously and at the same time improve efficiency and power. When running in gas mode the engine works according to the Otto process where the lean air-fuel mixture is fed to cylinders during the suction stroke. At leaner combustion, less NO_x is produced and the engine efficiency is increased—efficiencies exceeding 47% have been recorded.

The dual or bi-fuel engine is a diesel engine that operates on gaseous fuels while maintaining some liquid fuel injection to provide a deliberate source for ignition. Such a system is usually designed to minimize use of diesel fuel by replacing it with various gaseous fuels and their mixtures while maintaining satisfactory engine performance. There are problems associated with conversion of a conventional diesel engine to dual fuel operation. At light loads, dual fuel engines tend to exhibit inferior fuel utilization and power production efficiencies, with higher unburned gaseous fuel and carbon monoxide emissions relative to corresponding diesel performance. Operation at light loads is also associated with greater cyclic variation in performance parameters, such as peak cylinder pressure, torque, and ignition delay, which have narrowed the effective working range for dual fuel applications in the past. These trends arise mainly as a result of poor flame propagation characteristics within the very lean gaseous fuel/air mixtures and originating from the various ignition centers of the pilot[67].

The quality of natural gas used to fuel a converted engine, with respect to its percentage makeup of component gases, will directly affect power, efficiency, emissions, and longevity of the engine. As a general rule, higher methane content results in higher fuel quality. Butane is the most common variable to adversely affect engine performance. Hexane is more destructive than butane, but is seldom seen at levels high enough to cause concern. In any case, maintaining hydrocarbon levels at or below indicated target levels is necessary for achieving rated power performance. Acceptable levels (in molar percent) for various component gases have been proposed, with the sum of all non-methane hydrocarbons not to exceed 8% of the total fuel mixture[68].

Certain applications require the use of a modified cooling system for the converted engine to run properly and produce fully rated output. Burlington Railroad has used the system since the late 1990s on some of its locomotives. Nabors Offshore applied the dual fuel system to offshore drilling rig power generation[69]. Many newer land drilling rigs and most offshore drilling rigs use SCR (selective catalytic reduction) technology to covert NO_x to nitrogen and water, thus reducing emissions loading. A combination of fuel mixing and SCR could reduce emissions further.

Synthetic Fuels

Various chemical characteristics and natural impurities in diesel fuel can affect exhaust emissions from diesel engines, can damage or impede operation of emission control devices, and can increase secondary pollutant formation in the atmosphere. The EPA, which has a mandate to assure healthy air quality, most recently established low sulfur requirements in diesel fuel starting in 2006.

Synthetic fuel (synfuel) is any liquid fuel obtained from coal or from natural gas. It can sometimes refer to fuels derived from other solids such as oil shale, tar sand, waste plastics, or from the fermentation of biomatter. It can also (less often) refer to gaseous fuels produced in a similar way. The best known process is Fischer-Tropsch synthesis which converts carbon dioxide, carbon monoxide, and methane into liquid hydrocarbons of various forms. Carbon dioxide and carbon monoxide are generated by partial oxidation of coal, wood-based fuels, and more recently stranded natural gas. This process was developed and used extensively in World War II by Germany, which had limited access to crude oil supplies.

Synthetic Diesel and Lubricant Oils

There is considerable debate as to whether synthetic oil increases lubricity and fuel efficiency of internal combustion engines. Emissions in high load engines, such as used on drilling rigs, could be reduced by proper selection and use of lubricants. Additionally, synthetic diesel from Fischer Tropsch process is very clean and could help meet EPA requirements for diesel engines. Thus, the following discussion is presented as a technology that is available today to improve fuel efficiency and reduce emissions.

Synthetic Lubricant Oils to Improve Engine Efficiency

The majority of oil lubricants are mineral oils—mixtures of refined fractions of crude oil. Synthetic oil is oil manufactured for enhanced lubrication performance using the Fischer-Tropsch process. The differences between these types of oils are in molecular make up. Synthetic oil has a very consistent molecule size which gives the oil very consistent properties. Mineral oil, being a product of nature, has a range of molecule sizes. The advantage of synthetic oil is that it potentially has a more stable suite of properties that can be tailored to a wider range of applications.

Synthetic oils are polymerized from short-chain hydrocarbon molecules into longer single-chain hydrocarbons. Their lubrication characteristics can be adjusted by controlling the spectrum of molecular weights that go into the finished formulation, which usually includes thickeners. The most common synthetic types used include synthetic hydrocarbon oils (SHC), polyglycols (PAG) and ester oils (E).

Synthetic oils provide a number of advantages. However, they do not necessarily out-perform mineral oils in all respects and may even result in some drawbacks. Advantages of synthetic lubricating oils (depending on the base oil) include[70]:

- improved thermal and oxidation resistance
- improved viscosity-temperature behavior, high viscosity index (in most cases)
- improved low temperature properties
- lower evaporation losses
- reduced flammability (in some cases)
- improved lubricity (in some cases)
- lower tendency to form residues
- improved resistance to ambient media

The following application-related advantages result from the improved properties of synthetic lubricating oils as compared to mineral oils[70]:

- higher efficiency due to reduced tooth-related friction
- lower gearing losses due to reduced friction, requiring less energy
- oil change intervals three to five times greater than mineral oils
- reduced operating temperatures under full load, increasing component life; cooling systems may not be required

Possible disadvantages include:

- higher price
- reactions in the presence of water (hydrolysis, corrosion)
- material compatibility problems (paints, elastomers, certain metals)
- limited miscibility with mineral oils

Advantages of synthetic oils are generally significant in high performance applications such as motor racing and aviation, road haulage, or for general lubrication in extreme environments.

Synthetic hydrocarbons[70] (SHC) are similar to mineral hydrocarbons in their chemical structure. They have nearly identical properties relating to their compatibility with sealing materials, disposal, reprocessing and miscibility with mineral oils. The main advantage is excellent low temperature behavior. It is possible to manufacture food-grade lubricants for food processing and pharmaceutical industries with SHC base oils using special additives.

Synthetic lubricating oils based on ***polyglycols*** ensure especially low friction coefficients, which makes them suitable for gears with a high sliding percentage (worm and hypoid gears). With appropriate additives, they provide excellent antiwear protection in steel/bronze worm gears, and have good extreme pressure performance. In gear systems, higher polarity polyglycols allow greater interaction on the metal gear surface (adhesion). This gives polyglycols extreme pressure performance even without additives. Polyglycol oils may have a negative impact on sealing materials and may dissolve some paints. At operating temperatures above 212°F (100°C), only seals made of fluorinated rubber or PTFE are resistant. Before using PAG oils in production applications, it is advisable to test compatibility with paints, seals and sight glass materials. Miscibility with mineral oils is limited; mixtures should therefore be avoided. Polyglycols are neutral toward ferrous metals and almost all nonferrous metals. If the application has a loaded contact with one component consisting of aluminum or aluminum alloys (rolling bearing cages containing aluminum), there may be increased wear under dynamic load (sliding movement and high load). In such cases, compatibility tests should be conducted. If a worm gear is made of an aluminum bronze alloy, polyglycols should not be used because the reaction in the load zone could result in increased wear[70].

Ester oils are the result of a reaction of acids and alcohols with water splitting off. There are many types of esters, all of them having an impact on the chemical and physical properties of lubricants. In the past, these lubricating oils were mainly used in aviation technology for the lubrication of aircraft engines and gas turbines as well as gear systems in pumps, starters, etc. Ester oils have a high thermal resistance and excellent low temperature behavior. In industrial applications, rapidly biodegradable ester oils will gain importance because it seems possible to achieve the same efficiency as with polyglycol oils by selecting appropriate ester-base oil.

Certain ester oils may exhibit low hydrolytic stability[70]. Hydrolysis is the cleavage of the ester into an alcohol and an acid in the presence of water. Ester lubricants need to be hydrolytically stable because they are often exposed to humidity in use. In practice, hydrolysis may be a less serious problem than commonly reported. Hydrolytic stability of an ester depends on:

- type of ester used
- type of additives used
- how the ester was processed
- application

Synthetic oils have a lower friction coefficient than mineral oils in a gearbox and a more favorable viscosity/temperature relationship. This generally permits use of synthetics at lower viscosity grades and also offers the possibility of reduced oil temperature during operation. In such cases, the life extension factors for oil change intervals of synthetic oils are greater than stated above, which refers to identical oil temperature. The following comparison of test results illustrates this advantage. Three lubricants were tested in a splash lubricated worm gear test rig. Test records show the following oil sump temperatures after 300 operating hours:

- Mineral oil: 230°F (110°C)
- SHC: 194°F (90°C)
- PAG: 167°F (75°C)

Life extension factors of synthetic oils as compared to mineral oil are as follows[70]:

- Mineral oil = 1
- SHC = 9.5 times longer
- PAG = 31 times longer

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Tests have also shown synthetic oils make gears more efficient than mineral oils. PAG oil resulted in the highest degree of efficiency: 18% more than the high performance mineral gear oil.

Synthetic GTL Oils Used as Fuels

Synthetic diesel is made the same way as synthetic oils (SHC) except thickeners are not added and different additives used. Note that the additives in motor oils, whether natural mineral oil or synthetic oils, make up about 60% of the volume of the motor oil. Synthetic diesel (SynD) made from Fischer Tropsh process has extremely low (0–5 ppm) sulfur, aromatics, and toxics. SynD can be blended with non-complying diesel fuel to make a cleaner diesel fuel complying with stringent diesel fuel standards.

Preliminary testing of an unmodified diesel engine fueled with neat synthetic diesel fuel, shows substantial emission reductions compared to typical diesel (Figure 33).[71]

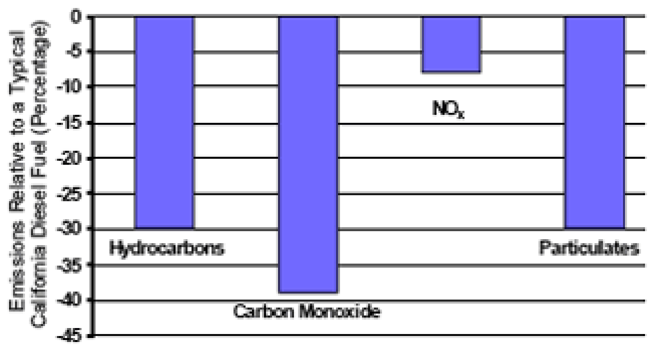

Figure 33: Gas to liquid diesel exhaust emissions relative to typical California diesel exhaust emissions

Synthetic diesel can be easily contaminated with sulfur from storage in tanks previously used to store regular diesel.

Table 8: Comparison of Synthetic Diesel to Conventional Diesel

Fuel Property	Sulfur (ppm)	Aromatics (%)	Cetane Number	Heating Value (Btu/gal)	Specific Gravity
October 2006 EPA Conventional Diesel	15	35	40	130,000	0.85
EU EN 590 Diesel	50	N/A	51		
Synthetic diesel	0	0	>74	120,000	0.77

Biodiesel

Biodiesel is a clean-burning alternative fuel, produced from domestic, renewable resources. Though derived from biological sources, it is a processed fuel that can be readily used in diesel engines, which distinguishes biodiesel from the straight vegetable oils (SVO) or waste vegetable oils (WVO) used as fuels in some modified diesel vehicles.

Biodiesel contains no petroleum, but it can be blended at any level with petroleum diesel to create a biodiesel blend. Biodiesel blends are denoted as "BXX," with "XX" representing the percentage of biodiesel contained in the blend (e.g., B20 is 20% biodiesel, 80% petroleum diesel). It can be used in compression-ignition (diesel) engines with little or no modification. Biodiesel is simple to use, biodegradable, nontoxic, and essentially free of sulfur and aromatics.

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Biodiesel is made through a chemical process called transesterification (vegetable oil, alcohol, with a catalyst with by-products of fatty acids and glycerine) whereby the glycerin is separated from the fat or vegetable oil. The process leaves behind two products—methyl esters (chemical name for biodiesel) and glycerin (a valuable by-product usually used in soaps and other products).

Biodiesel is reported to be favorable for the environment because it is made from renewable resources and has lower emissions compared to petroleum diesel (i.e., PM, HC, and CO), but NO_x increases slightly. The claims to reduce CO_2 emissions are primarily attributed to the fact that it is a renewable resource and not the result of comparative exhaust CO_2 emissions[72]. European studies show mixed results[73,74]. The USDOE and USDA did a life cycle analysis of biodiesel and Petroleum Diesel in the late 1990's[75]

A 2002 EPA investigation[72] revealed that biodiesel impacts on emission for diesel powered vehicles vary depending on the type of biodiesel (soybean, rapeseed, or animal fats) and on the type of conventional diesel in the blend. Additionally, predictions could not be made regarding the effects of biodiesel on nonroad diesel powered equipment. EPA's study drew no conclusions on appropriateness of its use for any purpose or in any particular context, but was to inform parties considering biodiesel. States may use the EPA report but it is not intended to be used as a guide to promulgate regulations either by the federal or local regulatory bodies. The EPA study's scope did not include

Engine Durability	Renewability/full fuel lifecycle emissions
Materials Compatibility	Biodiesel production feedstocks or costs
Fuel Storage Stability	Cold flow properties
Lubricity	Cost

The EPA study did incorporate:

Engine/vehicle technology	Base fuel to which biodiesel is added
Highway versus nonroad engines	Light versus heavy-duty
Test cycle	Type of biodiesel (soybean, rapeseed, grease)

Biodiesel is less toxic than table salt and biodegrades as fast as sugar. Since it can be readily made in the US and other countries from renewable resources such as soybeans, its use decreases dependence on foreign oil and contributes to the US economy.

Chemically, most biodiesel consists of alkyl (usually methyl) esters instead of the alkanes and aromatic hydrocarbons of petroleum derived diesel. Biodiesel has combustion properties similar to petrodiesel; however, its combustion energy content is lower by 8 to 10%. Paraffin biodiesel also exists. Due to the purity of the source, it has a higher quality than petrodiesel.

Biodiesel does have the disadvantage of degrading certain types of rubber gaskets and hoses in vehicles (mostly found in vehicles manufactured before 1992). Biodiesel's higher lubricity index compared to petrodiesel is an advantage and can contribute to longer fuel injector life. Biodiesel is a better solvent than petrodiesel and has been known to break down deposits of residue in the fuel lines of vehicles that have previously been run on petroleum. Fuel filters may become clogged with particulates if a quick transition to pure biodiesel is made, but biodiesel cleans the engine in the process.

The flash point of biodiesel (>150°C) is significantly higher than petroleum diesel (64°C) or gasoline (−45°C). The gel point of biodiesel varies depending on the proportion of different types of esters contained. However, most biodiesel, including that made from soybean oil, has a somewhat higher gel and cloud point than petroleum diesel. In practice this often requires heating storage tanks, especially in cooler climates.

Pure (B100) biodiesel tends to gel at 4°C (40 °F) or so, depending on the mix of esters. As of 2006, there is no available product that will significantly lower the gel point of straight biodiesel. A number of studies have concluded that winter operations require a blend of biodiesel, #2 low sulfur diesel fuels, and #1 kerosene. The exact blend depends on the operating environment; successful operations have used a 65% LS #2, 30% K #1, and 5% bio blend. Others have run a 70% LS #2, 20% K #1, and 10% bio blend or a 80% K#1, and 20% bio blend. Factors in choosing a blend include volume, component availability, and local economics.

Biodiesel is hydrophilic. Some of the water present is residual to processing, and some comes from storage tank condensation. Water is a problem because:

- Water reduces the heat of combustion of the bulk fuel. This means more smoke, harder starting, and less power.
- Water causes corrosion of vital fuel system components: fuel pumps, injector pumps, fuel lines, etc.
- Water freezes to form ice crystals near 0°C. These crystals provide sites of nucleation and accelerate gelling of the residual fuel.
- Water accelerates growth of microbe colonies which can plug up a fuel system. Biodiesel users who have heated fuel tanks therefore face a year-round microbe problem.

Biodiesel has a number of advantages:

- Biodiesel reduces emissions of CO by approximately 50% and carbon dioxide by 78% on a net life-cycle basis because the carbon in biodiesel emissions is recycled from carbon that was already in the atmosphere, rather than being new carbon from petroleum that was sequestered in the earth's crust[76].
- Biodiesel contains fewer aromatic hydrocarbons: benzofluoranthene: 56% reduction; benzopyrenes: 71% reduction.
- It also eliminates sulfur emissions (SO_2), because biodiesel does not contain sulfur.
- Biodiesel reduces by as much as 65% the emission of particulates, small particles of solid combustion products. This reduces cancer risks by up to 94 % according to testing sponsored by the Department of Energy.
- Biodiesel does produce more NOx emissions than petrodiesel, but these emissions can be reduced through the use of catalytic converters. Increase in NOx emissions may also be due to the higher cetane rating of biodiesel. Properly designed and tuned engines may eliminate this increase.
- Biodiesel has higher cetane rating than petrodiesel, and therefore ignites more rapidly when injected into the engine. It also has the highest energy content of any alternative fuel in its pure form (B100).
- Biodiesel is biodegradable and non-toxic
- In the US, biodiesel is the only alternative fuel to have successfully completed the Health Effects Testing requirements (Tier I and Tier II) of the Clean Air Act (1990).

Biomass to Liquid

Another process to obtain a renewable energy source is biomass to liquid (BTL). BTL is a multistep process to produce liquid fuels out of biomass. The Fischer Tropsch process is used to produce synfuels out of gasified biomass. While biodiesel and bio-ethanol production process only uses parts of a plant, i.e., oil, sugar or starch, BTL production uses the whole plant which is gasified or converted by enzymatic action to carbon monoxide or dioxide. The result is that for BTL, less land area is required per unit of energy produced compared with biodiesel or bio-ethanol. The process hydrogenates the oils (fatty acid esters) into alkanes, to produce diesel and chemically decomposes the organic materials by heating in the absence of oxygen or any other reagents and produces sour oil, charcoals and gas at 450°C (also called anhydrous pyrolysis).

E Diesel

E diesel is a blend of diesel fuel, up to 15% ethanol, and one of several proprietary additives to keep the ethanol emulsified under all conditions. A number of on-road and off-road fleet demonstrations have shown E-diesel has the potential to reduce emissions from diesel engines, especially particulate emissions. There is considerable debate if this can be accomplished and does not have an energy deficit.

3.7.4 Unconventional Power Generation

Generating power in the E&P sector more efficiently could reduce emissions, reduce noise, and reduce costs. Assume the following scenario: a 2500 hp drawworks rig (7500 hp total); 0.33 brake specific fuel consumption or an equivalent 40% thermal efficiency; 137,000 BTU/gal LHV diesel, diesel price of $2.00/gallon, and 80% utilization factor (7,000 hours); then an estimate of the emission abatement and cost savings for generating power differently than by using diesel generators or much more efficiently. Table 9 shows that for a reduction of power generated with diesel an annual savings of at least $500,000 are realized and a reduction of over 2800 tons of emissions.

Realistically, it is extremely doubtful that diesel or gas engines will be replaced as prime movers on a drilling rig in the near term. However, they can be supplemented by other energy sources. Additionally, converting a "free" energy source to electrical energy and storing it efficiently during less energy demanding operations should accomplish this objective. Electrical power could be obtained by wind, solar cell panels, and regenerative braking and stored in batteries, capacitor banks, or through hydrogen using electrolysis and then using a fuel cell to convert the hydrogen back to water. The hydrogen could be used to supplement fuel in the regular engine especially if bi-fuel is used.

Table 9: Benefits of Reduced use of Diesel to Generate Electricity

% power generated without diesel	10%	20%	65%
Power saved hp (kW)*	750 (560)	1500 (1120)	4875 (3637)
Diesel saved gals/hr	35	70	227
(gals/year)	245,000	490,000	1.6×10^6 gals
Savings /rig @$2.00/gal	$490k	$980k	$3.2MM
Emissions reduction tonnes/year			
NO_x	88	175	573
CO	13	26	85
SO_x	19	39	125
CO_2	2766	5531	17976

*Assumes 0.33 BSFC $GPH = \frac{BSFC * HP}{\rho}$; TE=40%; TE= $\frac{0.1335}{BSFC}$

$\rho = 7.1$ lbs/gal; HP= Power Saved BSCF = Brake Specific HP

Power from Wind

Generation of power for drilling and production operations by wind is feasible and capacity and costs for a 500 kW wind turbine could be about $0.5 million. Ideally this could generate about 10% of the power needed on the hypothetical 2500 hp drilling rig or approximately 4.4MWhr per year of energy assuming 100% capacity factor. Most of the information is taken from the National Renewable Energy Laboratory Documentation or from the America Wind Energy Association (AWEA)[77].

The wind is slowed dramatically by friction as it brushes the ground and vegetation, it may not feel very windy at ground level. Yet the power in wind may be five times greater at the height of a 40-story building (the height of the blade tip on a large, modern wind turbine) than the breeze on your face. Furthermore, the wind is accelerated by major land forms, so that entire areas of the country may be very windy while other areas are relatively calm.

Wind turbines come in a variety of sizes, depending on the use of the electricity (Figure 37). Large, utility-scale turbines described above may have blades over 40 meters long, meaning the diameter of the rotor is over 80 m – nearly the length of a football field. The turbines might be mounted on towers 80 meters tall (one blade would extend about half way down the tower), produce 1.8 MW of power, supply enough electricity for 600 homes and cost over $1.5 million. Additionally there are two basic designs of wind electric turbines: vertical-axis wind turbine (VAWT) or "egg-beater" style and horizontal-axis (propeller-style) wind turbine (HAWT) machines (Figure 34). Horizontal-axis wind turbines are most common today, constituting nearly all of the utility-scale (100 kW capacity and larger) turbines in the global market.

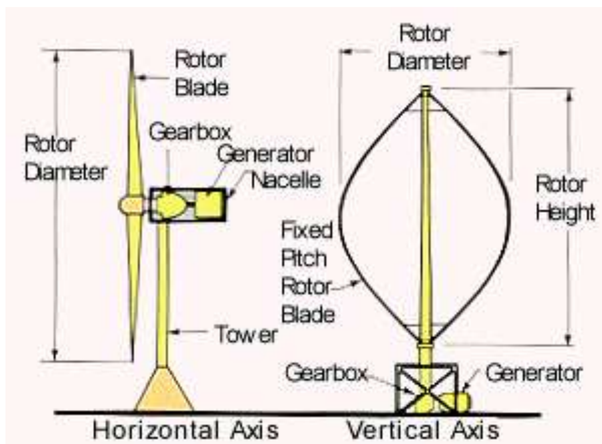

Figure 34: Wind Turbine Configurations

The Darrieus wind turbine consists of a number of aerofoils vertically mounted on a rotating shaft or framework (right drawing in Figure 34). This design was patented by Darrieus, a French aeronautical engineer, in 1927 and is sometimes referred to as the "egg-beater" wind turbine.

Unlike the more common type of generator which uses a propeller, the Darrieus generator rotates around the vertical axis rather than the horizontal one, and is thus referred to as a vertical axis wind turbine (VAWT). Conventional propeller-based systems are known as a horizontal axis wind turbine (HAWT), although this term is used only when discussing VAWTs. The vertical arrangement has several advantages, notably the generator can be placed at the ground for easy servicing, and the main supporting tower can be much lighter as much of the force on the tower is transmitted to the bottom.

The Darrieus type is theoretically just as efficient as the propeller type, but in practice this efficiency is rarely realized due to the physical stresses and limitations imposed by a practical design. In addition, propeller based designs have a wider operating speed range and are self-starting.

One problem with the design is that the angle of attack changes as the turbine spins, so each blade generates maximum torque at two points on its cycle (front and back of the turbine). This leads to a sinusoidal power cycle that complicates design. In particular, almost all Darrieus turbines have resonant modes where, at a particular rotational speed, pulsing is at a natural frequency of the blades that can cause them to (eventually) break. For this reason, most Darrieus turbines have mechanical brakes or other speed control devices to keep the turbine from spinning at these speeds for any lengthy period of time.

Another problem arises because the majority of the mass of the rotating mechanism is at the periphery rather than at the hub, as it is with a propeller (HAWT). This leads to very high centrifugal stresses on the mechanism, which must be constructed stronger and heavier to withstand them. One common approach to minimize this is to curve the wings into an “egg-beater” shape such that they are self supporting and do not require heavy supports and mountings.

In this configuration, the Darrieus design is theoretically less expensive than a conventional type, as most of the stress is in the blades which supply torque against the generator located at the bottom of the turbine. The only forces that need to be balanced vertically are the compression load due to the blades flexing outward (thus attempting to squeeze the tower), and the wind force trying to blow the complete turbine over, half of which is transmitted to the bottom and the other half of can easily be offset with guy wires.

By contrast, a conventional design has all of the force of the wind attempting to push the tower over at the top, where the main bearing is located. Additionally, guy wires cannot easily be used to offset this load, because the propeller spins both above and below the top of the tower. Thus, conventional designs require an extremely strong tower that grows dramatically with the size of the propeller.

In an overall comparison, the Darrieus design allows placing much more of its weight (and cost) into components that actually generate power—the blades—and much less into supporting them. Additionally, the generator and main bearings are located at the bottom where they can be easily serviced. A final advantage to the design is that the blades typically spin at a speed near that of the wind, which birds do not have a problem avoiding. By contrast, propeller tips of conventional designs spin at very high speeds, often over 100 km/h (62 mph), which causes serious problems with bird and bat strikes.

There are several variations of the Darrieus design. One is the Giromill which replaces the long egg beater blades of the Darrieus design with straight vertical blade sections attached to the central tower with horizontal supports (Figure 35). The Giromill blade design is much simpler to build, but places more weight into the structure as opposed to the blades, and requires that the blades be stronger. Cycloturbines have blades that are mounted so they can rotate around their vertical axis. This allows the blades to be “pitched” so that they always have some angle of attack relative to the wind. The main advantage of this design is that torque generated remains almost constant over a fairly wide angle, so a Cycloturbine with three or four blades has a fairly constant torque. Over this range of angles, the torque itself is near the maximum possible and therefore generates more power.

Savonius wind turbines are a type of vertical axis wind turbine used for converting the power of the wind into torque on a rotating shaft. They were invented by the Finnish engineer Savonius in 1922. Savonius turbines are one of the simplest turbines. Aerodynamically, they are drag-type devices consisting of two or three scoops. Savonius turbines extract much less of the wind's power than other similarly-sized lift-type turbines. Most anemometers are Savonius turbines, because efficiency is completely irrelevant for that application.

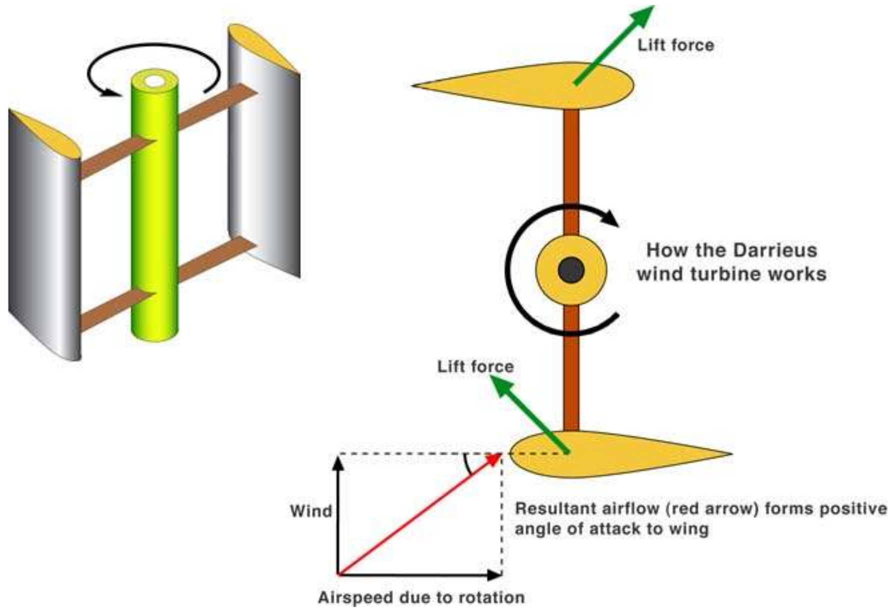

Figure 35: Darieus "egg-beater" wind turbine—working principles (source Wikepedia)

Wind turbines designed to supply part of the electricity used by a home or business are much smaller and less costly. A residential- or farm-sized turbine may have a rotor up to 15 m (50 ft) in diameter and be mounted on a metal lattice tower up to 35 m (120 ft) tall. These turbines may cost from as little as a few thousand dollars for very small units up to perhaps $40,000–$80,000[78].

The taller the turbine tower and the larger the area swept by the blades, the more powerful and productive the turbine. The swept area of a turbine rotor is a function of the square of the blade length (the circle's radius). Therefore, a fivefold increase in rotor diameter (from 10 meters on a 25-kW turbine built in the 1980s to 50 meters on a 750-kW turbine common today) yields a 55-fold increase in electricity output, partly because the swept area is 25 times larger and partly because the tower height has increased substantially, and wind speeds increase with distance from the ground[79] .

$$P = \frac{\rho \pi r^2 v^3}{2}$$

P = power (kW)
ρ = density of power fluid (i.e., air)
r = length of blade
v = wind velocity

Economics of wind energy have changed dramatically over the past 20 years, as the cost of wind power has fallen approximately 90%. Despite that progress, the wind industry is still immature, with production volumes that pale in comparison to what is expected two decades from now. Factors affecting the cost of wind energy are still rapidly changing, and wind energy's costs will continue to decline as the industry grows and matures. Currently the costs of installing a large wind facility are about $1.3 MM/MW. The primary factor affecting economics of wind energy is wind speed. Average wind speeds in the US are shown in Figure 38.

Capacity Factor

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Since the wind does not blow at the maximum rate to develop the design power of a wind turbine constantly, a capacity factor is used to calculate or evaluate a turbine's power generating ability in a certain area. Typical capacity factors range from 0.25 to 0.4 (note these are not efficiency ratings). Capacity factors are calculated by the energy generated over a specific time divided by the energy generated over that same period of time at the rated power or capacity. Capacity factors for a coal fired or fossil energy fueled system are about 0.85 or greater since they operate practically constantly. Efficiency of these fueled systems, however, is less than 35%. If the initial power of a 500-kw wind turbine was 100% approximately 4.4MWhr per year of electricity would be available however about 30% is a realistic value or 1.3MWhr per year of electricity would be generated. Energy storage devices would allow more efficient use of this and other power as needed in industrial operations like drilling rigs.

Wind Turbine Component Characteristics

Wind turbines have considerable components. Research has significantly improved the efficiency of the rotor and maximized the energy capture of the machine and developed light weight plades and generating machinery. Nonethelss the machines for high capacity energy generation can be quite large. A tower is roughly 60% of the turbines' weight above the foundation.

Table 10: Example of Cost of Components for A 750-Kw Wind Turbine Total Cost $781,940 2005 USD

Component	Weight (tons)	Dimensions Feet	Typical % Machine Wt	Typical % of Machine cost
Rotor	16	164 feet	10-30	28
Hub	4	7.4feet x 7.4feet		
Blade	4	80 feet		
Tower	66	213 feet	30-65	26*
Base diameter		12.1 Feet		
Top diameter		6.2 Feet		
Nacelle.	34	20' x 10' x 10 '	25-40	21.7
Gearbox and drivetrain			5-15	17.3
Generator System			2-6	7.0
Total	116		100	100
Sources "wind Turbine Development: Loacation of Manufacturing Activity"; REPP September 2004 "Wind Tubine _material and Manufacturing Fact Sheet", Princeton Energy Resources Int. August 2001				
Includes tower base cost				

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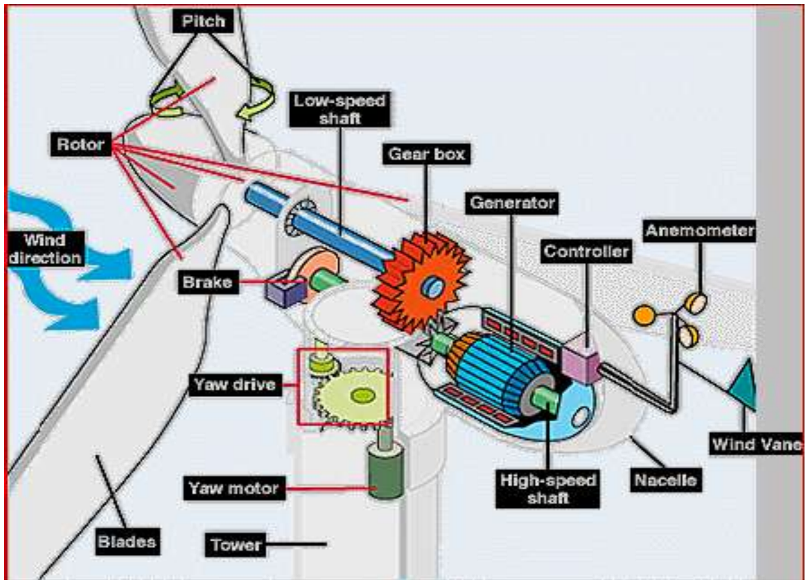

Figure 36: Schematic of Wind Turbine major subcomponents

The installation of windpower at remote site becomes a cumbersome and difficult project for larger turbines as they necessitate the use of large conventional cranes which become a significant part of the installation cost. In 2001 DOE contracted Global Energy Concepts (GEC) through Wind Partnerships for Andvanced Compnent Technologies (WindPact) to explore the feasibility including cost effectiveness of self erecting wind turbines. GEC evaluated 10 different concepts with two methods selected for further evaluation. The two methods compared favorably to conventional cranes for 1.5-MW and larger turbines but were more expensive than conventional cranes for smaller turbines. For remote locations GEC concluded that self-erection techniques has the potential to reduce the costs for larger turbines in complex terrain where significant disassembly of the large conventional cranes will be required to change turbine locations. Additionally the use of self erection techniques has the potential to reduce the costs of installing smaller turbines on taller towers.[80] GEC also reports that several companies are developing selferection schems for self-erecting turbines as small as 660 kW.

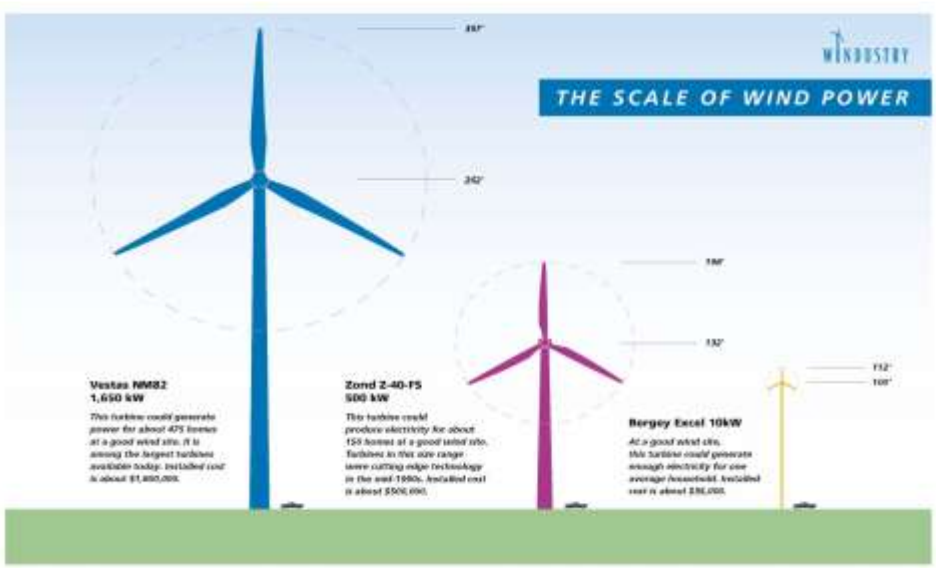

Figure 37: Wind Turbine Scales

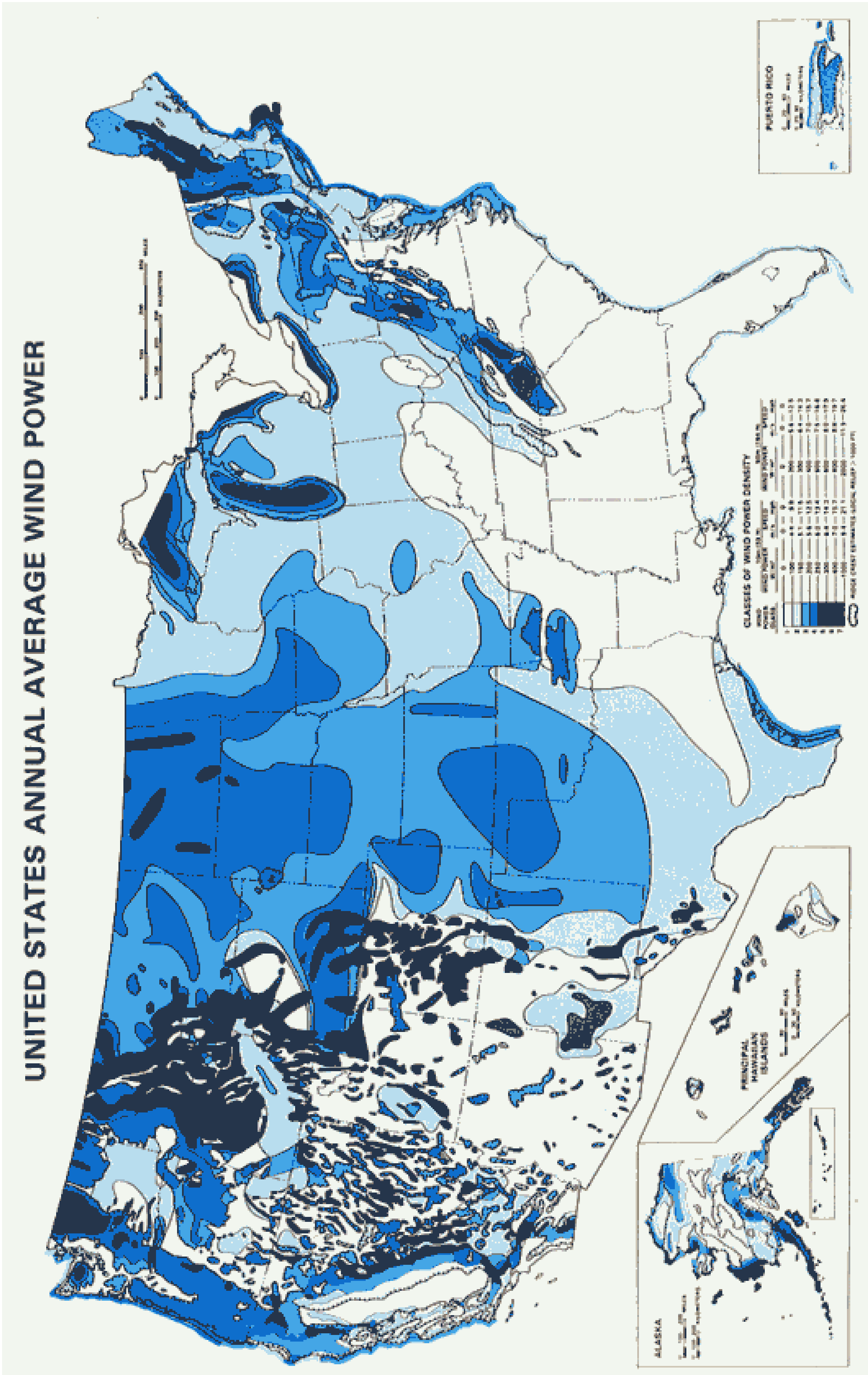

Figure 38: United States Average Wind Speed

Solar Cells

A solar cell is a semiconductor device that converts photons from the sun into electricity. The general term for a solar cell including both solar and non-solar sources of light (such as photons from incandescent bulbs) is a photovoltaic cell. Fundamentally, the device needs to fulfill only two functions: photogeneration of charge carriers (electrons and holes) in a light-absorbing material, and separation of the charge carriers to a conductive contact that will transmit electricity.

Solar cells have many applications. They are particularly well suited to situations where electrical power from the grid is unavailable, such as in remote area power systems, Earth orbiting satellites, handheld calculators, remote radiotelephones, and water pumping applications. Assemblies of solar cells (in the form of modules or solar panels) on building roofs can be connected through an inverter to the electricity grid in a net metering arrangement.

There is a common notion that solar cells never produce more energy than it takes to make them. While the expected working lifetime is around 40 years, the energy pay-back time of a solar panel is anywhere from 1 to 30 years (usually under 5). This means that solar cells can be net energy producers and can "reproduce" themselves from 6 to more than 30 times over their lifetime. Figure 39 illustrates various commercial large-area module energy conversion efficiencies and the best laboratory efficiencies obtained for various materials and technologies.

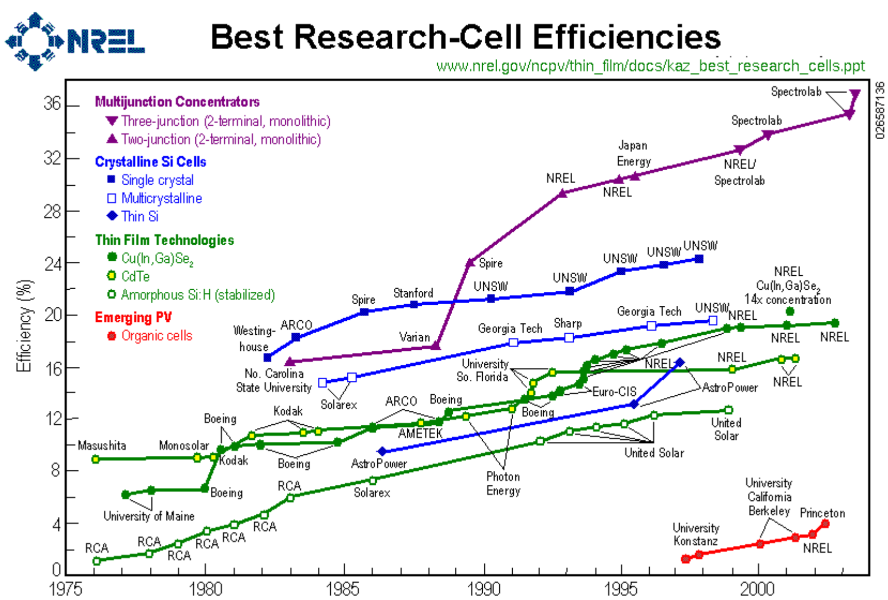

Figure 39: Reported timeline of solar cell energy conversion efficiencies (from National Renewable Energy Laboratory (USA))

Today's commercial PV systems can convert from 5% to 15% of sunlight into electricity. They are highly reliable, and usually last 20 years or longer. The cost of PV-generated electricity has dropped 15- to 20-fold, and PV modules now cost around \$6/W and produce electricity for as little as \$0.25–0.30/kW-hr (www.sandia.gov/pv).

On a bright day, the sun delivers about 1 kW/m² to the Earth's surface. Typical solar panels have an average efficiency of 12% (with the best commercially available panels at 20%, and recent prototype panels at around 30%). This would result in 200 W/m². However, not all days have bright sunlight, and therefore less solar energy can be captured. At middle northern latitudes, on average 100 W/m² in winter and 250 W/m² in summer reach the ground. With a conversion efficiency of about 20%, one can expect between 20 and 50 W/m^2 of solar cells. The unpopulated Sahara desert is over 9 million km², with less cloud cover and better solar angle, corresponding to 83 MW/km², or 750 TW total. The Earth's current electrical energy consumption is near 1.6 TW, and total energy is around 14 TW at any given moment (including oil, gas, coal, nuclear, and hydroelectric power).

In 2005, the most important issue with solar panels was cost, which was at $3–4/W ($3,000 to $4,000 per kW) of installed power. Because of much increased demand, the price of silicon used for most panels is now experiencing upward pressure. This has caused developers to start using other materials and thinner silicon to keep costs down. Due to economies of scale, solar panels is less costly as people buy more. As manufacturers increase production, cost is expected to continue to drop in the years to come. As of early 2006, average cost per installed watt increased to $4.50 to $6.

While solar's theoretical potential is enormous, the high cost of power limits the use of solar energy in most applications. If its potential is to be realized, solar costs must be reduced. Until costs are reduced, solar power is most likely to be developed in areas with high electricity costs, where solar's ability to generate during summer peak hours is most valued, and in off-grid applications, where the expense of electric line extensions make distributed solar technologies cost-effective. Compare this with generating with diesel at $3/gal (137,000 btu/gal) equates to $0.075/kW-hr and efficiency of 40% of $0.187/kW-hr with an installed cost for an engine/generator set of approximately $360/kW.

The industry's focus has been to reduce the PV system cost "culprit"—the silicon solar cell. Most approaches strive to reduce the silicon material content, many of which involve reducing the thickness of the cells themselves by using very thin films (like paints) of the material. Amonix, because of its extensive background in high-tech semiconductor design and manufacturing, pursued a highly effective approach which involves reducing the area of cell material required to generate a given amount of electricity. This is the high-concentration concept. Amonix has been successful in reducing the silicon cell area by over 250 times with its high-concentration photovoltaic (HCPV) system and MegaModule™ design.

An ordinary, flat-plate solar module has its entire sun-receiving surface covered with costly silicon solar cells and is positioned at a fixed tilt to the sun. In contrast, Amonix's systems offer significant cost savings by using inexpensive flat, plastic Fresnel lenses as an intermediary between the sun and the cell (Figure 40). These magnifying lenses focus and concentrate sunlight approximately 250 times onto a relatively small cell area and operate similarly to the glass magnifying used in light house to concentrate the light using a short focal length (Figure 40). Through concentration, the required silicon cell area needed for a given amount of electricity is reduced by an amount approximating its concentration ratio (250 times). In effect, a low cost plastic concentrator lens is being substituted for relatively expensive silicon.

To optimize PV performance, concentrating systems must track the sun to absorb its direct normal light. Amonix developed a proprietary hydraulically-driven tracker to accomplish this. Because Amonix's systems actively track the sun to concentrate sunlight onto the cell, they maximize energy production throughout the day. Field results indicate that approximately 30% more energy is captured by Amonix's systems than with fixed, one-sun systems. Amonix's effective implementation of concentration and tracking offers the possibility of the lowest levelized cost (cents/kWh) of any solar generated electricity[81].

The characteristics of this low-cost solar electricity generator concept are: low footprint and minimum land requirements; air-cooled (excellent for dry environments); modular design and scalability; Plug&Power™ design; proven performance and reliability; variable applications; pollution-free and quiet.

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Technical specifications are presented in Table 11 and examples shown in Figure 41 and Figure 42. Amonix estimated a budgetary figure of $6/W installed for a system size of 3 MW peak in 2007.[82]

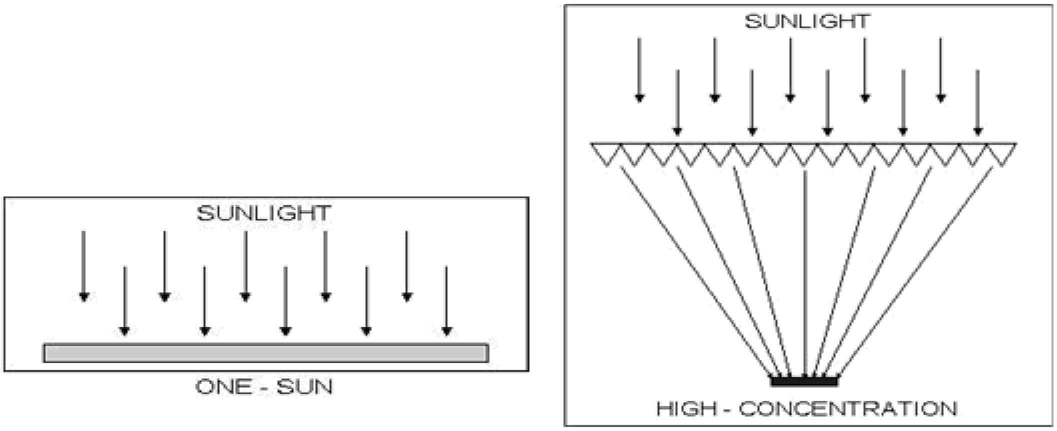

Figure 40: High-Concentration Photovoltaic (HCPV) Concept

Figure 41: A four MegaModule™ System produces 20,000 watts

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Figure 42: APS's 100 kW Amonix HCPV installation at Glendale, Arizona

Table 11: HCPV Specifications

	Individual MegaModule™	**Full-Size IHCPV System**
Rated Power Output:	5 kW AC	25 kW AC
Rating Conditions:	850 W/m^2 DNI, 25°C ambient, 1 m/s wind speed	850 watts/m^2 DNI, 25°C ambient, 1 m/s wind speed
Concentration Ratio:	250:1	250:1
MegaModule™ Size:	45' x 11' x 2.5'	45' x 55' x 2.5'
MegaModule™ Weight:	6000 lb	
Aperture Area:	392 ft^2 (36.4 m^2)	1960 ft^2 (182 m^2)
Average DC Efficiency:	18%	18%
Tracking Accuracy:		<0.25° RMS
Average DC System Efficiency:		18%
Average AC System Efficiency:		16%
Operating Voltage:		277/480 volts AC
Average Land Requirements:		0.01 acres per kilowatt
Stow Position Wind Speed:		30 mph

Fuel Cells

Fuel cells are electrochemical devices that convert chemical energy in fuels into electrical energy directly, thereby promising power generation with high efficiency and low environmental impact. Because the intermediate steps of producing heat and mechanical work typical of most conventional power generation methods are avoided, fuel cells are not limited by thermodynamic limitations of heat engines such as the Carnot efficiency. In addition, because combustion is avoided, fuel cells produce power with minimal pollutants associated with internal combustion engines. However, unlike batteries the reductant and oxidant in fuel cells must be continuously replenished to allow continuous operation. Fuel cells bear significant resemblance to electrolyses. In fact, some fuel cells operate in reverse as electrolyses, yielding a reversible fuel cell that can be used for energy storage. The latter is the primary but not the only emphasis of this project to use fuel cells[83].

Though fuel cells could, in principle, process a wide variety of fuels and oxidants, of most interest are those fuel cells that use common fuels (or their derivatives) or hydrogen as a reductant, and ambient air as the oxidant. A variety of fuel cells are in different stages of development. The most common classification of fuel cells is by the type of electrolyte used in the cells and includes (1) polymer electrolyte fuel cell (PEFC), (2) alkaline fuel cell (AFC), (3) phosphoric acid fuel cell (PAFC), (4) molten carbonate fuel cell (MCFC), and (5) solid oxide fuel cell (SOFC). Broadly, the choice of electrolyte dictates the operating temperature range of the fuel cell. The operating temperature and useful life of a fuel cell dictate the physicochemical and thermomechanical properties of materials used in the cell components (i.e., electrodes, electrolyte, interconnect, current collector, etc.).

An international consortium is developing the world's largest fuel cell vehicle, a 109 metric-ton 1.2 MW locomotive for defense and commercial railway applications. Commencing May 2003 with funding of $1 million for its one-year first phase, the five-year development and demonstration project completed a major deliverable: conceptual design of the fuel cell locomotive's onboard fuel storage, off-board hydrogen generation plant, refueling system, fuel cell powerplant, and locomotive layout (http://www.fuelcellpropulsion.org/). The project was conceived, organized, and is led by Vehicle Projects LLC of Denver, and is funded and administered by the US Army Research, Development, and Engineering Command's National Automotive Center (NAC), Warren (MI).

This same concept can be used for drilling rigs and production operations, where all or a portion of the power can be obtained using a fuel cell. Hydrogen can be obtained from electrolysis of water using the electricity generated from solar cell panels, wind turbines, or regenerative braking. These technologies and current art are discussed in this technology assessment.

Regenerative Power Capture

Eddy current braking mechanisms are fairly common on larger drilling rigs, especially offshore. When the industry moved offshore into waters requiring subsea BOPs and marine risers, it was no longer considered safe to use hydromatic brakes to control the huge weights involved. Gribbin and Baylor acquired the rights to build dynamic brakes for rigs in 1946. The eddy-current braking system does not depend on water pressure to work and is not at risk for burst connections. Moreover, the dynamic brake can handle cyclic overloads often encountered when floating vessels heave in ocean swells. In 1954, they formed the Baylor Company to build and install Elmagco brakes. So effective was their product that it can be said that every offshore rig using a subsea BOP system is equipped with the Baylor-Dynamic Elmagco Brake[84]. National Oilwell now owns Baylor.

Eddy current brakes slow down motion effectively, but do not provide dynamic stability (they cannot completely stop motion). While friction brakes are not replaced, they can become smaller, cheaper, and safer. When metal moves through a spatially varying magnetic field, or is located in a changing magnetic field, induced currents (eddy currents) begin to circulate through the metal. In the case of the eddy current brake, a rotating disk has a magnetic field passing through it perpendicularly, but it is only strong where the magnet is located. Currents in that area experience a side thrust, which opposes the rotation of the disk. This interaction of field and current, results in braking of the disk. The return currents close via parts of the disk where the field is weak, so there is a drag force only in the generating region. Note that motion does not have to be rotational but can be linear as for dynamic braking of a railway train using the rails. These systems can also be designed as linear motors to propel trains. This same linear motor concept could be used as lifting units and vertical braking also, possibly replacing the drawworks.

Though not a new concept, regenerative brakes have most recently been introduced to produce battery-electric and hybrid-electric vehicles. Electric regenerative brakes descended from dynamic brakes (rheostatic brakes in the UK) which have been used on electric and diesel-electric locomotives and streetcars since the mid-20th century. In both systems, braking is accomplished by switching motors to act as generators that convert motion into electricity instead of electricity into motion, but in the earlier systems the electrical power was dissipated through banks of resistors rather than being stored for future use. This means the system was no more efficient than conventional friction brakes, but it reduced the use of contact elements (brake pads), which eventually wear out. Traditional friction-based brakes must also be provided to be used when rapid, powerful braking is required.

Like conventional brakes, dynamic brakes convert rotational energy into heat energy, but this is accomplished by passing the generated current through large banks of resistors that dissipate the energy. When the energy is meant to be dissipated externally, large radiator-like cowls can be employed to house the resistor banks.

Electric railway vehicles feed recaptured energy back into the grid, while road vehicles store it for re-acceleration using flywheels, batteries, or capacitors. It is estimated that regenerative braking systems currently provide 31.3% efficiency; however, actual efficiency depends on numerous factors, such as the state of charge of the battery, how many wheels are equipped to use the regenerative braking system, and whether the topology used is parallel or serial.

The main disadvantage of regenerative brakes when compared with dynamic brakes is the need to closely match electricity generated with the supply. With DC supplies, this requires the voltage be closely controlled. Only with the development of power electronics has it been possible with AC supplies where the supply frequency must also be matched (this mainly applies to locomotives where an AC supply is rectified for DC motors).

It is usual (in railway use) to include a back-up system such that friction braking is applied automatically if the connection to the power supply is lost. Also in a DC system or in an AC system that is not directly grid connected via simple transformers, special provision also has to be made for situations where more power is being generated by braking than is being consumed by other vehicles on the system.

A small number of mountain railways have used three-phase power supplies and three-phase induction motors and have thus a near constant speed for all trains as the motors rotate with the supply frequency both when giving power or braking.

An eddy-current brake and an induction motor are similar machines with very few differences[85]. A properly designed induction motor can therefore be operated as a motor-generator, as an eddy current brake or both at the same time. It is suggested that induction motors can be used for trains, cars, and hoisting apparatus via various energy storage and controlling technology. As mentioned previously these do not have to be rotating devices but can be liner horizontal or vertical.

Patent application 2006/0076171 by Donnelly et al. presents technology to use regenerative braking in a hybrid train locomotive. Four methods for recovering energy and energy storage are disclosed using traction motors as well as using a battery pack

In 1983 patent US 4,382,189 suggested that electrical energy generated from traction motors of a train system be used to electrolyze water into its components of hydrogen and oxygen. Wilson suggested that hydrogen be used in the diesel engine for additional power when needed. Previous researchers suggested using pre-stored liquefied hydrogen and not generate it using the unutilized electrical energy. Using hydrogen as a fuel directly in an internal combustion engine is well known and not much different from the engines used with gasoline. The problem is that while hydrogen supplies three times the energy per pound of diesel and gasoline, it has only one-tenth the density when the hydrogen is in a liquid form and very much less when it is stored as a compressed gas.

Eckstein suggests in patent application 2002/0117857 a similar concept but to use hydrogen in a fuel cell to generate electricity for the additional power when needed instead of increasing diesel consumption. This creates fewer emissions and improves the economy of rail operations. The water is a closed system as the hydrogen and oxygen formed by electrolysis cell is used to reform the water in a fuel cell. Hydrogen and oxygen are compressed and stored for a time when needed. The chemical theory and practical application of water electrolysis and fuel cells are well known. This concept is currently being demonstrated[86].

A similar diesel-electric regenerative hydropower cell system which uses two proven and uniquely complementary electro-chemical conversion techniques to store and regenerate the tremendous amounts of electricity created by the dynamic brakes of diesel-electric engine/generator sets which is currently being dissipated as heat, could be used to improve operational efficiency, reduce emissions, improve economy of drilling rig drawworks and other hoisting devices such as cranes, elevators, and the like. Hydropower cells use hydro-electrolysis to convert electricity into hydrogen and oxygen gas. The hydrogen and oxygen gas are pressurized and stored and subsequently used to supply fuel cells which create electricity via a chemical interaction with these two elements, with the only by-product being water and heat when peak power is needed.

Patent application US 2005/0173197 and US 2005/0173197 by Takehara and Ichimura described using a capacitor bank or a flywheel concept to store unutilized energy during load lowering process using a DC motor in hoisting apparatus such as cranes. Their claim is that the battery and generator energy storage of current art imposes small electrical capacity, electrical inefficiency, large, physical battery volume, heavy weight, and short battery life. Takehara and Ichimura also claim that the fly wheel has limits since the DC motor is not capable of the speeds necessary for efficient use of the system. They propose using a DC motor controlled by an AC generator delivering power through a diode converter. The system will be controlled through a programmable logic controller or PLC.

Guggari in patent 6,029,951 in 2000 disclosed a control system for oil rig drawworks. The method facilitated movement of a load suspended from the drawworks system and provided an improved method for transferring control between the brake arrangement and the prime mover associated with the drawworks system. Tajima et al. revealed in US patent application 2001/0011618 a power management control system for an elevator apparatus. The system uses a power storage device to capture energy generated during a braking cycle and during off-peak times from the power grid which is then used during peak power time instead of calling for power from the electric grid.

Power management control during regenerative braking has been proposed to reduce and monitor emissions and fuel consumption during power generation (US2005/0285554 King, and Staphanos 2005/0188745, US2005/0029814, 2006/0012320).

3.7.5 Energy Storage Devices

Most unconventional power generating technologies discussed above need an energy storage system to affect an environmentally friendly system. There are several commercially viable energy storage systems that are being improved for hybrid electric vehicles (HEV's) today. Major advances are being made regularly. This is a result of the government subsidizing a large amount of the alternative fuel research by many US as well as foreign manufacturers. Types of devices that hold the most promise to solve energy storage problems are batteries, flywheels, and ultracapacitors (Figure 43). A good cost comparative study of energy storage devices up to 2001 is provided in the Sandia National Laboratory report by Susan M. Schoenung[87]

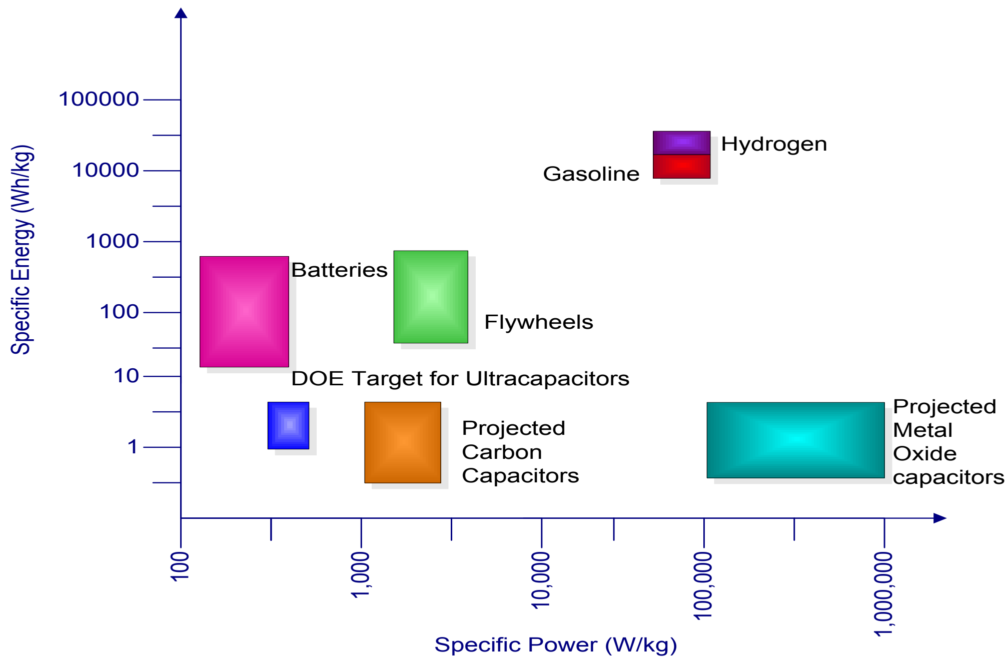

Figure 43: Electrical Power and Energy Storage Comparison (from NREL)

Batteries

There any many battery technologies currently in use or being developed, with lead-acid (Pb-acid), nickel cadmium (NiCd), and nickel metal hydride (NiMH) being the most promising technologies. Batteries have a limited number of charge/discharge cycles and take time to charge and discharge because the process involves chemical reactions with non-instantaneous rates. These chemical reactions are accompanied by parasitic thermal release that causes the battery to heat up. Batteries have a limited life cycle with a degrading performance and acidic batteries are hazardous to the environment. Once used, disposal becomes a significant environmental concern.

Capacitor Banks

Capacitors are among the most essential building blocks of electronic circuits to hold DC voltages. Based on the same principle, but on a much larger scale, it is conceivable that capacitors could be used to store energy for extended periods of time. Until recently capacitors only managed to hold very little energy compared to a conventional battery.

In 1997, researchers from CSIRO (Australian Research Organization) developed the first supercapacitor—a capacitor able to hold significantly more charge using thin film polymers for the dielectric layer. The electrodes are made of carbon nanotubes. Energy density of a normal capacitor is only 0.5 W-hr/kg. PET (polyethylene terephthalate) supercapacitors can store four times more energy.

Carbon nanotubes and polymers are practical for supercapacitors. Carbon nanotubes have excellent nanoporosity properties allowing the polymer tiny spaces to sit in the tube and act as a dielectric. Polymers have redox (reduction-oxidation) storage mechanism along with a high surface area.[88] Some researchers are replacing carbon nanotubes with ceramics for their superconducting properties.

Supercapacitors are well suited to replace batteries in many applications. This is because at the moment their scale is comparable to that of batteries, from small units used in cellular phones to large that can be found in cars. Even though supercapacitors have a lower energy density as compared to batteries, they avoid many of the battery's disadvantages.

Supercapacitors can be charged and discharged an almost unlimited number of times. They can discharge in a matter of milliseconds and are capable of producing enormous currents. Hence they are very useful in load leveling applications and fields where a sudden boost of power is needed in a fraction of a second. They do not release any thermal heat during discharge.

Supercapacitors have a very long lifetime, which reduces maintenance costs. They do not release any hazardous substances that can damage the environment. Their performance does not degrade with time and they are extremely safe for storage as they easily discharged. They have low internal resistance, even if many of them are coupled together. Even though they have a lower energy density, are bulkier and heavier than an equivalent battery, they have already replaced batteries in many applications due to their readiness in releasing power.

Supercapacitors were initially used by the US military to start the engines of tanks and submarines. Most applications nowadays are in the field of hybrid vehicles and handheld electronic devices. NASA has a research project to use supercapacitors in an electric bus called the Hybrid Electric Transit Bus. The energy used to start the engine and accelerate the bus is regenerated from braking. During test runs, a bus loaded with 30 supercapacitors, each weighing 32 kg and releasing energy of 50 kJ at 200 V, managed to run for four miles.

In most hybrid vehicles, 42 V supercapacitors are used. General Motors developed a pickup truck with a V8 engine that uses a supercapacitor to replace the battery. The efficiency of the engine rose by 14%. The supercapacitor supplies energy to the alternator. Toyota developed a diesel engine using the same technology and it is claimed to use just 2.7 liters (0.7 gals) of fuel per 100 km (62 miles). In rural areas, where there are voltage sags in the power grid, supercapacitors can be used to reduce the effect of fluctuations.

A commercial supercapacitor can hold 2500 Farads, release 300 A of peak current with a peak voltage handling of about 400 V. The life-cycle of this supercapacitor is more than 10^6 charge/recharge cycles.

Flywheels

Very-high-speed flywheel systems are promising energy storage means for hybrid vehicles and systems. Flywheels store kinetic energy in a high-speed rotor. However, current technology makes it difficult to use the flywheel directly. The most common approach is to couple the flywheel to an electric machine—a combination often referred to as a mechanical battery. They provide many advantages over chemical batteries, including high specific energy, high specific power, long cycle life, high energy efficiency, low maintenance requirements, reduced environmental contamination, reduced sensitivity to temperature and cost effectiveness[85].

Flywheel energy storage (FES) works by accelerating a rotor to a very high speed and maintaining the energy in the system as inertial energy. Commercially available FES systems are used for small uninterruptible power systems. The rotors normally operate at 4000 RPM or less and are made of metal. Advanced flywheels, made of high-strength carbon-composite filaments, spin at speeds from 20,000–100,000 RPM in a vacuum enclosure. Magnetic bearings are necessary as rotary speeds increase to reduce friction found in conventional mechanical bearings. Quick charging is complete in less than 15 minutes. Long lifetimes of most flywheels, plus high energy (~130 Wh/kg) and high power are positive attributes. The round trip energy efficiency of flywheels can be as high as 90%. Since FES can store and release power quickly, they have found a niche in providing pulsed power. Flywheels are not affected by

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temperature changes as are chemical batteries, nor do they suffer from memory effects. Moreover, they are less limited in the amount of energy they can store. They are also less potentially damaging to the environment, being made of largely inert or benign materials. Another advantage of flywheels is that by a simple measurement of the rotation speed it is possible to determine the exact amount of energy stored. However, use of flywheel accumulators is currently hampered by the danger of explosive shattering of a massive wheel due to overload.

One of the primary limits to flywheel design is the tensile strength of the material used for the rotor. Generally speaking, the stronger the disc, the faster it may be spun, and the more energy the system can store. When the tensile strength is exceeded the flywheel will shatter, releasing all of its stored energy at once. This is commonly referred to as a “flywheel explosion” since wheel fragments can reach kinetic energy comparable to that of a bullet. Consequently, traditional flywheel systems require strong containment vessels as a safety precaution, which increases the total mass of the device. Fortunately, composite materials tend to disintegrate quickly once broken, and so instead of large chunks of high-velocity shrapnel, the containment vessel is only filled with red-hot sand. Still, many users of modern FES systems prefer to have them embedded in the ground to halt any material that might escape the containment vessel.

Where there is high cycle duty with a high ratio of peak-to-average power, there is strong potential to make systems smaller, lighter weight, and more efficient overall. For the oil industry this translates into higher portability, more rapid deployment, and quicker completion of wells. The ALPS flywheel (Figure 44) being developed by the University of Texas Center for Electromechanics, is a high density energy storage system to supply transportable power leveling in the rail industry. The 2-MW (3-MW peak) power rating and 100 kW-hr of usable energy storage are of a size useful to the drilling environment as well as any small utility. The design speed range of the flywheel is 7500–15,000 rpm. To withstand the spin stresses of the supersonic tip speed, the main rotor body is constructed of filament-wound graphite-epoxy composite.

The flywheel rotor, which weighs 5100 lb, is designed to store 130 kW-hr of energy at a peak design speed of 15,000 rpm. The graphite-epoxy composite rotor, which runs in a vacuum, is supported by a five-axis active magnetic bearing system. A high-speed 2-MW motor/generator, which is outside the vacuum, is directly coupled to the flywheel with an industrial disk pack coupling, through a custom integral rotary vacuum seal.

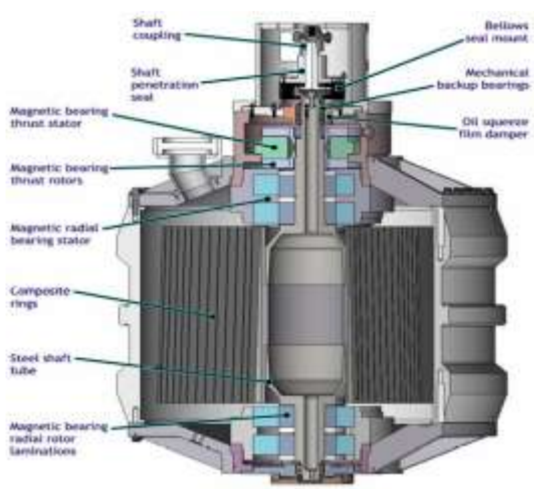

Figure 44: UT CENS ALPS Flywheel

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A bank of flywheels could be used to capture significant energy especially from regenerative and/or renewable energy sources[89]. Beacon Power suggested housing a group of flywheels in a transportable shipping container, as an energy matrix (Figure 45). The system is remotely controlled and monitored for maximum flexibility. Scale-power versions of this system are being demonstrated now in California and New York.

Additionally, at low power needs the flywheels could be energized to provide a method of power management. The US Navy is reportedly considering bidirectional flywheel energy storage devices that would power up off the ship's bus at steady-state power conditions and supply power during high power consumption transients. Naval research is now focused more on carbon fiber flywheels. As discussed above, they have small footprints and generate high rotational energies[90].

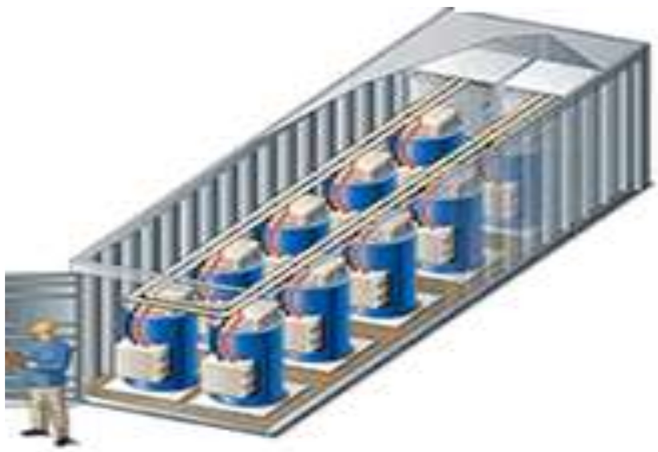

Figure 45: Flywheel Power Matrix (Beacon Power)

Superconducting Magnetic Energy Storage (SMES)

SMES is a device where energy is stored in a magnetic field produced by the current circulating through a superconducting coil. The system is efficient because there are no resistive losses in the superconducting coil and losses in the solid state power conditioning are minimal. SMES provides rapid response for either charge or discharge. Unlike a battery, the energy available is independent of the discharge rate. The interaction of the circulating current with the magnetic field produces large forces on the conductor. In a small magnet, these forces are easily carried by the conductor itself. In a large magnet, a support structure must be provided either within the coil windings or external to the coil to carry these loads. Today's SMES units use conventional metallic superconductor material (Nb-Ti or Nb3Sn) cooled by liquid helium for the coil windings. High temperature ceramic superconductors (HTS) cooled by liquid nitrogen are now being used in the power leads that connect the coil to the ambient temperature power conditioning system.

A chief contributor to the development of SMES technology components for the past ten years has been The Technology Development Laboratory (TDL) of the Houston Advanced Research Center (HARC). HARC completed a 3-year program funded by the Texas State Energy Conservation Office to bring SMES technology a step closer to widespread commercial acceptance. The State program focused on two different areas: site analysis to determine appropriate and cost effective locations for the implementation of large-scale transmission enhancement SMES, and development of a second generation Micro SMES system incorporating a novel persistent switch recently patented by HARC. HARC has developed a prototype consisting of six coils storing 1.25 MJ (0.347 kwH) of energy and power delivery of 200KW at a temperature of 4.5°K. Current direction is to increase the temperature to liquid nitrogen temperature 77.2°K using emerging high temperature superconducting wire.

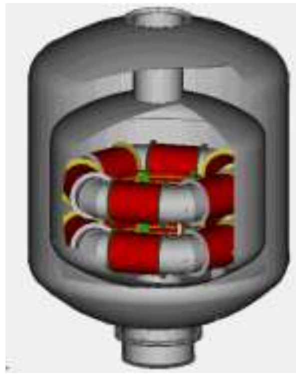

Figure 46: Conceptual drawing of the HARC/TDL MicroSMES unit showing 2 stacked superconducting toroids, fast persisting switch, power leads, thermal shields and vacuum

Electrolysis to Hydrogen for Energy Storage

Electrolysis of water into its components of hydrogen and oxygen can be considered an energy storage system since the hydrogen and oxygen can be stored for an extended time and then used in an engine or fuel cell to generate power on demand. Electrolysis has an efficiency of 50–80% depending on the system and size. Hydrogen forms at the cathode and oxygen at the anode. Thus it has an internal and automatic separation process. Again, the problem is that while hydrogen supplies three times the energy per pound of diesel and gasoline (see Figure 43), it has only one-tenth the density when hydrogen is a liquid and very much less when it is stored as a compressed gas.

Storing hydrogen is not well developed because it is a small molecule and tends to diffuse through most materials fairly easily. This is a central problem for using it as transportation fuel as liquid or compressed gas. However, using hydrogen in an industrial setting should not be problematic if safety policies and proper handling procedures for industrial gases are followed.

This concept as presented for the EFD project is to use it as a short term energy storage by generating the electricity from a “free source,” i.e., solar, wind, regenerative braking, etc. and compressing the hydrogen and oxygen and then using it as fuel in a fuel cell or in an engine directly when needed for peak power requirements. Since drilling rigs are an industrial setting in a relatively stationary state, safety issues of generation and storage can be addressed with rigid controls and procedures unlike that in over-the-road systems where the control of pressurized hydrogen and oxygen is difficult.

3.7.6 Summary Comparison of Power Generation

Recent history shows that drilling rigs have used diesel with some natural gas internal combustion engines. From 1,000 to 10,000 kW, there is a transition from reciprocating engines to CTs in terms of economic competitiveness. CT performance is adversely impacted by altitude and temperature. Applications must be viewed with these site-specific and temperature-specific factors in mind. If maximum generator output is required during hot summer months, then inlet cooling adds to the overall costs. Other issues to consider include the following:

- As higher firing temperatures are sought to increase performance, higher combustion pressures and fuel gas compression is required.

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- As load drops on the CT, the compressor energy use becomes a larger percentage of cycle energy use resulting in poor partial-load efficiencies.

The ability to utilize unconventional power generating technology may be severely limited by the cost and lack of favorable economics of wind, solar, and fuel cells (see Table 12). Though a thorough economic study was not the point of this technology assessment the findings that installed costs were considerably higher when compared with the ICs and CTs for all but the wind turbines. However, the wind turbines are very large and would require extremely heavy duty equipment in addition to that of the drilling rigs. (e.g., large cranes would be necessary as self erecting towers are impractical for a 500 to 750 kw wind turbine). A 750 kw wind turbine generator would weigh approximately 36 tons, the blades approximately 24 tons, and the tower itself approximately 100 tons. Solar panels are also extremely heavy as well as very high in cost per power provided.

Table 12: Characteristic Comparison of Power Generating Technology[91,92,93,94]

Technology / Characteristic	Internal Combustion Engine			Combustion Gas Turbines	Micro turbines	wind	Photovoltaic	Fuel Cell
	Compression Ignition		Spark Ignition					
Technology Status	Commercial/Mature			Commercial/ Mature	Commercial/limited	Mature	Mature/ Developing	Commercial/ Developing
Add ons	W/O SCR	w/SCR						
Rated Power (Kw)	10-5,000			500 - 300,000	30-500†	1-5000	1-1000	100-3,000
Capacity factor	90-95%		92-97%	90-98%	95%(?)	24-40%	30%	>95%
Installed cost ($/Kw)	425-805	700-1000	600-1200	600-1400	1700-2600	1000-1600	>4500	550-5000
Fuel	Diesel, fuel oils, Synthetic liquid fuels		NG, biogas	NG, Distillate, biogas	Multi-fuel	wind	None	Multi-fuel, Hydrogen
O&M cost ($/kWh)	0.008-0.018		0.007-0.015	0.004-0.01	0.013-0.02	0.005	Negligible	0.020-0.04
Electrical Efficiency	30-40%		23-45%	21-40%	14-30%	20-46%	15-30%	36-50%
Noise	High			Moderate	Moderate	Low	None	Low
Foot Print (sq ft/kw)	0.22-0.7		0.15-0.31	0.02-0.61	0.15-0.35	5-100	200-600	0.9
NOx (lb.MWh)	21.8	4.7**	2.07*	1.15	0.44	0	0	0.03
SO2 (lb.MWh)	0.49	0.454**	0.006*	0.008	0.008	0	0	0.006
PM (lb.MWh)	0.78	0.78**	0.03*	0.08	0.09	0	0	0
CO2 (lb.MWh)	1432	1432**	1099*	1494	1596	0	0	1078
Sources: Distribute Energy Forum (www.deforum.org); Gas Fired Distributed Energy Resource Technology Characterizations November 2003 USDOE NREL/TP-620-34783; EPA Greenhouse Summer 2002 EPA-43-N-02-004;Bluestein, Joel et al,"The Impact of Air Quality Regul								
SCR= Selected catalytic reactor								
*Lean Burn Gas Fired Engine; ** Diesel with SCR; †Larger sizes under development								

Reducing emissions by post-combustion add-ons (e.g., selected catalytic reactors) to the internal combustion engines or turbine exhausts can reduce the NOx emissions at a capital cost increase of 17% for a turbine and roughly 14%-23% for lean burn gas and diesel engines. SCRs are relatively insensitve to the size of the system, making the per-unit cost higher for small applications than for large applications. SCR for small turbine generators can add $150- $200/kW compared to $50/kW for large systems. SCR can reduce NOx emissions up to 90% but is effective only over a limited temperature range and does not reduce NOx emissions as effectively at high temperatures. Additionally, the ammonia used in the SCR is not completely consumed and is classified as a hazardous substance that requireds special handling and safety precautions. Urea is less hazardous and can be substituted for the ammonia but is still noxious and may not be acceptable in some applications. Adding SCR to turbines can add about 17% of the capital cost of the turbine generating system. Annualized cost of reduction using SCRs can be from $12,000 upt to $40,000 per ton of NOx reduced. The best available emissions control technology means the control technology that achieves the greates emission reduction within a preset cost-per-ton-of-reduction-criterion. Because BACT is a moving target that becomes more stringent over time and must be evaluated on a case-by-case basis. Since drilling rigs work over a number of states with sometimes different regulations that US EPA, as well as around the world with different regulatory constraints this also becomes a geographic analysis also.[94]

Another more stringent level of control is Lowest Achievable Emissions Reduction (LAER). LAER is defined as the most effective control technology demonstrated in practice, without regard to cost. Like the BACT, LAER is inherently a moving target that becomes more stringent over time. In areas of nonattainment the goal is restoring air quality through nonattainment NSR (new source review). Many of the EIA (environmental impact assessment) for well drilling could follow a LAER and the drilling program needs to fall under the major and minor source review to be exempt from environmental permitting. Well-Construction Methodology to Minimize E&P Ecological Impact

3.8 Directional, Multilateral, ERD and Pad Drilling

Over the past 20 years, horizontal drilling has progressed from an exotic technology to become a standard industry tool. Drilling a well horizontally through the pay interval exposes much more reservoir to the well bore, normally resulting in increased well productivity and/or increased ultimate resource recovery. Emergence and acceptance of horizontal drilling have enhanced productivity of individual pools. The technology has been credited with significantly increasing economically recoverable reserves.

Constructing single or multiple horizontal productive intervals within a reservoir is rapidly becoming a dominant exploitation practice in many fields that are uneconomic with conventional vertical wells (Figure 47).[95] Horizontal completions in water flood and/or CO_2 flood areas often have three to five times the productivity or injectivity of vertical wells. In tight gas fields horizontal wells have demonstrated two to 10 times the productivity and cumulative recovery of vertical wells. In high-pressure and naturally fractured tight gas fields, horizontal wells have demonstrated as much as 20 times more productivity than vertical wells.[96]

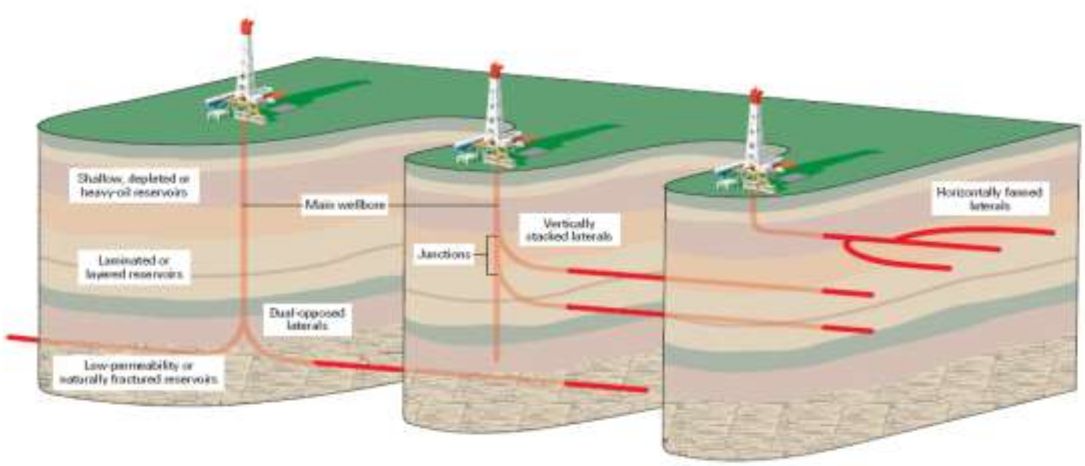

Figure 47: Basic Multilateral Configurations (courtesy of Schlumberger)

Aggressive adaptations of this form of exploitation have resulted in tremendous advances in enhanced oil recovery processes in many varied applications globally. A striking example of this application is the SAGD (steam assisted gravity drainage) developments being aggressively pursued in the bitumen (tar sand) deposits in North Central Alberta.

This advanced EOR process can not only salvage uneconomic and/or marginal, depleted reservoirs, but inherently delivers significant reduction in well construction environmental impact. By placing multiple surface locations in one central facility (pad), all surface gathering lines, production facilities, access roads, export pipelines, power grid right-of-ways, etc., are dramatically reduced. Figure 48 illustrates this advantage, where three sections (3 square miles) of reservoir area are being exploited from one central pad. When compared to conventional, 40-acre spaced vertical development program where three sections would contain 48 surface locations, access roads, related gathering and production facilities, etc., the dramatic reduction in surface impact provided by multiple horizontal wells is obvious.[97]

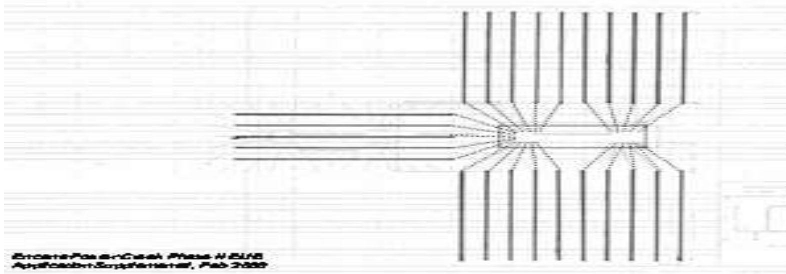
Figure 48: Example of Well Pad Design for SAGD

A US DOE study[98] looked at only four conventional field types and predicted incremental reserves of 1 billion barrels at $24 oil price (Table 13) if local independent operators effectively applied horizontal well exploitation technology to theses known assets. Similar benefits are being observed in many recent CBM (coal bed methane) applications in both the US and Canada. Multiple horizontal well applications are likely to be a favored tactic in many of these rapidly expanding development settings.

Table 13: Distribution of Future Reserves for New Horizontal Oil Wells (DOE 2000 study)

Resource	$16/bbl	$24/bbl
Austin Chalk Reservoirs	134	197
Other Fractured Reservoirs	19	121
Thin Bed Reservoirs	116	128
Profile Modification	266	401
Continuity Improvement	6	118
Total Reserves	541	965

The same benefits of surface impact reduction and operational consolidation are likely to be leveraged in many deeper tight gas, shale gas and also any conventional oil or gas development in environmentally sensitive areas that are currently being pursued throughout the petroleum basins across the US. This practice has itself benefited from technological gains in other areas such as improved drilling fluids, down-hole motors, and measurement-while-drilling instrumentation and rotary-steerable systems.

Probably the most significant well construction advancement is the paradigm shift to managed-pressure drilling (MPD) versus conventional overbalanced drilling[97]. Many depleted or uneconomic fields can be re-exploited by applying a combination of complex well design with MPD well construction practices. A recent field experience in central Illinois demonstrated this concept. A horizontal infield well was drilled with aerated water in a very old (1940s) abandoned light oil water-flooded field. The new horizontal well successfully accessed the top 5 ft of oil-saturated sand to initially produce 250 BOPD, and has currently recovered over 25,000 bbl of oil from this previously considered uneconomic pool.

Application of MPD well-construction practices can deliver auxiliary benefits in emissions reductions. In many cases the gas phase required will be air or nitrogen, which is vented to the atmosphere, leaving only produced reservoir water, or fresh water for disposal. This reduces both the volume and types of drilling fluid contaminants which must be disposed of following well construction. Unfortunately, applying these more complex well technologies has been a challenge to many of the smaller independent operators that hold the vast majority of the marginal, mature assets within the US. Significant industry training and exposure will be required before this potential is fully realized.

Directional/horizontal well construction has had a major impact on the petroleum worldwide. Extended reach drilling (ERD) enabled economic development of a remote offshore field in Russia from a land based location[99]. TVDs in these wells were over 6000 ft and horizontal displacement over 28,000 ft. In Ecuador directional drilling is a technique commonly used by oil companies to drill in the sensitive landscape of the Amazon region or “Oriente.” In this particular area is a tropical rain forest which is home to many of the indigenous tribes of Ecuador as well as exotic and unique flora and fauna[100]. Questar has had significant success in eliminating surface damage in the Pinedale Anticline in Wyoming using pad drilling and directional drilling techniques (Figure 49).

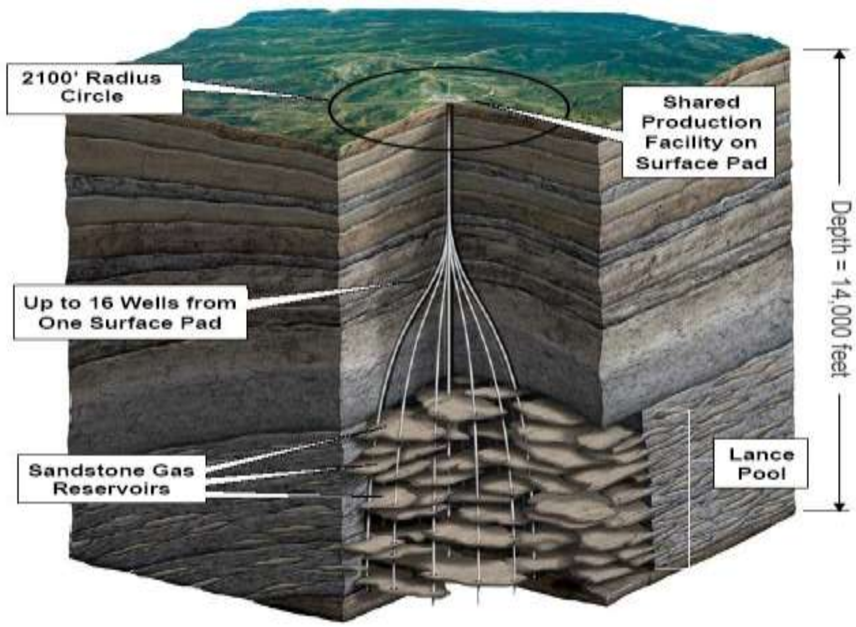

Figure 49: Example of direction drilling in Pinedale Unit Wyoming (Questar Resources)

The capability of horizontal directional drilling technology to accommodate and protect the varied stakeholders’ interests while producing huge amounts of oil and gas is again illustrated in production of oil from beneath the harbors of Los Angeles and Long Beach (Figure 50) from few surface facilities. The surface area needed to drill development wells has decreased dramatically due to enhanced lateral drilling capabilities (Figure 4) and continues to decrease as innovative application of horizontal wells is pursued.

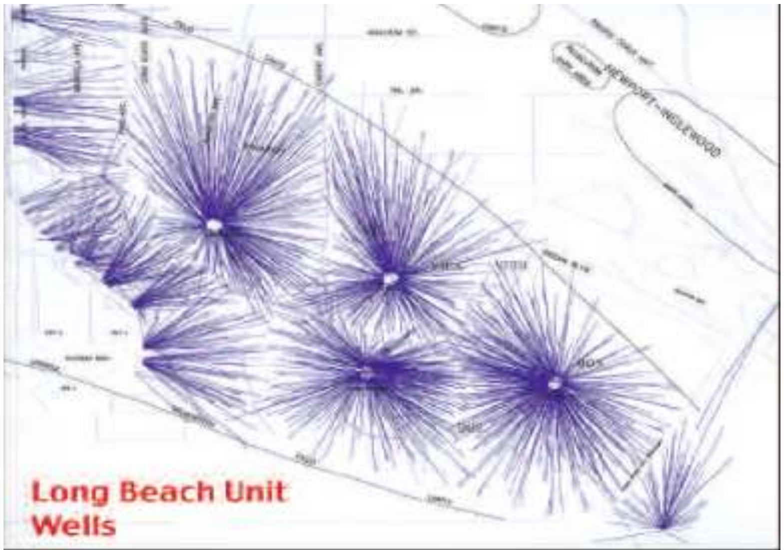

Figure 50: Example of Multilateral ERD Pad Drilling Concept (over 1800 wells)[101]

Halliburton-Sperry Sun set the record[102] for intersecting two wells toe-to-toe from wellheads 10,178 ft (3,104 m) apart (Figure 51) using an 8¾-inch roller cone bit, a rotary steerable system and magnetic ranging technology. Precision Drilling Company drilled both wells for Anadarko Canada in the Jedney field in Pink Mountain, British Columbia. Measured depth was 19,227 ft (5,864 m), and TVD was 5066 ft (1545 m). The wells were connected October 10, 2004. The longest horizontal section, at an inclination over 86°, was drilled in April 2004 for 26,735 ft (8,154 m). It is in the Al-Shaheen field in Block S offshore Qatar.

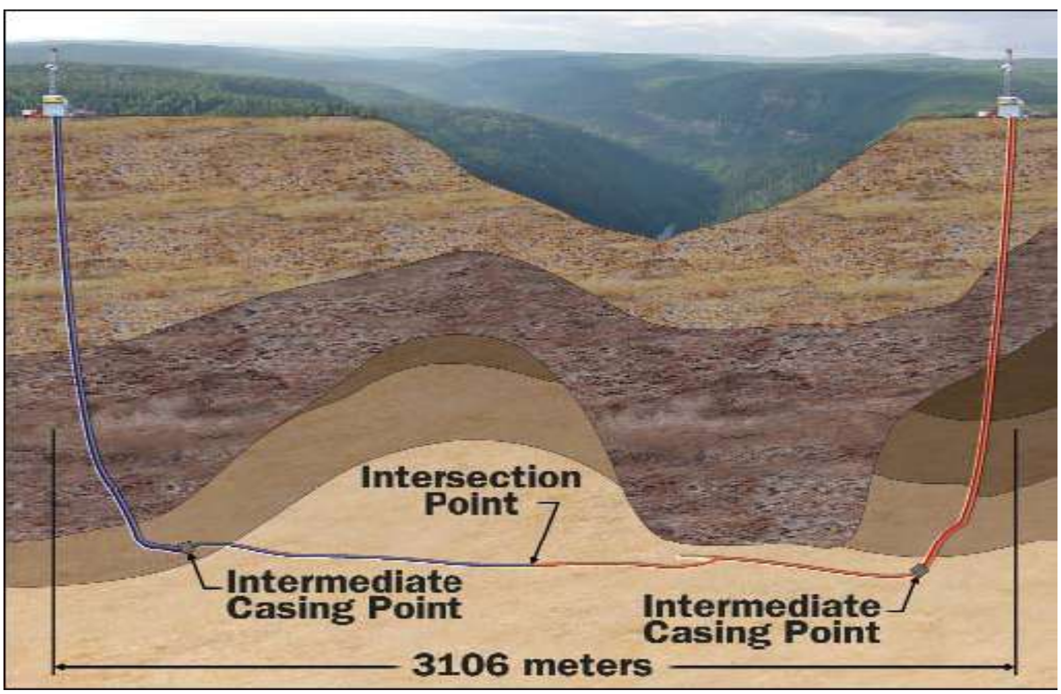

Figure 51: Toe-to-Toe Horizontal Wells (Sperry Sun)

Pad drilling is a methodology to reduce the footprint and costs and can also be used to protect the environment and reduce ecological impact, which is a significant emphasis of this project. Horizontal drilling makes pad drilling technology feasible.

3.9 Onshore Platform

Technology is described here to build temporary bridges and piers as presented in patents and other literature to develop onshore platforms as well as temporary roads (ingress and egress methods) in remote locations with low environmental impact. This section and Section 4.2.2 on temporary structural roads and bridges discuss these concepts as well as approaches to directly develop platforms for oil and gas drilling and production operations.

3.9.1 Related Technology

Bridges can be thought of as raised platforms above the surface they span. A number of bridge and pier techniques have been developed to span land gaps and extend over water (piers). Buildings and other structures have been built on these piers and bridges.

In 1970 Suter received a patent 3,511,057 for a method to erect and construct multispan bridges and piers. The concept was to build bridges that can be started at any point along the proposed bridge span in impassable country or water-covered subsoil, and continued in both direction of the proposed bridge span. The concept could be used for elevated road building or platform (foundation) construction onshore. Additionally Norrie suggested in his patent (US 6,986,319 (2006)) that piers could be constructed with deck sections that can be removed or allowed to float during times of high wave action or storms without floating away.

Cernosek was issued US patent 3,878,662 in 1975 describing drilling structures constructed in a remote area. The method included a foundation composed of permanent foundation units, a substructure mounted on the foundation and a derrick mounted on the substructure for drilling for oil or the like in remote areas. The permanent foundation units, substructure, and derrick are all comprised of members that can be transported to the remote area by a helicopter or similar transport. The foundation is suggested for use in mountains, marshy or swampy land located anywhere that is not easily reached by conventional ground transportation or conventional floating platforms. A helicopter will transport temporary foundation units to construct a temporary platform to support a crane and a device (pile driver of some sort) to build the permanent foundation (Figure 52). A substructure and derrick are then flown in after the foundation is constructed and placed atop the foundation.

In 1996 Connor et al. described a modular bridge constructed from module components suitable for use in both a dry span and floating role, comprising a buoyant structure having interconnection for connecting the module end to end to an adjacent similar module for a bridge. The components have one or more link members which are releasable securable to the underside of the bridge module. Connor was issued US patent 5,495,631 for this application. The objective was to transport and construct a bridge in a short time such as in military operations or in response to civil disaster. The preferable material is aluminum or an alloy of aluminum. Linkages are made of carbon fiber reinforced plastic material having a modulus of elasticity in the region of $200x10^3$ MPa. These linkages run along the bottom of each end of the module and can be connected. For a dry span the modules are cantilevered across a gap. For a very long gap it may be necessary to add support legs (note not part of patent) which could also allow a device as an elevated road or pad.

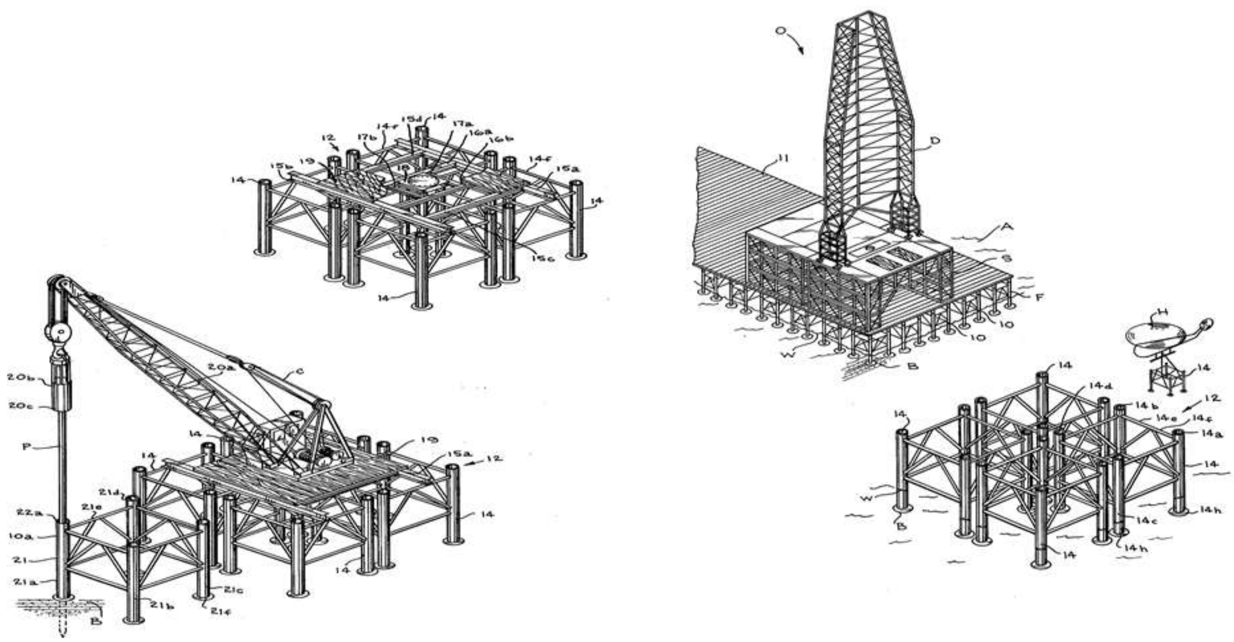

Figure 52: Permanent Onshore Platform for Remote Areas Patent 3,878,662

A light-weight aluminum modular bridge decking using hollow extruded aluminum elements was suggested in various patents issued to Ahlskog et al. and assigned to the Reynolds Aluminum Company (5,651,154 1997; 5,810,507 1998; 5,867,854 1999; 5,901,396 1999; 6,073,293 2000). A principal object of this invention is to provide a light-weight, easy-to-assemble bridge deck system using prefabricated deck panels which are field-spliced easily and inexpensively made from hollow extruded aluminum elements. Each of the deck panels is shop-fabricated by longitudinally welding flanges of adjacently placed multi-void extruded aluminum alloy structural elements. Transfer splices of longitudinally adjacent elongate elements are made by providing shear elements connecting individual elongate structural elements of each deck panel end-to-end prior to longitudinal welding of adjacent elongate elements, with the end joints between the elongate elements arrayed in a staggered manner. A safety rail system is mounted to run alongside and above outer edges of the finished bridge deck. Note the application is to provide decking only for heavy bridge traffic and does not define support structure.

3.9.2 Anadarko Onshore Platform

Kadaster et al. in 2004 were issued US patent 6,745,852 on an elevated modular, mobile platform for drilling oil and gas wells in the arctic, inaccessible, shallow water or environmentally sensitive geographical locations (Figure 53). The objective is to drill in sensitive areas without disturbing the ground surface as in conventional land drilling operations and perhaps extend the drilling cycle time in the arctic. The system consists of aluminum, or other light-weight material, modules approximately 12.5 ft wide and 50 ft long. Modules need not be in those dimensions, but should be light enough to be transported to a drilling location by aircraft, land vehicles, sleds, boats, barges, or the like. Additionally, the modules may be configured to float and to be towed on water to the drilling site.

The legs are adapted to be driven or otherwise inserted into the ground to support the elevated drilling platform. The platform modules may be transportable by aircraft or special purpose vehicles that are adapted to cause minimal harm to the environment. The first platform modules are interconnected to form a first drilling platform. The first drilling platform is then elevated over the first drilling location. Drilling equipment may be installed on the first drilling platform before or after elevation. In swampy areas legs could be rotated in with a power swivel to the proper depth of penetration. The platform modules were designed to interlace where any spillage onto the platform decks would be routed and contained within the bucket elements of the modules for containment and proper recovery and disposal[103].

Figure 53: Anadarko Onshore Platform in the Arctic in Summer

Part of the Anadarko platform patent suggests renewable energy sources may be supported by the platform (Figure 54). For example, a solar panel array or wind mill power generators may be added to provide energy for pumps, compressors, and other equipment. Renewable power sources may also provide energy for hydrate production. Renewable energy sources minimize fuel requirements for the drilling platform while minimizing air pollution and conserving production fluids.

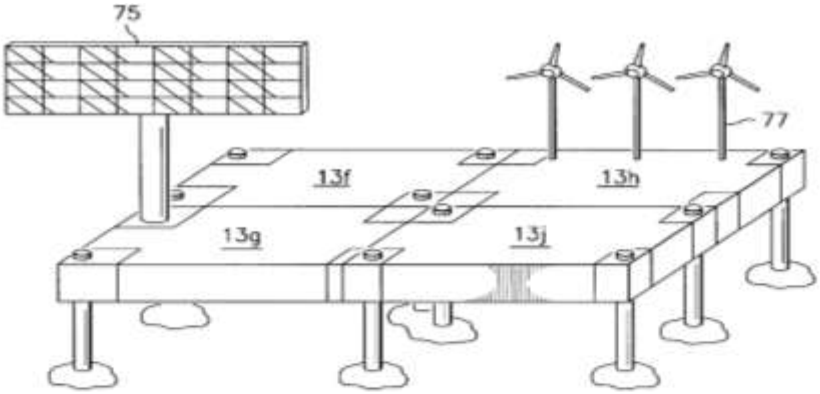

Figure 54: Onshore Platform using Renewable Energy for Drilling Support

3.9.3 BP – Pile Driving to Support Large Rig

Use of a raised platform in environmentally sensitive areas will require piles to support the platform. In 2006 BP is using piles to support a large rig to infill drill a deep gas resource in the Tuscaloosa reservoir in southern Louisiana (see Appendix C). Piles are used to mitigate settling. This type of effort currently cannot be justified on a less complicated well with shorter duration drilling times of 10–30 days (drilling time for this BP well is approximately 90–120 days).

The lessons and approach of this type of site construction should be captured and may represent some of the best available technology for the EFD project. This site could be cut into small sections, trucked to different drilling sites and reassembled. The impact it would have on the environmental effects of drilling could be significant. The drilling platform represents this general approach. It should be considered for not only those areas where contact with the ground requires the raised platform, but also for areas where setting the platform on the ground is possible, because other benefits of engineering and environmental impact can be obtained.

A cone penetrometer test is initially run to test soils for the depth and number of pilings (see appendix C2 and C3 for explanation of penetrometer pile testing). BP uses these results to determine how deep the piles need to be driven to support the weight of the rig. BP, as a conservative measure, considers the full rig weight (600,000 lb), full weight of heaviest string of casing (1.2 million lb), and buoyancy and surge loads are not included to determine the drive depth that is needed to support the load. Safety factor is in the range of 2 to 2.5:1. This compares to 8:1 for most civil engineering projects.

The 44 piles for this job are 14 in. diameter x 0.375 in. thick open-ended pipe. In calculating the load bearing ability of the pipe contact, the inner diameter is ignored and only the outside skin friction is taken into account. The piles are 80 ft long and welded together during the driving process. Equipment for driving the piles consists of a crane, hammer leads (frame), and a hammer.

The hammer for this job was a Vulcan air hammer (Figure 55) that operates on 250 psi air. It weighs 19,000 lb and delivers a 32,500 ft-lb blow force. It is capable of 50 blows per minute. The frame supporting the hammer has two long spikes on the bottom that are driven into the earth at the correct position, with the weight of the leads (frame). A simple level is used to align the pipe and frame to confirm that the pile is vertical. Once driving has been started no adjustment can be made other than pulling the pile. During the driving operation, the blows per foot are recorded. A dramatic change in the blow frequency and pile movement can indicate a change in the subsoil strata which may impact load bearing capacity of that pile.

Figure 55: Pile Driver for BP Tuscaloosa Operation (June 2006)

After being driven, the piles are cut off to the desired height and a cap sill added. The cap sill consists of a 112 lb/ft “I” beam with two pipe sleeves welded to the bottom. The pipe sleeves are designed to fit over the pile (Figure 56). The caps sills are recovered after drilling and completion of the well, but the piles remain in place and can be used again if the well needs to be worked over. After completion of the pile driving operations, the area around the pilings and cap sills is finished with compacted limestone at the same grade and elevation of the surrounding pad.

Figure 56: Pile Caps for BP Tuscaloosa Operation

4. Low-Impact Access/Transportation Processes

Moving equipment, supplies, and people to and from a drilling site at the right time can be logistically complex. Add the restriction that there must be no or limited impact to the environment, and complexity is magnified significantly. Protecting cryptobiotic soils in the west and southwest and inland and coastal wetlands will be challenging. However, implementing combinations of current technology can make this objective achievable.

4.1 Roadless Concept

The roadless concept is to develop a methodology of access to well sites that do not permanently harm the root system or the ecology of the area, but can transport large and heavy pieces of equipment and supplies into and out of the rig site. The definition of "permanent" has not been established. It has been estimated that cryptobiotic soil might not recover from some injuries for thousands of years. A system that would use hauling equipment that has very little ground pressure along with temporary roads that are not constructed conventionally and take into account methods to protect the ecosystem, would be the deliverable of this section.

4.1.1 Hovercraft

Hovercrafts, also called air cushioned vehicles, operate by using fans to push air under the vehicle and trap that air with a skirt. The hovercraft then lifts above the ground. The ground is contacted primarily by the skirt, which can lightly scrape the surface. Most hovercrafts are amphibious—they can travel over water, land, ice, snow, and otherwise impossible-to-reach areas like swamps and mud pits. Because hovercrafts do not pierce the land they travel, drag is reduced and operating efficiency is greatly increased. One adverse effect of hovercraft operation is noise pollution, but this can be reduced to the noise level produced by a typical truck or bus. Additionally, like rigs, trucks and buses, hovercraft emissions need to be considered.

Most hovercraft vehicles are used for toys, recreation, military or police activities. Some have been used in the past for commercial ferry transportation over short distances. They can be very fast but generally have not been used to any large extent for heavy equipment transportation—except for the military. For purposes where speed is important, costs escalate considerably especially if heavy equipment is moved. However, they can be used very efficiently for transporting loads if speed is not critical. Though not extensively used, the technology is well known and has been proposed and reduced to practice in the oil and gas industry previously. Lack of growth of this technology has primarily been due to lack of motivation, need and the poor industry economics over the last two decades. Use of hovercraft with other low-impact transportation methods may prove useful in sensitive areas.

Air cushion vehicles particularly useful for drilling rigs and the like have been proposed and used in arctic environments and others. In 1974 patent 3,783,627 issued to Blurton et al. proposed a hovercraft be employed in arctic environments having open water, muskeg, ice, snow, and tundra. Blurton described methods for launching the air cushion vehicle from a ship and for preparing an arctic drilling site for the air cushion supported drilling rig. Means are provided on the bottom of the vehicle for preventing thawing of the frozen soil or ice beneath the vehicle as oil well drilling or workover operations are performed.

Later in 1999, Ashton was issued US patent 5,871,061 for a hovercraft design to carry a load and a hydraulic means for lifting the load. About the same time (2001) Miller in patent US 6,200,069 disclosed the concept of a jack-up work platform configured as a hovercraft (Figure 57). The purpose was to provide an environmentally responsible method for oil and gas drilling and other operations in marshes without having to revert back to digging damaging canals.

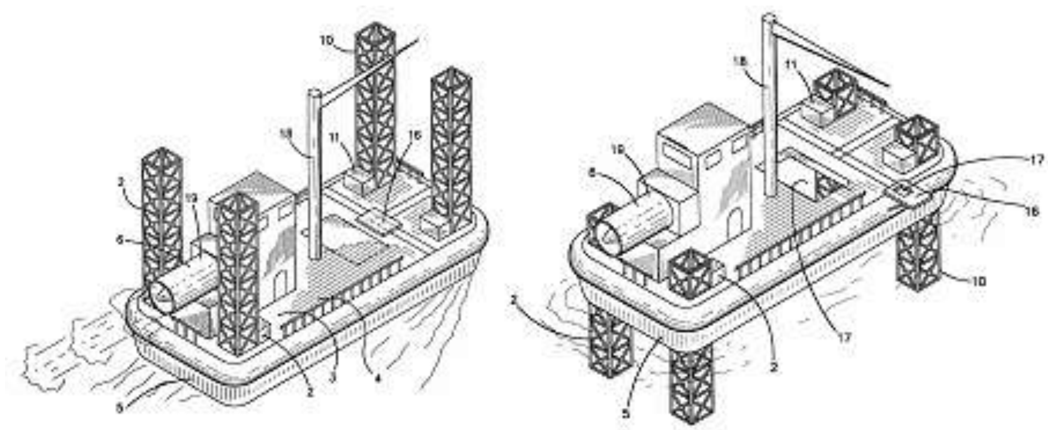

Figure 57: HoverCraft Jack-up Rig (patent 6,200,069)

Additionally in 2002 Newell et al. disclosed in patent 6,354,384 a hovercraft design to take continuous core samples in inaccessible environmentally sensitive regions such as wetlands. Primarily motivated for application in modern estuary and shallow lake margin R&D efforts, Newell et al. suggested that the hovercraft can be used instead of wheeled or tracked vehicles which damage the ecology.

The cost per ton hovered or lifted is not linear. Generally, the larger the unit and tons hovered, the more efficient the system. For example, for a single load of 100 tons, an area of 1555 ft^2 is required; for a 130 ton load, an area of 2015 ft^2 is necessary. This increase in 30% load requires a 19% area increase. The larger unit becomes more economical. Once in hovering mode, drag to induce linear motion is significantly reduced[104,105].

Hoverdril Inc. (now HoverTrans) hovercrafts have been previously used to build the TransAlaskan pipeline. Hoverdril claims that its hovercraft exert an average of 0.33 psi and can pass over bird eggs, tundra rodents, and animal burrows without harm or injury. If the fans stop working, or if a large section of the skirt is damaged, air will slowly seep out over a few minutes and the hovercraft will make a gentle landing. Hoverdril hovercrafts may be too big to transport as a single unit and can be disassembled for transport and easily reassembled. With a maximum payload of 160 tons, these hovercrafts are capable of transporting large objects that other vehicles cannot. Operating temperatures range to as low as -57°F. Most damage to the surface caused by skirt contact is in the first five passes; after that no significant additional damage is produced. This damage could be minimized by use of geotextiles or other temporary road conduit material. Noise pollution is an unavoidable byproduct of air-propellers, but can be minimized.

Hovertrans, Inc. (http://www.hovertrans.com) (formerly HoverDril) launched the world's largest hover barge during the first quarter of 2006 (Figure 58).[106] Capable of a 330-ton payload, it provides a stable drilling and equipment platform. Measuring 170 x 90 ft and weighing 900 gross tons, the barge is capable of accessing environmentally sensitive wetlands without causing any terrain damage. It features a 40 ft x10 ft keyway slot, which allows it to move away from the wellhead once drilling is complete.

- Hover height is 4 ft
- Exerts only 1psi while hovering
- No permanent construction
- No roads or docks required

- Hover over land, swamps or water
- Use as a drill rig and supply base
- Reusable on other projects

Figure 58: Hover Barge for Drilling Operations – Hovertrans

Figure 59: Alaska HoverCraft Vessels

Alaska HoverCraft model LACV-30 and AP.1.88 are small, light hovercraft (Figure 59) compared to HoverTrans models:

- Dimensions approximately 30 ft by 40 ft by 80 ft
- Maximum speed of 45 mph
- Maximum payload of 30 tons
- Fuel consumption at 260 gal/hr
- Endurance of up to 10 hr

These hovercrafts can be used to transport smaller objects and can also be used for offshore oil exploration, search and rescue operations, personnel transport, water and fuel transport, and fire-fighting. Note that these or similar vessels could be used as tug vessels for the larger Hover Barges.

4.1.2 Low-Ground-Pressure Equipment

Hauling vehicles can compact and rut soils in wetlands. Spreading the weight of vehicles over a larger surface area can reduce these impacts. *Wide tires, duals, tire tracks, bogeys,* or *tracked machinery* can reduce damage in sensitive areas by spreading a machine's weight over a larger area. They also increase traction, reducing wheel slippage. Wide or high-flotation tires are 34 to 72 inches wide. Dual tires are made up of four regular-width tires on an axle. They may be used on the front axle, back axle, or both axles. Tire tracks are wrapped around existing tires to make them wider. A bogey system connects rubber tires on adjacent drive axles with a track. Tracked machinery travels on steel or rubber tracks instead of tires. Lightweight equipment reduces ground pressure by reducing the weight of the machine.

Equipment with central tire inflation allows an operator to vary the inflation of a vehicle's tires while moving. By reducing inflation, the operator can increase the tire "footprint." This reduces the vehicle's pressure on the ground. A patented track system that can convert typical wheeled vehicles to a tracked vehicle is Mattrack (Figure 60). Mattracks reduce ground pressure of a wheeled vehicle (as low as 1.5 psi verses 8 psi for a person and up to 40 psi for conventional truck tires) and provide mobility in snow, slush, mud, sand, swamp and tundra conditions.

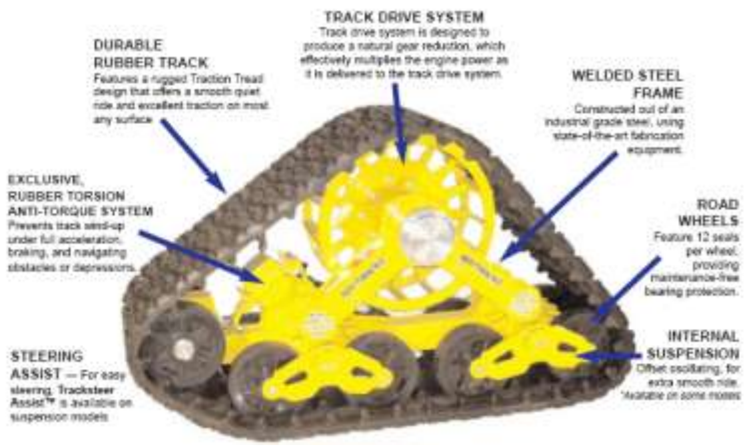

Figure 60: Mattrack Conversion

Rolligon vehicles (Figure 61) are used to transport heavy loads (2 to 100 tons), personnel, products or equipment in sensitive areas. Rolligon vehicles can operate in soft ground conditions, extremely rugged terrain or environmental conditions that are too harsh or sensitive for conventional trucks (e.g., arctic, desert and jungle applications). Low-pressure, high-flotation tires distribute the weight over a large area with a ground pressure of approximately 4 psi or less.


Figure 61: Rolligon Vehicle with Low Ground Pressure (4.4 psi) Transporting a Load of 100,000 lb

4.2 Artificial, Portable, or Temporary Roads and Drilling Sites

Crossing wetlands and semi-arid delicate ecologies with hauling vehicles and other equipment may harm water quality; alter water flow, and damage habitat. Temporary crossing options to minimize impacts work best with a nonwoven geotextile underneath. Geotextiles prevent material from mixing with the soil below, yet allow water to flow through. They also help distribute a load over a broad area and make an option easier to remove. A nonwoven fabric is less slippery than a woven one, reducing movement of the option during use. On very weak soils that have a low bearing strength (e.g., muck or peat), options may need to be longer and wider than on other soils to spread the weight over a larger area.[107] Temporary crossing methods include:

1. *Wood mats* made from logs or sawn hardwood. Cable together individual pieces to make a single-layer crossing.
2. *Wood panels* and *pallets* are stronger, larger versions of shipping pallets. They are reversible for easier repair.
3. *Expanded metal grating* is made from nongalvanized steel. It is light and inexpensive, and provides good traction. Build crossings by placing grating sections in the wheel path.
4. *PVC* or *HDPE* pipe mats are constructed by cabling together pipes to form mats of varying lengths. *PVC or HDPE plastic roads* are similar to pipe mats, except that the pipes are interconnected using PVC. Build transition mats/panels into the design to ease transition between firm soil and the mat.
5. *Bridge decks* consist of the decking of a timber bridge and are available commercially. They are best used to cross small wetlands.
6. *Tire mats* are constructed by interconnecting tire sidewalls. Modify lengths and widths to fit the soils and situation.
7. *Pole rail crossings* can be built on-site from straight hardwood poles cut from local trees. Lay them parallel to the direction of travel below each wheel. Use pole rails only with equipment that has wide, high-flotation, or dual tires.
8. *Corduroy crossings* are built from residues such as brush or slash; small, low-value logs; or mill slabs. Corduroy spreads a load over the length of the log or slab, increasing the load-bearing area.

Details of these technologies and others for temporary roads are reviewed below.

4.2.1 Mats for Roadways and Pads

The military has historically used mats made of aluminum and steel for quick airfield construction. Depending on the type of soil, different types of matting is used. Soil condition dictate which system can be used for expedient road construction. One test to determine soil condition is the California bearing ratio. CBR is a standardized test to determine the strength of soils for penetration resistance. At a CBR of 0.2 a normal weight person will sink to his knees; at a CBR of 0.5 to his ankles; and at a CBR of 1, about ¼ inch. A spiked heel will make a slight indentation at a CBR of 4[108].

The US Army Corps of Engineers developed the first cellular confinement system (CCS) during the late 1970s as a means to construct roads, airstrips, etc. for soft ground and wet weather conditions. The Corps determined that placement of thin walled, sand filled cells over a soft subgrade provided significantly greater load bearing capability than compacted soil alone. Various cell materials were tried, including resin-impregnated paper, aluminum and plastic. High-density polyethylene (HDPE) was found to provide the best combination of strength, service life and economy.

The three dimensional cellular confinement system “Geocell” has been used in the oil and gas industry, military etc. for:

- Replacing board roads for permanent roadways to drilling and production
- Field parking lots
- Pipeline applications – support and erosion
- Structural support for camps and heavy equipment
- Levees

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- Water crossings
- Structural supports, foundations
- Railroad track support
- Environmental sensitive areas using native infill

Three existing types of mats have been used by the military to create roadways over sandy soils. The first, Mo-Mat®, consists of semi-rigid panels of fiberglass-reinforced resin material that are rolled out, bolted together, and anchored in place to form temporary roadways and parking and storage pads. The second, the M8A1 light-duty airfield mat, works well for large turning area pads and straight roadway sections. The third roadway mat, the Uni-Mat®, is a patented interlocking mat made from hardwood lumber. Two layers of Uni-Mat create a heavy-duty roadway over sand or wet soil.

These mat systems have several limitations that prohibit their use in many military applications. Only limited supplies of Mo-Mat and M8A1 exist since they are not available commercially. The heavy-duty truss web aluminum mat has never been purchased for military use because its weight makes it difficult to transport. SOLOCO, Ltd., purchased the Uni-Mat patent and stopped making the original Uni-Mat design. SOLOCO now manufactures another wood mat instead of Uni-Mat.

SOLOCO designed a new interlocking mat, DURA-BASE® (Figure 62), for temporary roadway systems and construction platforms placed over soft soils and environmentally sensitive areas. DURA-BASE® is constructed from high density polyethylene (HDPE) and is available in two sizes: 8 x 14 ft and 8 x 7.5 ft. Both mat styles are 4.25 inches thick. The large mat weighs 1050 lb while the small mat weighs 550 lb. Each mat is equipped with a lip on two sides that creates an overlapping joint with an adjoining DURA-BASE® mat. Each mat is also equipped with 16 slots (or 10 for the small mat) into which locking pins are inserted and engaged to bind multiple mats together. DURA-BASE® Composite Mat System has been tested to demonstrate high load bearing capacity while undergoing extreme deflection. Pure compressive load capacity is approximately 600 psi (40 kg/cm^2). Compressive loads in excess of 1000 psi (70 kg/cm^2) have been observed in laboratory tests. The composite mats have a weight capacity of greater than 1200 tons. The mat system has been used in the muskeg and tundra of Alaska and Canada protecting the soft sensitive ecology. Each mat is constructed with a built-in tread pattern for added traction and safety. Other safety features include anti-static and UV protection agents blended into the plastic during the manufacturing process. SOLOCO is a Newpark Company and also provides hardwood mats for temporary roads and pads.

Figure 62: DURA-BASE Synthetic Matting

Roverdeck is a roll out roadway system (Figure 63) that can be rapidly deployed for vehicle access over sand, dirt, and muddy areas. Developed primarily for military use in desert environments, it is also suited for civilian applications in areas where permanent roadway system cannot be installed – beaches, marshes, and other environmentally sensitive areas. Its features include:

- Supports heavy loads up to 20-ton trucks moving at 15 mph
- Lightweight, roll-out design for quick deployment, removal and storage
- Mats can be securely connected
- Will not bunch up or wave under tires or vehicle movement
- Designed to be used with little ground preparation over grass, gravel, sand, soil, concrete, asphalt, ice, snow, mud and other standard surfaces
- Widths of 3, 5, 8, 10 and 13 ft
- Lengths of 10, 25, 50, 82 ft sections
- Sections roll up
- Individual modules interconnect to form larger roadway sections
- Easy to clean and maintain
- Can be used for helipads
- Can be used for creek crossings

HexaDeck is portable roadway and heavy-duty flooring system. HexaDeck can be used to create permanent or temporary pathways for vehicles, equipment, and pedestrians. Interlocking hexagonal tiles create an incredibly durable portable flooring surface for access and ground protection for special events, military deployments, and utility use. Operating range is -20°F to 150°F. Maximum load per panel is 13,000 lb, but permits road angles of 30, 60, and 90° with a capacity of 30,000 lb/ft^2 (208 psi).

Hexadeck and Rovadeck (Figure 63) are products marketed by Signature Fencing and Flooring Systems of New York City[109]. The material is PVC and HDPE.

Figure 63: Rovadeck Portable Roadway

Figure 64: Hexagonal Mat

Patent 3,859,000 issued to Webster in 1975 disclosed a road construction comprised of identical invertible polygonal panels and having a single piece peripheral frame of aluminum with roughly “L” shaped connectors to lock the polygons together. The patent suggests that this can be used as economical portable aircraft runways, floating roadways, and floating piers that can be easily installed. An internal honey comb structure is suggested for strength, the body of which is made of elastomeric material such as plastic.

Knafelc was issued US patent 6,652,184 in 2003 that provided a temporary road way claimed to have minimal damage to the ground surface beneath the temporary road. The apparatus is made up of sections held together by a retainer (Figure 65). The sections are formed from hollow molded plastic and are designed and formed to suitably interlock through a tongue and groove concept. It is claimed that it can be used for very heavy equipment. Because the interface is oriented non-perpendicularly to the direction of travel over substantially the length of the interface, shock loading on the individual sections is reduced by allowing gradual weight transfer from the first section to adjacent sections. This is the primary benefit over prior art that used logs etc. laid lengthwise across the path of the road perpendicular to travel. The prior art is classified as corduroy roads and causes sudden impact loading to each successive member as load is transferred to each member of the corduroy road. This patent claims to mitigate that problem by substantially spreading the load and minimizing impact loading.

An example of a corduroy road element is shown in Figure 66 as described in US patent 5,282,697 issued to McLeod in 1994. The corduroy road can be made of a plurality of rigid bars made of wood, plastic or other material joined to form an articulated assembly. A rope is threaded through bores in the bars. Spacers are placed over the rope between the bars. Ends of the spacers can be angled for inclining, declining or flat arrangements of adjacent bars. In the alternative, ends of spacers can be rounded and received in a rounded depression of the bore. Interlocking elements can have engaging male and female portions or can be screwed together. When laid flat over a surface, the articulated assembly may be used as a support that forms a deck, walkway, or similar structure. The invention relates to flexible surfaces for use as walkways, roadways, support barriers or the like.

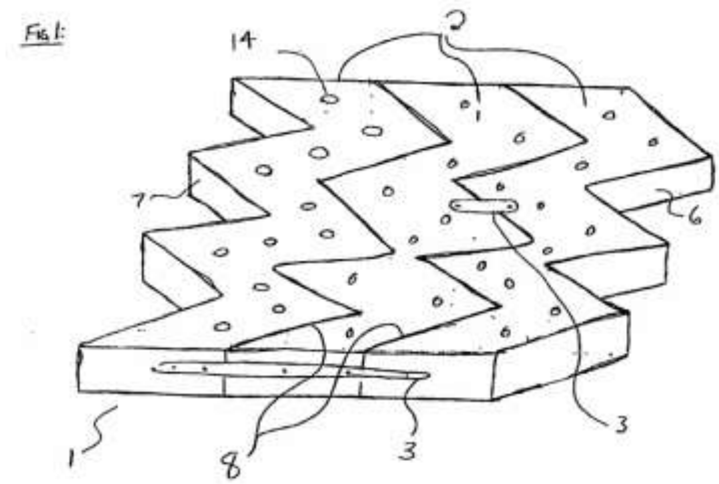

Figure 65: Schematic from Temporary Roadway Patent 6652184

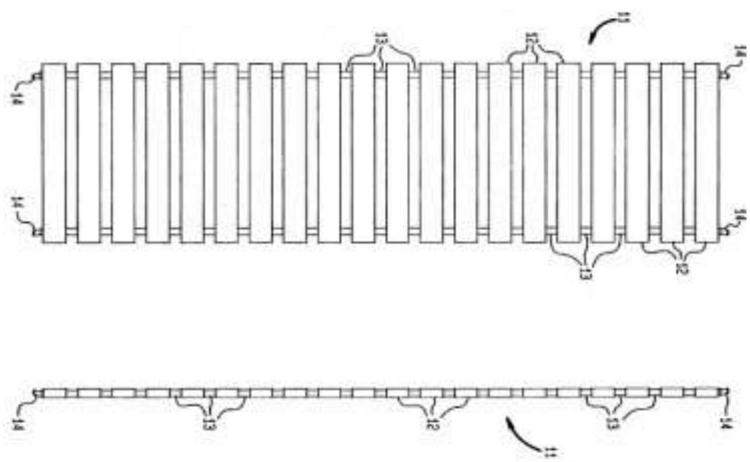

Figure 66: Corduroy road element patent 5,282,692

The Army Engineer Research and Development Center identified discrete fibers as a potential material for constructing roads and airfields over sandy soils; developed several structural matting systems to support operations over sandy soils; and evaluated several structural mats and geosynthetic-reinforced pavement systems to support heavy-truck traffic over soft soil. Fiberglass-reinforced mats, hexagonal mats, and geofiber stabilization are recommended alternatives to the existing Geocell technology for sandy soils. The fiberglass-reinforced mat should be used for small roadway sections (less than ½ mile) and geofibers should be used for large roadway sections (longer than ½ mile) in sandy soil. 2,252 DURA-BASE panels would be required to construct a 1-mile section of road over very soft soil[108].

Belton Industries, Inc.[110] manufactures a new 100% biodegradable geotextile fabric. This has recently been introduced for two applications:

- Temporary subsoil stabilization
- Wide width erosion control – a rolled erosion control blanket.

Sold under the trade name of Geojute Stabilizer®, it is available in rolls of 12.5 ft by 100 ft covering 139 square yards. Geojute Stabilizer is used in sensitive areas to build temporary roads where it acts as a separation/stabilization fabric for up to one year. By using Geojute Stabilizer, end users do not have to incur the added expense to decommission temporary roads. The fabric possesses grab tensile properties of lighter weight (3.2 oz) woven polypropylene/polyethylene fabrics. Geojute Stabilizer® also works as erosion control fabric for areas where soil bioengineering applications are being designed. It works with all coir (fiber from coconut husks) fabrics as a cost effective inner-liner when designed in conjunction with Geocoir 700/900 vegetated geogrids along stream and river banks.

Board Mat Roads

Wooden mats and roads have been used for many years particularly in the oil and gas industry to provide temporary roads and pads for construction equipment and heavy trucks in areas that are environmentally sensitive or inaccessible due to poor soil conditions during the rainy part of the year. These roads and mats are typically constructed one piece at a time and are very time-consuming and labor intensive to construct.

As pressure on labor markets increased and time constraints on construction tightened, some mat systems appeared on the market, and worked well to relieve labor and time issues. Wooden mats are laid piece by piece, with the number of plies of lumber determined by the soil conditions and the size of the loads to be hauled. The mat systems commonly used today are three-ply systems. As a general rule, fewer plies of lumber are required to accomplish the same result as elevation increases above sea level. For example, a mat having four plies of lumber may be necessary to support typical oil industry equipment over a wet site close to sea level, while a mat having only two plies of lumber may be adequate to support the same equipment over a dryer site located well above sea level, etc.[111]

The patent literature is replete with concepts of using board matting for temporary roads. Most of these are primarily different methods of connecting the board mats or pallets to form a continuous road of a specified width. Patent 4,289,420 to Davis et al. in 1981 discussed wooden mat assembly for construction of temporary roadways or assembled from a flat platform for wheeled or tracked vehicles. The wooden mat assembly is formed from interlocking mats, each mat being formed from a plurality of layers or boards, each layer being formed from boards parallel to each other and perpendicular to boards forming the adjacent layer, the layers fastened together at points of intersection. The assembled roadway or turn-around has particular utility at or near oil well drilling sites, building construction sites, etc. Davis et al. proposed that their method overcame prior failings of lack of simplicity and efficiency, settling under heavy weight in soft soil and high labor costs. US 4,289,420 suggested that the mat assembly needed a travelable surface oriented in the direction of intended travel. Additionally the mats interlock in the longitudinal direction. Offsetting each mat contributes to stability because as one tire is leaving the previous mat while the other tire still has weight on the previous. This design of wooden mats would sustain a load of 180,000 lb for as long as one year of constant use and required 1/5 or less of labor cost and 40% less lumber compared to the conventional hand laid roadway.

Sarver was awarded patent 4,600,337 for a system of prefabricated board mats for assembling plank roads for supporting heavy equipment on unprepared surfaces. The system is based on standard 8 x 16 ft three-ply treated lumber prefabricated board road sections. Individual board mat sections are linked in the direction of travel using a mating male and female plug and socket system to evenly transfer loads of heavy equipment in the direction of travel. The mats are lifted by use of three or more eyebolts.

In practice a porous protector filter cloth section is laid under the area where a board mat is to be placed. Individual board mat sections are laid successively from an initial prepared position by rolling out the protective cloth, lifting the individual sections by crane, dropping the section into position, and linking them transversely through the lateral connections. The installation machinery and supply truck containing the individual board mat sections then proceed forward onto the section of boards laid and install a second

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section. Each successive section is longitudinally linked by installing a male plug end into an exposed female end which is at the outer edge as the normal laying process proceeds.

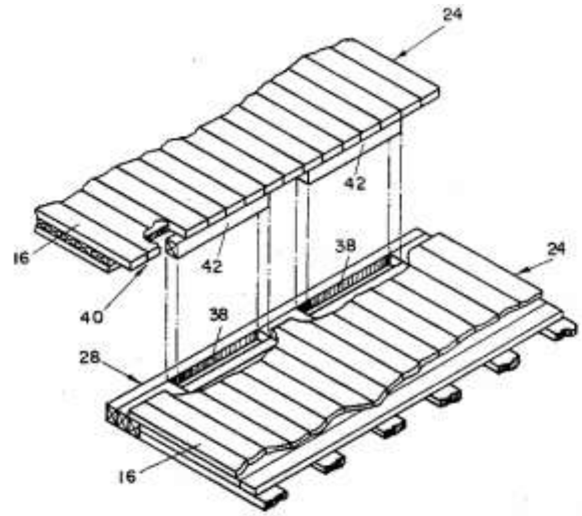

Figure 67: Board Mat System Patent 4600337

Yet another technique for interlocking systems for roads and construction sights is described by Penland in US patent 5822944 (Figure 68). He suggests this system is particularly well suited for use in areas with dry, sandy soil. The mat units include two layers of boards. Smaller sizes can be used to develop different shapes and configurations.

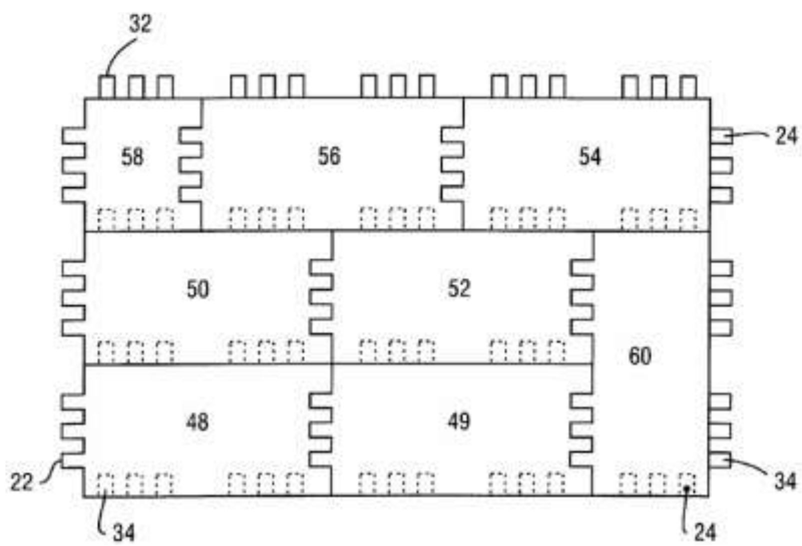

Figure 68: Double Locking Flooring System for a Construction Site

Pouyer, in a series of patents issued from 1990 to 1993 (US 5,020,937; 5,163,776; 5,273,776; 4,922,598; 4,889,444), claimed to have developed an improved method of construction of artificial roads primarily to be used in the oil and gas industry for access to drilling sites. Pouyer extended the method to constructing an artificial pad using the same techniques. He also developed a method to easily and consistently manufacture mats to be used in the construction of an artificial road. The preferred material was wood for mat (pallet) construction and can be interconnected longitudinally and laterally and does not have to be nailed together but is interlocked and can be laid down more quickly with reduced labor. The technology also suggests using a geofiber under the wooden pallets or mats to stabilize the soil.

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Hunt was issued US patent 5,234,204 (1993) that related to improving a series of designs to construct interlocking wooden road mat segments and the device to manufacture them for the construction of temporary roads. The technology disclosed a device for assembling the interlocking mat segments and how the interlocking segments were assembled in the field for temporary roads.

In 2005, US patent 6,945,732 was issued to Renick for an overlapping flanged wooden mat system and assembling system to fabricate an artificial road. He claims the design prevents heavy equipment trucks from sinking or becoming stuck and prevents damage of different soils. The ends of the mats can pivot up and down without damage as the interconnecting ends are not constrained.

Contrary to Renick, US patent 6,653,183 issued in 2003 to Stasiewich indicates that the mats need to have a retaining lip to prevent separation of the mats (Figure 69).

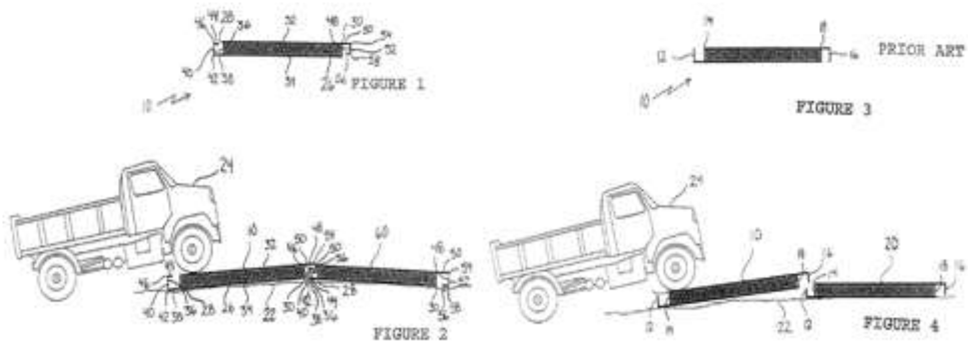

Figure 69: Patent 6,653,183 – Wooden Road Mat with Retaining Lip

A support structure for use in soft and environmentally sensitive areas to construct roads and pads to support heavy equipment typically used in the oil and gas industry was described in US patent 6,474,905 issued to Smith et al. in 2002. Roads and pads are constructed by interlocking a number of mats together to build a road or pad of the desired size. Each mat is comprised of two layers of boards made of a material with shear stress equal to or greater than that of hardwood lumber. The top layer of boards is superimposed over the bottom layer and fastened by bolts, nails, glue, etc. Forklifts, cranes, etc. are used to handle individual mats and to position the mats and lock them together (Figure 70).

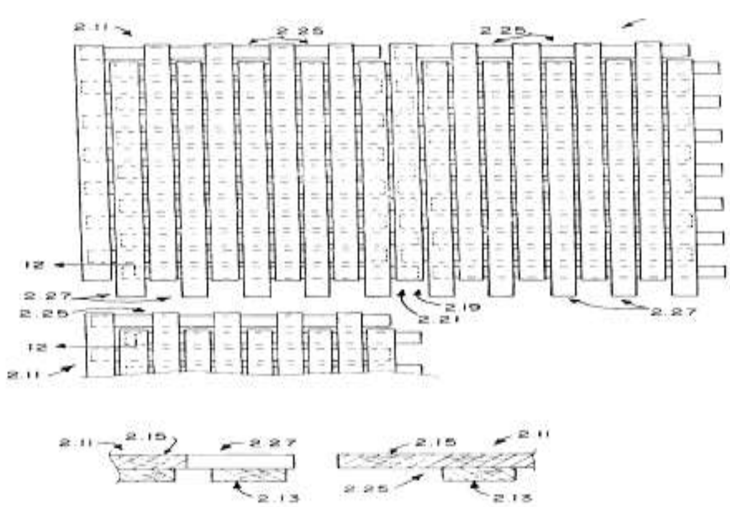

Figure 70: Wooden Road Mat (Patent 6,474,905)

A portable roadway is suggested by US patent 4,376,596 issued to Green in 1983 and is made up of removable interconnected sections for use during periods of adverse weather conditions during which soil conditions are such that it is impossible to build a permanent road, or when economics favor a temporary road. Each section consists of a hardwood frame which is connected to and supports a plywood surface. At the front and rear of each section, a transverse stiffening bar extends through and laterally to the side of the section. Connecting members are attached between the free ends of these stiffening bars. In the center of each section, a lifting bar is disposed to aid in removal and placement of the sections. Though it is suggested in the patent that the system be used in oilfield roads and construction and lumber industries, the plywood tops may not be suitable for heavy loads.

A patent application by Dagher (US 2002/022954) describes a composite structural panel (CSP) that includes a composite core preferably made of a number of vertically laminated oriented strand board (OSB) sheets. The CSP may be designed for a wide variety of applications, such as a road panel, a crane mat, a bridge deck, a soldier pile, and the like. This concept relates to developing a cost effective panel design that replaces existing solid sawn timber panels. According to the invention, a CSP comprises a composite core comprising sheets made of a composite material, the sheets being oriented parallel to a direction of an applied load.

The OSB sheets may be fastened together by adhesive. Preferably, the CSP also includes a layer of polymer concrete applied to the top surface of the composite core, and a layer of glass fiber reinforced polymer (GFRP) reinforcement material having E-glass fibers applied to the bottom surface of the composite core. When the CSP is supported directly on the ground, the E-glass fibers of the GFRP reinforcement material are oriented in a transverse direction with respect to the vertically laminated OSB sheets. A layer of protective material may be applied to the side surfaces of the composite core to provide additional protection from harsh environmental conditions. When OSB is exposed to direct water for extended times, its mechanical strength and stiffness are significantly reduced, and its dimensional stability is compromised. Industry practice is that OSB not be used in exposed environments. Other core configurations include sheets of glue-laminated solid-sawn lumber, a sub-core laminated with a unidirectional and bidirectional sub-skin, and a sub-core laminated with a single or multiple sub-skin sheet.

Roads from Plant Fiber – Biodegradable Roads

Patent 6,921,229 issued to Klyne describe a method of making temporary roads using plant fiber in undeveloped or environmentally sensitive areas. The advantage of using plant fiber in temporary roads is the relatively low cost of site restoration. Klyne claims that experimental roads have been built using plant fiber. This plant fiber can consist of sawdust, shavings, and wood chips. The technology provided in this invention is the claim that appropriate length fibers in the right proportion are needed to build an adequate road to protect the soils etc. and to develop a cohesive ground cover mat adequate for road surfaces.

A fiber block segment made from coconut fibers (coir) is developed in patent 6,893,193 for primary use of controlling erosion and stabilizing soil. This same fiber is used as a biodegradable road fiber (GeoCoir) marketed by Belton industries described above. Though developed as a shoreline erosion control, it should be possible to use these coir blocks to build biodegradable roads as the concept promotes vegetation growth.

The Army Engineer Research and development Center (ERDC) in Vicksburg, Mississippi identified discrete fibers as a potential for constructing roads and airfields over sandy soils. ERDC suggested hair-like, 5-cm-long polypropylene fibers mixed into moist sand with a self propelled rotary mixer and then compacted with a vibratory roller. A wear surface is made by spraying a resin-modified emulsion or an emulsified asphalt onto the road surface to bond the sand grains with the fiber filaments and protect the sand-fiber surface. This approach seems to be contrary to the concept of low impact roads; however, coir or other natural binders could be used as the fiber to stabilize sand since it is biodegradable and the use of mats or other temporary removable surface placed over the modified sand.

4.2.2 Temporary Structural Roads and Bridges

A number of methods to construct temporary roads have been proposed in the patent literature that span distances for bridges but also could be considered for raised roads above the surface and have limited impact on the ecology. Many of these have technology that could be used in platforms also.

As reviewed in Section 3.9 on onshore platforms, Suter received a patent in 1970 (3,511,057) for a method to erect and construct multispan bridges and piers. The concept was to provide a method to build bridges that can be started at any point along the proposed bridge span in impassable country or water-covered subsoil, and continued in both direction of the proposed bridge span. The concept could be used for elevated road building or platform (foundation) construction onshore. Additionally Norrie suggested in his patent US 6,986,319 (2006) that piers could be constructed with deck sections that can be removed or allowed to float during high wave action or storms and tethered to the pilings so as not to be damaged.

Sedlacek (patent 4,075,727, 1978) developed a frame structure that could be used primarily for portable bridges. An entire road system was not necessarily an embodiment of this development.

Patent 4,017,932 assigned to Lotto et al. in 1977 described a temporary, modular, self-erecting bridge which can be transported from place to place by collapsing the side, top and bottom elements about pivot points to achieve a narrow and shorter unit. Hydraulic jacks (cylinders) or other fluid actuated mechanisms are used to expand and contract the elements.

Collapsible beam structures have been developed that can be used as towers or as cantilever style elements to provide frame support for temporary bridge structures. The improved beam structure collapses to a very small compact unit requiring minimum storage space (patent 4,126,974 to Hardin (1978)).

Collapsible bridges for military purposes and methods to transport and launch such devices have been proposed and built; examples are patents 5,042,101 (1991) and 4,602,399 (1986). These have limited spanning distances but are modular and may be capable of being used as temporary roads by connecting elements.

An interesting portable, foldable surfacing module for use by road vehicles over previously impassable terrain is disclosed in US patent 5,275,502 by Glaza et al. (1994) (Figure 71). The surfacing module employs hinged sections that rotate through 360° relative to each other and are foldable in accordion fashion for convenient storage, transport, deployment and retrieval. There are a number of prior art styles similar to this concept, but they do not rotate through 360°.

Road surface units of these types are particularly useful to provide reversible roadways for motor vehicles of varying sizes and weights over uneven and/or unstable terrain. Also, these units are used to provide an access area at the interface between land and water. Portable roadbed configurations have been tested for the above applications, but none have the features of folding 360° with respect to adjacent panels or either surface being the top or bottom. Extrusions that make up the module are symmetrical, and the module can be placed or retrieved for reuse by beginning at either end and can be driven onto on either side.

A typical module is composed of 25 hollow extruded aluminum panels that are roughly 2 ft wide, 16 ft long and 2 in. deep. Ribs roughly ¼ inch high are located on each side of the panels transverse to vehicle movement to provide traction on the top surface for the wheeled or tracked vehicles and an anchoring system on the bottom surface. Adjacent extruded panels are connected with an aluminum hinge pin and several hinge links. Connected panels were designed to cover an area of roughly 16 ft by 55 ft. This area can be covered through the full deployment of a typical module from a dispenser by three men in approximately 5 minutes.

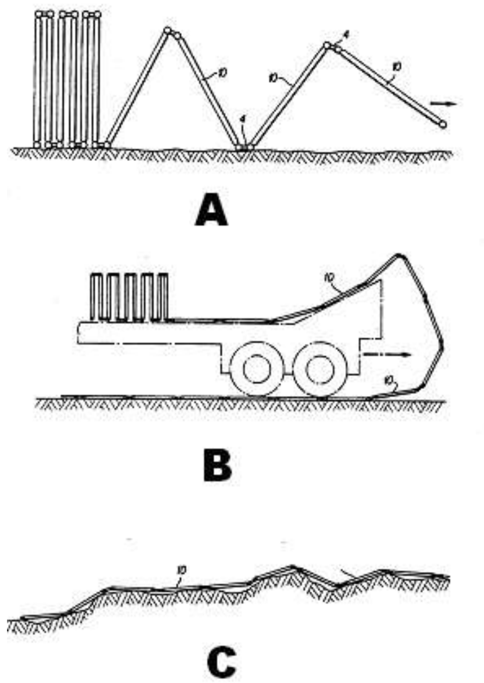

Figure 71: Accordion Folding Surfacing Module Operation and Deployment (US Patent 5,275,502)

Patent application 2004/0141809 was published for Wagstaff and was based on the use of square or round metal beams instead of boards. The tubing is filled by a filler material such as polyurethane foam to develop a durable construction mat. US patent 6,007,271 uses aluminum or steel in square or rectangular shapes to construct mats for use in temporary roads or pads. Wagstaff improved on this patent by filling the tubing with polyurethane to keep mud and water out.

US patent 4,405,262 to Nagashima (1983) suggests a method for temporary bridges and piles to be used for construction by cantilever installation (Figure 72). The proposed method is characterized as a metallic pipe form with an open upper end and a closed lower end rotated by a prime mover for an earth-auger, whereby the pile member is driven into the ground by spiraling around its outer periphery. The pile member, after reaching a desired depth, is then rotated in reverse while it is prevented from moving upwards so that the soil around it is forced radially to be tightly compressed. A height adjusting member is then introduced into the pile member from its upper open end till the bottom of the height adjusting member abuts the partition plate previously secured to the inside of the pile member at its upper portion. Then sand etc. is added into the height adjusting member, whereby, when it is lifted bit by bit the sand flows through an orifice previously formed in the bottom to fill the space formed between it and the partition plate of the pile member to adjust the height of the height adjusting member relative to the pile member. After a number of pile members and height adjusting members have been driven into the ground, bridge girders, cover plates, etc. are mounted on them to erect a temporary bridge. By repeated applications, an elevated road could be constructed.

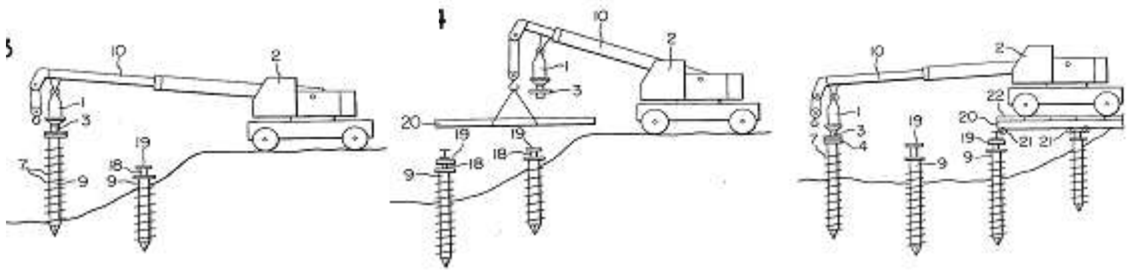

Figure 72: Cantilevered Bridge and Elevated Road Construction

Hasselkvist, in US patent 5,173,981 (1992), described a bridge construction kit and bridging elements for building a temporary multispan military bridge (Figure 73). This concept could be extended to continuous elevated roads as it is implemented by cantilever concept and with periodic self contained leg support. One objective of this invention is to provide a framework of construction where each bridge element is made of a high load bearing capacity to enable several bridge elements to be joined together in a row and form a cantilever construction.

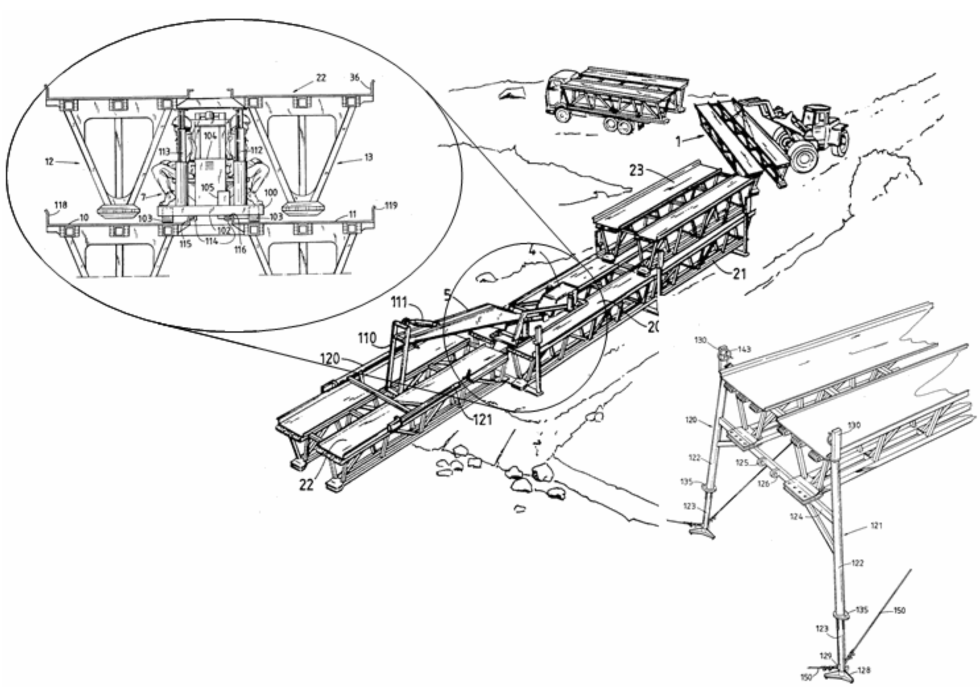

Figure 73: Concept Continuous Cantilevered Bridge (Patent 5,173,981)

The construction kit is characterized in that it comprises a crane carriage for lifting a bridge element into a position in which it can be coupled to another bridge element; locking devices for coupling bridge elements together; and support-leg pairs which support the mutually coupled bridge elements. The carriage crane shuttle is fitted with a hydraulic lifting arm that lifts an element section and shuttles it to the end of the bridge and then via hydraulic arms places the section for pinning and bolting. The construction kit can be accommodated on conventional trucks. The invention also relates to the bridge element, crane carriage, locking devices and support-leg pairs themselves.

US patent application 2004/0098817 relates to a method and apparatus for creating a temporary roadway or platform in wetlands, marshlands and other wet areas. Suggested uses include drilling oil wells and/or searching for oil fields in remote locations that often require transport of heavy equipment across unstable terrain. When construction of a permanent road or platform is not cost-effective or, in the case of federally protected wetlands, not permitted, a means for providing temporary access to these remote locations that can be easily removed and does not destroy the terrain is desirable.

A gabion container, having a number of compartments, is composed of PVC-coated wire mesh, although PVC coating is not essential. Further, the gabion container is typically a wire gabion basket that is approximately 3 ft wide by 12 ft long by 1 ft thick.

In each compartment a filler material is optionally fitted to the dimensions of the compartment. The filler material is comprised of a buoyant material. If buoyancy is not required, the filler material could be hay or some other like material. To reduce the possibility of contamination of the environment, the filler material can be encapsulated in a wrapper of a fabric that is a woven geotextile composed of polypropylene yarns such as the Filterweave product sold by TC Mirafi or other like materials in the event breakage occurs. Belton Industries Inc. markets a similar concept with Geojute with bales of coir for erosion control.

A portion of a completed platform or roadway is shown in Figure 74. Four support components are connected side by side via a connection mechanism to form a large top surface. Wires, hooks and factory provided connections are used. The result is a layer of support components.

Panels are then placed on the top surfaces of the gabion containers to permit equipment placement. These panels are generally a wooden interlocking mat system. The water level is shown in Figure 74 relative to the terrain to demonstrate the flotation capability of the concept, even when equipment (load) is placed on the panels. The platform or roadway will also work with support components resting directly on the terrain instead of floating.

In appropriate circumstances, more than one layer can be placed on top of another to provide more buoyancy or to reach the terrain depending on the need. The support components can easily be connected into multiple surface areas and thicknesses. The primary purpose is to form temporary platforms and roadways in areas of unstable terrain (especially wetlands).

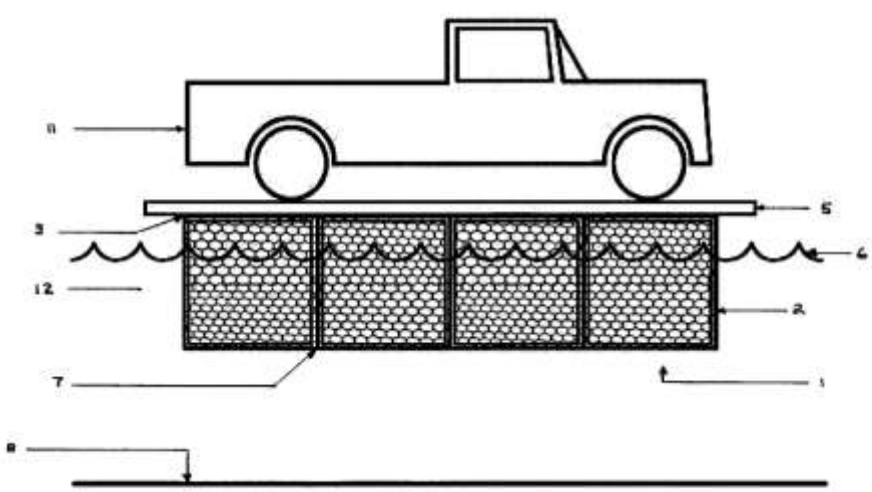

Figure 74: Temporary Platform or Roadway for Use in Wetlands

Appendix A – Thermal Processing of Drill Cuttings

Incineration

Incineration technologies oxidize waste at high temperatures (1,200 to 1,500°C) and convert them into less bulky materials that are nonhazardous or less hazardous than prior to incineration.[112] Incineration is typically used to destroy organic wastes that are highly toxic, highly flammable, resistant to biological breakdown, or pose high levels of risk to human health and the environment. Incineration of drilling wastes is normally not necessary, unless operations are located in sensitive environments and other disposal options are not available. Incinerators are generally permanent (non-mobile) units. In commercial incinerators, combustion can be optimized because residence time, temperature, and turbulence within the chamber can be controlled. Commercial incinerators are also frequently equipped with pollution control devices to remove incomplete combustion products and particulate emissions and to reduce SOx and NOx emissions. Advantages of incineration include volume reduction, complete destruction (rather than isolation), and possible resource recovery. Because energy requirements for incineration relate directly to water content, costs for incinerating drilling wastes with high water content can be high.

Rotary Kilns: Most incineration of drilling wastes uses rotary kilns, a mature and commercially available technology, which is durable and able to incinerate almost any waste, regardless of size or composition. A rotary kiln tumbles the waste to enhance contact with hot burner gases. The Canadian Crude Separator's Incineration Process (CSS) is an example of a rotary kiln process that operates under starved oxygen conditions. The unit is permanently installed near Big Valley, Alberta, Canada. Primary chamber temperatures reach 600 to 1,000°C. Venturi section temperatures reach 1,200°C. The kiln handles 10 metric tons/day. The process can handle wastes with up to 10% hydrocarbons. Minimum costs to process solids with 10% hydrocarbons at the plant are $90/metric ton. There is adequate mix material available to handle wastes arriving at the facility with hydrocarbon concentrations up to 40%, but prices increase with percentage of hydrocarbons in the drilling waste.[60]

Cement Kilns: If available, a cement kiln can be an alternative to a rotary kiln. In cement kilns, drilling wastes with oily components can be used in a fuel-blending program to substitute for fuel that would otherwise be needed to fire the kiln. Cement kiln temperatures (1,400 to 1,500°C) and residence times are sufficient to achieve thermal destruction of organics. Cement kilns may also have pollution control devices to minimize emissions. Ash resulting from waste combustion becomes incorporated into the cement matrix, providing aluminum, silica, clay, and other minerals typically added in the cement raw material feed stream. A process for converting drill cuttings to raw materials for cement production has been patented.[113]

Thermal Desorption

Thermal desorption uses a non-oxidizing process to vaporize volatile and semi-volatile compounds. Thermal desorption easily removes light hydrocarbons, aromatics, and other volatile organics, but heavier compounds such as polycyclic aromatic hydrocarbons are less easily removed. Low-temperature thermal desorption systems typically operate at 250 to 350°C and may be sufficient to treat wastes with light hydrocarbons, aromatics (e.g., benzene, toluene, ethylbenzene, and xylenes), and other volatile organics, which are easily removed. High-temperature systems may operate at temperatures up to 520°C, and can produce lower final oil contents for wastes with heavier compounds such as polycyclic aromatics.[114]

Thermal desorption produces various secondary waste streams, including solids, water condensate, and oil condensate, each of which may require analysis to determine the best recycle/disposal option. In most cases, the liquids are separated and reused in drilling mud to improve economics of this method. In other cases (for example, original wastes with high salts and metals contents), additional treatment may be required to reduce the potential for environmental impact from these streams.

Capital equipment costs for a thermal desorption plant that processes between 3 to 10 tons/hour range from $3 to $5 million dollars. Contractor operator treatment costs range from $75 to $150/ton.[60] Many factors impact treatment costs, including oil and moisture content of the waste, particle size distribution of the solids, organic composition and volatility, management of the hydrocarbon byproduct, and management of the water product. Economics may improve in cases where thermal desorption is operated as part of the overall production facility.

Many variations of thermal desorption have been developed and are applicable for treating drilling wastes. Examples include indirect rotary kilns, hot oil processors, thermal phase separation, thermal distillation, thermal plasma volatilization, and modular thermal processors.

Indirect Rotary Kilns: Indirect rotary kilns use hot exhaust gases from fuel combustion to heat drilling wastes. The technology consists of a rotating drum placed inside a jacket. Heat is supplied through the wall of the drum from the hot exhaust gas that flows between the jacket and the drum. Drilling wastes are agitated and transported through the processor inside the rotating drum. Treated solids are recirculated to prevent formation of an isolating layer of dried clay in the inside of the drum. Because the overall heat transfer from the exhaust to the material is low, relatively large heating surfaces are required, and the process units are correspondingly large. Units typically heat wastes to about 500°C, which provides efficient removal of oil from the wastes, but which can lead to thermal degradation and decomposition of residuals in recovered solids.

Hot Oil Processors: In hot oil processors, heat is transported to drilling wastes by circulating hot oil inside hollow rotors. Rotors also agitate and create the required axial transport in the bed. Conventional fuels provide the primary heat source for the hot oil. Large heating surfaces are required because (1) there is a relatively low heat transfer coefficient between the hot oil and waste material inside the processor, and (2) commercial hot oils have maximum operating temperatures that are close to the required process temperature, which limits useable temperature difference for heat transfer. Some units augment the heat from hot oils with electric heating on part of the heat surface to reach temperatures needed for complete removal of the oil in the waste. Retention times for complete removal of oils are about 30 to 150 minutes.

Thermal Phase Separation: The thermal separation process (TPS) consists of five subsystems. In the first, drilling wastes are screened to remove foreign matter prior to delivery to the desorption chamber. Next, the shell of the chamber is heated externally with a series of burners fueled by propane, natural gas, diesel, or recovered drilling fluid. Drilling wastes are heated indirectly to raise their temperature to the boiling point of the hydrocarbons (usually about 220°C, but sometimes up to 500°C), where they are volatilized and separated from the host matrix under a vacuum. Screw augers, which slowly draw the wastes through the inner heating shell, ensure suitable agitation and thorough heating of the solids matrix. Water vapor and gaseous hydrocarbons extracted in the desorption chamber are rapidly cooled by direct contact with water sprays fed with recirculated process water. Condensed liquids and recirculated quench water are then sent to an oil/water separator, where recovered fluid is collected, analyzed, and recycled.

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Treated solids are contained and tested prior to use as an onsite fill material. TPS removes 99% of hydrocarbons from the feedstock.[115] Recovered water is cooled and contained for recirculation.

Advantages of TPS over rotary kilns or directly fired desorption systems are more sophisticated air emissions control, ability to treat materials with up to 60% undiluted oil (because there is no potential for combustion), and opportunity of visual inspection during operations. Economic value of the process lies in the quality of the recovered base oil and its readiness for reuse or resale.[115] Mobile TPS units can treat 10 to 50 tons per hour of waste material, and highly mobile, heli-transportable equipment treats drilling wastes in remote locations. TPS systems are used for oil-based drilling wastes in environmentally sensitive areas.

Thermal Distillation: Because constituents of liquid mixtures evaporate at different temperatures, thermal distillation allows separation of solids, liquids, and different constituents of liquids. In high-temperature thermomechanical conversion and cracking, drill cuttings are distilled and cracked to boil off water and oil. Sometimes vapors are condensed to allow recovery. In the thermomechanical process, heat is produced internally in the drilling waste by friction forces generated by intense agitation. High mechanical shear combined with in-situ heat generation creates an environment that promotes flash evaporation of water and hydrocarbons. Efficient turbulent mixing promotes an efficient steam distillation of the oils, which makes it possible to vaporize oils at a temperature well below their atmospheric vaporization point (about 200 to 350° C), thereby eliminating risk for thermal degradation. Intense agitation in the process mill requires that the layer of abrasion-resistant material welded on the active surfaces of the mill be refurbished regularly. Thermomechanical units operating today recover solids with residual oil levels less than 1,000 ppm. After removing free residual oil in settling tanks or oil separators, recovered water (with less than 15 ppm oil) can be reused, discharged to the sea, or sent to available wastewater treatment facilities.

Benefits of thermomechanical desorption include the following:

- Direct mechanical heating, which eliminates the need for large heating surfaces and complex heating systems
- The ability to use engines, turbines, or electric motors to generate mechanical energy, which allows compact designs
- Limited process temperatures and short retention times required for complete removal of oil from solids (6 to 12 minutes for solids and 15 to 30 seconds for oil), which significantly reduces risk for thermal degradation of the valuable mud oils (TNW undated) and the quantity and cost of the heat required.

In lower-temperature thermal stripping, oil is not cracked, and can therefore be reused. The treated cuttings resulting from distillation can be reused, if the concentrations of heavy metals and salts are acceptable.

RLC Technologies developed an Anaerobic Thermal Desorbtion Unit (ATDU) that can be used to process drill cuttings. They have supplied ATDU's to customers in the North Atlantic and the Middle East regions complete with complete with feed, vapor recovery and water treatment systems for thermal processing of drill cuttings from on- and offshore oil and gas exploration platforms. Thermal desorption can effectively remove mineral and synthetic based oils from cuttings.

They have two different size plants. The smaller unit is mobile:

Sizing:
42" diameter x 40' length x 8' wide
1067 mm diameter x 12.19 m length x 2.44 m wide

The larger unit may be suited for higher material processing rates.

Sizing:
66" diameter x 54' length x 8' wide
1163 mm diameter x 16.46 m length x 2.44 m wide

RLC Technologies innovative technology is based on an indirect-heated rotary desorber system which employs an oxygen-deficient atmosphere while desorbing/separating volatile and semi-volatile organic compounds from the solids. Rotating system is capable of maintaining material temperatures ranging from 600–1400ºF (315–760ºC). Slightly negative pressure is continuously maintained on the desorber. This assists in removing process gases from the desorber and into the vapor recovery unit. Here process gases undergo treatment inside a series of scrubbers and separators where entrained solids, water and hydrocarbon vapors are removed from the gas stream.

The second step in gas treatment is accomplished when effluent from the primary scrubber is passed through a heat exchanger/condenser where gas temperature is further reduced to below 100ºF (38ºC). Vapors exiting the heat exchanger include residual non-condensable gasses and water vapor. Depending on local regulatory guidelines and emission requirements, these vapors may be discharged directly into the atmosphere. Should it be determined that additional treatment of off-gases is required, final gas treatment to remove any residual contaminants can be achieved using activated carbon, bio-filters or thermal oxidation in an ATDU furnace.

All condensed vapors from the vapor recovery unit undergo a separation and cooling process once inside the water treatment unit. Output from the water treatment has commercial value and consists of three separate streams: solids, oil, and water. The oil can be further treated and used to fire ATDU burners. Recovered water once cooled can be recycled through the plant as cooling/process water.

Pyrolytic Methods

NAVSEA-Carderock, one of the Navy's laboratories, has investigated various pyrolytic methods that may be applicable to disposal of drill cuttings. Thermal plasma volatilization has not yet been used for the treatment of drilling wastes. Thermal plasma results when a common gas is heated to extremely high temperatures (up to 15,000°C). The technology is used for various applications including metallurgy; steel making; and treating medical, industrial, and petroleum wastes. Pyrolytic methods are now also being used on commercial cruise ships. It is also being used to treat oil-contaminated soils that include substances such as chlorides, which are unsuitable for a combustion process because of their potential to generate dioxins and furan compounds as byproducts. The process uses a plasma reactor, which contains a plasma torch operating in an inert atmosphere. Waste material is fed into the reactor. In the reactor, the torch, whose jet temperature is about 15,000°C, is used to heat waste to 900° C without combustion, causing any hydrocarbons to volatilize. In subsequent stages, these hydrocarbons are condensed, and most are reclaimed as clean oil and returned to a process stream. Resulting solids are inert and contain less than 0.01% hydrocarbons. Reduction in mass of the waste materials is typically about 70%, and reduction in volume is about 85%. If wastes have toxic materials, such as heavy metals, a subsequent plasma vitrification process can be used. In plasma vitrification, the toxic waste goes to a vitrification reactor, where temperatures above 1,600°C are maintained and where chemical and physical reactions form ceramic and ferrous matrices in liquid forms. When tapped from the reactor, the toxic materials become solid, inert phases, which can be used in construction and metallurgical applications.

Advantages of the process include significant reductions in waste volume, reduced costs for preparation and transport of wastes, avoidance of harmful stack emissions, compact installation, and higher energy efficiency than combustion. (With thermal plasma volatilization, 85% of the energy is transferred as heat, compared with about 20% for combustion processes.)

Pyrolytic methods are distinguished from oxidative methods even though ultimate products of destruction are oxidized. Pyrolytic methods, as used for materials destruction, are two-stage processes in which the waste material is first pyrolyzed and then oxidized. This aspect makes it unlikely that any of the waste will escape destruction.

Plasmas are highly ionized gases that can be brought to very high temperatures through coupling of electrical energy from a power supply. Whereas combustion temperatures rarely exceed 2,000°F (1,100°C), plasma temperatures range from 5,000° F to 22,000° F (3,000° C to 12,000° C) or higher. When chemical substances are subjected to temperatures in the plasma range, they are torn apart, i.e., reduced to atoms or fragments containing only a few atoms. This process is called pyrolysis. If waste is passed through a plasma arc, the materials are vaporized atomically and lose all memory of their former structure. As this waste passes out of the plasma region and cools, metal and glass components form a slag or, alternatively, molten metal. The paper, cardboard, and plastic portion, consisting mainly of carbon, hydrogen, and oxygen, tends to form low molecular weight compounds such as the hydrocarbons—methane, ethane, and so on—and some related oxygenated species. This latter component is gaseous and may be used as low-grade fuel to recover some of the energy consumed in generating the plasma.

The pyrolysis process differs from combustion. Temperature is much higher and oxygen does not participate in the reactions in a dominant way. Products of pyrolysis will be different from those of combustion, and differences could be environmentally favorable. Oxidation must also be controlled to avoid formation of noxious compounds, e.g., dioxins. Pyrolysis products are usually burned in an afterburner. Vitreous slag resulting from plasma destruction of waste tends to occlude metals, effectively removing them from the environment. Volatile metals from electrodes or feed stock will need remediation. A great deal remains to be done in characterizing plasma arc products, but there is hope of environmental advantage.

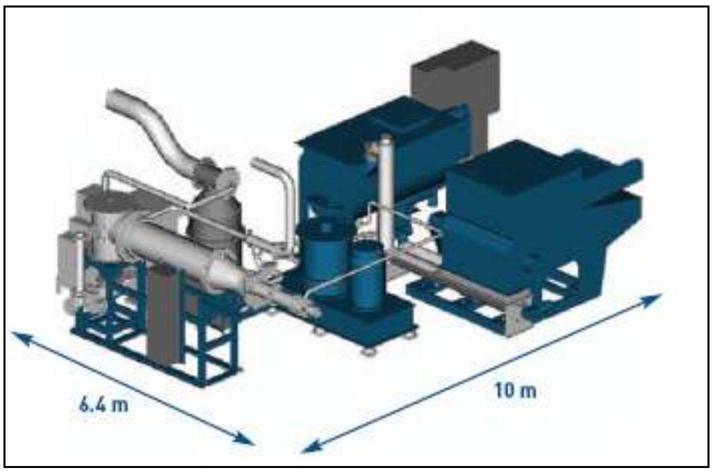
High temperatures of a plasma arc ensure that reactions are very fast, and this allows short residence times of materials being pyrolyzed. On this basis, the plasma arc processor might be made smaller than an incinerator with comparable throughput. The downside of the comparison with the incinerator is the required power source for the plasma arc machine.

Vitrification is closely related to plasma arc. Waste is heated to about 3,000°F by electrical current or by contacting an electrical discharge with the material to be destroyed. Organic materials are destroyed by pyrolysis and the products burned in an afterburner. A key feature of this technology is that inorganics are melted so that a liquid pool is formed at the bottom of the treatment chamber. When this melt is cooled, a vitreous solid mass is formed and elements contained in it are nonleachable by ground water. This is valuable when the waste is hazardous (specifically, radioactive), but advantages for shipboard waste destruction are not as clear.

Battelle Pacific Northwest Laboratories[116,117] has extensive experience in research, development, and application of this technique to management of radioactive and other hazardous wastes. The technology has been successfully tested on medical wastes at a nominal throughput of 25 tons/day. Shipboard waste on the largest ships in the Navy is produced at a rate of about 10 tons/day. With suitable modification, vitrification can probably be employed to destroy black water sludge. This technology is viewed as sufficiently advanced and that major research is not required. Normal engineering and testing work remain for shipboard waste destruction applications. Flux addition may be necessary to obtain a stable glass. Proponents of the method see no major hurdles in applying vitrification to shipboard solid wastes.

NAVSEA-Carderock and PyroGenesis developed a plasma arc waste destruction system (PAWDS) for shipboard use. Use of this technology resulted in an efficient and compact design with the ability to dispose of a vast variety of unsorted ship garbage unlike any existing shipboard incinerator. PAWDS operates at extreme temperatures so that combustion is almost complete with very little pollutants exhausted into the environment. PAWDS eliminates the current need for hand sorting garbage prior to incineration. A prototype system is available for testing drill cuttings disposal.

The PAWDS was installed on board a Carnival Cruise Line ship and has been in operation since October 2003. The system, having the same capacity as a multi-deck incinerator, occupies a surface of only 64 m^2 and fits on one single deck of the ship. The PAWDS is capable of treating a variety of waste generated on board, including cardboard, food, food contaminated waste, plastics, cabin waste and sludge oil. In the near future, black-water and gray-water sludges will also be treated by the system. Efficient destruction of all of these types of waste eliminates the need for discharging food waste overboard or off-loading such waste in port, thereby allowing ships to be one step closer to the ultimate goal of "zero-discharge."



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Appendix B – Diesel Engine Emission Standards

Tier 1-3 Standards – The 1998 nonroad engine regulations are structured as a three-tiered progression. Each tier involves a phase-in (by horsepower rating) over several years. Tier 1 standards were phased in from 1996 to 2000. The more stringent Tier 2 standards take effect from 2001 to 2006, and yet more stringent Tier 3 standards phase in from 2006 to 2008 (Tier 3 standards apply only for engines from 37–560 kW).

Tier 1–3 emissions standards are listed in the following table. Nonroad regulations are in the metric system of units, with all standards expressed in grams of pollutant per kWh.

EPA Tier 1-3 Nonroad Diesel Engine Emission Standards, g/kWh (g/bhp·hr)							
Engine Power	**Tier**	**Year**	**CO**	**HC**	**NMHC+NOx**	**NOx**	**PM**
kW < 8 (hp < 11)	Tier 1	2000	8.0 (6.0)	-	10.5 (7.8)	-	1.0 (0.75)
	Tier 2	2005	8.0 (6.0)	-	7.5 (5.6)	-	0.8 (0.6)
8 ≤ kW < 19 (11 ≤ hp < 25)	Tier 1	2000	6.6 (4.9)	-	9.5 (7.1)	-	0.8 (0.6)
	Tier 2	2005	6.6 (4.9)	-	7.5 (5.6)	-	0.8 (0.6)
19≤ kW < 37 (25 ≤ hp < 50)	Tier 1	1999	5.5 (4.1)	-	9.5 (7.1)	-	0.8 (0.6)
	Tier 2	2004	5.5 (4.1)	-	7.5 (5.6)	-	0.6 (0.45)
37 ≤ kW < 75 (50 ≤ hp < 100)	Tier 1	1998	-	-	-	9.2 (6.9)	-
	Tier 2	2004	5.0 (3.7)	-	7.5 (5.6)	-	0.4 (0.3)
	Tier 3	2008	5.0 (3.7)	-	4.7 (3.5)	-	-†
75 ≤ kW < 130 (100 ≤ hp < 175)	Tier 1	1997	-	-	-	9.2 (6.9)	-
	Tier 2	2003	5.0 (3.7)	-	6.6 (4.9)	-	0.3 (0.22)
	Tier 3	2007	5.0 (3.7)	-	4.0 (3.0)	-	-†
130 ≤ kW < 225 (175 ≤ hp < 300)	Tier 1	1996	11.4 (8.5)	1.3 (1.0)	-	9.2 (6.9)	0.54 (0.4)
	Tier 2	2003	3.5 (2.6)	-	6.6 (4.9)	-	0.2 (0.15)
	Tier 3	2006	3.5 (2.6)	-	4.0 (3.0)	-	-†
225 ≤ kW < 450 (300 ≤ hp < 600)	Tier 1	1996	11.4 (8.5)	1.3 (1.0)	-	9.2 (6.9)	0.54 (0.4)
	Tier 2	2001	3.5 (2.6)	-	6.4 (4.8)	-	0.2 (0.15)
	Tier 3	2006	3.5 (2.6)	-	4.0 (3.0)	-	-†
450 ≤ kW < 560 (600 ≤ hp < 750)	Tier 1	1996	11.4 (8.5)	1.3 (1.0)	-	9.2 (6.9)	0.54 (0.4)
	Tier 2	2002	3.5 (2.6)	-	6.4 (4.8)	-	0.2 (0.15)
	Tier 3	2006	3.5 (2.6)	-	4.0 (3.0)	-	-†
kW ≥ 560 (hp ≥ 750)	Tier 1	2000	11.4 (8.5)	1.3 (1.0)	-	9.2 (6.9)	0.54 (0.4)
	Tier 2	2006	3.5 (2.6)	-	6.4 (4.8)	-	0.2 (0.15)
† Not adopted, engines must meet Tier 2 PM standard.							

Manufacturers who signed the 1998 Consent Decrees with the EPA may be required to meet the Tier 3 standards one year ahead of schedule (i.e., beginning in 2005).

Voluntary, more stringent emission standards that manufacturers could use to earn a designation of "Blue Sky Series" engines (applicable to Tier 1–3 certifications) are listed in the following table.

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EPA Voluntary Emission Standards for Nonroad Diesel Engines, g/kWh (g/bhp·hr)		
Rated Power (kW)	NMHC+NOx	PM
kW < 8	4.6 (3.4)	0.48 (0.36)
8 ≤ kW <19	4.5 (3.4)	0.48 (0.36)
19 ≤ kW <37	4.5 (3.4)	0.36 (0.27)
37 ≤ kW < 75	4.7 (3.5)	0.24 (0.18)
75 ≤ kW <130	4.0 (3.0)	0.18 (0.13)
130 ≤ kW < 560	4.0 (3.0)	0.12 (0.09)
kW ≥ 560	3.8 (2.8)	0.12 (0.09)

Engines of all sizes must also meet smoke standards of 20/15/50% opacity at acceleration/lug/peak modes, respectively.

Regulations include several other provisions, such as averaging, banking and trading of emission credits and maximum “family emission limits” (FEL) for emission averaging.

Tier 4 Standards – The Tier 4 emission standards—to be phased-in from 2008–2015—are listed in the following table for engines below 560 kW. These standards introduce substantial reductions of NOx (for engines above 56 kW) and PM (above 19 kW), as well as more stringent HC limits. CO emission limits remain unchanged from the Tier 2–3 stage.

Tier 4 Emission Standards—Engines Up To 560 kW, g/kWh (g/bhp-hr)						
Engine Power	Year	CO	NMHC	$NMHC+NO_x$	NO_x	PM
kW < 8 (hp < 11)	2008	8.0 (6.0)	-	7.5 (5.6)	-	0.4[a] (0.3)
8 ≤ kW < 19 (11 ≤ hp < 25)	2008	6.6 (4.9)	-	7.5 (5.6)	-	0.4 (0.3)
19 ≤ kW < 37 (25 ≤ hp < 50)	2008	5.5 (4.1)	-	7.5 (5.6)	-	0.3 (0.22)
	2013	5.5 (4.1)	-	4.7 (3.5)	-	0.03 (0.022)
37 ≤ kW < 56 (50 ≤ hp < 75)	2008	5.0 (3.7)	-	4.7 (3.5)	-	0.3[b] (0.22)
	2013	5.0 (3.7)	-	4.7 (3.5)	-	0.03 (0.022)
56 ≤ kW < 130 (75 ≤ hp < 175)	2012-2014[c]	5.0 (3.7)	0.19 (0.14)	-	0.40 (0.30)	0.02 (0.015)
130 ≤ kW ≤ 560 (175 ≤ hp ≤ 750)	2011-2014[d]	3.5 (2.6)	0.19 (0.14)	-	0.40 (0.30)	0.02 (0.015)

a - hand-startable, air-cooled, DI engines may be certified to Tier 2 standards through 2009 and to an optional PM standard of 0.6 g/kWh starting in 2010
b - 0.4 g/kWh (Tier 2) if manufacturer complies with the 0.03 g/kWh standard from 2012
c - PM/CO: full compliance from 2012; NOx/HC: Option 1 (if banked Tier 2 credits used)—50% engines must comply in 2012-2013; Option 2 (if no Tier 2 credits claimed)—25% engines must comply in 2012-2014, with full compliance from 2014.12.31
d - PM/CO: full compliance from 2011; NOx/HC: 50% engines must comply in 2011-2013

In engines of 56–560 kW rated power, the NOx and HC standards are phased-in over a few year period, as indicated in the notes in the table above. As an alternative to introducing required percentage of Tier 4

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compliant engines, manufacturers may certify all their engines to an *alternative NOx limit* in each model year during the phase-in period.

These alternative NOx standards are:

- Engines 56-130 kW:
    - Option 1: NOx = 2.3 g/kWh = 1.7 g/bhp-hr (Tier 2 credits used to comply, MY 2012-2013)
    - Option 2: NOx = 3.4 g/kWh = 2.5 g/bhp-hr (no Tier 2 credits claimed, MY 2012-2014)
- Engines 130-560 kW: NOx = 2.0 g/kWh = 1.5 g/bhp-hr (MY 2011-2013)

The following table is for engines above 560 kW

Tier 4 Emission Standards—Engines Above 560 kW, g/kWh (g/bhp-hr)					
Year	**Category**	**CO**	**NMHC**	**NO_x**	**PM**
2011-2014	Generator sets > 900 kW	3.5 (2.6)	0.40 (0.30)	0.67 (0.50)	0.10 (0.07)
	All engines except gensets > 900 kW	3.5 (2.6)	0.40 (0.30)	3.5 (2.6)	0.10 (0.07)
2015	Generator sets	3.5 (2.6)	0.19 (0.14)	0.67 (0.50)	0.03 (0.022)
	All engines except gensets	3.5 (2.6)	0.19 (0.14)	3.5 (2.6)	0.04 (0.03)

Existing Tier 2-3 smoke opacity standards and procedures continue to apply in some engines. Exempted from smoke emission standards are engines certified to PM emission standards at or below 0.07 g/kWh (because an engine of such low PM level has inherently low smoke emission).

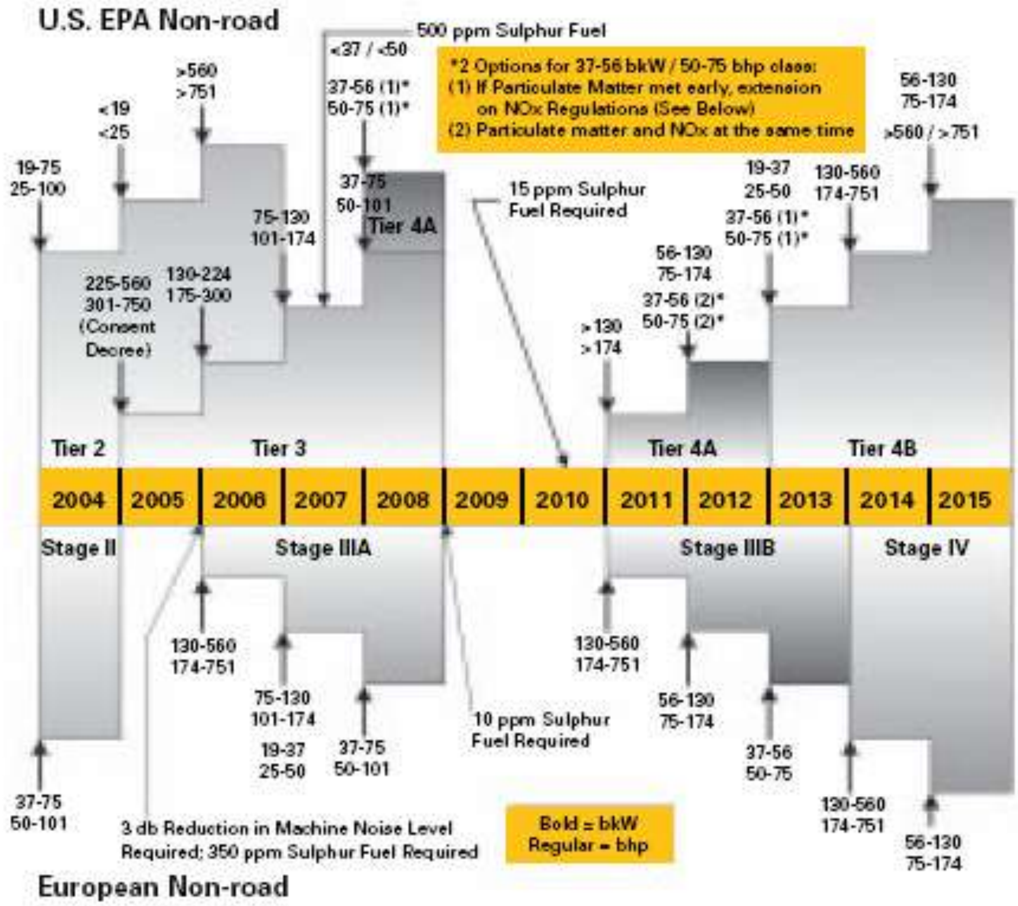
The Tier 4 regulation does not require closed crankcase ventilation in nonroad engines. However, in engines with open crankcases, crankcase emissions must be measured and added to exhaust emissions in assessing compliance.

Similarly to earlier standards, the Tier 4 regulation includes such provisions as averaging, banking, and trading of emission credits and FEL limits for emission averaging.

Caterpillar (www.cat-oilandgas.com) has published the following chart illustrating the various emissions regulations and timing.

EPA & EU NON-ROAD EMISSIONS REGULATIONS*

Tier 3 Changes for Consent Decree Signatories



*Additional information available at www.dieselnet.com

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Appendix C – Field Trip BP Pile Driving

Purpose of Trip

The purpose of this trip was to view a pile-driving operation being conducted on a BP location near Baton Rouge, Louisiana. Use of the raised platform in environmentally sensitive areas will require the use of piles to support the platform. It is necessary to develop an understanding of this operation and from that determine how it might be applied in an actual situation, what modifications will be necessary and if there are any "show stoppers" to this technology.

The material presented is in order as it occurs in the field Cost estimate for preparation of this location is $850,000 and can only be justified because the rig will be on location 90 to 120 days to drill the well to 19,000 to 22,000 ft.

Conclusions and Recommendations

The BP location represents the top end of engineered and environmentally sound site development. The $850,000 cost is justified due to the complex nature (Appendix C-1) of these wells and drilling time of 90–120 days. This type of effort currently cannot be justified on a less complicated well with shorter duration drilling times; 10–30 days. However, lessons and approach of this type of pad should be the main goal of the project. Imagine, that this site could be cut into small sections trucked to different drilling sites and reassembled. The impact it would have on the environmental effects of drilling would be significant. The drilling platform represents this general approach. It should be considered for not only those areas where contact with the ground requires the raised platform, but also for areas where setting the platform on the ground is possible, but the other benefits of engineering and environmental impact can be obtained.

What Was Learned/Observed

The site visited is agricultural land used to raise sugar cane. The process begins with surface use agreement negotiations with the land owner. This negotiated agreement can dramatically affect size, shape, and location of the final installed facility/well site. In this case the land owner wanted an all-weather road built to provide access to this area of his operations. As a result the road for this facility is larger and nicer than is typical. Once the negotiations are completed, site investigation begins with borings (Figure C-1) and a cone penetrometer test.

Figure C-1. Coring Rig

The cone penetrometer is a pointed rod that is pushed into the ground (Figure C-2). Different types are available, but the one used by BP is a small traced vehicle that pushes the cone on a rod into the ground at the center of the small remote controlled vehicle (Figure C-3). Rods are added as the cone is pressed at a constant rate into the ground while several measurements are recorded. These data along with core sample data are compiled into a report for BP. The most important part of the report for the pile driving operation is shown Appendix C-3. This graph shows the loading in tension and compression that the specified pile size driven to different depths can support. BP uses this to determine how deep the piles need to be driven to support the weight of the rig. BP, as a conservative measure, takes the full rig weight (600,000 lb), full weight of heaviest string of casing (1.2 million lb), buoyancy and surge loads are not included, to determine drive depth that is needed to support the load. Safety factor for this calculation is in the range of 2 to 2.5:1. This compares to 8:1 for most civil engineering projects.

Figure C-2. CPT Head

Figure C-3. Track CPT

After soil conditions are determined, the site is designed. This includes the amount and depth of crushed limestone that is needed to form the base. The area is leveled, geotex fabric is installed and a limestone base is laid down; in this case 14 in. compacted to 10 in. under load areas. The area where living quarters and trailers are placed starts out at this and tapers to 5 in. compacted. The slope of the pad is such that noncontact storm water coming off of the trailers is shed to the surrounding ground. Contact storm water that comes off the rig and other equipment is shed to a sump were it is pumped into the pits and used as part of the make-up water for the water-base mud system. The area where the rig substructure will set is left open. Pits are also constructed, and this case, earthen pits without liners will be used because the clay in this area has absorption and transmission numbers that allow for this practice (Figure C-4). More on the pits and prevention of contamination will be discussed later. The site layout includes locations for all equipment including fuel bunker, engine package, and injection equipment.

Figure C-4. Pits with flow lines

Figure C-5. Pipe in pipe for mud line

Piping for fuel, and mud, water, and electrical lines are also designed into the pad and are placed below the limestone. Fuel lines are laid with a pipe in a pipe so that should the supply line leak the fuel flows back to the fuel bunker and does not contaminate the earth below the pad. Figure C-5 is an example of the pipe-in-pipe construction for lines that carry contaminants. Figure C-6 shows the riser for the injection package; hook up is completed when the rig is brought in.

Figure C-6. Water, electrical, and fuel lines for injection package

Once the major portion of the pad is in place, preparation begins for setting the conductor pipe. This consists of constructing the well cellar by driving sheet piles around the well head area and then excavating the cellar. The 30-in. conductor is driven in the well cellar (Figure C-7, behind worker). The conductor on this well was driven to a depth of 285 ft, but typically is 300–350 ft. Wall thickness of the bottom joint of conductor pipe is 1½ inches. A drive shoe is placed over this that is also 1½-in. thick and 6–8 in. long, for a total wall thickness of 3 inches. Other joints are 1 in. thick wall. The first joints are vibrated in to approximately 80 ft depth; from this point a diesel hammer is used. The hammer has a dead weight of 40,000 lb and delivers a 175,000 ft-lb blow. A steel base plate is placed in the bottom of the cellar and welded to the conductor pipe. Cement is placed both on top and below the base plate. The combination of the base plate and cement seals the bottom of the cellar to allow it to be used as a sump and provides additional assurance that the conductor can support additional casing string weights and the BOP.

Figure C-7. Conductor pipe cellar

Once the cellar and conductor pipe have been installed, the piles are driven. Previously BP used the reverse procedure, but found that the process of vibrating in the conductor could, in some cases, reduce the load the piles could support.

The 44 piles for this job are 14 in. OD x 0.375 in. wall thickness open-ended pipe. When calculating the load bearing ability of the pipe, contact on the ID is ignored and only the outside skin friction is considered. The piles are 80 ft long and are welded together during the driving process.

Equipment for driving piles is shown in Figure C-8, and consists of the crane, hammer leads (frame), and hammer. The crane operator must be very experienced as he has to handle three lines during the operation. The first line holds the leads (frame) in place; the leads (frame) are used to guide both the hammer and pipe during driving. The second line supports the hammer and the third line picks up the pipe and holds it in place. The crane operator must keep the hammer in contact with the pipe during the driving operation. If he lets the pipe get away from the hammer then the force of the blow is transmitted into the crane cable and boom. Keeping the hammer in contact can be difficult, particularly when driving in the first section of pipe because the pipe can move several ft by one blow of the hammer.

The hammer for this job was a Vulcan air hammer that operates on 250-psi air (Figure C-9). It weighs 19,000 lb and delivers a 32,500 ft-lb blow force. It is capable of 50 blows/minute. The leads (frame) supporting the hammer have two long spikes on the bottom that are driven into the earth with the weight of the leads (frame). A simple level is used to align the pipe and frame to make sure that the pile is vertical. Once driving has been started, no adjustment can be made other than pulling the pile. During the driving operation the number of blows per foot is recorded. If performance changes dramatically it can indicate that there has been a change in the subsoil strata which may impact the load-bearing capacity of that pile. BP hires an outside engineering firm to provide this service so that there is an independent observer to confirm that each pile is driven correctly. On this job, there were 13–15 blows/ft of penetration. For the first joint of pipe, the weight of the hammer and pipe alone will drive the pipe 25 ft into the ground.

Figure C-8. Pile Driving Operation

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Figure C-9. Vulcan Air Hammer

After driving is complete, the piles are cut off to the desired height and then a cap sill is added. The cap sill consists of a 112 lb/ft I-beam with two pipe sleeves welded to the bottom (Figure C-10). The pipe sleeves are designed to fit over the pile. The caps sills are recovered after drilling and completion of the well, but the piles remain in place and can be used again if the well needs to be worked over.

Figure C-10. Pile Cap

After pile driving operations are finished, the area around the pilings and cap sills is filled with compacted limestone at the same grade and elevation as the surrounding pad.

Interesting Well Construction Facts

BP upgraded the traditional solids-control system with new generation shakers to improve solids removal efficiency and reduce the volume of spent mud entrained with drill cuttings. In addition, a reserve pit system is used to allow additional recovery of fluids from the waste stream using natural settling. The reserve pit system is supplemented with a high-speed shaker used to process reserve pit fluids to mechanically separate reusable mud from drill cuttings.

BP begins annular injection of spent drill mud and cuttings while drilling is underway. Formations from approximately 5000–10,000 ft are dominated by massive porous sands and shale stringers. All spent drill mud and cuttings, including oil based mud and cuttings are injected into this zone (Appendix C-1). Pits are sequentially drained, cleaned and dismantled so that by the end of the well approximately 500–1000 barrels of spent drill mud and cuttings (mostly heavy sand and shale) must be disposed at a commercial site. As the pits are cleaned, the soil is cut back to remove any contaminated soil. This contaminated soil is commingled with spent drill mud and cuttings and injected. After the pits are closed, a post-closure analysis to Louisiana Statewide Order Number 29B is completed and an ENG-16 Waste Disposition Form is completed and filed to the State.

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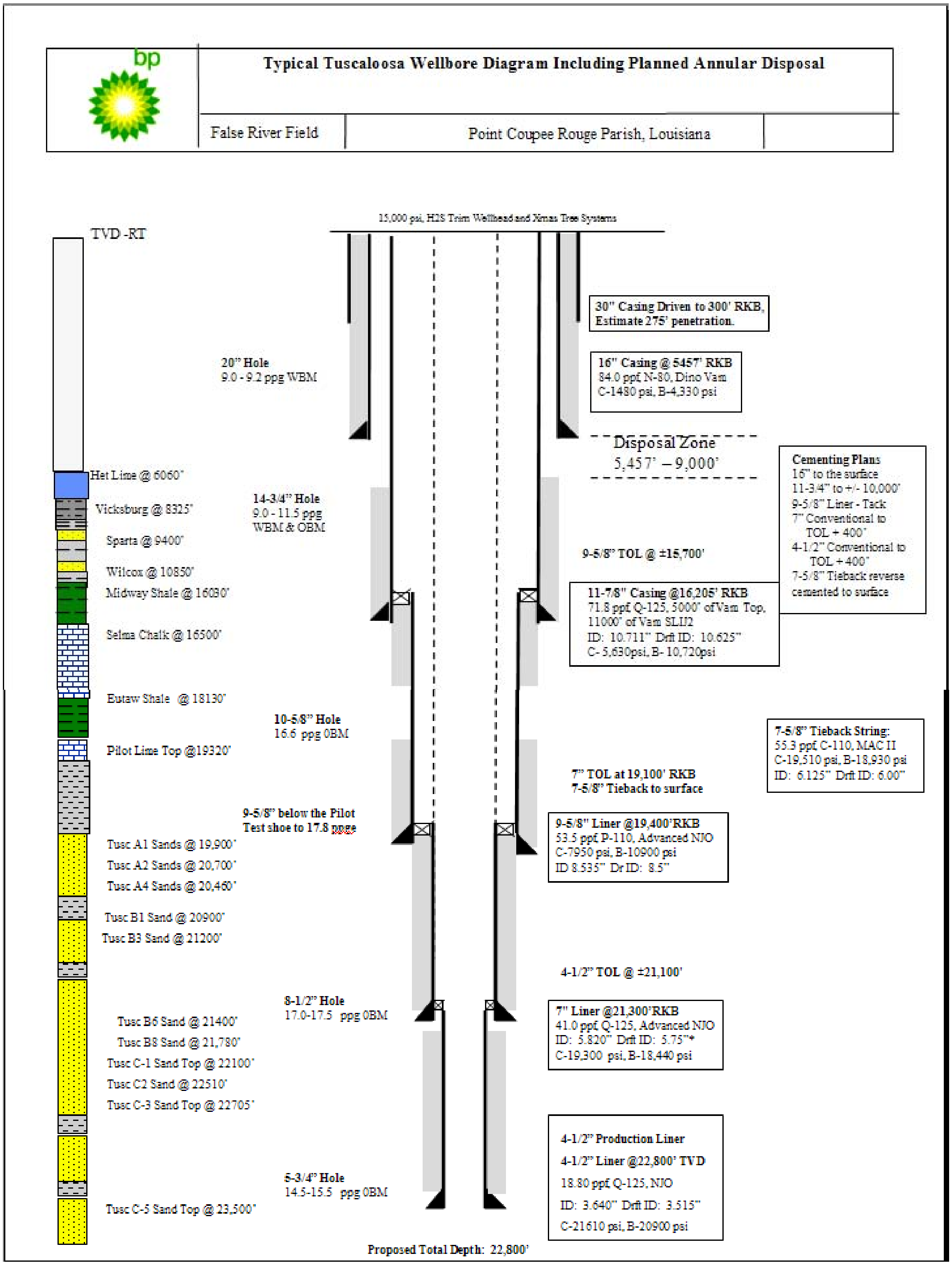
Appendix C1 – Tuscaloosa Wellbore Sketch



Appendix C2 – Introduction to Dynamic Pile Testing Methods

Introduction and Historical Development

This article provides historical, theoretical, and practical information on high strain dynamic pile test (DPT) applications using the Pile Driving Analyzer® (PDA) and related DPT services (e.g., low strain applications, GRLWEAP, etc.). Beginning in 1964, The Federal Highway Administration and several state highway departments joined the Case Institute of Technology (now the Case Western Reserve University) in Cleveland, Ohio, to initiate a new research project to improve pile installation and construction control methods using electronic measurements and modern analytical methods. The goal of the original project was to develop an efficient, economical, and practical method to estimate the static bearing capacity of piles.[1] With advances in computer technology and instrumentation along with the expansion of the results from the original investigation, DPT has developed into a comprehensive and economical method to quickly and quantitatively evaluate the hammer-pile-soil system. The DPT is based on force and velocity measurements taken by pairs of strain gauges and accelerometers bolted at the top of the pile during each hammer impact. The data from the instruments is processed and analyzed in real time by a state-of-the-art dedicated computer system called a PDA®.[3]

Worldwide, more than 350 PDA's are being used by companies, universities, and government agencies on more than 4,000 projects each year.[3] Eustis Engineering Company, Inc., began providing DPT services in February 1994 and owns the only commercial PDA in continuous operation in the Louisiana, Mississippi, Alabama, and Arkansas areas. Eustis Engineering has performed more than 1,000 DPTs on steel, concrete, timber, plastic, and composite piles. The majority of our work has been on square precast concrete piles, open end steel pipe piles, and steel H-Piles. Eustis Engineering has provided DPT services primarily in the New Orleans area, but we have also worked on projects throughout Louisiana, and in Alabama, Arkansas, Mississippi, Missouri, South Carolina, and Texas.

Types of DPT and Services Available

High Strain/Energy Tests (PDA). High energy DPTs using a PDA provides a method to measure and evaluate piles and the driving system in the field during construction. High energy DPT methods are the most common and provide extensive information about the foundation and the driving system. High strain testing of piles is covered by ASTM D 4945-89.

Case Pile Wave Analysis Program (CAPWAP™). The wave records obtained by the PDA during a DPT can be evaluated by CAPWAP computer analyses to verify the allowable pile load capacity and to determine the correct soil damping (JC) value for the soil conditions at the site. The CAPWAP program matches the actual wave record collected by the PDA to a mathematical model using modern numerical methods. CAPWAP allows input of changes in the soil parameters, pile cross-section and numerous other parameters affecting the soil/pile system. A series of analyses is performed to optimize the quality of the match between the actual wave record and the model. An accurate match allows verification of the pile capacity, distribution of the resistance along the pile, determination of the JC value, and other information about the soil/pile system.

Wave Equation Analysis (GRLWEAP). GRLWEAP is a computer program which predicts the behavior of the pile based on a specific soil model and pile driving system using purely analytical methods (i.e., no measurements or equipment). GRLWEAP predicts pile stresses and driving behavior to help optimize the pile driving system in advance of any construction equipment being mobilized to the project site.

Low Strain/Energy Tests and PITWAP™. Low energy tests using a Pile Integrity Tester (PIT) are also available to evaluate the integrity of piles and shafts either before or after installation. A highly sensitive accelerometer attached to the top of the pile measures a velocity wave induced by a special hand held hammer. The resultant wave record can be interpreted to determine the location and extent of pile damage. Since the magnitude of the velocity wave is small and is dampened by skin friction along the pile, the PIT is generally effective to approximately 30 pile diameters in length. The PITWAP Program may be used to evaluate the low strain records obtained by the PIT to determine an approximate pile profile. This information is helpful in identifying abnormalities in drilled shafts and cast-in-place piles.

Other DPT Equipment and Services. Several other DPT methods and equipment are available to help evaluate piles and hammer systems. The Hammer Performance Analyzer™ (HPA) uses a radar to measure the ram velocity and helps to evaluate the performance of the hammer. Acceleration measurements added to the pile top measurements from the PDA can then be used to determine the pile cushion stiffness.[3] The Saximeter™ measures the time between hammer impacts to determine the fall height on open end diesel hammers. Wave equation modeling can then be used to determine the combustion pressure for diesel hammers.[3] The Pile Installation Recorder (PIR) accurately measures auger rotation, withdrawal and grout injection rates, and other information to increase the quality control during the installation of augercast piles and other cast-in-place concrete foundations. Sonic testing and other testing methods are also available.

Purpose of DPT

The PDA is used worldwide in the evaluation of both driven piles and drilled shafts.[2] The PDA results can be obtained faster and more economically than traditional static pile load tests. DPT methods have the ability to test many piles or shafts per day at a fraction of the cost of traditional testing methods. However, cost and time savings are not the only advantage of DPT methods. DPT also provides information on driving stresses in the pile, pile integrity, performance of the driving system, and other factors affecting the foundation.

DPT methods are particularly useful on small jobs where traditional load tests are not normally economically feasible. On large jobs or areas with highly variable soil conditions, numerous DPTs can be performed to provide more information at the site. This helps to minimize potential construction problems and costly delays, and helps to prevent over design of the foundation. DPT applications during construction can help identify problems early thereby helping to prevent costly delays, increase efficiency, verify pile integrity, and assure quality control.

Bearing Capacity Estimates. The PDA can calculate the capacity of piles using a variety of pile capacity equations based on the total resistance of the pile during an impact of the hammer. Several of these methods and their application to specific soil conditions are discussed in more detail in "Theoretical Solutions." To verify the pile capacity, the pile should be allowed to set for a sufficient period of time to develop capacity before being evaluated during a "restrike" DPT. The set time allowed should be similar to traditional static load tests. On occasion, construction constraints may require expediting the DPT. On some jobs, DPTs have been performed during construction and with only minimal set, however, shorter set times can lead to under prediction of the pile capacity.

Measurement of Driving Stresses. Measurement of driving stresses is important to determine if the piles can be installed at the site with the proposed driving system without being damaged. The PDA can measure compressive driving stresses at the pile top directly from readings taken from the gauges. Tension and compression stresses, along the pile and bearing at the pile toe, are then calculated using wave equation theory. This information is also helpful in evaluating eccentric hammer impacts, bending in the pile, and evaluating changes in the pile driving system.

Pile Integrity Determination. Evaluation of pile integrity can be made during and after installation of the pile. The PDA determines the integrity of the pile by comparison of the measured wave reflections in the pile to a model. A change in the pile impedance (i.e., change in a cross-sectional area such as damage, open splices, etc.) sends a reflection back up the pile. The pile integrity is displayed as a relative pile integrity factor (BTA). However, BTA can be affected by several other factors; therefore, pile integrity should be evaluated only by a geotechnical engineer experienced with DPT methodologies.

Driving Energy and Installation Efficiency. The efficiency of the energy transferred by the hammer can be estimated by dividing the maximum energy transferred past the gauges (EMX) by the rated hammer energy. This efficiency is not a direct measurement of the mechanical efficiency of the hammer due to energy dissipation through the cap block and other factors.

Statistical data is available for most hammer types and piles to compare to records obtained from individual job sites. This historical data indicates single acting air hammers driving steel piles have a mean transfer efficiency of approximately 50.2% with a standard deviation of 11.5%. A single acting air hammer operating between transfer efficiencies of 38.7% and 61.7% is within one standard deviation of the mean hammer performance. Single acting air hammers driving concrete piles have a mean transfer efficiency of approximately 40.4% with a standard deviation of 12.0%; therefore, hammers operating between transfer efficiencies of 28.4% and 52.4% are within one standard deviation of the mean hammer performance.[2] Hammer efficiency on concrete piles is also affected by the type and thickness of the pile cushion and can very significantly.

PDA Field Procedures and Testing Methodology

Two to four sets of strain transducers and accelerometers are typically attached to opposite sides of the pile to help compensate for eccentric hammer blows. The gauges are attached a minimum of 1.5 pile diameters below the pile butt (generally 2 to 3 feet). The gauges are generally attached to the pile in the leads just prior to driving to minimize the potential of physical damage to the instruments while raising the pile into place. The instruments are checked and calibrated before, during, and after driving the pile. The PDA operator, always a trained geotechnical engineer, also monitors displays of various quantities graphically versus time to evaluate the behavior of the instruments and the pile, and to check data quality throughout the drive.

The PDA can monitor a wide variety of quantities during pile driving. These quantities are obtained either through direct measurement or derivation of the data obtained from the gauges during each hammer blow. The entire wave record and numeric variable quantities are saved at intervals selected by the PDA operator in the field. Numeric quantities commonly monitored during the DPT are listed below:

- mean of maximum compressive stress at the gauge location (CSX),
- maximum compressive stress at a single gauge location (CSI),
- maximum derived tensile stress at any location along the pile (TSX),
- maximum energy transferred past the gauges (EMX),
- pile integrity factor (BTA),
- maximum static load capacity at the time of driving as evaluated by the Case-Goble method assuming a preselected JC (RMX) and using a specific JC (e.g., JC=0.9 (RX9), JC=0.8 (RX8), JC=0.7 (RX7), ...),
- Case-Goble static resistance automatically selected capacity method independent of soil damping (RA2), and
- maximum static load capacity as evaluated by the Case-Goble method and corrected for early unloading, i.e., the velocity curve becomes negative prior to the 2L/c time in cases of high skin friction (RSU).

Up to nine of these quantities can be continuously monitored numerically on the PDA screen. Graphical representations showing several of these quantities may be produced by the PDAPLOT program to prepare professional documents.

Construction should be phased to maximize the amount of set time (and the subsequent pile capacity) prior to performing the DPT. Generally, the DPT is performed as part of the test pile program in advance of construction or early during construction. If the DPT is performed during construction, one of the first piles driven for the foundation is selected for the restrike DPT. At the time of the restrike DPT, a "sister" pile may also be evaluated with the PDA to measure driving stresses and determine pile installation criteria.

Ideally the pile subjected to the restrike DPT should be tested at the same tip embedment as the design pile. In this regard, the top of the pile is generally exposed by excavation for the DPT, or the length of the tested pile increased to leave a sufficient amount of the pile exposed above grade at the final pile tip embedment. As a last resort, the pile may be left above the final pile tip embedment to leave the top of the pile above the ground surface for the DPT. On steel piles, paint beneath the PDA gauges should be removed to minimize potential problems with data quality.

Theoretical Solutions

Bearing Capacity using the Case Method. Static load capacity can only be measured during a restrike DPT after the pile has been allowed to set for sufficient time to develop its capacity. The static pile capacity calculated by the PDA software is usually shown as the maximum Case-Goble (RMX) pile capacity. The RMX capacity is computed assuming a dimensionless damping factor (JC) which is dependent on the energy attenuation properties of the soils penetrated by the pile tip.

The Case Method is a common closed form solution for the pile capacity. The equation is simplified by assuming ideal plastic soil behavior and ideally elastic and uniform pile properties. Using measurements from the strain gauges and accelerometers, the total soil resistance is a combination of static and dynamic resistance components and is determined using the equations below:[2,3]

$$R(t) = \tfrac{1}{2}\{[F(t) + F(t_2)] + Z[v(t) + v(t_2)]\}, \qquad (1)$$

and

$$R_s(t) = R(t) - R_d(t) \qquad (2)$$

where,

- $R(t)$ = Total soil resistance,
- $R_s(t)$ = Static soil resistance,
- $R_d(t)$ = Dynamic soil resistance,
- $F(t)$ = Measured force at the top of the pile at time (t),
- $v(t)$ = Measured velocity at the top of the pile at time (t),
- (t_1) = Time at the maximum resistance or beginning of the hammer impact,

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(t_2) = Time at t + 2L/c,
Z = The pile impedance (EA/c),
L = Pile length below the gauges,
p = Pile mass density (0.15 kcf for concrete and 0.492 kcf for steel),
A = Cross sectional area of the pile,
E = Elastic Modulus of the pile, and
c = Wavespeed (i.e., the speed of the stress wave in the pile $(E/p)^{1/2}$).

The static resistance is the desired component of the pile bearing capacity equations and is the capacity traditionally measured by static pile load tests. The dynamic component may be computed using a JC and the pile toe velocity $v_t(t)$ which is conveniently calculated for the pile toe. Using dynamic wave equations and the PDA measurements, the dynamic resistance is given by the following equation:[1]

$$R_d(t) = JC\,[F(t) + Zv(t) - R(t)] \qquad (3)$$

This equation is substituted into Equation (2) to solve for the static resistance of the pile. The solution to this equation is simple enough to be calculated in "real time" (i.e., between hammer blows) to be continuously monitored throughout the drive with the PDA. However, this equation requires the JC value be assumed and the time (t) selected. Often the time (t) is selected where the maximum static resistance is calculated and is provided as the RMX value by the PDA software. The static pile capacity may further be highly sensitive to the JC value selected especially for a restrike DPT. In this regard, the JC value and the static capacity should be verified by CAPWAP computer analyses performed on the PDA records obtained from the field. For comparison, the RMX capacity may be monitored simultaneously for a variety of JC values by monitoring RX# variables (e.g., RX9 (JC = 0.9), RX8 (JC = 0.8), ...).

Variations of the Case equations are used to support the RMX capacity and to provide better solutions for special driving cases. The time (t) may be selected such that the $R_d(t)$ term is zero and the JC value is no longer needed. The resulting capacity method is therefore independent of JC and is provided as the RA2 capacity by the PDA. In cases where the PDA records show negative unloading (i.e., the velocity wave becomes negative prior to the 2L/c time), the RMX capacity may under predict the actual static pile capacity. The RSU values modify the RMX capacity to account for the negative unloading and provide a better estimate of capacity in these situations. The CAPWAP results summarize the resultant RMX, RSU, and RA2 capacity estimates for a variety of JC values for comparison.

<u>Driving Stresses.</u> Driving stresses are generally better evaluated during the initial driving of piles. These stresses typically represent the maximum stress imposed on the pile. The PDA measures pile stresses directly or through derivation of data obtained from the gauges. The CAPWAP and GRLWEAP solutions include estimates of stresses along the pile.

The compression stress is calculated at the gauge location directly from the strain readings from the strain transducers. For concrete piles, the maximum tension stress is important. The maximum tension stress in the pile is determined by the pile top measurements from the magnitude of the upward and downward traveling wave in the pile using Equation (4) below. A tension wave exists in the pile if either of these waves is negative. The PDA determines if the wave traveling in the opposite direction has sufficient compression to reduce the net tension wave to acceptable levels.

$$W_u = \tfrac{1}{2}[F(t) - Zv(t)] \quad \text{and} \quad W_d = \tfrac{1}{2}[F(t) + Zv(t)] \qquad (4)$$

Pile Integrity. A portion of the stress waves in the pile are reflected for each change in the pile impedance (Z = EA/c). These changes in pile impedence are used to indicate damage (i.e., changes in the pile cross section). These reflected waves arrive at the top of the pile at a time relative to the location of the change in Z and cause changes in pile top force and velocity measurements. The magnitude of this change may be used to determine the magnitude of the relative change in the pile cross-section. Pile damage is shown as a relative pile integrity factor (BTA) which is calculated using Equation (5) below:

$$B_i = (1 - a_i) / (1 + a_i) \quad \text{where,} \qquad (5)$$

a_i = $\tfrac{1}{2}(W_{ur} - W_{ud}) / (W_{di} - W_{ur})$,

W_{ur} = the upward traveling wave at the onset of the reflected wave caused by resistance,

W_{ud} = the upward traveling wave caused by reflection of the damage, and

W_{di} = the maximum downward traveling wave due to the hammer impact.

Changes in the wavespeed, bending in the pile, and other factors may affect the BTA values calculated by the PDA. Pile integrity must be evaluated by a geotechnical engineer experienced with PDA methodologies by evaluating the BTA values and the shapes of the wave records produced by each hammer blow to determine if there is structural damage to the pile.

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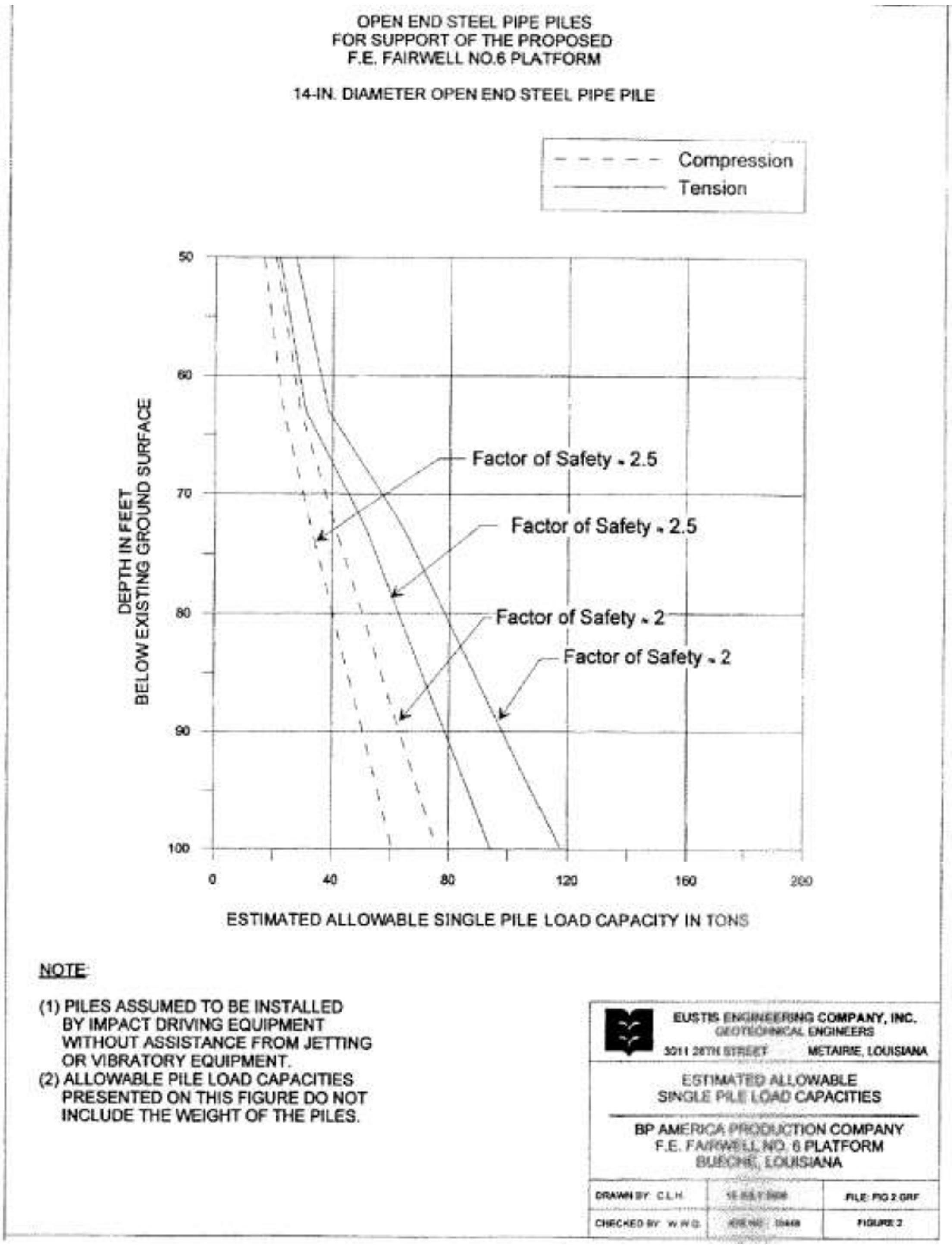
Appendix C3 – Open-End Steel Pipe Piles



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Chapter 3: Development of a Systems Approach to Technology Evaluation

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Chapter Summary

The information contained in this chapter represents one of the research projects funded as part of "Field Testing of Environmentally Friendly Drilling Systems" sponsored by the U.S. Department of Energy and companies from oil and gas industry. The main purpose of this project is to integrate current and new EFD technologies into a viable drilling system compatible with environmentally sensitive areas and finally to suggest a small number of systems (1~5) that should be particularly attractive for a given site. The proposed method is based on a systems analysis that can be used for integrating current and new EFD technologies into an optimal EFD system. The system draws upon a large number of technologies (more than 100) identified by a government-industry joint venture studying low impact operations in sensitive ecological areas. In order to provide flexibility to the user, a small number of systems (1~5) are proposed for a given site, instead of a single best system. An optimization scheme is suggested based on a combination of multi-attribute utility theory and exhaustively enumerating all possible technology combinations (i.e., exhaustive search optimization) to provide a quantitative rationale and suggest the best set of systems according to a set of criteria, with the relative importance of the different criteria defined by the decision-maker.

To meet the deliverables specified in the NETL SOW Task 11 (*Full-Scale Engineering System Design*) and Task 12 (*Combine Selected Components into Integrated System for Test Site*), the EFD program has created a quantitative decision tool based on a system analysis to incorporate a number of current and emerging EFD technologies into a single and clean drilling system with no or very limited environmental impact. This tool will help decision makers select an optimal drilling system for a specific site to minimize impact and maximize profit at that specific site. Since exhaustive search optimization technique is a simple, practical and very robust method given the speed of modern computers (Cover et al. 2007), it is used combined with multi-attribute utility theory to evaluate all possible systems in a quantitative basis and to suggest the best set of systems according to a set of attributes, with the relative importance of the different attributes defined by the decision-maker.

In this chapter we describe how systems analysis with decision-analytic method could be used as part of the technology selection process, we introduce an application of our quantitative decision tool in Green Lake at McFaddin, TX, and we discuss the opportunities and limitations of our tool in future practice.

Research Objectives

This segment of the overall EFD program sought to accomplish the following:

1. Develop a technology evaluation protocol based on a systems analysis to synergistically incorporate a number of current and emerging EFD technologies into a single and clean drilling system with limited environmental impact and then to suggest a small number of systems that should be particularly attractive for a given site. This decision-analytic model will help decision-makers select an optimal drilling system for a given site to minimize environmental impact and maximize profit at that specific site.

2. Develop a prototype of a web-based decision optimization tool to help decision-makers easily follow the proposed technology evaluation procedure and then select an optimal drilling system for a specific site. The web-based application can also help to manage used input parameters permanently if a central repository is maintained regularly so that decision-makers or drilling operators can easily retrieve a previously designed well model for their future operations in different ecosystems.

A Systems Approach to Technology Evaluation

The methodology described in this research is designed to help decision-makers select an optimal drilling system for a given site in order to minimize environmental impact and maximize profit at that specific site. The technology evaluation protocol can be refined based on EFD experts' inputs and feedbacks if necessary. Further interaction with appropriate experts would be valuable in revising this evaluation protocol. The overall procedure is briefly illustrated as follows:

Step 1: Identify the main subsystems, subsets, and technologies within each subset for the EFD operations.

Step 2: Define attributes and develop attribute scales to evaluate technologies.

Step 3: Assign scores to all technologies using the attribute scales.

Step 4: For each attribute, calculate the overall attribute score of a system by adding the technology scores or selecting the minimum technology score.

Step 5: For each attribute and in order to homogenize the scores, develop a "utility function (u_i)" to convert the overall dimensional score of a system (e.g., $, acres, and grades) into a non-dimensional utility value (between 0 and 1) of the system that reflects the decision-maker(s) value.

Step 6: Decide on a weight factor (k_i) for each attribute (i_{th}).

Step 7: Calculate the overall score of the system as "$\Sigma\ k_i u_i$" (multi-attribute utility function).

Step 8: Use optimization technique to evaluate all possible systems and to find the best system for a specific site. Once all possible systems have been evaluated, the system with the highest overall score is the best system.

Step 9: Conduct a sensitivity analysis to examine the impacts of possible changes in the attribute scores, weight factors, and utility functions on the optimal system.

Step 10: Suggest a small number of systems that should be attractive for a given site.

Application of the Proposed Technology Evaluation Protocol

In order to test the proposed evaluation protocol in a real site and then to refine the protocol, a case study is conducted in Green Lake at McFaddin, TX. It is assumed that an independent operator is to drill a well on their lease in South Texas in an environmentally sensitive wetland area. The lease extends to the center of Green Lake on the McFaddin Ranch in Calhoun County, Texas (Figure 1). The formation target is the upper Frio sand (Hovorka et al. 2001) at approximately 8500 ft in vertical depth. Low impact drilling and utilizing the very best drilling system is extremely important in order to protect and environmentally affect the ranch to the least extent possible. The step by step procedures to arrive at the optimal drilling system for this site are fully described in this section.

Step 1: Identify Main Subsystem and Subsets for the EFD Operation.

Four main subsystems and thirteen subsets have been identified for the EFD operations as shown in Figure 2.

Step 2: List Available Technologies within Each Subset.

Three different systems are pre-specified by an EFD expert in order to identify possible drilling technologies for Green Lake drilling site as shown in Table 1. A list of EFD experts contacted is available from the author. Although the technology list shown in Table 1 is not an exhaustive search, what it shows is the current and state of the art technologies for onshore oil and gas drilling operations. The Figure 3 shows an example of the EFD technology selection. Each path through the subset tables represents one example of a possible EFD system.

Step 3: Define Attributes and Attribute Scales.

Attribute is one of the parameters considered in the evaluation of the system (e.g., cost, land area, emission, perception, and safety). Each attribute has an attribute scale used to score the technology on how well it meets the objective for this attribute (e.g., minimizes cost, footprint, emission, and maximizes positive perception and safety value). In order to evaluate available technologies for onshore oil and gas drilling projects against each attribute, attribute scales that explicitly described their possible impacts on a project are needed to be specified (Keeney and Raiffa 1976). Nine attributes and their draft scales are defined by EFD subject matter experts in this section. These attributes should be both comprehensive and measurable (Keeney and Raiffa 1976) and it should be noted that each attribute dose not need to be directly measurable entity (i.e., $ and acres) but constructed attributes (i.e., perception) can be used instead (Keeney 1992). The attribute scales developed in this section are draft scales and thus further interaction with appropriate experts would be valuable in revising these scales.

1. Total cost (x_1) = total technology costs in US dollars; minimizing total cost is preferred.

2. Ecological footprint (x_2) = the total used land area in acres; minimizing ecological footprint is preferred.
3. Emissions of Environmental Protection Agency (EPA) and state regulated air pollutants (x_3) = it is suggested by an environmental expert to consider three air contaminants (i.e., CO, Nox, and PM) for this attribute. The relative importance of those contaminants is CO (20%), Nox (40%), and PM (40%) as shown in Table 2. Table 2 shows an example of how to calculate air emission score for each technology. First, estimate three contaminants' real value for each technology in pound per operating hours. Second, in order to get an overall air emission score for each technology, it is required to transform each contaminant's score into a non-dimensional score (U-value) between 0 and 1 using the proportional scoring approach, (x – worst score)/(best score – worst score). In this calculation, best and worst score should be obtained among all possible technologies being used. Finally, calculate the overall air emission score of a technology as $\sum k_i u_i$ (where k_i is a weight factor for each air contaminant, u_i is a non-dimensional score for each contaminant). This approach allows the decision-maker to make all air emission scores uniform and comparable; minimizing air emissions is preferred.
4. Emissions of EPA and state regulated solid and liquid pollutants (x_4) = the ordinal draft scale was constructed by an EFD subject matter expert as shown in Table 3; minimizing solid and liquid emissions is preferred.
5. Emissions of EPA and state regulated noise pollutants (x_5) = according to Occupational Safety & health Administration (OSHA), the eight-hour time-weight average sound level (TWA), in decibels, is recommended as the noise emission's scale. TWA may be computed from the dose, in percent, by means of the formula: TWA = 16.61 log(D/100) + 90. D is the noise dose, in percent: D=100 C/T (where C is the total length of the work day, in hours, and T is the reference duration corresponding to the measured sound level, L in decibel). $T = 8/2^{(L-90)/5}$; minimizing noise emission is preferred.
6. Government, as regulators, perception (x_6) = the ordinal draft scale was constructed as shown in Table 4; maximizing government perception is preferred.
7. Industry, as decision makers, perception (x_7) = the ordinal draft scale was constructed as shown in Table 5; maximizing industry perception is preferred.
8. General public perception (x_8) = the ordinal draft scale was constructed as shown in Table 6; maximizing public perception is preferred.
9. Safety value (x_9) = the ordinal draft scale was constructed as shown in Table 7; maximizing safety value is preferred.

It is required that these attributes and their scales discussed above be revised and restructured, if necessary, through a series of meeting with EFD subject matter experts until the attributes are clearly and meaningfully defined and met the independent assumption. These nine attributes are assigned to each available technology. In this paper, it is explicitly assumed that the attributes are independent for each possible technology in conducting the technology evaluation over one attribute at a time

Step 4: Assign Scores to All Technologies Using the Attribute Scales.

In order to evaluate available technologies with respect to the nine attributes (i.e., x_1

through x_9), EFD subject matter experts' inputs, basic assumption, and other references are used as shown in Figure 4. Figure 5 briefly shows an influence diagram of each subset in a typical drilling site. As can be seen in Figure 5, attribute scores of a technology can be correlated with attribute scores of another technology in a different subset. For example, different rig type causes the variation of total drilling time and total drilling time varies total cost of technologies within many subsets.

Moreover, selected technologies within subset (5) through subset (8) shown in Figure 2 are mutually related each other as shown in Figure 6. For example, the number of possible fuel types for a conventional power generation engine varies by what kind of engine is selected, and whether using an energy storage device or not should be dependent on whether an unconventional power generation method is used or not. If it is decided not to use an unconventional power generation method, an energy storage device is not necessarily considered as a subset in the "Rig" subsystem. In this technology evaluation, the range of unconventional power usage is varied from 0% to 30% of total power usage.

The construction strategy and constraints for the "Rig" subsystem are specified as shown in Figure 6. Figure 7 shows an example of input spreadsheet used to score technologies in several subsets. The cost, footprint, and emission scores of a technology in subset (1), "Transportation", are not included in the input spreadsheet because those scores are already included as a mobilization part of technologies within other subsets. For example, the cost of gravel road shown in Figure 7 includes material, mobilization, and installation costs.

Step 5: Calculate the Overall Attribute Score for Each Attribute.

After each technology is evaluated with respect to the nine attributes (i.e., x_1 through x_9), for each attribute, the overall attribute score of a system is calculated by adding the technology scores of the system or selecting the minimum technology score of the system. The addition of individual scores is used for attributes such as cost, footprint, and emission as shown in Eq. 1 while the minimum score is used for attributes such as perception and safety as shown in Eq. 2. The overall score on the i^{th} attribute (X_i) is:

$$X_i = \sum_{n=1}^{N} x_{in} y_n \quad \text{for attribute } x_1 \text{ and } x_5 \text{ (i.e., i = 1 to 5)} \tag{1}$$

$$X_i = \mathrm{Min}\left[x_{in} y_n\right] \quad \text{for attribute } x_6 \text{ through } x_9 \text{ (i.e., i = 3 to 9)} \tag{2}$$

where n is the index for possible technologies, N is the number of possible technologies, i is the index for the attributes, x_{in} is the score of the n^{th} technology on the i^{th} attribute, and y_n is a binary decision variable that is one if n^{th} technology is selected and zero if it is not. The constraint required to consider is:

$$\sum_{n=1}^{M} y_n = 1 \quad \text{for each subset except subset (7), (8), and (13)} \tag{3}$$

where n is the index for possible technologies, M is the number of possible technologies within each subset, and y_n is a binary decision variable. One technology should be selected within each subset except subset (7), (8), and (13) in Figure 2. Subset (7), (8), and (13) are optional. Figure 8 shows the overall attribute score for each attribute of a system. As can be seen in Figure 8, the overall scores of cost (x_1), footprint (x_2), and emissions (x_3 through x_5) are calculated by summing the scores of technologies selected within each subset. The overall scores of perceptions (x_6 through x_8), and safety (x_9), however, are calculated by choosing the worst score among technologies selected within each subset for a system because it is suggested that perception and safety values should be considered on the systems level not on the individual technology level.

Step 6: Develop Utility Functions for Each Attribute.

Utility Function is a relationship between the dimensional attribute score (e.g., $, acres, and grades) and a non-dimensional number (between 0 and 1). The utility function is used to transform all scores into non-dimensional values between 0 and 1. This allows the decision-maker to make overall attribute score for each attribute uniform and comparable. Once the overall attribute score for each attribute of a system is calculated with respect to the nine attributes (i.e., x_1 through x_9), for each attribute (i^{th}) and in order to homogenize the scores, a utility function (u_i) needs to be developed to convert the overall dimensional score of a system into a non-dimensional utility value (between 0 and 1) of the system.
The proportional scoring approach is mainly used in this paper to develop a single-attribute utility function. This can be revisited as needed based on interactions with EFD subject matter experts. A general formula for the proportional scoring approach is given by:

$$u_i(X_i) = \frac{X_i - \text{Worst Score}}{\text{Best Score} - \text{Worst Score}} \quad (4)$$

where, X_i is the overall score on the i^{th} attribute of a system.
Figure 9 shows the utility function curve used for the cost attribute. As can be seen in this example, first maximum and minimum values for total cost are obtained. It is found that the range should go from $0.78 million dollars to $1.9 million dollars, where obviously less total costs are preferred to greater ones. Thus, to remain consistent with the scaling rule where the utility functions ranged from 0 to 1, it is defined u_1 ($0.78 M) = 1 and u_1 ($1.9 M) = 0. Procedures similar to those described above are also used to assess utility functions for attribute x_2 through x_9 except attribute x_5.
According to OSHA, the employer shall administer a continuing, effective hearing conservation program if employee noise exposures equal or exceed an 8-hour time-weighted average sound level (TWA) of 85 decibels. In this research, therefore, it is assumed that if TWA of a technology does not exceed 85 decibels, the noise utility score of the technology would be closed to 1 while the noise utility score of the technology would be rapidly down to 0 if TWA of the technology exceeds 85 decibels. There are five noise making subsets (2, 3, 4, 5, 9) in a system and thus it is considered that a utility value of the noise attribute (x_5) would be similar until a combined TWA exceeds 425 (5×85) for a system. Figure 10 shows the utility function curve used for the noise attribute developed by the author.
In this research, the general shapes of the utility function for each attribute are linear. This implies risk neutrality, but it is very important, before proceeding, to do consistency checks on the reasonableness of the shape of the utility functions (i.e., exponential, linear,

and so on) (Keeney and Raiffa 1976). This can be fulfilled by asking additional questions about the decision-maker's preferences, and comparing his/ her responses to the implications of the "fit" utility functions. When they are consistent with each other, the utility functions can be more confidence. When they are inconsistent, on the other hand, the inconsistencies are discussed, and part of all the assessment should be repeated (Keeney and Raiffa 1976). Figure 8 shows single-attribute utility values of a system.

Step 7: Decide on a Weight Factor for Each Attribute.

Since it is assumed that there is no interaction between each attribute, all of the weights are positive and they must sum to one (Hardaker 2004). In general, weight factors are decided by a decision-maker. For this case study, the weight factors are defined by an EFD expert who participated in this study. Table 8 shows the assigned weight factor for each attribute.

Step 8: Calculate the Overall Score of the System.

Once each single-attribute utility function $u_i(X_i)$ is derived for its attribute measure, these individual utility values are combined in some way into a final utility value. If mutual preferential and utility independence are satisfied, it is possible to define the multi-attribute utility function to the additive form (Clemen and Reilly 1999):

$$U(X_1, X_2, \dots, X_I) = U\{u_1(X_1), u_2(X_2), \dots, u_I(X_I)) \\ = k_1 u_1(X_1) + \dots + k_I u_I(X_I) = \sum_{i=1}^{I} k_i u_i(X_i) \qquad (5)$$

where $u_i(X_i)$ is a single-attribute utility function scaled from 0 to 1, k_i is a weight factor for $u_i(X_i)$.

A multi-attribute utility function of the additive form can be derived in two steps. First, single-attribute utility functions $u_i(X_i)$ of a system are derived for each attribute measure in turn, then these individual utility values are combined into an overall utility value of the system to simplify comparisons with other possible systems. Figure 8 shows a multi-attribute utility value of a system with the weighting factors given in Table 8.

Step 9: Find the Best System.

In this section, an optimization scheme is suggested based on a combination of multi-attribute utility theory and exhaustively enumerating all possible systems to provide a quantitative rationale and suggest the best set of systems according to a set of attributes, with the relative importance of the different attributes defined by the decision-maker. Since exhaustive search optimization is a simple, practical and very robust method given the speed of modern computers (Cover et al. 2007), it is used to evaluate all possible systems and to find the 'best' available system that should be particularly attractive for a specific site. Figure 11 briefly illustrates the total possible number of systems used in this case study. Once all possible systems have been evaluated, the system with the highest overall utility score is the best system with given weighting factors.

Step 10: Conduct a Sensitivity Analysis.

After the optimization scheme has given the ‘best’ system, a sensitivity analysis can be conducted to examine the impact of possible changes in the attribute scores, weight factors, and utility functions on the best system. For example, the weights assigned to cost attribute could be changed from the initially assigned value of 0.40. Since the weighting factors must sum to one in this study, the weights assigned to other attributes are known once a weight assigned to cost attribute is decided. Conducting a sensitivity analysis for the technology selection process is an importance step because it can give an idea the range of weights over which certain systems should be selected for a specific site (Guikema and Milke 1999).

Step 11: Suggest a Small Number of Systems.

Table 9 gives an example of the best systems of varying the weight on the cost attribute from zero to one. Selected technologies in subset (2), (4), (10), (12), and (13) are always same for all possible weights on cost attribute while selected technologies in other subsets are changed. For example, as the weight assigned to cost attribute increases, conventional diesel truck is selected for subset (1) instead of low sulphur diesel truck with tier III engine and with noise suppressor. More extensive sensitivity analyses need to be conducted for other input variables such as attribute scores, the utility function for each attribute in addition to weighting constants for other attributes to suggest more robust optimal systems for this case study.

Conclusion

Throughout this paper, a system optimization approach is suggested based on a combination of multi-attribute utility theory and exhaustive search optimization. This methodology is designed to help decision-makers with their choices of EFD technology in onshore drilling operations. However, the approach used in this study does have some limitations. The crucial limitation is that the computational burden of the procedure may become prohibitive for problems with a large number of decision variables. One possible way to resolve this problem in this research is if the analyst can identify subsets that will always select the same technology for any weight combinations, the elimination of those subsets from the original thirteen subsets can significantly reduce computational burdens in future steps.

Moreover, since the suggested systems would be based on subjectively assessed data, there can be considerable uncertainty about the input parameters used. Therefore, the sensitivity of the optimal solution to the input parameters and the effects of the uncertainty of those parameters are required to be examined and an approach that can be used to conduct a sensitivity analysis for multi-attribute technology selection problem is suggested to present. The sensitivity analysis is an important area for further research. Another issue is that estimating input values for available technologies is time consuming. Even though many EFD subject matter experts are already participated in this study, more people’s inputs and feedbacks are necessary to make the proposed technology selection process easier and quicker.

In conclusion, technology selection process for a drilling project is mainly based on managerial experience, but that a more logical approach based on systems analysis is possible, and additional research could reduce the amount of effort required to use systems analysis for technology selection in a drilling project. Even though the technology selection process can be computationally burdensome, it can be very helpful to decision-makers in refining their decisions on a more scientific basis.

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Figures and Tables

Figure 1. Satelite map of Green Lake in Calhoun County, Texas on the McFaddin Ranch.

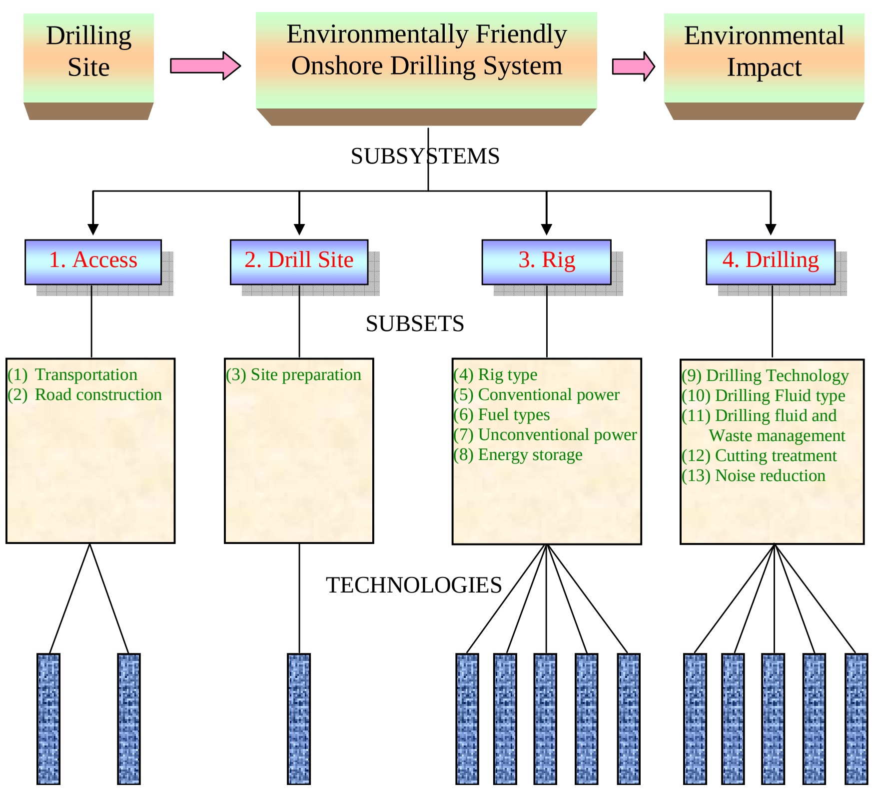

Figure 2. The structure of the EFD operations.

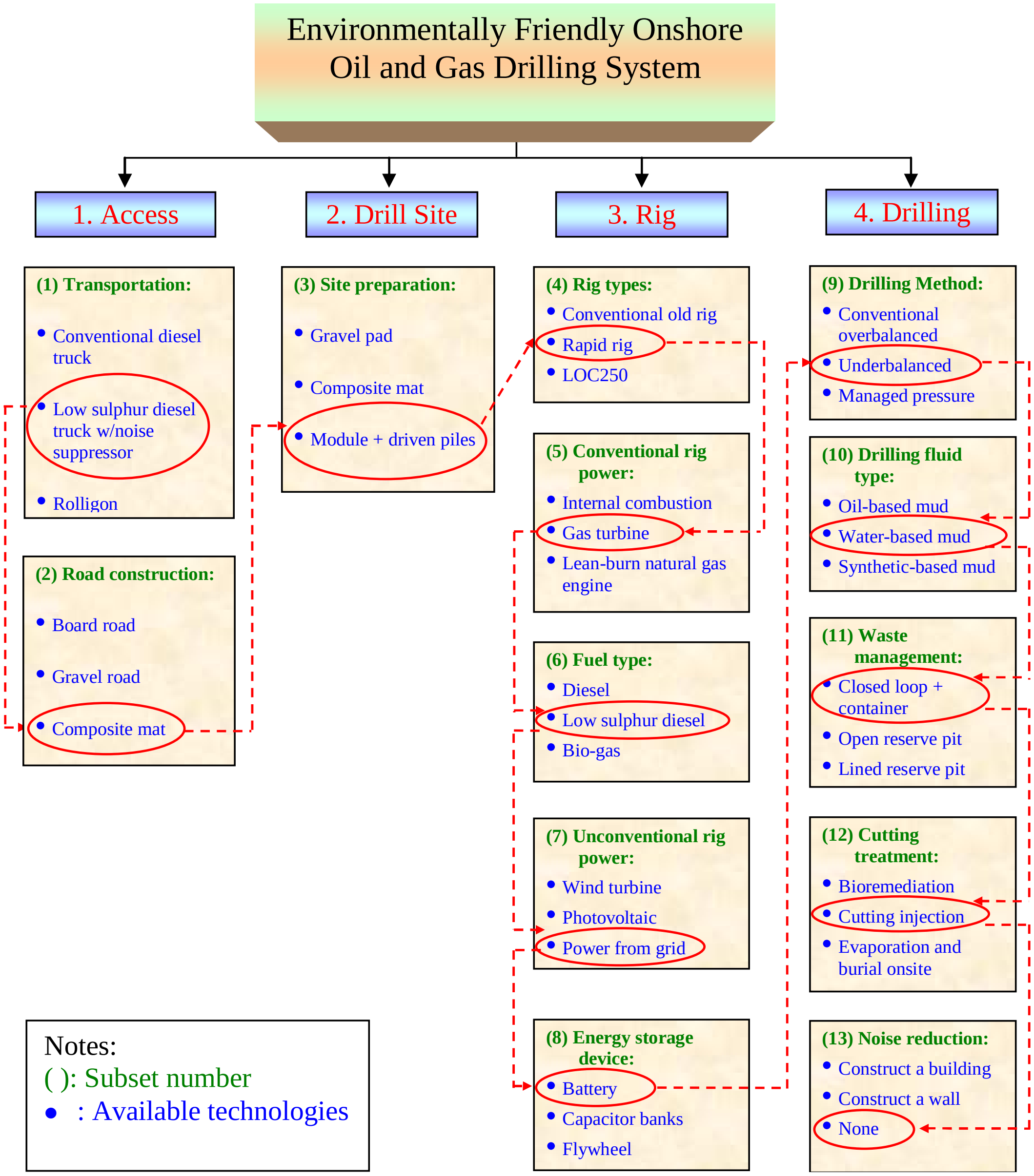

Figure 3. An example of the EFD technology selection.

Basic Assumptions

- Power consumption (peak): 1 MW
- Access road width: 25 ft (2 lanes)
- Access road length: 1 miles
- Width of drilling site: 350 ft (conventional rig + pad)
  300 ft (compact rig + pad)
  200 ft (conventional rig + modules + piles)
  150 ft (compact rig + modules + piles)
- Length of drilling site: 350 ft (conventional rig + pad)
  300 ft (compact rig + pad)
  125 ft (conventional rig + modules + piles)
  100 ft (compact rig + modules + piles)

Access Road ⇒ **Composite Mat**

- Width = 25 ft (2 lanes)
- Length = 5280 ft (1 miles)
- Purchase rate = \$20.50 / ft^2
- Rent (30 days) = \$1.00 / ft^2

∴ Total cost when purchasing = 25 × 5280 × \$20.50 = \$2,706,000.00

Total cost when leasing = 25 × 5280 × \$1.00 = \$132,000.00

Figure 4. Basic assumptions and cost estimation of Dura-Base Composite Mat for access road.

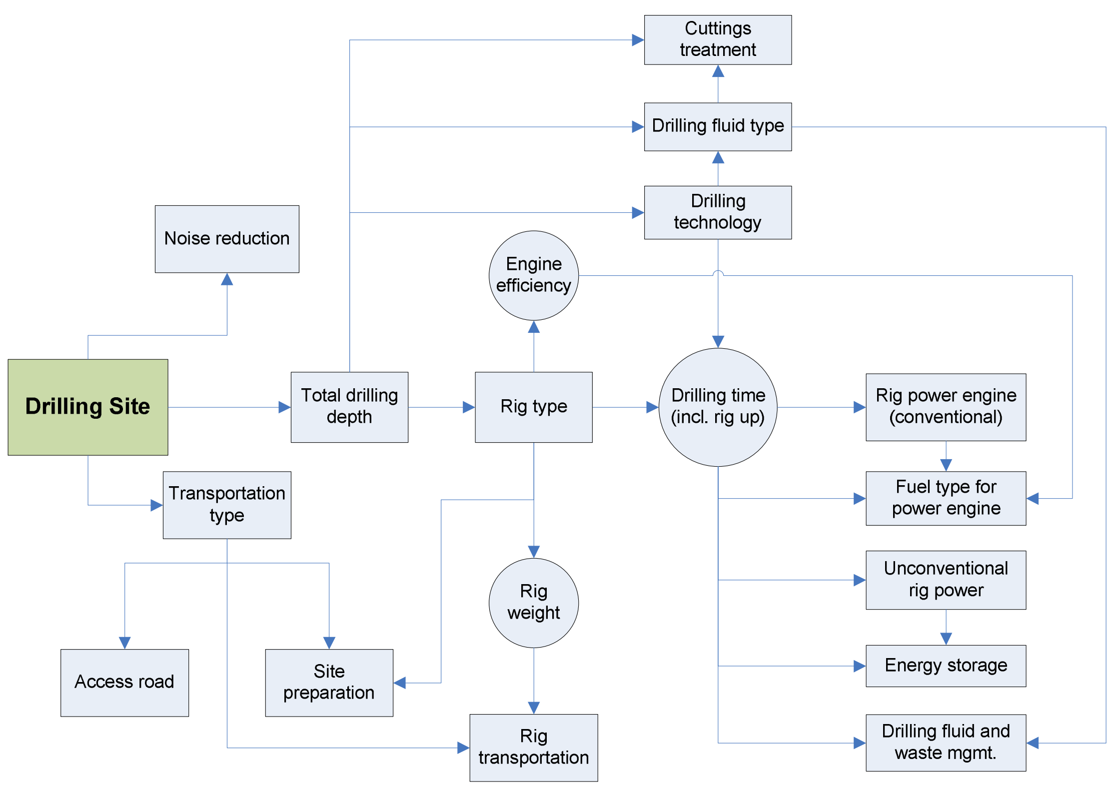

Figure 5. Brief influence diagram of a drilling project.

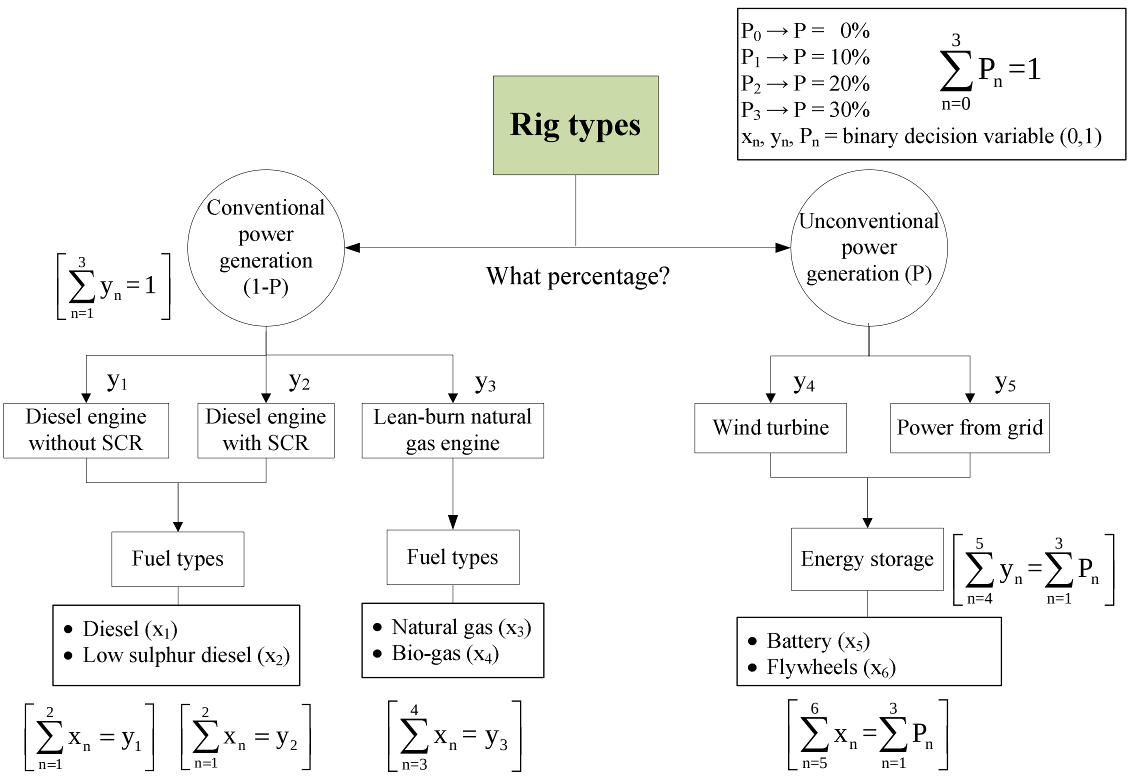

Figure 6. Construction strategy and constraints for the "Rig" subsystem.

Sub-sets	Technologies	Total cost ($)	Ecological Footprint (Acres)	Emissions: Air	Emissions: Solid& Liquid	Emissions: Noise (TWA)	Perceptions: Gov.	Perceptions: Ind.	Perceptions: Public	Safety Value
1	Coventional diesel truck						0.250	1.000	0.250	0.750
	MAX						0.250	1.000	0.250	0.750
	MIN						0.250	1.000	0.250	0.750
2	Gravel roads	$148,500	3.030	0.566		98.562	0.250	1.000	0.250	0.500
	DURA-BASE from Composite Mat (buy)	$541,200	1.515	0.964		82.870	1.000	0.500	1.000	1.000
	DURA-BASE from Composite Mat (rent)	$132,000	1.515	0.964		82.870	1.000	0.500	1.000	1.000
	MAX	$541,200	3.030	0.964		98.562	1.000	1.000	1.000	1.000
	MIN	$132,000	1.515	0.566		82.870	0.250	0.500	0.250	0.500
3	Gravel pad	$137,813	2.812	0.598		98.019	0.250	1.000	0.250	0.500
	DURA-BASE from Composite Mat (buy)	$502,250	1.406	0.967		82.242	0.750	0.750	0.750	1.000
	DURA-BASE from Composite Mat (rent)	$122,500	1.406	0.967		82.242	0.750	0.750	0.750	1.000
	Aluminum modules + driven piles	$372,408	0.007	0.973		97.614	1.000	0.500	1.000	0.500
	MAX	$502,250	2.812	0.973		98.019	1.000	1.000	1.000	1.000
	MIN	$122,500	0.007	0.598		82.242	0.250	0.500	0.250	0.500
4	Traditional older vintage rig	$220,000		0.973		78.630	0.500	1.000	0.500	0.500
	MAX	$220,000		0.973		78.630	0.500	1.000	0.500	0.500
	MIN	$220,000		0.973		78.630	0.500	1.000	0.500	0.500

Figure 7. An example of input spreadsheets.

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Environmental Friendly Drilling Systems

Report 4

Low Impact Rigs

This Introduction and Overview represents Volume 4 in the compilation of work accomplished during the years 2005 through 2008.

Work in this project was designed to meet the deliverables represented by the NETL SOW Task 2 (*Technology Status Assessment*) and Task 4 (*Planning Prototype Development, Testing and Deployment*)

The EFD program has sponsored a series of studies on the technology of improving rig performance and lowering the impact of their operation in ecologically sensitive areas. This section of the EFD program contains technology reports in 3 specific areas.

4.1 Low Footprint, Light Weight Rigs: Description

4.2 Modular Platform Designs for Light Weight Rig Well Sites

4.3 Microhole Technology (from Previous Study)

Section 4.3 represents a comprehensive study commissioned by DOE earlier in the decade to spur development of technology that would reduce the surface footprint of drilling, be more cost effective, and provide faster development of on shore reserves. This report contains only the executive summery of the overview report. For a complete report the reader can go to

http://sites.google.com/a/pe.tamu.edu/efd-final-reports-2005-2009-doe-public-site/home/chapter-4-advanced-drilling-technology-low-impact-rigs

1. INTRODUCTION

1.1 Background

The petroleum industry has well demonstrated its economic contribution and the benefits it brings to society through energy, wealth generation, and employment creation (Rogers et al. 2006). However, they needs a key change in focus from simply improving their economic performance to now considering environmental impact of oil and gas operations because the environmental issues such as loss of biodiversity and acid raid have become a significant part of the social, political, and business agenda.

Nowadays, petroleum industries endeavor to develop technologies to minimize the environmental impact during drilling operations in environmentally sensitive areas because they realize effectively managing environment will lead greater access to large potential reserves in environmentally sensitive areas that are currently off-limit (Rogers et al. 2006). For example, directional drilling technology has allowed the industry to contact almost 60 times the volume of subsurface rock material that could be accessed in 1970 while occupying only one-third the surface area (Harrison 2005). Moreover, reducing the environmental footprint during drilling operations using a reusable Modular Platform and small mobile rig in the Arctic was demonstrated in 2003 by Anadarko and Noble's Subsidiary, Maurer technology Inc.. The objective was to drill in an ecologically sensitive area without disturbing the ground surface. The successful demonstration used a small mining rig to evaluate the potential of drilling for hydrates under the frozen tundra of the Alaska North Slope and showed the usefulness of an onshore platform to drill in environmentally sensitive areas (Kadaster and Millheim 2004).

Recent studies conducted by the Department of the Interior estimate that federal lands contain more than 20 billion barrels of untapped oil – most of which is currently off limits to drilling primarily due to state and federal regulations. Since EFD technologies can greatly reduce the above-ground footprint as well as the risk of spills,

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This dissertation follows the style of the *Journal of Geotechnical and Geoenvironmental Engineering.*

those off-limits areas might become accessible with greater adoption of EFD systems in the near future.

1.2 Problems

One of the petroleum industry's goals is to reduce the environmental impact of oil and gas operations in environmentally sensitive areas. To achieve this, a number of Environmentally Friendly Drilling (EFD) technologies have been developed to varying degrees. For example, the use of an elevated platform as an alternative to the gravel pad for leveling and carrying capacity purposes is less intrusive and leads to a more environmentally friendly approach to oil and gas drilling operations. Elevated drilling platforms will require the use of piles. Another alternative to the gravel pad is the use of composite mats. As the demand of low impact technologies for drill site construction is rapidly increasing, parametric studies for the feasibility of using these technologies have become a more important part of the petroleum industry. The parametric study for the feasibility of using pile foundations and composite mats is conducted for various soil conditions and applied load areas in this research.

Even though a number of EFD technologies and concepts have already been developed to varying degrees, few have been integrated into a field demonstrable drilling system (i.e., combination of technologies) compatible with ecologically sensitive or off-limits areas. Such sensitive areas include wetlands of the Gulf Coast and federal lands in the Western U.S. In general, it is difficult to select the best combination of EFD technologies for a given site because there are many possible combinations and many different and perhaps competing evaluation criteria. How to logically measure and select the best available EFD system for a specific site is fully described in this research.

1.3 Research Objectives

The key objectives of this research are to:

1. Help the petroleum industry engineers to get a basic idea about environmentally friendly foundation designs of a rig or an elevated platform for various weights and soil conditions in environmentally sensitive areas (e.g., desert environments and wetland applications). In order to encourage petroleum industry people to use environmentally friendly foundations such as elevated platforms and composite mat systems more often for their drilling sites instead of using gravel pads, it is an essential task in this research.
2. Develop a technology evaluation protocol based on a systems analysis to synergistically incorporate a number of current and emerging EFD technologies into a single and clean drilling system with limited environmental impact and then to suggest a small number of systems that should be particularly attractive for a given site. This decision-analytic model will help decision-makers select an optimal drilling system for a given site to minimize environmental impact and maximize profit at that specific site.
3. Develop a prototype of a web-based decision optimization tool to help decision-makers easily follow the proposed technology evaluation procedure and then select an optimal drilling system for a specific site. The web-based application can also help to manage used input parameters permanently if a central repository is maintained regularly so that decision-makers or drilling operators can easily retrieve a previously designed well model for their future operations in different ecosystems.

2. METHODOLOGY

2.1 Parametric Study of Foundations for Drill Sites

Three different types of foundations for drill sites are considered in this research.

1. Two different types of pile foundations (i.e., driven pile and bored pile): elevated platforms will require the use of piles. About one thousand different cases of pile capacity calculations are conducted depending on various soil types, pile types, and design methods. The results of these calculations are organized into a series of tables for the petroleum industry engineer to choose an appropriate pile size for a given condition without performing an extensive pile design analysis. The optimal pile selection procedure is also described in this research.
2. Dura-Base Composite Mat: feasibility study of using the Dura-Base Composite Mat System for the drill site construction is demonstrated with various applied load areas from 6 inches to 10 feets in diameter and soil types.

2.2 Development of a Systems Approach to Technology Evaluation

The information contained in this research is part of the research project entitled "Field Testing of Environmentally Friendly Drilling Systems" sponsored by the U.S. Department of Energy and companies from oil and gas industry. The main purpose of this project is to integrate current and new EFD technologies into a viable drilling system compatible with environmentally sensitive areas and finally to suggest a small number of systems (1~5) that should be particularly attractive for a given site. The proposed method is based on a systems analysis that can be used for integrating current and new EFD technologies into an optimal EFD system. The system draws upon a large number of technologies (more than 100) identified by a government-industry joint venture studying low impact operations in sensitive ecological areas. In order to provide flexibility to the user, a small number of systems (1~5) are proposed for a given site, instead of a single best system. An optimization scheme is suggested based on a combination of multi-attribute utility theory and exhaustively enumerating all possible technology combinations (i.e., exhaustive search optimization) to provide a quantitative rationale and suggest the best set of systems according to a set of criteria, with the relative importance of the different criteria defined by the decision-maker.

Since an optimal system for a specific site would be based on subjectively assessed data, there can be considerable uncertainty about the input parameters used. Therefore, even if finding the optimal system is valuable to the decision-makers, they also would like to know how robust the decision is to changes in the input parameters such as the attribute scales, weight factors for attributes, risk-attitude (i.e., risk-neutral, risk-averse, and risk-seeking), and single-attribute utility functions assessed by different individuals (Guikema and Milke 2003). In this research, a sensitivity analysis is conducted using a case study to address this problem.

The methodology described in this research is designed to help decision-makers select an optimal drilling system for a given site in order to minimize environmental impact and maximize profit at that specific site. The technology evaluation protocol can be refined based on EFD experts' inputs and feedbacks if necessary. Further interaction with appropriate experts would be valuable in revising this evaluation protocol. The overall procedure is briefly illustrated as follows:

Step 1: Identify the main subsystems, subsets, and technologies within each subset for the EFD operations.

Step 2: Define attributes and develop attribute scales to evaluate technologies.

Step 3: Assign scores to all technologies using the attribute scales.

Step 4: For each attribute, calculate the overall attribute score of a system by adding the technology scores or selecting the minimum technology score.

Step 5: For each attribute and in order to homogenize the scores, develop a "utility function (u_i)" to convert the overall dimensional score of a system (e.g., \$, acres, and grades) into a non-dimensional utility value (between 0 and 1) of the system that reflects the decision-maker(s) value.

Step 6: Decide on a weight factor (k_i) for each attribute (i^{th}).

Step 7: Calculate the overall score of the system as "$\sum k_i u_i$" (multi-attribute utility function).

Step 8: Use optimization technique to evaluate all possible systems and to find the best system for a specific site. Once all possible systems have been evaluated, the system with the highest overall score is the best system.

Step 9: Conduct a sensitivity analysis to examine the impacts of possible changes in the attribute scores, weight factors, and utility functions on the optimal system.

Step 10: Suggest a small number of systems that should be attractive for a given site.

2.3 A Case Study with Pre-Specified Systems

An application of the proposed approach is described by conducting a case study in Green Lake at McFaddin, TX; some of the difficulties in using this approach in practice are also discussed. The main purpose of this case study is to test the proposed technology evaluation protocol in a real site and then to refine the protocol. Three different systems are pre-specified by an EFD expert in order to identify possible drilling technologies for Green Lake drilling site: (1) conventional drilling; (2) moderately improved drilling; and (3) EFD in five years. First, all technologies selected in these three systems are evaluated with respect to the nine attributes. Second, these three systems' overall scores are evaluated by the proposed technology evaluation protocol. Third, use optimization technique to evaluate all possible systems and to find the best system for Green Lake drilling site. The best system is the system with the highest overall score among all possible systems. After that, a sensitivity analysis is conducted to examine the impacts of possible changes in the attribute scores and weight factors on the optimal system. Finally, a small number of systems (1~5) that should be attractive for the site are suggested.

The results of the case study which provided a more logical and comprehensive approach that maximized the economic and environmental goals of both the landowner and the oil company leaseholder are described in this research.

3. EXISTING KNOWLEDGE

3.1 Onshore Drilling Sequence

According to Dyke (1997), the standard drilling operation procedure is briefly illustrated as follows:

Step 1: Receive initial well planning information including Surface Hole Location (SHL) with Bottom Hole Location (BHL) if applicable.

Step 2: Confirm lease issues including surface ownership.

Step 3: Check the site specific state permit requirements.

Step 4: Check the topographical/ cultural requirements.

Step 5: Confirm operational parameters including mud system and disposal options (onsite vs. offsite).

Step 6: Construct access road.

Step 7: Construct pad (site preparation) including mud reserve pits if applicable.

Step 8: Place a rig and other required components.

Step 9: Drill the hole.

3.2 Foundation Design

Use of a raised platform in environmentally sensitive areas will require the use of piles to support the elevated platform instead of gravel pads as used in a conventional platform. Piles are used to transfer the load from the structures on/above the ground surface to the underlying soil mass. The axially transferred loads are resisted by the friction between the pile and the surrounding soil as well as the end bearing resistance at the bottom of the pile. It is critical in pile designs to estimate the proper axial capacity of the pile depending on the pile and soil types. In addition, the lateral capacity of the pile also should be checked since most piles must resist the horizontal component of the applied loads. In other words, the designed pile should meet not only the axial capacity criterion but also the lateral capacity criterion. The estimated capacities of piles are checked against the applied loads according to a design method, such as the Load and Resistance Factor Design (LRFD) and the Working Stress Design (WSD).

3.2.1 Axial Pile Capacity

The ultimate capacity of the pipe piles is obtained by adding the outside skin friction and the end bearing resistance. The end bearing resistance assumes that the bottom of the pile is closed or that the open ended pipe pile would plug during static loading. The ultimate axial bearing capacity of a pile (Figure 3-1) can be expressed as the sum of the skin friction and end bearing resistances in Eq. (3-1):

$$Q_u = Q_f + Q_p = \sum f_i \times A_{si} + q \times A_p \qquad (3\text{-}1)$$

where, Q_u = ultimate bearing capacity (kN, lbs),

Q_f = skin friction resistance (kN, lbs)

Q_p = total end bearing (kN, lbs),

f_i = unit skin friction capacity in i^{th} layer (kPa, lb/ft^2)

A_{si} = side surface area of pile in i^{th} layer (m^2, ft^2),

A_p = gross end area of pile (m^2, ft^2)

q = unit end bearing capacity (kPa, lb/ft^2)

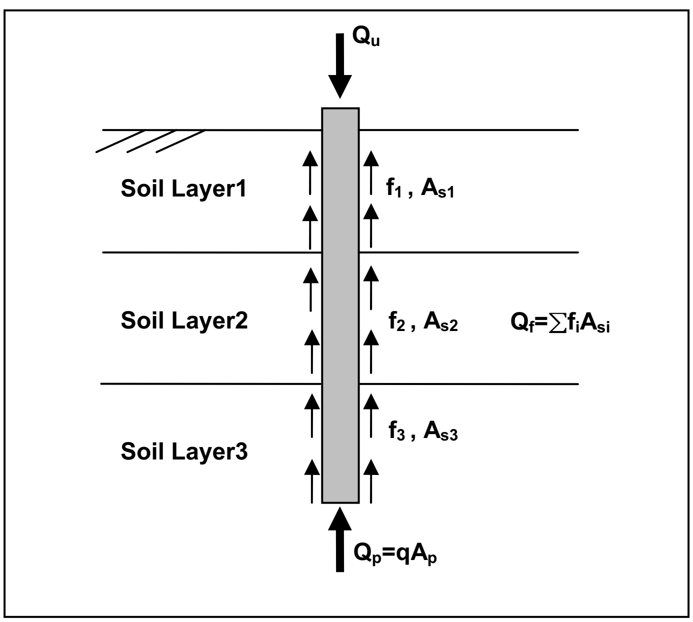

Figure 3-1. Schematic drawing of an axially loaded pile

The skin friction and end bearing resistances are calculated in different ways depending on the pile type such as driven piles or bored piles. The type of underlying soil (i.e., fine grained or coarse grained soil) also affects the calculation method. The API RP2A-LRFD (2003), API RP2A-WSD (2000), and the ADSC (1999) are referred to the calculation procedures for the unit skin friction, f_i, and the end bearing resistance, q, of driven piles and bored piles.

3.2.1.1 Driven Pile

The unit skin friction is the shear stress between the pile and soil at failure. According to the API RP2A-LRFD (2003) and API RP2A-WSD (2000), the unit skin friction of a driven pile in coarse grained soils can be calculated by Eq. (3-2):

$$f = K \times p_0' \times \tan\delta \qquad (3\text{-}2)$$

where, K = dimensionless coefficient of lateral earth pressure

p_0' = effective overburden pressure at the point in question (kPa, lb/ft^2)

δ = friction angle between the soil and pile wall

The friction angle of a soil, φ, corresponds to the friction coefficient μ_1 of a soil-soil interface through: $\mu_1 = \tan \varphi$. The angle δ is the friction angle which corresponds to the friction coefficient μ_2 of the soil-pile interface through $\mu_2 = \tan\delta$. The unit end bearing of a driven pile in coarse grained soils can be computed by Eq. (3-3):

$$q = p_0' \times N_q \qquad (3\text{-}3)$$

where, N_q = dimensionless bearing capacity factor

Recommended values of Nq are tabulated in Table 3-1.

Table 3-1. Design parameters for coarse grained soils (API RP2A-LRFD, 2003)

Density	Soil Description	Friction Angle, δ (deg)	Limiting Skin Friction kPa (kips/ft^2)	N_q	Limiting Unit End Bearing MPa (kips/ft^2)
Very Loose Loose Medium	Sand Sand-Silt Silt	15	47.8 (1.0)	8	1.9 (40)

Loose Medium Dense	Sand Sand-Silt Silt	20	67.0 (1.4)	12	2.9 (60)
Medium Dense	Sand Sand-Silt	25	81.3 (1.7)	20	4.8 (100)
Dense Very Dense	Sand Sand-Silt	30	95.7 (2.0)	40	9.6 (200)
Dense Very Dense	Gravel Sand	35	114.8 (2.4)	50	12.0 (250)

According to the API RP2A-LRFD (2003) and WSD (2000), the unit skin friction of a driven pile in fine grained soils can be calculated by Eq. (3-4):

$$f = \alpha_1 \times s_u \quad (3\text{-}4)$$

where, α_1 = dimensionless adhesion factor

s_u = undrained shear strength of the soil (kPa, lb/ft^2)

The factor, α_1 is an empirical adhesive factor for reduction of the average undrained shear strength. The α_1 value can be calculated by Eq. (3-5) with the constraint that $\alpha_1 \leq$ 1.

$$\begin{aligned} \alpha_1 &= 0.5 \times \psi^{-0.5} \quad (\psi \leq 1.0) \\ \alpha_1 &= 0.5 \times \psi^{-0.25} \quad (\psi > 1.0) \end{aligned} \quad (3\text{-}5)$$

where, $\psi = s_u / p_0'$

The shaft friction acts on both the inside and outside of the pile. The total shaft resistance is the sum of the external friction and the internal shaft friction if the internal shaft friction is less than the end bearing capacity.

The unit end bearing a driven pile in fine grained soils can be computed by Eq. (3-6):

$$q = 9 \times s_u \quad (3\text{-}6)$$

where, s_u = undrained shear strength (kPa, lb/ft^2)

In fine grained soils, the capacity of piles follows an undrained analysis using s_u. The reason is that a fine grained soil does not have time to drain during the loading and this corresponds to the time where the fine grained soil is the weakest. Indeed right after the loading the pore pressures are high and the effective stress is low while in the long term the pore pressures generated by the loading dissipate, the effective stress increases and so does the shear strength of the fine grained soil. In coarse grained soils, the capacity of piles follows a drained analysis because a coarse grained soil has time to drain during loading.

3.2.1.2 Bored Pile

According to the ADSC (1999), the unit skin friction of a bored pile in coarse grained soils can be calculated by Eq. (3-7):

$$f = \beta \times p_0' \tag{3-7}$$

where, β = dimensionless correlation factor

Suggested values of β for granular soils classified as sand can be obtained by Eq. (3-8) if $N_{SPT} \geq 15$ blows per 0.3m:

$$\beta = 1.5 - 0.245 \times z(m)^{0.5}, \qquad (0.25 \leq \beta \leq 1.20) \tag{3-8}$$

where, z = depth below the ground surface in meter

If $N_{SPT} < 15$ blows per 0.3m, β value can be computed by Eq. (3-9):

$$\beta = \left(N_{SPT}/15\right)\left[1.5 - 0.245 \times z(m)^{0.5}\right], \qquad (0.25 \leq \beta \leq 1.20) \tag{3-9}$$

The unit end bearing of a bored pile in coarse grained soils can be computed by Eq. (3-10):

$$q\ (tsf) = 0.60 \times N_{SPT} \tag{3-10}$$

where, N_{SPT} = uncorrected SPT blow count (blows/ft)

The Standard Penetration Test (SPT) is a geotechnical field test. It is performed at the bottom of a borehole which is about 4 inches in diameter. The SPT consists of driving a standard sampler about 2.5 inches in diameter called the split spoon sampler starting at the bottom of an open borehole while using a standard 140 lbs hammer. This hammer is raised 30 inches above the anvil and dropped freely for each blow. The number of blows required to drive the sampler one foot into the soil is recorded as the blow count N (bpf). The N values are obtained every 5 to 10 feet with depth and a blow count profile is generated.

According to the ADSC (1999), the unit skin friction of a bored pile in fine grained soils can be calculated by Eq. (3-11):

$$f = \alpha_2 \times s_u \qquad (3\text{-}11)$$

where, α_2 = shear strength reduction factor

= 0 between the ground surface and a depth of 1.5m (5ft)

= 0 for a distance of B_b above the base

= 0.55 for $s_u / P_a \leq 1.5$

= $0.55 - 0.1(s_u / P_a - 1.5)$ for $1.5 \leq s_u / P_a \leq 2.5$

B_b = diameter on the base of the bored pile (m, ft)

P_a = atmospheric pressure (101kPa or 2116 lb/ft^2)

s_u = undrained shear strength of the soil (kPa, lb/ft^2)

The α_2 values are developed from measured data on full-scale load tests and depend on the undrained shear strength, s_u. If the fine grained soil has a value of s_u ≥96 kPa (2000lb/ft^2), the unit end bearing of a bored pile in fine grained soils can be computed by Eq. (3-12):

$$q = 9 \times s_u \qquad (3\text{-}12)$$

However, if the embedded pile length (L_p) is less than three times the diameter of the base of the bored pile ($3B_b$), then the unit end bearing capacity (q) should be reduced as follows:

$$q = 0.667\left[1 + 0.1667(L_p / B_b)\right] N^*{}_c \times s_u \qquad (3\text{-}13)$$

where, L_p = embedded pile length (m, ft)

B_b = diameter on the base of the bored pile (m, ft)

$N^*{}_c$ = modified bearing capacity factor

Recommended values of $N^*{}_c$ are tabulated in Table 3-2.

Table 3-2. N^*_c values (ADSC, 1999)

s_u	N^*_c
24 kPa (500lb/ft^2)	6.5
48 kPa (1000lb/ft^2)	8.0
96 kPa (2000lb/ft^2)	8.7
192 kPa (4000lb/ft^2)	8.9

3.2.2 Lateral Pile Capacity

Piles are often subjected to relatively large horizontal loads and overturning moment due to wind loads, seismic loads, etc. In this case, the lateral pile capacity should be checked for two criteria. The piles should have enough lateral soil bearing capacity to resist against the horizontal loads and the horizontal deflection of the pile should be within an allowable limit. The methods for performing lateral capacity analyses depend on the type of connection between the pile and the structure. If the pile is connected to the structure in such a way that the top of the pile may freely move laterally and rotate (Figure 3-2 a), it may be assumed to be a free head condition. If the top of the pile may move laterally but is not allowed to rotate (Figure 3-2 b), it may be assumed to be a fixed head condition.

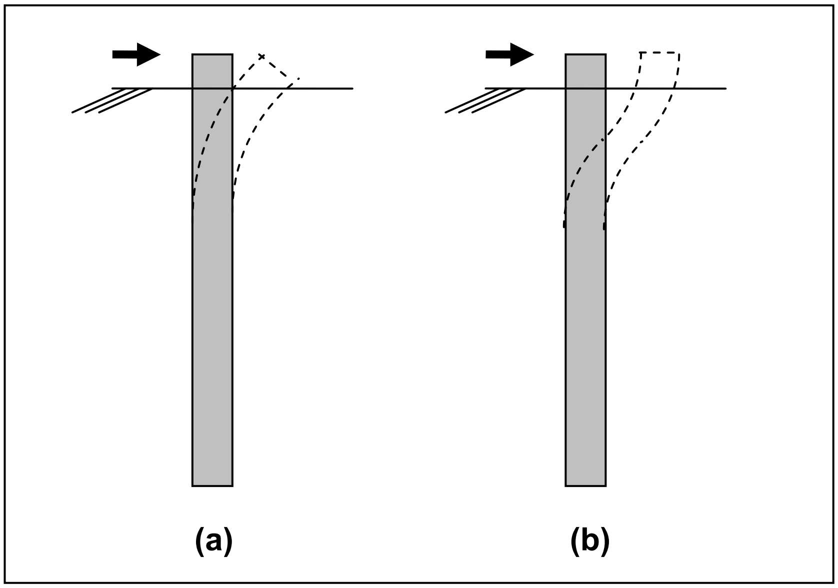

Figure 3-2. Types of connections: (a) free head, and (b) fixed head

3.2.2.1 Free Head Case

The spring constant, K_s, is the ratio of the lateral resistance of the soil per unit length of a pile to the lateral displacement of the pile. It can be obtained by Eq. (3-14) (Briaud 1997):

$$K_s = 2.3E_0 \tag{3-14}$$

E_0 is the first load pressuremeter (PMT) modulus. The pressuremeter is a geotechnical field test. It consist of drilling a 3 inch borehole, removing the drilling tool, lowering a cylindrical probe about 2.5 ft in length and 3 inch in diameter, and expanding that probe laterally against the borehole walls while recording the volume of the probe and the pressure exerted on the soil. This gives an in situ stress strain curve from which a soil modulus (E_0) and a horizontal limit pressure (P_L) are obtained. E_0 can be obtained by using the following correlations if PMT tests are not available:

E_0 (kPa) $= 383N_{SPT}(blow/30cm)$, or E_0 (tsf) = $4N_{SPT}(blow/ft)$ (Briaud 1992)

= average pressuremeter modulus (kPa, tsf)

where, N_{SPT} = blow count in Standard Penetration Test

The factor 2.3 is determined empirically by comparing measured deflections for over twenty full scale lateral load tests and the predicted deflections (Briaud 1997). For a pipe pile, the moment of inertia of the pile, I (m^4, ft^4), can be calculated by Eq. (3-15):

$$I = \frac{\left(\pi D_o{}^4\right)}{64} - \frac{\left(\pi D_i{}^4\right)}{64} \tag{3-15}$$

where, D_0 = outside diameter of the pile (m, ft)

D_i = inside diameter of the pile (m, ft)

The transfer length, l_0, is a parameter which comes from the differential equation. It has no physical meaning except that it indicates the relative stiffness between the pile and the soil in units of length. The transfer length l_0 can be computed by Eq. (3-16):

$$l_0 = \left(\frac{4EI}{K_s}\right)^{1/4} \tag{3-16}$$

where, E = modulus of elasticity for the pile material (kPa, lb/ft^2)

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If the embedded pile length, L_p, is larger than three times the transfer length, the pile can be treated as a long flexible pile. If $L_p < l_0$, the pile is short and rigid. Since most piles satisfy $L_p \geq 3l_0$, the equations only for long flexible piles are considered in this report. The zero-shear depth, D_v, shown in Figure 3-3 can be determined by Eq. (3-17) depending on the value of l_0 for the pile:

$$D_v = l_0 \tan^{-1}\left(\frac{1}{1+\frac{2M_0}{l_0 H_0}}\right), \quad if\ L_p \geq 3l_0 \tag{3.17}$$

where, L_p = embedded pile length (m, ft)

H_0 = applied horizontal load at the ground surface (kN, lbs)

M_0 = applied moment at the ground surface (kN-m, lbs-ft) = $H_0 h$

h = height of the point of application of the load, H_0 above ground surface (m, ft)

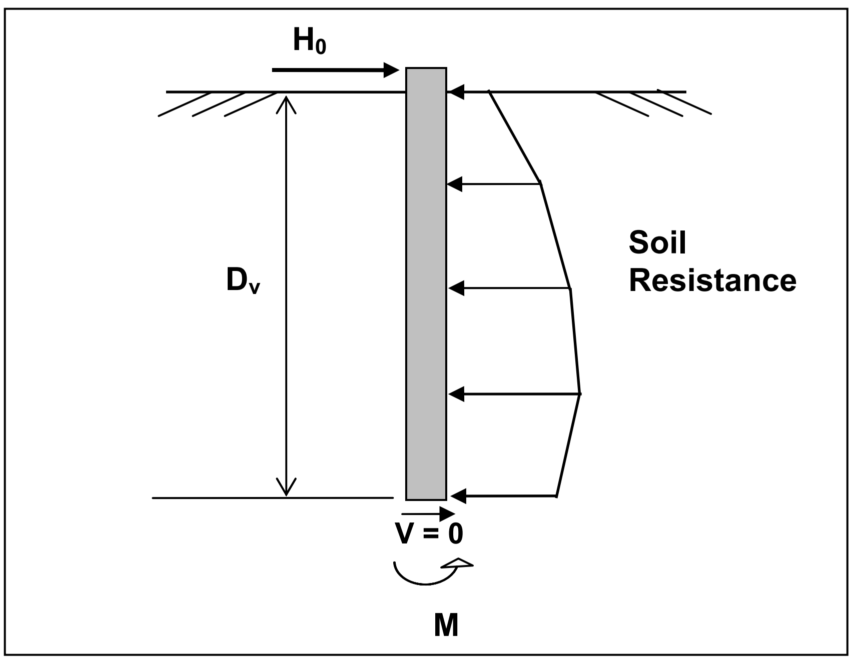


Figure 3-3. Free body diagram of pile down to zero-shear depth (Briaud 1997)

The ultimate lateral capacity of the pile with respect to soil capacity, H_{ou}, is computed by Eq. (3-18) (Briaud 1997):

$$H_{ou} = 0.75 P_L D_o D_v \tag{3-18}$$

P_L is the pre-boring pressuremeter (PMT) limit pressure within D_v (kPa, lb/ft^2). If P_L is not available from PMT tests at the site, then the following correlations can be used with reduced accuracy:

P_L (kPa) = $47.9N_{SPT}(blow/30cm)$, or P_L (tsf)= $0.5N_{SPT}(blow/ft)$ (Briaud 1992)

In addition to the lateral capacity of the pile, both the deflections of the pile at the ground surface and the pile head should be checked and satisfy a certain limit. A deflection of 0.5 inches is a common limit of deflection for many structures. For that reason it is used in this report as a target value. The deflection of a long flexible pile at the ground surface can be calculated by Eq. (3-19) (KNR 1999) and should be less than 0.5 in.:

$$y_0 = \frac{(1 + h/l_0)H_0 l_0^{\,3}}{2EI} \tag{3.19}$$

where, h = height of the pile above the ground surface (m, ft)

The deflection at the long flexible pile head can be obtained by Eq. (3-20) (KNR 1999):

$$y_h = \frac{\left[(1 + h/l_0)^3 + 0.5\right]H_0 l_0^{\,3}}{3EI} \tag{3-20}$$

where, h = height of the pile above the ground surface (m, ft)

Finally, the maximum bending moment, $M_{\max}$ in the pile should be less than or equal to the allowable moment for the pile. The value of $M_{\max}$ for a long flexible pile can be calculated by Eq. (3-21) (KNR 1999):

$$M_{\max} = \frac{H_0 l_0}{2}\sqrt{(1 + 2h/l_0)^2 + 1}\,e^{-(Z_{\max}/l_0)} \tag{3-21}$$

where, $Z_{\max} = D_v$ since $M_{\max}$ occurs where the shear stress is equal to zero

The equation for $M_{\max}$ for a short and rigid pile is not included since all of the piles calculated in this report turned out to be long flexible piles. Although the maximum bending moments are computed, they are not checked against the yield moment of the pile material. In other words, the lateral pile capacity is checked only against failure of the surrounding soil, not failure of the pile itself.

The procedures for the lateral pile capacity in the fine grained soils are almost the same as those in the case of coarse grained soils. The average pressuremeter modulus, E_0 and the pre-boring pressuremeter limit pressure within D_v, P_L in the fine grained soils can be determined by Eq. (3-22) and Eq. (3-23), respectively (Briaud 1992);

$$E_0 = 100 s_u \tag{3-22}$$

$$P_L = 7.5 s_u \tag{3-23}$$

Once these two values are obtained, the same procedures as described in the previous section should be applied to check the lateral pile capacity.

3.2.2.2 Fixed Head Case

The spring constant, K_s, is the ratio of the lateral resistance of the soil per unit length of a pile to the lateral displacement of the pile. It can be obtained by Eq. (3-24) (Briaud 1997):

$$K_s = 2.3 E_0 \tag{3-24}$$

E_0 is the first load pressuremeter (PMT) modulus and can be obtained by using the following correlations if PMT tests are not available:

E_0 (kPa) $= 383 N_{SPT}(blow/30cm)$, or E_0 (tsf) = $4 N_{SPT}(blow/ft)$ (Briaud 1992)

= average pressuremeter modulus (kPa, tsf)

where, N_{SPT} = blow count in Standard Penetration Test

The moment of inertia of the pipe pile, I (m^4, ft^4), can be calculated by Eq. (3-25):

$$I = \frac{(\pi D_o{}^4)}{64} - \frac{(\pi D_i{}^4)}{64} \tag{3-25}$$

where, D_0 = outside diameter of the pile (m, ft)

D_i = inside diameter of the pile (m, ft)

The transfer length, l_0, is a function of the relative stiffness between the pile and the soil, and it can be computed by Eq. (3-26):

$$l_0 = \left(\frac{4EI}{K_s}\right)^{1/4} \tag{3.26}$$

where, E = modulus of elasticity for the pile material (kPa, lb/ft^2)

The moment at the pile head can be computed by Eq. (3-27):

$$M_h = -0.5\left(1+\frac{h}{l_0}\right)H_0 l_0 \tag{3-27}$$

where, H_0 = applied horizontal load (kN, lbs)

If the embedded pile length, L_p, is larger than three times of the transfer length, the pile can be treated as a long flexible pile. If $L_p < l_0$, the pile is short and rigid. Since most piles satisfy $L_p \geq 3l_0$, the equations only for long flexible piles are considered in this report. The zero-shear depth, D_v, can be determined by Eq. (3-28) (KNR 1999) depending on the value of l_0 for the pile:

$$D_v = l_0 \tan^{-1}\left(\frac{l_0}{h}\right), \quad if\ L_p \geq 3l_0 \tag{3-28}$$

where, L_p = embedded pile length (m, ft)

The lateral capacity of the pile, H_{ou}, is computed by Eq. (3-29) (Briaud 1997):

$$H_{ou} = 0.75 P_L D_o D_v \tag{3-29}$$

P_L is the pre-boring pressuremeter (PMT) limit pressure within D_v (kPa, lb/ft^2). If P_L is not available from PMT tests at the site, then the following correlations can be used with reduced accuraty:

P_L (kPa) = $47.9 N_{SPT} (blow/30cm)$, or P_L (tsf)= $0.5 N_{SPT} (blow/ft)$ (Briaud 1992)

As checked in the free head case, the deflections of the pile at the ground surface and the pile head should meet the 0.5 in. criterion. The deflection of a long flexible pile at the ground surface can be calculated by Eq. (3-30) (KNR 1999):

$$y_0 = \frac{(1+h/l_0)H_0 {l_0}^3}{4EI} \tag{3-30}$$

The deflection at the long flexible pile head can be obtained by Eq. (3-31):

$$y_h = \frac{\left[(1+h/l_0)^3 + 2\right]H_0 {l_0}^3}{12EI} \tag{3-31}$$

where, h = height of the pile above the ground surface (m, ft)

Finally, the maximum bending moment, $M_{\max}$ in the pile should be less than or equal to the allowable moment for the pile. The value of $M_{\max}$ for a long flexible pile can be calculated by Eq. (3-32):

$$M_{\max} = 0.5 H_0 l_0 e^{-(Z_{\max}/l_0)} \sqrt{\left[1 + (h/l_0)^2\right]} \tag{3-32}$$

where, $Z_{\max} = D_v$ since $M_{\max}$ occurs where the shear stress is equal to zero

The equation of $M_{\max}$ for a short and rigid pile is not included since all of the piles calculated in this report turned to be long flexible. Although the maximum bending moments are computed, these are not checked with the yield moment of the pile material. In other words, the lateral pile capacities are checked only against failure of the surrounding soil.

The procedures for lateral pile capacity in fine grained soils are almost the same as those in coarse grained soils. In the absence of site specific pressuremeter data, the average pressuremeter modulus, E_0 and the pre-boring pressuremeter limit pressure, P_L within D_v, in fine grained soils can be determined by Eq. (3-33) and Eq. (3-34), respectively with reduced precision (Briaud 1992);

$$E_0 = 100 s_u \tag{3-33}$$

$$P_L = 7.5 s_u \tag{3-34}$$

Once these two values are obtained, the same procedures as described in the previous section should be applied to check the lateral pile capacity.

3.2.3 Pile Capacity Check

Once the axial and lateral pile capacities are estimated, they should be compared with the applied loads to check if the pile is safe against the loads. There are two different methods used extensively in the field: Load and Resistance Factor Design (LRFD) and Working Stress Design (WSD).

3.2.3.1 Load and Resistance Factor Design (LRFD) Method

The Load and Resistance Factor Design (LRFD) method is based on a reliability approach to provide a more uniform level of safety on both loads and resistance. The LRFD factors are developed on the basis of a probability of failure varying between 0.0005 to 0.001. In the LRFD method the applied loads are multiplied by load factors, λ_i which are equal or larger than 1. The resistances are multiplied by resistance factors, ϕ_i which are equal or less than 1. The magnitude of these factors depends on the types of loads and the types of resistance components, respectively. The λ_i and ϕ_i values are found in various guidelines including AASHTO and API RP2A. All calculations of driven pile capacities in this report followed API RP2A-LRFD (2003), and these values are shown in Table 2.3. The worst case among the three different conditions in Table 3-3 should be checked with correspondingly factored resistance. For bored piles, the values of load factors are obtained from those values for driven piles, and the values of resistance factors in Table 3-4 can be used.

Table 3-3. Load and resistance factors for driven piles (API RP2A-LRFD, 2003)

Load Condition	Load Factors	Resistance Factor
Gravity Loads	$1.3DL+1.5LL$	0.70
Operating environmental	$1.3DL+1.5LL+1.2W_o$	0.70
Extreme environmental	$1.1DL+1.1LL+1.35W_e$	0.80
Lateral Capacity	-	0.75

Note: DL = dead load; LL = live load;

W_o = wind load for operating environmental condition;

W_e = wind load for extreme environmental condition

Table 3.4. Recommended resistance factors for bored piles (ADSC, 1999)

Load Condition	Capacity Term	Resistance Factor	
		Sand	Clay
Operating environmental	End Bearing	0.50	0.55
	Skin Friction	0.65	0.65
	Uplift	0.65	0.55
Extreme environmental	Overall	1.00	1.00
Lateral Capacity	Overall	0.75	

According to API RP2A-LRFD (2003), “The operating environmental condition should be representative of moderately severe conditions at the platform. Typically, a 1-year to 5-year winter storm is used as an operating wind condition in the Gulf of Mexico. On the other hand, the extreme environmental condition uses a 100-year return period event. Return period means the average interval of time between exceedances of the magnitude of an event.”

The general equation in the LRFD method can be expressed as:

$$\sum \lambda_i \times L_i \ (Loads) = \sum \phi_i \times R_i \ (Resistance) \tag{3-35}$$

where, λ_i = load factors (≥ 1.0)

ϕ_i = resistance factors (≤ 1.0)

For the pile capacity check, the appropriate factors for the resistance (capacity) obtained in the previous sections should be selected according to the guideline. Then, the factored resistance is to be compared with the factored loads and it should be larger or equal to the factored loads.

3.2.3.2 Working Stress Design (WSD) Method

Working Stress Design (WSD) is a traditional method to achieve a level of conservatism against various uncertainties in many aspects. In the WSD method, the factor of safety is employed to reduce the risk level against failure and it is the ratio of resistance to the applied load:

$$Factor\ of\ Safety\ (SF) = \frac{Resistance\,(R)}{Load\,(L)} \tag{3-36}$$

The allowable pile capacities are determined by dividing the ultimate pile capacity by the proper factor of safety. The API RP2A-WSD recommends the following minimum values for driven piles in Table 3-5 depending on the load condition. For bored piles the values in Table 3-6 can be used according to the ADSC (1999).

Table 3-5. Recommended factor of safety for driven piles (API RP2A-WSD, 2000)

Load Condition	Factor of Safety
Operating environmental conditions	2.0
Extreme environmental conditions	1.5
Uplift (pullout) conditions	2.0
Lateral Capacity	3.0

Table 3-6. Recommended factor of safety for bored piles (ADSC, 1999)

Load Condition	Factor of Safety
Operating environmental conditions	3.0
Extreme environmental conditions	2.0
Uplift (pullout) conditions	3.0
Lateral Capacity	3.0

Briaud (1997) recommend a factor of safety of 3 for their lateral capacity calculation method. In the case of LRFD, it is decided to use a resistance factor for lateral capacity equal to 0.75. This is a relatively high resistance factor because the data shown by Briaud (1997) indicates little scatter in the predicted vs. measured comparison. For the pile capacity check, the actual resistance (capacity) obtained in the previous sections is to be divided by the actual loads. It becomes the factor of safety for the pile and it should be higher than the recommended value.

3.3 Decision Analysis

In general, it is almost impossible to predict with certainty what the best result of each strategy will be because there are many uncertainties in real problems. Therefore, formal analysis is required to consider many complex problems. The goal of decision analysis is to structure and simplify the task of making hard decisions through quantitative basis (Jimenez et al. 2003). This approach provides logical analysis of the alternatives and quantitative rationale for the recommendation. Decision analysis is usually concerned with multiple conflicting objectives for many real world problems and, therefore, it is simply not true that "qualitatively speaking, business decisions are simple because the objective function is crystal clear (Keeney and Raiffa 1993)."

According to Keeney and Raiffa (1993) and (Keeney 1992), the simple paradigm of decision analysis can be summarized in a five-step process as follows:

1. Preanalysis: the problem has been identified and the viable alternatives are given.
2. Structural analysis: the decision-maker structures the problem which includes specifying objectives, attributes, and attributes scales.
3. Uncertainty analysis: the decision-maker assigns probabilities to the branches emanating from chance nodes. These assignments are based on past empirical data and expert judgment.
4. Utility or value analysis: the decision-maker quantifies his/her preferences and then converts these preferences into utility numbers. The assignment of utility numbers to consequences must be such that the maximization of expected utility becomes the appropriate criterion for the decision-maker's optimal action.
5. Optimization Analysis: once decision-maker assigns utilities, he/she calculates his/her optimal strategy – the strategy that maximizes expected utility. There are various techniques to obtain an optimal strategy for a specific problem.

3.3.1 The Assumption of Utility Function

In order to be able to decompose the general multi-attribute utility function with i attributes into a simple functional form of the i individual attributes, two assumptions about the nature of the decision-maker's preferences for the underlying attributes must be specified and verified (Hardaker 2004). These two assumptions are mutually preferential independence and utility independence. The preferential independence concerns only ordinal preferences and no probabilistic elements are involved (Keeney and Raiffa 1993). For example, suppose there are two attributes, X and Y. If preferences for levels of attribute X do not depend on the level of attribute Y, an attribute X is said to be preference independent of another attribute Y. Utility independence, on the other hand, concerns the cardinal preferences of the decision-maker (Keeney and Raiffa 1993). For example, if preferences for uncertain choices such as lotteries involving different levels of attribute X do not depend on the level of attribute Y, an attribute X is said to be utility independent of another attribute Y. Full mutual utility independence is almost impossible in reality, but the assumption is commonly made since to do otherwise would make the analysis too difficult (Hardaker 2004). It is very important to ascertain whether any of the preferential independence or utility independence assumptions discussed above is appropriate for this research.

3.3.2 Forms of the Utility Function

If mutual preferential and utility independence are satisfied, it is possible to define the multi-attribute utility function in the general form (Clemen and Reilly 1999):

$$U\left(x_1, x_2, \ldots, x_I\right) = U\left\{u_1(x_1), u_2(x_2), \ldots, u_I(x_I)\right\} \qquad (3\text{-}37)$$

Once each single-attribute utility function $u_i(x_i)$ is derived for its attribute measure, these individual utility values are combined in some way into a final utility value.

If single-attribute utility functions $u_i(x_i)$ are scaled from zero to one, and if U is also scaled from zero to one, the function U is either of the additive form (Hardaker 2004):

$$U\left(x_1, x_2, \ldots, x_I\right) = \sum_{i=1}^{I} k_i u_i\left(x_i\right) \qquad (3\text{-}38)$$

or of the multiplicative form (Hardaker 2004):

$$U\left(x_1, x_2, \ldots, x_I\right) = \left\{\prod_{i=1}^{I}\left(K \cdot k_i u_i\left(x_i\right) + 1\right) - 1\right\} / K \qquad (3\text{-}39)$$

where $u_i(x_i)$ is a single-attribute utility function scaled from 0 to 1, k_i is a scaling factor between zero and one for $u_i(x_i)$. K is another scaling constant and the value of K depends on the values k_i. If $\Sigma k_i = 1$, then K = 0 and U takes the additive form as expressed in Eq. (3-38) and it indicates there is no interaction between each attribute. In contrast, if $\Sigma k_i \neq 1$, then $K \neq 0$ and U takes the multiplicative form as expressed in Eq. (3-39). If K is greater than 0, then the attributes interact destructively so that a low utility for one attribute can result in a low overall utility U. On the other hand, when K is less than 0, the attributes interact constructively so that a high individual attribute utility results in a high overall utility U. Keeney (1974) describes more detail information about the derivation of K from the k_i values in the multiplicative case.

3.3.3 Sensitivity Analysis

Sensitivity analysis for multi-attribute utility problems can be categorized based on the number of times an optimization routine needs to be run to analyze sensitivity (Guikema and Milke 2003). If various individuals have distinct weight combinations for multi-attribute utility problems, each combination could be given as a discrete weight combination to the optimization routine and any result change in the technology selected would indicate sensitivity to an individual's choice of weight combination. In this case, not only does relatively few optimization need to be run, but also relatively little post-processing of the optimization results is needed to evaluate sensitivity (Guikema and Milke 2003). The sensitivity analysis for discrete weight combinations of multi-attribute utility problems has been addressed many times in the literature. Call and Merkhofer (1988), for example, developed one approach to sensitivity analysis using predefined weight combinations (i.e., high and low for each attribute).

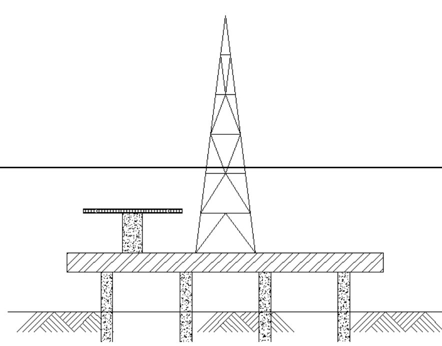
On the other hand, if decision-makers do not feel confident enough in their assessments to specify precise values, uncertainties of input parameters such as the weights of each attribute in multi-attribute utility problems can arise. In this case the proper values can lie anywhere within a possibly wide range of values specified by the decision-makers. For this type of sensitivity analysis, multiple optimizations need to be run and the breakpoints become important. In this research, for example, the breakpoints where the optimal drilling systems change are very important aspect. This type of sensitivity analysis is more difficult and time consuming than discrete sensitivity analysis. Significantly less has been addressed for this type of sensitivity analysis in the literature than for the discrete sensitivity analysis.

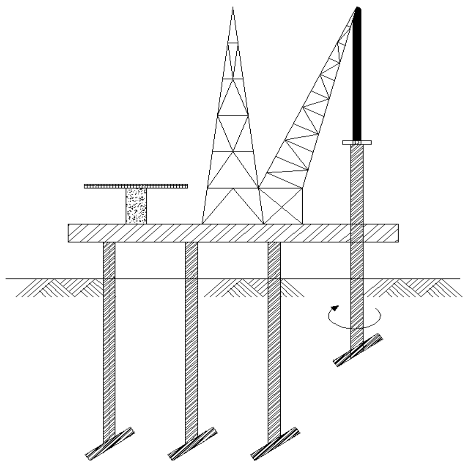
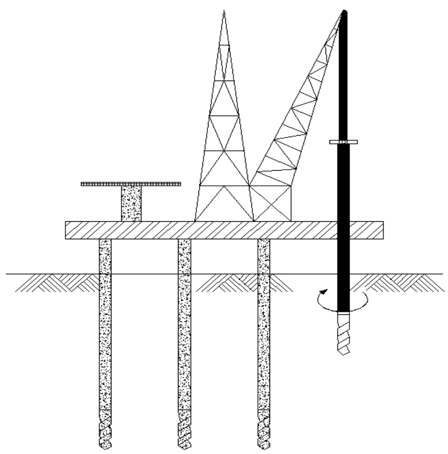
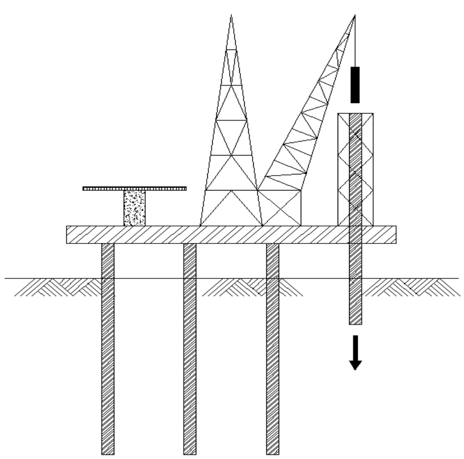
4. PARAMETRIC STUDY OF FOUNDATIONS FOR DRILL SITES

4.1 Foundation Options for Drill Sites

After having several meetings with EFD foundation experts, some of possible foundation options for a drilling site containing the advantage and disadvantage associated with those options are identified as shown in Table 4-1.

Table 4-1. Foundation options for a drilling site

1. Gravel pad	Advantages
	• Easier and faster installation • Maybe cheaper in construction stage **Disadvantages** • Less environmentally friendly • Non-resuable
2. Composite mat	Advantages
	• Easier and faster installation • Great effect on small loading area over soft soil (E<10 MPa) **Disadvantages** • Less effect on large loading area over stiff soil (E>50 MPa)
3. Spread footing	Advantages
	• Simple (no equipment) • Uplift on marshes • Easy to remove on rock • No discharge **Disadvantages** • No uplift on rock • Suitable contact on rock • Hard to remove on marsh

4. Screw anchor	Advantages
	• Light equipment • No discharge • Removable • Uplift capacity
	Disadvantages
	• Limited to soft soils
5. Bored pile	Advantages
	• Drill through any soil • Noise level is low • Familiar technology
	Disadvantages
	• Drilling fluid in marsh • Equipment heavier • Access • More complicated
6. Driven pile	Advantages
	• Uplift capacity • Minimal imprint • Vibratory is less noisy
	Disadvantages
	• Equipment heavier • Access • More complicated • Vibratory limited to some soils

Among those foundation options, three different foundations (i.e., driven pile, bored pile, and composite mat) for drill sites are considered for the parametric study in the following Section 4.2 through 4.3. In order to encourage site location engineers to use environmentally friendly foundations such as elevated platforms and composite mat systems more often for their drilling sites instead of using gravel pads, the parametric study is an essential task in this research.

4.2 Pile Foundation System for Low Impact Onshore Platforms

Environmental issues are a significant part of every industry. The petroleum industry endeavors to minimize the existing environmental impact during drilling operations whether developing new resources or extending field in environmentally sensitive areas. For example, reducing the environmental footprint during drilling operations using a reusable Modular Platform and small mobile rig in the Arctic was demonstrated in 2003 by Anadarko and Noble's Subsidiary, Maurer technology Inc.. The objective was to drill in an ecologically sensitive area without disturbing the ground surface. The successful demonstration used a small mining rig to evaluate the potential of drilling for hydrates under the frozen tundra of the Alaska North Slope (Kadaster and Millheim 2004) and showed the usefulness of an onshore platform to drill in sensitive areas.

The objective of this study is to help the petroleum industry engineers to get a basic idea regarding pile designs of a platform for various platform weights and soil conditions in environmentally sensitive areas (e.g., desert environments and wetland applications). Use of a raised platform in environmentally sensitive areas will require the use of piles to support the elevated platform instead of gravel pads as used in a conventional platform. About one thousand different cases of pile capacity calculations are conducted depending on various soil types, pile types, and design methods. The results of these calculations are organized into a series of tables in order for the engineer to be able to easily choose an appropriate pile size for a given condition from these tables without performing an extensive pile design analysis.

4.2.1 Description of the General Case

Anadarko's onshore platform in Alaska (Kadaster and Millheim 2004) is adopted for the foundation design of the general case. The platform consists of "bucket" modules (12.5 ft wide, 50 ft long, and 3.5 ft deep), piles for its leg, and drilling rig components. Figure 4-1 shows the dimension of one module, Figure 4-2 shows the plan view of several modules connected each other, and Figure 4-3 shows the cross sectional view of the platform. It is assumed that the mast is 90 ft high, 10 ft long and the living quarter is 28 ft high, 40 ft long, respectively.

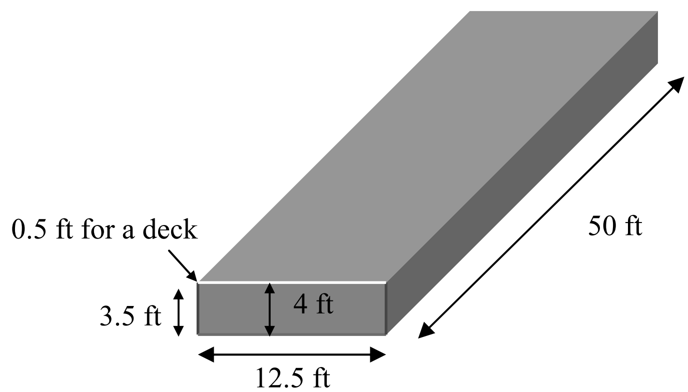


Figure 4-1. Module dimension

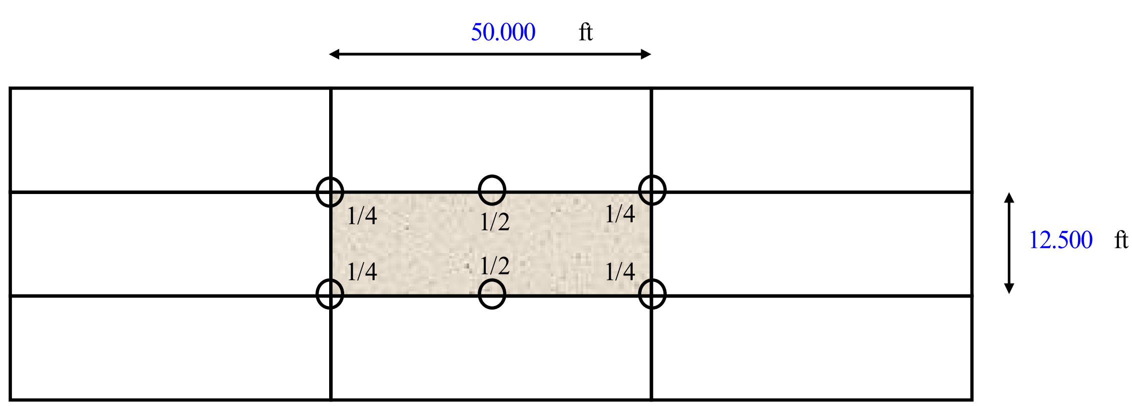


Figure 4-2. Plan view of modules

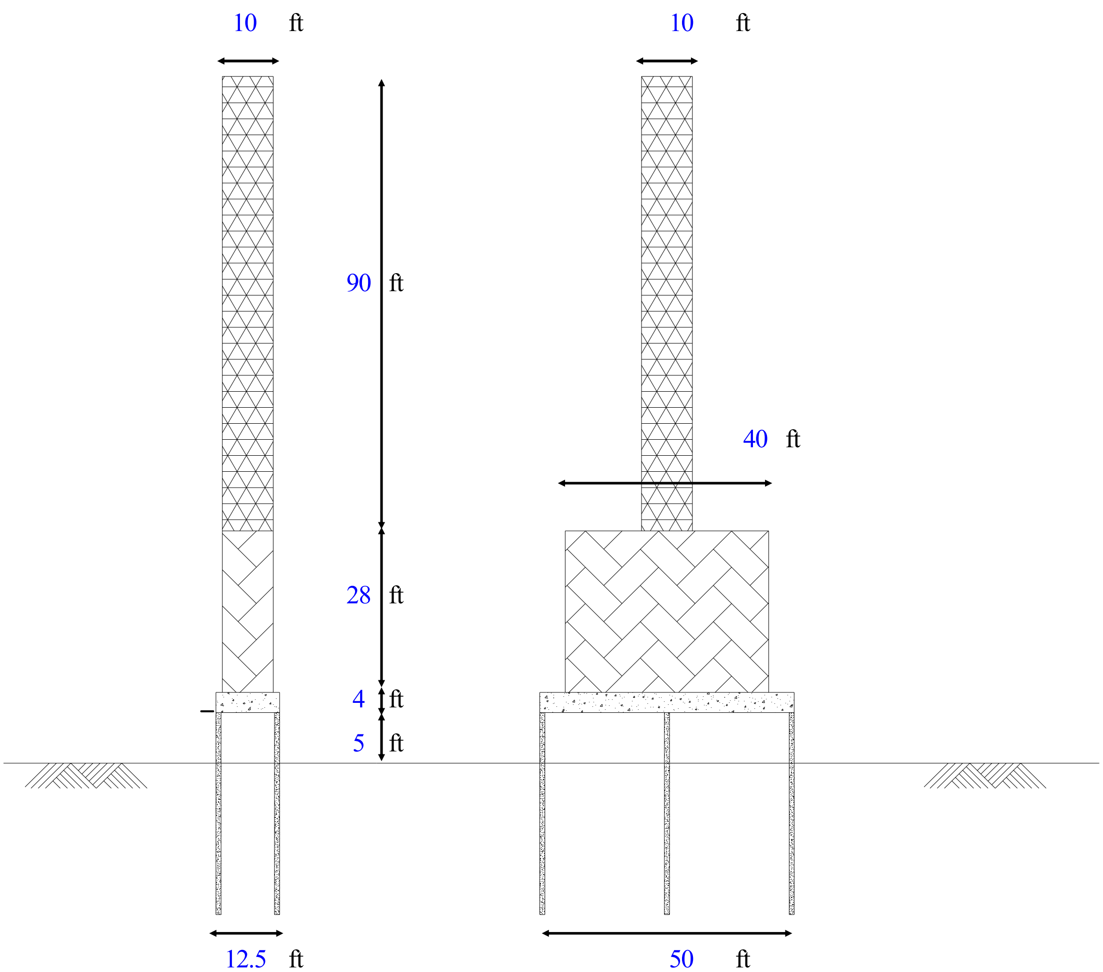


Figure 4-3 Cross section of the platform for one module in design

4.2.1.1 Soil Conditions

Pile capacities are strongly affected by the underlying soil type. If there is very dense sand under the ground, a pile will resist a much higher applied load than a pile in loose sand. Although it is highly desirable to calculate pile capacities in a site specific fashion, six typical types of soils are considered in this report. Furthermore, a homogeneous condition with respect to depth is assumed for simplicity in the calculations. The engineering properties of these soils are shown in Table 4-2.

Table 4-2. Soil conditions of pile capacity calculations

Gravels & Sands			Silts & Clays		
Type I (very dense)	Type II (medium)	Type III (very loose)	Type IV (hard)	Type V (medium)	Type VI (soft)
γ_{sat} = 127 pcf G.W.L = 20 ft N_{SPT} = 50 bpf	γ_{sat} = 120 pcf G.W.L = 10 ft N_{SPT} = 30 bpf	γ_{sat} = 115 pcf G.W.L = 0 ft N_{SPT} = 10 bpf	γ_{sat} = 127 pcf G.W.L = 20 ft Su = 2090 psf	γ_{sat} = 120 pcf G.W.L = 10 ft Su = 1255 psf	γ_{sat} = 115 pcf G.W.L = 0 ft Su = 0.25 P_0'

Note: P_0' = effective overburden pressure (psf)

G.W.L = ground water depth measured from the ground surface

4.2.1.2 Weight Distribution on Platform

For the general case, it is assumed that 65% of the total vertical loads are evenly distributed over 6 modules and that this load consists of dead load (30%) and live load (70%).

The wind load is one of the primary sources of horizontal loads against a structure. According to API RP2A-LRFD (2003), wind load may be computed by Eq. (4-1);

$$W = \frac{\rho}{2} V^2 C_s A \qquad (4\text{-}1)$$

where, W = wind force, V = wind speed

C_s = dimensionless shape coefficient for perpendicular wind approach angles with respect to each projected area

A = area of object perpendicular to the wind

ρ = mass density of air at standard temperature and pressures

= 1.226 kg/m^3 = 0.00238 lb·sec^2/ft^4)

The one hour mean wind speed at elevation z can be calculated by Eq. (4-2);

$$V(1hr, z) = V(1hr, z_R)\left(\frac{z}{z_R}\right)^{0.125} \qquad (4\text{-}2)$$

where, $V(1hr, z_R)$ = one hour mean speed at the reference elevation (m/s, ft/s)

z_R = reference elevation (= 10m or 33ft)

According to API RP2A-LRFD (2003), the extreme wind speed to be considered in design for the Gulf of Mexico area is 49 m/s. In this report, 25m/s and 49m/s are assumed for operational and extreme wind speeds, respectively. More detailed load calculations in the general case can be found in APPENDIX A.

4.2.1.3 Pile Capacity Check

For the general case, the capacities of the driven steel pipe piles and bored piles are calculated in accordance with the LRFD and WSD methods. The step-by-step calculations can be found in APPENDIX A. First, the axial capacity is checked against the applied loads. Second, the lateral capacity is checked for the free head condition. Finally, the lateral capacity in the fixed head condition is evaluated.

4.2.1.4 Results Summary

Based on the pile capacity calculations in the general case, the following four tables (Table 4-3 ~ 4-6) provide a simple way to choose an appropriate pile size for a given condition. Once the soil type and the applied loads are known, the desirable pile size can be decided by following procedure;

1. Choose a design method: LRFD or WSD
2. Choose a pile type: driven or bored
3. Go to a table corresponding to the selected design method and pile type
4. Read the recommended diameter and length of the pile in the table

Table 4-3. Recommended size of driven piles in the general case (LRFD)

Weight of Rigs & Accessories (Unfactored)	Soil types / Factored max. vertical loads on one pile	Sand & Gravels			Silts & Clays		
		very loose	medium	very dense	soft	medium	hard
		γ_{sat} = 115 pcf G.W.L = 0 ft N_{SPT} = 10 bpf	γ_{sat} = 120 pcf G.W.L = 10 ft N_{SPT} = 30 bpf	γ_{sat} = 127 pcf G.W.L = 20 ft N_{SPT} = 50 bpf	γ_{sat} = 115 pcf G.W.L = 0 ft Su = 0.25 P_o'	γ_{sat} = 120 pcf G.W.L = 10 ft Su = 60 kPa	γ_{sat} = 127 pcf G.W.L = 20 ft Su = 100 kPa
1000 kips	178.0 kips	D = 24 in.	D = 24 in.	D = 12 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 58 ft	L = 26 ft	L = 28 ft	L = 70 ft	L = 41 ft	L = 27 ft
1500 kips	207.8 kips	D = 24 in.	D = 24 in.	D = 16 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 64 ft	L = 30 ft	L = 21 ft	L = 75 ft	L = 47 ft	L = 32 ft
2000 kips	237.6 kips	D = 24 in.	D = 24 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 69 ft	L = 33 ft	L = 17 ft	L = 81 ft	L = 52 ft	L = 36 ft
3000 kips	297.1 kips	D = 24 in.	D = 24 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 79 ft	L = 40 ft	L = 21 ft	L = 91 ft	L = 63 ft	L = 45 ft
4000 kips	356.7 kips	D = 24 in.	D = 24 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 20 in.
		L = 94 ft	L = 48 ft	L = 27 ft	L = 104 ft	L = 77 ft	L = 66 ft

Table 4-4. Recommended size of driven piles in the general case (WSD)

Weight of Rigs & Accessories (Unfactored)	Soil types / Unfactored max. vertical loads on one pile	Sand & Gravels			Silts & Clays		
		very loose	medium	very dense	soft	medium	hard
		γ_{sat} = 115 pcf G.W.L = 0 ft N_{SPT} = 10 bpf	γ_{sat} = 120 pcf G.W.L = 10 ft N_{SPT} = 30 bpf	γ_{sat} = 127 pcf G.W.L = 20 ft N_{SPT} = 50 bpf	γ_{sat} = 115 pcf G.W.L = 0 ft Su = 0.25 P_o'	γ_{sat} = 120 pcf G.W.L = 10 ft Su = 60 kPa	γ_{sat} = 127 pcf G.W.L = 20 ft Su = 100 kPa
1000 kips	141.9 kips	D = 24 in.	D = 24 in.	D = 16 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 57 ft	L = 25 ft	L = 20 ft	L = 68 ft	L = 39 ft	L = 26 ft
1500 kips	169.0 kips	D = 24 in.	D = 24 in.	D = 16 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 63 ft	L = 29 ft	L = 21 ft	L = 74 ft	L = 46 ft	L = 31 ft
2000 kips	196.0 kips	D = 20 in.	D = 24 in.	D = 20 in.	D = 20 in.	D = 24 in.	D = 24 in.
		L = 79 ft	L = 33 ft	L = 17 ft	L = 89 ft	L = 52 ft	L = 36 ft
3000 kips	250.2 kips	D = 24 in.	D = 24 in.	D = 20 in.	D = 20 in.	D = 20 in.	D = 24 in.
		L = 79 ft	L = 40 ft	L = 21 ft	L = 101 ft	L = 74 ft	L = 45 ft
4000 kips	304.4 kips	D = 24 in.	D = 20 in.	D = 16 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 93 ft	L = 58 ft	L = 37 ft	L = 104 ft	L = 77 ft	L = 56 ft

Table 4-5. Recommended size of bored piles in the general case (LRFD)

Weight of Rigs & Accessories (Unfactored)	Soil types / Factored max. vertical loads on one pile	Sand & Gravels			Silts & Clays		
		very loose	medium	very dense	soft	medium	hard
		γ_{sat} = 115 pcf G.W.L = 0 ft N_{SPT} = 10 bpf	γ_{sat} = 120 pcf G.W.L = 10 ft N_{SPT} = 30 bpf	γ_{sat} = 127 pcf G.W.L = 20 ft N_{SPT} = 50 bpf	γ_{sat} = 115 pcf G.W.L = 0 ft Su = 0.25 P_o'	γ_{sat} = 120 pcf G.W.L = 10 ft Su = 60 kPa	γ_{sat} = 127 pcf G.W.L = 20 ft Su = 100 kPa
1000 kips	178.0 kips	D = 24 in.	D = 20 in.	D = 16 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 38 ft	L = 19 ft	L = 19 ft	L = 85 ft	L = 41 ft	L = 24 ft
1500 kips	207.8 kips	D = 24 in.	D = 20 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 46 ft	L = 26 ft	L = 19 ft	L = 97 ft	L = 53 ft	L = 31 ft
2000 kips	237.6 kips	D = 24 in.	D = 20 in.	D = 16 in.	D = 24 in.	D = 24 in.	D = 20 in.
		L = 54 ft	L = 32 ft	L = 31 ft	L = 109 ft	L = 66 ft	L = 48 ft
3000 kips	297.1 kips	D = 24 in.	D = 24 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 70 ft	L = 36 ft	L = 33 ft	L = 131 ft	L = 94 ft	L = 56 ft
4000 kips	356.7 kips	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 86 ft	L = 46 ft	L = 34 ft	L = 149 ft	L = 122 ft	L = 73 ft

(where, P_o' = effective overburden pressure, G.W.L. = ground water depth measured from the ground surface,

Table 4-6. Recommended size of bored piles in the general case (WSD)

Weight of Rigs & Accessories (Unfactored)	Soil types / Unfactored max. vertical loads on one pile	Sand & Gravels			Silts & Clays		
		very loose	medium	very dense	soft	medium	hard
		γ_{sat} = 115 pcf G.W.L = 0 ft N_{SPT} = 10 bpf	γ_{sat} = 120 pcf G.W.L = 10 ft N_{SPT} = 30 bpf	γ_{sat} = 127 pcf G.W.L = 20 ft N_{SPT} = 50 bpf	γ_{sat} = 115 pcf G.W.L = 0 ft Su = 0.25 P_o'	γ_{sat} = 120 pcf G.W.L = 10 ft Su = 60 kPa	γ_{sat} = 127 pcf G.W.L = 20 ft Su = 100 kPa
1000 kips	141.9 kips	D = 24 in.	D = 24 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 53 ft	L = 24 ft	L = 21 ft	L = 108 ft	L = 65 ft	L = 39 ft
1500 kips	169.0 kips	D = 24 in.	D = 24 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 60 ft	L = 29 ft	L = 26 ft	L = 118 ft	L = 78 ft	L = 46 ft
2000 kips	196.0 kips	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 68 ft	L = 34 ft	L = 23 ft	L = 128 ft	L = 91 ft	L = 54 ft
3000 kips	250.2 kips	D = 24 in.	D = 20 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 89 ft	L = 57 ft	L = 43 ft	L = 153 ft	L = 129 ft	L = 77 ft
4000 kips	304.4 kips	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 114 ft	L = 59 ft	L = 44 ft	L = 174 ft	L = 166 ft	L = 99 ft

4.2.2 Description of an Elevated Platform with Rapid Rig

In May 2006, National Oilwell Varco (NOV) began offering a smaller, fully automatic land drilling rig called "Rapid Rig." The total vertical load of Rapid Rig is used for the foundation calculation of the proposed modular platform. The load breakdown and the layout of Rapid Rig are shown in Table 4-7, Figure 4-4, and Figure 4-5, respectively. In this case, the operating environmental condition governs the foundation calculation.

Table 4-7. Load breakdown structure of Rapid Rig in operating condition

No.	COMPONENTS	WEIGHTS [lbs] (DEAD)	WEIGHTS [lbs] (LIVE)	Factored Weights [lbs]	Dimension		Notes
				D.L = 1.3 L.L = 1.5	W	L	
1.	Substructure/Drillfloor package	80,000		104,000	10	58.5	
2.	Mast including installed equipment	100,000		130,000	18	25	
3.	Drawworks package includes Accumulator unit	70,000		91,000	10	29	
4.	Utilities Skid	25,000		32,500	10	28	
5.	Service Skid	20,000		26,000	10	38.75	
6.	Electrical Control House	30,000		39,000	10	42	
7.	Generator House #1	40,000		52,000	10	27.5	
8.	Generator House #2	40,000		52,000	10	27.5	
9.	Air Compressor House	30,000		39,000	10	27.5	
10.	Mud Pump #1	55,000		71,500	8.75	22	
11.	Mud Pump #2	55,000		71,500	8.75	22	
12.	Pipe Handling equipment	35,000		45,500	3	80	
13.	Control House skid including choke manifold	23,000		29,900	18	12.5	
	Choke Manifold hauled on same trailer	15,000		19,500	7.5	14	
14.	Mud Tank Skid #1 (Empty)	40,000		52,000	11.25	55	
	Mud Tank Skid #1 (Full)		204,750	307,125	11.25	55	375 barrels, 13 lbs/gal
15.	Mud Tank Skid #2 (Empty)	40,000		52,000	11.25	55	
	Mud Tank Skid #2 (Full)		204,750	307,125	11.25	55	375 barrels, 13 lbs/gal
16.	Water Tank (Empty)	20,000		26,000	7.5	45	
	Water Tank (Full)		139,440	209,160	7.5	45	400 barrels, 8.3 lbs/gal
17.	Work shop/Storage Skid	20,000		26,000	10	27.5	
18.	Fuel Tank Skid	10,000		13,000	8	30	
19.	Casing		530,000	795,000	18	25	53 lbs/ft, 10000 ft
20.	Pipes		234,000	351,000	18	25	19.5 lbs/ft, 12000 ft
21.	Collars		2,720	4,080	18	25	80 lbs/ft, 34 ft
22.	Drill collars		60,000	90,000	18	25	6000 lbs x 10
Total Weights without Casing		748,000	845,660	2,240,890			
Total Weights		748,000	1,375,660	3,035,890			

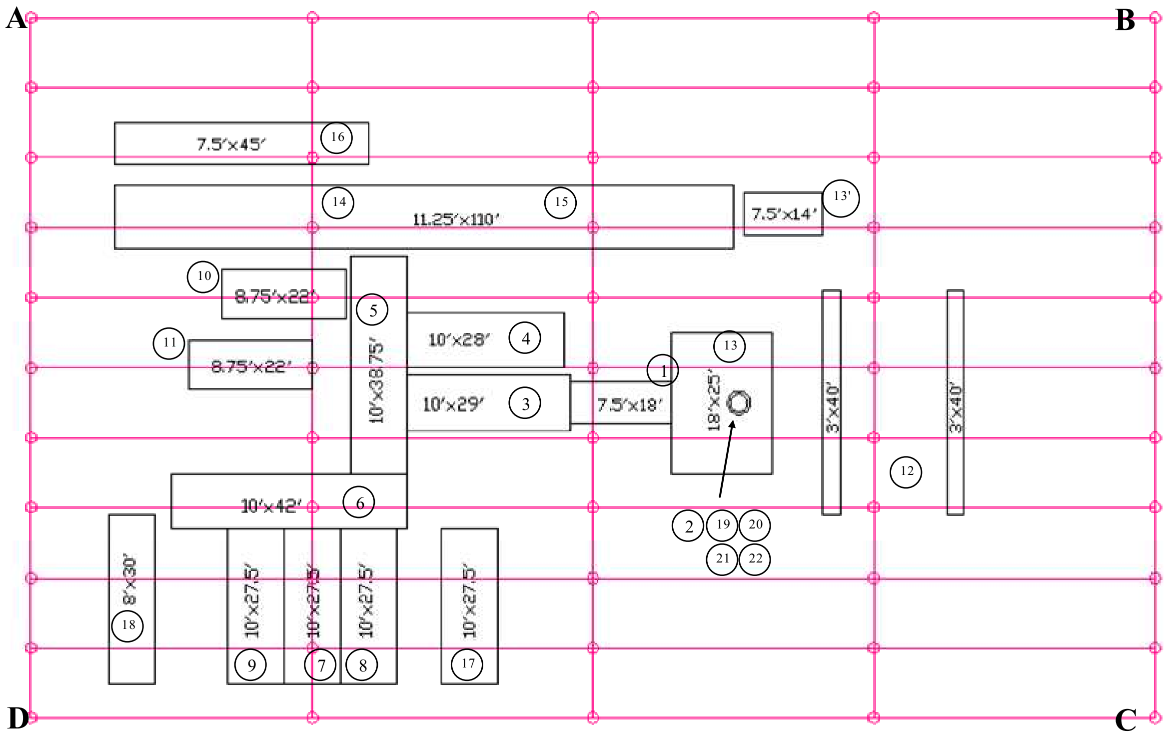


Figure 4-4. Rapid Rig layout

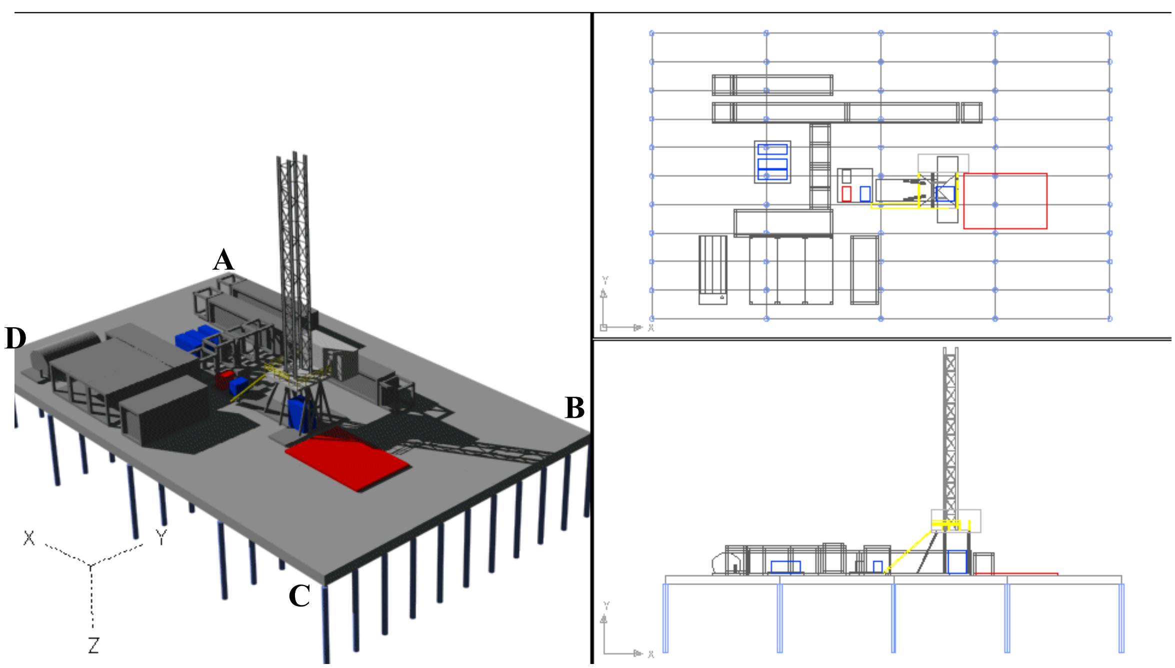


Figure 4-5. Three dimensional (3-D) layout of Rapid Rig

4.2.2.1 Soil Condition

The six soil conditions adopted for the general foundation calculations are used for the Rapid Rig foundation calculation (i.e., very dense, medium, and very loose for sand; hard, medium, and soft for clay).

4.2.2.2 Weight Distribution on the Platform

In order to calculate the load distribution of Rapid Rig on the proposed modular platform, a numerical analysis program, VisualFEA, is used. Since the wind load in Rapid Rig is significantly smaller than that in the general case, the dead and live loads governed the design. The following assumptions are made to perform the numerical analysis for this problem:

1. Young's modulus (E) for the aluminum material of each module is 1.44E + 09 psf.
2. The modules are in the form of upside down aluminum boxes. The deck of these modules is 6 inches thick. In order to simplify the mesh generation for the numerical simulations, the modules are modeled as flat plates (called thin shells in Finite Element Analysis) which are 6 inches thick. This is a conservative assumption since it ignores the stiffness benefit derived from the 4 ft thickness of the side beams (Figure 4-1).
3. Self weight of modules is not considered in this analysis.
4. Rigid boundary conditions are adopted (The supports of the platform do not settle).

Four node quadrilateral elements are used in this analysis and the applied load layout of Rapid Rig is shown in Figure 4-6.

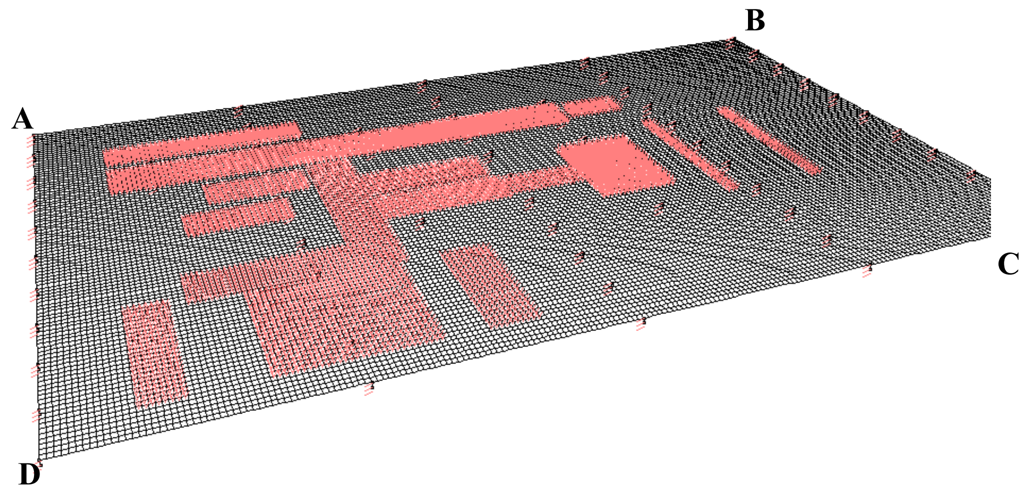


Figure 4-6. The applied load layout of Rapid Rig on the proposed platform

The pile reaction forces and the deformation of the deck on the modules are calculated by using only four piles for each module as shown in Figures 4-7 ~ 4-9. According to the results, the most critical pile reaction force and deformation are 208.3 kips, and 0.934 ft, respectively. Since 0.934 ft is not an acceptable deformation, several critical modules are required to have six piles, each. The results of the analysis using six piles for critical modules are shown in Figures 4-10 ~ 4-12.

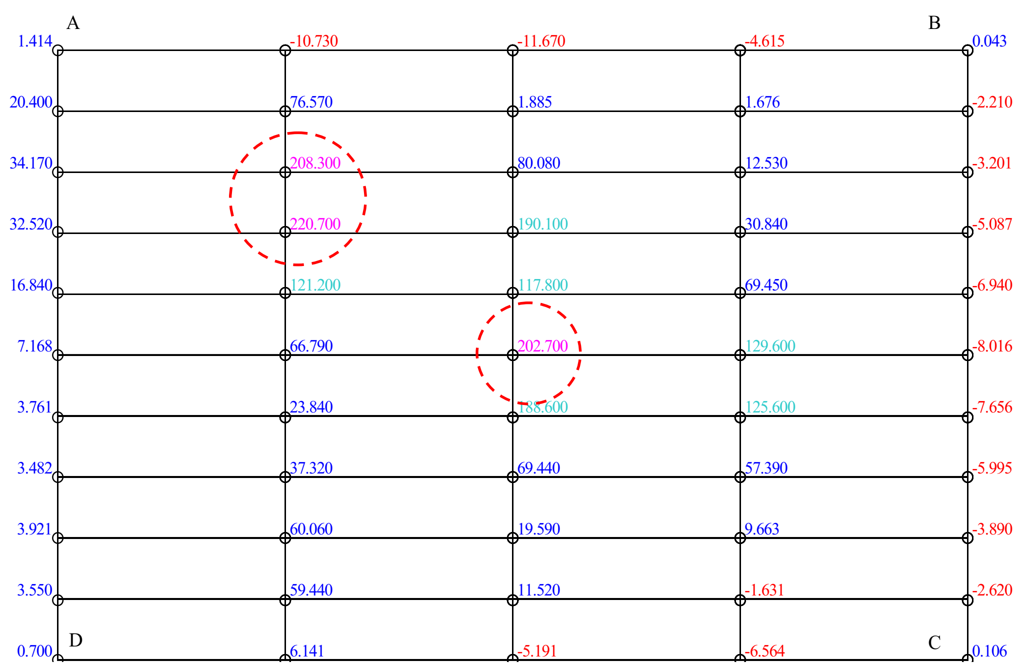


Figure 4-7. Pile reaction force [kips], (using only four piles per module)

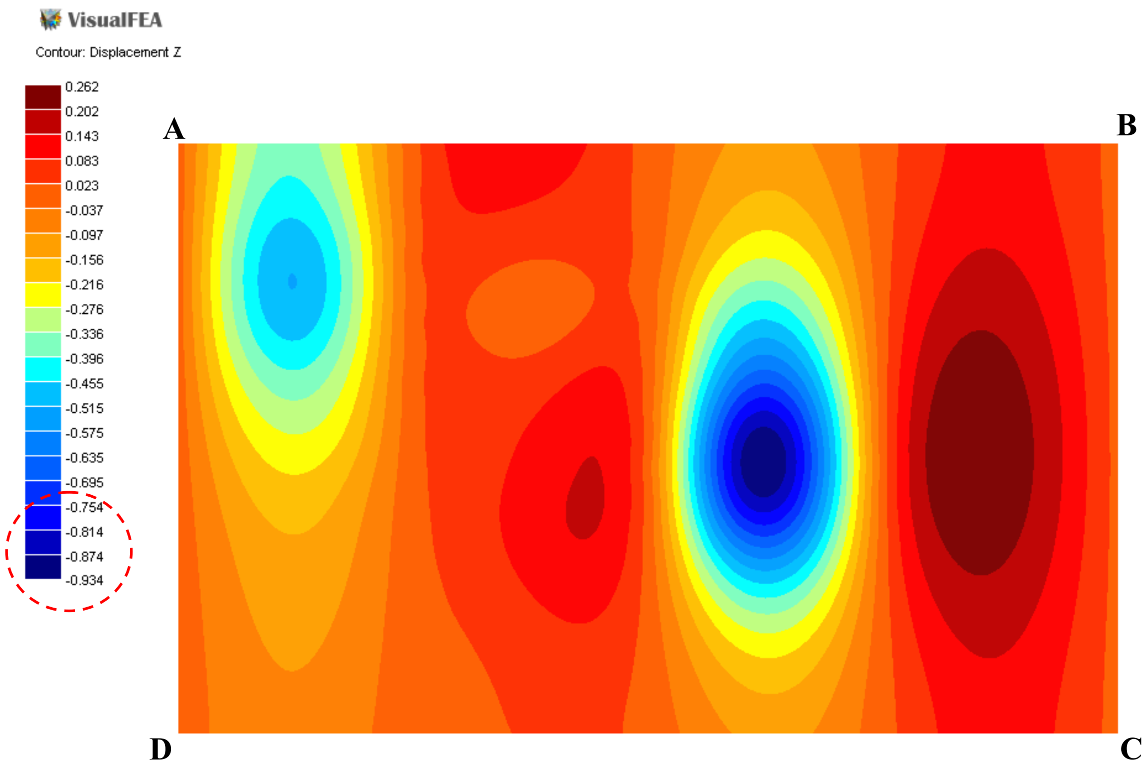


Figure 4-8. Module deformation [ft], (using only four piles per module)

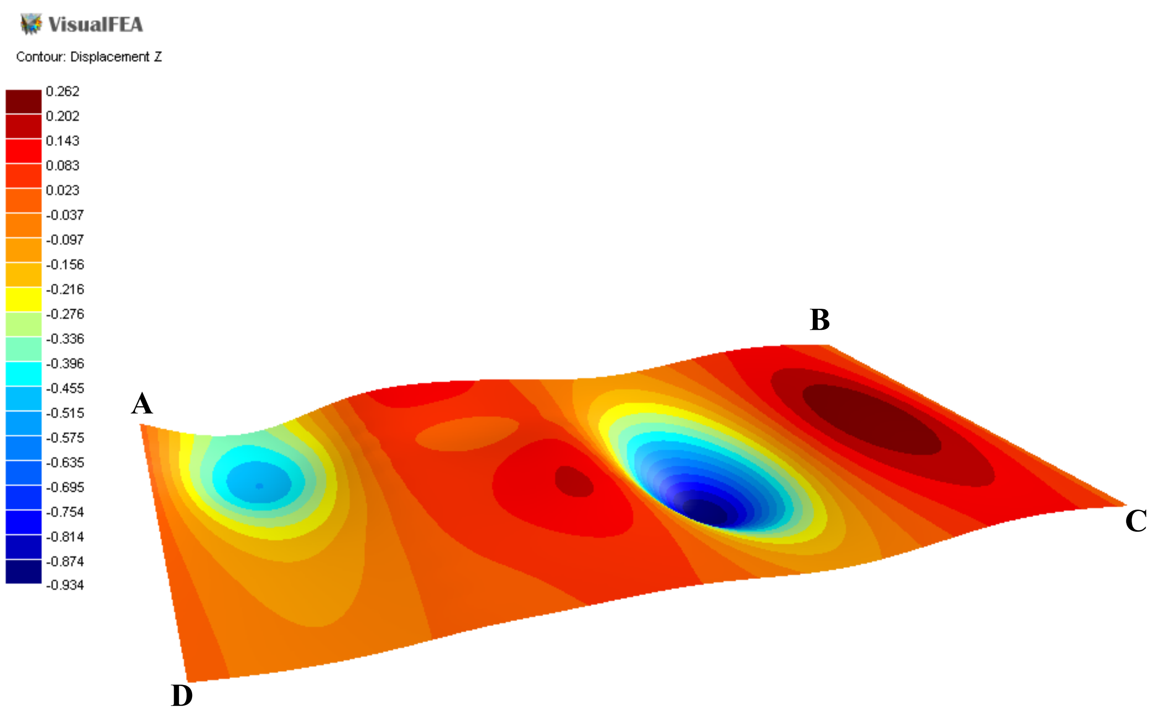


Figure 4-9. Module deformed shape (using only four piles per module)

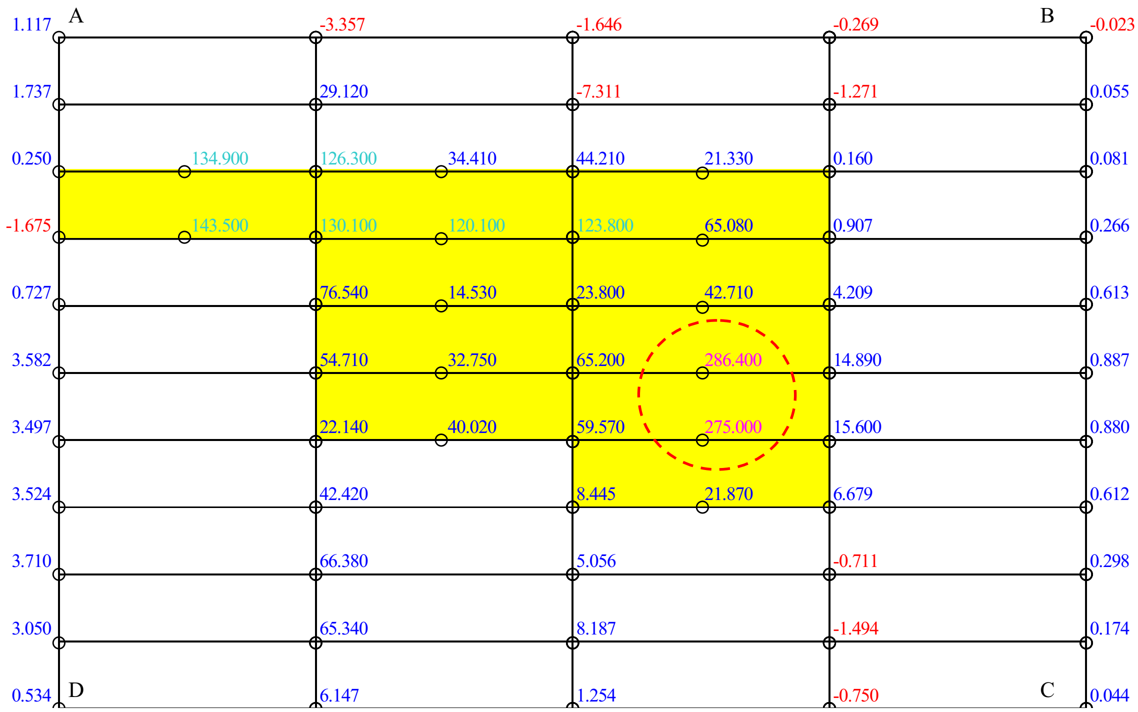


Figure 4-10. Pile reaction force [kips], (using six piles for critical modules)

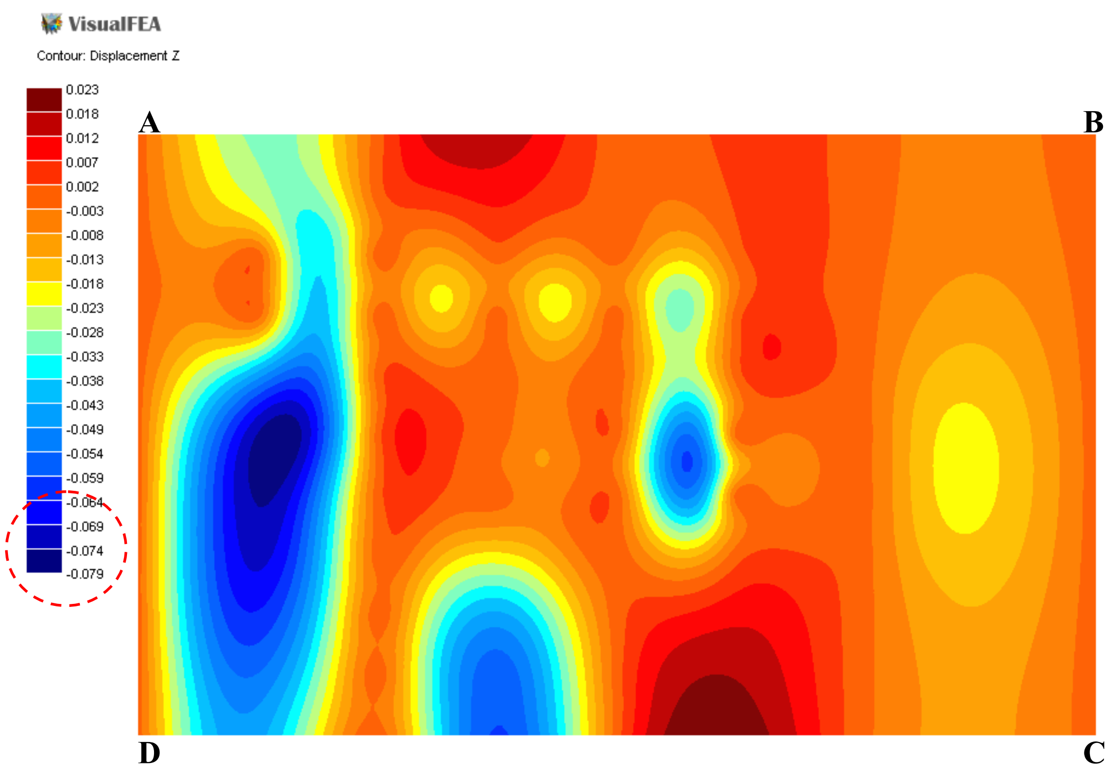


Figure 4-11. Module deformation [ft], (using six piles for critical modules)

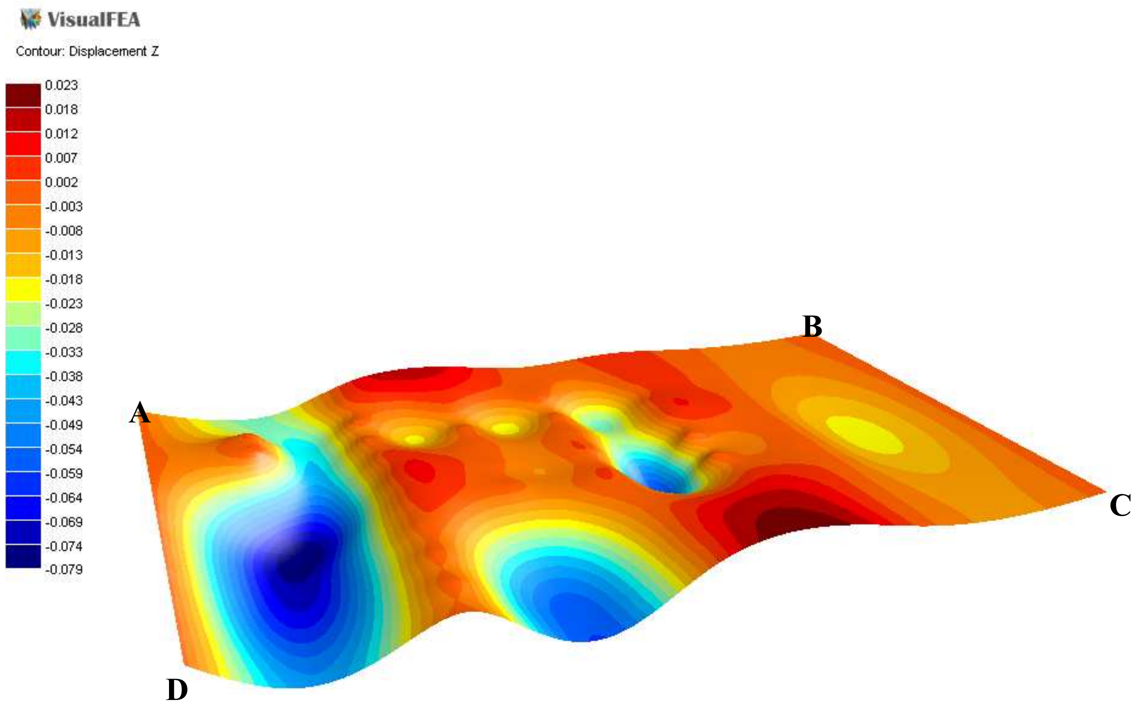


Figure 4-12. Module deformed shape (using six piles for critical modules)

4.2.2.3 LRFD Method

In the case of Rapid Rig, the pile capacity calculations are performed for the driven steel pipe piles and bored piles in accordance with the LRFD method. The maximum reaction force obtained from the Finite Element simulations as described in Section 4.2.2.2 is considered as an applied load for generating the recommended pile selection tables in the Rapid Rig case similar to the tables in the general case. Since this force is the maximum value over the platform, it is conservative to choose one size of pile based on the maximum force and to apply it for all other piles.

As can be seen in Figure 4-10, the reaction forces on most piles besides the two piles right underneath the mast are significantly lower than the maximum reaction value. Therefore, if a single size of pile is used for the whole area, it is not an economical design. Instead, Table 4-3 and 4-5 developed in the general case can be used to choose a proper size for those piles subjected to relatively low reaction forces.

4.2.2.4 Result Summary

Based on the pile capacity calculations in the case of Rapid Rig, two tables (Table 4-8 ~ 4-9) are developed to provide a simple way to choose an appropriate pile size for various soil conditions according to the LRFD method.

Table 4-8. Recommended size of driven piles in the Rapid Rig case (LRFD)

Weight of Rigs & Accessories (Unfactored)	Soil types / Factored max. vertical loads on one pile	Sand & Gravels			Silts & Clays		
		very loose	medium	very dense	soft	medium	hard
		γ_{sat} = 115 pcf G.W.L = 0 ft N_{SPT} = 10 bpf	γ_{sat} = 120 pcf G.W.L = 10 ft N_{SPT} = 30 bpf	γ_{sat} = 127 pcf G.W.L = 20 ft N_{SPT} = 50 bpf	γ_{sat} = 115 pcf G.W.L = 0 ft Su = 0.25 P_o'	γ_{sat} = 120 pcf G.W.L = 10 ft Su = 60 kPa	γ_{sat} = 127 pcf G.W.L = 20 ft Su = 100 kPa
1594 kips	286.4 kips	D = 24 in.	D = 24 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 84 ft	L = 43 ft	L = 23 ft	L = 96 ft	L = 68 ft	L = 48 ft

Table 4-9. Recommended size of bored piles in the Rapid Rig case (LRFD)

Weight of Rigs & Accessories (Unfactored)	Soil types / Factored max. vertical loads on one pile	Sand & Gravels			Silts & Clays		
		very loose	medium	very dense	soft	medium	hard
		γ_{sat} = 115 pcf G.W.L = 0 ft N_{SPT} = 10 bpf	γ_{sat} = 120 pcf G.W.L = 10 ft N_{SPT} = 30 bpf	γ_{sat} = 127 pcf G.W.L = 20 ft N_{SPT} = 50 bpf	γ_{sat} = 115 pcf G.W.L = 0 ft Su = 0.25 P_o'	γ_{sat} = 120 pcf G.W.L = 10 ft Su = 60 kPa	γ_{sat} = 127 pcf G.W.L = 20 ft Su = 100 kPa
1594 kips	286.4 kips	D = 24 in.	D = 24 in.	D = 20 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 75 ft	L = 40 ft	L = 36 ft	L = 137 ft	L = 103 ft	L = 62 ft

(where, P_o' = effective overburden pressure, G.W.L. = ground water depth measured from the ground surface,

4.2.3 Description of an Elevated Platform with Rapid Rig and a Wind Turbine

Generation of power for drilling and production operations by wind is a feasible approach in environmentally sensitive areas. The total vertical load of a wind turbine manufactured by Made, (a Spanish company with a specialty in wind and solar technology), is used for the foundation calculation of the proposed modular platform. Technical characteristics of the wind turbine chosen for this calculation are shown in Table 4-10. The load breakdown and the layout of Rapid Rig with the wind turbine are shown in Table 4-11, Table 4-12, Figure 4-13, and Figure 4-14, respectively. Since the wind load is considerably high for the wind turbine, the operating environmental condition and extreme environmental condition are both considered in this foundation calculation.

Table 4-10. Specification of the wind turbine

Rotor	Rated power	660 kW
	Rotor diameter	46 m
	Power control	1662 m^2
	Yaw system	Upwind, active
	Rotor swept area	1662 m 2
	Number of blades	3
	Blade type	LM 21
	Rotor speed	25,5 / 17 rpm
	Hub height	45 m
	Tilt angle	5º
Weights Estimation	Rotor	12.000 kg
	Nacelle (without rotor)	25.000 kg
	Tower	40.000 kg (43.5 m)
	Total weight	70.000 kg (43.5 tower)

[Source: http://www.made.es/06/english/html/ae_46.html]

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Table 4-11. Load breakdown of Rapid Rig with the wind turbine in operating condition

No.	COMPONENTS	WEIGHTS [lbs] (DEAD)	WEIGHTS [lbs] (LIVE)	Factored Weights [lbs]	Dimension		Notes
				D.L = 1.3	W	L	
				L.L = 1.5			
1.	Substructure/Drillfloor package	80,000		104,000	10	58.5	
2.	Mast including installed equipment	100,000		130,000	18	25	
3.	Drawworks package includes Accumulator unit	70,000		91,000	10	29	
4.	Utilities Skid	25,000		32,500	10	28	
5.	Service Skid	20,000		26,000	10	38.75	
6.	Electrical Control House	30,000		39,000	10	42	
7.	Generator House #1	40,000		52,000	10	27.5	
8.	Generator House #2	40,000		52,000	10	27.5	
9.	Air Compressor House	30,000		39,000	10	27.5	
10.	Mud Pump #1	55,000		71,500	8.75	22	
11.	Mud Pump #2	55,000		71,500	8.75	22	
12.	Pipe Handling equipment	35,000		45,500	3	80	
13.	Control House skid including choke manifold	23,000		29,900	18	12.5	
	Choke Manifold hauled on same trailer	15,000		19,500	7.5	14	
14.	Mud Tank Skid #1 (Empty)	40,000		52,000	11.25	55	
	Mud Tank Skid #1 (Full)		204,750	307,125	11.25	55	375 barrels, 13 lbs/gal
15.	Mud Tank Skid #2 (Empty)	40,000		52,000	11.25	55	
	Mud Tank Skid #2 (Full)		204,750	307,125	11.25	55	375 barrels, 13 lbs/gal
16.	Water Tank (Empty)	20,000		26,000	7.5	45	
	Water Tank (Full)		139,440	209,160	7.5	45	400 barrels, 8.3 lbs/gal
17.	Work shop/Storage Skid	20,000		26,000	10	27.5	
18.	Fuel Tank Skid	10,000		13,000	8	30	
19.	Casing		530,000	795,000	18	25	53 lbs/ft, 10000 ft
20.	Pipes		234,000	351,000	18	25	19.5 lbs/ft, 12000 ft
21.	Collars		2,720	4,080	18	25	80 lbs/ft, 34 ft
22.	Drill collars		60,000	90,000	18	25	6000 lbs x 10
23.	Wind turbine (500 Kw)	154,000		200,200	36	36	
24.							
Total Weights without Casing		902,000	845,660	2,441,090			
Total Weights		902,000	1,375,660	3,236,090			

For the operating environmental condition, the load factors of dead load, live load, and wind load are 1.3, 1.5, and 1.2, respectively.

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Table 4-12. Load breakdown of Rapid Rig with the wind turbine in extreme condition

No.	COMPONENTS	WEIGHTS [lbs] (DEAD)	WEIGHTS [lbs] (LIVE)	Factored Weights [lbs]	Dimension		Notes
				D.L = 1.1 L.L = 1.1	W	L	
1.	Substructure/Drillfloor package	80,000		88,000	10	58.5	
2.	Mast including installed equipment	100,000		110,000	18	25	
3.	Drawworks package includes Accumulator unit	70,000		77,000	10	29	
4.	Utilities Skid	25,000		27,500	10	28	
5.	Service Skid	20,000		22,000	10	38.75	
6.	Electrical Control House	30,000		33,000	10	42	
7.	Generator House #1	40,000		44,000	10	27.5	
8.	Generator House #2	40,000		44,000	10	27.5	
9.	Air Compressor House	30,000		33,000	10	27.5	
10.	Mud Pump #1	55,000		60,500	8.75	22	
11.	Mud Pump #2	55,000		60,500	8.75	22	
12.	Pipe Handling equipment	35,000		38,500	3	80	
13.	Control House skid including choke manifold	23,000		25,300	18	12.5	
	Choke Manifold hauled on same trailer	15,000		16,500	7.5	14	
14.	Mud Tank Skid #1 (Empty)	40,000		44,000	11.25	55	
	Mud Tank Skid #1 (Full)		204,750	225,225	11.25	55	375 barrels, 13 lbs/gal
15.	Mud Tank Skid #2 (Empty)	40,000		44,000	11.25	55	
	Mud Tank Skid #2 (Full)		204,750	225,225	11.25	55	375 barrels, 13 lbs/gal
16.	Water Tank (Empty)	20,000		22,000	7.5	45	
	Water Tank (Full)		139,440	153,384	7.5	45	400 barrels, 8.3 lbs/gal
17.	Work shop/Storage Skid	20,000		22,000	10	27.5	
18.	Fuel Tank Skid	10,000		11,000	8	30	
19.	Casing		530,000	583,000	18	25	53 lbs/ft, 10000 ft
20.	Pipes		234,000	257,400	18	25	19.5 lbs/ft, 12000 ft
21.	Collars		2,720	2,992	18	25	80 lbs/ft, 34 ft
22.	Drill collars		60,000	66,000	18	25	6000 lbs x 10
23.	Wind turbine (500 Kw)	154,000		169,400	36	36	
24.							
Total Weights without Casing		902,000	845,660	1,922,426			
Total Weights		902,000	1,375,660	2,505,426			

For the extreme environmental condition, the load factors of dead load, live load, and wind load are 1.1, 1.1, and 1.35, respectively.

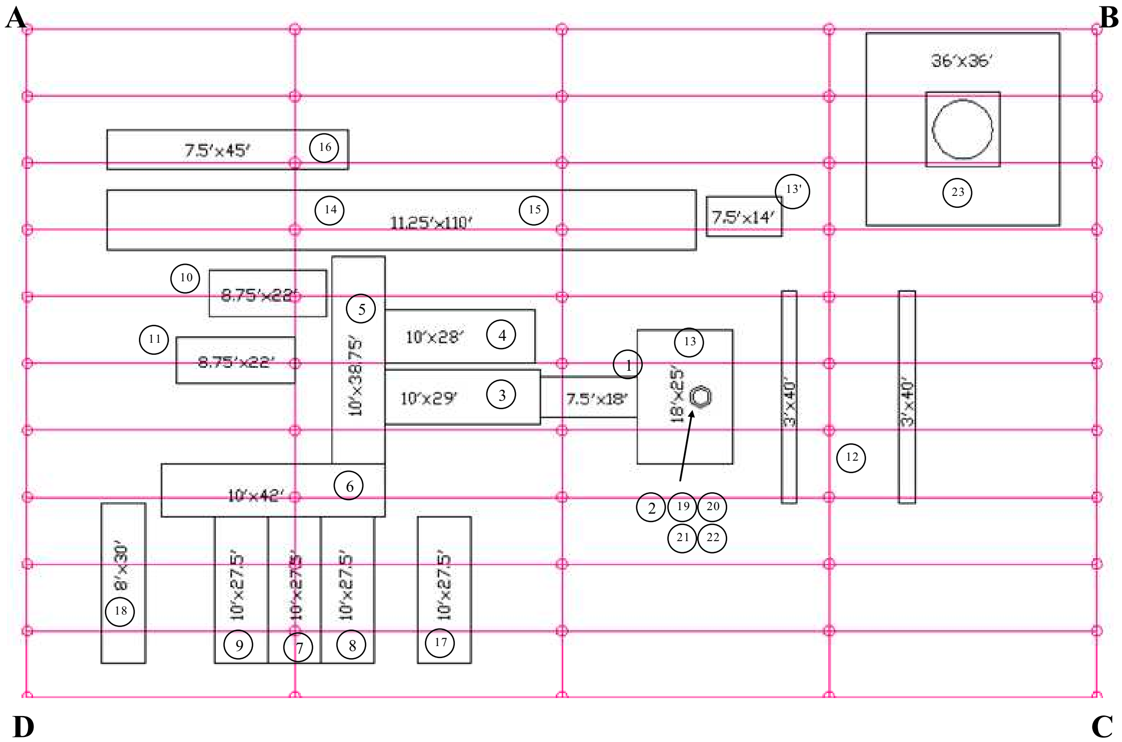


Figure 4-13. Layout of Rapid Rig and the wind turbine

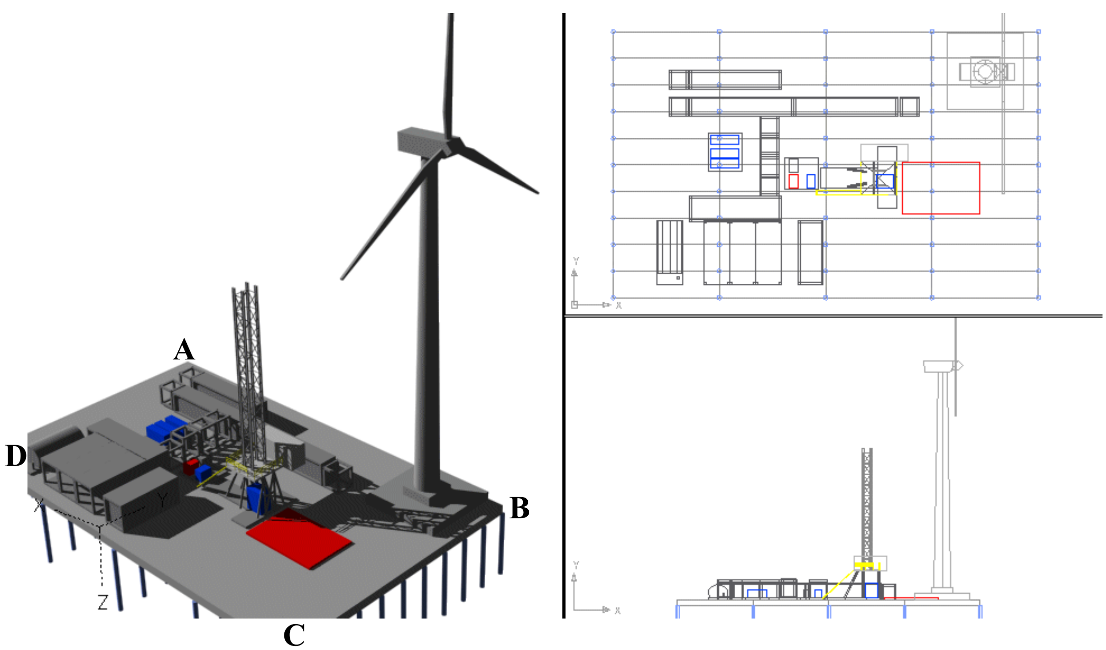


Figure 4-14. Three dimensional (3-D) layout of Rapid Rig and the wind turbine

4.2.3.1 Soil Condition

The six soil conditions adopted for the general foundation calculations are used for this foundation calculation (i.e., very dense, medium, very loose for sand; hard, medium, soft for clay).

4.2.3.2 Weight Distribution on Platform

In order to calculate the load distribution of Rapid Rig with the wind turbine on the proposed modular platform, a numerical analysis program, VisualFEA, is used. Since the height of the wind turbine is around 150 ft, the wind load should be considered in this analysis. Following assumptions are made to perform the numerical analysis for this problem:

1. Young's modulus (E) for the aluminum material of each module is 1.44E + 09 psf.
2. The modules are represented by a 6 inches thick plate.
3. Self weight of modules is not considered in this analysis.
4. Rigid boundary conditions are adopted (The supports of the platform do not settle).

Four node quadrilateral elements are used in this analysis and the applied load layout of Rapid Rig with the wind turbine is shown in Figure 4-15.

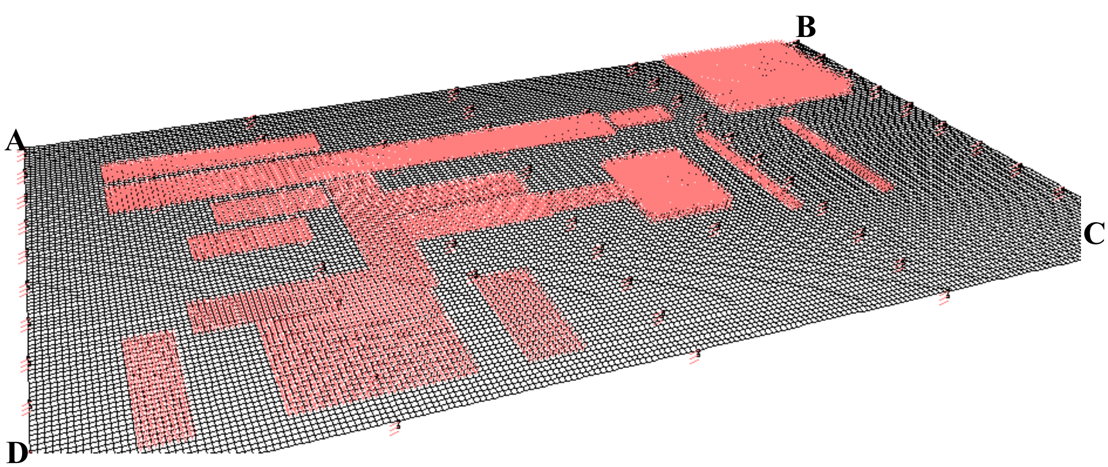


Figure 4-15. Applied load layout of Rapid rig and the wind turbine

The pile reaction forces and the deformation of the deck on the modules are calculated by using only four piles for each module as shown in Figures 4-16 ~ 4-21. According to the results, the most critical pile reaction force and deformation for the operating environmental condition and the extreme environmental condition are 221.7 kips, 0.909 ft, 167.4 kips, and 1.054 ft, respectively. Since 1.0 ft is not an acceptable deformation, several critical modules are required to have six piles, each. The results of the analysis using six piles for critical modules are shown in Figure 4-22 ~ 4-27.

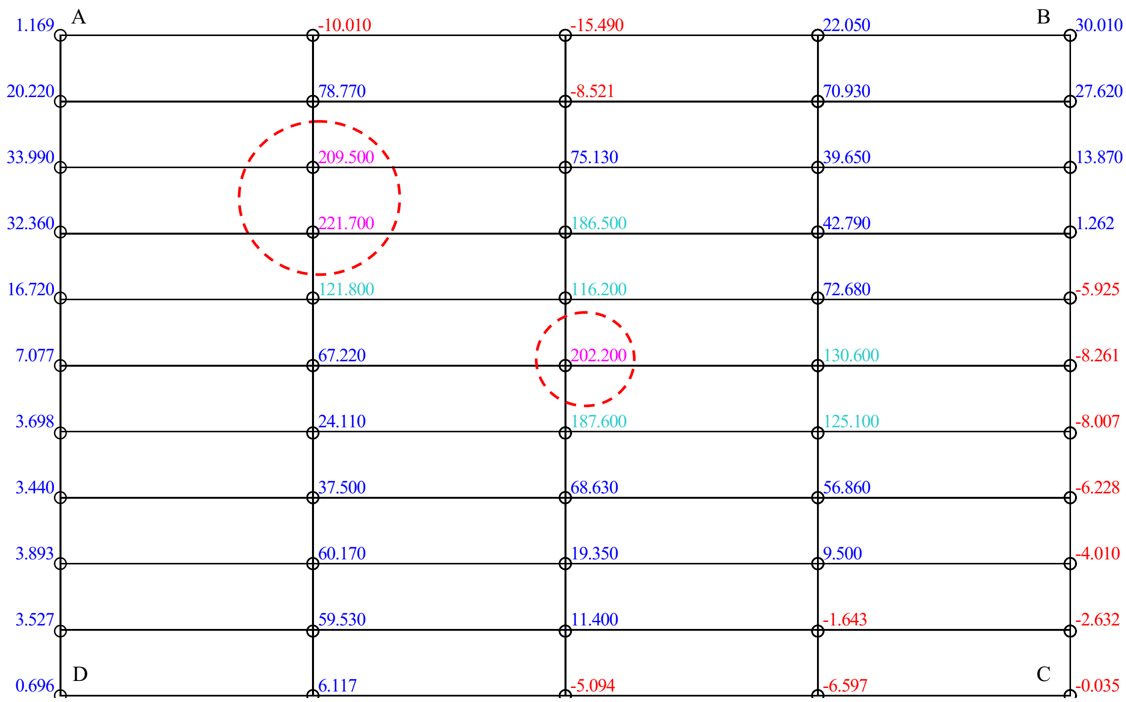


Figure 4-16. Pile reaction force [kips] in operating condition

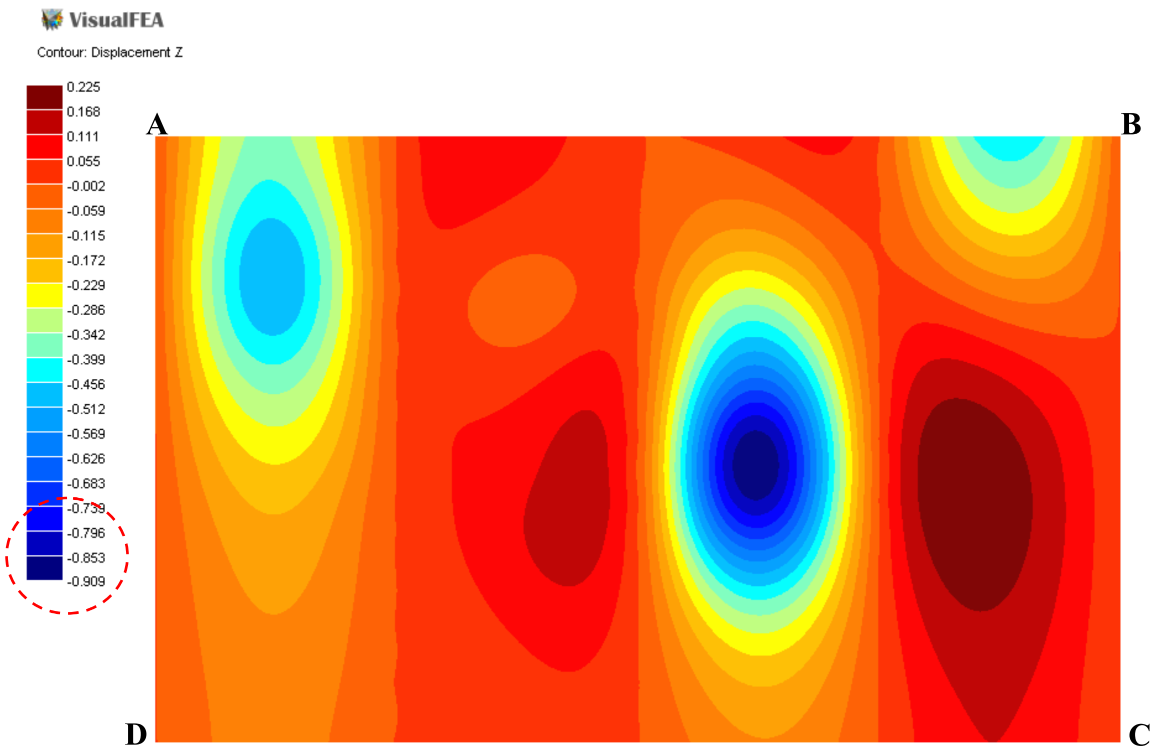


Figure 4-17. Module deformation [ft] in operating condition

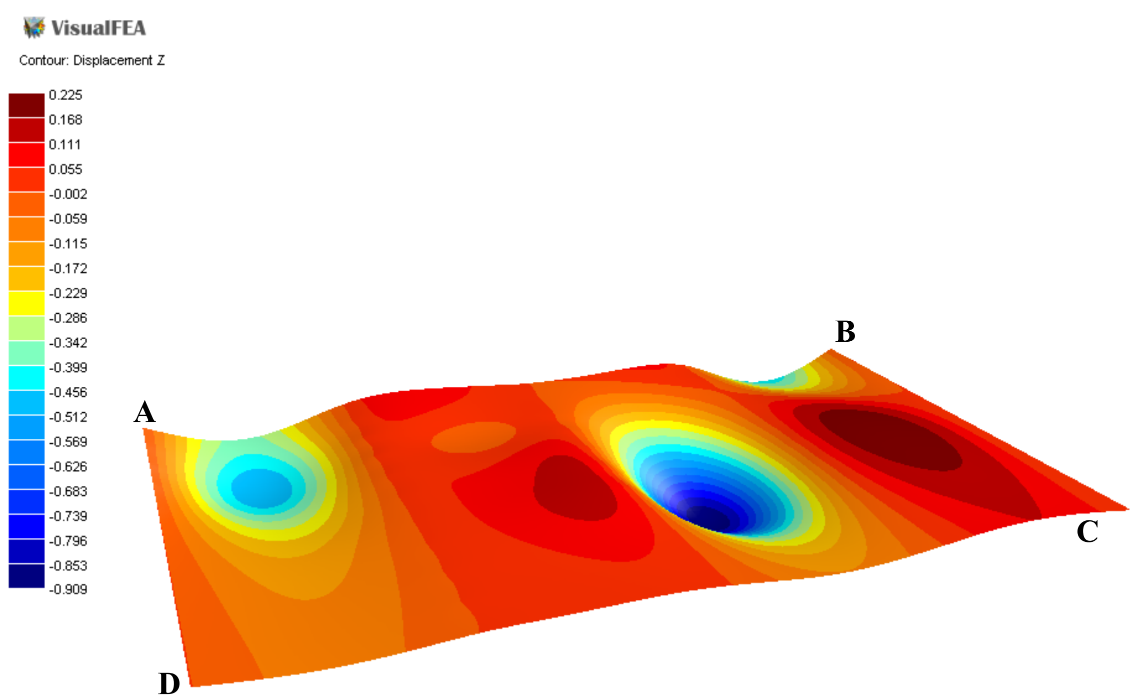


Figure 4-18. Module deformed shape in operating condition

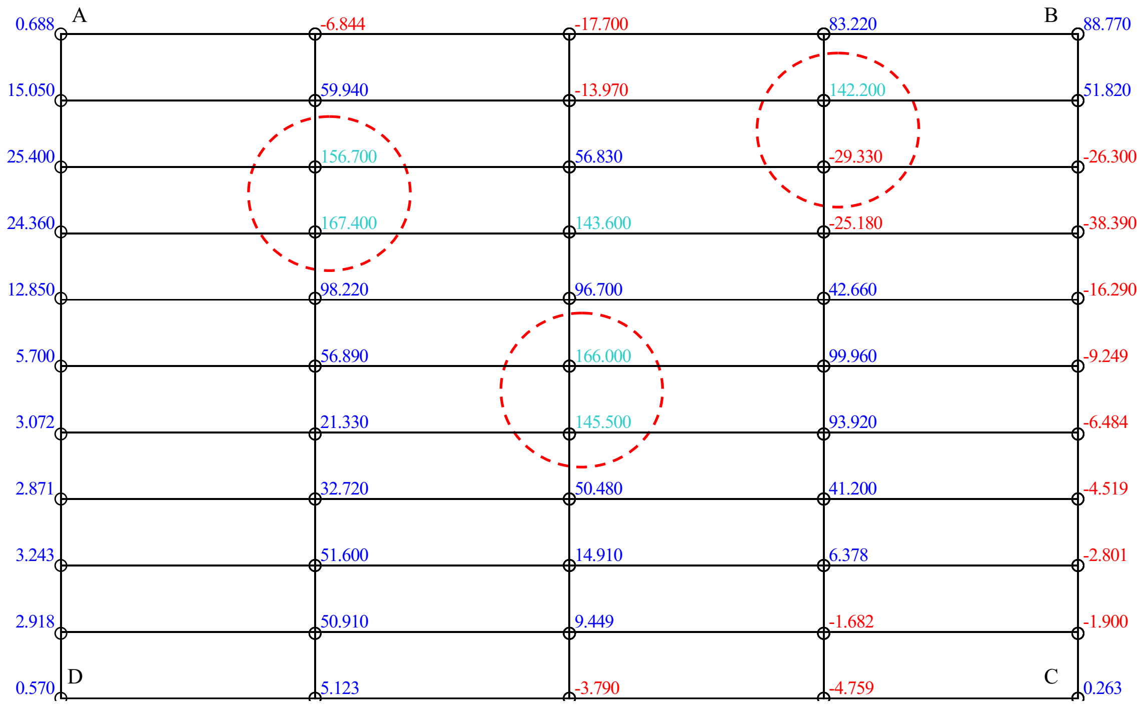


Figure 4-19. Pile reaction force [kips] in extreme condition

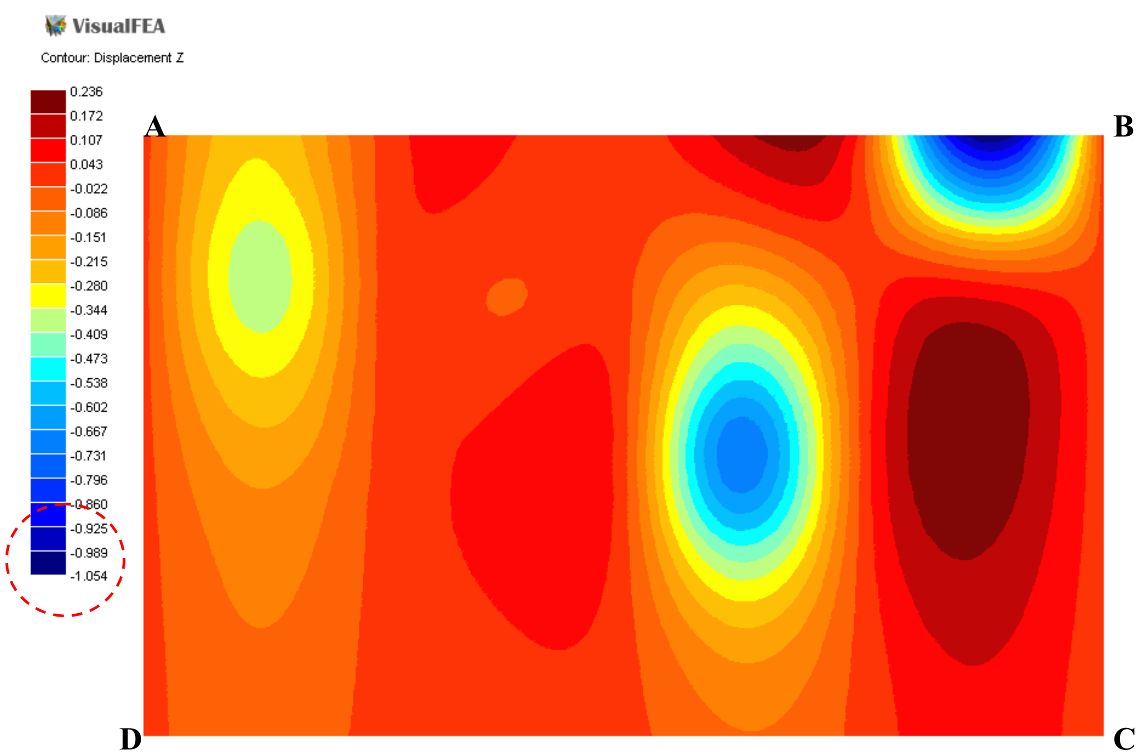


Figure 4-20. Module deformation [ft] in extreme condition

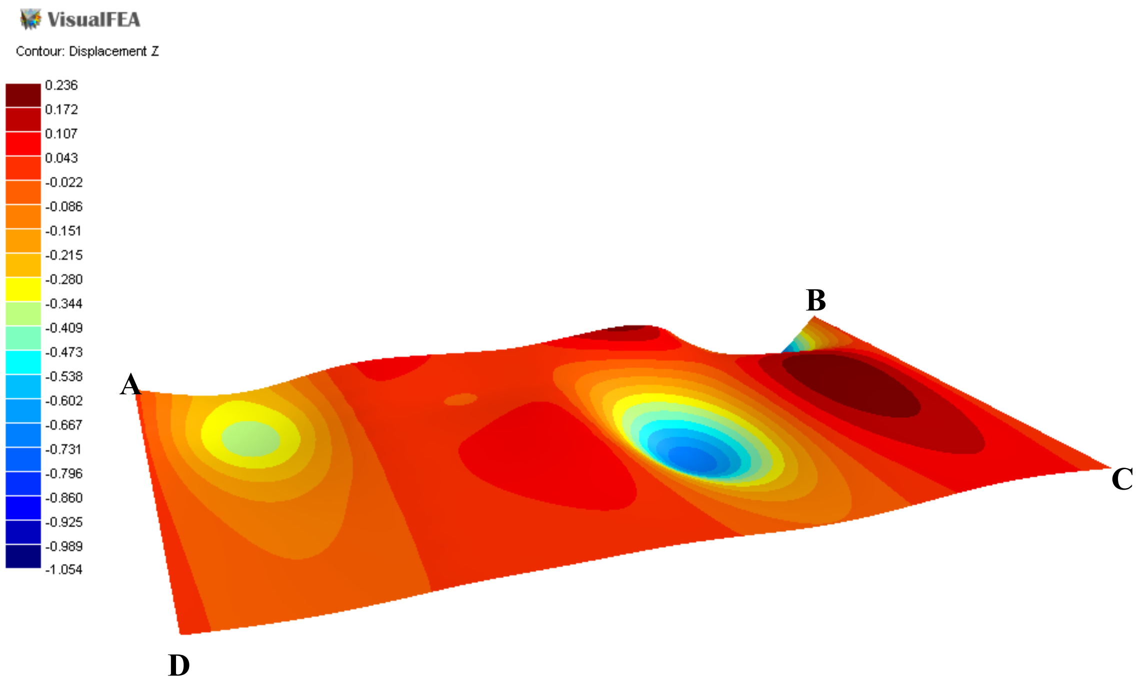


Figure 4-21. Module deformed shape in extreme condition

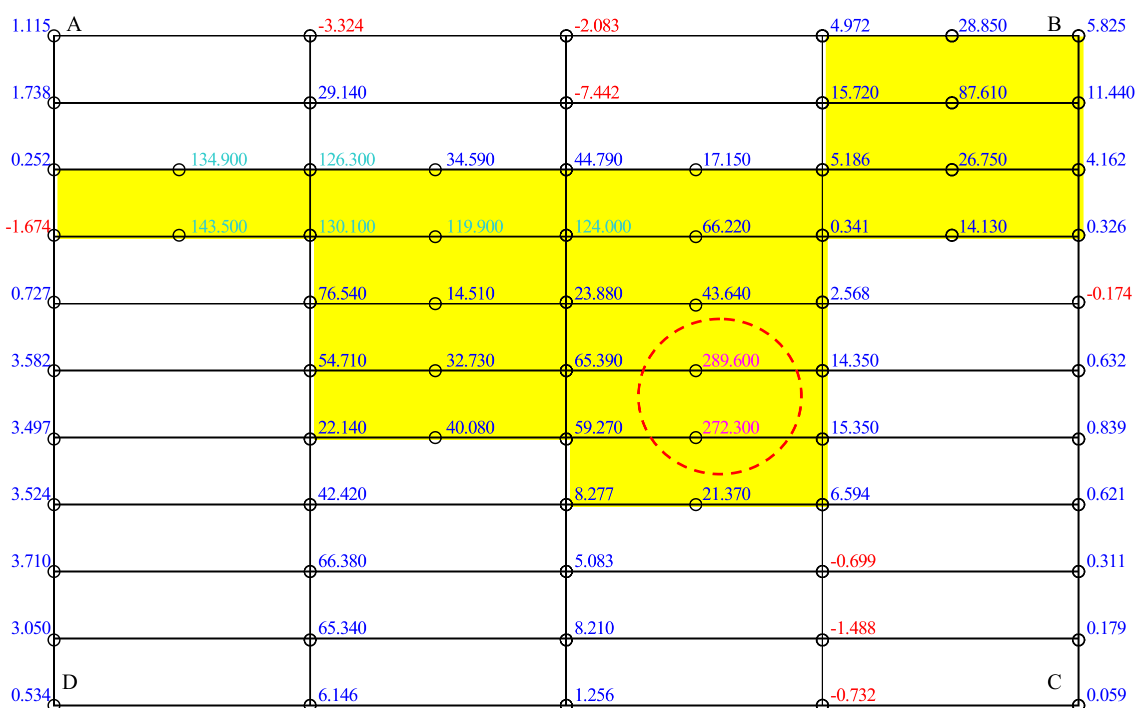


Figure 4-22. Reaction force [kips] in operating condition (using six piles)

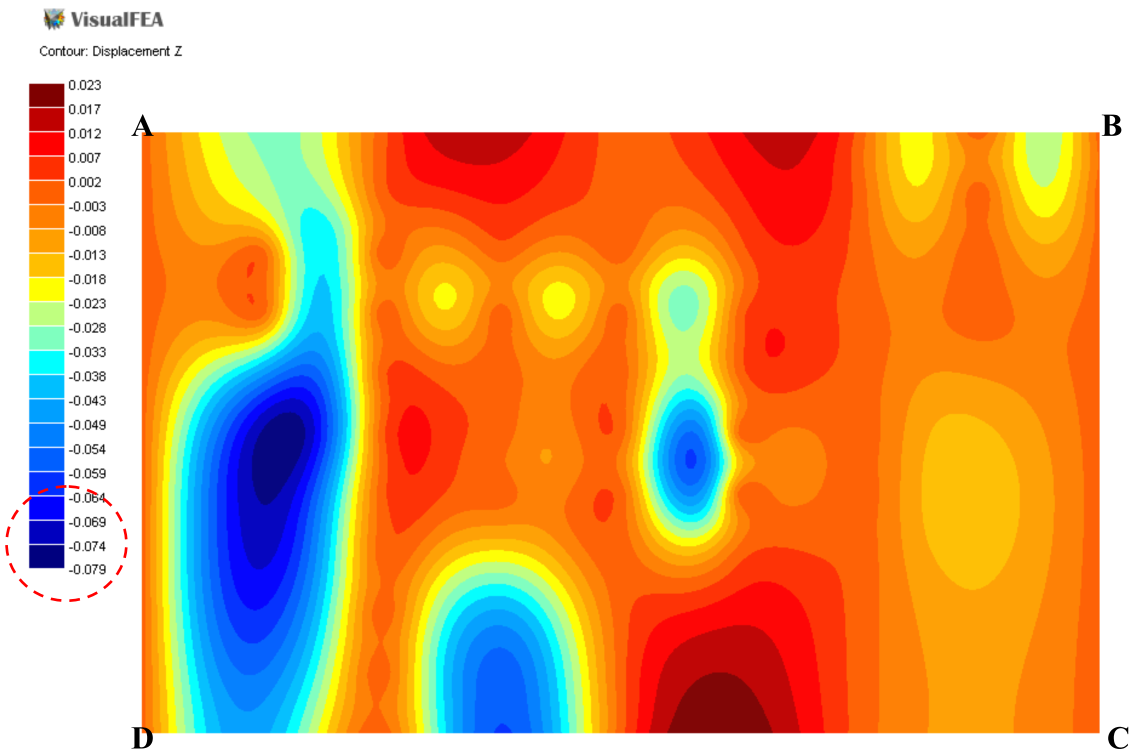


Figure 4-23. Module deformation [ft] in operating condition

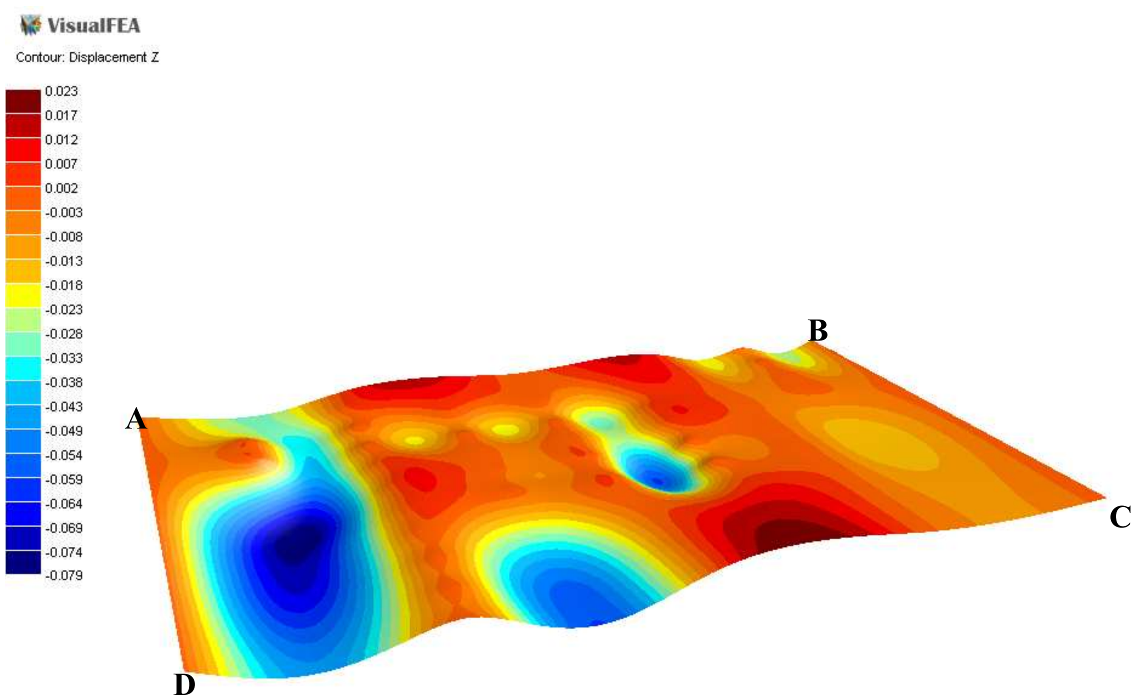


Figure 4-24. Module deformed shape in operating condition

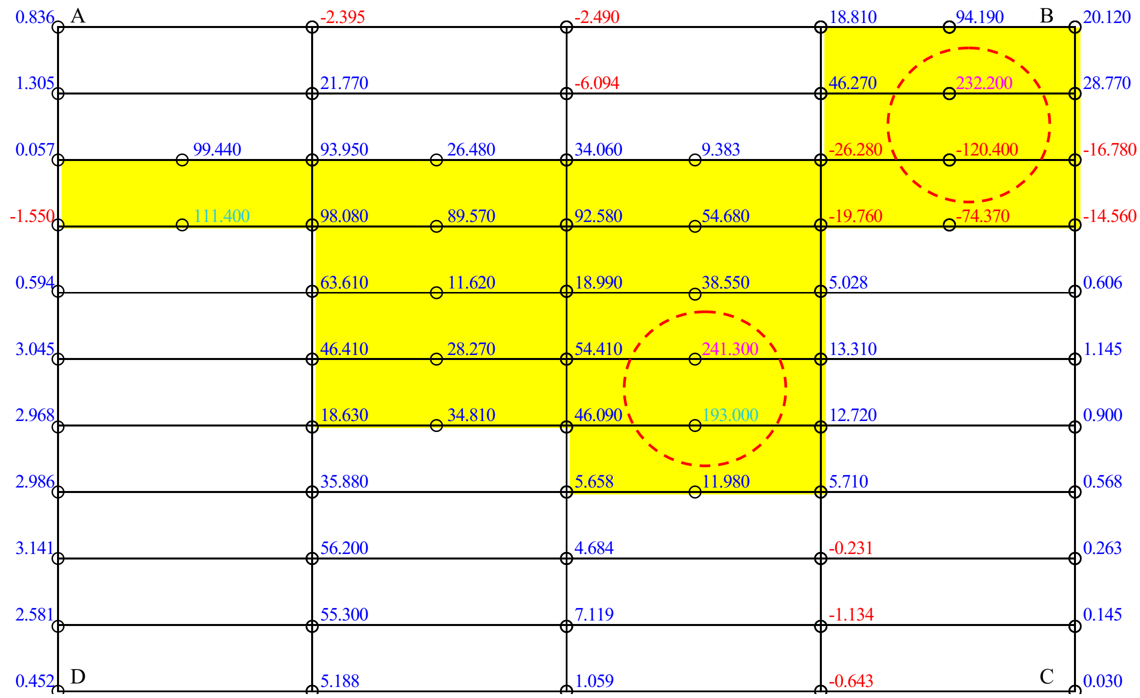


Figure 4-25. Reaction force [kips] in extreme condition (using six piles)

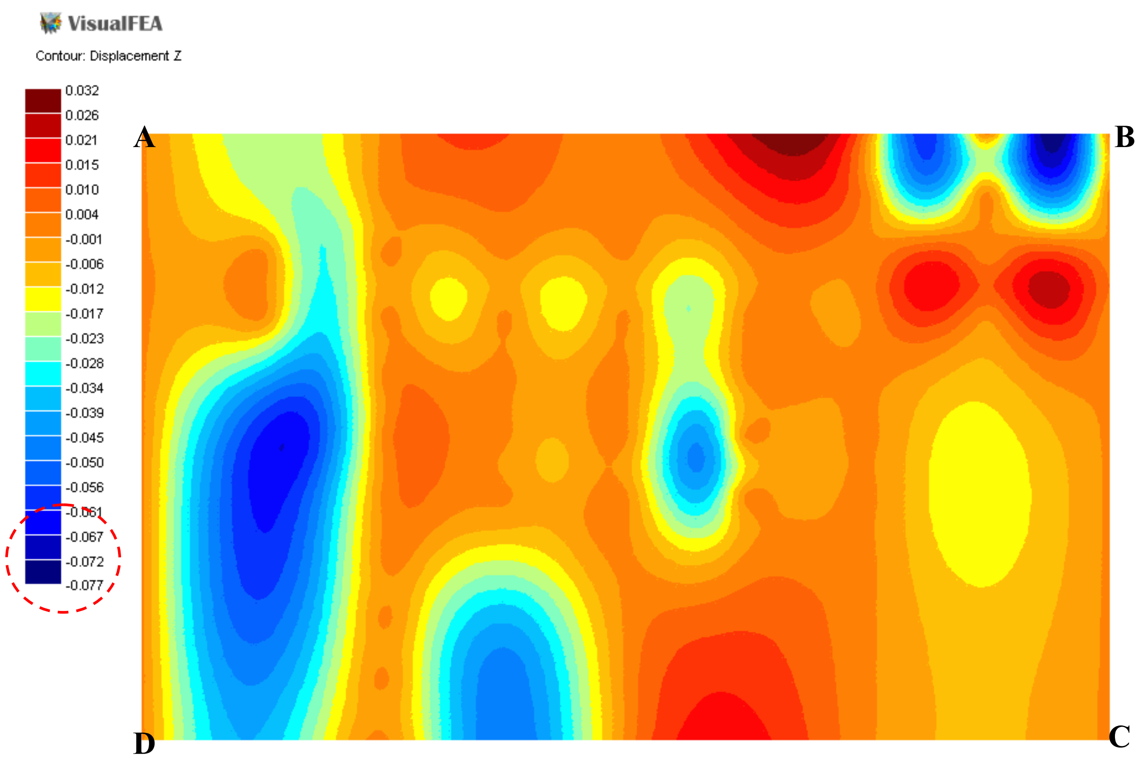


Figure 4-26. Module deformation [ft] in extreme condition

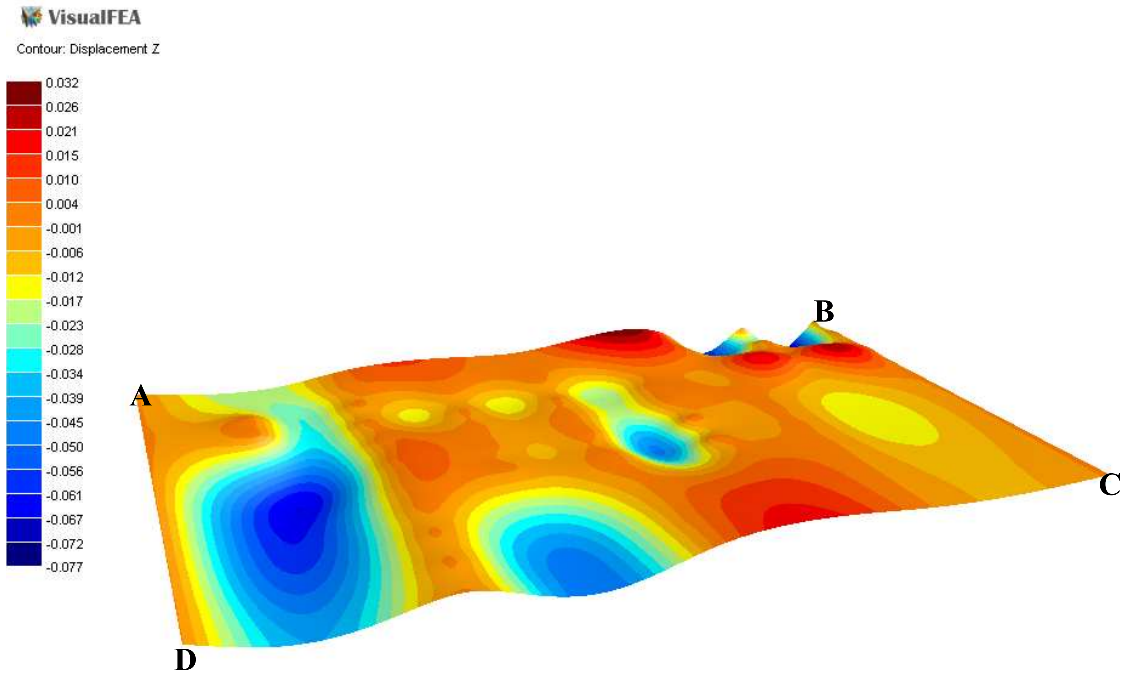


Figure 4-27. Module deformed shape in operating condition

4.2.3.3 LRFD Method

In the case of Rapid Rig and the wind turbine, the pile capacity calculations are performed for the driven steel pipe piles and bored piles in accordance with the LRFD method. The maximum reaction force obtained from the 3-D simulations as described in Section 4.2.3.2 is considered as an applied load for generating the recommended pile selection tables in the Rapid Rig with wind turbine case similar to the tables in the general case. Since this force is the maximum value over the platform, it is conservative to choose one size of pile based on the maximum force and to apply it for all other piles.

As can be seen in Figure 4-22 and Figure 4-25, the reaction forces on most piles besides the four piles right underneath the mast and the wind turbine are significantly lower than the maximum reaction value. Therefore, if a single size of pile is used for the whole area, it is not an economical design. Instead, Table 4-3 and 4-5 developed in the general case can be used to choose a proper size for those piles subjected to relatively low reaction forces.

4.2.3.4 Result Summary

Based on the pile capacity calculations in the case of Rapid Rig with the wind turbine, two tables (Table 4-13 ~ 4-14) are developed to provide a simple way to choose an appropriate pile size for various soil conditions according to the LRFD method.

Table 4-13. Recommended size of driven piles in the Rapid Rig with wind turbine case

Weight of Rigs & Accessories (Unfactored)	Soil types / Factored max. vertical loads on one pile	Sand & Gravels			Silts & Clays		
		very loose	medium	very dense	soft	medium	hard
		γ_{sat} = 115 pcf G.W.L = 0 ft N_{SPT} = 10 bpf	γ_{sat} = 120 pcf G.W.L = 10 ft N_{SPT} = 30 bpf	γ_{sat} = 127 pcf G.W.L = 20 ft N_{SPT} = 50 bpf	γ_{sat} = 115 pcf G.W.L = 0 ft Su = 0.25 P_o'	γ_{sat} = 120 pcf G.W.L = 10 ft Su = 60 kPa	γ_{sat} = 127 pcf G.W.L = 20 ft Su = 100 kPa
1748 kips	289.6 kips	D = 24 in.	D = 24 in.	D = 16 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 84 ft	L = 43 ft	L = 33 ft	L = 96 ft	L = 68 ft	L = 49 ft

(where, P_o' = effective overburden pressure, G.W.L. = ground water depth measured from the ground surface,

Table 4-14. Recommended size of bored piles in the Rapid Rig with wind turbine case

Weight of Rigs & Accessories (Unfactored)	Soil types / Factored max. vertical loads on one pile	Sand & Gravels			Silts & Clays		
		very loose	medium	very dense	soft	medium	hard
		γ_{sat} = 115 pcf G.W.L = 0 ft N_{SPT} = 10 bpf	γ_{sat} = 120 pcf G.W.L = 10 ft N_{SPT} = 30 bpf	γ_{sat} = 127 pcf G.W.L = 20 ft N_{SPT} = 50 bpf	γ_{sat} = 115 pcf G.W.L = 0 ft Su = 0.25 P_o'	γ_{sat} = 120 pcf G.W.L = 10 ft Su = 60 kPa	γ_{sat} = 127 pcf G.W.L = 20 ft Su = 100 kPa
1748 kips	289.6 kips	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.	D = 24 in.
		L = 76 ft	L = 40 ft	L = 29 ft	L = 137 ft	L = 104 ft	L = 62 ft

(where, P_o' = effective overburden pressure, G.W.L. = ground water depth measured from the ground surface,

4.2.4 Construction Strategies of Pile Foundation

In this section, four different construction methods of a driven steel pipe pile for an elevated platform with Rapid Rig are described for one specific soil condition with the LRFD method. The soil condition is assumed "Very dense sand" and the required soil parameters are shown in Figure 4-28.

Rapid Rig is placed on the platform as shown in Figure 4-29. It is noted that the layout shown in Figure 4-29 is not the same as the one shown in Figure 4-4. This is because EFD subject matter experts decided to reduce the number of modules being used in this study as many as possible since the cost of each module is very high. The refined platform consists of 24 aluminum modules (40 modules were initially used in Figure 4-4) and 45 piles as shown in Figure 4-30. Figure 4-30 also shows the reaction force on each pile and each pile is numbered as shown in Figure 4-31. The dimension of each component of Rapid Rig is provided by National Oilwell Varco.

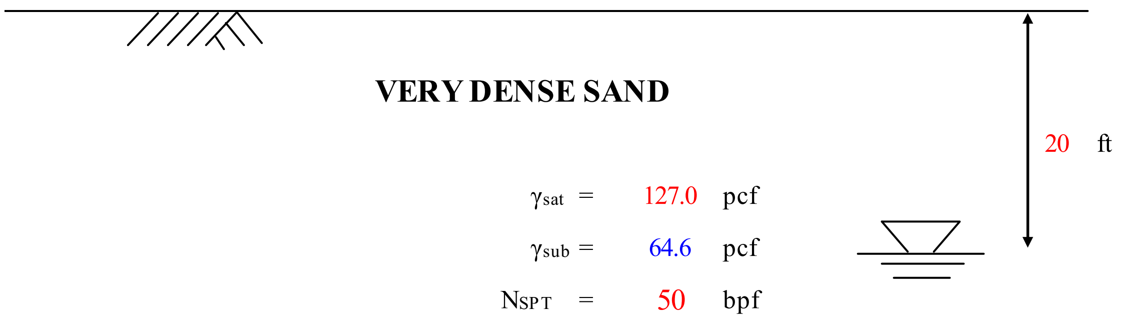


Figure 4-28. Assumed soil condition

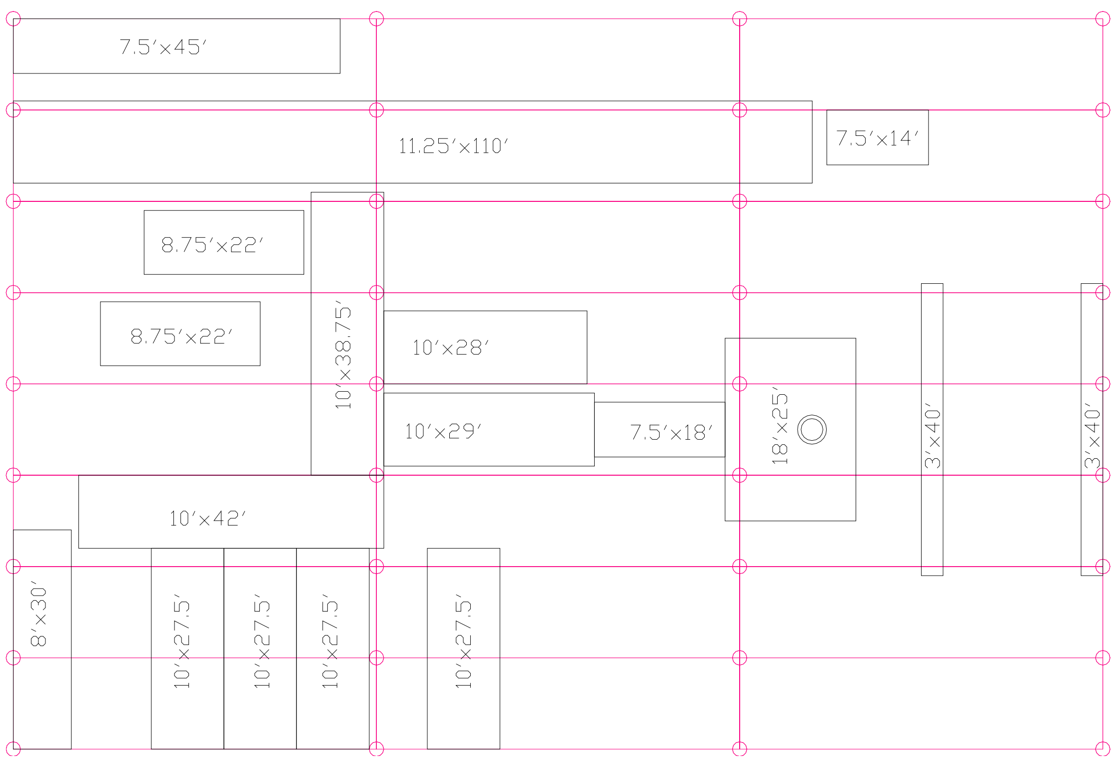


Figure 4-29. Layout of Rapid Rig on the elevated platform

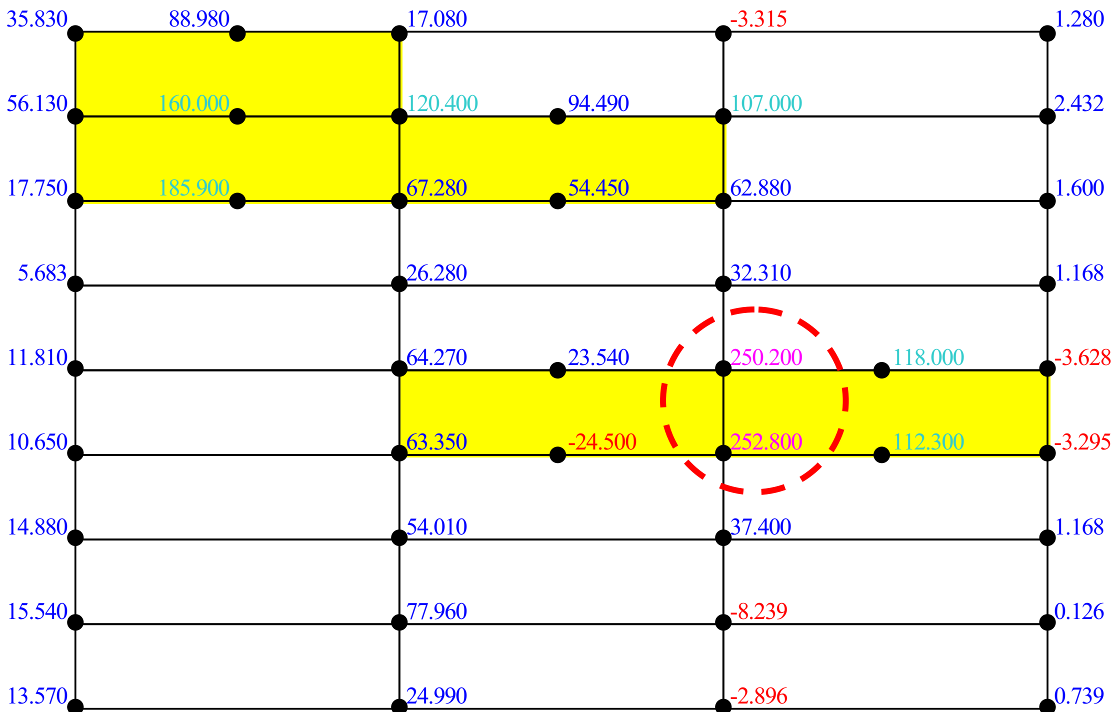


Figure 4-30. Reaction force on each pile [kips]

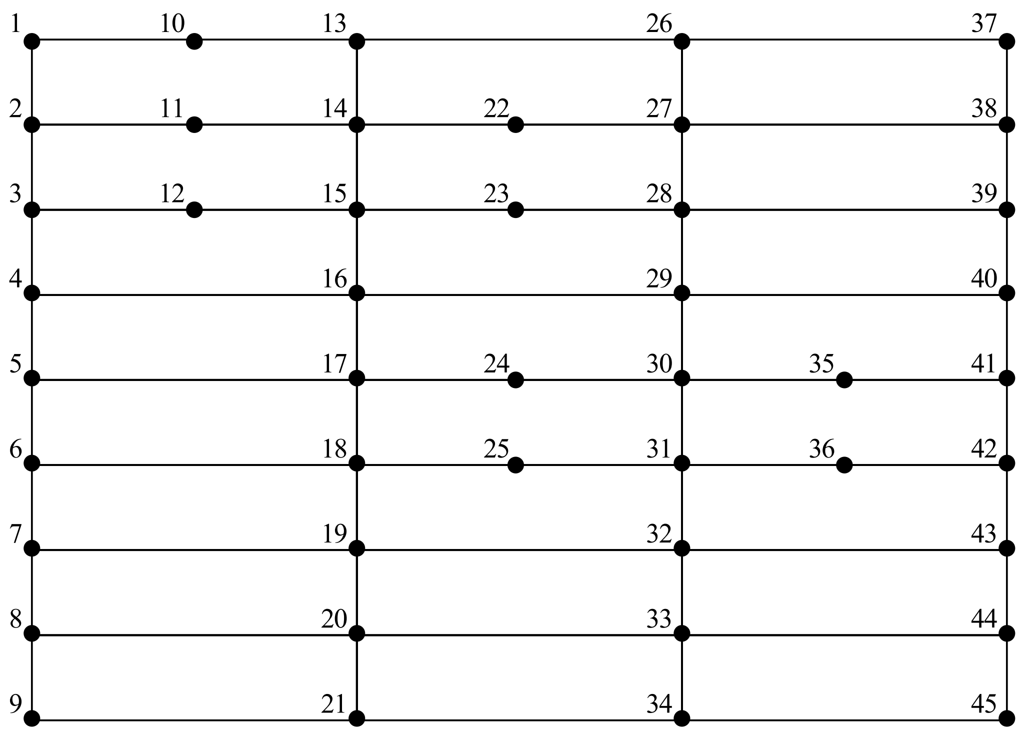


Figure 4-31. Numbers assigned to each pile

In order to estimate the cost of pile foundations, “RSMeans”, the reference book of construction cost information, and several EFD experts’ inputs are used in this study. After gathering the cost information, Eq. (4-3) is developed to be used for the cost estimation of piles. Eq. (4-3) is the best fit for the piles, the range from 10 to 24 inches in diameter and from 10 to 100 feets in length.

$$\text{Cost} = [50 + (D - 10) \times 2.8] \times L \tag{4-3}$$

where D is the diameter in inches and L is the length in feets.

Four different construction strategies of pile foundation are described as follows:

1. Optimal pile size for each pile: for each pile with its reaction force, an exhaustive search optimization routine is run to find the optimized pile size (i.e., diameter and length). Once all possible pile sizes, which satisfy the pile capacity design criteria described in Section 3.2, have been evaluated, the size with the lowest cost is the best pile size. Table 4-15 shows the optimized pile size and cost for each pile.
2. Using same piles for the entire platform area: This is the simplest method to construct piles. Since no. 31 and no. 32 piles shown in Figure 4-31 sustain the biggest applied load among all 45 piles, the pile size of no. 31 and no. 32 are used for the entire platform area. Table 4-16 shows the total cost of using this method.
3. Using two piles: Since the reaction forces on only two piles (no. 31 and 32) are significantly greater than other piles, two pile sizes are used. One is for those two piles (no. 31 and 32) and the other one is for the remaining piles. Table 4-17 shows the total cost of using this method.
4. Categorized by reaction forces: This method categorizes pile size by three different reaction forces: (1) the reaction force is greater than 200 kips; (2) the reaction force is greater than 100 kips and less than or equal to 200 kips; (3) the reaction force is less than or equal to 100 kips. Table 4-18 shows the total cost of using this method.

Table 4-15. Optimal pile size and cost for each pile

Pile no.	Diameter (in.)	Length (ft)	Quantities	Total	Pile no.	Diameter (in.)	Length (ft)	Quantities	Total
1	10	11	1	$550.00	24	10	10	1	$500.00
2	14	10	1	$612.00	25	12	16	1	$889.60
3	10	10	1	$500.00	26	10	10	1	$500.00
4	10	10	1	$500.00	27	20	10	1	$780.00
5	10	10	1	$500.00	28	16	10	1	$668.00
6	10	10	1	$500.00	29	10	10	1	$500.00
7	10	10	1	$500.00	30	24	15	1	$1,338.00
8	10	10	1	$500.00	31	24	15	1	$1,338.00
9	10	10	1	$500.00	32	12	10	1	$556.00
10	18	10	1	$724.00	33	10	11	1	$550.00
11	24	11	1	$981.20	34	10	10	1	$500.00
12	24	12	1	$1,070.40	35	22	10	1	$836.00
13	10	10	1	$500.00	36	20	10	1	$780.00
14	22	10	1	$836.00	37	10	10	1	$500.00
15	16	10	1	$668.00	38	10	10	1	$500.00
16	10	10	1	$500.00	39	10	10	1	$500.00
17	16	10	1	$668.00	40	10	10	1	$500.00
18	16	10	1	$668.00	41	10	10	1	$500.00
19	14	10	1	$612.00	42	10	10	1	$500.00
20	18	10	1	$724.00	43	10	10	1	$500.00
21	10	10	1	$500.00	44	10	10	1	$500.00
22	20	10	1	$780.00	45	10	10	1	$500.00
23	14	10	1	$612.00			∑	45	$28,741.20

Table 4-16. Pile size for "using same pile" method

Pile no.	Diameter (in.)	Length (ft)	Quantities	Total
all	24	15	45	$60,210.00
		∑	45	$60,210.00

Table 4-17. Pile size for "using two piles" method

Pile no.	Diameter (in.)	Length (ft)	Quantities	Total
30 & 31	24	15	2	$2,676.00
others	24	12	43	$46,027.00
		∑	45	$48,703.00

Table 4-18. Pile size for "categorized by reaction forces" method

Category	Diameter (in.)	Length (ft)	Quantities	Total
P > 200 kips	24	15	2	$2,676.00
100 < P ≤200	24	12	6	$6,422.00
P ≤ 100	20	10	37	$28,860.00
		∑	45	$37,958.00

4.2.5 Lessons Learned

Conventional onshore drilling for oil and gas consists of placing a gravel pad for leveling and carrying capacity purposes. The use of an elevated platform as an alternative to the gravel pad is less intrusive and leads to a more environmentally friendly approach to oil and gas drilling. Since elevated drilling platforms require the use of piles, many different cases of pile design are conducted through Section 4.2 to give site location engineers a basic idea about pile foundation designs of a platform for various platform weights and soil conditions. The four different construction strategies of pile foundation are also described in Section 4.2.4. "Using optimal pile size for each pile" method is the least expensive method while "using same pile size for the entire platform" method is the most expensive method. However, in real construction, some other construction factors such as pile set up time and possibility of wrong pile placement are also required to be considered. Therefore, site location engineers should select the appropriate pile construction strategy based on each site condition.

4.3 Feasibility of Using Composite Mat System in Drilling Sites

Another alternative of environmentally friendly foundations for drill sites is composite mats. Since the total construction cost of an elevated platform is considerably high and the construction is time consuming, a composite mat system can be a good alternative to the gravel pad. DURA-BASE Composite Mat System from Newpark mats and Integrated Services is considered for the feasibility study in this section.

4.3.1 Specification of DURA-BASE Composite Mat System

The large size of DURA-BASE Composite Mat System is used in this feasibility study. Table 4-19 shows the specification of this mat. More specific information about this mat system can be found in the following website (http://www.newparkmats.com).

Table 4-19. Brief information about DURA-BASE Composite Mat System

Dimensions	8 ft wide, 14 ft long, and 4 inches depth (for one layer)
Weight	1,050 lbs
Material	High density polyethylene
Young's Modulus	1 GPa ≈ 2.09e+07 psf
Purchase rate	$\$20.50/ft^2$ (the rate was obtained in 2006)
Rent rate (90 days)	$\$2.00/ft^2$ (the rate subject to change)

4.3.2 Finite Element Analysis for the Composite Mat System

In order to conduct a parametric study of the composite mat, a finite element mesh (i.e., two-dimensional axisymmetric mesh and three node triangular elements) is generated using a numerical analysis program, VisualFEA as shown in Figure 4-32. For this parametric study, the applied load area is varied from 6 inches to 10 feets in diameter (i.e., D = 0.5, 1.0, 2.0, 4.0, 6.0, and 10 ft) and the ratio of Young's Modulus between the composite mat and the soil is varied from 1 to 100 (i.e., 1, 10, 20, and 100). The results of the analysis are summarized by ρ-values. The ρ-values are calculated by $P_{(max)}$ / $P_{(applied)}$. The $P_{(applied)}$ is the applied load on the mat system and the $P_{(max)}$ is the maximum pressure obtained from the ground. In this parametric analysis, the applied load is 1 psf and the result summary is shown in Table 4-20. In order to better display the results, result graphs are summarized as shown in Figure 4-33.

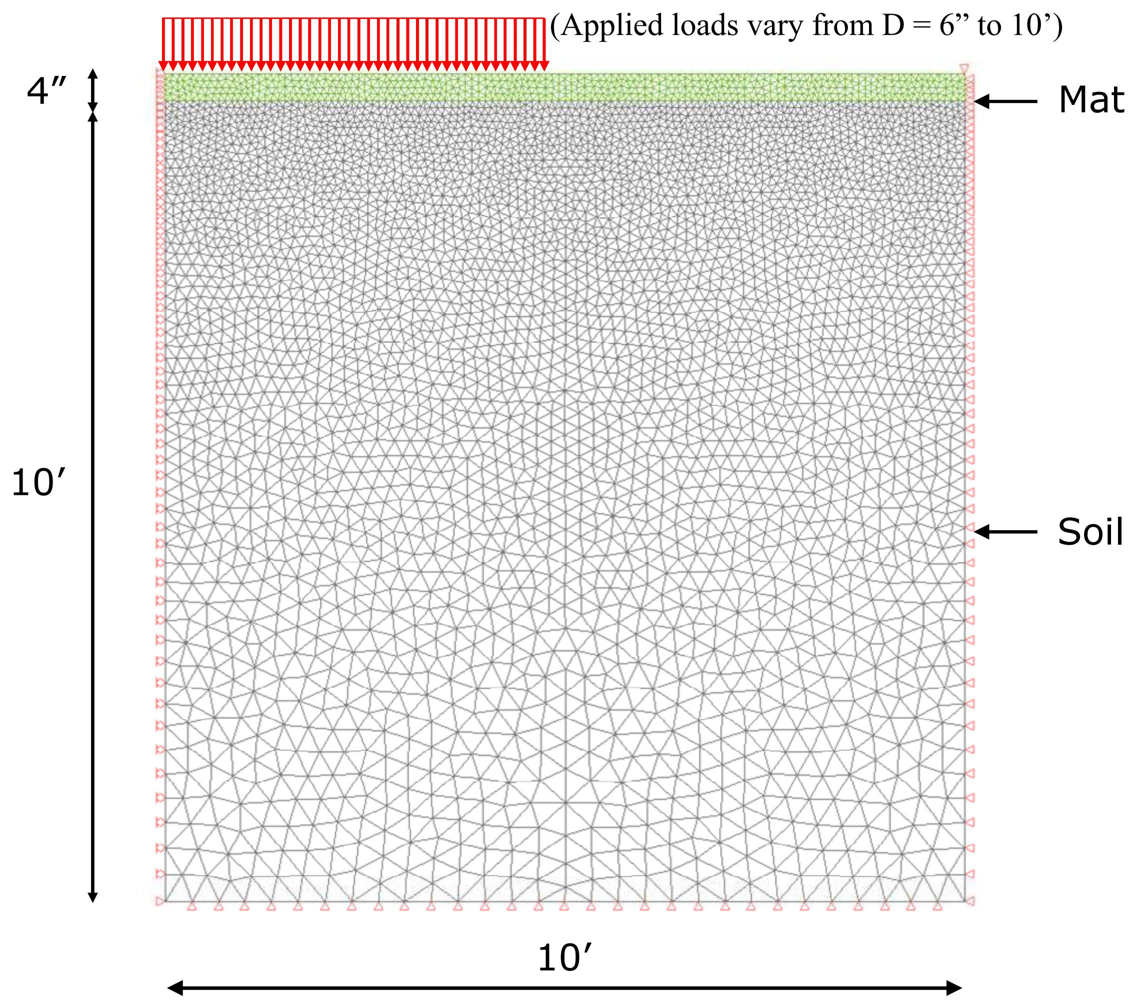
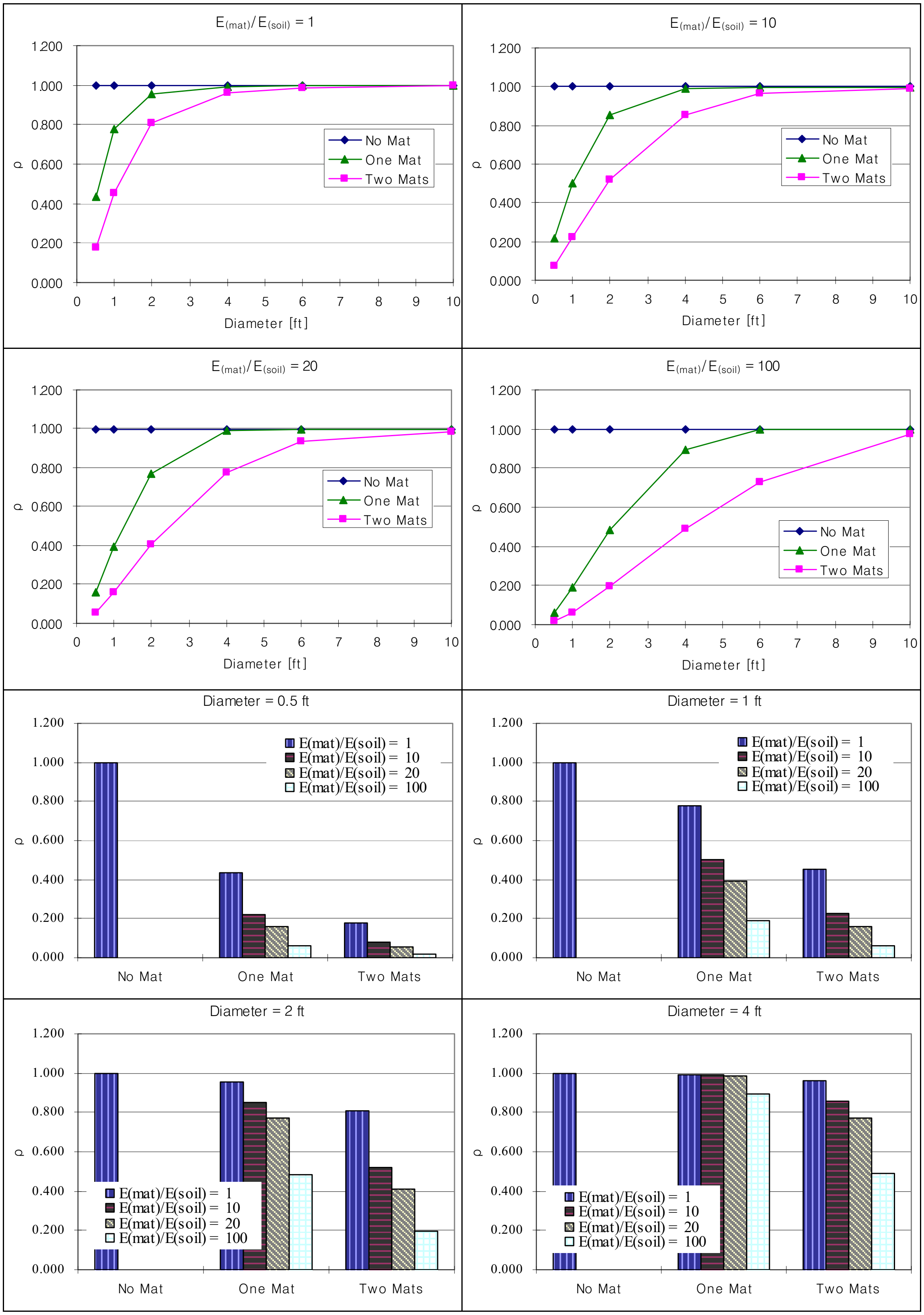


Figure 4-32. Actual mesh generated for this parametric analysis

Table 4-20. $\rho = P_{(max)} / P_{(applied)}$ values

Parameters		No Mat	One Mat	Two Mats
D = 0.5 ft	$E_{(mat)}/E_{(soil)}$ = 1	1.000	0.437	0.175
	$E_{(mat)}/E_{(soil)}$ = 10		0.218	0.077
	$E_{(mat)}/E_{(soil)}$ = 20		0.158	0.053
	$E_{(mat)}/E_{(soil)}$ = 100		0.064	0.020
D = 1 ft	$E_{(mat)}/E_{(soil)}$ = 1	1.000	0.776	0.454
	$E_{(mat)}/E_{(soil)}$ = 10		0.501	0.224
	$E_{(mat)}/E_{(soil)}$ = 20		0.394	0.160
	$E_{(mat)}/E_{(soil)}$ = 100		0.189	0.063
D = 2 ft	$E_{(mat)}/E_{(soil)}$ = 1	1.000	0.955	0.807
	$E_{(mat)}/E_{(soil)}$ = 10		0.853	0.519
	$E_{(mat)}/E_{(soil)}$ = 20		0.771	0.409
	$E_{(mat)}/E_{(soil)}$ = 100		0.486	0.193
D = 4 ft	$E_{(mat)}/E_{(soil)}$ = 1	1.000	0.991	0.961
	$E_{(mat)}/E_{(soil)}$ = 10		0.992	0.856
	$E_{(mat)}/E_{(soil)}$ = 20		0.988	0.773
	$E_{(mat)}/E_{(soil)}$ = 100		0.895	0.487
D = 6 ft	$E_{(mat)}/E_{(soil)}$ = 1	1.000	0.995	0.985
	$E_{(mat)}/E_{(soil)}$ = 10		0.993	0.962
	$E_{(mat)}/E_{(soil)}$ = 20		1.000	0.936
	$E_{(mat)}/E_{(soil)}$ = 100		1.000	0.729
D = 10 ft	$E_{(mat)}/E_{(soil)}$ = 1	1.000	0.999	0.996
	$E_{(mat)}/E_{(soil)}$ = 10		0.994	0.987
	$E_{(mat)}/E_{(soil)}$ = 20		0.996	0.984
	$E_{(mat)}/E_{(soil)}$ = 100		1.000	0.972


E(mat)/E(soil) = 1
E(mat)/E(soil) = 10
E(mat)/E(soil) = 20
E(mat)/E(soil) = 100
ρ
1.200
1.000
0.800
0.600
0.400
0.200
0.000
0 1 2 3 4 5 6 7 8 9 10
Diameter [ft]
No Mat
One Mat
Two Mats
Diameter = 0.5 ft
Diameter = 1 ft
Diameter = 2 ft
Diameter = 4 ft
E(mat)/E(soil) = 1
E(mat)/E(soil) = 10
E(mat)/E(soil) = 20
E(mat)/E(soil) = 100

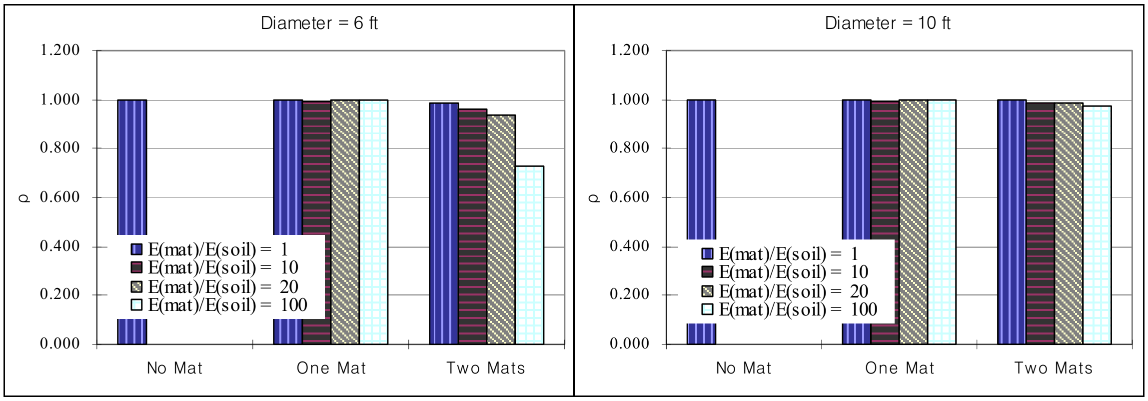


Figure 4-33. The result summary graphs

4.3.3 Lessons Learned

Throughout this parametric study, it is indicated that the single layer mat system (one mat) can decrease the pressure up to 95% for small loading areas (i.e., D = 6" such as car or truck tire areas) over soft soil (i.e., Young's Modulus is less than 10 MPa). Therefore, the mat system seems to be very beneficial for traffic areas such as small tires over soft soils. On the other hand, the single layer mat system does not provide significant decrease in pressure for large loading areas (i.e., D > 6') over stiff soil (i.e., Young's Modulus is greater than 50 MPa). Therefore, the mat system seems not to be significantly beneficial for large bins on desert soils. The double layer mat system (two mats) also looks beneficial for small loading areas but as applied load area increases, it seems to lose the benefit of using it especially on hard soils.

Report 4:

Advanced Drilling Technology: Low Impact Rigs

Tom Williams, TerraPlatforms, L.L.C
Richard C. Haut, Houston Advanced Research Center

Chapter Summary

This segment of the overall EFD program sought to identify systems using new technology such as light weight drilling rigs compatible with smaller well pad locations to reduce the footprint of drilling activities. A number of studies were conducted. The first study evaluated the industry's new generation of light weight rigs that require smaller well pads or could be utilized with modular platforms to reduce well site size while retaining the capability of drilling greater than 10,000 ft. The next effort was to ascertain if a modular platform design previously used in the Arctic on the North Slope (Kadaster and Milheim, [1]) could be adapted to use in coastal margins and/or desert ecosystems drilling operations. Later in the program the EFD team incorporated the technology developed within the Microhole Technology program funded by DOE (Roy Long[2]). The EFD program also studied the feasibility of incorporating alternate sources of energy in drilling operations including solar, wind, fuel cell technology, and connecting to the grid. The most promising technology, grid drilling, was studied in detail and an engineering design was created for a power transmission link (up to 2 miles) to provide prime power to the rig as an alternate to diesel/generator packages.

Work in this project was designed to meet the deliverables represented by the NETL SOW Task 2 (*Technology Status Assessment*) and Task 4 (*Planning Prototype Development, Testing and Deployment*)

Low Footprint, Light Weight Rigs: Description

One of the major goals of this project is to reduce the 'physical' drilling site footprint of the drill site and access road. The project's stated goal is to achieve a well footprint of less than one acre per well. This can be accomplished if an environmentally friendly drilling system is employed. This report will identify additional technologies that could

[1] Kadastar, A.G. and Milheim K.K. "Onshore Mobile Platform: A Mobile Platform for Drilling and Production Operations in Remote and Environmentally Sensitive Areas." Paper IADC/SPE 87140 Drilling Conference presented in Dallas, Texas March, 2004.

[2] http://www.netl.doe.gov/technologies/oilgas/EP_Technologies/AdvancedDrilling/Microhole/microhole.html

be used in an EFD system to meet this goal and provides a quick look at the advances in how the drilling footprint has been reduced. The EFD program has established a systems approach to reduce the footprint.[3] The system and options continue to evolve as new innovations are identified and applied. Balancing the environmental stewardship of our land and meeting our nation's energy needs is being met with these improvements. The well site footprint is impacted by the rig innovations and some the technology covered in this report that allows these smaller rigs to drill deeper, at greater distances horizontally, safer and more efficiently.

Two of our industry sponsors – Huisman and National Oilwell Varco (NOV) manufacture rigs and have supported our project. This report incorporates information from meetings with these sponsors, plus other companies who build and operate rigs including Helmerich & Payne, Nabors Drilling and Xtreme Coil Drilling. The evolution of rigs in the drilling industry is evident as other companies are introducing new smaller footprint rigs including Schramm, Honghua America, MD Cowen (DC Electric super single), Pioneer Drilling, IDM Quicksilver and others.
These companies and others are building the next generation small, efficient rigs. The features include:

- Minimized rig-up/down time
- Compact well site footprint
- Reduced environmental impact
- Smaller crew size
- Lower transport cost
- Fast, efficient pipe handling
- Minimized accident exposure
- Smaller equipment size
- Reduced transport loads by as much as two thirds
- Smaller access road requirement,
- AC driven – Minimized hydraulics, reduced emissions
- Meet the majority of drilling conditions

Also important is the transportability of the new types of rigs, so they can get in, drill the well and get out as fast as possible. The rigs are modular so the access roads can be smaller, with less environmental impact, and it takes fewer people to assemble the rigs.
The name "super single" is associated with many of these rigs. This means that the mast is much shorter because the rigs only use a single strand of drill pipe, and thus not as visible. This also allows the rigs to be more portable. The automation design used on these rigs makes this practical and does not compromise the drilling speed. Improvements to the drilling process include AC driven power, so the rigs are much quieter. It also reduces much of the hydraulics that potentially poses a threat of leaks. Some rigs are

[3] Yu, O.Y., Guikema, S.D., Bickel, J.E., Briaud, J.L., and Burnett, D.B.: 'Systems Approach and Quantitative Decision Tools for Technology Selection in Environmentally Friendly Drilling,' SPE 120848.

designed to use power from the power grid when it is available; this can also reduce the noise and need for additional generators.

Other improvements include better environmentally acceptable drilling fluids and fluids handling, managed pressure and underbalanced drilling and new bit designs; all designed to improve the drilling process, making it more efficient, safer with less impact on the environment. So even with a higher day rate associated with a more modern drilling system, the well construction can cost less in many cases (per completed well) than drilling with conventional rigs. When horizontal drilling is applied, the total field development cost is less than drilling several vertical wells in the same area, especially when adding the cost of well site, associated mobilization cost of the rigs, operating costs associated with roads, infrastructure, and production facilities.

There are over 250 drilling contractors in the U.S. These companies range from very large contractors including Patterson-UTI, Nabors, Helmerich & Payne to small companies who only operate one or two rigs. The current fleet of rigs is old and many rigs are out of date, they are too big and expensive to move and have a large footprint. According to an annual report published by Hadco International the average rig in the field is 20 years old, and there are some rigs that are 50 years old and still running.

The depth capability of the rig is controlled by the input horsepower (HP) of the draw works, but its limits also have to do with the rig design. On average the foot per HP is 11 (but this depends upon the size and weight of the drill pipe) – so that a 1,000 HP rig is generally capable of drilling 11,000 feet. The modular rigs covered in this report have on average 1,500 drawworks HP rating. Most gas wells today are drilled horizontally. It is reasonable to expect a modern 1,500 HP rig can drill the majority of gas wells that are 10,000 – 12,000 feet in depth and 4,000 foot plus horizontal sections. These rigs also have two 1,600 HP mud pumps and are set for top drives.

It is important to note that there are also a number of shallow (> 8,000 TVD) oil and gas wells drilled n the U.S. Many coal-bed methane wells are less than 2,000 deep, and even including a horizontal section the total wellbore is relatively shallow. A 1,500 HP rig is “overkill” for drilling these wells. While not thoroughly covered in this report, most rig manufacturers build smaller, more compact and even more mobile rigs for these conditions. Many are truck mounted and are easily transported, such as the coiled tubing rig shown in Figure 5.

Figure 5. Truck Mounted Coiled Tubing Rig.

The rigs highlighted in this report have a footprint of 25,000 to 30,000 square feet. The total drilling footprint must also include the other equipment used in drilling process that can double the pad site. Even doubled, at 60,000 square feet, the site is only 1.4 acres, well below the 2004 chart. However, more than one well can be drilled from a pad, so that the drill site may slightly increase when multiple wells are drilled, but the per-well average can be less than one acre.
.. Figure 3 shows an H&P rig drilling a pad site for Williams Company where 11 wells are drilled from one site. This is similar to how wells are drilled offshore and is becoming more common in areas where it is critical to eliminate the number of well sites. Figure 4 shows the various conductor pipes for the wells as well as the rail system that was used for skidding the rig.

Horizontal drilling, illustrated in Figure 5, is another offshore drilling technology that has been applied to onshore locations, enabling long-throw wells to be economically drilled and completed.
Pad drilling enables multiple wells to be drilled from

Figure 3. H&P Rig Drilling for Williams Company.

Figure 4. Cellar showing various conductor pipes for wells. Also shown is the rail system for moving the rig.

one surface location. Drilling steerable technologies enable these wells to be safely drilled, avoiding other wellbores in the process as illustrated in Figure 6.

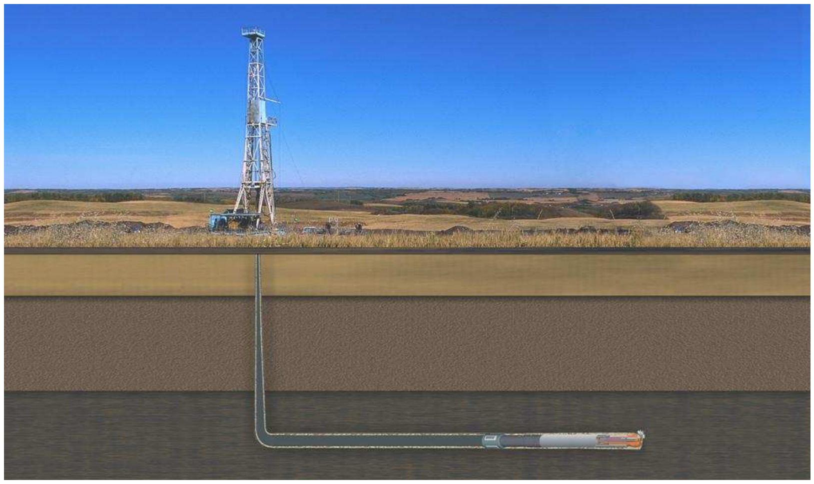


Figure 5. Illustration of Horizontal Drilling

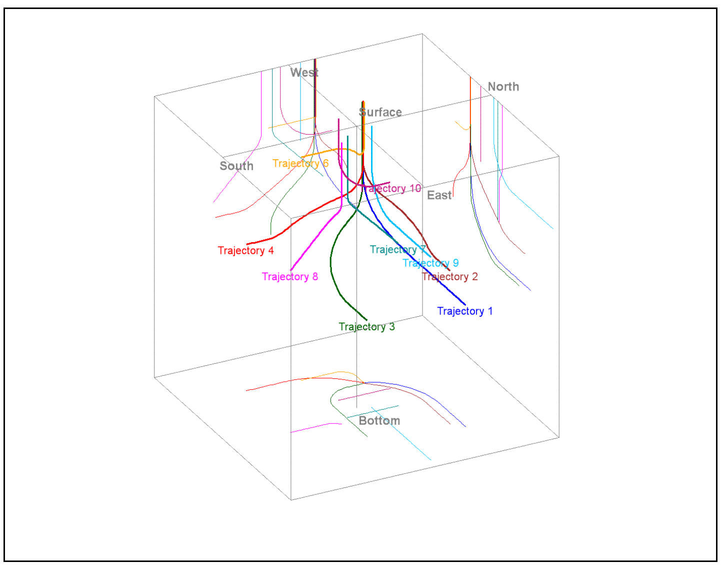


Figure 6. Well planning software allows drillers to use Drilling Steerable Technologies that Enable Multiple Wellbores to be drilled.

This report shows the average footprints from using newer generation rigs and the rig capabilities. Added benefits include the reduced size of work crew, improved safety performance, and improved environmental performance in emissions, roads, discharges, and land impacts.

Statistics show that pipe and material handling cause almost 50% of the recorded accidents during well drilling. The fully automated pipe handling, with its automated drill floor, eliminates the need for personnel on the drill floor and thus eliminates the potential for accidents. In addition, the simple modular rig-assembly process – with smaller loads, less rig crew involvement and improved overview and visibility – effectively mitigates the risk for the crew and the potential for accidents and damage during rig moves.

COMPLEMENTARY TECHNOLOGIES

The project has identified additional technologies that can be incorporated into an EFD system:

Casing While Drilling. With the exception of the coiled tubing rig, most rigs can be equipped with a Casing While Drilling (CWD) tool on the drill works. The CWD is a new and accepted way to drill. In CWD, a well is drilled using standard oilfield casing instead of drill pipe. This enables the operator to simultaneously drill and case a well. Drill bits and other tools can be lowered inside the casing to the bottom of the hole on a wireline, where they are latched to the last joint of casing, while mud circulation continues. Retrieval of the bits and the tools occurs the same way. The CWD process eliminates tripping and its associated blowout risks. There are several possible configurations for CWD systems: the casing rotates during drilling but there are various rotation-speed options, and the drilling tools may be integrated into the casing string or be part of an assembly that extends below the casing shoe. A top-drive system is used to rotate the casing, which remains in the hole at all times and is eventually cemented in place when the casing point is reached. The benefits of CWD include reduced drilling flat time (no tripping); the casing is always on bottom, which eliminates the risks associated with open holes; improved circulation; drilling through difficult layers such as depleted zones and unstable formations is made easier; and improved wellbore stability, which often means that a casing string can be eliminated. It has been proven in many wells that drilling efficiency can be improved by 20 to 50% with CWD. Since the casing remains in the well and circulation is maintained at all times, wellbore integrity is preserved and unscheduled events such as well control problems, swelling or sloughing formations, and washouts are avoided. This also significantly reduces the number of loads of drill pipe required to be hauled to the drill site. The Huisman rig discussed in the Appendix is designed for CWD operations.

Aluminum Alloy Drill Pipe. Aluminum Drill Pipe (ADP) has been used by the petroleum industry for decades. Most of this experience comes from Russia and the FSU, where drillers use ADP extensively. Based on this field history, ADP is a proven product. ADP was used in North and South America on a limited basis in the 1960s and 1970s to extend the depth capacity of existing rigs and to reduce weight for helicopter-transported rigs. ADP advantages include: Lower weight, so that it can extend the capabilities of the smaller environmentally friendly drilling rigs. This is particularly advantageous for long horizontals and extended reach drilling. An improvement of 40% to 50% in added drilling length has been documented. It is easier to haul and transport. ADP also has good corrosion resistance, enhanced fatigue resistance and is non-magnetic. Providers of ADP like Alcoa and Weatherford provide improved a product today with better alloy’s, tool joints and connections making this more reliable for more applications than in the past.

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Figure 9. Coiled Tubing Drilling Rig on Location.

heart of most of the significant advantages attributable to CT over conventional drilling. Coiled-tubing drilling can be done safely and effectively in vertical, deviated, and horizontal wells, Figure 9. Tubing with installed electric lines is used for steering downhole drilling. Conventional overbalanced drilling of shallow gas wells with CT has become a growing market in Canada and in the U.S. In certain applications drilling shallow gas wells with CT is more efficient and economical than conventional rigs. Advances to CT drilling have been introduced by companies like Xtreme Coil Drilling Company. The Hybrid rigs can drill with both conventional rotary and CT and have the ability to drill 10,000 foot wells. The mast allows the rig to drill land run pipe which had been one of the biggest disadvantages in the past.

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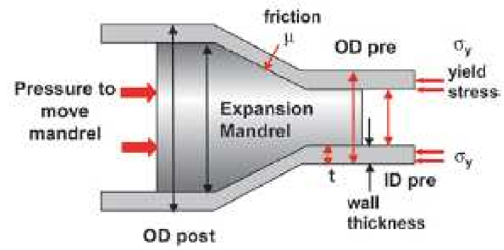

Figure 11. Interfaces during pipe expansion process.

- Slimmer well profiles which increase rate of penetration (ROP) and enable the use of smaller rigs and less consumables with better hydraulics and hole cleaning
- Mitigate risk in reaching total depth by providing additional casing string options
- Eliminating non-productive time and reducing the days-to-depth curve
- Accelerating production by helping bring reserves online faster
- Eliminating need for large blowout preventers (BOP)

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- Reducing environmental impact (less cuttings, mud, cement, steel tonnage)

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Work is also underway to combined casing while drilling technology with expandable casing technology. This would enable a rig to drill with the expandable casing and then expand the pipe when the casing setting depths are reached.

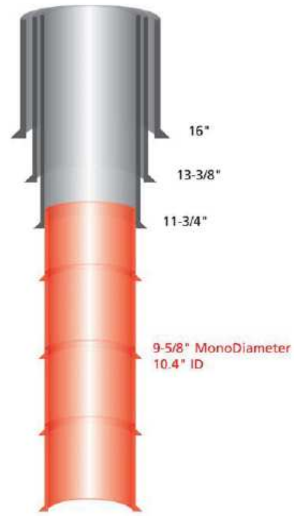

Figure 12. Monobore well design.

ACKNOWLEDGEMENT

This chapter was created with the assistance of Laura Williams and Bill Pike at Hart's E&P for their assistance with the poster for Energy Day. Only with their expertise were the authors able to meet all the deadlines and requirements.

[4] Frisch, J. and McKee, R.: “Reach Further with a Single-Diameter Wellbore,” Hart’s E&P, August 2007.

Field Testing of Environmentally Friendly Drilling Systems

DE-FC22-05NT42658

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May 26, 2009

DISCLAIMER

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GOAL AND OBJECTIVES

The long range goal of the Environmentally Friendly Drilling (EFD) program is the integration of currently known but unproven or novel technology to develop drilling systems that have very limited environmental impact and enable moderate to deep drilling and production operations and activity in environmentally sensitive areas should these areas be opened for exploration and production.

The specific objectives of the DOE Environmental Drilling Systems Project have been as follows:

- Identify new technology that can reduce or eliminate the impact of drilling operations on environmentally sensitive areas.
- Design an EFD system using most promising technology.
- Include environmental stakeholders in the designs.

TASK

One of the major goals of this project is to reduce the 'physical' drilling site footprint of the drill site and access road. The project's stated goal is less than one acre. This can be accomplished if an environmentally friendly drilling system is employed. This report will identify additional technologies that could be used in an EFD system to meet this goal. Two of our industry sponsors – Huisman and National Oilwell Varco (NOV) manufacture rigs and have supported our project. This report incorporates information from meetings with these sponsors, plus other companies who build and operate rigs including Helmerich & Payne, Nabors Drilling and Xtreme Coil Drilling. The evolution of rigs in the drilling industry is evident as other companies are introducing new smaller footprint rigs including Schramm, Honghua America, MD Cowen (DC Electric super single), Pioneer Drilling, IDM Quicksilver and others.

These companies and others are building the next generation small, efficient rigs. The features include:

- Minimized rig-up/down time
- Compact wellsite footprint
- Reduced environmental impact
- Smaller crew size
- Lower transport cost
- Fast, efficient pipe handling
- Minimized accident exposure
- Smaller equipment size
- Reduced transport loads by as much as two thirds
- Smaller access road requirement,
- AC driven – Minimized hydraulics, reduced emissions
- Meet the majority of drilling conditions

There are over 250 drilling contractors in the U.S. These companies range from very large contractors including Patterson-UTI, Nabors, Helmerich & Payne to small companies who only operate one or two rigs. The current fleet of rigs is old and many rigs are out of date, they are too big and expensive to move and have a large footprint. According to an annual report published by Hadco International the average rig in the field is 20 years old, and there are some rigs that are 50 years old and still running.

The depth capability of the rig is controlled by the input horsepower (HP) of the draw works, but its limits also have to do with the rig design. On average the foot per HP is 11 (but this depends upon the size and weight of the drill pipe) – so that a 1,000 HP rig is generally capable of drilling 11,000 feet. The modular rigs covered in this report have on average 1,500 drawworks HP rating. Most gas wells today are drilled horizontally. It is reasonable to expect a modern 1,500 HP rig can drill the majority of gas wells that are 10,000 – 12,000 feet in depth and 4,000 foot plus horizontal sections. These rigs also have two 1,600 HP mud pumps and are set for top drives.

It is important to note that there are also a number of shallow (> 8,000 TVD) oil and gas wells drilled n the U.S. Many coal-bed methane wells are less than 2,000 deep, and even including a horizontal section the total wellbore is relatively shallow. A 1,500 HP rig is "overkill" for drilling these wells. While not thoroughly covered in this report, most rig manufacturers build smaller, more compact and even more mobile rigs for these conditions. Many are truck mounted and are easily transported, such as the coiled tubing rig shown in Figure 1.

Figure 1. Coiled Tubing Rig on Location.

One potential benefit of the current downturn with only 855 rigs running, is that some of these the older rigs may be retired. A year ago (according to RigData) there were 2,155 land rigs with 1,768 operating the week of May 16, 2008.

When the EFD project was initiated an illustration, Figure 2, from the University of Kansas was used that showed a "Present" footprint size of 6 acres. The evolution, as shown, documented the progress the industry has made to reduce the footprint and produce more oil and gas. "Present" was in 2004.

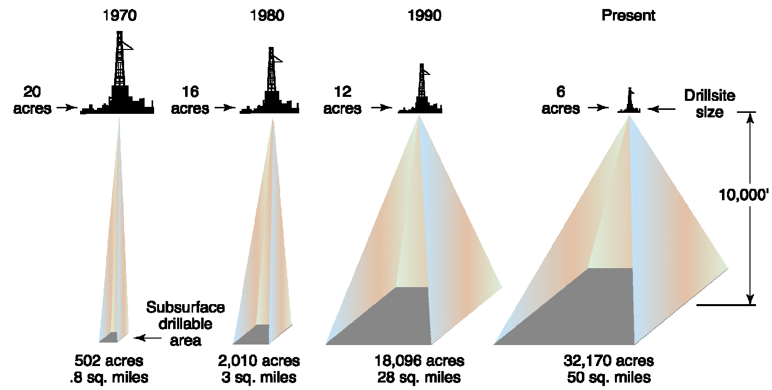

Figure 2. Kansas Graphic.

We believe it is possible to reduce this footprint to a one acre site and still achieve the depth targets required for the majority of gas and oil wells being drilled in the U.S. by incorporating a system of EFD technologies.

The rigs highlighted in this report have a footprint of 25,000 to 30,000 square feet. The total drilling footprint must also include the other equipment used in drilling process that can double the pad site. Even doubled, at 60,000 square feet, the site is only 1.4 acres, well below the 2004 chart. However, more than one well can be drilled from a pad, so that the drill site may slightly increase when multiple wells are drilled, but the per-well average can be less than one acre. Figure 3 shows an H&P rig drilling a pad site for Williams Company where 11 wells are drilled from one site. This is similar to how wells are drilled offshore and is becoming more common in areas where it is critical to eliminate the number of well sites. Figure 4 shows the various conductor pipes for the wells as well as the rail system that was used for skidding the rig.

Figure 3. H&P Rig Drilling for Williams Company.

Figure 4. Cellar showing various conductor pipes for wells. Also shown is the rail system for moving the rig.

Horizontal drilling, illustrated in Figure 5, is another offshore drilling technology that has been applied to onshore locations, enabling long-throw wells to be economically drilled and completed.

Pad drilling enables multiple wells to be drilled from one surface location. Drilling steerable technologies enable these wells to be safely drilled, avoiding other wellbores in the process as illustrated in Figure 6.

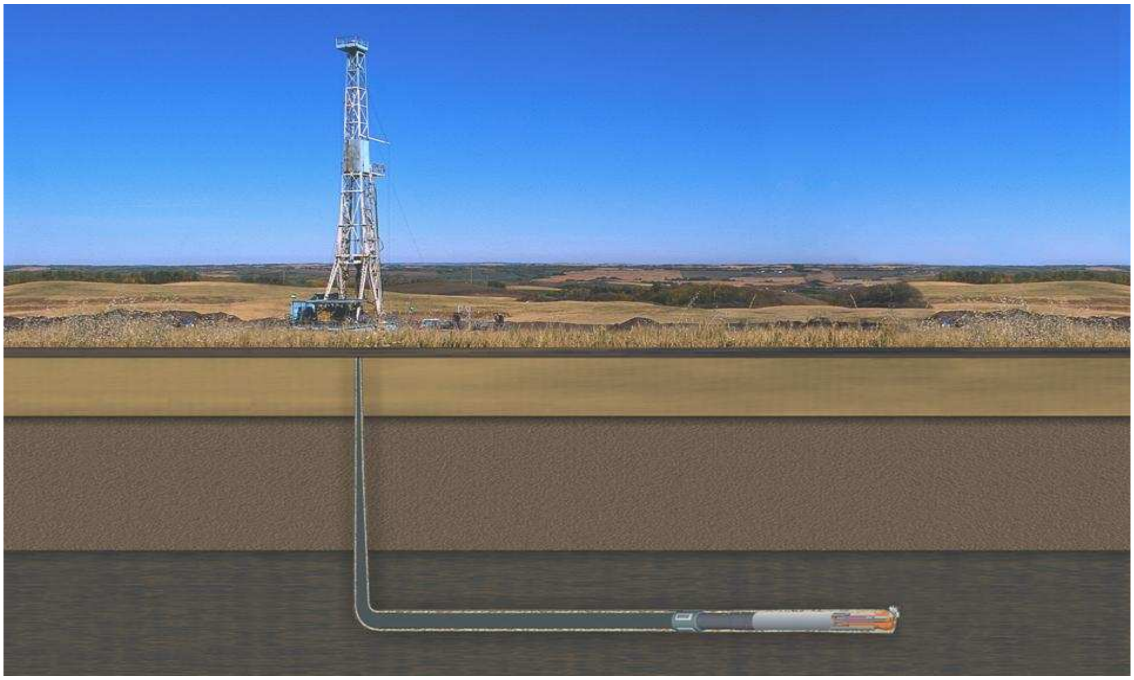

Figure 5. Illustration of Horizontal Drilling.

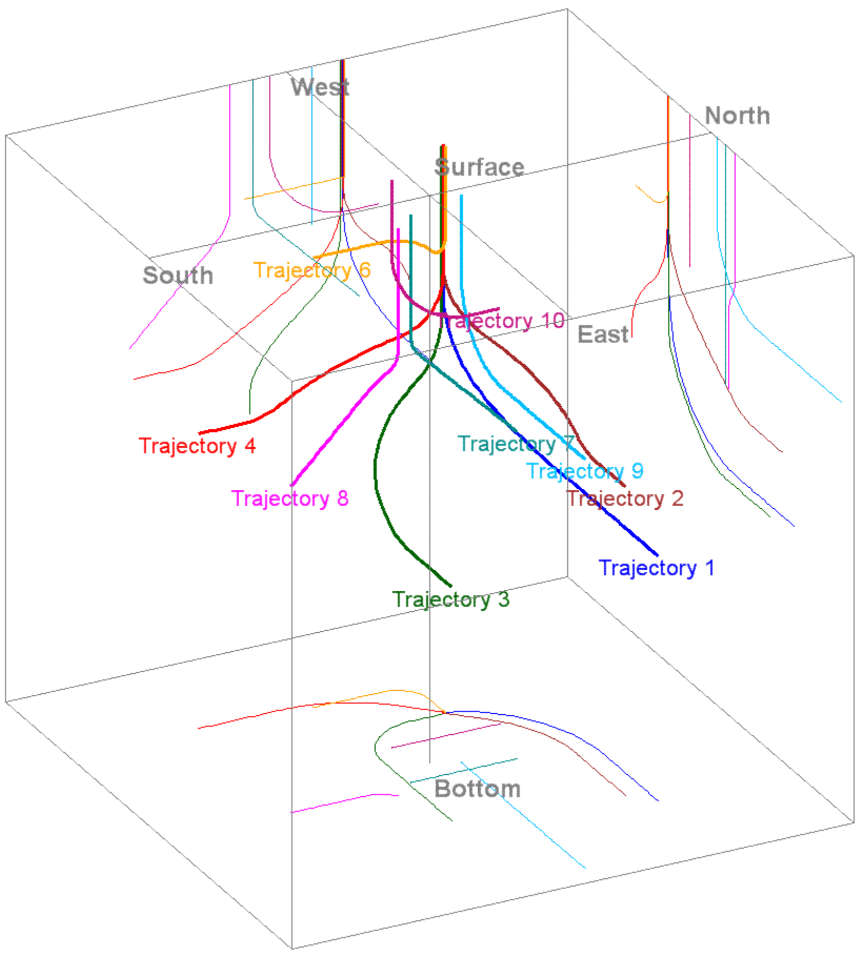

Figure 6. Well planning software allows drillers to use Drilling Steerable Technologies that Enable Multiple Wellbores to be Drilled.

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This report shows the average footprints from using newer generation rigs and the rig capabilities. Added benefits include the reduced size of work crew, improved safety performance, and improved environmental performance in emissions, roads, discharges, and land impacts.

Statistics show that pipe and material handling cause almost 50% of the recorded accidents during well drilling. The fully automated pipe handling, with its automated drill floor, eliminates the need for personnel on the drill floor and thus eliminates the potential for accidents. In addition, the simple modular rig-assembly process – with smaller loads, less rig crew involvement and improved overview and visibility – effectively mitigates the risk for the crew and the potential for accidents and damage during rig moves.

ENERGY DAY PRESENTATION

Outreach and education is an important part of the EFD project. The EFD team was asked by the Consumer Energy Alliance as Host to present the results at the National Energy Day. This annual event was held at the U.S. Capital visitor center in Washington DC on May 13, 2009. A poster, Figure 7, with graphics and a hand out was presented.

New technology must be cost effective. The presentation given at Energy Day showed that the newer, modern rigs are smaller, designed for horizontal drilling, and that drilling pads are used in some cases where multiple wells are drilled from one site. The way each field is developed and the methods and technologies employed depend upon geology and geography. Operators utilize information resources like the EFD project to take into account all the available options to plan the best way to develop a field with the least impact on the environment and importantly still be able to make a profit. As new technologies are identified and proven the case studies and lessons learned are presented at numerous forums, workshops and conferences. Organizations like the Petroleum Technology Transfer Council, the International Association of Drilling Contractors, Society of Petroleum Engineers and the American Association of Drilling Contractors are just some of the organizations that provide these forums. Websites like www.efdsystems.com are also valuable tools for operator's reference.

A contrast was shown at the Energy Day exhibit on how fields were developed in the past with how they are being developed today. When horizontal drilling is used, the wells can drain four to 25 times as that of vertical well bores. These new rigs drill horizontal wells faster and with less down time than older conventional rigs. The rigs, new instrumentation, down hole tools, geo-steering innovations and software make this possible. Topography is not as big of a hurdle to develop as reservoir as it has been in the past.

Figure 7. Poster Presented at Energy Day 2009.

Also important is the transportability of these rigs, so they can get in, drill the well and get out as fast as possible. The rigs are modular so the access roads can be smaller, with less environmental impact, and it takes fewer people to assemble the rigs.

The name "super single" is associated with many of these rigs. This means that the mast is much shorter because the rigs only use a single strand of drill pipe, and thus not as visible. This also allows the rigs to be more portable. The automation design used on these rigs makes this practical and does not compromise the drilling speed. Improvements to the drilling process include AC driven power, so the rigs are much quieter. It also reduces much of the hydraulics that potentially poses a threat of leaks. Some rigs are designed to use power from the power grid when it is available; this can also reduce the noise and need for additional generators.

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Other improvements include better environmentally acceptable drilling fluids and fluids handling, managed pressure and underbalanced drilling and new bit designs; all designed to improve the drilling process, making it more efficient, safer with less impact on the environment. So even with a higher day rate associated with a more modern drilling system, the well construction can cost less in many cases (per completed well) than drilling with conventional rigs. When horizontal drilling is applied, the total field development cost is less than drilling several vertical wells in the same area, especially when adding the cost of well site, associated mobilization cost of the rigs, operating costs associated with roads, infrastructure, and production facilities.

COMPLEMENTARY TECHNOLOGIES

The project has identified additional technologies that can be incorporated into an EFD system:

Casing While Drilling. With the exception of the coiled tubing rig, most rigs can be equipped with a Casing While Drilling (CWD) tool on the drill works. The CWD is a new and accepted way to drill. In CWD, a well is drilled using standard oilfield casing instead of drill pipe. This enables the operator to simultaneously drill and case a well. Drill bits and other tools can be lowered inside the casing to the bottom of the hole on a wireline, where they are latched to the last joint of casing, while mud circulation continues. Retrieval of the bits and the tools occurs the same way. The CWD process eliminates tripping and its associated blowout risks. There are several possible configurations for CWD systems: the casing rotates during drilling but there are various rotation-speed options, and the drilling tools may be integrated into the casing string or be part of an assembly that extends below the casing shoe. A top-drive system is used to rotate the casing, which remains in the hole at all times and is eventually cemented in place when the casing point is reached. The benefits of CWD include reduced drilling flat time (no tripping); the casing is always on bottom, which eliminates the risks associated with open holes; improved circulation; drilling through difficult layers such as depleted zones and unstable formations is made easier; and improved wellbore stability, which often means that a casing string can be eliminated. It has been proven in many wells that drilling efficiency can be improved by 20 to 50% with CWD. Since the casing remains in the well and circulation is maintained at all times, wellbore integrity is preserved and unscheduled events such as well control problems, swelling or sloughing formations, and washouts are avoided. This also significantly reduces the number of loads of drill pipe required to be hauled to the drill site. The Huisman rig discussed in the Appendix is designed for CWD operations.

Aluminum Alloy Drill Pipe. Aluminum Drill Pipe (ADP) has been used by the petroleum industry for decades. Most of this experience comes from Russia and the FSU, where drillers use ADP extensively. Based on this field history, ADP is a proven product. ADP was used in North and South America on a limited basis in the 1960s and 1970s to

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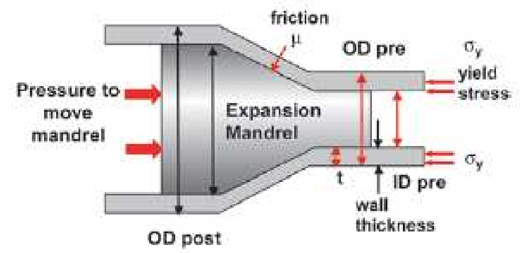

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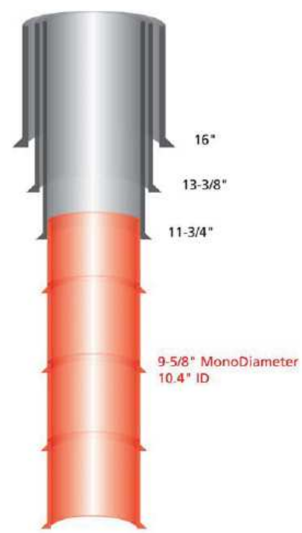

Figure 12. Monobore well design.

Alternative Power. Diesel-electric powered rigs employing silicon-controlled rectifier (SCR) technology provide more precise control of drilling components and greater power efficiency than mechanical rigs and are well suited for horizontal and directional drilling. Having SCR already incorporated into the rig, other energy sources may be used as the prime movers. For example, Encana has used natural gas powered rigs in the Jonah field of Wyoming, reducing emissions.[2] If available, SCR enabled rigs could possibly be connected directly to the grid. Texas A&M University has performed a study

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[1] Frisch, J. and McKee, R.: “Reach Further with a Single-Diameter Wellbore,” Hart’s E&P, August 2007.

[2] Moen, R. **Casper-Star Tribune**, June 6, 2008.

to develop an energy inventory of the drilling process from a rig perspective.[3] With an energy inventory, technologies that can be used to partially provide power to a rig may be evaluated to reduce fuel consumption and emissions. A study to evaluate the feasibility of adopting technology to reduce the size of the power generating equipment on drilling rigs and to provide "peak shaving" energy through the new energy generating and energy storage devices such as flywheels.[4]

SUMMARY

This report provides a quick look at the advances in how the drilling footprint has been reduced. The EFD program has established a systems approach to reduce the footprint.[5] The system and options continue to evolve as new innovations are identified and applied. Balancing the environmental stewardship of our land and meeting our nation's energy needs is being met with these improvements. The well site footprint is impacted by the rig innovations and some the technology covered in this report that allows these smaller rigs to drill deeper, at greater distances horizontally, safer and more efficiently.

ACKNOWLEDGEMENT

The authors would like to acknowledge the great help from Laura Williams and Bill Pike at Hart's E&P for their assistance with the poster for Energy Day. Only with their expertise were we able to meet all the deadlines and requirements.

[3] http://sites.google.com/a/pe.tamu.edu/gpri-alternate-rig-power-study/Home

[4] Verma, Ankit and Burnett, D,: 'Alternate Power and Energy Storage/Reuse for Drilling Rigs: Reduced Cost and Lower Emissions Provide Lower Footprint for Drilling Operations,' SPE 122885.

[5] Yu, O.Y., Guikema, S.D., Bickel, J.E., Briaud, J.L., and Burnett, D.B.: 'Systems Approach and Quantitative Decision Tools for Technology Selection in Environmentally Friendly Drilling,' SPE 120848.

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APPENDIX – INFORMATION CONCERNING NOV AND HUISMAN RIGS

In May 2006 NOV rolled out a smaller fully automatic land drilling rig, “Rapid Rig”. This rig is a singles rig as it has the pipe handling capability to rapidly pickup/laydown, makeup/breakout drill pipe and run casing and be able to mobilize/demobilize in approximately 8 hours. It utilizes range II or III drill pipe. The Rapid Rig is deployed with a single forklift as it requires no cranes or gin pole trucks and is capable of moving in sixteen highway-legal transport loads. The automated rig floor and pipe handling systems allows operation by three person crew. The rig floor has an iron roughneck and stabbing guide, automated pipe slips, AC drawworks rated at 1000 hp and gear driven with regenerative dynamic braking system, and top drive controlled from a climate controlled driller’s cabin on the mud pit side.

As illustrated in Figure A-1, the foot print of the Rapid Rig is 153 feet by 119 feet. The rig is rated for approximately 11,000 feet and has a hook load rating of 500,000 pounds. The pipe handling system has a weight limit of 6,000 lbs with a drill pipe capacity of 5.5 inch range III and a drill collar capacity of 8 inch range II and a casing capacity of up to 13-3/8 inch. The rig may be transported by heavy lift helicopter. Table A-1 compares the Rapid Rig to another potential, similar rig, the Ideal Rig.

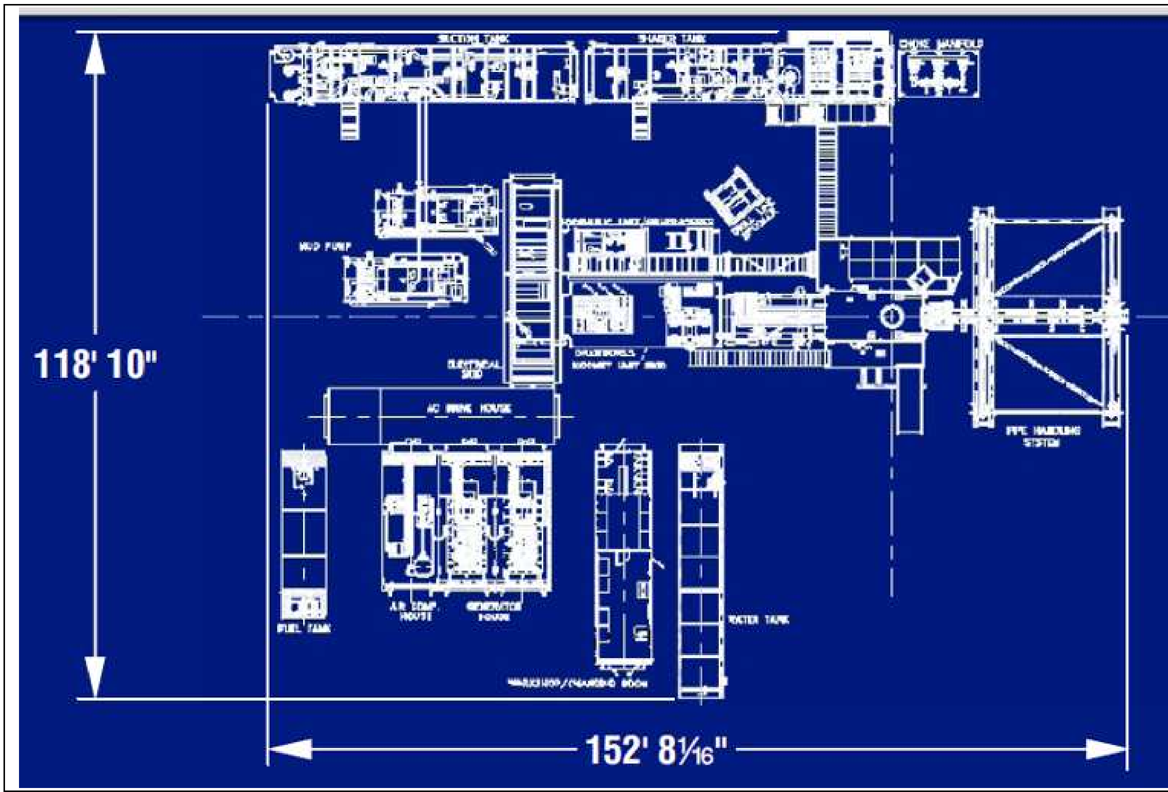

Figure A-1. Layout of Rapid Rig.

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Table A-1: NOV Rapid and Ideal Rig Typical Specifications

	Rapid Rig	Ideal Rig
Mast Hook Load	250 tons (8 lines)	300 ton
Mast Height	80 ft (telescoping)	142 feet
Base Dimensions	7 ft x 5 ft	12 ft x 12 ft
Wind Rating	70 knot free standing	70 Knot w/ full set back 208 stands of 5.5 inch DP 8 Stands 8 inch DC
Rotary load Rating	250 tons	375 tons (w/ set back)
Drill floor height	20 ft	25 ft
Clear height under floor	17 ft	21 ft 8 inches
Drill Floor Dimensions	16 ft x 17 ft	32 ft x 32 ft
Substructure setback	N/A	250 ton Slingshot
Drawworks Nominal Power	1000 hp	1500 hp
Braking System	Regenerative Dynamic Disk Parking/Emergency Brakes	Disc brakes, Ideal Auto Drilling and Brake control System (IABC)
Top Drive	350 HP, 20,000 ft-lbs 250 ton	Optional
Pipe Handling System	6,000 lbs range II and III 5.5 pipe 8 inch collars and 13-3/8 inch casing	Optional
Control/instrumentation	SDAQ	SDAQ
Mud System	620 BBLS two tanks 3-panel linear motion shale shaker, Atmospheric Degasser Two Cone Desander	620 BBLS two tanks 2- 4-panel high G shale shaker, 1000 GPM Degasser Desander, Desilter
Mud Pumps	2-1000 HP Triplex AC electric Motor Driven	2-1600 HP Triplex AC electric Motor Driven
Power Generation	2- 1350 BHP, 1800 RPM 1750 KVA	3- 1350 BHP, 1800 RPM 1750 KVA
Hydraulic Power	Dual Driven System 70 GPM Diesel, 40 GPM Electric	Dual Driven System 70 GPM Diesel, 40 GPM Electric
Fuel Tanks	Diesel 190 Bbls	400 bbl cylindrical
Water Tanks	400 Bbl	400 Bbl

Netherlands based Huisman Special Lifting Equipment BV and Drillmar Inc. of Houston, through a technology development joint venture, has developed an innovative new rig concept: the LOC250, Land and Offshore Containerized 250 ton hookload rig, Figure A-2. The LOC250 is designed to take advantage of today's emerging casing while drilling (CWD) technology to reduce the costs as well as the environmental impact of drilling a well. The drilling depth capability of the LOC250 is illustrated in Figure A-3.

Figure A-2: Huisman LOC250 Rig.

Two of the most important features of the LOC250 rig are its compact size and the fact that the entire rig can be broken down into 17 modules with the shape and the dimensions of standard ISO containers. Within 24 hours (including limited transportation time) and without cranes, a five-man crew with three trucks can demobilize the compact rig and rebuild it in another location. As standard container ships, trains and oilfield trucks can transport ISO containers rapidly and economically, the LOC250 rig can be used to drill wells anywhere in the world. This has been accomplished by designing the rig in a manner whereby its load bearing components are either in the shape of, or can be pivoted, rotated, or connected into, an ISO container. Figure A-4 illustrates the rig during rig up. The rig may be transported by heavy lift helicopter.

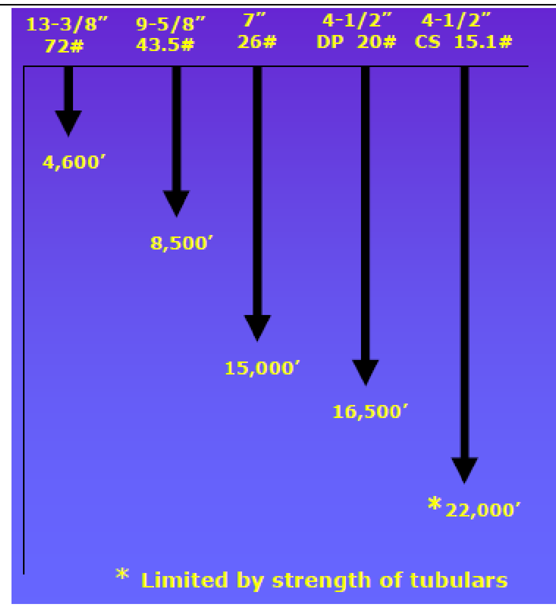

Figure A-3. Drilling Depths for the LOC 250.


Figure A-4: Huisman Rig during Rig Up.

The LOC250 is equipped with a fully automated pipe handler, which enables highly efficient handling of both casing and DP. When the pipe handler has upended the tubulars, they are taken over by elevators in the rig. A top drive is utilized to spin the tubulars in and to torque-up the connections. Fully automated power slips are integrated within the rotary table. Capable of tripping DP at 2000 ft/hr makes the LOC250 as efficient as existing conventional DP drilling rigs and more efficient than other specially designed CWD rigs. The DP drilling and CWD processes (including pipe and casing handling) are fully controlled from the control room without personnel on the drill floor. As DP handling is identical to casing handling and uses the same equipment, the same team can carry out both tasks. While a conventional pipe-drilling rig needs a crew of 10, the efficient design of the LOC250 means it requires only a five-man crew for full and safe operation.

Statistics show that pipe and material handling cause almost 50% of the recorded accidents during well drilling. The fully automated pipe handling of the LOC250, with its automated drill floor, obviates the need for personnel on the drill floor and thus eliminates the potential for accidents. In addition, the simple rig-assembly process –smaller loads, less rig crew involvement and improved overview and visibility – effectively mitigates the risk for the crew and the potential for accidents and damage during rig moves. The operation of the LOC 250 is illustrated in Figure A-5.

Figure A-5: Huisman LOC 250 Drawing of Operations.

The LOC250 has a significantly lower adverse impact on the environment when compared with conventional rigs. Because drilling a well with the LOC250 requires less drilling time and lower mud pump pressures and flow rates, two 800-hp mud pumps are sufficient, compared with the three 1000-hp pumps required for conventional DP drilling. This means a 45% lower fuel consumption per day of drilling and a reduction in hydrocarbon emissions per well of up to 75%. Solid waste volumes are reduced by up to 30%, as the cascading shaker system provides drier cuttings. Mud and cement costs are reduced by 10 to 20%. Because the LOC250 has only a single 38-m (125 ft) mast, its silhouette does not impact significantly on the horizon. The footprint of the LOC250, at 700 m^2 (7,500 sq ft) is 75% smaller than the 3000 m^2 (32,300 sq ft) required for a conventional rig. Figure A-6 illustrates the layout of the LOC 250 system for a well pad or platform.

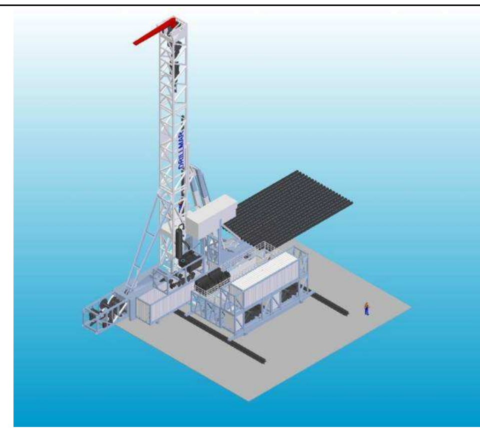

Figure A-6. Huisman LOC 250 Well Pad (Platform) Layout.

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Field Demonstration of Existing

Microhole Coiled Tubing Rig (MCTR) Technology

Final Technical Report

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Disclaimer

Acknowledgements

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Abstract

The performance of an advanced Microhole Coiled Tubing Rig (MCTR) has been measured in the field during the drilling of 25 test wells in the Niobrara formation of Western Kansas and Eastern Colorado. The coiled tubing (CT) rig designed, built and operated by Advanced Drilling Technologies (ADT), was documented in its performance by GTI staff in the course of drilling wells ranging in depth from 500 to nearly 3,000 feet. Access to well sites in the Niobrara for documenting CT rig performance was provided by Rosewood Resources of Arlington, VA. The ADT CT rig was selected for field performance evaluation because it is one of the most advanced commercial CT rig designs that demonstrate a high degree of process integration and ease of set-up and operation. Employing an information collection protocol, data was collected from the ADT CT rig during 25 drilling events that encompassed a wide range of depths and drilling conditions in the Niobrara. Information collected included time-function data, selected parametric information indicating CT rig operational conditions, staffing levels, and field observations of the CT rig in each phase of operation, from rig up to rig down.

The data obtained in this field evaluation indicates that the ADT CT rig exhibited excellent performance in the drilling and completion of more than 25 wells in the Niobrara under varied drilling depths and formation conditions. In the majority of the 25 project well drilling events, ROP values ranged between 300 and 620 feet per hour. For all but the lowest 2 wells, ROP values averaged approximately 400 feet per hour, representing an excellent drilling capability. Most wells of depths between 500 and 2,000 feet were drilled at a total functional rig time of less than 16 hours; for wells as deep at 2,500 to 3,000 feet, the total rig time for the CT unit is usually well under one day. About 40-55 percent of the functional rig time is divided evenly between drilling and casing/cementing. The balance of time is divided among the remaining four functions of rig up/rig down, logging, lay down bottomhole assembly, and pick up bottomhole assembly.

Observations made during all phases of CT rig operation at each of the project well installations have verified a number of characteristics of the technology that represent advantages that can produce significant savings of 25-35 percent per well. Attributes of the CT rig performance include: 1) Excellent hole quality with hole deviation amounting to 1-2 degrees; 2) Reduced need for auxiliary equipment; 3) Efficient rig mobilization requiring only four trailers; 4) Capability of “Zero Discharge” operation; 5) Improved safety; and, 6) Measurement while drilling capability. In addition, commercial cost data indicates that the CT rig reduces drilling costs by 25 to 35% compared to conventional drilling technology.

Widespread commercial use of the Microhole Coiled Tubing technology in the United States for onshore Lower-48 drilling has the potential of achieving substantially positive impacts in terms of savings to the industry and resource expansion. Successfully commercialized Microhole CT Rig Technology is projected to achieve cumulative savings in Lower-48 onshore drilling expenditures of approximately 6.8 billion dollars by 2025. The reduced cost of CT microhole drilling is projected to enable the development of gas resources that would not have been economic with conventional methods. Because of the reduced cost of drilling achieved with CT rig technology, it is estimated that an additional 22 Tcf of gas resource will become economic to develop. In the future, the Microhole Coiled Tubing Rig represents an important platform for the continued improvement of drilling that draws on a new generation of various technologies to achieve goals of improved drilling cost and reduced impact to the environment.

Glossary of Terms

Acronym	Meaning
ADT	Advanced Drilling Technologies, Inc.
API	American Petroleum Institute
BCF	Billion Cubic Feet
BHA	Bottom Hole Assembly
BOP	Blowout Preventor
BTU	British Thermal Unit
CD	Compact Disc
CSG/CMNT	Casing and Cementing
CT	Coiled Tubing
CTR	Coiled Tubing Rig
CTS	Coiled Tubing Solutions, Inc.
DOC	United States Department of Commerce
DOE	United States Department of Energy
DOT or U.S. DOT	United States Department of Transportation
EEA	Energy and Environmental Analysis, Inc.
E&P	Exploration and Production
EPA	United States Environmental Protection Agency
FAQ	Frequently Asked Question
GTI	Gas Technology Institute
IADC	International Association of Drilling Contractors
IcoTA	International Coiled Tubing Association
IPAA	Independent Petroleum Association of America
IPAMS	Independent Petroleum Association of Mountain States
LD BHA	Lay Down Bore Hole Assembly
MCTR	Microhole Coiled Tubing Rig
MHT	Microhole Technology
MIRU-RDMO	Move In Rig Up – Rig Down Move Out
Moxie	Name of the CTS Coiled Tubing Rig
MWD	Measurement While Drilling
NETL	National Energy Technology Laboratory
NPC	National Petroleum Council
NPV	Net Present Value
PBHA	Pick Up Bore Hole Assembly
PI	Principal Investigator
Psi	Pounds per Square Inch
PTTC	Petroleum Technology Transfer Council
R&D	Research and Development
RD&D	Research, Development and Demonstration
ROP	Rate of Penetration
RPM	Revolutions per Minute
SPE	Society of Petroleum Engineers
Tcf	Trillion cubic feet
TRG	Total Functional Rig Time
UBD	Underbalanced Drilling
USGS	United States Geological Survey

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Executive Summary

The Gas Technology Institute, with the support of the Department of Energy/National Energy Technology Laboratory (NETL) has completed field performance documentation of coiled tubing (CT) microhole drilling technology in the Niobrara gas play of Kansas and Colorado. The CT technology (also referred to as Microhole Coil Tubing Rig or MCTR technology) has the potential to substantially reduce the costs of drilling and completing oil and gas wells, which is key to increasing future U.S. production.

Natural gas was first discovered in the Niobrara formation in 1912 when a strong flow of gas was encountered while drilling the Goodland No. 1 well near Goodland, Kansas1. The well was plugged and abandoned. Since that first well the Niobrara gas play has undergone several episodes of activity driven by gas prices and improvements in technology. Recently, the development of coiled tubing drilling in combination with a microhole approach to borehole size has helped reenergize activity in this mature gas play.

Geology and Reservoir Characteristics

The Niobrara formation chalks were deposited during the last major transgression of the western interior Cretaceous sea, which extended from the Gulf of Mexico to the Arctic Ocean. Gas bearing chalk of the upper Cretaceous Niobrara formation is encountered at depths from 1000 to 3000 feet. Gas accumulations in the Niobrara formation generally are related to low relief structural features found along the eastern margins of the Denver geologic basin[2]. The formation is low permeability, underpressured and marginally economic.

DOE Microhole Drilling Program

The Department of Energy's Tulsa office has designed and is implementing a research program to develop marginal oil and gas resources utilizing microhole wellbores. The overall approach is to develop a portfolio of tools and techniques that will allow the drilling of 3 5/8" holes and smaller enabling through better economics the development of marginal oil and gas resources. The field testing and demonstration of a "fit for purpose" coiled tubing drilling rig is one project within the program. The objective is to measure and document the rig performance under actual drilling conditions. A description of the rig and a summary of its performance in the Niobrara gas play follow.

Description of the Rig

The coiled tubing drilling rig (designed and built by Tom Gipson with Advanced Drilling Technologies Inc. (ADT)) is a trailer mounted rig with the coil and derrick combined to a single unit. The rig has been operating for approximately one year drilling shallow gas wells operated by Rosewood Resources, Inc., in Western Kansas and Eastern Colorado. The rig operations have continued to improve to the point where it now drills 3,100 foot wells in a single day. Well cost savings of approximately 30% over conventional rotary well drilling have been documented. Improved well performance due to less formation damage as a result of minimizing formation exposure to drilling fluid through fast drilling and drilling operations is another important aspect.

Efficient Rig Mobilization

The rig moves with 4 trailer loads mitigating mobilization and transportation cost while meeting U.S. Department of Transportation limitations for highway transport. These features allow for smaller access roads and well locations reducing well costs. The rig contains all the equipment needed for drilling operations including a zero discharge mud system, has pipe handling capacity for casing up to7 5/8" and can support a rotary and top drive.

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Small Environmental Footprint

The small size of the rig provides several environmental advantages over a conventional rig. As a result of its efficient design and size the following environmental advantages are realized:

- A small drilling pad (1/10th acre) or no pad under some conditions can be utilized. Smaller access roads are required.
- No mud pit is needed; mud tanks contain the required drilling fluids and are moved with the rig from one location to the next. The only pit required is a small (3'x 6'x 6') pit for drill cuttings. If needed, cuttings are easily hauled off location allowing no pit drilling as needed.
- Smaller equipment yields less air emissions and low noise engines minimize disturbances to the surrounding environment.
- The microhole approach (4 ¾" holes) requires less drilling mud and fluids to be treated and yields fewer drill cuttings.
- The utilization of coiled tubing mitigates the risk of spills due to no drill pipe connections.

Rapid Drilling

Very high rates of penetration have been achieved by experimenting with bit-downhole motor combinations and by fully utilizing the advantages of coiled tubing drilling. Drilling rates as high as 620 feet/hour have been realized with the average rate of penetration per well in the 400 feet/hour range. This rate of drilling and other rig efficiencies allowed the drilling of a 2850 foot well in approximately 22 hours including all rig moving time, logging, casing setting and cementing and wells drilled at depths of 800 to 2000 feet required only 10 to 19 hours of total functional rig time.

Good Hole Quality and Cement

The benefits of fast drilling by the ADT rig is augmented by excellent hole quality. All the wells drilled have resulted in a gauge hole with very little hole deviation (1 to 2 degrees - well within State requirements) despite the high penetration rates. Good cement job quality and well bonded cement also derive from the gauge hole quality. As mentioned previously, the Niobrara is an under pressured reservoir and as such is susceptible to formation damage due to fluid loss from drilling operations. The ability of the CT rig to rapidly penetrate the pay zone while avoiding any of the pressure surges observed with conventional drilling helps to mitigate fluid loss that leads to formation damage. This is an important factor given the marginal nature of the resource.

Rig Capable of Running Casing, Handling Bottomhole Assemblies and Logging Tools –

No auxiliary equipment is required to run casing, log wells or for handling drill collars and bottom hole drilling assemblies. With its derrick, traveling block and rotary table components, all required drilling processes can be performed without additional equipment. While not currently equipped with a top drive, the rig can accommodate one if needed. Drilling with coiled tubing eliminates drill pipe connection time and fewer crew members are required to operate the rig.

Zero Discharge if Required

The rig has the capability to drill a well with zero discharge of any fluid or other materials if required. The procedure is as follows:

- Rig up on a sealed/booted tarp to contain any overflow or accidental spill.
- No earthen pits are prepared; all cuttings and drilling fluid are confined to tanks with which the rig is equipped.
- A hole is augured for conductor pipe and a boot is placed around the conductor pipe.

Using this process, the ground is protected from any inadvertent spills and all fluids and cuttings are removed from the location. While obviously an added expense, this procedure may be required for drilling in sensitive environmental areas. The small rig size and efficiency of drilling coupled with the zero discharge capability enables drilling in sensitive areas.

Improved Safety

Safety is always of utmost importance and the conventional drilling rig environment is one where extra caution and safety training is necessary due to the handling of drill pipe and other equipment. The ADT coiled tubing rig significantly reduces drill pipe handling and has less equipment to mobilize from well to well. All of this creates a much safer operating environment which is important during any time of drilling but especially so during today's high rig count when experienced roughnecks are difficult to find.

Barriers to Microhole Coiled Tubing Drilling

Barriers exist to full utilization of this type of approach to the drilling and completion of marginal resources. Operators have identified the following as concerns that must be addressed for microhole to reach its full potential:

- Production engineers have long-term concerns about the ability to rework wells.
- Handling of significant fluids is an issue in small boreholes.
- There is limited space for downhole mechanical equipment.
- A general lack of experience and familiarity with microhole and coiled tubing drilling of this type was identified as a barrier to usage.
- There is a depth limitation given current coil metallurgy and coiled tubing procedures.
- Coiled tubing is limited in its ability to overcome problems in difficult drilling environments. One example is where fluid loss and severe pipe sticking is encountered. Coiled tubing has limited tensile strength for freeing stuck pipe.

Technology Trends

Operators pursuing marginal resources are doing so in a new era. Driven by a growing economy, U.S. energy demand is expected to reach record levels in the near future. The higher quality resources have been exploited, increasing the challenge for future developments.

The rate of new technology improvement is beginning to be offset by the increasing challenges created by lower quality reservoir rock and increasing costs from environmental issues.

A concerted technology effort to both better understand marginal oil and gas resources and develop solid engineering approaches (such as the microhole program) is necessary for significant production increases from these widely dispersed resources.

Introduction

The Gas Technology Institute, with the support of the Department of Energy/National Energy Technology Laboratory (NETL) has completed field performance documentation of coiled tubing (CT) microhole drilling technology in the Niobrara gas play of Kansas and Colorado. The CT technology has the potential to substantially reduce the costs of drilling and completing oil and gas wells, which is key to increasing future U.S. production. In addition, the technology enables a reduced environmental footprint that should result in the ability to access resources in areas where environmental concerns would have been an impediment.

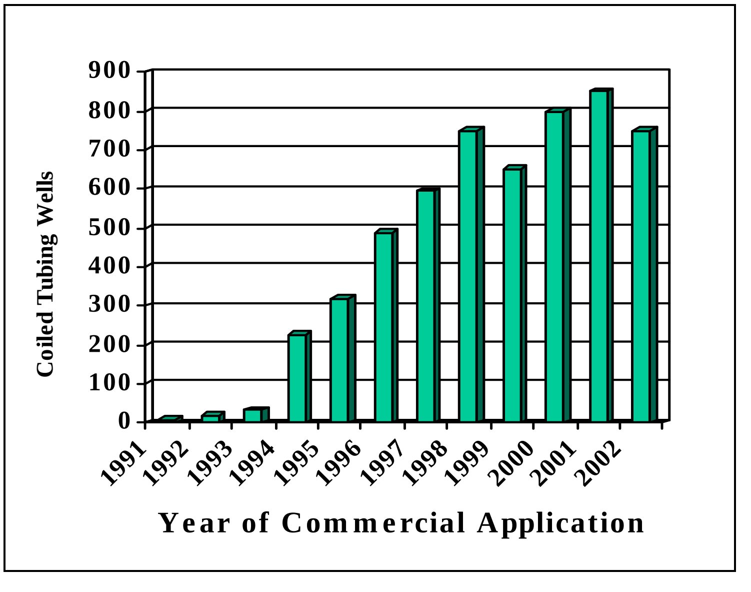
Coiled tubing microhole technology uses a coiled tubing rig and smaller diameter and less cumbersome drilling equipment that greatly reduce drilling time and costs. For this demonstration project, Microhole technology was defined as open hole drilling of 4 3/4 inch holes allowing wells to be completed with 2 7/8 inch tubing as the production casing. Much of the technology is comprised of downsized versions of existing standard diameter drilling equipment, including bits, motors, and bottomhole assemblies (Duttlinger, 2006). Drilling is accomplished utilizing continuous 2 5/8 inch coiled tubing. The bit is powered through turbines that are powered by the mud circulation.

Technologies include “built for purpose” coiled tubing (CT) rigs, specialized bits, and bottom hole assemblies to allow for steering, logging and communication with the surface. Well bores can be vertical or can have substantial horizontal components. Technologies to facilitate longer horizontal components are under development, and include downhole “tractors” to provide additional force on the bit. The small bit diameter not only allows faster rates of penetration, but results in a much lower volume of well cuttings and mud volume, and less expensive tubulars. The rig requires fewer personnel, and is faster to rig up and rig down. A closed mud system means that no mud pits are required.

A significant advantage of CT drilling is that it can be performed in an “underbalanced” mode, resulting in much less formation damage. Research has shown that many tight gas reservoirs are damaged during traditional drilling, resulting in a loss of eventual productivity. By not damaging the formation during drilling, CT often allows better production, whether the reservoir is stimulated or not. Under drilling conditions where overbalanced drilling is required, CT drilling has the advantage of rapid drilling through the pay zone without the pressure surges that accompany jointed drill pipe connections.

One of the most promising mechanical devices in achieving the benefits of well-bore diameter reduction is the coil tubing rig or CTR. Coil Tubing Rig (CTRs) of various commercial designs have made the first incremental reductions in wellbore diameters, though applications have generally emphasized simple vertical, non-steered holes in shallow reserves. As shown in **Figure 1**, CTRs have been in use for well drilling since the

Figure 1 - Annual Coiled Tubing Drilled Wells (Source; Spears and Associates, April 1993)



early 1990’s and over the past 15 years have increased from a few dozen wells in 1993 to nearly 800 per year by 2000 (Spears and Associates, April 2003). Although, worldwide, more than 8,000 wells have been drilled with a coil (mostly in Canada), the lower-48 of the U.S. has seen a more modest market penetration involving about 300 coiled tubing wells. In recognition of the potential beneficial impact of the technology to U.S. energy and environmental interests, the Department of Energy in collaboration with the oil and gas industry has pursued a Microhole Technology (MHT) Program aimed at developing a number of technologies that enable the drilling of wells with casings less than 4 ½ inches in diameter using coiled tubing drill rigs and downhole tools that are small, easier to mobilize than conventional drill rigs and tools and capable of drilling shallow and moderate depth holes for exploration, field development and long-term subsurface monitoring.

The Gas Technology Institute (GTI), in partnership with Coiled Tubing Solutions (now Advanced Drilling Technologies or ADT) and Rosewood Resources, Inc., has conducted a field test of a state-of-the-art Microhole Coiled Tubing Rig (MCTR) in the Niobrara gas fields (extending across Northwest Kansas and Southeastern Colorado) and conducted technology transfer efforts to augment interest and acceptance of the technology within the natural gas industry. In this effort, GTI has provided overall project management, collected operational data during field testing, prepared the field test documentation and managed the technology transfer aspect of the program. In coordination with the testing, ADT provided the MCTR rig and the rig crew as well as maintenance and operations support during the field testing phase of the project. Rosewood Resources, Inc. served a vital role in providing drilling locations for the test drilling.

The purpose of the MCTR project was to conduct a series of field demonstrations of a commercial microhole drilling rig to objectively measure the performance and capabilities of currently-available microhole technology (MHT) equipment under varied drilling conditions. The work was conducted against the backdrop of anecdotal information on commercial CTRs that suggested that coil tubing drilling could be used at moderate depths at significantly reduced cost compared to conventional techniques. The aim of the MCTR project was to develop an objective information base that could be used to more accurately determine the envelope of conditions where applications of the environmentally friendly technology are clearly feasible and cost-effective with the end result of augmenting interest in the industry for greater use of the technology.

Background

In concept, microhole technology based on coil tubing uses less cumbersome drilling equipment that enables smaller crews to rig up, drill and rig down for exploration, thereby significantly reducing the costs and risks of drilling wells for gas and oil producers. The smaller drilling operation also reduces drilling waste and minimizes environmental impact, which has been a major obstacle to expanded oil and gas exploration and development in the United States, especially in environmentally sensitive areas.

The coiled tubing rig design concept consists of using a reduced-diameter, continuous coiled tube mounted on a large spool (about 7 ft in diameter) to drill an open hole using a trailer mounted drill rig that supports and feeds the coil into the hole as drilling progresses. Coiled tubing (CT) was first employed for solving an oilfield problem in the 1960’s when the California Oil Company and Bowen Tools created the first fully functional CT unit to wash out sand that was obstructing oil flow in its wells. Further development of the technology to enable application to oil and gas exploration and field development did not occur, however, for several decades.

In terms of its effective market penetration into modern E&P practices, coiled tubing (CT) drilling represents a recent innovation that has been used for mostly shallow drilling for oil and gas exploration since the early 1990's (Fultz and Pitard, 1990). Application of the technique was reported in a successful horizontal well case history conducted in 1992 (Ramos, et al.). During this period, field trials and qualitative observations revealed a number of strengths and limitations of the early CT rig designs (Byrom, 1999), the most notable of which was the ability of CT to speed up oilfield operations for certain types of applications. Specific advantages compared to conventional jointed pipe well construction designs and limitations revealed by field application of early CT designs are shown in Table 1.

Table 1 - Observations from First Generation CT Applications to Oil and Gas Exploration and Production (Source: Byrom, 1999)

Advantages	Limitations
• Portability and mobility • Ability to drill and trip under pressure • Significantly reduced tripping time for bit or bottom hole assembly changes • Enabled continuous, high-quality telemetry between surface and downhole for real-time data acquisition and control • Continuous drilling fluid circulation while tripping • Ability to drill under pressure • Significantly reduced footprint of the operation • Reduced drill rig labor compared with conventional tripping	• High maintenance requirements for first generation units • Relies on slide drilling because it is not able to rotate the drill stem • Requires a downhole drilling motor (hydraulic or electric powered) • Short tube life • Limited fishing capabilities • High circulation pressures • Low circulation rates

Some functional components of a CT drill rig are similar to those of conventional drill rigs. Each type of rig has circulating pumps, mud mixing process, mud tanks, solids removal equipment, controls, etc. However, a major strength of the CT system is the ability to mobilize, demobilize and rapidly transport equipment in and out of each drilling site. This ability is enabled by the relatively compact design of the CT assembly which is mounted on six or less trailers. For most CT systems, the distinctive elements of the assembly that are most visible include the reel, injector head, pumping unit, power pack, blowout preventor (BOP), and the control housing; all of these pieces are trailer mounted and easily moved from location to location (Byrom, 1999).

The reel consists of a large drum on which the coiled tubing is wound and unwound during the operation of the rig. The tubing diameter can range from 0.8 to 4 inches. The injector head is the device that provides the force to run the CT down the well and to retrieve it. This piece of equipment features a "goose neck" that straightens the CT and prepares it to be introduced into the well. Supporting these components is the power pack that generates the pneumatic and hydraulic power required for operating the CT rig operation. The BOP is a well control component that allows an operator to isolate the downhole CT as a safety measure. The control house is where the operator monitors well bore pressures, gases, equipment pump rates, fluid volumes, drill rates, speeds, torques, and other parameters related to CT operation. From this center, the operator can make necessary adjustments in equipment operation and can institute several safety interventions if needed.

Considerable redundancy in safety is incorporated in commercial CT rigs as a standard practice. Unlike a conventional drillstring, if the well is under pressure, the entire CT that is not in the hole is also under pressure. To address this situation, several redundant safety devices are incorporated into the CT system design to allow safe well intervention, if needed. First, the BOP, located below the injector and above the wellhead, is controlled from the operator's station and isolates the well with pipe blind, and shear rams. Second, several safety features have been installed in the bottom hole assembly (BHA) for added protection. To prevent leaks from the CT that is not in the hole, one or two check valves can be installed in the BHA. Further safety is provided by an emergency disconnect that allows a CT unit operator to disconnect the CT from the BHA if it becomes stuck (Byrom, 1999).

Downhole equipment for CT drilling can be simple or complex. For simple vertical drilling, equipment may consist of a bit, downhole motor and a few drill collars. A directional bottomhole assembly may consist of a bit, a steering tool to sense and transmit directional data, a bent-housing mud motor, an orientation tool to change the direction of the bit, and an array of optional transducers to obtain log data on bottomhole pressure, weight on bit, bit torque, temperature, and vibrations. Sensing and control devices are usually in a two-way communication with the surface through one or more electric and (often) hydraulic lines inside the coiled tubing (CT). These cables and tubes provide a two-way telemetry and control between the operator and the devices in the bore hole assembly (BHA). Cables and tubes add to the weight of the CT string and can restrict internal flow. However, they also provide an advantage over conventional of improved two-way communication and high-quality real-time data from downhole instruments. Contributing to the success of commercial CT drilling in Canada and around the world has been the value of communication and the integration of real-time data required to make rapid and concise decisions pertaining to drilling operations, underbalanced conditions and directional performance (Elsborg, 1996).

Although CT drilling is conducted with a low weight on bit compared to conventional drilling, improved monitoring and control of downhole equipment continues to improve rates of penetration (ROP) for CT, from below 100 ft per hour in the late 1980's to ROP's over 200 ft per hour less than a decade later (Elsborg, 1996). However, much of the advantage of achieving higher ROPs can be eroded if the complexity of the CT rig requires considerable time for rig up and rig down. Typically, conventional CT units require 5 to 6 truckloads of equipment and possibly more if the drilling is to be done underbalanced. Even for vertical drilling in shallow-to-moderately deep formations, significant time may be required for assembly of the CT rig and for the careful alignment of the injector head with the reel and wellhead equipment. New rigs that are built for purpose have made progress in simplifying mobilization and rig up procedures. Thus, future improvements in efficiency and economics of CT drilling depend on continued progress in not only achieving higher ROP levels but on decreasing operator time components related to maintenance, rig up and rig down.

Notwithstanding the progress made in CT design and overall performance, little market penetration has been achieved for CT drilling services in the lower 48 compared with the rest of the world. Within the U.S., individual CT drilling service firms working in niche applications have obtained valuable knowledge of CT field performance, but very little of this information has been communicated to the oil and gas industry. To date, CT drilling performance has yet to be quantified in a systematic manner that is meaningful across an array of drilling functions, conditions and parameters that affect performance and cost. The purpose of this project was to obtain field measurements of performance and cost on one of the most advanced commercial CT rig designs that has reached new levels of ROP performance, process integration, reduced turn-around times for rig-up/rig-down and ease of mobility. The aim of this project was to supplement industry awareness and increase confidence in the potential applications, capabilities and benefits of CT technology in the challenging arena of expanded oil and gas exploration and development for the lower 48 in the 21st century.

Statement of Work

Objective

The overall objective of this project was to evaluate the operating efficiency of a microhole coiled tubing rig for drilling and completing boreholes in oil or gas formations to depths up to 5,000 ft. The rig that was tested was fabricated by Coiled Tubing Solutions Inc. (CTS) and was deployed on many leaseholds owned by Rosewood Resources Inc. (Rosewood). The testing was aimed at evaluating, objectively and subjectively, the performance of the rig as compared to performance of a conventional rotary rig under similar circumstances. Evaluations were to be made on a wide array of CT rig functions and included analyses of mobilization and rig up times and costs, drilling of surface and production holes (time, cost, crew size, safety, environmental factors), running surface casing and cementing (time, cost, crew size, safety, environmental factors, and subjective comparison with conventional rotary rig operation), running production casing (costs, times, efficiencies, safety), logging and evaluation, and demobilization and move out. Factors that were to be evaluated included time, cost, crew size, safety, environmental factors (such as drilling mud control), site access (drill roads, need for drill pad, time to reach drill site with full rig), operational issues (drilling speed, weight on bit, bit RPM, torque requirements, drag, pump pressures, weight-on-bit, fuel consumption), linearity of the hole, ability to control bit direction, and mobilization and demobilization issues (time, crew size, need for external equipment). Subjective observations of operational efficiency were also to be included in the performance analysis. Project goals included extensive videotaping of the CT rig in operation to document performance and provide materials for technology transfer. A second major objective was to initiate technology transfer industry to communicate the capabilities, performance and cost of the CT rig technology to the oil and gas industry.

Tasks

Within the scope of work, GTI was to evaluate the performance of the CTS coiled tubing rig on drilling leases held by Rosewood Resources. Prior to initiating field work, the GTI/CTS/Rosewood team, with the concurrence of DOE, selected the drilling sites that test the efficiency of the drilling equipment in both shallow and deep formations and under various drilling conditions. Testing was to monitor drilling at sites with depths of 1,000’, 2,500 feet, and up to 5,000 and was to be conducted, as available, at leaseholds in the Niobrara formation within Oklahoma, western Kansas, and/or Colorado. The scope of work included the following specific tasks.

- Task 1 – Finalize Test Plan
- Task 2 – CTS Rig Testing and Data Collection
- Task 3 – Technology Transfer
- Task 4 – Final Report Preparation
- Task 5 – Project Management

Descriptions in detail of each of the above tasks are given in the following sections.

Task 1 – Project Planning

This task was to be comprised of the Planning Phase. This task was to consist of defining the exact wells and locations for the drilling program. This task was to be performed in conjunction with Rosewood Resources and was to include an evaluation of their final year 2005 drilling program and the selection of a portfolio of wells for the research project best suited to achieving the project objectives. The aim of the project planning was to design an equipment performance verification effort for the CTS Microhole Drilling System that could establish an information base that could be used by commercial firms to assess the technical feasibility and economic benefit of implementing the technology in their future exploration and production businesses. Ideally, this information base could be used to attract energy companies to use the new microhole technology and accelerate the benefits of this technique to the industry, the public and to the environment. To construct a database of this nature, the information collected in the field verification study was to cover a range of conditions that potential customers could relate to in their assessment of the technology for future well field development efforts.

Well selection criteria were to be established as part of the planning phase to obtain a meaningful information base on microhole drilling performance and to establish an optimum portfolio of customer-relevant conditions. Selection criteria were to include items such as well depth, drilling problems known to the specific area, casing size requirements based on expected production, surface conditions including required drilling pad size and requirements for protecting crops and fresh water resources. The selection criteria were to be designed to document drilling performance and costs under conditions that have relevance to a wide span of potential oil and gas industry applications.

Working with Rosewood, DOE Project Management and Mr. Tom Gipson, GTI was to prepare a matrix of well drilling parameters and conditions that were projected to be encountered during the field performance trials of CTS equipment. Then, a drilling plan was to be prepared that would identify wells that relate to the characteristics and parameter values of each element of the test matrix. Objectives for each well to be drilled were to be established based on the overall project objectives and wells of opportunity. The final project schedule for drilling of the project wells was to be determined according to both project requirements and area of operations drilling windows. Using these considerations, a test plan document was to be prepared; this plan was called a *"Portfolio of Project Wells, Individual Well Objectives and Drilling Schedule".*

Task 2 – Data Collection and Field Operations and Analysis

This task consisted of executing a carefully-designed field effort to measure and document the performance and economics of Coiled Tubing Microhole Drilling equipment. Approximately 15 wells were to be drilled; each of these wells was to relate to an element in the test matrix based on its anticipated characteristics. The characteristics of each well were to be described in a manner that would provide a meaningful contextual framework, yet protect the proprietary aspects of exact locations and business-sensitive planning information. The specific subtasks included in this effort are described in the following sections.

Subtask 2.1 – Data Collection and Field Operations

Based on the schedule, test matrix and test plan prepared in Task 1, field operations and data collection were to be performed. The following test protocol steps were to be performed on each of the approximately 15 project wells:

1. Prepare individual well data requirements for all project wells

2. Based on overall project objectives finalize specific well objectives
3. Identify and procure any special testing instruments or services for the well
4. Hold planning meeting with field personnel to define roles and responsibilities and to impress upon all that this is a research experiment requiring quality operations and attention to detail
5. Drill the project well to gather required data
6. Assess results of data gathering, analyze procedures, review with all team members and utilize results for modification of plans for the next project well
7. Repeat procedure at Step 2 for all subsequent project wells

The deliverable for Subtask 2.1 was to be a database consisting of a tabulation of all relevant field data.

Subtask 2.2 – Data Analysis

GTI was to compile and assess the field data and perform an evaluation to identify the performance attributes, shortfalls and overall efficacy of microhole drilling in the area of operations. GTI was to compare the CT drilling rig results to those for conventional drilling and compile the results into a format suitable for workshops, publications and the final report. Integral to the analysis was to be a presentation of the results of an estimated 15-well information base with important “take away messages” clearly identified.

Task 3 – Technology Transfer

Task 3 was to involve activities that contribute to technology dissemination in the oil and gas industry. Major activities were to include participating in industry workshops designed to present the important results of the CTS microhole drilling performance and, if possible, providing a field demonstration of the equipment at an actual site.

Task 4 – Report Writing

A final report documenting all results of the project was to be prepared according to DOE criteria.

Task 5 – Project Management

Project management and data collection coordination was to be provided by GTI. Particular attention was to be directed at tracking the progress of the project consistent with achieving project objectives/deliverables within schedule and within budget while maintaining close communication with the DOE Project Manager.

GTI/CTS/Rosewood Approach

Overall, this project was aimed at documenting the field performance and operating efficiency of an advanced coiled tubing rig in the course of drilling wells at various depths under a range of well-defined conditions. This required the coordinated effort of an R&D organization, an energy developer and CT rig services company to first create and implement a test plan encompassing a range of test conditions to document CT rig performance in the field. The project involved the collection of objective measurements and subjective observations during the drilling of 25 project wells. In addition to direct observations of the quality of well bore construction, waste management, worker safety and environmental footprint resulting from the rig operation, a set of empirical measurements on mechanical operation (e.g. drilling speed, weight on bit, bit RPM, torque requirements, drag, pump pressures, fuel consumption, etc.) were obtained from the CT rig. Equally important, for each well that was drilled with the advanced CT rig, a set of time-function data was obtained to provide detailed information on operational efficiencies. In addition, still photos and videotaping were employed to provide detailed visual information on the CT rig during its set-up, take-down and operation. This multi-faceted effort depended upon the cooperation and combined capabilities of the organizational team of GTI, CTS and Rosewood Resources, Inc. and represents an unprecedented effort in the documentation of commercial MCTR technology under field conditions.

Roles of Project Team Members

Three organizations participated in the Microhole Coiled Tubing Drilling project: Gas Technology Institute (GTI), Rosewood Resources and Coiled Tubing Solutions (CTS). Coiled Tubing Solutions through the course of the project formed a new company (Advanced Drilling Technologies, Inc. (ADT)) which is located in Yuma, Colorado. ADT served as the project partner replacing CTS. Following is a brief description of each organization and their respective roles in the project.

GTI is a leading research and development organization serving the energy industry. GTI's E&P center has a history of solving the industry challenges and moving the results to the marketplace. GTI's multi-disciplinary research program to coal-bed methane development contributed to the economic development of this resource. For the Coiled Tubing Drilling project, GTI served as overall project manager and documented the performance of the drilling rig in the field. Additionally, GTI had responsibility for technology dissemination assuring widespread distribution of the project results.

Coiled Tubing Solutions (CTS), located in Eastland, Texas, was founded by Tom Gipson in response to a need for a company to build coiled tubing rigs. Mr. Gipson filed a coiled tubing patent in 1987 that helped him pioneer the used of coiled tubing for plug and abandonment work. Mr. Gipson subsequently went on to build or supervise the fabrication of 15 coiled tubing rigs, including 7 of the 24 currently running in Canada drilling gas wells up to 5,000 feet deep. CTS has the ability to prepare the engineering designs and calculations for drilling rigs, and to fabricate the final drilling rigs. CTS formed Advanced Drilling Technologies (ADT) and participated in the project through that entity. ADT is located in Yuma, Colorado. ADT role in the project was to make available the coiled tubing rig and assist GTI in documentation of rig performance. This was accomplished as the rig operated on commercial wells.

Rosewood Resources is a division of Rosewood Corp., and owns oil and gas leases throughout the Gulf Coast, Oklahoma and Colorado. Rosewood drilled over 100 wells in 2005. Rosewood Resources provided access to the leases they were drilling in the Niobrara formation of Northwestern Kansas and Southeastern Colorado. Overall, 23 project wells were provided by

Rosewood for monitoring and documentation of the coiled tubing rig performance. Rosewood also provided advice and information regarding the geology, well completion procedures and other data important to the program.

The table below identifies all of the project participants and their respective roles. PTTC was not a contractual partner to GTI but provided Technology Transfer functions such as workshop opportunities and organizing review meetings.

Table 2 - Microhole Coiled Tubing Drilling Project Team Members

Subcontractors/Industry Partner	Role	Project Role
Coiled Tubing Solutions (CTS) / Advanced Drilling Technologies (ADT)	Supplier/ Consultant	Experimental Rig Supplier Design/Fabrication consulting Coiled Tubing Costs
Rosewood Resources Inc	Leaseholder	Sites for Testing Authorizations for Expenditure Historical drilling costs
PTTC	Forum For Tech. Transfer	Outlet for Technology Transfer
Department of Energy	Government Partner	Contracting Source

Rosewood Geologic Setting

Rosewood owns reserves in the Niobrara formation (see **Figures 2 and 3**), chalks deposited during the last major transgression of the western interior Cretaceous sea, which extended from the Gulf of Mexico to the Arctic Ocean.

The current play extends through Northwest Kansas and Eastern Colorado (**Figure 3**). Gas bearing chalk of the upper Cretaceous Niobrara formation is encountered at depths from 1000 to 3000 feet. Gas accumulations in the Niobrara formation generally are related to low relief structural features found along the eastern margins of the Denver geologic basin (Brown, et al.,1982).

Figure 2 - Photomicrograph of Niobrara Chalk Formation, Characterized by high porosity (30 to 50%), Low k (.01 to 3 md), Depth = 1500 to 3000 Ft, Biogenic Gas in Low Relief Structures

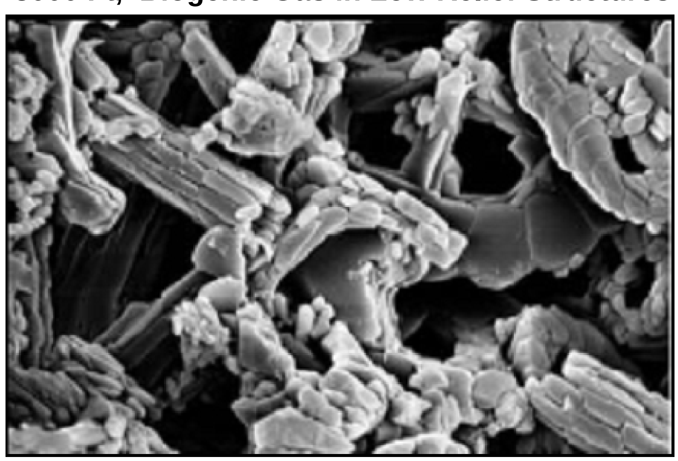
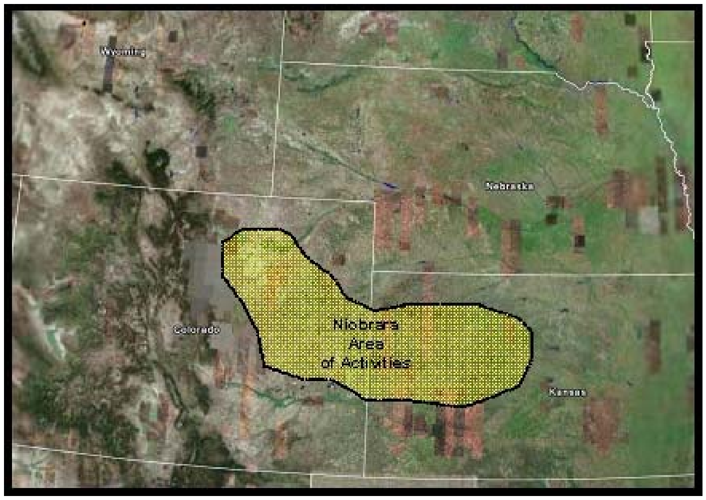


Figure 3 - Niobrara Gas Play area in Kansas and Colorado

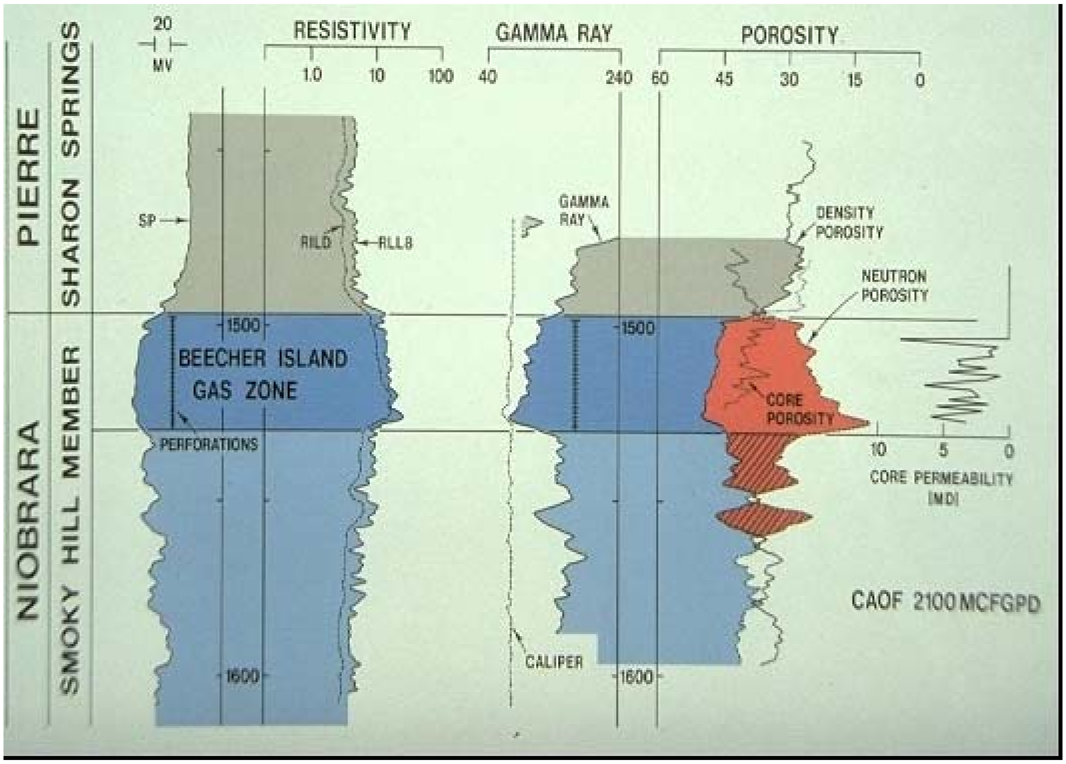


Niobrara gas fields are characterized by high porosity, low permeability and low reservoir pressure. These features are typical of a chalk subjected to modest burial depths (Scholle, 1977). At greater depth, porosity and permeability decrease causing a reduced total pore volume and higher water saturation at a given structural position.

Reported values for porosity in the Niobrara formation range from 30% to 50%, with lower values found at greater depths. Despite the high porosity of the chalk, permeability is inherently low because of the fine grain size. Values for permeability range from 0.01 to 0.3 millidarcies in the fairway with microdarcy permeability found on the fringes. The Niobrara is an underpressured gas reservoir with geostatic pressure gradient ranges from 0.06 to 0.24 psi/ft. In the Goodland, Kansas area, at a depth of 1,000 feet the pressure is only 50 to 60 psi.

Thin pay zones (sometimes near water), low reservoir pressures and low in-situ formation permeability (requiring wells be hydraulically fractured) combine to create a challenging environment for successful field development. Certainly, an efficient low cost approach to well drilling and completion is needed (**Figure 4**). The production stabilizes at 30 to 50 mcf/Day and reserves per well amount to approximately 75 to 125 mmcf with 30 year producing life.

Figure 4 - Niobrara Formation Logging Showing Pay zone Area

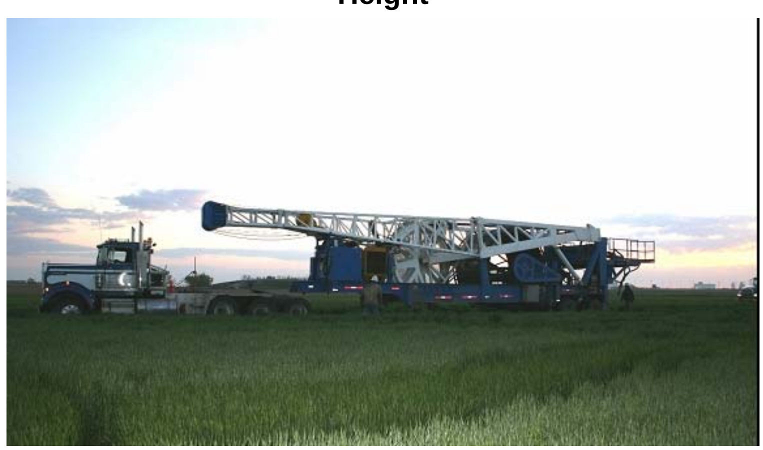


CTS Rig Description

The coiled tubing drilling rig used in this study is a trailer mounted rig with the coil and derrick combined to a single unit (**Figures 5 and 6**) and was built by Advanced Drilling Technology (ADT).

The rig has been operating for approximately one year, drilling shallow gas wells operated by Rosewood Resources, Inc., in Western Kansas and Eastern Colorado. Rig operations have continued to improve to the point where it now drills a 3,100 foot deep well in a single day. The rig (**Figure 5**) moves with 4 trailer loads to mitigate mobilization and transportation costs while meeting U.S. Department of Transportation limitations for highway transport. During transit, the rig trailer hosts the drilling rig and reel. The trailer weighs 140,000 lb and is 50 feet long by 12 feet wide. These features allow for smaller access roads and well locations, which in turn reduces well costs. The rig contains all the equipment needed for drilling operations including a zero discharge mud

Figure 5 - CT Rig in Trailering Position; Rig Trailer with Dimensions of 50' in Length, 12' Wide and 15' in Height



system (discussed later), has pipe handling capacity for casing up to 7 5/8” and can support a rotary and top drive.

The rig trailer is the first trailer to be aligned on the surface hole. The tower is positioned flat on the trailer while transporting the rig, but rises hydraulically when the rig is raised. The height of the crown is 53 feet, when measured from the rig platform (**Figure 6**).

The coiled tubing is mounted on a reel (**Figure 7**) on the rig that can handle 1 to 2 5/8” of coiled tubing size and drill up to 5000 feet from the surface into the formation. Mud and fluid circulation enter the tubing on the surface through swivel mounted on the reel.

Figure 6 - Coiled Tubing Rig - 53 feet High.

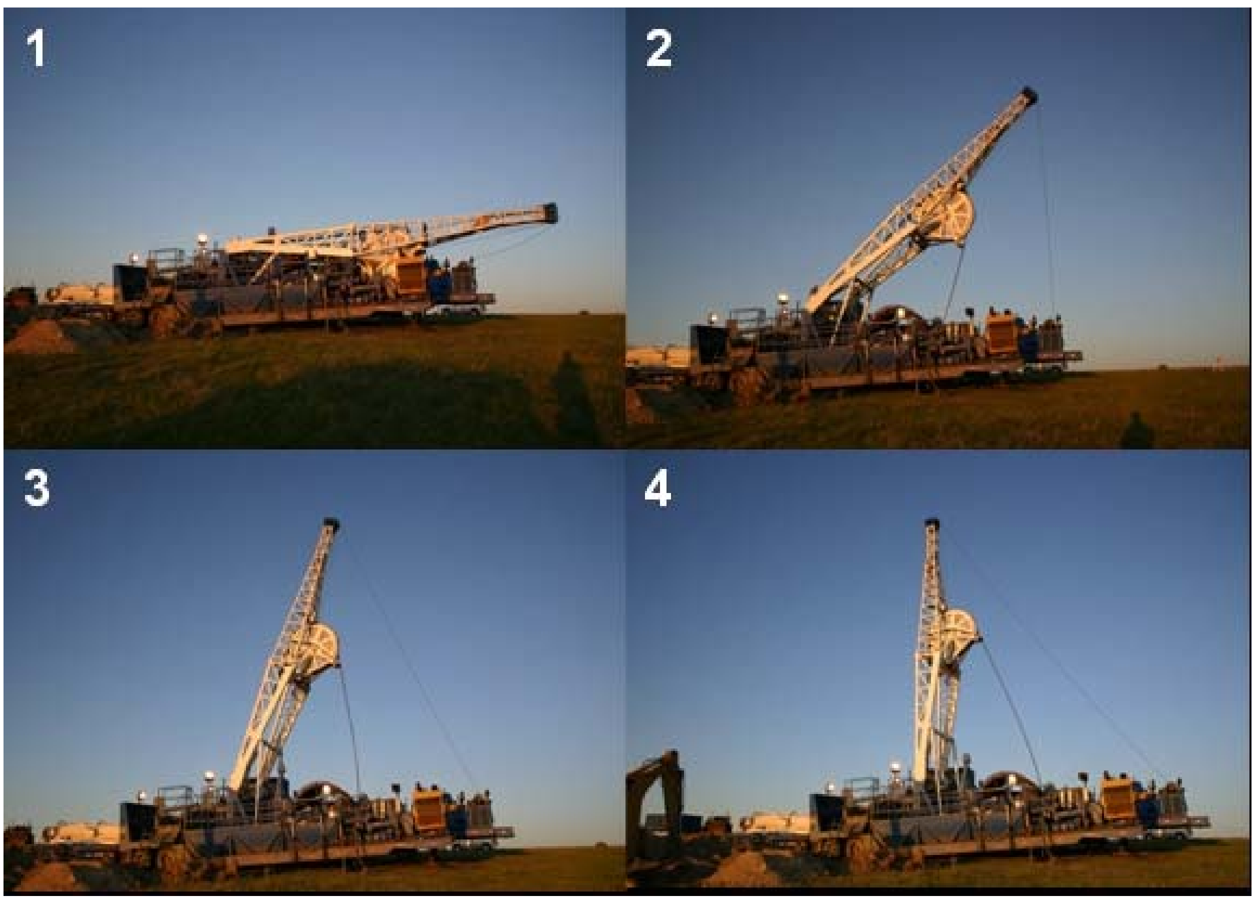
Figure 7- Coiled Tubing Drilling Rig Reel Mounted on the Rig Trailer

After positioning the rig on the surface hole, the rig can by aligned precisely by hydraulic mechanism that is available in the rig (**Figure 8**).

Figure 8 - Rig Surface Alignment for Precise Positioning

Once the rig is aligned on the surface hole, the tower rises up hydraulically from horizontal to vertical position; (Figure 9) shows the elevated stages.

Figure 9 - Coiled Tubing Drilling - Rig Up



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The Second trailer, which is aligned with the rig trailer is the operator and power trailer, and the dimensions if this trailer is 50 feet long with 10 feet wide and weigh 50,000 lb (**Figure 10**).

Figure 10 - The Operator Trailer controls and provides power to the Drilling Rig

Figure 11 - Operator Trailer aligned next to the Rig Trailer.

The operator trailer is positioned next to the rig trailer, as shown in **Figure 11**. The trailer holds the fuel tank and generator (**Figures 12 and 13**). The generator consumes approximately 450 gallons per day of diesel fuel. The power supply is much smaller and quieter than a conventional drilling rig.

Figure 12 - Fuel Tank Mounted on the Operator Trailer

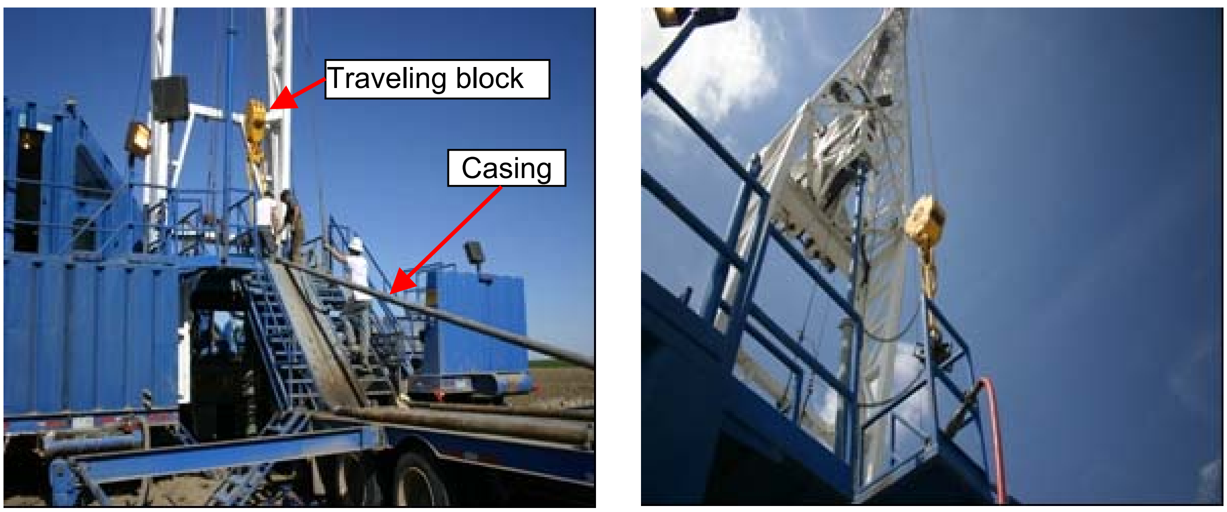
Figure 13 - Generator on the Operating Trailer

The operator room includes all of the necessary rig operations and monitoring tools. From this location the operator can control the rig operation from move in, rig up, circulation, connection, BHA, drilling, casing, cementing and logging, and rig-down. **Figure 14** shows the control room (doghouse) from inside with the monitoring instrumentation and viewing window.

The traveling block can be controlled from the operations room. Through the traveling block all the operations associated with raising, lowering or handling the pipes for connections can be controlled, as shown in **Figure 15.** The traveling block improves pipe handling capabilities and eliminates the need for auxiliary equipment to run casing and for make-up of bottomhole assemblies (BHA).

Figure 14 - View from the CT control room ("doghouse")

Figure 15 - The traveling block is controlled from the control room and allows the operator to control all rig operations, including rig up, BHA, casing and logging



The rig also has a rotary table that allows precise placement of the coiled tubing as well as centralizing the casing as it is installed.

The third trailer is a mud tank with a zero discharge system; the trailer is approximately the same size as the operations trailer - 50 feet long, 10 feet wide and weighing 50,000 lbs. It is aligned on the opposite side of the drilling rig trailer from the operations trailer (**Figure 16**).

The trailer contains the mud tanks, mesh for filtering the cuttings and mud shakers, and mud circulation system, as shown in **Figure 17**

Figure 16 - Mud Trailer and Zero Discharge System Aligned Next to the Drilling Rig Trailer, on the left hand side of the photograph

Figure 17 - Mud Tank Trailer, Mud Shaker and Zero Discharge Mud System

The rig has the capability to drill a well with zero discharge of any materials. The drill rig and mud sump trailer are placed on a sealed/booted tarp to contain any overflow or accidental spill. In most cases, cuttings and drilling fluid are held in tanks on the mud trailer. Using this process, the ground is protected from any inadvertent spills and all fluids and cuttings are removed from the location. While obviously an added expense, this procedure may be required for drilling in sensitive environmental areas. The mud tanks containing the required drilling fluids are moved with the rig from one location to the next.

Figure 18 - Mud Pit for Drill Cuttings if needed; The Pit is (3'x 3'x 6')

The only pit required is a small (3'x 6'x 6') pit (**Figure 18**) to hold the drill cuttings. Alternately, if needed due to environmental concerns, these cuttings (usually amounting to less than 4 tons) can be contained and hauled offsite for disposal.

The fourth trailer is the casing trailer. The dimensions of this trailer are again similar to the operating and mud trailer - 50 feet long, 10 feet wide and weighing 50,000 lb. When the rig is set up on the drilling site, the casing trailer (**Figure 19**) is aligned with the back of the drilling rig.

Figure 19 - Casing Trailer Aligned on the Back of the Drilling Rig Trailer

When the drilling rig is set up, the four trailers are integrated for operation. **Figure 20** shows the layout of the four trailers. The casing rig is backed up to the drilling rig when in operation.

Figure 20 - Integration of the Four Trailers, Casing, Operator, Drilling Rig and Mud Tank

The CT rig has the following design advantages over conventional drilling rigs:

- The coiled tubing drilling rig has a small foot print. It is approximately 50 feet high and only about 100 feet long, including the drilling trailers and the casing trailer.
- The rig is capable of running casing as well as handling bottom hole assemblies and logging tools
- No auxiliary equipment is required to run casing, log wells or for handling drill collars and bottom hole drilling assemblies.
- With its derrick, traveling block and rotary table components, all required drilling processes can be performed without additional equipment.
- Drilling with coiled tubing eliminates drill pipe connection time and fewer crew members are required to operate the rig. Casing pipes for the selected wells were of 2 7/8” in diameter with each piece of casing being 30’ long. **Figure 21** shows casing in progress, with the casing trailer backed up to the drilling rig. The figure shows handling capability of the coiled tubing drilling rig.

Figure 21 - Coiled Tubing Drilling Rig handling Casing without Extra Equipment

With these capabilities, the casing time is cut very short. For example, casing a well to a depth of 1512 feet required only 1 hour and an average of 1 to 3 minutes to connect each casing pipe; these tasks were easily handled by 3 staff members of the rig.

A bottomhole assembly (BHA) can be assembled without any extra equipment. The traveling block allows all necessary pieces of the BHA to be held in place while the BHA is being assembled. A bottomhole assembly can be put together in about one hour, including the bit, multiple drilling collars and the drilling motor, **Figure 22**.

Figure 22 - Bottom Hole Assembly (BHA) being assembled on Coiled Tubing Drilling Rig

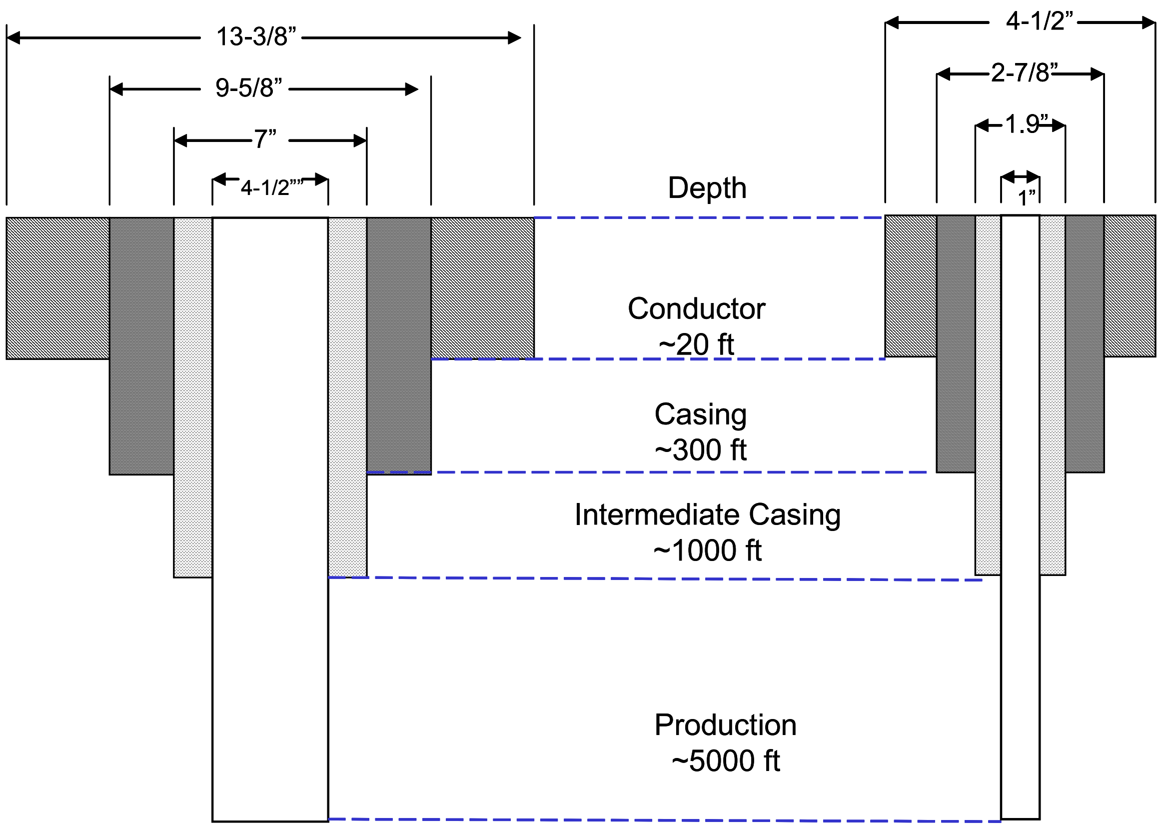
As with the BHA, the logging unit is assembled with simple components and handled with no extra custom-made equipment,. The logging tool is taken from the logging service company truck and lowered down-hole by the traveling block as shown in **Figure 23**.

Figure 23 - Logging Tool and Logging Trucks

Coiled tubing has several advantages over conventional drilling rig, one of the comparison that is made is the location and the size required to operate, the well sites are only one-quarter to one-third the size of the conventional drilling pad. The small size of the rig provides several environmental advantages over a conventional rig. As a result of its efficient design and size, the Coiled tubing have environmental advantages such as a small drilling pad (1/10th acre) or no pad under some conditions can be utilized. Smaller access roads are required, no mud pit is needed; mud tanks contain the required drilling fluids and are moved with the rig from one location to the next, the only pit required is a small (3'x 6'x 6') pit for drill cuttings, If needed, cuttings are easily hauled off location allowing no pit drilling as needed, smaller equipment yields less air emissions and low noise engines minimize disturbances to the surrounding environment, the microhole approach (4 ¾" holes) requires less drilling mud and fluids to be treated and yields fewer drill cuttings and the utilization of coiled tubing mitigates the risk of spills due to no drill pipe connections.

A comparison has been made by Albright (2001) between two wells of 5000' deep, one is conventional and the other one is microhole coiled tubing, the result is presented in **Figure 24**.

Figure 24 - Comparison between conventional and microhole at 5000 feet deep well.



Integrated Approach

The Gas Technology Institute (GTI), in partnership with Coiled Tubing Solutions, Inc. (CTS) and Rosewood Resources, Inc., proposed to field test a state-of-the-art Microhole Coiled Tubing Rig and conduct technology transfer efforts to generate interest and gain acceptance for the technology. GTI provided project management, collect operational data during field-testing, prepare the field test documentation, and manage the technology transfer aspect of the program. CTS provided the rig and the rig crew as well as maintenance and operations support during the field-testing. Rosewood Resources, Inc. is the owner that provided drilling locations for the testing program.

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The rig shown in Figures 5 and 6 is a state-of-the-art, 2 5/8"coiled tubing rig fabricated by Coiled Tubing Solutions specifically for coiled and microhole drilling to depths up to 5,000 feet. This rig, deployed in August 2004, includes its own Zero Discharge Mud System.

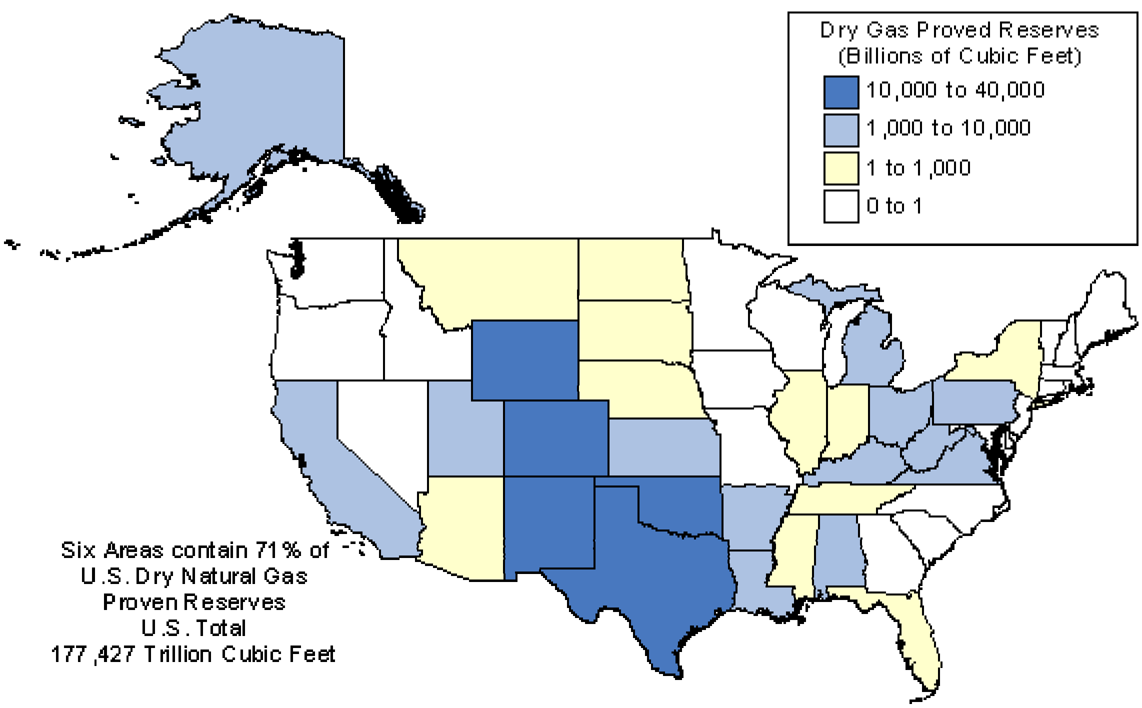
DOE's Oil and Gas Technology Program mission is to invest in long-term research with the potential for high public payoffs (cleaner environment, more secure and stable supplies, lower production costs, and new energy resources).

The CTS 'Coiled Tubing' Rig addresses DOE's goals, as follows:

- The 'Coiled Tubing' Rig has the capability to handle 1" through 3 ½"coiled tubing, has the ability to drill and case surface, intermediate, production and liner holes, and supports both rotary and top drive units.
- The rig is designed to drill as deep as 5,000 and supports both low-cost directional drilling and through-tubing micro-lateral drilling using a directional cutter head
- The rig includes a zero-discharge mud sump system, handles low density, compressible drilling fluids, and includes a sealed containment system under laying the rig to contain any fluids.
- The Rig is able to run 7⅝" range 3 casing
- The Rig is trailer mounted (4 trailers) and meets USDOT limitations for highway transport

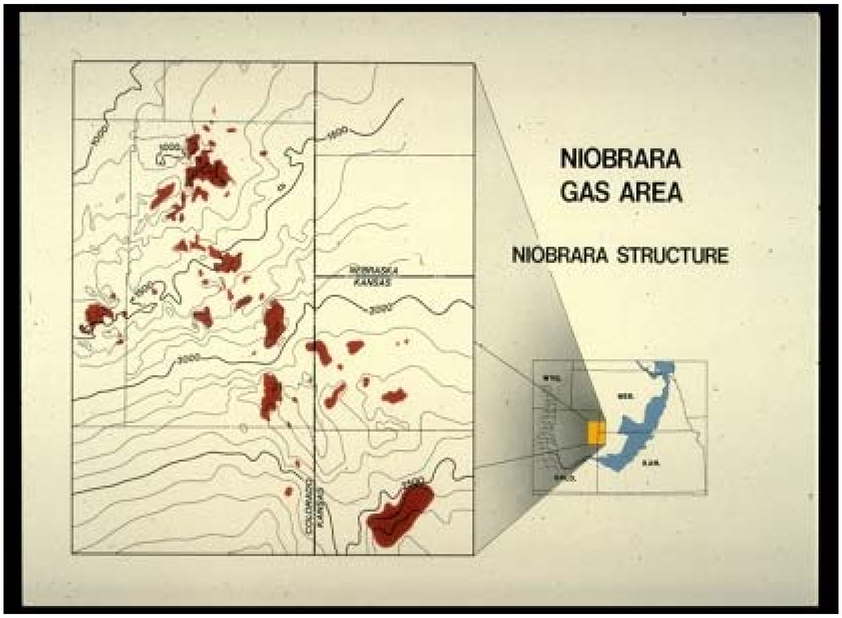
Figure 25 shows the location of U.S. Natural Gas Reserves, excluding offshore reserves. U.S. oil reserves have a similar distribution, although some states have higher petroleum reserves than those for natural gas.

Figure 25 - Location of U.S. Natural Gas Reserves



Rosewood Resources and its parent company, Hunt Petroleum, own reserves in the most productive states, and are currently funding drilling by Coiled Tubing Solutions (CTS) in the Niobrara Gas Area in western Kansas. **Figure 26** sows the Niobrara Gas Area drilling sites in Kansas and Colorado. Preliminary results of the drilling program have been sufficiently successful that Rosewood has extended the drilling program to other leases and has requested a quotation from CTS for a second rig, to be dedicated expressly to Rosewood Resources. This rig was subsequently built and is now drilling in the same Kansas/Colorado area.

Figure 26 - Rosewood Drilling Locations



Rosewood Resources drilled multiple sites in Kansas and Colorado. GTI worked with Rosewood to identify multiple locations with varying geology and depth to resource. GTI monitored drilling performance at 25 locations and tested the CTS rig at depths of 1,500 to 3,500 feet.

Well Drilling and Completion Plan

The well drilling and completion plan included approximately 25 wells in the Goodland, Kansas and Yuma, Colorado areas. The target formation is the Niobrara with well depths ranging from 1500 feet to 3500 feet. The wells are completed as small volume gas wells. The Niobrara is a low permeability chalk formation with high porosity. Development of this area dates back to the 1970's and has been sporadic. Current activity within this economically marginal gas play is based on today's higher gas prices, the latest completion practices and the ability to control well costs.

The planned well drilling and completion utilized the following well prognosis:

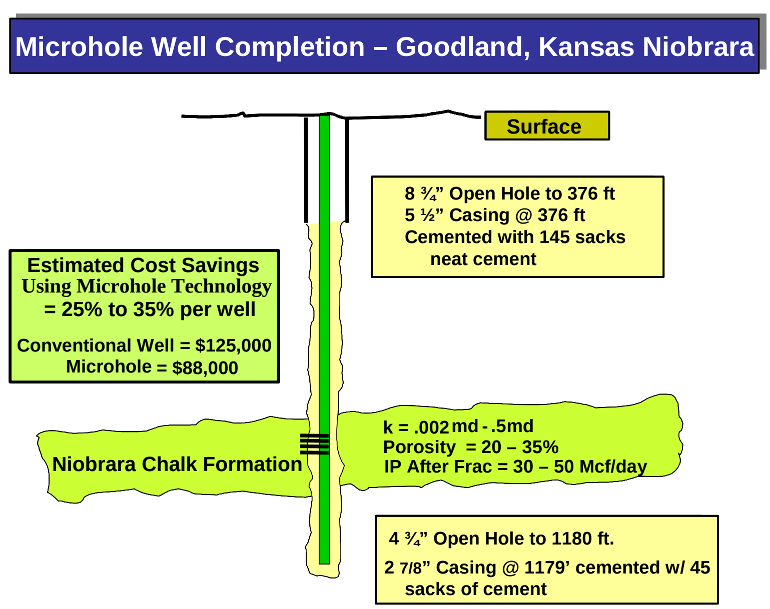
- Well locations and roads (if needed) are prepared prior to COILED TUBING rig arrival. Roads and drilling pad are kept to minimum size
- A local water well rig moved in, rigs up, and drills an approximately 7 inch open hole to a depth below the fresh water formations. Surface casing (5 ½ inch) is set at drilled depth and cemented to surface to protect potable water sources. The depths of the surface casing set points vary by geographic area and are established in conformance to depth requirements of the Kansas and Colorado well permitting agencies.
- The COILED TUBING rig moves onto the location, rig up and initiate drilling.
- Drill a 6 ½-inch hole to a depth adequate to penetrate the Niobrara formation.
- The hole is drilled with fresh water treated with potassium chloride for formation-damage control. Fluid loss is monitored.

- At total depth, open hole logs are run including (neutron, density and resistivity logs).
- If the well is determined to have production potential, 2 7/8 inch casing will be set to total depth and cemented to a depth to cover the top of the Niobrara formation.
- At this point, the COILED TUBING rig was rigged down and moved out to drill the next location.
- A well work over rig is moved onto the well site after allowing adequate time for cement behind the pipe to set.
- The selected logging company truck is rigged up over the well and cased hole logs including a casing collar locater, gamma ray and cement bond log are run.
- If the cement bond is determined adequate, the production zone is selected and perforated with two jet shots per foot. Approximately 10-foot zones are perforated.
- Preparations for performing a hydraulic fracturing stimulation treatment on the well are made including moving onto the location the necessary fluids, proppant and pumping equipment.
- The formation stimulation treatment is performed. A typical treatment in the Goodland, Kansas area includes 50,000 gallons of fracturing fluid and 100,000 pounds of sand proppant. Nitrogen is included in the fluid pumping to assist with fluid clean up after the treatment. The Niobrara formation is a less than normally pressured formation that inhibits fluid clean up by reservoir pressure and volume alone. This aspect of the Niobrara formation is where minimizing drilling time and exposure of the formation to fluids is important.
- After the well stimulation treatment, production tubing (if needed) is run and the well swabbed until it is adequately cleaned up to produce on its own. The workover rig is rigged down and moved off the location.
- Production equipment is installed and the well hooked up to the gas gathering system and production operations begin.

A wellbore schematic of a typical completed Niobrara well is presented as **Figure 27.** The selected area of operations (Goodland, Kansas and Yuma, Colorado Niobrara gas plays) is an excellent area for assessing the efficacy of microhole drilling and developing a case study that can be utilized in many areas of the United States to disseminate microhole drilling advantages. Specifically, the selected area lends itself to assessment of microhole drilling because of the following conditions:

- The Niobrara is an economically marginal gas play requiring strict attention to cost savings. The cost

Figure 27 - Wellbore Schematic of Completed Niobrara Well For the Goodland, Kansas - Justification for Area of Operation and Well Drilling and Completion Plan



savings that microhole drilling will enable has direct impact and can be documented.

- The Colorado and Kansas areas of operation are farming areas that require minimization of drilling footprint. The ability to minimize drilling location size and road building enabled by the Coiled Tubing rig has direct economic and environmental impact and can be documented.
- The Niobrara formation is a very low permeability chalk formation. Additionally, it is a severely under-pressured reservoir, with reservoir pressures in the Goodland area about 50 pounds per square inch (psi) at 1200 feet of depth (normal pressure for this depth would be approximately 600 pounds per square inch). Extended exposure of this type of formation to drilling fluids causes formation damage that significantly impedes gas production. The ability to drill, log and case the well with alacrity is enabled by the microhole drilling approach and is amenable to testing and documentation.
- The area of operations and planned wells provide an opportunity for several depth ranges to be tested. The Kansas area will entail testing at 1200 feet and the Yuma, Colorado area will allow depths to 3500 feet. These opportunities will enable documentation of microhole case studies with broad application to other areas in the United States and will enable effective workshops.
- The area of operations being a farming area requires drilling to be conducted within windows of opportunity in the spring and fall, before and after crop planting and harvesting. This requires that drilling be conducted as rapidly as prudent and requires multi-well project planning. This aspect of the project area of operations will have direct relevancy to sensitive locations in the Rocky Mountains and other regions of the country that have “drilling windows” due to wildlife patterns and other environmental constraints. The approaches utilized in this project can be documented for dissemination to other sensitive areas.
- Rosewood Resources has a significant operation in the Kansas and Colorado area, with plans to drill 75 to 100 wells in year 2005. This level of activity and having Rosewood as a partner allows for identification of some special tests or drilling/completion procedures that could be performed during the project. The testing of the Microhole approach to high angle or horizontal drilling, utilization of the approach for drilling water disposal wells, testing of new downhole motors and other approaches to well drilling and completion have potential with this level and type of activity.

In summary, the area of operations due to the geologic conditions, surface constraints and environmental concerns, marginal economics of the prospects combined with the size and type of the project partners (Rosewood) operations and the Coiled Tubing rig justified this area as an excellent test bed for microhole drilling.

Performance Measurement

A test plan was prepared and reviewed by the GTI/CTS/Rosewood Team prior to rig test initiation. This plan not only included protocols for well construction and completion but also included a list of priority measurements and observations to be taken in all stages of Coiled Tubing Rig Operation from “rig up” to “rig down.” Priority performance parameters that were to be measured included rate of penetration, pump pressure, and time duration for each operation like BHA, casing, cementing, and logging.

CTS Rig Testing - Data Collection

The GTI team field tested the “Coiled Tubing” Rig to develop information on its capabilities. Testing followed six defined categories of test standards (Table 3). Data availability permitting, this allows comparisons to the times and efficiencies to be compared to conventional rotary rig operations in comparable settings. Rig performance was also documented by videotaping.

Table 3 - Microhole rig measurements template to be collected by GTI

Test Standard	Type of Data Collected
1. Mobilization and Rig Up	• Number of loads and load out schedule • Weight per trailer and total rig weight • Time to rig up to reach operational status • Requirements for external equipment to rig up
2. Drilling Surface or Production Holes	• Trip time • Connection time • Instantaneous and average rates of penetration • Weight on Bit • RPM, Torque and Drag • Pump Pressures and Flow Rates • Mud Properties during drilling • Circulation time • Solids control efficiencies • Vibration (if measurement while drilling is used) • Deviation Survey • Rock Compressive Strength (from sonic log measurements) • General lithology
3. Running Surface Casing and Cementing	• Rig up to run casing time • Connection time • Running time per joint • Cementing rig up and rig down time
4. Logging / Evaluation	• Trip time
5. Running Production Casing and Cementing	• Rig up to run casing time • Connection time • Running time per joint • Cementing rig up and rig down time
6. Rigging Down and Move Out	• Number of loads and load out schedule • Need for external equipment to rig up • Time to rig down to transport status

Drilling reports from the rig and logs from the service company are available in electronic and hard copy format. Data from the rig were transferred to a data collection form. An example of field data entered into a data collection form is shown in Table 4.

Table 4 - Typical - Microhole Rig Measurements Collected by GTI Staff

Microhole rig measurement to be collected by GTI		
Date:_05/13/05		
Well Name:_Duell 3-7	**County: Sherman, KS**	
Sec : 17 Twn: 7s	**Rng: 39 w GR.ELEVATION: 3535**	
Operator: Dennis Marchadant		
Starting:5:00 AM	**End:7:30 M____**	
Depth: 1180 ft	**Location: Cheyenne County, KS**	
1. Mobilization and Rig Up	Number of loads and load out schedule	4 Main Total 6
	Weight per trailer and total rig weight	140,000 lb
	Time to rig up to reach operational status	1
	Requirements for external equipment to rig up	0
	Number of staff	4
2. Drilling Surface or Production Holes	Trip up	15 minutes
	Connection time	4 minutes
	Instantaneous and average rates of penetration	300 ft/hr
	Weight on bit	6 to 6000 lb
	RPM, Torque and drag	300
	Pump pressure and flow rate	1300 psi .200 gal/min
	Mud Properties during drilling	mud weight 8.7 lb/gal- Visc 34
	Circulation time	10 minutes
	Solids control efficiencies	shale 220 mesh screen
	Vibration (if measurement while drilling is used)	na
	Deviation Survey	500 ft depth - ½ ft 750 ft depth – 2 ½ ft 1000 ft depth-1 ¼ ft
	Rock Compressive strength (from sonic log measurements)	NA/ Density and Gamma logs
	General lithology	Shale
	Number of staff	4
3. Running Surface Casing and Cementing	Rig up to run casing time	
	Connection time	
	Running time per joint	
	Cementing rig up and rig down time	
	Number of staff	
4. Logging/evaluation	Trip time	2
	Number of staff	3
	Logging type	Density and Gamma
5. Running Production Casing and Cementing	Rig up to run casing time	5 minutes
	Connection time	3 minutes
	Running time per joint	3 minutes
	Cementing rig up and rig down time	3 1/2 hr
	Number of staff	5
6. Rigging down and move out	Number of loads and load out schedule	0
	Need for external equipments to rig up	0
	Time to rig down to transport status	1
	Number of staff	4
7.BHA	Bit type	633
	Assembly	1
	Time for disassembly	1
	Number of staff	2

Database CD

To facilitate the review and use of the information collected by this project that documents the operational performance of the MCTR technology, a Database CD has been prepared and is available upon request from the Gas Technology Institute, Des Plaines, IL. The Database CD includes a spreadsheet of performance data and movie clips of the CT rig in every stage of setup and operation.

For each well drilling event that was observed by GTI staff, a set of data has been collected and is presented in Appendix A; the data in Appendix A represents information from 13 wells. In addition to this information, CTS personnel collected MCTR operations data on an additional 12 wells in the absence of GTI staff using the GTI data collection protocol; this information is presented in Appendix B. Data in both Appendix A and Appendix B cover MCTR conditions and mechanical performance across a number of parameters, including the following:

- Drilling Assembly (BHA)
  - Bit Type
  - Mud Motor
  - Drill Collar
- Mud Record
  - Weight
  - Funnel Viscosity
  - KCL
  - Bicarb
  - Poly
  - Pac
- Deviation Survey
  - For each 500 ft interval
- Depth Interval and shale formation
- Rig Parameters
  - Rotary Speed
  - Weight on bit
- Time Logging
  - Move in and rig up
  - Pick up BHA
  - Drilling time
  - Circulation
  - Logging
  - BHA lay down
  - Casing and Cementing
  - Rig down and move out

For ease of analysis, the information from Appendices A and B are presented in tabular form in an Excel spreadsheet with the title of "MCTR Database.xls" which is included on the Database CD. Using the tabular data, a number of graphs can be examined as shown in the spreadsheet.

Instructions for Viewing Video Clips of the CT Rig are as follows:

- Place GTI MCTR Database CD into computer.
- Click the Word Document file called "Easy Access Guide to Video Clips."
- Click the desired operation for viewing from the bulleted list.

To order the Microhole Coiled Tubing Rig Database CD containing the video clips, submit a request to the following contact:

Kent Perry
Executive Director, Exploration & Production Center
Gas Technology Institute
1700 S. Mount Prospect Road
Des Plaines, IL 60018
kent.perry@gastechnology.org

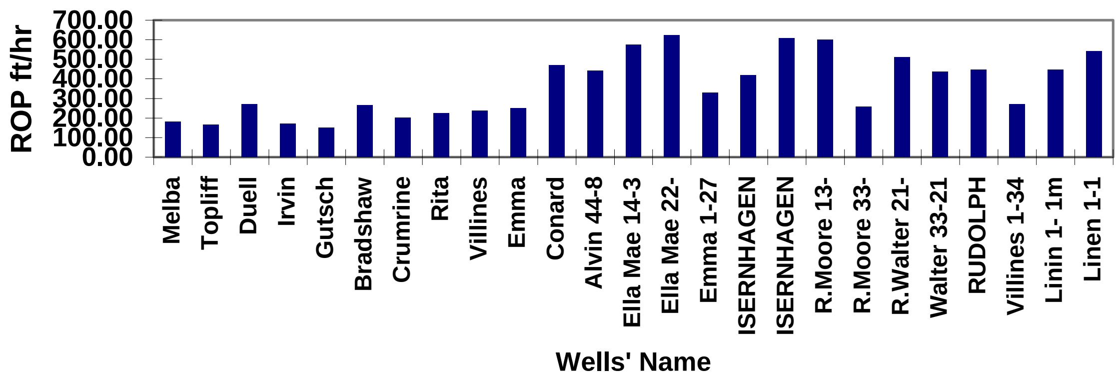
Results

Results of the drilling effort are summarized in this section. Quantitative measurements include Rate of Penetration and time-function measurements taken from the CT rig at each well. This section also includes qualitative observations by GTI staff that were made in the field during CT rig operation at 13 well sites. These observations include quality of the hole drilled, staff requirements, ease of operation, site disturbance, and apparent environmental footprint.

Direct ROP and Time-Function Measurements

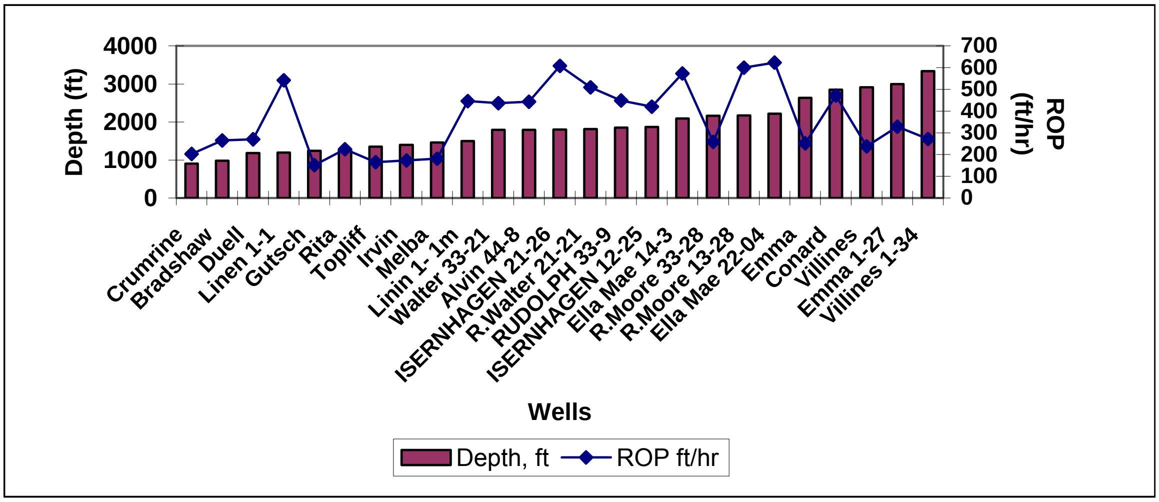
One of the most important performance measurements in well drilling is Rate of Penetration, or ROP. Figure 28 shows the average ROP for each of the wells that were drilled. As shown, the ROP varied between 150 and 600 feet per hour. In this figure, the wells are arranged in the order drilled in the field.

Figure 28 - Rate of Penetration of Well Drilled with Microhole Coiled Tubing Rig



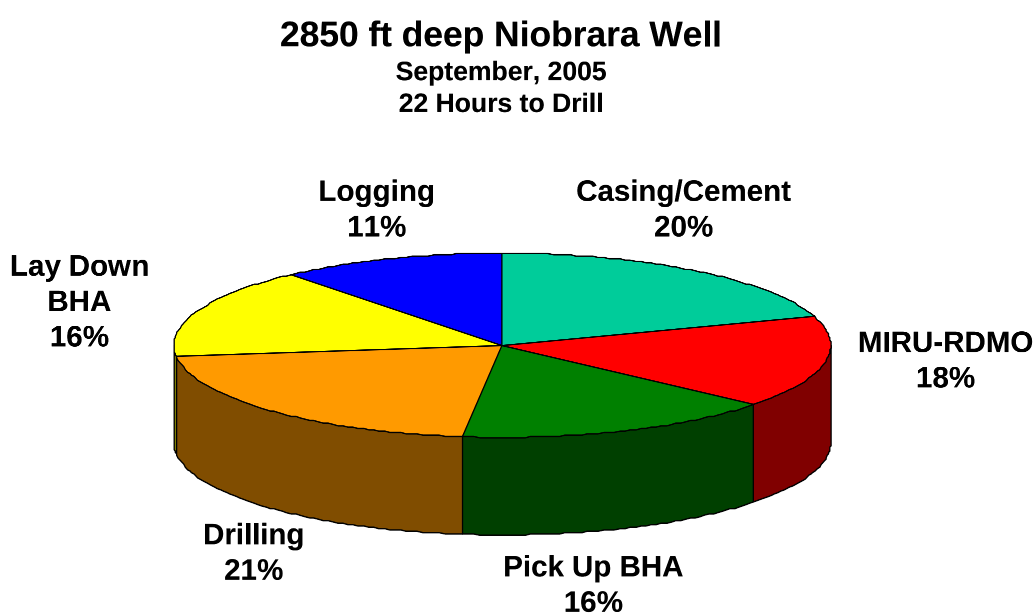
The lack of relationship between ROP and the depth of wells is suggested in **Figure 29.** The vertical bars show the depth of the wells in ascending order, while the superimposed line shows the penetration rate. Well depth varied from less than 1,000 feet to greater than 3,000 feet. It is noteworthy that for the majority of these wells, ROP values between 300 and 623 ft/hr were measured as shown in the plot.

Figure 29 - ROP and Depth of the Wells



Performance of the rig was also documented by monitoring how much time is expended on each functional operation. The total functional time used by the CT rig can be broken down into six categories: Rigup, Pick up Bore Hole Assembly (PBHA), Drilling, Lay Down Bore Hole Assembly (LD BHA), Logging, and Casing/Cementing (CSG/CMNT). An example of a CT operational time distribution across these categories is shown in the pie chart of Figure 30 for a 2850 ft deep well drilled in the Niobrara. This well required only 22 hours of total CT functional time; the categories of operation requiring the greatest share of time included drilling and casing/cementing at around 20 percent each.

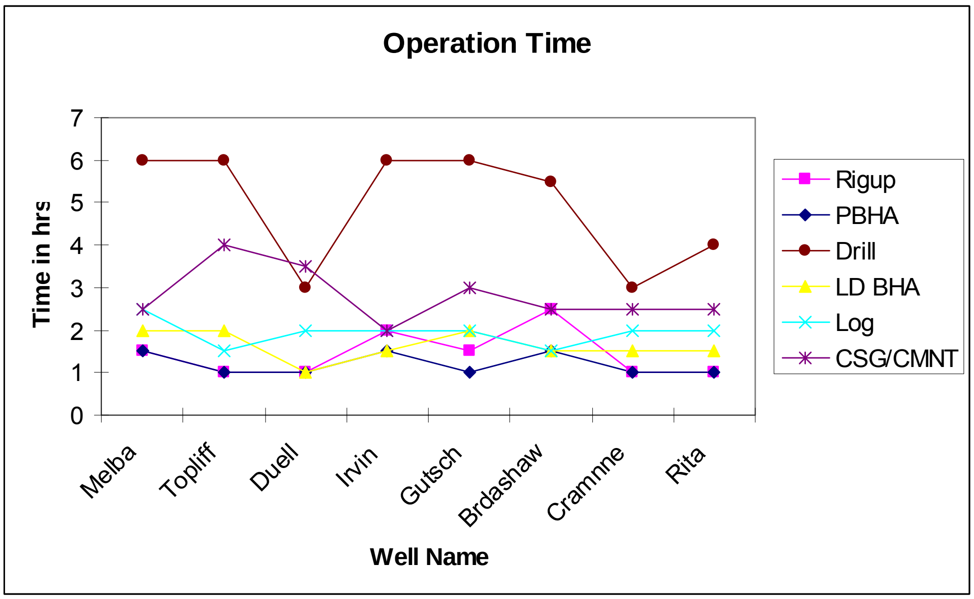
Figure 30 - Allocation of Drilling Time for 2850' Niobrara Well



Variations in the times required for the six functional categories can be seen in the line plots of Figure 31 representing data collected from eight wells drilled with the CT rig. From this graph, it can be seen that the variations for the drilling and casing/cementing functions are greater than the other functions; this arises from the fact that these functions are affected to a greater degree by the depth and nature of the well drilled. Also shown in the diagram, the drilling function usually requires only 3-6 hours to accomplish; this is due to the elevated rate of penetration that can be achieved with the CT rig (usually ranging from 300 to 600 ft/hr). Time-function data for all of the observed drilling runs using the CT rig are given in the table of Appendix B.

Equally important, the time requirements for nearly all of the other functions were also held to low values of 1-2 hours each (as indicated in Figure 31). The ability of the CT design to achieve time reductions in these categories is due to the high degree of equipment integration that enables the entire CT rig to be comprised of four trailers (instead of five or six) and allows easier setup, alignment, operation, and demobilization.

Figure 31 - Operation time and Operation for Selected Well to Measure the Well Performance.



Perhaps the best indicator of overall CT rig performance is the total rig time (TRG) representing the summation of time expenditures in all of the six functional categories. The TRG parameter is plotted with depth of well in Figure 32 for all of the 25 wells of this study that were drilled with the CT rig in the Niobrara. The points plotted in this graph strongly suggest that there is a general nearly-linear relationship between well depth and Total Rig Time. It is noteworthy that for wells as deep as 2,500 to 3,000 feet, the Total Rig Time for the CT unit is usually well under one day.

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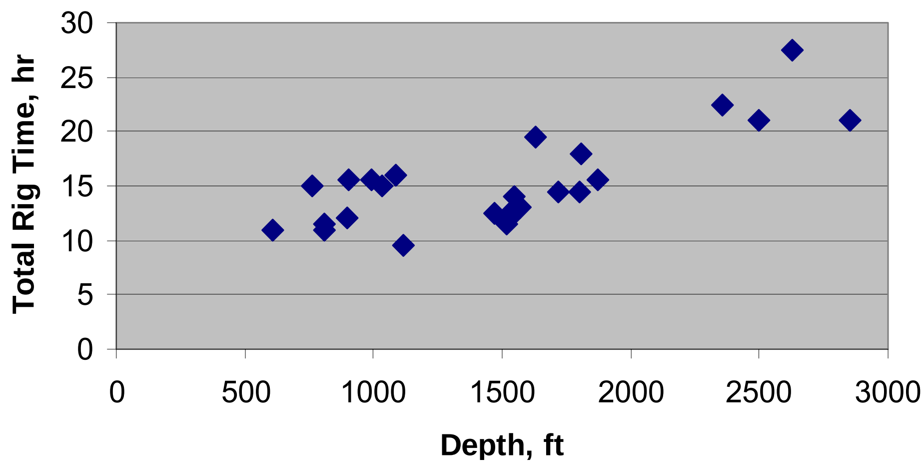
Figure 32 - Total Rig Time (In Hours) Versus Well Depth

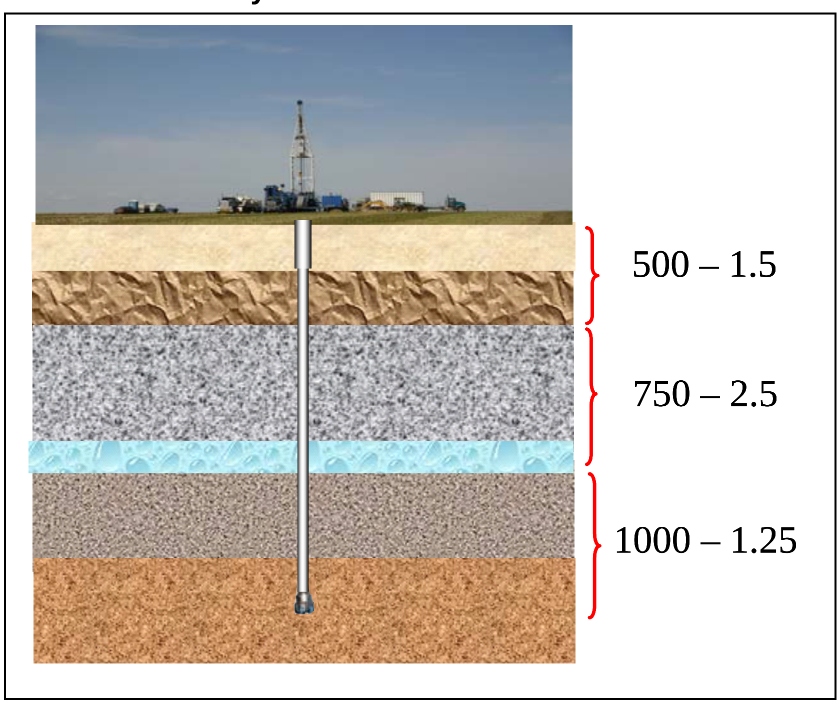


Hole Quality and Cement

The benefits of fast drilling by the ADT CT rig is augmented by excellent hole quality. All the wells drilled have resulted in a gauge hole with very little hole deviation (1 to 2 degrees - well within State requirements) despite the high penetration rates (**Figure 33**). Good cement job quality and well bonded cement also derive from the gauge hole quality. As mentioned previously, the Niobrara is an under pressured reservoir and as such is susceptible to formation damage due to fluid loss from drilling operations. Both the rapid penetration rate through the pay zone and the lack of any pressure surges caused by conventional drilling pipe connections help to mitigate fluid loss and therefore formation damage. This is an important factor given the marginal nature of the resource.

With Coiled tubing, there is no auxiliary equipment is required to run casing, log wells or for handling drill collars and bottom hole drilling assemblies. With its derrick, traveling block and rotary table components, all required drilling processes can be performed without additional equipment. Drilling with coiled tubing eliminates drill pipe connection time and fewer crew members are required to operate the rig.

Figure 33 - Microhole Coiled Tubing Hole Quality and Deviation Survey



Improved Safety and Environmental Footprint

Observations by GTI staff in the field of the function of the ADT CT rig has verified a number of advantages that have implications for improved safety and environmental compatibility of this emerging generation of drilling technology.

Safety

Safety is always of utmost importance and the conventional drilling rig environment is one where extra caution and safety training is necessary due to the handling of drill pipe and other equipment. The ADT coiled tubing rig significantly reduces drill pipe handling and has less equipment to mobilize from well to well. All of this creates a much safer operating environment that is important during any time of drilling, but especially so during today's high rig count when experienced roughnecks are difficult to find.

The ADT CT rig incorporates state-of-the art features that provide a number of safeguards during operation. First, the ADT CT rig includes a blowout preventor (BOP) that allows an operator to isolate the downhole section of coiled tubing as a safety measure. The BOP can be actuated from the control house, where the operator monitors well bore pressures, gases, equipment pump rates, fluid volumes, drill rates, speeds, torques, and other parameters related to CT operation. From this center, the CT operator can make adjustments in equipment operation and can implement safety interventions if needed.

As with pervious commercial CT systems, the ADT CT rig incorporates other features that represent considerable redundancy in safety. In addition to the BOP device, several safety features are included in the bottom hole assembly (BHA) for added protection. To prevent leakage from the CT that is not in the hole, one or two check valves can be installed in the BHA. Consistent with current best practices, further safety is provided by an emergency disconnect that allows a CT unit operator to disconnect the CT from the BHA if it becomes stuck.

During the observation of the 25 project wells drilled with the CT rig, there were no conditions that represented a situation where an intervention was required. Each well was drilled with the appropriate precautions under conditions that were well within the operational safety envelope that represents low risk to operators and observers.

Environmental Footprint

The small size of the rig, the compressed time for rig functions and the drilling mud and cuttings handling system provides several environmental advantages over conventional drilling. As a result of its efficient design and size, GTI staff has noted advantages during the field operation of the ADT CT rig in the course of drilling the project wells:

- A small drilling pad of less than 1/10 acre or no pad under some conditions can be utilized. Modest access roads are required.
- No mud pit is needed; mud tanks contain the required drilling fluids and are moved with the rig from one location to the next. The only pit required is a small (3'x6'x6') pit for drill cuttings. If needed, cuttings are easily hauled off site.
- Smaller equipment yields less air emissions and low noise engines minimize disturbances to the surrounding environment.

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- The microhole approach requires less drilling mud and fluids to be treated and yields fewer drill cuttings.
- The utilization of coiled tubing mitigates the risk of spills due to no drill pipe connections.

The area of impact that is left by the CT rig after the well has been installed and after the rig is moved out appears to be minimal. In the observed drilling of 25 project wells, most impacted areas were limited to less than 200 ft^2. A typical area of impact after CT rig deployment is shown in Figure 34.

Figure 34 - Small Rig Size Yields Small Drilling Foot Print

Zero Discharge (If Required)

The CT rig has the capability to drill a well with zero discharge of any fluid or solid residues (e.g. cuttings) if required. The procedure is as follows:

- Move the rig in and rig up on a sealed/booted tarp to contain any overflow or accidental spill.
- No earthen pits are prepared; all cuttings and drilling fluid are confined to tanks with which the rig is equipped.
- A hole is augured for conductor pipe and a boot is placed around the conductor pipe.

Using this protocol, the ground is protected from any inadvertent spills and all fluids and cuttings are removed from the location. While obviously an added expense, this procedure may be required for drilling in environmentally sensitive areas. The small rig size and efficiency of drilling coupled with the zero discharge capability enables drilling in many sensitive areas at a reasonable cost.

Observed Operational Advantages

Based upon field observations, the ADT has a number of operational advantages over conventional drilling technology. These advantages can be summarized as follows

- Reduced Drilling Cost
  - Reduced rig size and staff (as reflected in the example well drilling data of Table 4)
  - Reduced BHA, casing, cement, mud system, time and material to drill hole with small diameter to 5000 ft
  - Ease of data acquisition (like logging)
  - High ROP
  - Support directional drilling
- Reduced Mobilization, Demobilization Cost and site preparation
  - 4-5 trail able unites provide all tools for drilling and drill mud hauling
  - Small drill pad or no drill pad
  - Smaller roads or skid trail access
- Improved Pipe Handling Capacity
  - Uses traveling block and rotary table for making-up BHA component
  - No auxiliary equipment required to run casing
- Measurement While Drilling (MWD)
  - Using microhole coiled tubing, MWD technology can be attached to coiled tubing without concern about pipe joints
- Improved Well bore Transmissivity and Reservoir Delivery
  - Microhole coiled tubing is highly compatible with under-balanced drilling (UBD)
  - UBD improves safety, initial production, and longer period production by minimizing well bore transmissivity damage

Impact / Benefits on Lower 48 Resource

This section was a collaborative effort between Energy and Environmental Analysis and GTI. GTI contracted with Energy and Environmental Analysis to evaluate the potential impact of coiled tubing on future U.S. gas development and resources. EEA specializes in modeling and forecasting North American gas resources and production. Recently, EEA served as the principal modeling contractor for the 2003 NPC study.[1] EEA worked with the gas industry representatives to develop the resource and technology assumptions that went into that study. EEA also develops its own company forecasts and assumptions about remaining resources and technologies.

The objective of the current study was to build a set of realistic assumptions about the future market penetration of CT microhole drilling in the onshore Lower-48, and to evaluate the impact of the expected improved drilling economics and the potential to tap resources more rapidly and efficiently than with conventional drilling. The primary impact to be evaluated is the potential impact on U.S. gas drilling markets and expenditures over the next 20 years.

Because the technology is still evolving, it is necessary to make assumptions about which portion of the undeveloped resource base could be targeted in a technical sense, and assumptions about what a realistic market penetration could be.

Potential Resources

EEA has evaluated the potential resource base that could be targeted by coiled tubing microhole drilling in coming decades. While most current applications of this technology are for non-conventional (to date, primarily coalbed and tight gas) reservoirs of less than 5,000 feet vertical depth, future technology advances should allow applications to at least 10,000 feet. Shale gas, shallow oil, and deep tight gas are potential markets in the future.

Another area of consideration not covered in this study is resource access. The CT technology, through a reduced environmental footprint, likely will result in significant additional access to resources that are currently restricted or off limits.

EEA has assessed the U.S. gas resources and potential wells that could be drilled from 0-5,000 ft and 5-10,000 ft. in onshore areas.

The last comprehensive assessment of U.S. developed and undeveloped gas resources was carried out in the 2003 National Petroleum Council study. That study was primarily based on recent USGS assessments for onshore areas, and included the results of USGS assessment work in recent years, primarily focused on the Rockies. The National Petroleum Council (NPC) adjusted the USGS assessed resource base for a number of larger-impact plays. In addition, conventional undiscovered resources were adjusted to include the small field component for each play.

The NPC resource base was characterized for analysis and modeling in the EEA Hydrocarbon Supply Model, which includes an economic characterization of the various categories of conventional and non-conventional resources. Non-conventional resources are categorized in a set of input files that include wells, well recovery, and costs.

Since the 2003 NPC study was published, industry activity has resulted in changes to the NPC-assessed resource base. EEA has developed a resource base that includes re-assessments of emerging resources such as the Barnett Shale and the Powder River Basin coalbeds. It also includes several new assessments of shale gas in new formations.

[1] NPC, 2003, "Balancing Natural Gas Policy," National Petroleum Council, September, 2003.

Table 5 summarizes the EEA gas resource base for the U.S. Undeveloped resources include the following categories:

- Old field appreciation
- New fields
- Shale gas
- Coalbed gas
- Tight gas
- Low BTU gas

Bolded entries on the table are assessed resources that differ from NPC. Major changes relative to NPC include a larger assessment for the Barnett Shale in the Fort Worth Basin, the Powder River coalbed play, and tight gas in the Arkla-Tex region. Resource categories that have been added since the NPC study include the Fayetteville Shale and Woodford/Caney shale in the Mid-Continent, and the Woodford Shale in the Permian Basin. The Green River Basin tight gas assessment was reduced. Conventional Gulf of Mexico resources were increased for drilling below 15,000 feet on the shelf.

Table 6 shows the number of potential non-conventional gas wells and gas resources for onshore Lower-48 depths above 10,000 feet. For each region, the resource is broken out for shale gas, coalbed gas, and tight gas resources by depth interval. Using the current EEA gas resource base and well recoveries and spacing assumptions within the model, a total of 228,000 shale gas wells, 179,000 coalbed wells, and 551,000 tight gas wells remain to be drilled in onshore regions above 10,000 ft. The total non-conventional resource base targeted is 203 Tcf.

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Table 5 - U.S. Gas Resource Base

Bcf, Dry Total Gas
Current Technology

		Discovered/ proved			Discovered Undeveloped	Unproved						
Region Number	Region Name	Cumulative Production	Proven Reserves	Ultimate Recovery	Discovered Undeveloped	Old Field Appreciation	New Fields	Shale	Coalbed	Tight	Low-BTU/ other	Unproved Plus Discovered Undeveloped
United States												
Lower-48 onshore												
1	Appalachian Basin	45,887	9,396	55,283	0	1,982	6,196	16,986	8,158	34,746	0	68,068
2	Black Warrior Basin	2,648	1,283	3,931	0	121	1,450	0	4,465	0	0	6,036
3	Mississippi, South Alabama, and Florida	9,214	1,916	11,130	0	4,373	11,035	0	0	0	0	15,408
4	Michigan & Illinois Basins	6,404	2,976	9,380	0	2,630	7,830	**7,300**	1,580	0	0	19,340
5	East Texas, South Arkansas, & North Louisiana	64,515	14,198	78,713	0	14,652	18,152	0	0	**10,400**	0	43,204
6	South Louisiana (onshore)	102,105	5,185	107,290	0	6,497	24,043	0	0	0	0	30,540
7	South Texas (onshore)	145,669	16,209	161,878	0	34,646	39,148	0	0	**4,600**	0	78,394
8	Williston, Northern Great Plains	4,490	1,286	5,776	0	2,061	3,396	0	0	7,660	0	13,117
9	Uinta-Piceance Basin	4,722	7,182	11,904	0	3,824	2,063	*0*	5,862	**27,500**	0	39,249
10	Powder River Basin	2,250	2,399	4,649	0	957	1,478	*0*	**26,600**	764	0	29,799
11	Big Horn Basin	1,860	103	1,963	0	535	361	*0*	0	0	0	896
12	Wind River Basin	3,249	2,424	5,673	0	2,000	1,635	*0*	413	0	0	4,048
13	Southwestern Wyoming (Green Rvr B)	12,829	12,703	25,532	0	7,299	4,729	*0*	1,966	**38,800**	14,535	67,329
14	Denver Basin, Park Basins, Las Animas Arch	4,238	1,980	6,218	0	1,995	1,668	*0*	0	2,019	0	5,682
15	Raton Basin-Sierra Grande Uplift	153	1,213	1,366	0	0	37	*0*	1,931	0	0	1,968
16	San Juan and Albuquerque-Santa Fe Rift	29,134	19,621	48,755	0	5,418	671	*0*	8,413	21,002	0	35,504
17	Montana Thrust Belt and SW Montana	241	28	269	0	48	8,280	0	0	0	0	8,328
18	Wyoming Thrust Belt	3,902	741	4,643	0	1,393	12,008	0	0	0	0	13,401
19	Great Basin and Paradox	1,405	1,033	2,438	0	995	2,714	0	0	0	0	3,709
20	Western Oregon-Washington	66	6	72	0	0	1,092	0	676	11,846	0	13,614
21	Anadarko Basin	141,082	17,726	158,808	0	21,378	**23,000**	**1,000**	0	0	0	45,378
22	Arkoma-Ardmore	25,596	4,788	30,384	0	6,791	3,799	**9,300**	2,558	0	0	22,448
23	Northern Midcontinent	13,196	1,496	14,692	0	4,090	2,066	0	2,295	0	0	8,451
24	Permian	105,398	16,376	121,774	0	21,472	19,624	**34,400**	0	0	0	75,496
25	Northern California	9,241	635	9,876	0	2,105	3,447	0	0	0	0	5,552
26	Central and Southern California	22,554	1,961	24,515	0	1,090	5,878	321	0	0	0	7,289
	total	**762,048**	**144,864**	**906,912**	**0**	**148,352**	**205,800**	**69,307**	**64,917**	**159,337**	**14,535**	**662,248**
Lower 48 offshore												
29	Eastern GOM Offshore Shelf	3,528	3,421	6,949	700	3,432	17,714	0	0	0	0	21,846
30	Eastern GOM Offshore DW Shallow	0	0	0	0	0	1,883	0	0	0	0	1,883
31	Eastern GOM Offshore DW Deep	0	0	0	0	0	8,996	0	0	0	0	8,996
32	Central & Western GOM Offshore Shelf	152,158	14,765	166,923	0	43,616	**101,850**	0	0	0	0	145,466
33	C & W GOM Deepwater Plio-Pleistocene	7,443	10,983	18,426	0	3,417	23,630	0	0	0	0	27,047
34	C & W GOM Deepwater Miocene	0	0	0	0	3,040	78,262	0	0	0	0	81,302
35	C & W GOM Deepwater Foldbelts	0	0	0	0	1,059	27,085	0	0	0	0	28,144
36	Pacific Offshore	2,579	625	3,204	0	1,035	20,654	0	0	0	0	21,689
37-39	Atlantic Offshore	0	0	0	0	0	32,817	0	0	0	0	32,817
	total	**165,708**	**29,794**	**195,502**	**700**	**55,599**	**312,891**	**0**	**0**	**0**	**0**	**369,190**
Lower 48 onshore total		***762,048***	***144,864***	***906,912***	***0***	***148,352***	***205,800***	***69,307***	***64,917***	***159,337***	***14,535***	***662,248***
Lower 48 offshore total		***165,708***	***29,794***	***195,502***	***700***	***55,599***	***312,891***	***0***	***0***	***0***	***0***	***369,190***
Lower 48 total		***927,756***	***174,658***	***1,102,414***	***700***	***203,951***	***518,691***	***69,307***	***64,917***	***159,337***	***14,535***	***1,031,438***

Table 6 - Number of Potential Non-Conventional US Lower 48 Well Sites for Microhole Drilling by Depth Interval and Resource Type (EEA, March 2006)

Region code	Region	Resource Type	Potential Wells Above 10,000 Feet by Interval: 0-5,000 ft	5- 10,000 ft	Total	Resource above 10,000 ft by Drilling Depth - Bcf: 0-5,000 ft	5- 10,000 ft	Total	NonConv Resource All Depths Bcf
1	Appalachia	Shale	63,209	56,598	119,807	12,699	4,288	16,987	16,987
		Coalbed	39,148	0	39,148	8,406	0	8,406	8,406
		Tight	350,268	64,860	415,128	26,647	8,087	34,734	34,734
		Total	452,625	121,458	574,083	47,752	12,375	60,127	60,127
2	Warrior	Shale	0	0	0	0	0	0	0
		Coalbed	10,439	494	10,933	4,481	120	4,601	4,601
		Tight	0	0	0			0	0
			10,439	494	10,933	4,481	120	4,601	4,601
4	MI-IL	Shale	75,443	0	75,443	7,273	0	7,273	7,273
		Coalbed	0	0	0	1,628	0	1,628	1,628
		Tight	0	0	0			0	0
			75,443	0	75,443	8,901	0	8,901	8,901
5	ArklaTX	Shale	0	0	0	0	0	0	0
		Coalbed	0	0	0	0	0	0	0
		Tight	0	533	533	0	403	403	10,400
			0	533	533	0	403	403	10,400
7	So. TX	Shale	0	0	0	0	0	0	0
		Coalbed	0	0	0	0	0	0	0
		Tight	0	7,966	7,966	0	2,202	2,202	4,600
			0	7,966	7,966	0	2,202	2,202	4,600
8	Williston	Shale	0	0	0	0	0	0	0
		Coalbed	0	0	0	0	0	0	0
		Tight	43,162	0	43,162	7,194	0	7,194	7,660
			43,162	0	43,162	7,194	0	7,194	7,660
9	Uinta - Pic.	Shale	0	0	0	0	0	0	0
		Coalbed	18,166	0	18,166	4,858	0	4,858	5,862
		Tight	4,705	26,230	30,935	1,412	19,279	20,691	27,500
			22,871	26,230	49,101	6,270	19,279	25,549	33,362
10	Powder	Shale	0	0	0	0	0	0	0
		Coalbed	69,767	0	69,767	22,187	0	22,187	26,600
		Tight	5,228	0	5,228	627	0	627	764
			74,995	0	74,995	22,814	0	22,814	27,364
12	Wind River	Shale	0	0	0	0	0	0	0
		Coalbed	887	0	887	383	0	383	413
		Tight	0	0	0	0	0	0	0
			887	0	887	383	0	383	413
13	Green River	Shale	0	0	0	0	0	0	0
		Coalbed	5,872	0	5,872	1,216	0	1,216	1,966
		Tight	0	0	0	0	0	0	38,800
			5,872	0	5,872	1,216	0	1,216	40,766

Table 6 (continued)

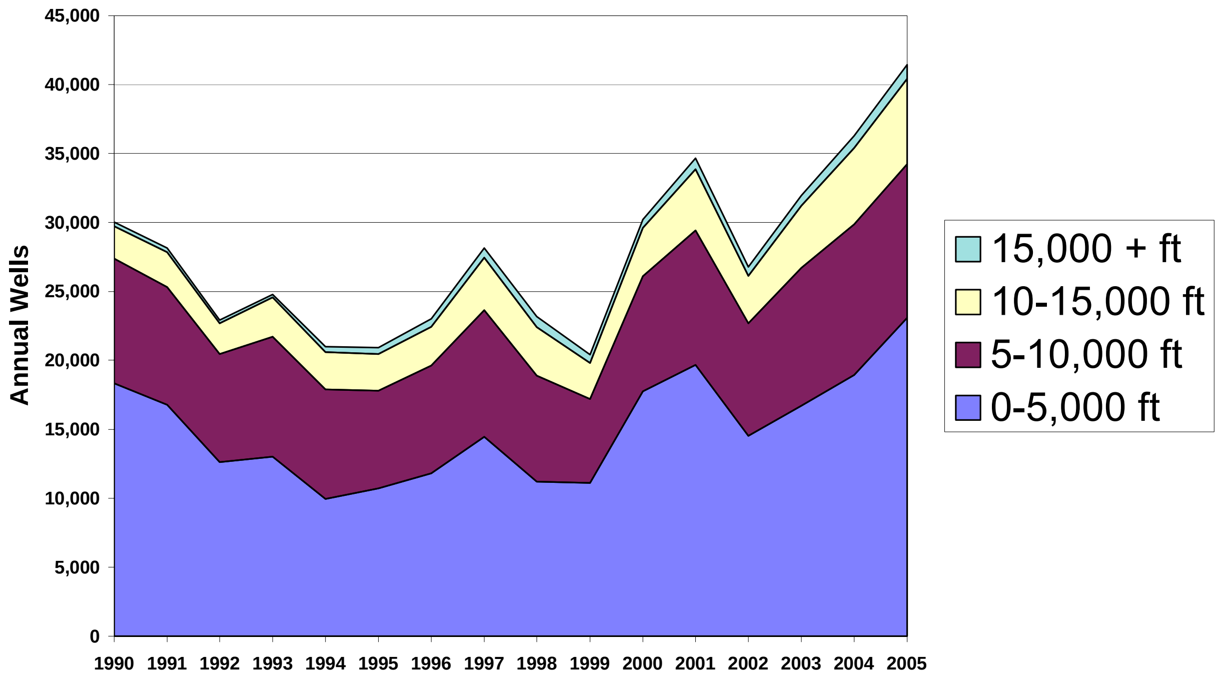
	Resource Type	Potential Wells Above 10,000 Feet by Interval: 0-5,000 ft	5- 10,000 ft	Total	Resource above 10,000 ft by Drilling Depth - Bcf: 0-5,000 ft	5- 10,000 ft	Total	Total NonConv Resource All Depths Bcf
14 Denver	Shale	0	0	0	0	0	0	0
	Coalbed	0	0	0	0	0	0	0
	Tight	2,783	3,615	6,398	974	1,084	2,058	2,058
		2,783	3,615	6,398	974	1,084	2,058	
15 Raton	Shale	0	0	0	0	0	0	0
	Coalbed	2,200	0	2,200	1,890	0	1,890	1,890
	Tight	0	0	0			0	0
		2,200	0	2,200	1,890	0	1,890	1,890
16 San Juan	Shale	0	0	0	0	0	0	0
	Coalbed	8,414	0	8,414	7,795	0	7,795	8,413
	Tight	38,452	2,766	41,218	15,349	3,532	18,881	21,002
		46,866	2,766	49,632	23,144	3,532	26,676	29,415
20 OR - WA	Shale	0	0	0	0	0	0	0
	Coalbed	1,005	0	1,005	697	0	697	697
	Tight	0	0	0	0	0	0	11,486
		1,005	0	1,005	697	0	697	12,183
21 Anadarko	Shale	0	1,253	1,253	0	1,008	1,008	1,008
	Coalbed	0	0	0	0	0	0	0
	Tight	0	0	0	0	0	0	0
		0	1,253	1,253	0	1,008	1,008	1,008
22 Arkoma	Shale	0	13,252	13,252	0	9,267	9,267	9,267
	Coalbed	6,832	0	6,832	1,872	0	1,872	2,558
	Tight	0	0	0	0	0	0	0
		6,832	13,252	20,084	1,872	9,267	11,139	11,825
23 N. Midcon.	Shale	0	0	0	0	0	0	0
	Coalbed	15,598	0	15,598	2,366	0	2,366	2,366
	Tight	0	0	0	0	0	0	0
		15,598	0	15,598	2,366	0	2,366	
24 Permian + Ft W.	Shale	0	18,435	18,435	0	23,315	23,315	34,400
	Coalbed	0	0	0	0	0	0	0
	Tight	0	0	0	0	0	0	0
		0	18,435	18,435	0	23,315	23,315	34,400
26 C. and S CA	Shale	0	33	33	0	330	330	330
	Coalbed	0	0	0	0	0	0	0
	Tight	0	0	0			0	0
		0	33	33	0	330	330	330
Total L-48	**Shale**	**138,652**	**89,571**	**228,223**	**19,972**	**38,208**	**58,180**	**69,265**
	Coalbed	**178,328**	**494**	**178,822**	**57,779**	**120**	**57,899**	**65,400**
	Tight	**444,598**	**105,970**	**550,568**	**52,203**	**34,587**	**86,790**	**159,004**
		761,578	**196,035**	**957,613**	**129,954**	**72,915**	**202,869**	**293,669**

Historic Gas Well Drilling by Depth Interval and Play in the U.S.

EEA gas evaluated statistics published by the API on the number of oil, gas, and dry holes, completed in the U.S.

Figure 35 shows recent trends in U.S. onshore completions by depth interval. In 2005, there were 41,400 reported or estimated onshore total completions (oil, gas, and dry). Gas completions in 2005 are estimated at 26,600. Gas well completion activity as recently as the late 1990s was at a level of only 11,000 completions.

Figure 35 - Onshore U.S. Total Well Completions by Depth Interval



As shown on the charts almost all of the increase in onshore completion activity of the past decade has been in the 0-5,000 and 5-10,000 foot intervals. Most of this increase was coalbed methane. As many as several thousand gas wells per year were completed in the Powder River coalbed play.

EEA has evaluated gas completion statistics for over 200 U.S. gas plays or formations. This analysis has been based upon commercial well completion level analysis and EEA database processing. As part of our economic analysis of each of play, we evaluate EUR per well, depth, and drilling and stimulation costs.

Onshore Rig Day Rates

Figure 36 shows average U.S. onshore rig day rates since 1991. The chart shows a relatively constant rate of about $6,000 per day through 2000, followed by a spike in 2001 and a recent climb to historically high levels of over $12,000 per day.

Rig rates have historically been correlated with energy prices. Higher prices lead to greater utilization and more demand, resulting in higher rates. The current surge in day rates reflects higher oil and gas prices and the current supply constrained condition of U.S. markets.

Figure 36 - Average U.S. Onshore Day Rates for Drilling Rigs

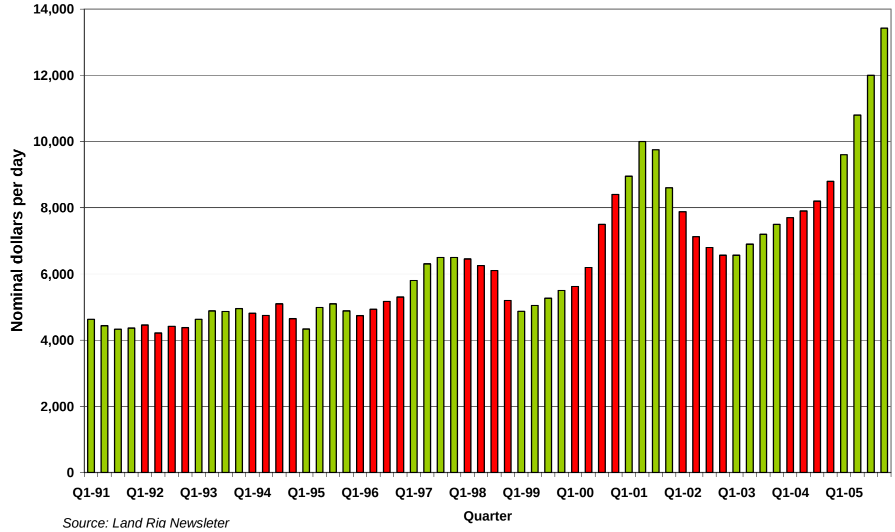
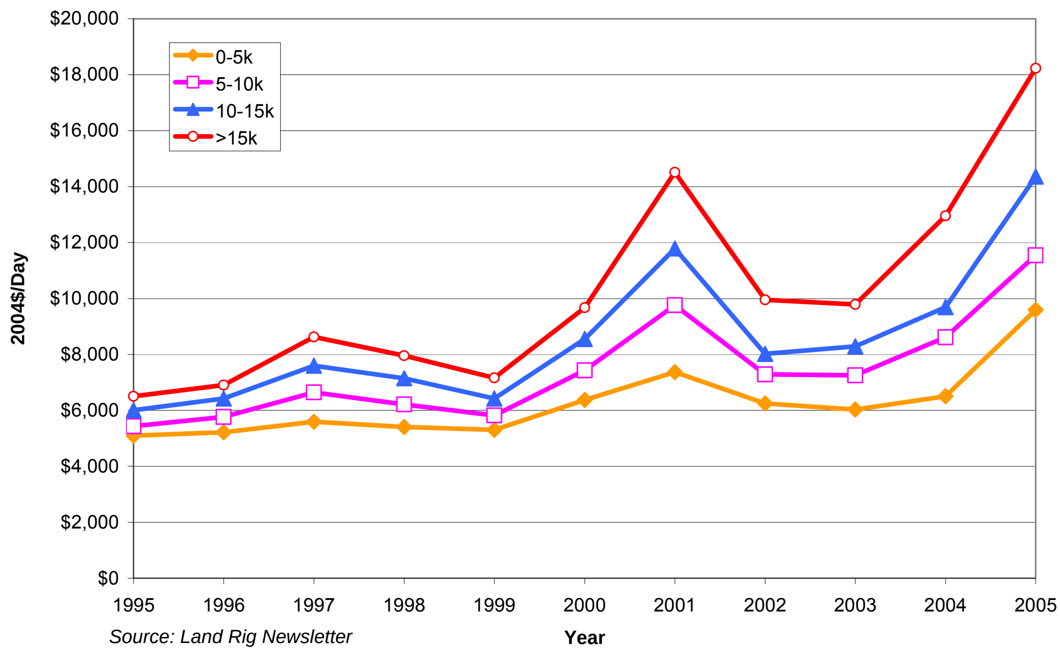


Figure 37 shows the onshore day rates by depth rating of the rig. The increases in 2004 and 2005 affected all classes of rigs.

Figure 37 - Onshore Day Rates by Rig Depth Rating

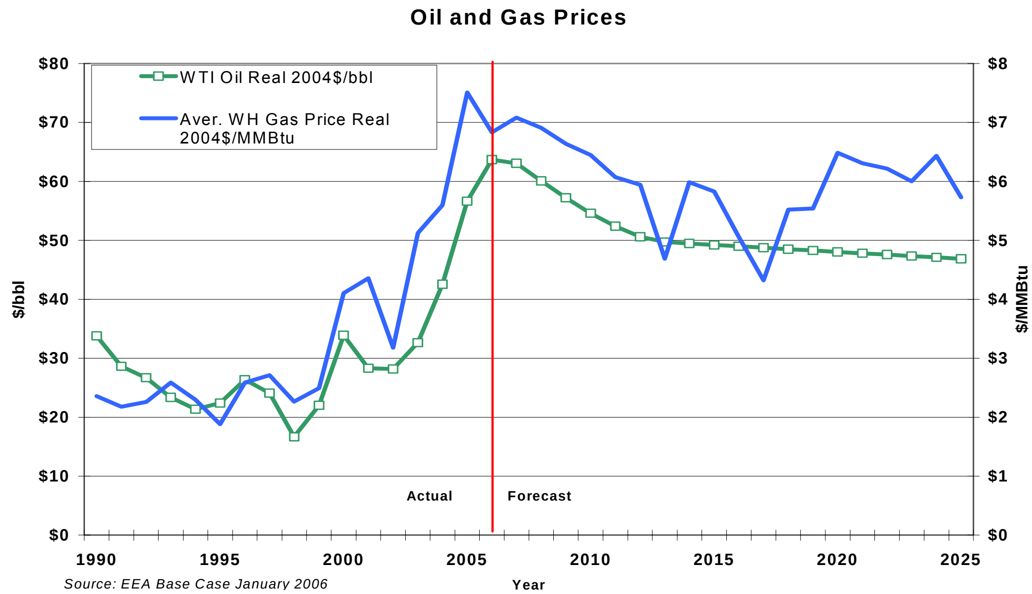


EEA Price, Drilling Cost, and Activity Forecasts

Figure 38 presents the current EEA "Basecase" forecast of oil and gas prices through 2025. The wellhead gas price increase since 2004 is forecast to moderate and decline through much of the forecast period in real dollars. Wellhead prices are forecast to decline to a range of approximately $5 to $6 per MMBtu in 2004 dollars over the coming decade.

Oil prices have also greatly increased and are currently over $60 per barrel. EEA is forecasting that oil prices will gradually decline over the coming decade to about $50 per barrel in 2004 dollars.

Figure 38 - Historic and Forecasted Oil and Gas Prices



Historical and EEA Basecase forecast drilling costs by depth interval are presented in **Figure 39**. The historic data are from the API Joint Association Survey.[2] The chart shows the national onshore data by depth and a separate plot of Appalachia and the Shallow Midwest costs. The average cost per foot for the 0-5,000 foot interval has been in a range of about $50 to $75 and the cost per foot for 5-10,000 feet has been somewhat higher, about $75 per foot. The Appalachian and Shallow Midwest cost has been below $50 per foot.

Since 2000, total drilling costs have risen for all categories, but not as dramatically in recent years as implied by the day rates. The reason is that operators are becoming more efficient and therefore the number of drilling days has generally declined, partially offsetting the rate increases.

[2] API, 2006, "Joint Association Survey of Drilling Costs, "API, Washington, DC.

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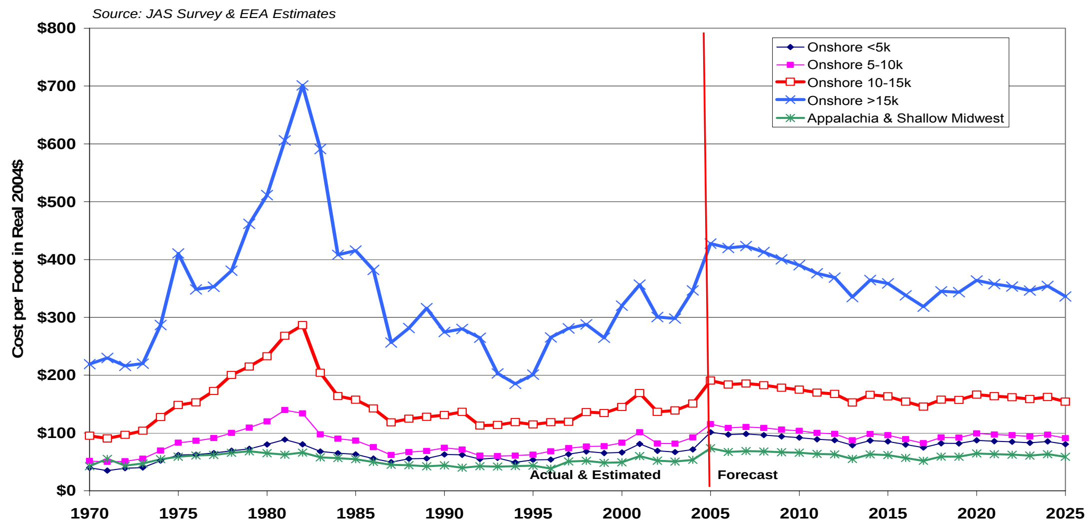
Figure 39 - Historic Onshore Drilling Cost



Figures 40 and 41 show the EEA forecast of U.S. onshore drilling activity by depth interval through 2025. As discussed previously, the major recent trend in activity is a large increase in drilling in the 0-5,000 foot and 5-10,000 foot intervals, dominated by coalbed, tight gas, and shale gas drilling. The EEA forecast indicates a continued strong level of annual drilling at about 45,000 wells per year and increasing to 50,000 wells per year.

On a depth interval basis, the forecast calls for a sustained level of drilling in the 0-5,000 foot interval of about 25,000 wells per year, and over 10,000 wells per year in the 5-10,000 foot interval. Overall, drilling levels in the onshore shallower than 10,000 feet will dominate future drilling.

Cumulatively, the forecast drilling activity level of 25,000 wells from 0 to 5,000 feet translates into 500,000 well completions over a 20 year forecast. An activity of approximately 12,000 wells per year in the second depth interval represents 240,000 wells. This is indicative of a very large potential market for microhole drilling.

Figure 40 - U.S. Onshore Drilling by Depth Interval

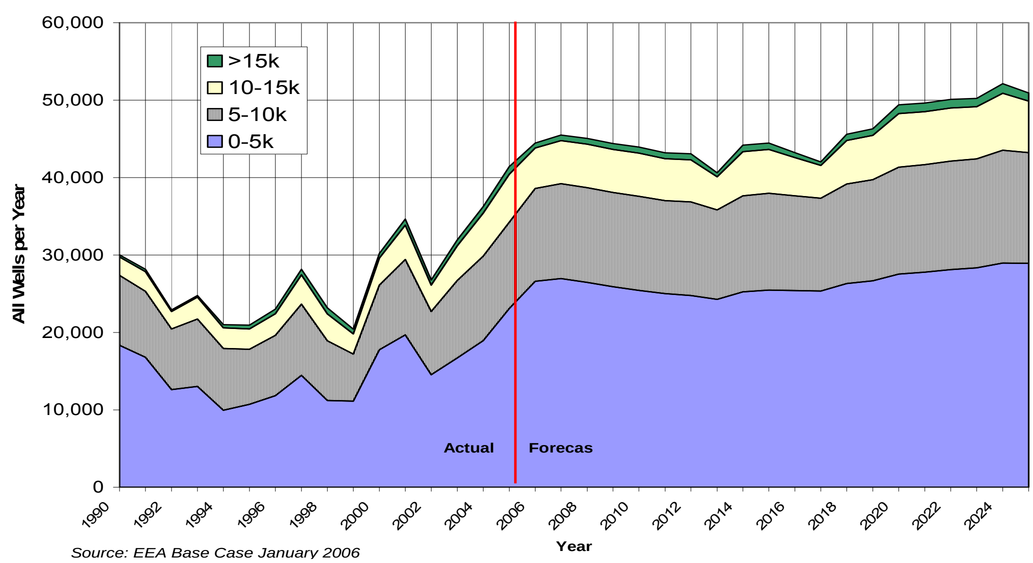
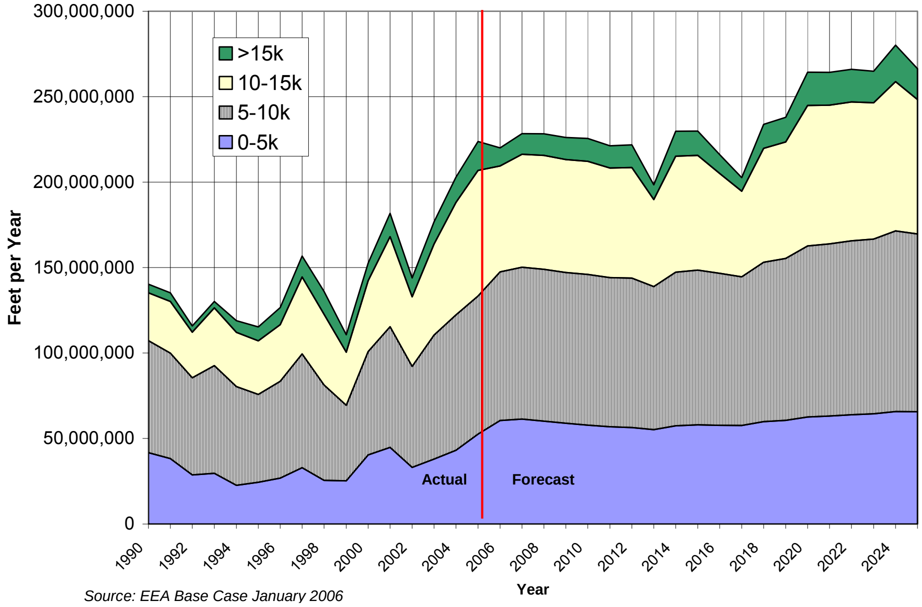


Figure 41 - U.S. Onshore Footage by Depth Interval

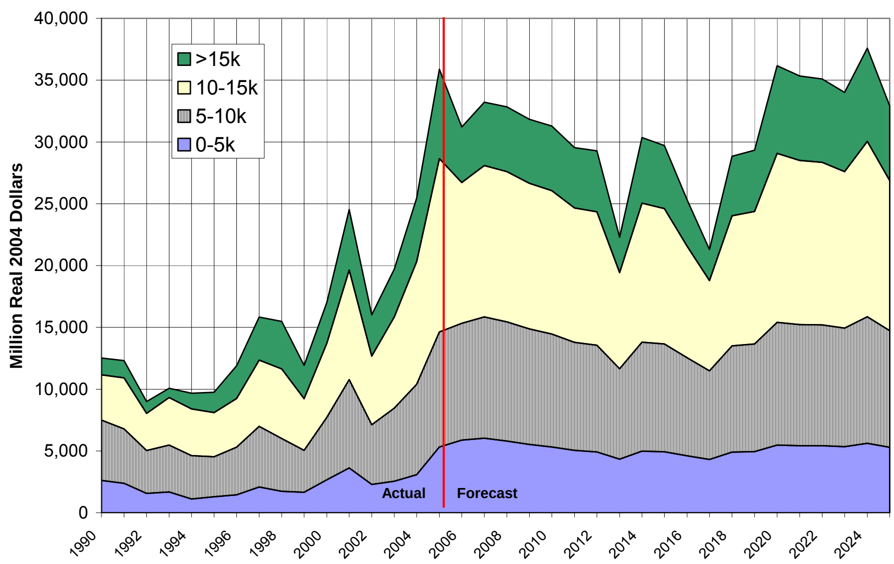


Source: EEA Base Case January 2006

Figure 42 shows the U.S. onshore drilling expenditures in real 2004 dollars. Until recently, annual drilling expenditures averaged less than $15 billion. In 2005, expenditures surged to over $30 billion. The chart shows that, while recent onshore drilling has been dominated by objectives shallower than 10,000 feet, expenditures for drilling to less than 10,000 feet have been about one-half of the total, or about $15 billion.

The EEA onshore drilling expenditure forecast calls for an overall level of $25 to $35 billion per year with about $15 billion for intervals shallower than 10,000 feet.

Figure 42 - U.S. Onshore Drilling Expenditures by Depth Interval



Source: EEA Base Case January 2006

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Analysis of Potential CT Microhole Market Penetration and Impact on Industry

While CT microhole drilling currently represents a very small percentage of U.S. activity, it is possible to develop a set of assumptions about future market penetration and to evaluate the cost savings and impact on the gas industry.

Table 7 shows the assumptions that were developed for the analysis. In 2006, approximately 92 percent of total drilling was vertical and 8 percent was horizontal. CT microhole drilling will represent less than one percent of total drilling. (Total drilling completions in 2005 were 23,000 from 0-5,000 feet and 11,000 between 5,000 and 10,000 feet).

As shown in the table, the study assumes that microhole drilling will see the initial market penetration for vertical wells in the 0-5,000 foot interval. This will be followed by horizontal drilling from 0-5,000 feet. After 2010, an increasing share of drilling between 5,000 and 10,000 feet will be microhole, with vertical drilling first, followed by more horizontal drilling.

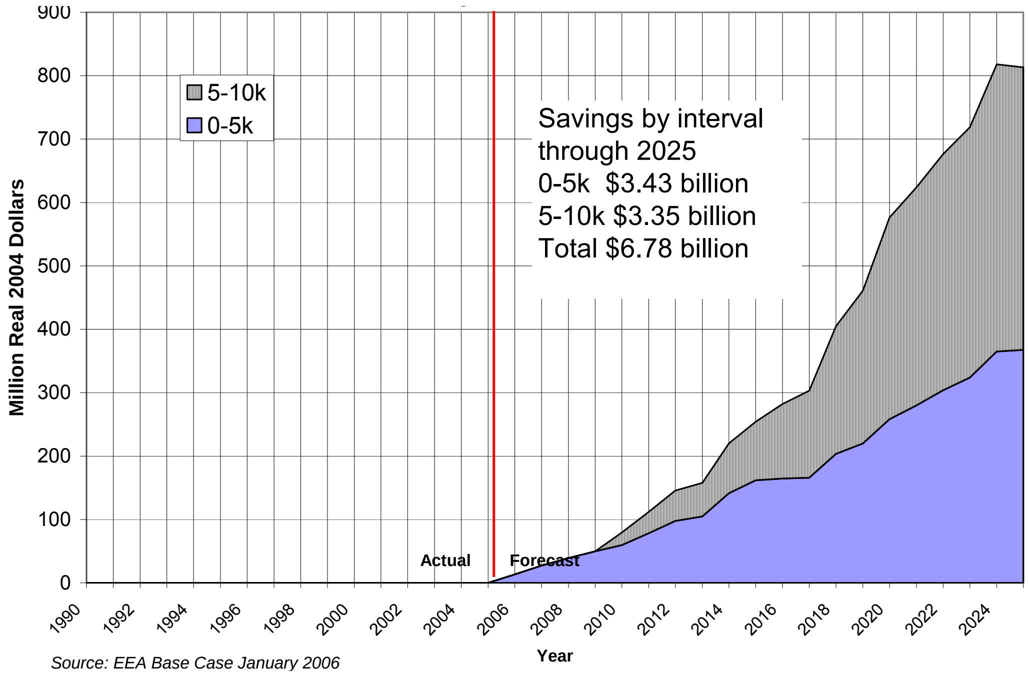
Table 7 - EEA Assumptions for CT Microhole Market Share – Onshore L-48

Scenario for Analysis
Percent of Total Well Completions (Gas and Oil)
Surface drilling; excludes sidetracks

	2006	2010	2015	2020	2025
Drilling 0-5,000 ft					
Percent of all wells vertical	92%	87%	81%	78%	78%
Percent of all wells horizontal	8%	13%	19%	22%	22%
total	100%	100%	100%	100%	100%
Microhole share of vertical wells	1%	5%	15%	20%	30%
Microhole share of horizontal wells	0%	1%	5%	15%	20%
Vertical microhole share of total wells	0.92%	4.35%	12.15%	15.60%	23.40%
Horiz. microhole share of total wells	0.00%	0.13%	0.95%	3.30%	4.40%
Total microhole market share	**0.92%**	**4.48%**	**13.10%**	**18.90%**	**27.80%**
Drilling 5-10,000 ft					
Percent of all wells vertical	92%	87%	81%	78%	78%
Percent of all wells horizontal	8%	13%	19%	22%	22%
total	100%	100%	100%	100%	100%
Microhole share of vertical wells	0%	1%	5%	15%	20%
Microhole share of horizontal wells	0%	0%	1%	5%	15%
Vertical microhole share of total wells	0.00%	0.87%	4.05%	11.70%	15.60%
Horiz. microhole share of total wells	0.00%	0.00%	0.19%	1.10%	3.30%
Total microhole market share	**0.00%**	**0.87%**	**4.24%**	**12.80%**	**18.90%**

Figure 43 shows the annual amount of savings through 2025, based upon an average 25% drilling cost reduction relative to conventional drilling. The conventional drilling expenditures are those that were documented previously, as estimated through the EEA Basecase forecast. Annual CT microhole savings reach a level of over $800 million by 2025. Cumulative savings through 2025 are $6.8 billion dollars.

Figure 43 – Forecast Annual U.S. Microhole Drilling Savings through 2005 by Depth Interval



Source: EEA Base Case January 2006

Additions to U.S. Gas Resource Base

Because CT microhole drilling is significantly lower cost than conventional drilling, it will result in development of gas resources that would not have been economic with conventional methods. As discussed previously and shown in T**able 8**, an estimated 203 Tcf of non-conventional gas is assessed to be available for future drilling to depths of 10,000 feet, assuming current technology. Conventional new field resources to 10,000 feet are approximately 101 Tcf, and reserve appreciation to existing fields is 103 Tcf.

Because of the reduced development costs, EEA has estimated that an additional 5.5% of shale gas, 4.4% of coalbed gas, and 9.5% of tight gas will become economic. This translates into an additional non-conventional resource of 14 Tcf. EEA also estimates that an additional 6 Tcf of new fields and an additional 2 Tcf of reserve appreciation will become economic. The total additional gas resource that would become economic is 22 Tcf.

Table 8 - Estimated Additional U.S. Onshore Gas Resource Made Economic Through Drilling.

	0-5k Resource Tcf	5-10k Resource Tcf	0-10k Resource Tcf	Percentage Added Through Lower Costs	Additional Economic Resource Tcf
Non-Conventional Gas					
Shale	20.0	38.2	58.2	5.5%	3.2
Coalbed	57.8	0.1	57.9	4.4%	2.5
Tight	52.2	34.6	86.8	9.5%	8.2
Total	130.0	72.9	202.9	6.9%	14.0
Conventional New Fields	39.0	62.0	101.0	5.9%	6.0
Reserve Appreciation	44.0	59.0	103.0	2.1%	2.2
U.S. Onshore Total	**213.0**	**193.9**	**406.9**	**5.4%**	**22.1**

Technology Dissemination

A comprehensive program to disseminate the results of the Microhole field demonstration project was undertaken. This program included a portfolio of dissemination techniques which ranged from press releases to personal communications and others.

Table 9 which follows describes the dissemination activities undertaken during the performance of the project in chronological order. Following the table some of the results of the efforts are summarized and any issues identified.

Table 9 - Information Dissemination

Technology Dissemination Activity	Date	Description
Article published in American Oil and Gas Reporter.	May, 2005	Unconventional Gas topic pointing out the importance of new technology and the marginal nature of the resource. Microhole applications to marginal resources emphasized.
Brownfield Conference to Producing Community, Denver	September 19, 2005	Presented Microhole Drilling Project results with linkage as to how they can be utilized to recover marginal oil and gas resources.
Press Release to Major Newspaper Energy Editors	September 23, 2005	Press Release Title: MICROHOLE TECHNOLOGY SUCCESSFUL IN SHALLOW, LOW-MARGIN FIELDS (Attached in Appendix C)
Press Release to Oil and Gas Journals and Publications	November 7, 2005	Press Release Title: Microhole Technology Holds Potential to Increase Domestic Natural Gas and Oil Production - *New drilling approach lowers cost of recovery and lessens environmental impact* (Attached in Appendix C)
DOE PTTC Workshop #1	August 16-17, 2005	Workshop in Tulsa and Houston to introduce the portfolio of Microhole technologies to the producer community.
DOE PTTC Workshop #2	November 16, 2005	Workshop in Houston to update the producer community as to the status of the Microhole projects.
Article published in Oil and Gas Journal, November 28th, 2005 issue.	November 2005 Issue	Drilling Market Focus: Coiled-tubing use growing faster than drilling industry *Oil and Gas Journal,* November 28, 2005 – (Excerpt Only attached in Appendix C)
Article published in Hart's E&P publication on Microhole drilling and its application to the Niobrara.	February, 2006 Issue	Article Title: Application of Microhole Coiled Tubing Drilling to the Niobrara Gas Play in Kansas and Colorado (Attached in Appendix C)

Technology Dissemination Activity	Date	Description
DOE PTTC Workshop #3	March 22, 2006	Workshop in Houston to update the producer community as to the status of the Microhole projects.
EIA Gas Supply Conference	March 28, 2006	Presented results and impact of Microhole drilling at the EIA conference in Washington with emphasis on Unconventional gas recovery.
Hart's Unconventional Gas Conference	March 29, 2006	Presented results and impact of Microhole drilling at the Hart's Unconventional conference in Washington with emphasis on Unconventional gas recovery.
KIOGA Mid-Year Meeting, McPherson, Kansas	April 12, 2006	Presented the project results to the Kansas Independent Producers at their mid-year meeting.
Personal Communications	Ongoing Throughout Project	As a result of the publications, press releases and presentations we fielded numerous phone calls and emails regarding information on coiled tubing drilling. All were responded to by providing more material and/or information.
Future Activities – Beyond the project End date that GTI will conduct.	May 19, 2006, Denver May 31, 2006, Ohio June 21, 2006 DEA Workshop, Galveston	Workshops to present Microhole drilling project results to industry in Denver, Ohio and to the DEA at their annual workshop.

Overall, the technology dissemination activities have generated a significant level of interest in this technology area. Many producers have contacted GTI for more information and access to drilling operations of this type. It is our view that as a result of this dissemination project and with additional development of downhole tools as is underway within the overall DOE Microhole project, that this type of coiled tubing drilling will displace rotary drilling for the 0' to 5000' drilling depth range. Additionally, with time this approach will penetrate the 5000' to 10,000' depth market.

Summary and Conclusions

The Gas Technology Institute (GTI), in partnership with Coiled Tubing Solutions (now Advanced Drilling Technologies or ADT) and Rosewood Resources, Inc., has completed a field-based test of a state-of-the-art Microhole Coil Tubing Rig (MCTR) in the Niobrara gas fields to determine performance advantages of the ADT CT rig and to estimate the national impact of the technology at full commercial deployment. The ADT CT rig was selected for field performance evaluation because it is one of the most advanced commercial CT rig designs that demonstrates a high degree of process integration and ease of set-up and operation. Employing an information collection protocol, data was collected from the ADT CT rig during 25 drilling events that encompassed a wide range of depths and drilling conditions in the Niobrara. Information collected included time-function data, selected parametric information indicating CT rig operational conditions, staffing levels, and field observations of the CT rig in each phase of operation, from rig up to rig down.

In general, the data obtained in this field evaluation indicates that the ADT CT rig exhibited excellent performance in the drilling and completion of more than 25 wells in the Niobrara under varied drilling depths and formation conditions. Quantitative information that was collected showed the following:

- During field trials, the rate of penetration (ROP) values that were achieved ranged between 150 and 620 feet per hour. In the majority of the 25 project well drilling events, ROP values ranged between 300 and 620 feet per hour. For all but the lowest 2 wells, ROP values averaged approximately 400 feet per hour, representing an excellent drilling capability.
- ROP is not sensitive to the parameter of well depth at values between 500 and 3,000 ft.
- Most wells of depths between 500 and 2,000 feet were drilled at a total functional rig time of less than 16 hours; for wells as deep at 2,500 to 3,000 feet, the total rig time for the CT unit is usually well under one day.
- There is a general, nearly linear relationship between well depth and total rig time.
- About 40-55 percent of the functional rig time is divided evenly between drilling and casing/cementing. The balance of time is divided among the remaining four functions of rig up/rig down, logging, lay down bottomhole assembly, and pick up bottomhole assembly.

Observations made during all phases of CT rig operation at each of the project well installations have verified a number of characteristics of the technology that represent advantages that can produce significant savings of 25-35 percent per well. Attributes of the CT rig performance that were observed and documented in the field are summarized below.

- **Excellent Hole Quality.** All wells observed to be drilled at 25 project wells with the ADT CT rig were of excellent hole quality. All wells that were drilled had resulted in a gauge hole with very little hole deviation amounting to 1 to 2 degrees, well within State requirements. Good cement job quality and well-bonded cement is derived from the gauge hole quality.
- **Reduced Need for Auxiliary Equipment.** No auxiliary equipment is required to run casing, log wells or for handling drill collars and bottom hole drilling assemblies.
- **Efficient rig mobilization.** The rig is transported with 4 trailers, thereby reducing mobilization and transportation costs while meeting U.S. Department of Transportation limitations for highway transport. The CT rig contains all the equipment required for drilling

operations with the pipe handling capacity for casing up to 7 5/8" and supports a rotary and top drive.

- **Zero Discharge Operation.** The rig has a zero-discharge mud handling system and is capable of drilling a well with zero discharge of any fluid or solid residues (such as cuttings) if required. This is a considerable advantage for operations in environmentally sensitive areas.
- **Improved Safety.** The ADT CT rig substantially reduces drill pipe handling and has less equipment to mobilize from well to well. These characteristics translate into a far safer operating environment. The CT rig design also incorporates a number of redundant safety features that further reduce the risk to workers and observers proximal to rig operations.
- **Measurement While Drilling.** Using coiled tubing, measurement while drilling technology can be attached to the coiled tubing without concern about pipe joints.
- **Reduced Drilling Cost.** Commercial service estimates that the CT rig reduces drilling costs by 25 to 35% compared to conventional drilling technology.

Widespread commercial use of the Microhole Coiled Tubing technology in the United States for onshore Lower-48 drilling has the potential of achieving substantially positive impacts in terms of savings to the industry and resource expansion. This impact was assessed in this project using the conservative assumption that CT technology could achieve an average savings of at least 25% per well drilled in the Lower-48 over a twenty-year horizon. The findings of this analysis indicate:

- The likely market scenario for deployment of the technology in the years 2006-2026 will involve the following steps:
    - Initial CT market penetration for vertical wells in the depth range of 0-5,000 feet
    - Then commercial use of CT for horizontal drilling in the depth range of 0-5,000 feet.
    - After 2010, an increasing share of drilling between 5,000 and 10,000 feet will be based on microhole technology.
- Successfully commercialized Microhole CT Rig Technology is projected to achieve cumulative savings in Lower-48 onshore drilling expenditures of approximately 6.8 billion dollars by 2025.
- The reduced cost of CT microhole drilling is projected to enable the development of gas resources that would not have been economic with conventional methods. Because of the reduced cost of drilling achieved with CT rig technology, it is estimated that an additional 22 Tcf of gas resource will become economic to develop.

The Microhole Coiled Tubing Rig design represents the next step in the continued journey of the drilling technology toward smaller bore holes and toward systems that utilize increasingly complex downhole instrumentation for improved control and real-time data acquisition and sensing technology to allow informed decision making by the operator. Since the CT rig design concept by its nature facilitates the use of many of these technological improvements, it follows that there is an advantage to encourage its continued development. In other words, the Microhole Coiled Tubing Rig represents an important platform for the continued improvement of drilling that draws on a new generation of various technologies to achieve goals of improved drilling cost and reduced impact to the environment.

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Appendix A. Data Collected by GTI Staff during CT Rig Operation

Well Name: Gutsch 1 – 26
Date : 5-15-2005
County : Sherman, KS

Depth	**1245 ft**	
	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(8)Drilling Collar (3 ¾”),	246.07 length in ft	
Mud Record		
Weight	8.7 lbs/gal	
Funnel Viscosity	32 centipoise	
KCL	10 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	1 gal/well	
Deviation		
Depth	Deviation Value	
500 ft	0.75 ft	
750 ft	1.50 ft	
1000 ft	0.75 ft	
1200 ft	1.25 ft	
Depth Interval		
400 ft	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
Time Log		Time, hr
7:00 to 10:30	Rig up	3.5
10:30 to 16:30	Drill	6
16:30 to 18:00	Pull out	1.5
18:00 to 20:00	Casing	2
20:00 to 21:00	Cement 2% cacal	1
21:00	Plug down	1
22:00	Rig down	

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Well Name: Irvin 1 - 33
Date : 5-14-2005
County : Sherman, KS

Depth	**1400 ft**	
	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(8)Drilling Collar 3 ¾	246.07 length in ft	
Mud Record		
Weight	8.8 lbs/gal	
Funnel Viscosity	33 centipoise	
KCL	10 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	1 gal/well	
Deviation		
Depth	Dev	
500	0.75 ft	
750	0.75 ft	
1000	1.50 ft	
1350	0.75 ft	
Depth Interval		
366	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
Time Log		Time, hrs
19:00 to 5:00	Rig down wait for the sun	10
5:00 to 7:00	Move rig	2
7:00 to 9:00	Rig up	2
9:00 to 10:30	BHA trip in	1.5
10:30 to 16:30	Drilling till 366, clays slow down	6
16:30 to 18:00	Tooth LD BHA	1.5
18:00 TO 20:00	Logs	2
20:00 to 22:30	Run casing and cementing.	2.5
	44 jts, 2 7/8" J-55. 6.50# 8rd csg	
22:30 to 23:00	Cement w/50 sks STD cement 2% cacal	1
23:00 to 24:00	Set slips Plug down 11:00 PM 1200# release rig	1

Well Name: Duell 3 – 17
Date : 5-13-2005
County : Sherman, KS
Depth **1180 ft**

	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(6)Drilling Collar 3 3/4	184.42 length in ft	
Mud Record		
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
Deviation		
Depth	Dev	
500	1.50 ft	
750	2 ½ ft	
1000	1 ¼ ft	
Depth Interval		
370 to 1180 ft	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
Time Log		Time, hrs
6:00 to 7:00	Pickup BHA	1
7:00 to 8:00	Safety meeting	1
8:00 to 11:00	Drilling till 1180 ft	3
11:00 to 13:00	Trip and circulate for 15 minutes	2
13:00 to 15:00	Logs- Density and Gamma	2
15:00 to 18:30	Run casing and cementing.	3.5
	38 jts, 2 7/8" J-55. 6.50# 8rd csg	
18:30 to 19:30	Set slips release rig	1

Well Name: Topliff 1 - 25
Date : 6-08-2005
County : Sherman, KS

Depth	**1400 ft**	
	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(6)Drilling Collar 3 3/4	184.42 length in ft	
	Mud Record	
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	10 gal/well	
Bicarb	3 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
	Deviation	
Depth	Dev	
500	*NA	
750	NA	
1000	NA	
	Depth Interval	
360 to 1350 ft	Shale	
Rotary Table speed	200 rpm	
WT on bit	5000 lbs	
Mud pressure	1300 psig	
	Time Log	Time, hrs
4:30 to 7:00	Moving	2.5
7:00 to 8:00	Rig up	1
8:30 to 9:30	Pick up BHA	1
9:30 to 3:30 pm	drill F/360 T/1350	6
3:30 to 5:30	POOH L,D,BHA	2
5:30 to 7:00 pm	log slb	1.5
7:30 to 11:30	casing and cementing	4
	38 jts, 2 7/8" J-55. 6.50# 8rd csg	
12:00 AM	Rig down	

* NA = Data Not Available

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Well Name: Melba 1-29
Date : 6-09-2005
County : Sherman, KS
Depth **1460 ft**

	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(6)Drilling Collar 3 3/4	184.42 length in ft	
Mud Record		
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
Deviation		
Depth	Dev	
500	1 ½ ft	
750	2 ½ ft	
1000	1 ¼ ft	
Depth Interval		
375 to 1460 ft	Shale	
Rotary Table speed	300 rpm	
WT on bit	5000 lbs	
Time Log		Time, hrs
7:00 to 8:30	Rick up	1.5
8:30 to 10:00	Pick up BHA	1.5
10:00 to 4:00	Drill F/375 T/1475	6
4:00 to 6:00	Lay down BHA	2
6:00 to 8:30	Logs- Density and Gamma	2.5
8:30 to 9:30	Water Ordering	1
9:30 to 12:00	RHIT 1375 PLUG DOWN @1375	2.5

Well Name: Cramnne 1-29
Date : 6-15-2005
County : Sherman, KS

Depth	**900 ft**	
	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(6)Drilling Collar 3 3/4	184.42 length in ft	
	Mud Record	
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
	Deviation	
Depth	Dev	
200	1.00 ft	
400	1 ½ ft	
600	1 ½ ft	
800	1 ¼ ft	
850	1 ¾ ft	
	Depth Interval	
290 to 900	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
	Time Log	Time, hrs
7:00 to 8:00 PM	Rig up Carmine 1-29	1
8:00 to 11:00	drill 290 to 900	3
11:00 to 11:30	Circulation	0.5
11:30 to 1:00 am	Lay BHA	1.5
1:00 to 2:00 am	wait to log	1
2:00 to 4	Logging	2
4:00 to 6:30	Casing	2.5
6:30 to 7	Well head	0.5
7 to 7:30	Survey	1.5
7:30 to 6 pm	Rig down and move stuck	10.5
6:00 to 7	Pick up BHA	1

Well Name: Rita Ihrig 1-29
Date : 6-16-2005
County : Sherman, KS

Depth	**1250 ft**	
	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(6)Drilling Collar 3 3/4	184.42 length in ft	
Mud Record		
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
Deviation		
Depth	Dev	
350	1.00 ft	
500	¾ ft	
750	1 ft	
1000	½ ft	
1220	½ ft	
Depth Interval		
290 to 900	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
Time Log		Time, hrs
7:00 to 11:00 pm	Drilling 350/1250	4
11:00 to 11:30	Circulation	0.5
11:30 to 1:00 am	Pick up BHA	1.5
1:00 to 3:00 am	Logging	2
3:00 am to 4:00	wait on orders	1
4: to 6:30	Casing	2.5
6:30 to 7	Well head	0.5
7:00 to 7:30	Survey	0.5

Well Name: Bradshaw 1-15
Date : 6-13-2005
County : Sherman, KS
Depth **1200 ft**

Drilling Assembly		
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(6)Drilling Collar 3 3/4	184.42 length in ft	
Mud Record		
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
Deviation		
Depth	Dev	
200	1.25 ft	
400	1 ½ ft	
600	1 ft	
800	½ ft	
945	1 ft	
Depth Interval		
200 to 980	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
Time Log		Time, hrs
7 to 11:30 am	Move on and Rig up	4.5
11:30 to 5:00 am	Drill from 220 to 980 Lost circulation at 780	5.5
5:00 to 5:30	Circulation	0.5
5:30 to 7:00 am	Pick up	1.5
7:00 to 8:30	Logs- Density and Gamma	1.5
8:30 to 10:30	Run casing 2 7/8	2
10:30 to 11:00	Cementing	0.5
11:00 to 11:30	Well head	0.5
11:30 to 12:00	survey	0.5
12:00 to 4:00	Rig down and move	4
4:00 7:00	Rig up Carmine 1-29	3

Well Name: Emma 1-27

Date : 9-06-2005

County : Sherman, KS

Depth **2630 ft**

	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(8)Drilling Collar 3 3/4	246 length in ft	
Mud Record		
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
Deviation		
Depth	Dev	
500	½ ft	
1000	1 ft	
1500	2 ¼ ft	
2000	2 ½ ft	
Depth Interval		
200 to 980	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
Time Log		Time, hrs
7 to 1:30	Drilling	6.5
1:30 to 4:30	POOH LD BHA	3
4:30 TO 7:00	LOG	2.5
7: TO 11:30	Run casing 2 7/8	4.5
11:30 TO 12	FLANGE WELL	0.5
12 TO 2	RDMO	2

Well Name: Conrad 1-25
Date : 9-4-2005
County : Sherman, KS

Depth	**2850 ft**	
	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(8)Drilling Collar 3 3/4	246 length in ft	
Mud Record		
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
Deviation		
Depth	Dev	
500	1 ft	
1000	1 ft	
1500	2 ft	
2000	2 ¾ ft	
Depth Interval		
2200 to 2850	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
Time Log		Time, hrs
7 to 12	Drilling	5
12 to 3.5	POOH LD BHA	3.5
3:30 TO 6	LOG WITH SLB	2.5
6 TO 7	Run casing 2 7/8	1
7 TO 10:30	CEMENT	3.5
10:30 11	FLANGE	0.5
11 TO 5:30	Rdmo ru emma	6.5

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Well Name: Villines 1-34
Date : 9-7-2005
County : Yuma, CO
Depth **2910 ft**

Drilling Assembly

Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(8)Drilling Collar 3 3/4	246 length in ft	
Mud Record		
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
Deviation		
Depth	Dev	
500	1 ft	
1000	1 ft	
1500	2 ft	
2000	2 ¾ ft	
Depth Interval		
485 to 2910	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
Time Log		Time, hrs
7 to 7:30	RIM W /BHA	0.5
7:30 TO 6	DRILL F/415 TO 2910	11.5
6 TO 7	POOH LD BHA	1
7 to 9	BHA	2
9 TO 12	SCHEN	3
12 TO 4	PLUG WELL	4
4 TO 7	RDMO	3

Well Name: Linin 1-1m
Date : 9-7-2005
County : Sherman, KS
Depth **1500 ft**

	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(8)Drilling Collar 3 3/4	246 length in ft	
Mud Record		
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
Deviation		
Depth	Dev	
500	1.50 ft	
1000	¾ ft	
1450	1 ¾ ft	
Depth Interval		
385 to 1500	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
Time Log		Time, hrs
7 to 7:30	BHA	0.5
7:30 TO 10	DRILL 385 TO 1500	2.5
10 TO 10:30	CIRCULATION	0.5
10:30 TO 12:00	POOH BHA	1.5
12: TO 3:30	CSG	3.5
3:30 TO 4	FLANGE WELL	0.5
4:00 TO 7	RDMO	3

Well Name: Linen
Date : 8-3-2005
County : Sherman, KS
Depth 1200 ft

	Drilling Assembly	
Bit	4 ¾ inches	
Mud Motor	15.79 ft	
(8)Drilling Collar 3 3/4	246 length in ft	
	Mud Record	
Weight	8.7 lbs/gal	
Funnel Viscosity	34 centipoise	
KCL	20 gal/well	
Bicarb	2 gal/well	
Poly	4 gal/well	
Pac	2 gal/well	
	Deviation	
Depth	Dev	
500	1 ½ ft	
1000	¾ ft	
1450	1 ¾ ft	
	Depth Interval	
385 to 1500	Shale	
Rotary Table speed	300 rpm	
WT on bit	4000/6000 lbs	
	Time Log	Time, hrs
7 to 9:30	RU	2.5
9:30 to 11	RIH W/BHA	1.5
11 TO 1:30	DRL 388 TO 1200	2.5
1:30 TO 2:30	CIRC	0.5
2:00 TO 3:30	TRIP OUT	1.5
3:30 TO 5:30	LOG	2
5:30 TO 7	CSG	1.5

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Appendix B - Tabulated Data Collected from All Test Wells Drilled with the CT Rig.

						---------------------------- Time Increment, hrs ----------------------------						
Well	Depth, ft	Surface, ft	Actual Depth, ft	Time, hrs	ROP ft/hr	Rigup	PBHA	Drill	LDBHA	Log	CSG/CMNT	Total Functional CT Rig Time At Site
Melba	1460	375	1085	6	180.83	1.5	1.5	6	2	2.5	2.5	16
Topliff	1350	360	990	6	165.00	1	1	6	2	1.5	4	15.5
Duell	1180	370	810	3	270.00	1	1	3	1	2	3.5	11.5
Irvin	1400	366	1034	6	172.33	2	1.5	6	1.5	2	2	15
Gutsch	1245	340	905	6	150.83	1.5	1	6	2	2	3	15.5
Bradshaw	980	220	760	5.5	265.40	2.5	1.5	5.5	1.5	1.5	2.5	15
Crumrine	900	290	610	3	203.00	1	1	3	1.5	2	2.5	11
Rita	1250	350	900	4	225.00	1	1	4	1.5	2	2.5	12
Villines	2910	410	2500	10.5	238.10	0.5	1	10.5	2	2.5	4.5	21
Emma	2630	1000	1630	6.5	250.77	2	2	6.5	2	2.5	4.5	19.5
Conard	2850	494	2356	5	471.20	3.5	3.5	5	3.5	2.5	4.5	22.5
Alvin 44-8	1794	244	1550	3.5	442.86	1.5	1.5	3.5	1.5	2.5	3.5	14
Ella Mae 14-3	2094	374	1720	3	573.33	2	2	3	1.5	2.5	3.5	14.5
Ella Mae 22-04	2213	343	1870	3	623.33	2.5	2	3	2	2.5	3.5	15.5
Emma 1-27	2999	369	2630	8	328.75	6.5	3	8	3	2.5	4.5	27.5
ISERNHAGEN 12-25	1866	396	1470	3.5	420.00	1.5	1.5	3.5	1.5	1.5	3	12.5
ISERNHAGEN 21-26	1802	282	1520	2.5	608.00	1.5	1.5	2.5	1.5	1.5	3	11.5
R.Moore 13-28	2169	369	1800	3	600.00	2	2	3	2	2	3.5	14.5
R.Moore 33-28	2160	355	1805	7	257.86	2	2	7	1.5	2	3.5	18
R.Walter 21-21	1818	288	1530	3	510.00	1.5	1.5	3	1.5	1.5	3	12
Walter 33-21	1790	260	1530	3.5	437.14	1.5	1.5	3.5	1.5	1.5	3	12.5
RUDOLPH 33-9	1857	287	1570	3.5	448.57	1.5	1.5	3.5	1.5	2	3	13
Villines 1-34	3335	485	2850	10.5	271.43	0.5	1	10.5	2	2.5	4.5	21
Linin 1-1m	1500	385	1115	2.5	446.00	0.5	0.5	2.5	1	1.5	3.5	9.5
Linen 1-1	1200	388	812	1.5	541.33	2.5	1.5	2.5	1	2	1.5	11
Key												
Names in Bold =	CT Rig Drilling Observed by GTI Staff On Site				Names Not in Bold =	CT Rig Drilling Data Collected by CTS Staff						
PBHA	Pickup Bottom Hole Assembly											
LDBHA	Lay Down Bottom Hole Assembly											
CSG/CMNT	Casing and Cementing											

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Appendix C. Technology Transfer Coordinated by GTI

Denver Section Society of Petroleum Engineers

Continuing Education Short Course Offering

In Association with PTTC:

Microhole Drilling with Coiled Tubing – It's Here and Growing

A Half-day Short Course

May 19, 2006, 8:30 am – 1 pm
Denver Athletic Club, 1325 Glenarm Place, Denver
Fee: $95, includes lunch

Course Description: This concise half-day workshop will describe the history and technology of using coiled tubing for drilling shallow grass-roots wells and deep reentries. Case studies will review economic and operational considerations; potential new applications will be discussed.

Course Content

- An Overview of the Development of Coiled Tubing Drilling and Current Activities in North America, Movement into Lower 48 (Dwight Rychel, Consulting Petroleum Engineer and PTTC)
- Coiled Tubing Grassroots Drilling of Shallow Unconventional Gas (Kent Perry, GTI)
- Coiled Tubing Re-entry for Reservoir Life Extension – Technology and Case Study from Texas (IPS Procoil)
- Technology Developing in the Department of Energy's Microhole Technology Program & PTTC's Role and Informational Website (Dwight Rychel, PTTC)
- Geological Overview of the Niobara Chalk Natural Gas Play (Lynn Watney, Kansas Geological Survey)
- Coiled Tubing Drilling in the Rockies (Kyle Zemlak, Pioneer Resources)
- Feedback from participants on the potential application in the Rocky Mountain Region
- Lunch (included) and networking will follow the presentations

Who Should Attend: The workshop will benefit engineers, geologists, planners, executives; anyone setting strategic direction on plays and the best exploitation techniques.

Technical questions: Lance Cole 918.241-5801 or Dwight Rychel 918.492.6964
Workshop information: Sandra Mark, 303.273.3107
Register online: www.pttcrockies.org

Hart's E&P Article – February, 2006

Microhole Approach to Microdarcy Reservoirs

Application of Microhole Coiled Tubing Drilling to the Niobrara Gas Play in Kansas and Colorado

Kent Perry and Samih Batarseh; Gas Technology Institute

Introduction

Natural gas was first discovered in the Niobrara formation in 1912 when a strong flow of gas was encountered while drilling the Goodland No. 1 well near Goodland, Kansas1. The well was plugged and abandoned. Since that first well the Niobrara gas play has undergone several episodes of activity driven by gas prices and improvements in technology. Recently, the development of coiled tubing drilling in combination with a microhole approach to borehole size has helped reenergize activity in this mature gas play.

Geology and Reservoir Characteristics

The Niobrara formation chalks were deposited during the last major transgression of the western interior Cretaceous sea, which extended from the Gulf of Mexico to the Arctic Ocean. The current play extends through Northwest Kansas and Eastern Colorado (Figure 1). Gas bearing chalk of the upper Cretaceous Niobrara formation is encountered at depths from 1000 to 3000 feet. Gas accumulations in the Niobrara formation generally are related to low relief structural features found along the eastern margins of the Denver geologic basin[2].

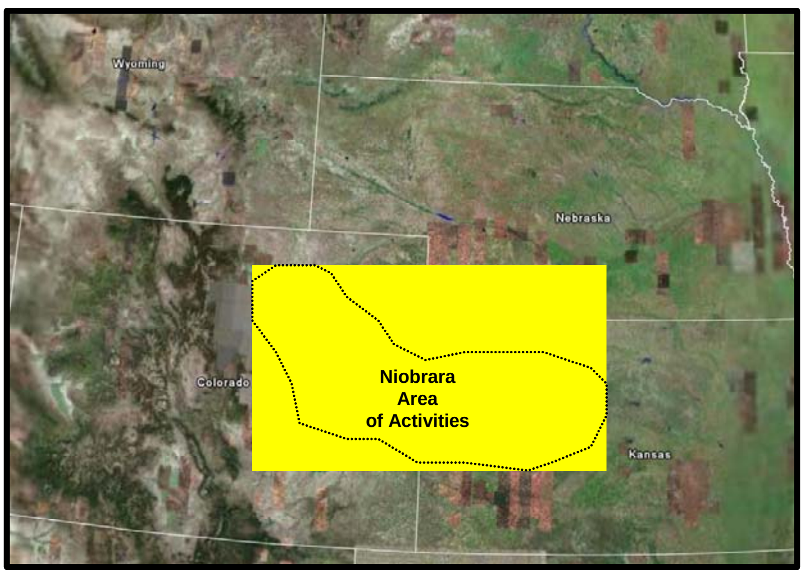

Figure 1 - Niobrara Gas Play Area

Niobrara gas fields are characterized by high porosity, low permeability and low reservoir pressure. These features are typical of a chalk subjected to modest burial depths[3]. At greater depth, porosity and permeability decrease causing a reduced total pore volume and higher water saturation at a given structural position. Reported values for porosity in the Niobrara formation range from 30% to 50%, with lower values found at greater depths. Despite the high porosity of the chalk, permeability is inherently low because of the fine grain size. Values for permeability range from 0.01 to 0.3 millidarcies in the fairway with microdarcy permeability found on the fringes. The Niobrara is an underpressured gas reservoir with geostatic pressure gradient ranges from 0.06 to 0.24 psi/ft. In the Goodland, Kansas area, at a depth of 1,000 feet the pressure is only 50 to 60 psi.

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Thin pay zones (sometimes near water), low reservoir pressures and low in-situ formation permeability (requiring wells be hydraulically fractured) combine to create a challenging environment for successful field development. Certainly, an efficient low cost approach to well drilling and completion is needed.

DOE Microhole Drilling Program

Roy Long, with the Department of Energy's Tulsa office has designed and is implementing a research program to develop marginal oil and gas resources utilizing microhole wellbores. The overall approach is to develop a portfolio of tools and techniques that will allow the drilling of 3 5/8" holes and smaller (see accompanying article) enabling through better economics the development of marginal oil and gas resources. The field testing and demonstration of a "fit for purpose" coiled tubing drilling rig is one project within the program. The objective is to measure and document the rig performance under actual drilling conditions. A description of the rig and a summary of its performance in the Niobrara gas play follow.

Description of the Rig

The coiled tubing drilling rig (designed and built by Tom Gipson with Advanced Drilling Technologies Inc. (ADT)) is a trailer mounted rig with the coil and derrick combined to a single unit (Figure 2). The rig has been operating for approximately one year drilling shallow gas wells operated by Rosewood Resources, Inc., in Western Kansas and Eastern Colorado. The rig operations have continued to improve to the point where it now drills 3,100 foot wells in a single day. Well cost savings of approximately 30% over conventional rotary well drilling have been documented. Improved well performance due to less formation damage as a result of minimizing formation exposure to drilling fluid through fast drilling and drilling operations is another important aspect.

Figure 2 – Advanced Drilling Technologies (ADT) Coiled Tubing Drilling Rig

Efficient Rig Mobilization

The rig moves with 4 trailer loads mitigating mobilization and transportation cost while meeting U.S. Department of Transportation limitations for highway transport. These features allow for smaller access roads and well locations reducing well costs. The rig contains all the equipment needed for drilling operations including a zero discharge mud system (discussed later), has pipe handling capacity for casing up to7 5/8" and can support a rotary and top drive.

Small Environmental Footprint

The small size of the rig provides several environmental advantages over a conventional rig. As a result of its efficient design and size the following environmental advantages are realized:

- A small drilling pad (1/10th acre) or no pad under some conditions can be utilized. Smaller access roads are required.
- No mud pit is needed; mud tanks contain the required drilling fluids and are moved with the rig from one location to the next. The only pit required is a small (3'x 6'x 6') pit for drill cuttings. If needed, cuttings are easily hauled off location allowing no pit drilling as needed.
- Smaller equipment yields less air emissions and low noise engines minimize disturbances to the surrounding environment.
- The microhole approach (4 ¾" holes) requires less drilling mud and fluids to be treated and yields fewer drill cuttings.
- The utilization of coiled tubing mitigates the risk of spills due to no drill pipe connections.

Rapid Drilling

Very high rates of penetration have been achieved by experimenting with bit-downhole motor combinations and by fully utilizing the advantages of coiled tubing drilling. Drilling rates as high as 500 feet/hour have been realized with the average rate of penetration per well in the 400 feet/hour range. This rate of drilling and other rig efficiencies allowed the drilling of a 2850 foot well in 19 hours including all rig moving time, logging, casing setting and cementing (Figure 3)

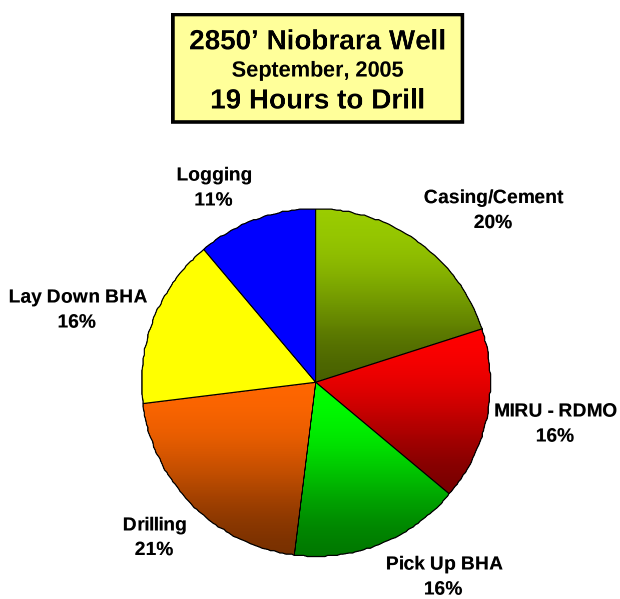

Figure 3 – Allocation of Drilling Time for 2,850 foot deep Niobrara Well

Good Hole Quality and Cement
The benefits of fast drilling by the ADT rig is augmented by excellent hole quality. All the wells drilled have resulted in a gauge hole with very little hole deviation (1 to 2 degrees - well within State requirements) despite the high penetration rates. Good cement job quality and well bonded cement also derive from the gauge hole quality. As mentioned previously, the Niobrara is an under pressured reservoir and as such is susceptible to formation damage due to fluid loss from drilling operations. Both the rapid penetration rate through the pay zone and the lack of any pressure surges caused by conventional drilling pipe connections help to mitigate fluid loss and therefore formation damage. This is an important factor given the marginal nature of the resource.

Rig Capable of Running Casing, Handling Bottomhole Assemblies and Logging Tools - No auxiliary equipment is required to run casing, log wells or for handling drill collars and bottom hole drilling assemblies. With its derrick, traveling block and rotary table components, all required drilling processes can be performed without additional equipment. While not currently equipped with a top drive, the rig can accommodate one if needed. Drilling with coiled tubing eliminates drill pipe connection time and fewer crew members are required to operate the rig.

Zero Discharge if Required

The rig has the capability to drill a well with zero discharge of any fluid or other materials if required. The procedure is as follows:

- Rig up on a sealed/booted tarp to contain any overflow or accidental spill.
- No earthen pits are prepared; all cuttings and drilling fluid are confined to tanks with which the rig is equipped.
- A hole is augured for conductor pipe and a boot is placed around the conductor pipe.

Using this process, the ground is protected from any inadvertent spills and all fluids and cuttings are removed from the location. While obviously an added expense, this procedure may be required for drilling in sensitive environmental areas. The small rig size and efficiency of drilling coupled with the zero discharge capability enables drilling in sensitive areas.

Improved Safety
Safety is always of utmost importance and the conventional drilling rig environment is one where extra caution and safety training is necessary due to the handling of drill pipe and other equipment. The ADT coiled tubing rig significantly reduces drill pipe handling and has less equipment to mobilize from well to well. All of this creates a much safer operating environment which is important during any time of drilling but especially so during today’s high rig count when experienced roughnecks are difficult to find.

Barriers to Microhole Coiled Tubing Drilling
Barriers exist to full utilization of this type of approach to the drilling and completion of marginal resources. Operators have identified the following as concerns that must be addressed for microhole to reach its full potential:

- Production engineers have long-term concerns about the ability to rework wells.
- Handling of significant fluids is an issue in small boreholes.
- There is limited space for downhole mechanical equipment.
- A general lack of experience and familiarity with microhole and coiled tubing drilling of this type was identified as a barrier to usage.
- There is a depth limitation given current coil metallurgy and coiled tubing procedures.
- Coiled tubing is limited in its ability to overcome problems in difficult drilling environments. One example is where fluid loss and severe pipe sticking is encountered. Coiled tubing has limited tensile strength for freeing stuck pipe.

Technology Trends

Operators pursuing marginal resources are doing so in a new era. Driven by a growing economy, U.S. energy demand is expected to reach record levels in the near future. The higher quality resources have been exploited, increasing the challenge for future developments.

The rate of new technology improvement is beginning to be offset by the increasing challenges created by lower quality reservoir rock and increasing costs from environmental issues.

A concerted technology effort to both better understand marginal oil and gas resources and develop solid engineering approaches is necessary for significant production increases from these widely dispersed resources.

Historical Technology Development

Marginal oil and gas technology development has evolved significantly over the last forty years. The trend has moved from one of high horsepower approaches to one of precision in all aspects of development. During the 1960's nuclear detonations were being tested with the goal of fracturing or stimulating a large volume of low permeability rock allowing for the recovery of a significant volume of gas from a single wellbore. This technical approach failed for many reasons including the fusing of rock as opposed to fracturing of rock.

During the 1970's and 1980's the approach to marginal oil and gas formations evolved to massive hydraulic fracture treatments. Here the goal was to create very long hydraulic fractures reaching hundreds of feet into the pay zone allowing for the production of large volumes. As research on the topic of hydraulic fracturing progressed, it was determined that extended length fractures were difficult, if not impossible, to create. The lack of formations to serve as fracture barriers to contain the upward growth and the complexity of multiple fractures limited the desired fracture length.

Today the evolution of lateral and horizontal drilling technology is beginning to allow the development of unconventional resources through the placement of smaller (microhole) wellbores into exactly the area and location required for optimum production. Hydraulic fracturing remains an important and necessary well stimulation procedure, but is being done in a highly optimized manner, integrated with unique well completion procedures. Figure 4 illustrates the evolution of these technologies over the past forty years.

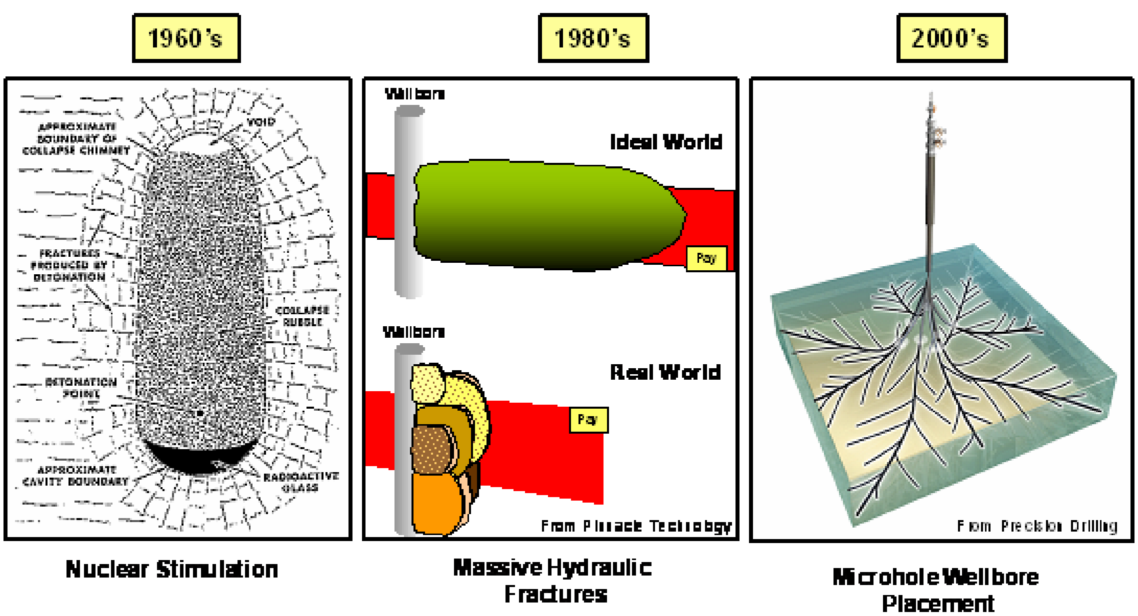

Figure 4 – Evolution of Drilling Technology over Time

The trend overall has been from large to small. Hydraulic fracture jobs pumped today are significantly smaller in size, but more effective than those in the 1970s. Microhole technology is being developed by the Department of Energy that will enable efficient placement of wellbores while minimizing the surface and other environmental impact. The evolution of “fishbone” well drilling patterns and the ability to identify, drill, and produce very thin pay zones all add to the “lighter and smaller” and more efficient approach.

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Press Release

Scheibel Halaska

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MICROHOLE TECHNOLOGY SUCCESSFUL IN SHALLOW, LOW-MARGIN FIELDS

Gas Technology Institute research shows profit possible

Des Plaines, Ill. — September 23, 2005 — Gas Technology Institute (GTI) of Des Plaines, Ill., with the support of NETL, the U.S. Department of Energy's National Energy Technology Laboratory, announces the successful field-testing of a coiled tubing drilling rig in shallow, low-margin natural gas fields in Kansas and Colorado.

The field tests demonstrate the efficiency of microhole technology, enabling a crew to move in, rig up, drill, rig down and move out within a day, with minimal environmental impact. To date tests have concentrated on Niobrara Chalk reservoirs drilling up to 4.75 inch open holes from 1,000 to 3,000 feet in depth. The wells are being drilled by Rosewood Resources, Dallas, Texas.

"In the 1980s the price of natural gas and crude oil did not make these fields viable," said Kent Perry, executive director of exploration and production research at GTI. "Today, minimal environmental footprint and drill time plus low cost makes microhole technology a viable option in the recovery of petroleum and natural gas from marginal natural gas and oil fields. It's important to note that these gas reserves can be accessed using microhole technology," The United States Geological Survey (USGS) has estimated the potential recovery from the Niobrara Chalk reservoirs to range from 340 billion cubic feet (BCF) to 2,100 BCF, with a mean recovery of 984 BCF. By comparison, the U.S. consumes approximately 25,000 BCF per year.

Microhole technology is not limited to natural gas recovery. With a recent Rand report that the United States is sitting on greater oil shale reserves than the Saudis, and in the wake of recent hurricane impact on off-shore oil rigs and on-shore refineries, this technology could help increase U.S. energy independence, as well as margins for drilling contractors.

Major features of the coiled tubing rig owned and operated by Advanced Drilling Technologies, Yuma, Colorado include:

Efficient Rig Mobilization (4-6 staff members)

- Small environmental footprint
- Rapid drilling
- Good hole quality and cement
- Rig capable of drilling, running casing, tool handling and logging
- Low noise, emissions
- Mud recycle, minimum cuttings and zero discharge if required
- Improved safety

Press Release
Microhole Technology Holds Potential to Increase Domestic Natural Gas and Oil Production

New drilling approach lowers cost of recovery and lessens environmental impact

Des Plaines, Ill. — November 7th, 2005 — Gas Technology Institute (GTI) with the support of the U.S. Department of Energy's National Energy Technology Laboratory, today announced the successful field-testing of a drilling technology that could improve U.S. energy independence.

Microhole technology uses less cumbersome drilling equipment that enables smaller crews to rig up, drill and tear down a drilling rig for exploration, dramatically cutting the costs and risks of drilling wells for gas and oil producers. The smaller drilling operation also reduces drilling waste and minimizes environmental impact, which has been a major obstacle to expanded exploration in the United States, especially in environmentally sensitive areas such as the Arctic National Wildlife Refuge.

GTI and partners Rosewood Resources, Inc. and Advanced Drilling Technologies are currently using microhole technology to successfully drill wells in the Niobrara Chalk Reservoirs in Kansas and Colorado. The U.S. Geological Survey has estimated the potential natural gas recovery from these reservoirs at 340 billion cubic feet (BCF) to 2,100 BCF, with a mean recovery of 984 BCF. The United States consumes approximately 25,000 BCF per year.

"Enough domestic natural gas and petroleum resources exist to help stabilize or lower energy prices in this country, but producers lack the technology to profitably recover most of these difficult-to-reach reserves," said GTI's Kent Perry, Director of Exploration and Production research. "The development of microhole drilling technology helps to create more economical means of petroleum and natural gas exploration in areas once passed over by producers."

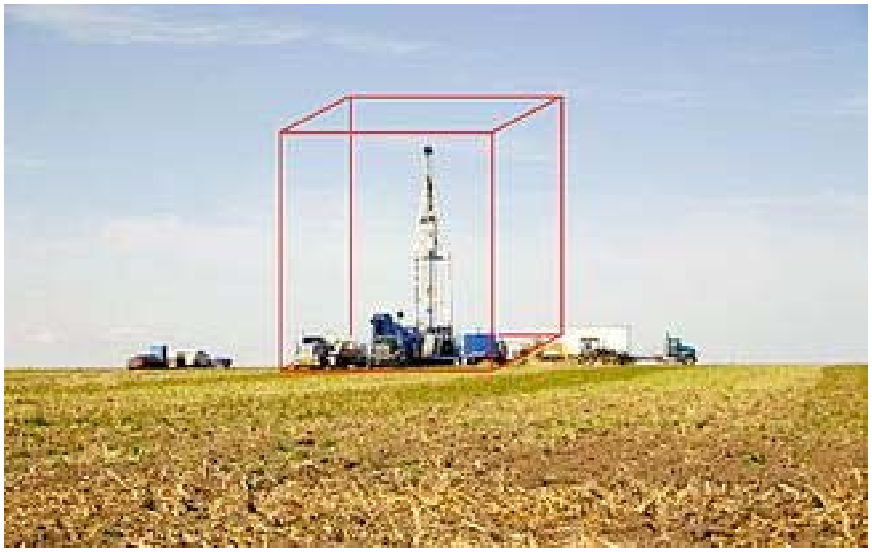
"The benefits in cost savings to the natural gas industry alone could be $8.4 billion during a 15-year period," said Rhonda Lindsey Jacobs, Project Manager, National Energy Technology Laboratory. "The volume of drilling waste could be reduced by 103 million barrels or to one-fifth the amount of waste volumes generated while drilling conventional wells. These targets are worth the government's investment."

The Potential Gas Agency estimates the U.S. natural gas resource at 1,119 trillion cubic feet (TCF) of technically recoverable natural gas, enough to fuel the entire country for approximately 40 years at current consumption rates. New technology such as microhole drilling will enable the conversion of "technically recoverable" resource into "economically recoverable" natural gas.

GTI is the leading research, development, and training organization serving the natural gas industry and energy markets. For more than 60 years, GTI has been meeting the nation's energy and environmental challenges by developing technology-based solutions for consumers, industry and government. Website: www.gastechnology.org

Drilling Market Focus: Coiled-tubing use growing faster than drilling industry

Oil and Gas Journal, November 28, 2005 – Excerpt Only



This coiled tubing drilling rig was recently designed by Advanced Drilling Technologies LLC and is shown drilling in Kansas. (Fig. 2; photo from Kent Perry, Gas Technology Institute).

The DOE is sponsoring field tests of a new zero-discharge CTD rig developed by Advanced Drilling Technologies LLC (Fig. 2). The CTD rig handles 1-in. to 2⅝-in. coiled tubing as well as 7⅝-in. R3 casing and has a 5,000-ft depth capability with 1,000 ft lateral. The trailer-mounted rig can be moved in only four loads and has a zero-discharge capacity mud system.

Art's Tom Gipson told OGJ that they are using the rig to drill in the Niobrara gas area: 17 wells in 2004, as well as 27 wells in western Kansas and 113 so far in northeastern Colorado in 2005.

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Report 5: Low Impact Access: Reduced Surface Environmental Footprint

The contents of *Report 5* represent one of the research projects created to integrate current and new EFD technologies into a viable drilling system compatible with environmentally sensitive areas. The impact of access roads and drilling pads has been identified by the EFD program as one of the major problems to be managed when conducting oil and gas operations in environmentally sensitive areas.

This approach was designed to meet the deliverables specified in the NETL SOW Task 11 (*Full-Scale Engineering System Design*) and Task 12 (*Combine Selected Components into Integrated System for Test Site*)

1. The "Disappearing Road Competition" is a yearly nation-wide scholastic competition sponsored by Halliburton to create a new concept of moving men and materials to and from well sites. A brief description of this year's awards is attached. From this program will come new ways to move across the landscape in a minimal way. http://sites.google.com/a/pe.tamu.edu/disappearing-roads-competition/

2. The Research Partnership to Secure Energy of America (RPSEA) http://www.rpsea.org Unconventional Oil & Gas Development (Environmental Issues) is funding a new project by Texas A&M University to construct and then perform demonstrations of low impact O&G lease roads designed to reduce the environmental impact of field development in sensitive new desert ecosystems. A summary of the winning projects is attached here while more information on the site is at:

Low Impact Access Roads Demonstration (Pecos Research Test Center)

3. The EFD program and DOE are sponsoring a study on the feasibility of using agri-business hydrology GIS models and databases to optimize siting of O&G operations on sensitive landforms. The concept is to modify biophysical hydrologic models developed in agriculture to determine the impacts of land management on water quality and the landscape. These models could serve terrestrial exploration and development in the oil and gas industry by providing a tool to evaluate environmental impact from drilling and recovery prior to operations. Minimizing Surface Impacts by Optimization of O&G Facilities. http://sites.google.com/a/pe.tamu.edu/optimization-models-for-surface-placement-of-o-g-drill-sites/Home?

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Global Petroleum Research Institute

Texas A&M University

Reducing the Environmental Impact of Oil & Gas Field Access Roads: Creation and Long term Monitoring of New Technology to Lower Footprint in Desert Ecosystems

The Research Partnership to Secure Energy of America (RPSEA) Unconventional Oil & Gas Development (Environmental Issues) is funding a new project by Texas A&M University to construct and then perform demonstrations of low impact O&G lease roads designed to reduce the environmental impact of field development in sensitive new desert ecosystems.

The site will be located at the newly established University Desert Test Center http://www.pecosrtc.org/ near Pecos Texas on the edge of the Chihuahua desert.

The new A&M Research project will test **three new types** of low impact roads **plus one comparison standard gravel lease road**) will constructed. The roads will be instrumented for remote measurement, and then evaluate them for ability to withstand both normal and heavy truck traffic over intermittent periods through a complete calendar year. Part of the heavy traffic will consist of moving two platform modules of 20,000 lbs each built for modular drill site pads (Anadarko Petroleum Company's Gas Hydrates Project 2003) which are stored that the test site in preparation for testing (see Figure 1.)

A fifth type of low impact road (a "**disappearing road")** will be incorporated into the test site as part of a nationwide competition currently being conducted by the Texas A&M Petroleum Engineering Department.

This GPRI joint venture project is expected to be part of a University-Industry-Government partnership to perform long term development and environmental monitoring of low impact oil and gas drilling technology developed to reduce to footprint of oil and gas operations in sensitive desert like terrain.

After the low impact road field test is completed and after a suitable time the roads will be removed and remediation measures undertaken to restore the desert floor. After preliminary remediation the final performance and cost effective ranking of the roads will be performed by project managers, sponsors and consultants. Widespread descriptions about the project, briefings, including public sector, industry, environmental groups and government agencies will be invited to tour the sites at regular intervals during the term of the project.

A continuing program is expected to continue at the **Low Impact Desert Test** Site subject to future funding. Sponsors of the project include O&G operators (through the Global Petroleum Research Institute, GPRI), government (Texas General Land Office and Texas Railroad Commission) and other key stakeholder groups.

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Texas A&M University
Harold Vance Department of Petroleum Engineering

LETTER OF TRANSMITTAL

Progress Report: No. 1 Technology Assessment Report

Date: March, 22, 2009

Title: **Oil & Gas Operations in Desert Ecosystems:** Creation and Long term Monitoring of New Technology to Lower Footprint of Access Roads to Well Sites

Project Number: **RPSEA: P 2007 UN001 – Small Producers Program**

From: David B. Burnett, Harold Vance Department of Petroleum Engineering, Texas A&M University

To: Ms. Martha Cather, Project Manager RPSEA

The Harold Vance Department of Petroleum Engineering is the lead contractor for the subject project. The enclosed report provides a background and gives a technology assessment of the current status of technology and societal acceptance for the adoption of low impact practices in construction of oil field access roads in sensitive environmental ecosystems. The goal of this project is to collect quantitative information on the performance of a variety of novel low environmental impact lease road construction alternatives. This information will be used to determine if such alternatives can be employed to reduce the footprint of oil and gas operations in ecologically sensitive desert locations.

Performers

Texas Engineering Experiment Station (TEES), Texas A&M University (TAMU), College Station, TX 77843 (actual test site will be the TAMU Desert Test Site in TX and NM on the edge of the Chihuahua Desert)

Deliverables for this project will include a series of reports on the various tasks as they are completed and a final report integrating the results of the project.

TECHNOLOGY ASSESSMENT REPORT

RESEARCH PARTNERSHIP TO SECURE ENERGY FOR AMERICA

RPSEA: P 2007 UN001 – Small Producers Program

Assessment of Factors Involved in Development of Low Impact Road Access in Environmentally Sensitive Ecosystems

Submitted by:

Texas A&M University – Texas Engineering Experiment Station

a non-profit 501(c) 3 organization

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Assessment of Factors Involved in Development of Low Impact Road Access in Environmentally Sensitive Ecosystems

Statement and Significance of Problem

The successful development of secure energy resources for America depends on three critical factors, (1) investment capital, (2) technology to find and develop the resources, and (3) permission to access those resources.

Access to potential oil and natural gas resources is limited because of the potentially detrimental effect of the E&P activity required to extract petroleum. Enabling technology is needed that would allow “road less” access to remote sites. Ideally, sensitive areas could be exploited with pad-free drilling and self-contained operations that generate minimal air or water emissions. After drilling or workover operations are completed, the mobilization/demobilization would leave the sites relatively undisturbed.

Because of public concern about providing access to environmentally sensitive areas that contain technically recoverable oil and gas resources, there is a significant barrier to development. These “un-permitted” resources may represent more than 800 tcf in the lower 48 U.S. states (Elcock 2004).

In addition, concern about recreational activity in undeveloped areas is growing. Access to wild and scenic areas is a contentious issue throughout the West and is certainly not restricted to O&G activity. The problem of off road vehicle public recreation access in National Forests and public lands is many times larger than the issue of O&G development. In fact, if new technology being developed by our industry is found to be applicable to other areas, then the market for commercial interests is only heightened.

In summary, the O&G industry needs not only to develop environmentally friendly practices in their operations but must also address the societal changes that must be made before our unpermitted resources can be considered as recoverable assets. This report discusses several issues, both technical, and societal that must be addressed to see adoption of and successes in low impact practices for development.

Relationship to RPSEA Independent Producer Program Goals and Objectives

Independents and small producers operate more than 90% of the onshore U.S. oil and gas fields. Most of these fields are mature reservoirs. It is generally thought that existing access roads, surface production facilities and production wells represent infrastructure that can be leveraged. In fact to maintain production facilities or in the case of enhanced recovery, most of this infrastructure will have to be upgraded to support increased field activity and production operations. Minimizing the impact of such increased field activity is the paramount objective of this proposed RPSEA project the Texas A&M University partnership.

How Access Roads Change the Environment

Access roads constructed for E&P operations can have immediate and long-term effects on the surrounding terrain and the life it supports. Pollutants can originate from construction or maintenance activities, vehicle traffic, seasonal road treatments, and spills and leaks related to vehicle operation and chemical transport. Elevated concentrations of heavy metals can extend up to 330 ft from the highway, and toxic levels may exist only a few feet from the highway (Ministry of Transport, Public Works and Water Management 1994). Erosion can be a significant in some areas and the displacement of soil during road construction can contribute to significant or severe changes in run-off and flow patterns (Forman 2003).

The simple roads typically associated with oil and gas operations can have both beneficial and detrimental effects on wildlife. Benefits include food, water and shelter provided by roadside ditches, while disadvantages include the removal of vegetation for construction purposes, dangers from traffic and run-off pollution containing minerals, heavy metals, organic compounds, sediments and agricultural chemicals (Forman et al 2003). In relatively arid lands, such as Otero Mesa, the forage and water accumulating by the roadside may have a positive impact on local wildlife populations.

A consequence of creating oil and gas lease roads in the desert is the segmentation of the ecosystem. This Ecological Effect of Linear Development has been addressed by several environmental organizations. According to Lyon et al. (1985), the linear development itself typically does not cause a disturbance response; it's the human presence on it that causes problems, therefore the level of use must be assessed and evaluated. Foreman (1995) determined that some linear features could be positive and some negative in terms of wildlife impacts: they can provide habitat, serve as conduits for travel or seriously impact wildlife by becoming barriers or sinks that negatively affect wildlife travel and mortality.

These effects are not always negative, but the existence of an access road can invite unwarranted traffic into sensitive areas. The O&G industry's ability to remediate its lease roads offer a way to reduce its impact on the environment (Haut, 2008).

Reducing the environmental footprint imposed by drilling operations will help enlarge support for these operations, given the current attention being paid to energy shortages that can be resolved by encouraging domestic exploration and production. Low impact roads are an important feature of the overall effort to persuade environmentalists, our own O&G industry, and the general public that sensitive lands and waters will not be spoiled in the process.

1. *Roads in Allegheny Forest*

Unconventional gas development in the East has become a controversial issue. As a result of a high level of oil and gas drilling, the Allegheny has the dubious honor of having as many miles of roads as much larger national forests in the western U.S. According to a 2003 roads analysis, the Allegheny has over 2,700 miles of roads, a figure that is higher today given the rate of drilling in recent years. In the Allegheny's revised forest plan, released in 2008, the Forest Service did not disclose how many new roads have been constructed, relying instead on the 2003 figure.

Figure 1. The photograph shows an eroded Forest Service logging road in the National Forest. The challenge is to change the characteristics of forest roads, the principle source of anthropo sediment entering streams on Forest Service lands.

Given the Allegheny’s relatively small size, this high level of road development translates into extremely high road densities, fragmenting habitat for numerous wildlife species including northern goshawk, cerulean warbler, timber rattlesnake, and wood turtle. For instance, some areas of the forest have road densities exceeding 18 mi/mi^2, a density that resembles an urban area rather than a national forest.

2. *Development in North American Deserts*

While not generally recognized, recreational activities in the West have a much larger impact on the environment than O&G development. Motorized off road vehicle recreation in National Parks and Forests, while enjoyed by many visitors, are often the center of conflict between those who want to keep impacts low and those who wish to have motorized access to wild and scenic sites. For example, Fishlake National Forest is a recreationalist's paradise known for its beautiful aspen forests, scenic byways, motorized and non-motorized trails, elk hunting, and mackinaw and trout fishing. Recreational opportunities include scenic drives, mountain biking, snowmobiling, ATV use, hiking, and camping. The mountains and plateaus of the forest provide exceptional use for All-Terrain Vehicle travel. The nationally recognized Paiute ATV Trail winds through 250 miles of the forest's most scenic terrain.

Figure 2 shows a steep and rocky section of trail, in Washington state with ORV caused erosion. Rutting evident. Trail is wider than average.

http://www.flickr.com/photos/wildlandscpr/3197758908/

Figure 3. South-Central Utah's 275-mile long Paiute ATV Trail is a loop trail with no beginning and no end! It passes through several towns and has side trails leading to others. Dirt Wheels magazine rated the Paiute ATV Trail as one of the best 15 trails in the country. It has been rated as one of the top 5 trails in the country by ATV Illustrated magazine. Many riders consider the Paiute Trial to be the top US trail

http://www.utah.com/offroad/paiute_trail.htm

The problem is with “temporary roads and their semi-permanence in the desert. North American deserts (Bagley, 1999) include the "warm" Mojave, Sonora, and Chihuahua deserts, and the "cold" Great Basin desert. Road removal in these areas requires that special attention be given to the harsh climatic conditions. The climate of the North American deserts is characterized by highly variable precipitation, large diurnal (day-night) variations in temperature, low humidity, and strong winds. Precipitation occurs irregularly as short, high intensity thunderstorms. Much of the water from these storms is lost to surface runoff, rather than infiltrating into the soil

Avoiding unnecessary road construction and its attendant use greatly improves desert ecosystems, since much of the degrading influences of roads in deserts relates to human access. Natural desert recovery is extremely slow, however, reflecting the harsh environmental conditions (Webb et al. 1983). Natural soil loosening depends on physical processes such as wetting/drying and freezing/thawing (esp. Great Basin desert), as well as biological activity. If there are existing desert roads because of human activity, there are a variety of techniques to use to enhance desert recovery. The techniques are either meant to improve the potential for natural vegetation establishment or to improve success of active revegetation. Unfortunately any such technique is a long and slow process.

Technology Assessment: Reducing Impact of Human Activity in Desert Ecosystems

A number of private companies, academic research groups, and environmental organizations are investigating and implementing ways to reduce the impact of human activity in sensitive environmental ecosystems In addition to the A&M EFD program and its attendant Low Impact Desert Roads Project funded by RPSEA, there are other groups working in this arena.

1. *Information on "Wild Lands CPR"*

This conservation group (http://www.wildlandscpr.org) serves its constituency by being an information source and publicizing issues related to all environmentally sensitive ecosystems in the U.S. The group's members are particularly sensitive to access to wilderness areas, such as the previously discussed Alleghany National Park and to the desert lands of the U.S. Its aims are to limit motorized travel through the wild and scenic lands. As a result of Wildlands CPR and other groups (it received more than 30,000 comments) the U.S. Forest has banned motorized travel on almost 200 miles of trails in north central Montana's Badger-Two Medicine area (Puckett, 2009).

The decision, announced in early March, 2009 is part of a travel plan for that section of Lewis and Clark National Forest. Few places in the United States rival the solitude, wildlife viewing and hunting afforded by the 130,000-acre Badger-Two Medicine, which tipped the scale in favor of travel by foot, horse and bicycle, Forest Supervisor Spike Thompson said.

O&G development in Utah is under scrutiny because of the federal land leases adjacent to national parks and scenic areas. In addition to the debate about viewsheds, oil and gas access roads will be a concern. Park Service officials raised the issue in a recent article in The Deseret News (Sparkman, 2008) saying those oil and gas roads will become "unwanted leftovers once the oil and gas are gone. The concern is that those roads will become new entry points into the parks, creating potential access and land-use headaches for park regulators."

2. *Forestry Service Programs: Remediation Initiative in the U.S. Pacific Northwest*

The Forest Service has developed a process and a set of tools for analyzing the impacts of roads on forested watersheds. The Geomorphologic Road Analysis and Inventory Package (GRAIP) assesses the impact of roads on forested watersheds. GRAIP uses information from USFS Global Positioning System (GPS) road surveys to analyze the impacts that the construction and use of forest roads can have on geomorphic processes and erosion patterns in forested basins. It is designed to help forest managers to effectively manage road and road drainage system and hence minimize the negative impacts of forest roads. Reference 12 is a URL site giving a brief introduction to the GRAIP process/tool, which is being used to assess the effectiveness of projects implemented through the Legacy Roads and Trails

3. *The Nature Conservancy*

The Nature Conservancy (http://www.nature.org/) is a $5 billion dollar not for profit corporation dedicated to conserving natural resources, land water, and air. While not focusing on land access issues, its organization is a clearing house for GIS metadata used in tracking resources and changes in sensitive environments. Conservation areas, species, habitation and threats are specific organized areas. It is affiliated with the he Society for Conservation GIS (SCGIS http://www.scgis.org/), an organization that assists conservationists worldwide in using GIS through communication, networking, scholarships, and training.

The Nature Conservancy is one of the few environmental organizations with ties to the O&G industry. The group operates the world's largest private system of nature sanctuaries with a significant number of these actually leased for O&G production, revenues helping to support conservation activities in the specific area and in other key sites.

4. *The Natural Resources Defense Council*

The NRDC (**http://www.nrdc.org/**) has as one of its critical issues, the preservation of “saving wildlands across America”. A politically savvy organization, its members use their voice to effect change in the political process to promote conservation and to push for additional effort to preserve the environment. It runs a number of programs pushing for environmental stewardship including the Land Program to protect the national forests, parks, and other public lands.

5. *Gene Theodori’s*

6. *O&G Efforts to Minimize Roads in Sensitive Environmental Ecosystems.*

As early as 1958, the O&G industry sought supportable development of petroleum reserves in sensitive ecosystems. A report on the development of the four corners area discussed drilling and production logistics in Navajo Lands (Young, 1958). These lands were characterized by poor surface coverage and, therefore, very little economic development. Telephone lines, power lines, and habitable communities were non-existent at the time major drilling programs were started. Roads consisted of Indian Service trails and were unsuited for either the volume of traffic or the truck loads suddenly imposed upon them. Improvement and extension of the trails was greatly handicapped by the extensive areas of unconsolidated sands and the distances to accessible rock suitable as aggregates for road construction. Since there were no small communities on the reservation around which either trailer or housing developments could be initiated, personnel and supplies had to be based at the nearest town or towns.

Later the Gas Research Institute instituted a ”Corridors Program” to assess the impact of pipeline right of ways through sensitive environmental areas. Later in 2004, the Gas Technology Institute (GTI) formed the Environmental Issues Consortium (EIC) in a collaborative effort to address environmental concerns through technology development GTI's Dr. Diane Saber, Director, Environmental Science & Forensic Chemistry. "From a wide range of environmental issues, a number of research areas were identified as high-priority."

- High-priority industry environmental concerns include the need to develop:
- Advanced chemical forensic techniques for identifying industry-associated wastes
- Rapid field testing techniques for PCB detection
- Pipeline integrity management programs
- Sediments management programs

- Greenhouse gas inventory techniques
- Air-quality management methods
- Techniques and technologies for manufactured gas plant site management.

"The new EIC provides a unique opportunity to bring together environmental professionals from gas utilities throughout the U.S. and Canada to discuss critical industry issues," says Saber. "Since ‘environmental' connotes so many different topics, we expect the discussions to be enlightening and lively. We hope to come away with an understanding of where research is most needed in this area, the specific problems which need to be addressed first, and the sources of funding for this research."

7. *Texas A&M University Environmentally Friendly Drilling Program*

The Environmentally Friendly Drilling (EFD) program was formed to identify new low-impact technologies that reduce the footprint of drilling activities. The program integrates light weight drilling rigs with reduced emission engine packages, addresses on-site waste management, optimizes the systems to fit the needs of a specific development sites and provides stewardship of the environment. In addition, the program includes industry, the public, environmental organizations, and elected officials in a collaboration that addresses concerns on development of unconventional natural gas resources in environmentally sensitive areas.

Texas A&M University’s current RPSEA program is helping to develop, test and adopt technologies that contribute to the cost-effective construction of low impact roads. Side by side comparison testing of several proposed road types under carefully controlled conditions will help researchers and producers identify the most promising technologies. These tests are being performed at a location where the environment is not overly susceptible to damage, yet the outcomes will be clearly manifested. By testing several types of road simultaneously, we can determine the best applications for each type and eliminate impractical or uneconomic options.

The Texas A&M EFD program and its attendant “Disappearing Road” contest are designed to achieve a general reduction in drilling footprint. The goal includes integrating currently known but unproven or novel technology to develop drilling systems that will have very limited environmental impact and will enable moderate to deep drilling and production operations and activity in environmentally sensitive areas.

The specific objectives of the DOE Environmental Drilling Systems Project are as follows:

- Identify new technology that can reduce or eliminate the impact of drilling operations on environmentally sensitive areas.
- Design an EFD system using most promising technology
- Include environmental stakeholders in the designs

Developing low impact access roads is an important part of the EFD effort. After drilling operations are completed or suspended, roads are often remediated. This removal is intended to allow the recovery of the lands to a pre-use condition so as to minimize additional access. Experience has shown that such efforts pose difficulty, highlighting the complexity of potential long-term consequences of oil and gas operations.

Is a road necessary? What other forms of transport can be considered? What are the potential impacts of other ways of shifting materials, equipment and personnel on and off site? What is the engineering practicality of alternatives to the current road approach?

A key topic within the program is identifying technology that would result in greater access, reasonable regulatory controls, lower development cost and reduction of the environmental**Error! Bookmark not defined.** footprint associated with operations for unconventional natural gas. Figure 1 shows the areas of technology development that are keys to lowering environmental footprints.

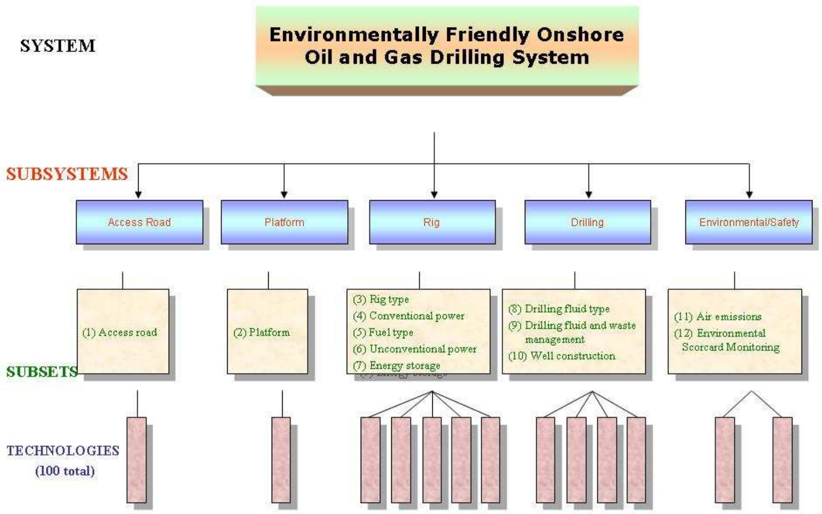

Figure 1 shows five key areas where the EFD program is focusing its efforts.

8. *Low Impact Access Projects within the EFD Program*

The impact of access roads and drilling pads has been identified by the Environmentally Friendly Drilling Program (EFD) as one of the major problems to be managed when conducting oil and gas operations in environmentally sensitive areas. Since 2005 the EFD program has been identifying technology and sponsoring research in reducing surface impact. Three major projects are underway specifically addressing such technology.

- The "Disappearing Road Competition" is a yearly nation-wide scholastic competition sponsored by Halliburton to create a new concept of moving men and materials to and from well sites. A brief description of this year's awards is attached. From this program will come new ways to move across the landscape in a minimal way. http://sites.google.com/a/pe.tamu.edu/disappearing-roads-competition/

- The Research Partnership to Secure Energy of America (RPSEA) http://www.rpsea.org Unconventional Oil & Gas Development (Environmental Issues)

is funding a new project by Texas A&M University to construct and then perform demonstrations of low impact O&G lease roads designed to reduce the environmental impact of field development in sensitive new desert ecosystems. A summary of the winning projects is attached here while more information on the site is at:
Low Impact Access Roads Demonstration (Pecos Research Test Center)

- The EFD program and DOE are sponsoring a study on the feasibility of using agri-business hydrology GIS models and databases to optimize site selection of O&G operations on sensitive landforms. The concept is to modify biophysical hydrologic models developed in agriculture to determine the impacts of land management on water quality and the landscape. These models could serve terrestrial exploration and development in the oil and gas industry by providing a tool to evaluate environ-mental impact from drilling and recovery prior to operations.
  http://sites.google.com/a/pe.tamu.edu/optimization-models-for-surface-placement-of-o-g-drill-sites/Home?previewAsViewer=1

9. *Converting Drilling Waste into Road Bed Materials*

The O&G industry has had several programs focusing on recycling of tank bottoms and drill cuttings. Sand and heavy hydrocarbon materials removed from tanks and other production facilities are typically nonhazardous (Cornwell, 1993). Tank bottom hydrocarbons exhibit cohesive properties that support the beneficial reuse of these materials as binders in road paving materials. Tank bottoms mixed with local aggregate yields a product that has minimal environmental impact.

Road mix variability can be high due to the nature of the materials used, but does not severely impact the overall quality of the final product. Process and issues that directly or indirectly impact road mix variability include: free liquid removal, aggregate mining, produced sand characteristics, oil/binder viscosity and mixing operations. Despite the variability of road mix materials and processes, test results show that heavy oil road mix products meet most of the minimum standards for commercial cold mix paving products.

Potential environmental concerns with oilfield road mix are offset when net air and waste management benefits of this process are considered. Air emissions are a potential concern and are related to the level of volatile organic constituents (VOC) in the oil. Offsetting this concern would be:

-Low VOC content in most SJV heavy crude.
-Particulate reduction from paving onsite roads.
In addition, offsite disposal of tank bottoms yields higher emissions from transport and disposal and fills up valuable landfill space with nonhazardous materials.

The effort to recycle drill cuttings in the U.K. has been well documented (Page, 2003). His work estimated that the UKCS produces between 50,000 to 80,000 tons wet weight of oily drill cuttings annually. With the implementation of new environmental rules, and given current offshore technology, it is no longer possible to discharge cleaned oily cuttings to sea. Increasingly stringent legislation it was likely that cuttings derived using water-based muds would not be discharged to sea in the future. Although several commercially available treatment processes can remove oil from oil based mud (OBM) cuttings, there are few satisfactory outlets for the residual solid material most of which currently goes to landfill. In light of the legislative changes, increased focus on duty of care, and commercial considerations, viable alternatives were sought for the recycling and reuse of large volumes of material from future drilling programs.

This paper described possible options for converting drill cuttings into reusable secondary products and discusses the advantages and disadvantages of each option when considered against the criteria of environmental impact, technical risk, logistics, liability and cost.

Locally, the Texas Railroad Commission issued the Guidelines for Processing Minor Permits Associated with Statewide Rule 8, or *Guidelines Developed by Environmental Surface Waste Management in Coordination with Field Operations*. This document outlines the specifications for drilling waste materials intended for use in road construction, including limits on total petroleum hydrocarbons (TPH), total organic halides (TOX), and electrical conductivity (EC), as well as analytical standards for the Toxicity Characteristic Leaching Procedure (TCLP) Test for organics, metals and pH. These requirements would govern the development and testing of the proposed low impact roads.

Since then new waste treatment and disposal practices have been developed to convert drilling muds and associated cuttings to beneficial and environmentally friendly road base material to help minimize E&P operator liability . A variety of techniques and methods are used to treat and dispose these wastes with the materials either land applied, injected or landfilled. At one landfill facility, the waste treatment process includes removing the water which decreases the soluble salt content and reducing the oil concentration by recovery or degradation.

One company, U.S. Liquids of Louisiana (USLLA), has a TXDOT (Texas Department of Public Safety) permit for recycling and storing drill cuttings and reconstitution into road base. With USLLA's land treatment process, soluble salt content is decreased, oil concentration is reduced by recovery or degradation, and clean cuttings or reuse materials are stored in secure onsite stockpiles. USLLA's road base program converts stockpile material to environmentally safe road base. Experiments conducted at USLLA's South Texas facilities with an independent lab have demonstrated that treated reuse material can be converted to new high-performance road base material. Lab tests of the new R3 road base have proved that the material is cleaner and more affordable than asphalt and has higher compressive strength.

Given the enormous volume of road base consumed every year in the areas surrounding USLLA facilities, all the existing and newly created stockpile from drilling operations can easily be reused beneficially in road repair and construction to help eliminate operator liability.

Scott Environmental Services Inc. (SESI) (http://www.scottenv.com/aboutus.html) provides environmental waste management services to the oil and gas industry and specializes in the reuse of oil & gas well drill cuttings and heavy mud. SESI has developed proprietary processes designed to allow the reuse of fresh water, saltwater, and oil based drill cuttings and heavy mud in a variety of applications including road and drill pad construction. SESI also provides environmental advisory services to the oil & gas industry. These services bring innovative solutions to a variety of environmental, safety, and operational problems.

10. *Using Recycled Material in Removable Mats.*

In 2003 representatives from Alberta Energy, British Columbia Ministry of Energy and Mines, CAGC, CAODC, CAPP and PSAC published a report for the Western Canadian oil and gas industry operating in annual and seasonal cycles. The report identified technology using suitable access matting to facilitate an extended drilling season. It would allow easier access to remote locations, thus allowing companies to move in earlier and stay longer.

Canadian companies provide replaceable mat technology to facilitate an extended drilling season. It would allow easier access to remote locations, thus allowing companies to move in earlier and stay longer In any event, the final report spawned by this study made some legitimate recommendations that some oil companies have since adopted and put into action. One such recommendation, for instance, suggested oil companies investigate the development and implementation of new technologies that would allow the extension of the drilling season in remote regions. A forerunner in this concept includes the use of access matting (ref. 15).

Temporary matted roads can be quickly installed and removed as a project dictates. Roadways of this kind are very functional in zones with closely-spaced wells and unstable ground soil conditions yet until recently desert lands have not been seen as a place where removable mats were of utility.

Interlocking access matting allows heavy equipment easy access to otherwise impassable territory by providing the load bearing strength needed to overcome the problems of over-saturated ground. Interlocking access matted roads are typically 16 feet wide and can extend for miles which can make access to summer drilling projects possible in areas previously thought to be unthinkable**.**

One of the industry sponsors of the A&M Desert Test Site is Newpark Mats & Integrated Services. http://www.compositemats.com. A letter of commitment to provide materials for this project is included in the contract for this project.

A&M Project - RPSEA Small Producers Project

What has not been available at the present time is a facility to test these new materials under field conditions and in an environmentally safe manner. The A&M program funded by RPSEA will be performing this work in the spring and summer of 2009.

RPSEA (http://www.rpsea.org) is a non-profit corporation established to help meet the nation's growing demand for hydrocarbon resources from U.S. reservoirs. RPSEA was founded by a consortium of the nation's premier energy research universities and research organizations to meet these key energy challenges: The Energy Information Administration (EIA) forecasts a nearly 100% increase in US domestic natural gas consumption by 2025 and a global increase of 89% over the same period. Over 55% of the crude oil and products used in the US currently comes from imports and that is forecast to increase to 68%. The Energy Policy Act of 2005 includes significant funding for accelerated R&D in the oil & gas industry.

RPSEA serves as an agency to facilitate the government plans to invest in research and development through collaborations with industry, state organizations, national laboratories and universities. RPSEA has leveraged its research dollars and the technical experience of its members to fund research to meet the supply needs of America's natural gas consumers. RPSEA, through several rounds of competitive solicitations, has focused specifically on developing a research portfolio of innovative technologies to:

- Reduce the cost of exploration and production of ultra-deepwater and unconventional natural gas;
- Expand and extend the nation's gas resource base; and
- Mitigate the environmental impacts of energy production in these regions.

RPSEA's Board structure and its membership eligibility - industry, academia, national laboratories, research organizations and government - is designed to maximize the effectiveness of its research dollars through a collaborative, informed, and highly-focused effort.

1. *Small Producer Program Aims*

The nature of United States domestic petroleum and natural gas production has changed over the years. Maturing production areas in the lower 48 states and the need to respond to shareholder expectations have resulted in major integrated petroleum companies shifting their exploration and production focus toward the offshore and foreign countries. Consequently, the role of the independent producer has become far more significant to domestic onshore petroleum production. For example, the independent share of the lower 48 states petroleum production increased from 45 percent in the mid-1980s to over 60 percent by 1995. Even more impressively, independent producers have been responsible for all of the major onshore discoveries since 1990.

The fundamental uniqueness of independent producers and their role in supplying the nation's energy must be recognized and addressed. There are thousands of independent oil and natural gas producers across the United States, and according to data from the Energy Information Administration (2006), approximately 15% of the nation's oil production comes from the well over 10,000 small producers; those U.S. companies producing less than or equal to 1000 BOEPD.

The price instability of the past years demonstrates the scope of challenges faced by small producers. Low prices in 1998-99 resulted in the loss of 700,000 barrels per day in domestic production - largely from the permanent closure of marginal wells that become uneconomic at low prices. Cuts in capital investment led to higher oil and natural gas prices in 2000-2001. As the nation now grapples with questions of national security, it cannot afford further losses in domestic oil production and reduced domestic capital spending to find and produce natural gas. The United States needs to recognize and encourage the efforts of the small independent producer in dealing with the maturing nature of our domestic oil and gas resources. Technology to assist the small producer in developing mature resources is the primary focus of the RPSEA small producer program.

The Energy Policy Act requires that all awards under the Small Producer program element "shall be made to consortia consisting of small producers or organized primarily for the benefit of small producers." All solicitations issued will require that proposals be submitted by a consortium consisting of two or more entities participating in a proposal through prime contractor-subcontractor or other formalized relationship that ensures joint participation in the execution of the scope of work associated with an award. Consortia are highly encouraged to have a minimum of one small producing company participating with a simple partnering agreement. The primary focus of the program will be technology development in mature oil and gas fields with the objective of extending the life and ultimate recovery of these fields.

2. *Small Producer Program Technology Themes*

The Texas A&M University Consortium is part of the RPSEA Small Producer Program. This program focuses on the following technology themes:

- Development of approaches and methods for water management, including produced water shutoff or minimization, treatment and disposal of produced water, fluid recovery, chemical treatments and minimizing water use for drilling and stimulation operations.
- Development of methods for improving the oil and gas recovery factor.
- Development of techniques that will extend the economic life of a reservoir.
- Development of methods to reduce field operating costs, including reducing production related costs as well as costs associated with plugging and abandoning wells and well site remediation. Consideration will be given to those efforts directed at minimizing the environmental impact of future development activities

The A&M program addresses both the technological and societal aspects of the development of “unpermitted” resources. This Technology Assessment Report begins that effort. It addresses methods to reduce field operating costs by lowering the environmental impact of O&G operations in mature fields and minimizes the footprint of future development activities.

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Disappearing Roads

An Exploration Into Low Impact And Efficient Gas Field Drilling

University of Wyoming

1

- To effectively and efficiently drill for gas while minimizing environmental impact.

Global Objective

2

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Where Are The Gas Fields?

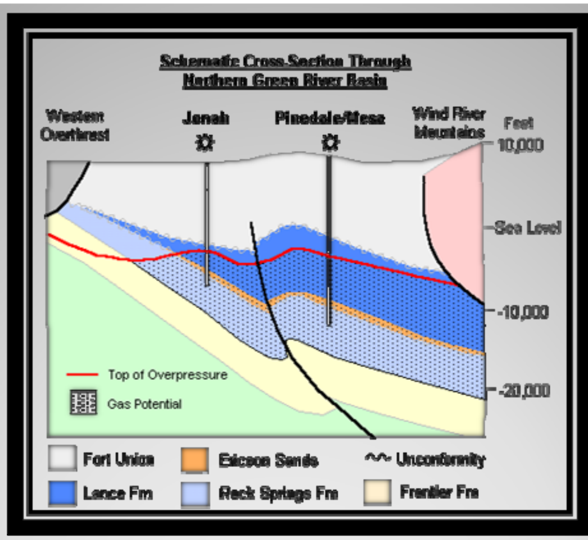
3

Tour Jonah Field

Briefing at BLM Pinedale

Initial Work

4



http://www.geminienergy.com/properties/crossection.gif

Geology – Jonah / Anticline

5

Alyssa Wechsler

- University of WY Graduate ('08)
  - B.S. Zoology/Physiology
  - B.S. Environment and Natural Resources
- Board Member: Biodiversity Conservation Alliance
- Will begin a graduate program in International Sustainable Development at the University of Oxford, England in fall 2008

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Current demands for environmental concern:

- **Mating and Nesting:** Sage grouse
- **Winter Range:** Big game
- **Vegetation:** Sagebrush, native species
- **Soil:** Topsoil and soil contamination and disturbance
- **Water:** Runoff and groundwater
- **Air Quality:** Viewshed (dust, NOx), SOx, ozone
- **Migratory Routes:** Pronghorn antelope

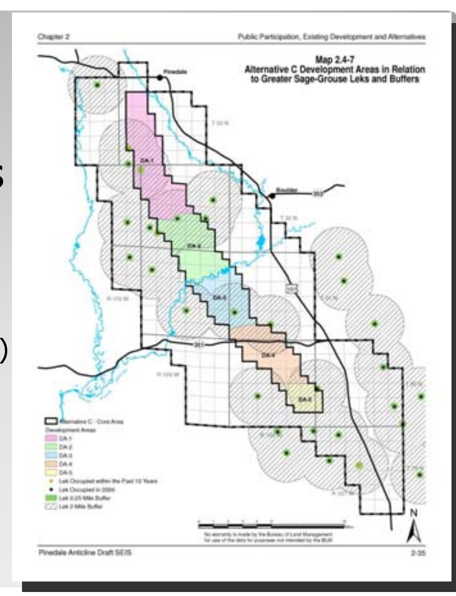
Environmental Overview

7

Sage Grouse Leks and Buffers

Lek stipulation dates:
Feb. 1-May 15 (¼ mi. buffer)

Nesting stipulation dates:
April 1-July 1 (2 mi. buffer)



Wildlife Concerns

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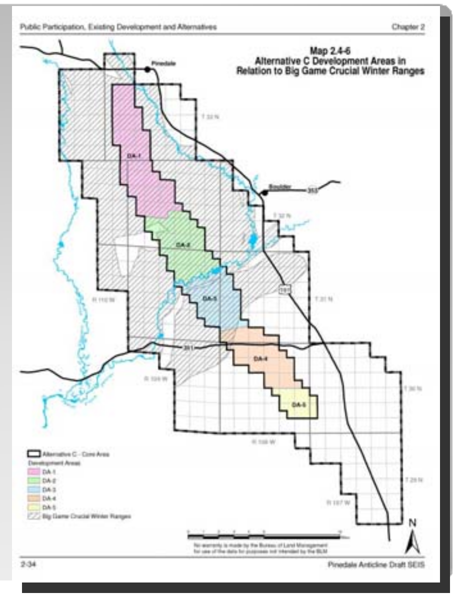
Big Game Winter Range

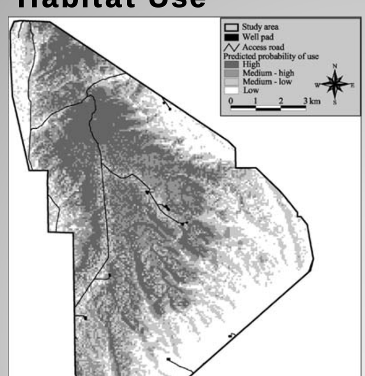
Winter range stipulation dates: November 15-April 30



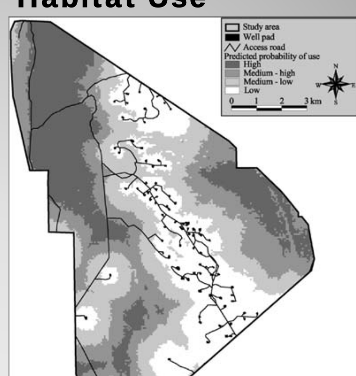
Wildlife Concerns

Mule Deer

Pre-development Habitat Use



Year 3 Development Habitat Use



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Wildlife Concerns

- Extremely Dry Climate
- Sagebrush very sensitive to disturbance
- Native vegetation reclamation
  - Grasses
  - Sagebrush
- Length of time for acreage credits to rollover

Vegetation Concerns

Jacob Olenick

- Mechanical Engineer
- Employed by Puget Sound Naval Shipyard
- Alternative Spring Break: Conservation work in Moab, Utah and Arches National Park
- Returning to UW for master's degree in Wind Energy

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Jonah Field Type Strategy

- Sectional development
- 10 acre well spacing (770 wells per section)
- 3080 total developed wells
- 15,400 acres at any time with little to no human activity
- Alleviates habitat fragmentation
- Each section developed in 4 to 6 years
- 16 to 22 year total infill timeline

The Plan (Jonah)

13

Pinedale Anticline Production Area (PAPA) Type Strategy

- 198,000 acres
- 17,500 wells
- Directional drilling
  - 32-50 wells per pad

The Plan (PAPA)

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<u>Creates an Environment That:</u>

- Limits habitat fragmentation
- Minimizes disruption of
  - Migration
  - Breeding
  - Nesting
- Limits noise pollution
- Minimizes soil disruption
- Minimizes reclamation

http://www.ourpubliclands.org/files/upload/sage-grouse.jpg

Benefits of Temporary Roads

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Existing Jonah Field

Possible Jonah Field

(Photo copyright Jeff Vanuga, used with permission)

Benefits of Temporary Roads

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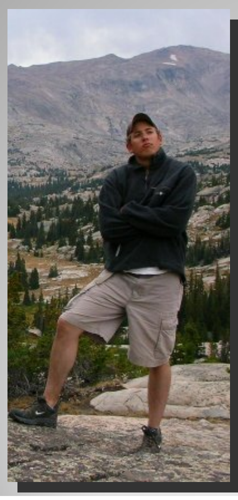
Tyrel James Hulet



- B.S.C.E. Emphasis in Structures
- Buffalo, Wyoming Native
- Outdoorsman
- Photographer
- Conservationist

PAPA concentrated drilling pads:
- Traditional drilling pad operation
- Delineation drilling

Jonah Field Drilling Operations:
- Suitable for all pads
- Dependent upon site conditions
- Limited to 8% cross slope

Modular Drilling Frame

Applications

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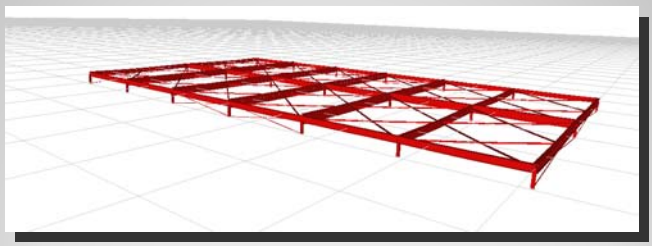
Advancements in conceptual design:

- Use on non-level terrain
- Ease of construction
- Hydraulic leveling system



Modular Drilling Frame

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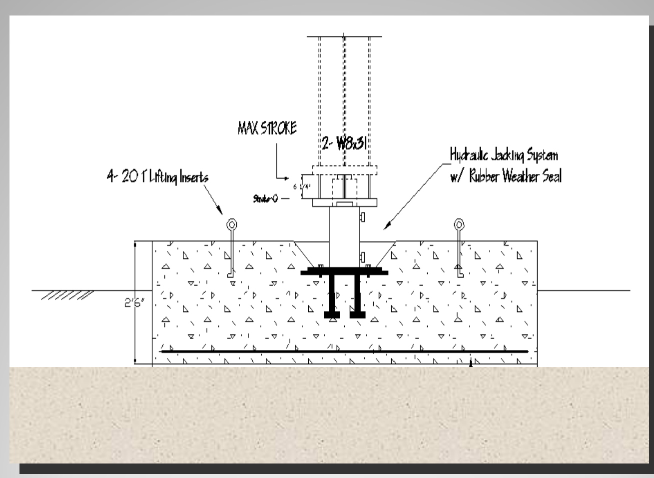

Foundation Schematic

20

- Drilling and completion
- Routine maintenance
- Heavy maintenance

Maintenance Access

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- Anything goes for emergencies

Emergency Access

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- 80,000lb loads
- 9,000lb axle loads
- Trip requirements

Type Of Traffic	Round Trips per Well
Construction (Pad, Access) (4 days)	20
Vertical Well Drilling (22 days)	200
Completion and Testing (17 days)	570
Pipeline Construction (4 days)	20
Total (47 days per well)	**810**

Roadway Requirements

23

- Two lanes
- Site preparation
- Five year service life
- Rotation scheme on drilling sites
  - Two years on – One year off

Roadway Requirements

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Heartland Bio-Composites

- Production material
- Recyclable materials
- Strength
- Field testing

Material Selection

25

Winkler Model

- Loads transferred
- Relatively low bending stiffness
- Foundation – linear elastic behavior
- Pressure proportional to deflection
- Subgrade Modulus (Ko)

$$y = \frac{P\beta}{2k} e^{-\beta_z} (\sin \beta_z + \cos \beta_z)$$

$$y_{\max} = \frac{P\beta}{2k} \frac{\cosh \beta L + \cos \beta L + 2}{\sinh \beta L + \sin \beta L}$$

Mat Deflections

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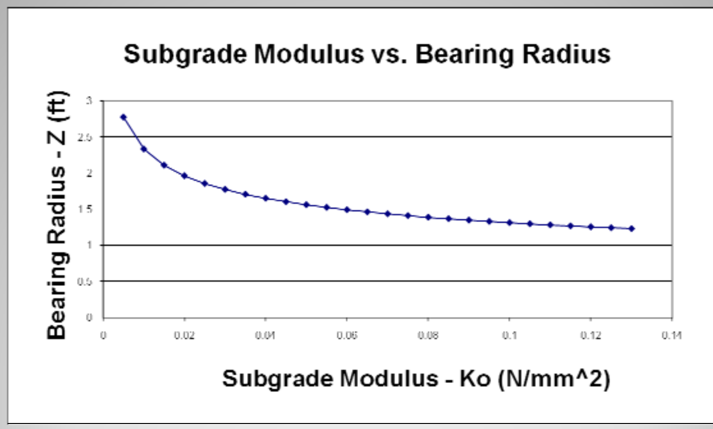
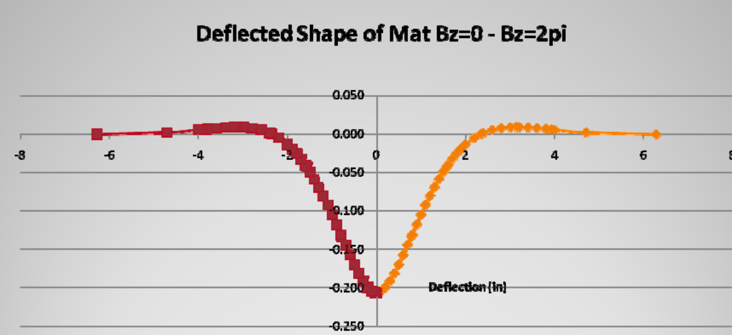
For a single layer bio-composite board 1.5in x 7.25in cross-section



Subgrade Modulus vs. Bearing Radius

Deflected shape of single layer bio-composite board 1.5in x 7.25in on extremely dense sand foundation



Maximum Deflection and Shape

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- Penetrometer

- Torsional Vane Shear Tester

Soil Tests

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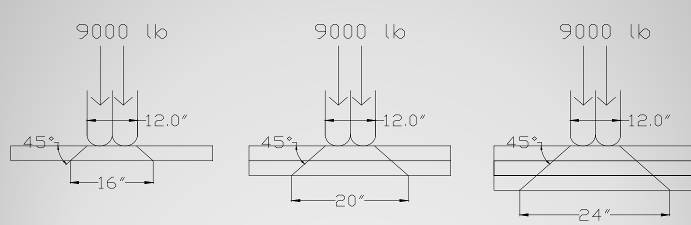
- Simple pavement design
- Ground pressure per layer
  - 1 layer – 6450 psf
  - 2 layer – 4124 psf
  - 3 layer – 2865 psf



Mat Layer Selection

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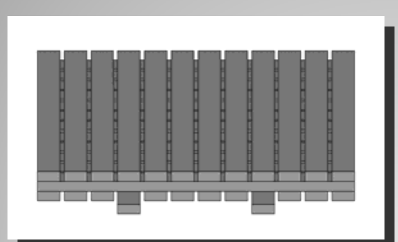
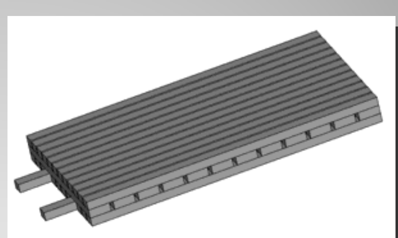
Kristen Beck

- Will graduate in ME in December 2008
- Will work for Naval Nuclear Reactor Facility in Idaho



Front View



Isometric View

Mat Concept

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- Mats similar to wood mats

- Uses current installation techniques

Mat Concept

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- Lab Tests
  - Abrasion
  - Shear
  - Deflection
  - Fatigue
  - Friction

Testing and Evaluation

34

- Field Test Movie

Testing and Evaluation

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Nolan Bray

- Graduating in May 09 with a degree in ME
- Currently working for Rio Tinto Minerals

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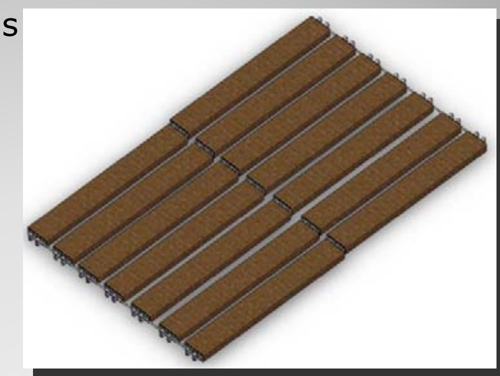
- General Specs
  - 2″ x 8″ Bio-composite boards
  - 40′ x 10′ sections
  - 2500 lbs



Rollout Road

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- Main Components
  - Conformable

  - Hinged board segments

Rollout Road

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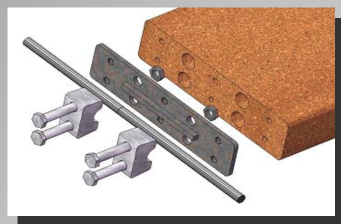
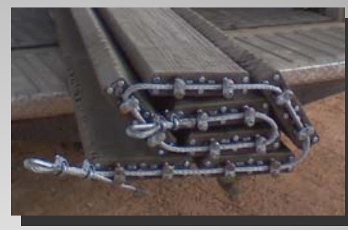
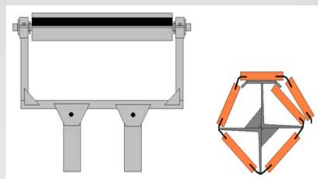
- Segments linked together with cable





- Installation and removal



Rollout Road

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- Testing and Evaluation
  - Fatigue
  - Tensile strength
  - Material selection

Rollout Road Concept

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- Field Test
  - Elastomer joints failed

Rollout Road Concept

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- Traditional dirt road costs $25/ft.
- Rollout road estimated at $65/ft
- Three reuses make it more cost effective
- No magnesium chloride, minimal maintenance and restoration costs

Rollout Road Cost Analysis

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- **Prototype Costs**
  - Hard Oak Mat
    - Base cost: $650
    - Lifetime: 2-3 yrs
    - Yearly Cost: $1920
  - Composite Mat
    - Base cost: $2,000
    - Lifetime: 20 yrs
    - Yearly Cost: $1200
  - Rollout Road
    - Base cost: $10,800
    - Lifetime: 20 yrs
    - Yearly Cost: $1050

Rollout Road Cost Analysis

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- Cost Recovery
  - Current methods offer no reuse
  - Composite material 100% recyclable

Rollout Road Cost Analysis

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Jacob Olenick – Wrap-up

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- Decreases environmental degradation
- Decreases acreage roll over time

Conclusion

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Follow-up

- Submitted report on March 17th, 2008 What's next?
  - April - Presentation to EnCana USA and Questar Exploration
    - EnCana USA to consider a demonstration project on Jonah Field
    - Questar to submit concept to BLM for access to a 3 well site that has been held back for 10 years
    - Senior design students next year

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Follow-up

- Wyoming Public Radio Feature
  - Request for information for Powder River applicaion
  - Local newspaper requests

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- US Senator John Barrasso (R-WY)
  - Member Energy and Natural Resources Committee
  - Ranking minority member Environment and Public Works Committee

Follow-up

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Sen. Barrasso Briefing

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Acknowledgements

- EnCana USA
- Questar Exploration Inc.
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- Heartland Biocomposites Inc.
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- Mountain Cement Inc.
- JVI Industries Inc.
- UW School of Energy Resources
- H. T. Person Endowment

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Student Members

Name	Major	Minor
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Nathan Foyil	Petroleum Engineering, Sr.	
Austin Gaskamp	Petroleum Engineering, Sr.	Geology
Cuong Phan	Petroleum Engineering, Sr.	Geology
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Name	Department	Areas of Expertise
Dr. Catalin Teodoriu	Petroleum Engineering	Drilling and Mechanical Engineering
Dr. Gioia Falcone	Petroleum Engineering	Production and Environmental Engineering

Statement of the Problem

The goal of this competition is to design a system to transport equipment and materials to drillsites in environmentally protected areas, with a focus on minimizing the environmental impact. The aim is not to encourage drilling in these areas, but to foster interest and dialogue in the education community regarding these areas.

Introduction

When drilling within environmentally protected areas, it is desirable to minimize the impact, so that the area is preserved and wildlife is able to live normally. In order to accomplish the development of a field within a protected area, it is proposed the use of a skylift system, similar to those adopted in mining operations (where they are often referred to as aerial tramways), that would be installed via helicopter. Pairing the skylift system with pipelines to transport drilling and production fluids outside the area would significantly minimize the environmental impact, especially when compared to using a traditional road. The team members believe that any form of site access by road may impair the environment by creating a preferential path for people to enter the area. Our recommendation is for fields that are outside the goals of extended reach drilling. This will be the case of a field located in the Chihuahuan Desert Province, in which extended reach drilling would prove to be less environmentally friendly than a skylift system.

The objective of this competition is focused on the use of a “Disappearing Road” to transport materials, equipment, and personnel for drilling operations for a one-year time window. However, when considering environmental impact, this window will be insufficient. We have chosen an integrated perspective that spans over the entire field life, ten to thirty years, assuming that the field has already been appraised and it is ready for the development phase. For the drilling operations, a hybrid coiled tubing rig would be transported onsite via the skylift. The generators, mud tanks, and other equipment would be located outside the protected area. Horizontally drilled pipelines would transport the drilling fluids from the rigsite to the facilities located offsite. Power would be delivered to the rig via powerlines running on top of the skyway. The only area impacted would be the extremely small rig footprint and that of each skyway tower. To allow for maximum exploitation, the wellsite would be used to drill deviated wells, allowing 40 wells to be drilled from a single drillsite.

After drilling, the rig would be removed and the skyway could be used for various purposes, including well-related work, tourism, alternative energy generation, and scientific studies. At field abandonment, a rig could be transported back to the wellsite to plug and abandon the wells. The skyway towers would be removed and everything would be returned to the way it was before drilling commenced.

Analog Field Data

For this competition, field data from fields located at the vicinity of the Chihuahuan Desert Province is used to assess some of the subsurface conditions that affect the selection of equipment used normally in oil and gas operations. As instances, the type of rig will be selected according to the target depth and type of wells to drill; and pipeline and separation units will be chosen according to the expected type of fluid and flow rates; among other things. **Table 1** shows the general data of the Dineh-bi-Keyah field, located in northeastern Arizona.

Table 1—General Data of Dineh-bi-Keyah Field	
Type of Fluid	Oil/Gas
Depth Range, ft	2800-5000
Pressure Range, psia	1200-2200
Reservoir Type	Carbonate
Avg Pay Thickness, ft	95
Age of Formation	Pennsylvanian
OOIP, MMstb	680

Rig Selection

For this competition two state-of-the-art technologies known for reducing environmental impact have been identified: Extended Reach Drilling (ERD) and Coiled Tubing Drilling (CTD). These technologies have been proved to be technically successful and many service companies are available to provide them. The rig selection and the recommended technology are based on minimizing the impact of the environment of the Chihuahuan Desert Province.

Extended Reach Drilling and Environmental Concerns

A way to develop oil and gas fields in environmentally sensitive areas is through the use of ERD. The use of ERD has made it possible to drill wells with extreme step-out. Many extended-reach wells have step-out lengths of 5-6 miles with more than 35,000 ft of measure depths. Vertical depth, step-out, and subsurface environment will determine the feasibility of drilling and completing extended-reach wells[1].

The use of ERD for the development of fields is driven by economical and environmental objectives. However, much emphasis is sometimes given to the environmental advantages that ERD might bring while the real reason of using this drilling operation is the savings in millions in development costs. For instance, in offshore fields the elimination of artificial islands or production platforms along with subsea equipment and pipelines will upset the high risks and costs that ERD projects bring. This goes together with the certainty that extended reach wells are drilled where high production rates are achievable. Lack of subsurface data and the uncertainty of available reserves in the Chihuahuan Desert Province will make an ERD project risky and probably unprofitable.

Even though ERD seems a better option to drill in very sensitive areas such as the Chihuahuan Desert Province, ERD also brings environmental disturbance that can be even greater than if a low impact road is built through the desert. First, emissions of CO_2 will be greater due to more power requirement for hoisting, hydraulics, and rotary systems. For the ERD of a well with a horizontal displacement of five miles, a rig rated for a hook load greater than 750,000 lbs with drawworks of 4,000 to 5,000 HP will be required[2]. Also, extra pumping capacity is essential to be able to lift the cuttings in the long, high-angle extended reach wells. This extra pumping is obtained by increasing the number of pumps from two to three or more, increasing the power rating of the pumps from 1,600 to 2,200 HP, and increasing the pressure rating of the pumps and surface system from 5,000 to 7,500 psi[2]. Furthermore, top drive rotary systems with torque capabilities in the range of 50,000 to 60,000 ft-lb will be needed[3]. Thus, to obtain this required power more generators will be used on-site polluting the local air, or if enough electrical power is available in the wellsite the CO_2 will be produced elsewhere.

Second, although state-of-the-art rigs occupy smaller footprint than previous generations of drilling rigs, the wellsite area for an extended reach well must have enough space for all surface equipment and materials, personnel facilities, and storage capacity for more than 30,000 ft of drillpipe and more than 16,000 ft casing[4]. Thus, this implies that at least an area of a few acres will be disturbed if not destroyed in the wellsite location.

Third, Oil Based Mud (OBM) is chosen in ERD due to lubricity and inhibition advantages over Water Based Mud. High friction factors and the length of the wellbore constrain ERD operations to OBM in order to reduce torque and drag, and minimize pipe sticking. Potential pollution problems and environmental incompatibilities are typically associated with OBM in both surface and subsurface environments. For instance, a formation bearing fresh water can be easily contaminated even if a low-toxicity OBM is used to drill through this formation. Furthermore, the quantity of fines and cuttings produced in ERD is far greater than a normal drilling operation, bringing the concern of how to properly dispose the solids produced. The proper disposal of the drilling mud and oil-soaked cuttings will be needed to reduce the impact that they might bring to the environment and nearby communities.

Finally, reduction of visibility and noise pollution, along with the concerns of possible water, land and air contamination from drilling and transportation activities might bring potential conflicts with local and adjoining land users. Therefore, given all the reasons above, the ERD will not be environmentally friendly in the Chihuahuan Desert Province.

Hybrid Coiled Tubing Drilling
As Coiled Tubing Drilling (CTD) is well known and has proven to be smaller in size and cause the least environmental impact, it is strongly recommended to use a hybrid coiled tubing rig (HCTR) unit for the drilling operations. As identified by looking at analog fields, the depth of the projected reservoir is fairly shallow with pressures reasonably low; therefore, the HCTR can efficiently drill and complete the wells with minimal impact on the environment.

In comparison with conventional drill pipe rigs, an HCTR is by far more environmentally friendly. After drilling and completing a well, due to its smaller structure and overall space occupancy, an HCTR usually leaves small to no footprint when it moves off the location. In addition, HCTR units produce relatively low noise during operation while having less visual impact. In terms of space, the module of a conventional drill pipe rig can occupy a much bigger space than an HCTR and might require the use of additional equipment such as a crane to rig up. An HCTR can handle hook loads up to 200,000 lbs at the top drive and 120,000 lbs at the injector. Depths up to 7,000 ft with 3 ½ in coiled tubing or drill pipe can be accomplished with HCTR. **Table 2** shows the general specifications of the HCTR proposed for this competition. However, not all the equipment will be at the wellsite since it is desired to reduce the footprint. Instead, most of the equipment like mud tanks and generators will be set outside the protected area. The connection between the wellsite and the equipment outside the protected area will be trough power lines and pipelines.

Table 2—General Specifications of HCTR[5]

	CTR type	Hybrid Coil/Single
General	Typical Application	Intermediate Drilling
	Total Loads (excluding boiler)	11
Coil Tubing	Typical Penetration Rates	300+ ft per hr
	Maximum Coiled Tubing Size	3 1/2"
	Drill Pipe Size	3 1/2"
	Typical Coiled Tubing Size	3 1/2"
	Reel Capacity with Above Tubing	7,200 ft
	Maximum Injector Pulling Force	120,000 lbs
Top Drive	Pipe Handling Range	46 ft (Range III)
	Hydraulic Rotary Table	13 7/8"
	Depth Capacity with Drill Pipe	7,200 ft
	Drawworks Type	Electric
	Drawworks & Top Drive Rating	200,000 lbs
	Tool Joint Make-up and Break-out	Back-up Wrench
	Bails and Elevators	Hydraulic

Table 3 shows the configuration and other specifications of the HCTR. The configuration given here for the HCTR is not the best available in the market. Rather, it is a typical size that is commonly used nowadays in sensitive and environmental protected area. Deeper drilling and higher capacity in terms of hook loads, pressure handling, pump efficiency, and other important factors to the drilling operation can be handled with the more advanced CTR available in the drilling industry. This usually depends on the specifications and requirements provided by the customer. **Fig. 1** depicts a picture of typical HCTR where it can be seen its size as well as its visual impact.

Table 3—Configuration of an HCTR[6]		
Trailer Dimensions (approx)	L × W × H	70 ft × 11.5 ft × 14.5 ft
Trailer Weight (approx)	Without Coil	160,000 lbs
Work Reel Capacity	2.875 in Coiled Tubing	18,000 ft
	3.5 in Coiled Tubing	10,000 ft
Work Reel Diameter	13 ft	
Work Reel Core Diameter	11 ft	
Work Reel Width	9 ft	
Spooling Force	8000 lbs	
Injector	Pull Capacity	200,000 lbs
	Push Capacity	100,000 lbs
	Max Speed	100 ft/min
Utility Winch Rating	7250 lbs	
Lubricator Winch Rating	2200 lbs	
Derrick Pipe Handling Range	46 ft (Range III)	
Derrick & Substructure Rating	300,000 lbs	
Rotary Table	Rating	3000 lbs A.P.I.
	Opening	13.875 in
	rpm	125 rpm
	Torque	1600 ft-lbs
Top Drive	Rating	140,000 lbs A.P.I.
	Max rpm	Up to 220 rpm
	Max Torque	Up to 250,000 ft-lbs
Substructure with B.O.P. Handling System	10,000 lbs	
Annular Preventer	7.167 in (180 mm)	3000 psi
Single Gate RAM Preventers	2 × 7.167 in (180 mm)	3000 psi
H.P.U.	Diesel	Up to 500 hp

Fig. 1 – HCTR units have a relatively small size compared to a conventional drill pipe rigs, thus reduce environmental impact.

Skylift Design

The skyway system proposed is a more robust version of what is used in mining and was used in the construction of the Hoover Dam. During literature search of mining publications, we found four aerial tramway builders – Garaventa AG, Global Technologies & Manufacturing, Interstate Equipment Corporation, and Reliance Barker Davies - but were unable to find capacities and dimensions. We suspect this lack of information is due to the fact that every installation must be custom built. However, we were able to find mentions of a wooden aerial tramway built in 1914. This system carried 2200 pounds and was reported to be significantly cheaper than building a traditional road[7]. Using modern materials and building techniques, it would be easy to build a system that could carry the desired loads. When examined aerially, as in **Fig. 2A and C**, the footprint of the skylift system is significantly less than a more traditional road.

The basic design consists of two loading/unloading platforms – one located at the wellsite and the other outside of the protected area. In between these platforms would be a series of towers that would support the two cables necessary to complete a skyway circuit. These would need to be tall enough to ensure that the tram was always above the local vegetation and wildlife. The cable between the towers will 'sag,' with the overall amount of sag related to the tram load and the cable material selected.

Our design calls for using a circuit skyway path, as opposed to a straightline path. Utilizing a circuit, we are able to transport more supplies within a shorter period of time. The straightline method only allows for one tram that travels from the dock to the wellsite and then returns before a second load can be sent. The circuit method allows for multiple cars, with no waiting for a car to return before the next can proceed.

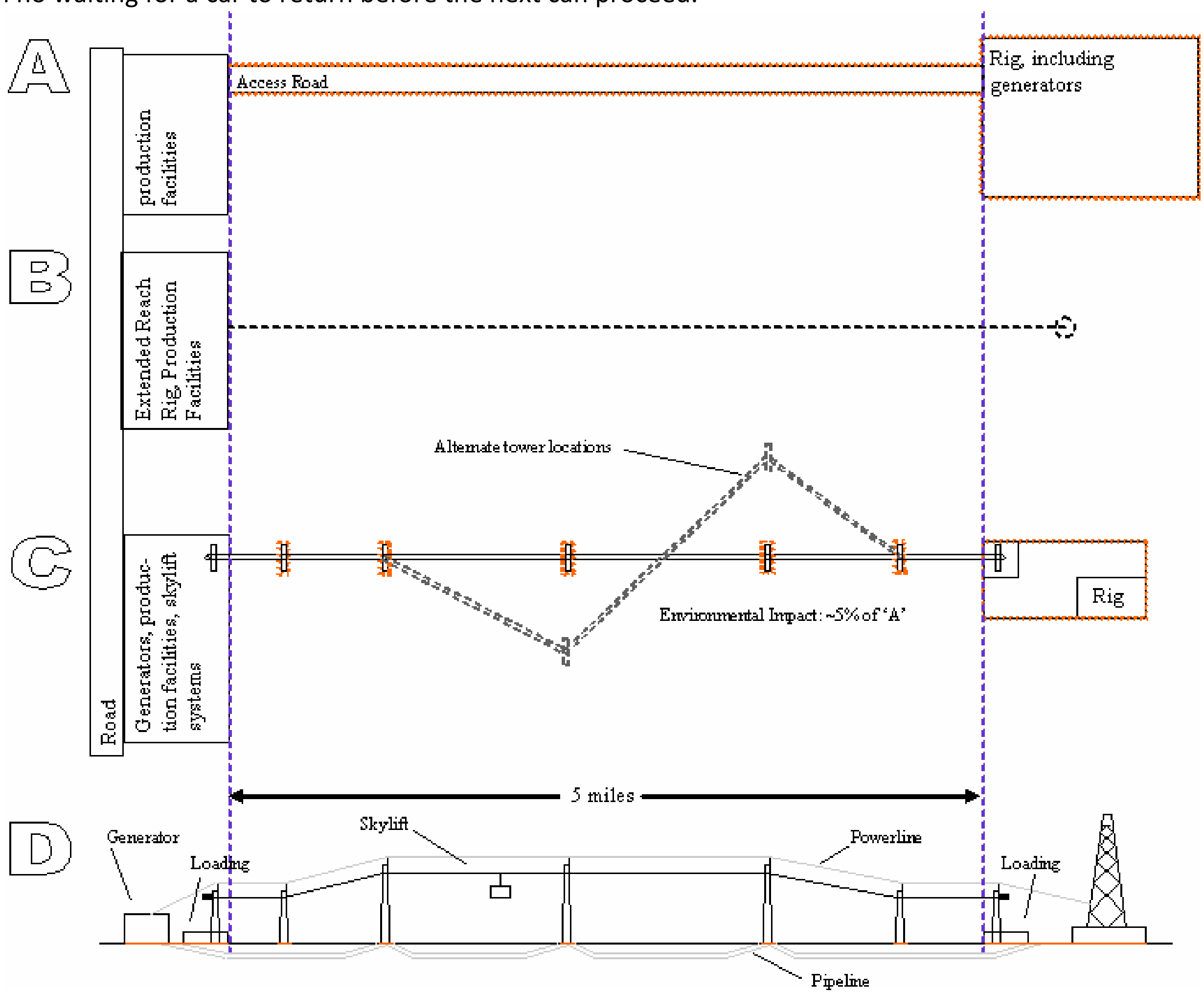

Fig. 2 – Comparison of footprints for a traditional road (A), extended reach drilling (B), and the skylift system (C). The orange lines represent the footprint of each method. Figure also shows side and aerial views (D) of the skylift system.

The recommended tram design is an open air cargo platform, roughly the size of a shipping trailer. This would facilitate the transport of the rig, tubulars, crews, and any other necessary supplies.

Before the skylift is built, the area should be examined so that the towers minimize environmental impact. One of the significant benefits of our plan is that the towers do not need to be located in a straight line, as shown in Fig. 2C. The towers can be located in the areas where there is no, or minimal, vegetation and animal life.

The implementation of this system is straightforward. Individual towers will be constructed as shown in **Fig. 3** and outlined below. Tower height would be dictated by local vegetation and would be limited by local wind speeds.

All construction is done with cargo airships to transport crews, equipment, and materials to and from any locations. Cargo airships come in varying sizes and are used around the world to successfully transport heavy loads. For construction work, they are superior to helicopters because they produce less noise and pollute less. Their downside is that they can be slower than a helicopter.

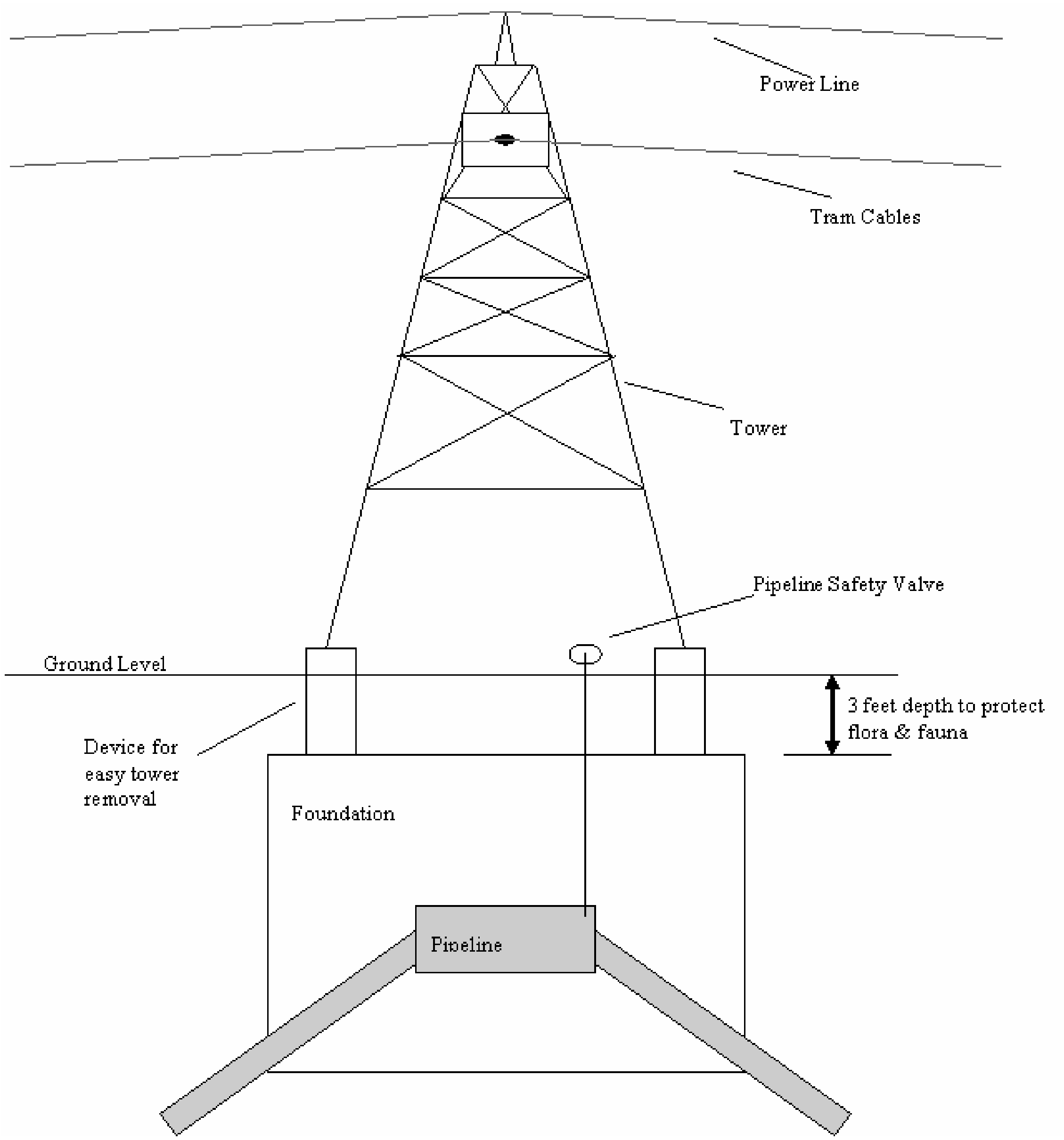

Fig. 3 – Side view of basic tower construction. Foundation is located three feet below ground level to protect local wildlife and vegetation. Also it is shown how tiny is the footprint that impacts the ground after installation.

The first step in construction is to excavate the footprint of the tower. A crew and equipment are placed on the site and the ground is removed. The removed soil is stored outside the protected area. Next, a concrete base is built that starts one meter below the ground. The base should be sufficiently deep so as safely support the towers. By keeping the top of concrete deeper than one meter, we are able to easily revert the footprint area back to its natural habitat at field abandonment. Flora and fauna exist within the first meter of the ground – they would not notice or be affected by the base. Once the concrete base is installed, horizontal pipe installation equipment would be placed upon the base and the pipeline would be installed. This setup allows using horizontal directional drilling techniques to install the pipelines and to inspect them during the lifetime of the project.

The next step is to install the towers into the base and fill the remaining hole with some of the excavated soil. This process is repeated for each tower. After all the towers are built, cables and power lines would be strung and the skyway access platforms would be installed. The final step is to install the skyway motor outside the protected area and to attach the trams. The system would now be operational. It must e noted that this type of installation is widely used to install towers in mountainous regions.

Once the skylift is no longer needed, at field abandonment or once the alternative uses are finished, it can be removed and the environment restored to its original conditions. The wellsite would be returned to its original condition using standard oilfield practices. Then the skylift would be removed, with the assistance of cargo airships. The trams, cables, and power lines would be removed from the towers. The footprint of each tower would be excavated down to the base; the tower would then be detached from the base and removed. The original dirt would be brought back in to fill up the hole. Once removed in this manner, the local environment would be unable to tell that anything had ever occurred in their area.

Pipeline Design

Two methods were chosen to transport hazardous material from drilling and production phases through an environmentally sensitive area. The large amounts of hazardous materials in question are from a production stream of a typical natural gas and oil reservoir. Surface separation systems will be set with the facilities outside of the protected area; therefore, the transported fluid will be a multiphase mixture of natural gas, oil, and water. Natural gas and liquid lines are subject to different regulations. A multiphase mixture is subject to both sets of standards. For example, when calculating impact radius, the spill area would be treated as a liquid and explosion radius would be that of a gas line. This is according to 49 Code of Federal Regulations 192 and 195. The line will consist of electric resistance weld steel pipe, and it will be cased for corrosion and leak protection. The critical integrity issues for this line to operate in an extremely sensitive environment are corrosion protection and leak detection. For this competition, the following Department of Transportation guidelines will be adopted: computational pipeline monitoring leak detection system must be in accordance with API 1130 (49 CFR 195.444), pressure/flow sensors and remotely operated valves must be tied to a control center, and right of way patrolling via skylift.

The two methods of pipeline settings are shallow burial and horizontal directional drilling (HDD) installation. Shallow burial can be quickly and easily installed and removed with simple leak and corrosion monitoring; however, installation can interfere with the surface vegetation. If shallow burial is chosen, a burial of 3 to 6 ft should ensure adequate frost protection. An alternative would be to use drilling rigs located at the base of each surface skylift support to drill a horizontal path for the pipeline. The benefits of this method are minimal environmental impact and complete isolation, however, this method is costly to install and remove, and makes leak and corrosion detection more complex. Shallow burial is orders of magnitude cheaper. Using a case study of horizontally drilled pipeline, the development and implementation of this project will require funding in the order of $250 millions for a length of 5 miles[8], making this not economically viable.

If cost is no issue, drilling and running pipeline through boreholes is recommended. It would ensure that, except for the surface stations, this pipeline would be completely isolated from the environment. Power lines should be run above ground, attached to the skylift system. Operating pressures can be safety-factored down to give extra assurance of integrity.

Some of the specifications for the pipeline recommended are in **Table 4**. By regulation these specifications yields a maximum allowable operating pressure of approximately 4,900 psi, meeting all requirements for safety and environmental protection as well as meting production throughput needs.

Table 4—Specifications of recommended pipeline

Diameter, in	6.5
Specified minimum yield strength, psi	42,000
Wall Thickness, in	0.5
Safety Factor	0.72
Joint Factor (E), electric resistance welded pipe	1

Effort to minimize environmental impact

By locating everything except for the rig outside of the protected area and by using a skyway instead of a physical road, we have minimized the impact on the environment to just the footprint of the towers and the wellsite. Noise pollution is also reduced due to the fact that skylifts and cargo airships produce little, if any, noise pollution.

Assessment of environmental restoration

The guidelines for this project state the environment should be assessed one and five years after drilling ceases. As stated earlier, focusing on a one-year time window does provide a complete picture of environmental impact. Under our proposed timeframe, the impact after one and five years would be identical. After drilling, it is still necessary to visit the wellsite during the life of the field for inspection purposes and workovers. If the wellsite is not accessible, it would be impossible to catch a potential equipment failure before it impacted the local environment. It is proposed that the environmental impact after drilling and at field abandonment should be considered instead.

After drilling has ceased, the skylift will be used when wellsite inspections occur, plus when desired if an alternative use is employed, as described later on in this report. Unlike a traditional road, no cleanup work is necessary at this stage, beyond the wellsite. The environment between the towers has not been affected, and is still pristine. Wildlife and vegetation would not be hindered in any way – land based wildlife could walk between the towers and flying fauna would be able to fly around or over the towers. Unlike traditional wind turbines, the skylift would not endanger birds by being difficult to see. Had a road been built, any flora or fauna underneath the temporary road would be destroyed, and the soil would have been heavily compacted.

After the field has been abandoned, and assuming no further use of the skylift, the towers can be removed. The wellsite and the footprint of each tower will be returned to their natural state. Since tower locations had been chosen where there was no vegetation, it will immediately be returned to its original condition. The environment will function as if drilling had never occurred. Had a road been chosen, it would have been necessary to relay the road, destroying the environment after it had just started to reestablish itself after the previous road was removed.

Future Use & Alternative Energy

Once drilling is completed, the skylift has several possible uses. These uses include future well workovers, tourism, science, and alternative energy exploitation. Should the well need future work, the skylift can be used to transport a rig or equipment back onto the site. The skylift can also serve as a tourist attraction by allowing visitors to view the area from a raised height. This would lead to taller towers, allowing a larger view. Scientists may also find value in the skylift by being able to study the area without disturbing it; in this case, shorter towers may be preferred to allow the scientists to be closer to the environment. Alternative energy systems can be installed as the skylift is built.

In desert environments, the three main sources of alternative energy are wind, solar, and geothermal. For this project, wind and solar could be utilized to generate electricity. This would be accomplished by designing the skylift supports to hold solar and wind generators in place. There are four main types of solar generators and two main types of wind generators that could be applied to this project. The four main types of solar generators are the standard power-plant type (elliptical mirror focusing sunlight onto a generator), traditional solid flat panels, flexible cells, and 'paintable' cells. The two types of wind generators are the traditional 3 or 4 blade model and the newly developed Aerotecture turbines.

Fig. 4 - Example of Nanosolar's flexible solar cells.

If generating power from alternative energy is desired, our recommendation would be to use a combination of Aerotecture wind generators and either 'paint' or flexible solar cells. To harness the sun's energy, using either 'paint' or flexible solar cells, shown in **Fig. 4**, to cover the majority of the supports would be the primary method[9]. To harness even more solar energy, it would be possible to install traditional solar power plants on top of each support. The Aerotecture wind generators, shown in **Fig. 5**, can operate in low wind environments and use wind from all directions[10]. Due to their design, they are also bird friendly, allowing us to harness wind energy without harming the local avian life. Another benefit of this type of wind generator is that they are relatively inexpensive and are transparent, allowing light to pass through – which will be beneficial for the solar generators.

Fig. 5 - Horizontal Aerotecture wind turbine.

Wind turbines and solar cells both require regular maintenance. Approximately once a month, the solar cells must be rinsed to remove dirt buildup that reduces their efficiency. This will require a method of bringing water to each platform – the two options are to either carry the water within the skycars or to have a water pipeline to each platform. Care must be taken to reduce the amount of water that comes into contact with the local environment. If not collected, the water could increase vegetation growth around the structures, altering the local environment. If this increase in local vegetation is considered unacceptable, the base of the platform would need a water collection vessel that would either be drained via pipeline or vacuumed into the skycar for removal from the area (The water would be nontoxic, containing only sand). The wind turbines would also require regular maintenance to keep them running at peak efficiency. Facility maintenance must be considered when designing the structures to allow personnel to work on the structure without coming in contact with the local environment. This would be easily accomplished by installation of walkways and ladders on each support that is accessible from the skycars.

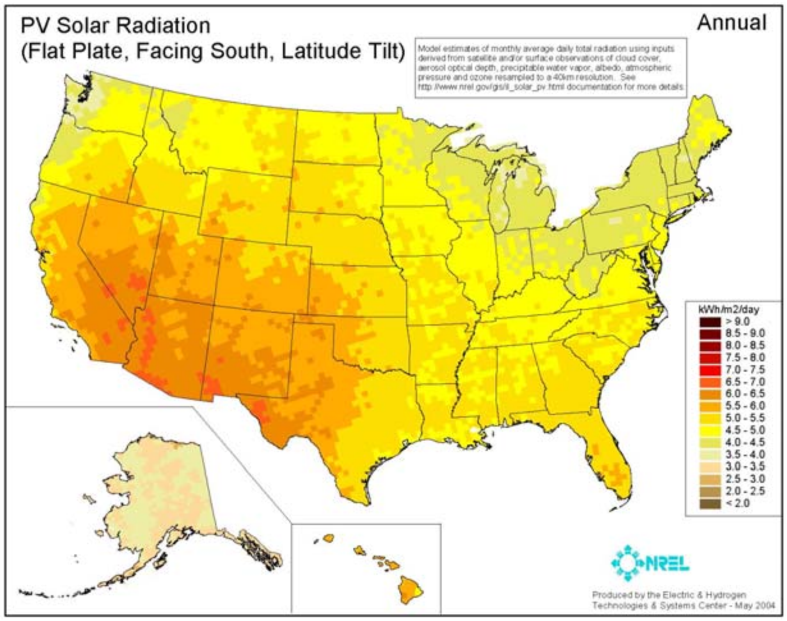

Fig. 6 - Solar energy map of the United States of America[11].

In order to install alternative energy generators, it is necessary to ensure that their installation is justifiable. **Fig. 6** shows that this area is located in the best part of the United States for solar energy. Also the use of Aerotecture wind turbines allows generation of electricity even in low wind conditions.

Conclusion

In approaching this challenge, an integrated approach was chosen. If the goal is to protect the local environment, it is necessary to consider the entire life cycle of the field, not just the drilling window. Our plan calls for using an skylift to reach the site, locating only the rig within the protected area, placing the remainder of the drilling (and production equipment) outside the area, and using horizontally drilled pipelines to transport fluids. This plan will produce less impact on the local environment than an ERD project or a traditional road.

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PRESENTATION TO HALLIBURTON
The
"Disappearing Road Competition"

Can You Make a Road Disappear?

A Part of the EFD Program Texas A&M University

EFD

The Driver

Theodori & Anderson;
The Social Cost of Energy Must be Considered

- *The value of oil and gas resources will increase in the coming decade.*
- *The value of protecting the environment will become more important.*
- *The public's interest in energy development will be more and more significant.*
- *The O&G Industry must engage the public in a more significant way.*

EFD

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DR is Part of A&M's Environmental Drilling Program:

The Scope

GPRI &The Crisman Center for Energy, Environment, & Transportation (EETI)

Objectives of EFD/DR Program

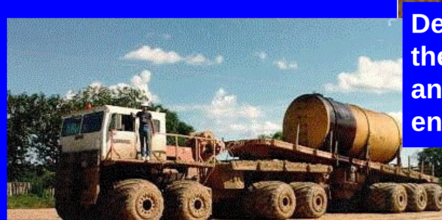
(1) To incorporate current and emerging technologies into a clean E&P system with no or very limited environmental impact

(2) To demonstrate a viable system used for the exploration and exploitation of oil & natural gas primarily in the lower 48 states (DOE),

(3) To create a team with skills to minimize impact of oil and gas activity in the lower 48 states, much of which is now being directed on lands officially designated as 'sensitive' and/ or 'protected' .

EFD

Roads Have Significant Impact – *Disappearing Roads Program Will*



Develop innovative concepts for reducing the footprint of transporting equipment and materials to drill sites in environmentally sensitive areas

EFD

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Disappearing Roads Competition

HALLIBURTON PARTNERSHIP

1. **Sponsorship Pays for Expenses & Cash Awards**
2. **Assists in Promoting the Competition through U.S. and International Universities**

BENEFITS:

Supports Halliburton's Sustainable Technology Strategy

Increases awareness of the short and long terms effects of roads on environmentally sensitive areas.

Better trained engineers and environmental scientists with ability to solve real world problems.

Encourage dialogue on ways to minimize the impact of industry activity in environmentally sensitive areas.

Goals

O&G Resources in Coastal Margins
Significant natural gas.
Problem:

To reduce or eliminate impact of O&G Activity

To measure the effect of low impact practices.

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DR Competition 2007 -2008: Desert Ecosystems

Example: Otero Mesa Landscape

Legislature Limiting Access to Federal Lands in New Mexico

Site for Disappearing Road Contest 2007 -2008

West Texas and U.S. Desert Ecosystem Problem: How to produce 10 tcf gas with minimal environmental impact?

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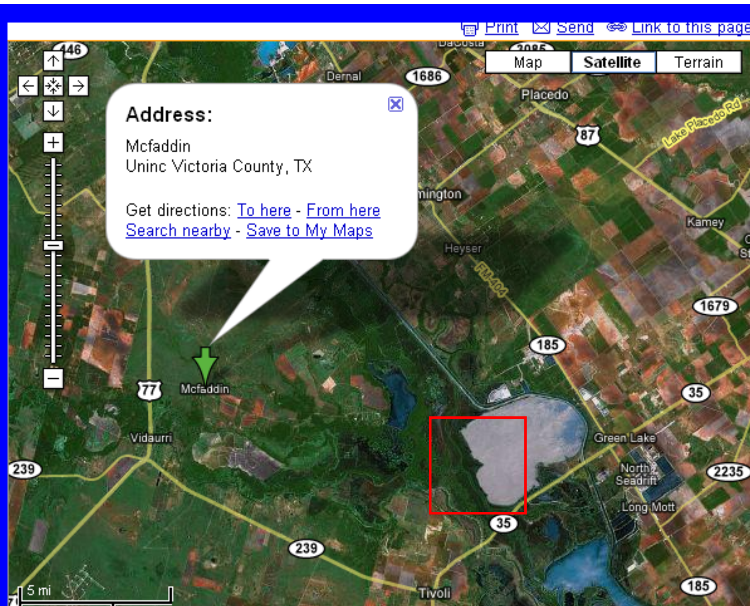
One Site for DR Contest 2008-2009



Site for DR Contest 2008-2009

Disappearing Road Systems at McFaddin Ranch

Rio Vista Bluff Ranch, McFaddin TX.

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One Site for DR Contest 2008-2009

J.A. Murphree WMA, Port Arthur, TX. April, 2007

One Site for DR Contest 2008-2009

J.A. Murphree WMA, Port Arthur, TX. April, 2007

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One Site for DR Contest 2008-2009

J.A. Murphree WMA, Port Arthur, TX. April, 2007

Disappearing Roads

Putting in a road has a multitude of impacts.

Disturb natural watersheds.
Remove vegetation coverage.
Change the topography and soil structure.
Remove natural habitat for wildlife.
Provide a barrier to movement and spread of plants and animals.
Affect animal behavior.
Provide further access to sensitive areas off the main highway.
Pose a visual disturbance to the landscape.

DR Contest: Environmental Guidelines; (Padre Island)

- Air Quality
- Soil Resources
- Water Resources
- Floodplain Values/Hurricane Preparedness
- Vegetation Page Descriptions
- Fish and Wildlife Page Descriptions
- Threatened and Endangered Species and their Habitats
- Cultural Resources
- Visitor Use and Experience including
- Visual Quality, including the Night Sky
- Natural Quiet

EFD

Disappearing Roads; Time Schedule

Submission of Phase I Documents	October 13, 2007
Notification to Teams About Outcomes of Phase I Evaluation	November 17th, 2007
Submission of Phase II Documents	March 16th, 2008
Notification to Teams About Outcomes of Phase II Evaluation Invitation of the Top Five Winners to Participate in Phase III	May 4th, 2008
Presentations by the Top Five Winners to the Panel Judges	May 29, 2008
Awards Banquet	May 29, 2008

EFD

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Disappearing Roads Competition Will

Create multi-disciplinary teams addressing environmental concerns and engineering challenges .

Develop educational tools to incorporate sound environmental practices into engineering projects.

Instill in students the need to develop engineering systems based not only on technical constraints but also under strict environmental conditions.

Establish a dialogue between students and experts from the oil and gas industry.

Increase the awareness of the short and long terms effects of roads in environmentally sensitive areas.

EFD

Thank You

Department of Petroleum Engineering
Crisman Institute, GPRI
Department of Civil Engineering
Wildlife & Fisheries Sciences
Rural Sociology & Community Studies, Department of
Recreation, Parks & Tourism
Texas Transportation Institute
Texas A&M University
Houston Advanced Research Center
Matagorda Consulting Partners LLC
Texas General Land Office

Halliburton, Year 2067 - 2008 Sponsor

Dave Burnett burnett@pe.tamu.edu 979 845 2274
http://www.gpri.org/EvironDrilling/EDContest.htm

EFD

Disappearing Roads Competition

U of Wyoming

A layered mat, roll-out road system and a modular frame design. These concepts came from the need to minimize soil disruption and wildlife fragmentation in Jonah Field and Pinedale Anticline Production Area, PAPA, of the upper Green River Valley, Wyoming

TAMU Petroleum Engineering

A skyway system with two loading/unloading platforms – one located at the well site and the other outside of the protected area. In between these platforms would be a series of towers that would support the two cables necessary to complete a skyway circuit.

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Report 6: Waste Management: Produced Brine and Mud Pit Reduction

Report 5 contains reports describing the Texas A&M research effort into reducing the waste brine created in the drilling process. By managing brine in a more environmentally responsible manner, the entire drilling system is smaller, uses less energy, and creates less waste.

Produced water and spent drilling fluids from petroleum operations represent a significant expense to companies developing new energy reserves. These spent fluids, seldom recycled, offer a viable source of water resources for oil-field reuse. A major obstacle to reuse is the presence of suspended solid material in the fluids. Such contaminants, if not removed, will not only prevent any reuse but will also impede disposal. The objective of this project was to evaluate membrane filtration as a way to remove suspended and entrained particles to produce re-useable effluents. A secondary objective was to identify operating practices that would allow long-term, cost-effective treatment technology to be incorporated into a mobile, low-footprint process design.

A comprehensive study was funded by EFD sponsors - to access the results see Dr. Sean Olatubi's PhD dissertation herein. A separate study evaluated the most efficient cleaning systems for the membranes selected in Olatubi's work. Mr. Scott Beech's report is enclosed as well.

This approach was designed to meet the deliverables specified in the NETL SOW Task 11 (*Full-Scale Engineering System Design*) and Task 12 (*Combine Selected Components into Integrated System for Test Site*)

OIL REMOVAL FOR PRODUCED WATER TREATMENT AND MICELLAR CLEANING OF ULTRAFILTRATION MEMBRANES

BY

SCOTT JAY BEECH

Edited

D.B.Burnett

August 2006

OIL REMOVAL FOR PRODUCED WATER TREATMENT AND MICELLAR CLEANING OF ULTRAFILTRATION MEMBRANES. (AUGUST 2006)

Produced water is a major waste generated at the oil and natural gas wells in the state of Texas. This water could be a possible source of new fresh water to meet the growing demands of the state after treatment and purification. This thesis describes a research project that evaluated the treatment of brine generated in oil fields (produced water) with ultrafiltration membranes. The characterization of various ultrafiltration membranes for oil and suspended solids removal from produced water were studied to test whether they could be a possible pretreatment method. The research measured the effect of pressure and flow rate on membrane performance of produced water treatment of three commercially available membranes for oily water. Oil and suspended solids removal were measured were by using turbidity and oil in water measurements taken periodically.

The study also analyzed the flux through the membrane and any effect it had on membrane performance. The research showed that an ultrafiltration membrane provided turbidity removal of over 99% and oil removal of 78% for the produced water samples. The results indicated that the ultrafiltration membranes would be useful as one of the first steps in purifying the water.

Membrane cleaning of produced water fouled membranes by micellar solutions was investigated. A neutral pH and ambient temperature micelle solution for effective cleaning of oily water fouled membranes was developed and studied. The performance of cleaning solutions on ultrafiltration membranes were investigated on lab size membrane testing equipment. Different micro emulsion solutions were studied to evaluate the effect of solution properties on cleaning performance. Three types of multiple membranes were studied, each having polyvinylidene fluoride PVDF material but with different nominal separation or flux characteristics. The data showed that the use of a micelle solution to clean the produced water fouled membranes was a feasible and effective method. The study showed with further adjustment of the micelle solution the cleaning effectiveness could be optimized to provide double the effectiveness of current industry methods for the type of foulant.

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FIGURE Page

I ASKED YOU TO CONVERT THESE PRESSURE MEASUREMENTS.

1. INTRODUCTION

Advances in membrane technology has allowed the development of an effective onsite treatment system for the conversion of produced water into a potable fresh water resource. Produced water represents waste generated by the oil and gas industry. If it is cleaned and desalinated, it can help in meeting future fresh water needs in the state of Texas.

The goal of this project was to determine the best membrane technology for the economical onsite pretreatment of produced water. This project included a study of the feasibility of using micellar solutions to clean the membrane fouling that occurs during onsite operation.

The specific objectives of this research has been 1) to determine the most effective commercial available ultrafiltration membrane and effect of operation parameters for onsite produced water pretreatment, 2) to determine whether micelle solutions for membrane cleaning are effective, 3) and to determine effects of different micelle solution compositions for membrane cleanup.

The research data are compiled and presented as two separate studies:

- The screening and evaluation of the most effective ultrafiltration membranes for use in oilfield brine pretreatment for turbidity and oil removal to meet feed water quality requirements for desalination.
- To evaluate cleaning parameters and use of micelle solutions to remove fouling caused by produced water fouled ultrafiltration membranes under ambient temperature and pH for an onsite treatment system.

.

1.1. Background

The oil and gas industry produces large amounts of wastewater as one of the byproduct of production. This wastewater is commonly referred as produced water or oilfield brine. In Texas, the oil and gas industries produce 250 billion gallons of produced water annually [1]. This produced water, treated currently as waste, could be a major resource to use to reduce water shortages in Texas [1].

Currently produced water is typically disposed in injection wells as waste or for pressure maintenance of the reservoir [1, 3]. Produced water disposal and handling is covered by the Clean Water Act and United States Environmental Protection Agency (EPA) and is treated as a non-hazardous waste from oil and gas production and is exempt from the Resource Conservation and Recovery Act (RCRA) for monitoring specific constituents [2-3]. These disposal wells are tightly monitored and controlled to prevent groundwater contamination through overfilling or too high contaminant loads [2]. These restrictions on injection wells size, depth, and capacity were developed by the EPA to prevent pollution of current underground fresh water supplies or future sources of fresh water. The current regulation on produce water is based on the Best Practicable Technology (BPT) for onshore production [2]. The BPT limit set by the EPA is 35 mg/L oil and grease daily max for use as an agricultural or wildlife reuse or no onsite discharge for onshore production facilities [2].

Produced water in Texas has widely varying composition [2-4]. Produced water contains suspended oil and grease, organics, dissolved and suspended solids, salts and various other trace metals. Their characteristics differ depending on the particular location of the oil well. They are typically saline with total dissolved solids (TDS) concentrations ranging from 100 ppm to over 300,000 ppm [2-4]. Produced water also typically contains between 50 to 100 ppm total oil and grease along with low concentrations of minor and trace metals [3-4].

1.2. Produced Water Treatment Technologies

Produced water treatment and purification was accomplished through a variety of chemical and physical separation techniques. Since produced water composition varies from location to location, a proven purification method has been difficult to develop. Depending on the exact characteristic of the particular source of produced water different pretreatment processed are applied. Hydrocyclones, centrifuges, membrane filtration, and activated carbon or depth filters are all techniques that have been tested to perform produced water treatment [2-5]. Removal treatments have concentrated on suspended solids and oil and grease removal. Removal of dissolved and suspended oil and grease has been especially difficult. Membrane treatment used to reduce or eliminate the oil and grease also achieved the necessary removal for trace metals. Oil removal to the 35 mg/L required by the EPA precluded the use of hydrocyclones or centrifuges.

The secondary concern is salt removal. The common techniques currently used for desalination are multistage flash or reverse osmosis [7]. New techniques for desalination of produced water are being researched including membrane pervaporation [7] and electrodialysis [8].

Most oil removal technologies cannot achieve the separation required to meet water quality standards [6]. These separation technology mechanisms did not remove the entrained or suspended oils. The concern or problem with use of the first two types of technologies for treatment of produced water was that the minute amounts typically found in produced water sources fall below the required concentration to make the technology operate efficiently or economically. For example, hydrocyclones are typically utilized to achieve separation between the crude oil and the brine. The suspended oil concentration remaining in the produced water was near the minimum that the separation technologies were able to economically obtain.. Absorption techniques can and would provide separation required but were limited by the suspended solids or by trace contaminates found in different sources that could react with absorption material and introduce different contaminates that would later need to be removed. Filtration techniques were capable of most of the necessary reduction in oil content and suspended solid removal. Membranes, a type of filtration, technology that provided the separation while minimizing replacement of filters or membranes.

1.3. Membrane Filtration

Membrane filters are classified into types based on their nominal size or molecular weight cutoff (MWCO). These classifications are commonly classified as microfiltration, ultrafiltration, nanofiltration, and reverse osmosis and correspond to the size of particle that is rejected by the membrane. Microfiltration rejects suspended solids ranging from 0.10 μm to about 100 μm [9]. Ultrafiltration membranes provide separation from 1000 to 100,000 MWCO or 0.001 μm to 0.02 μm for macromolecules and suspended solids [9]. Nanofiltration membranes increase the rejected range to include sugars, divalent salts, and dissociated acids below the 1000 MWCO range [9]. Reverse osmosis membranes are normally classified for ideal rejection of all components except solvent (e.g., water) [9].

The membrane technologies are also developed into four configurations for industrial applications. These four configurations are tubular membranes, hollow fibers, plate and frame, and spiral membranes. Each configuration has distinct advantages or disadvantages in their operation. Tubular membranes are able to handle larger size particles, higher flow rates, easier cleaning by clean-in-place techniques, but lowest surface area to volume ratio [9]. Hollow fiber membranes have the characteristics of highest surface area to volume ratio, back flushing capability, but require smaller particles in the feed to prevent plugging [9]. Plate and frame membranes provide easy onsite membrane replacement and visual observation of permeate for sample collection and detection of leaks [9]. Spiral membranes provide turbulent flow due the spacers, fairly high surface area to volume ratio, and lowest energy consumption due to low flow rates, pressure drops, and relatively high turbulence.

Membrane filtration technology developments are resulting in an increasing range of material of construction provide better membrane performance, higher temperature limits, and larger pH ranges. The membranes are currently manufactured in cellulose acetate, polysulfone, polyamide, nylon, PVDF, polytetrafluoroethylene, polypropylene, and others [9]. These materials provide increased the temperature, pH, and chemical compatibility ranges .. Also, membranes have been developed with different membranes structures including thin film composites [9].

Membrane filtration operations are affected by the feed water composition, temperature, and flow rate and turbulence [9]. These factors affect the flux of the membrane due to concentration polarization of the membrane [9]. Concentration polarization refers to the development of another layer on the membrane surface besides the boundary layer and the membrane that provides resistance to permeate flow. Concentration polarization effects can be minimized by increasing cross flow velocity or turbulence and lowering trans-membrane pressure (TMP) with by varying membrane configurations.

Fouling also occurs during membrane operation. Fouling is the result of interactions between the membrane surface chemistry and the solutes being separated. Membrane fouling by minerals, organics, particles and colloids, and microbial growth is a major operational factor that requires periodic cleaning [10-14]. Any of these four types of membrane fouling may occur during membrane filtration depending on the nature of the feed. Fouling of membranes is considered a consequence of the separation process itself [14]. The fouling of the membrane surface requires techniques to remove the fouling layers, Both physical and chemical methods are employed. Important parameters when cleaning fouling are the type of fouling, cleaning agent, pH, concentration, temperature, and time [10-11, 13-14]. The typical cleaning agents for membrane cleaning are bases, acids, enzymes, surface active agents, sequestering agents, detergents, and disinfectants [10-11]. Each type of cleaning agents has benefits and drawbacks for use with produced water. For example, an acid cleaning of an oily wastewater ultrafiltration membrane resulted in an appreciable increase of permeate flux but became time dependent, while an alkaline solution resulted in a lower flux with time independence [11].

Studies have observed the effect of chemical and physical aspects of cleaning organic fouled membranes [15], enzymatic cleaning [16], and biological cleaning [17]. In 2005, Ang, Lee, Eleimelech showed that the by optimizing the chemical reaction between the organic foulant and the cleaning chemical along with physical components of cleaning an efficient cleaning procedure was developed for the organic fouled reverse osmosis membranes [15]. Enzymatic cleaning of protein and lipid fouled ultrafiltration membranes were shown to an effective method to recover the membrane flux by using specific enzymes to remove the protein and lipid fouling the membrane surface [16]. Also in 2005, Pavlova showed that biological fouling could be treated similarly with the disinfectants specific to the membrane chemistry.

Membrane filtration has been proven effective in treating oily water in other industries including municipal wastewater [18-20], engine rooms [21], and industrial wastewater [2-4, 20]. Membrane technologies also have been utilized in the production of fresh water from surface water [22] and seawater [2-4, 18-19, 21]. The cost-effective use of membrane technology is determined by the reliability of the system and the maintenance of the permeate flow rate. The industry has developed a wide range of materials and techniques to improve the efficiency and applications of the membranes compared to the first cellulose acetate membranes. These new materials allow the technology to be used with new feeds including produced water. These membranes available for industrial use including thin film polyamide membranes on a polysulfone support, ceramic membranes, and stainless steel [9]. Novel bentonite clay membranes have been tested for produced water treatment but with high TDS [23].

Produced water, with its wide range of composition of feed, can cause significant operational problems. These problems include the fouling of the membrane surface, the loss of flux through the membrane surface, poor rejection characteristics, and failure due to chemical reactions with the membranes. The major operational concern is typically the fouling of the membranes. For efficient operation, pretreatment reduces the fouling of the membranes without creating other problems [14]. Also operation conditions can be selected to minimize the concentration polarization and membrane fouling with resultant increased the operational permeate flux.

As mentioned, produced water and oily water can cause severe fouling problems on most membranes. Produced water has contained all four categories of particle, organic, mineral, biological membrane fouling as possibilities and must be pretreated to minimize the fouling of the membranes RO desalination. Proper pretreatment and system design should include steps to reduce the suspended particles, oil and grease, mineral deposit, and biofilm formation through earlier treatment or the membrane configuration selection.. In actual operation, membrane fouling is not completely avoidable and requires periodic cleaning.

2. MATERIAL AND FEED SAMPLE COLLECTION

2.1. Feed sample collection

Produced water samples were obtained from transport trucks delivering brine to a Key Energy salt water disposal well in Brazos County Texas.. The raw water feed samples were temporarily stabilized (for transportation and temporary storage) by addition of commercially available and industry recommended oilfield chemicals, RSI 224sp, RSI 676, and RSI 513, . At the pilot plant, the water was pumped through a 10 μm (nominal) depth filter for bulk particle and oil separation of material possible added during transport and collection.

The produced water feed after filtration was then stored in barrels and sealed to reduce aeration and increase duration of water stability before 6-8 liter samples were aliquoted for each testing. The quality of the produced water was visually monitored for noticeable change in produced water color during obtaining of feed sample. Feed water samples were periodically replaced as dictated by a visible color change in collected feed water .

2.2. Description of experimental setup and equipment

The experiments were performed by using the GE Sepa™ CF II Med/High Foulant System (GE, YCFHFSYS01) for membrane testing designed for 140 cm^2 flat sheet membranes shown in *Figure 1*.

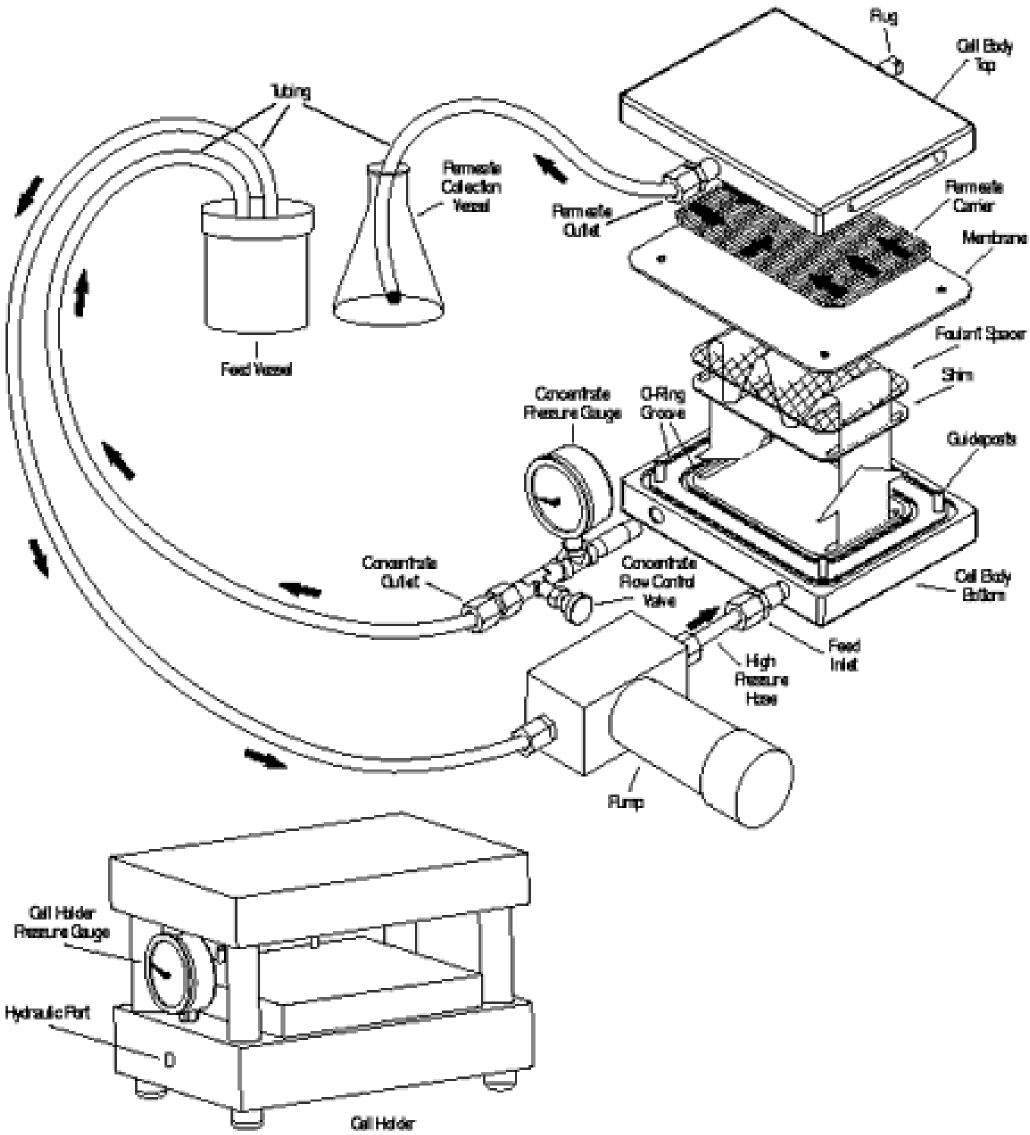


Figure 1 GE Sepa™ CF II Med/High Foulant System (GE, YCFHFSYS01) operation schematic

Figure 1 shows the placement of the feed spacers, permeate carrier, and membrane that model operation of spiral membranes. The apparatus includes a 15 liter feed tank, pulse dampener, high pressure pump with variable speed control, and pressure and temperature gauges to monitor inlet and outlet conditions.

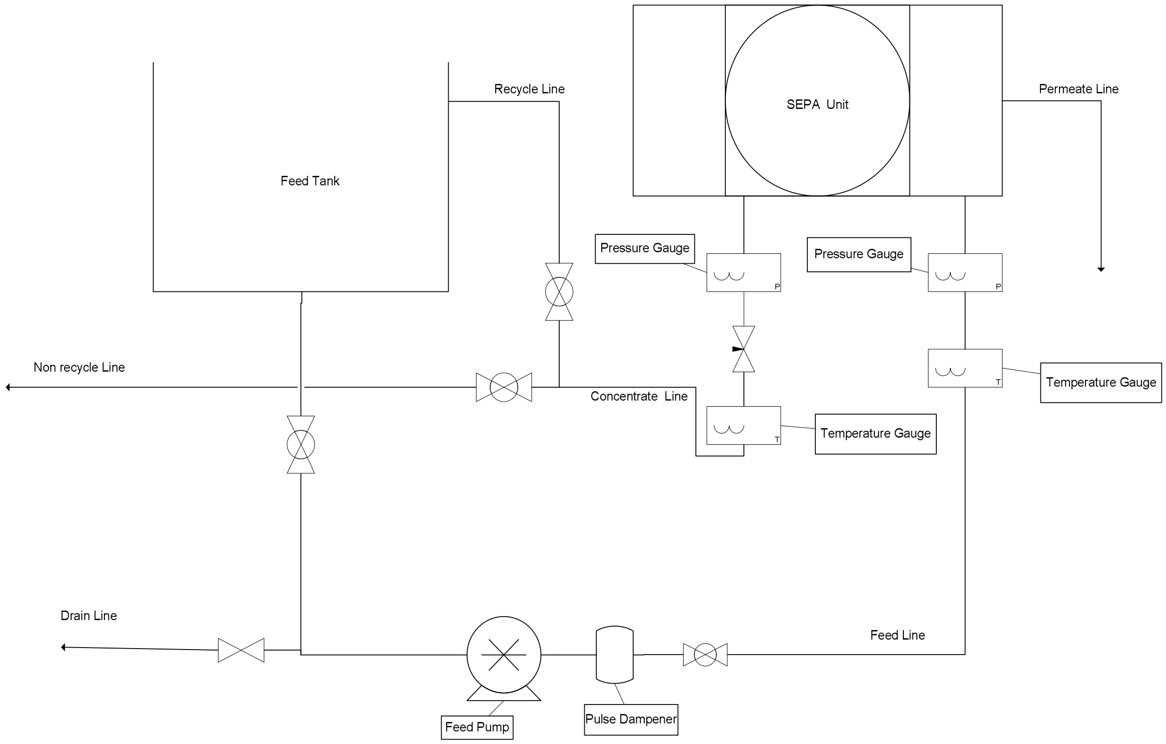


Figure 2 Laboratory process experimental schematic

The diagram (*Figure 2*) indicates location of instrumentation and flow control valves for different operating conditions. The pump and variable speed control were tested using a stopwatch and graduated cylinder to establish steady feed flow rates at specific frequency as indicated in *Table 1*.

Table 1 Pump flow rate control specification

Variable Speed Drive Frequency (Hz)	Feed Flow Rate (LPM)	Approximate Reynolds Number @293 K
3.5	1.9	488
7.3	3.8	977
11.5	5.7	1465
16.0	7.6	1953
21.4	9.5	2442

Standard pH paper was used to monitor the pH of the feed tank during testing. Permeate flow rate was measured by stopwatch and graduated cylinder as needed for cleaning analysis.

2.3. Obtaining membrane samples

Membrane manufacturers were contacted for ultrafiltration membrane recommendations for use in oily water separations. Three membranes were chosen, each having a spiral membrane configuration type for compact design configurations. Membranes also had a range of MWCO, and expected compatibility with micelle solutions. Flat sheet samples were obtained of each selected membrane and cut to fit the Sepa unit and the 140 cm^2 test area. The three types are classified and referred to as JW, 5k, and BN.

Table 2 Membrane Specifications

	JW	5k	BN
Membrane manufacturer	General Electric	PTI	Snyder
MWCO	30k	5k	30k
Material	PVDF	PVDF	PVDF
pH range	1-11	3-10	1-11
Typical Flux/psi GFD@PSI	275/30		

3. OIL AND SUSPENDED SOLIDS REMOVAL FOR PRODUCED WATER TREATMENT BY ULTRAFILTRATION MEMBRANES.

3.1. Abstract

The first set of experiments were performed to treat produced brine to measures he performance of ultrafiltration membranes for oil and turbidity removal. The research considered the effect of pressure and flow rate on membrane performance for flux and water quality of produced water treatment with the three membranes . Oil and suspended solids were evaluated using turbidity and oil in water measurements taken every 30 minutes. The studied showed that ultrafiltration membranes achieved turbidity removal of over 99% and oil content removal of greater than 87 %.

3.2. Introduction

The difficulty with produced water clean up is the need to design for the wide non uniformity of produced water from different sources from different wells. Systems should provide treatment of the bulk of contaminates in the produced water and be effective on most produced water sources. One method to help achieve this goal is to design the treatment system in stages with increasing water quality or separation requirements. Two of the major contaminates that need to be removed from oilfield brine to meet water quality standards are suspended and dissolved oil and grease and suspended solids. Removal of dissolved solids has been commercially available for seawater and use well characterized technologies like reverse osmosis and multistage flash evaporation. These technologies require a high quality of water feed for efficiency to minimize the energy requirement.

For suspended solids or turbidity removal, some form of filtration is the typical method used in industry. The filtration can be used after treatment of the water by a coagulant like for municipal water treatment. The concern with using filtration technology to remove the suspended solids from oilfield brine is the need to replace standard filters frequently if the water source has high concentration of suspended solids, (the case for most sources of produced water). Other techniques that have been tested for produced water suspended solid treatment including activated carbon [5], ceramic microfiltration [6], and ceramic ultrafiltration [3]. Oil removal or organics removal has been investigated using technology including check **correct spelling** electrofloculation [24], carbonaceous absorbent [25], bioreactors [26], wetland treatment [27], ultrafiltration [3, 28] and nanofiltration [29]. These studies have given varying results of for oil content removal. The use of ultrafiltration using new types of membranes offer the most promise for produced water pretreatment for later desalination The use of ultrafiltration membranes for water quality pretreatment to meet established feed conditions for reverse osmosis or multistage flash evaporation can be used to make the onsite treatment of produced water economically viable. Membrane technology utilized cross flow filtration to provide the treatment and was allowed to reduce the accumulation of suspended solids and oil content on the membrane surface..

With membrane technology, produced water can be treated onsite to meet feed water conditions of less than 5 normalized turbidity units (NTU) and high removal of oil content for treatment by reverse osmosis. Ultrafiltration membranes were selected to be compatible with oily water and to provide better separation without causing higher capital cost due to higher operation pressures. This study examined and evaluated the use of commercially available ultrafiltration membranes to achieve the desired reduction in both turbidity and oil content of the produced water. The study examined whether ultrafiltration membranes could be used for onsite produced water pretreatment for both turbidity and oil content removal before produced water desalination. The study examined the effect of operation pressure and flow rate on the effectiveness of membrane treatment to meet the desalination feed requirements..

3.3. Material and Methods

3.3.1. Experimental method

Evaluation of commercial ultrafiltration membranes for use in produce water treatment has been conducted. Ultrafiltration membranes should provide the necessary pretreatment separation for desalination with minimum space and cost requirement. . Each membrane type obtained was tested for produced water treatment under two operational factors of pressure and flow rate under a 3X2 factorial design with no replication based on the membrane specification provided by the membrane manufacture. The membrane specifications for the three ultrafiltration membranes suggested an operational pressure of about 30 psi or 207 kilopascals (kPa). This pressure indicated three factor levels of 138, 207, and 276 kPa **(convert)** for the factorial design experiment were appropriate. Limits on flow rates recommended by the Sepa System lab equipment and high fouling feed spacer indicated a maximum flow rate of approximately 8 liters per minute (LPM) for high fouling tests provided for flow rate operation levels of 1.9 and 3.8 LPM in the factorial design. Each experiment was monitored for temperature, flow rates, pressures, pH, operation time, and feed and permeates quality.

3.3.2. Experimental procedure

The test consisted of a batch operation with full concentrate recycle. Each experiment consisted of placing approximately 7 liter sample of produced water feed into the feed tank (see *Figure 2*). The test consisted of operating the Sepa system (*Figure 1*) for 2 hours while maintaining the operational flow rate and pressure for the particular test with concentrate being continuously recycled to the feed tank. Approximately 30 milliliter (mL) feed samples were taken before and after the two hours test duration to monitor the change in feed conditions during testing. Inlet and outlet pressure were constantly monitored and adjusted during the experiment to maintain the TMP at the specified level. Temperature, permeate flow rate, pressure measurements were taken every 30 minutes to monitor change in flux. Also, approximately 30 mL permeate samples were collected every 30 minutes to measure water quality achieved by the membrane. Finally pH was monitored throughout the duration of the experiment for any major change in pH for the produced water feed.

3.3.3. Data Analysis

Flux measurements were temperature adjusted for viscosity to a common temperature of 298 K and reported as liters per square meter per hour (LMH). The data collected during each of the runs were analyzed and computed to provide direct flux performance comparisons between the different membranes through plots: 120min Flux vs. TMP at 1.9 and 3.8 LPM and flux vs. time or fouling curve for direct comparison of the data for each membrane under the same operating conditions. The samples were analyzed for turbidity a reflection of suspended solids and oil. Water samples were measured for an estimated oil content to provide separation characteristics of the membranes. The classification and selection of the best will be based on the 120min flux, lowest TMP, and high rejection characteristics of the membrane obtained.

3.3.4. Water Sample Analysis

Water sample analyses consisted of two measurements, turbidity and oil content. Turbidity analyses were conducted using a Hach 2100p turbidity meter calibrated with factory standards for NTU. Oil analyses were conducted using the TD-500 oil in water meter developed by Turner Designs Hydrocarbon Instruments, Inc. The TD-500 oil in water meter involved use of solvent extraction procedure with high accuracy and repeatability and correlates to EPA and other industry accepted laboratory methods for oil and grease measurements in water. The TD-500 utilized the FastHEX procedure with the high accuracy and repeatability. The FastHEX procedure involved the extraction of the suspended and dissolved oil from the water samples then using ultraviolet light to detect the oil concentration in the solvent. The analysis method was compatible with all popular solvents including hexane, Vertrel, AK-225, Freon, xylene, and others. The water sample analyses used hexane as the extraction solvent and were calibrated to known oil concentrations. Each sample collected during an experiment was tested three times for instrument error and averaged to calculate the turbidity and oil content of a particular sample. The two feed samples were averaged and the five permeate samples averages were then averaged for a combined feed average and permeate average for both the turbidity and oil content. The average values were used to calculate removal percentages for the test as follows in *Eq. 1*.

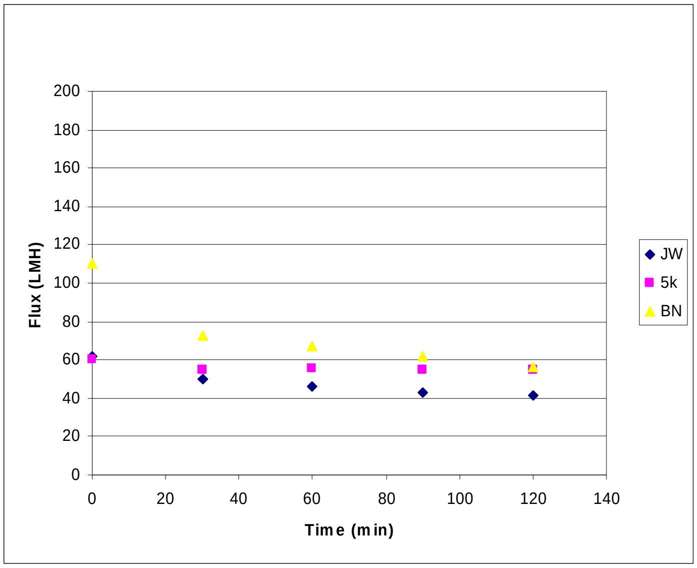
$$Percent\ \ Removal\ \ (\%) = \left(1 - \frac{permeate\ \ average}{feed\quad average}\right) * 100 \tag{1}$$

The calculated removal percentages were used in evaluating the separation characteristics under the same flow and pressure for each membrane type.

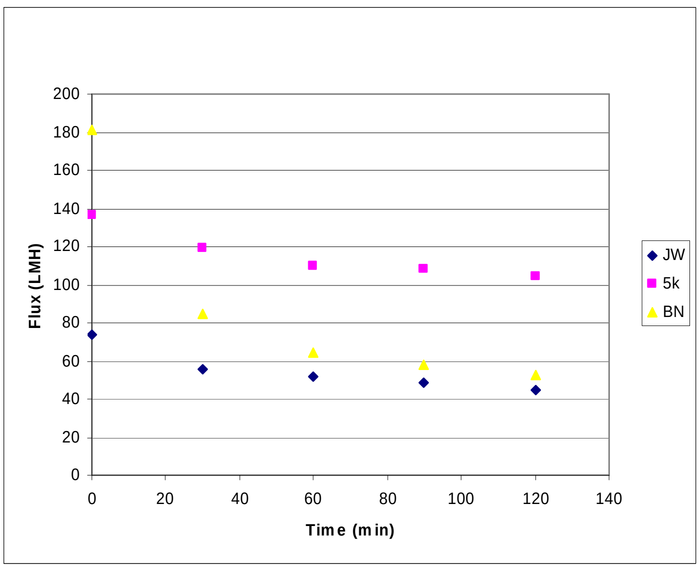
3.4. Results.

3.4.1. Flux curves

The temperature adjusted fouling curves or flux versus time for each membrane was shown in *Figure 3*.



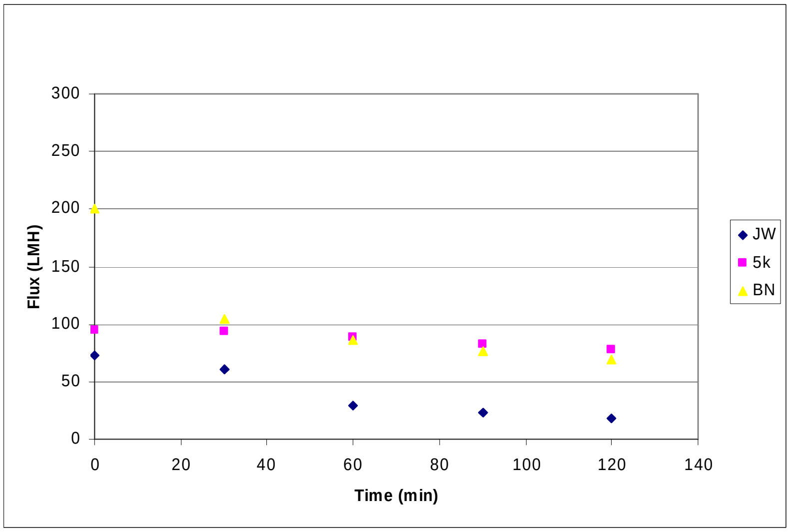
a)



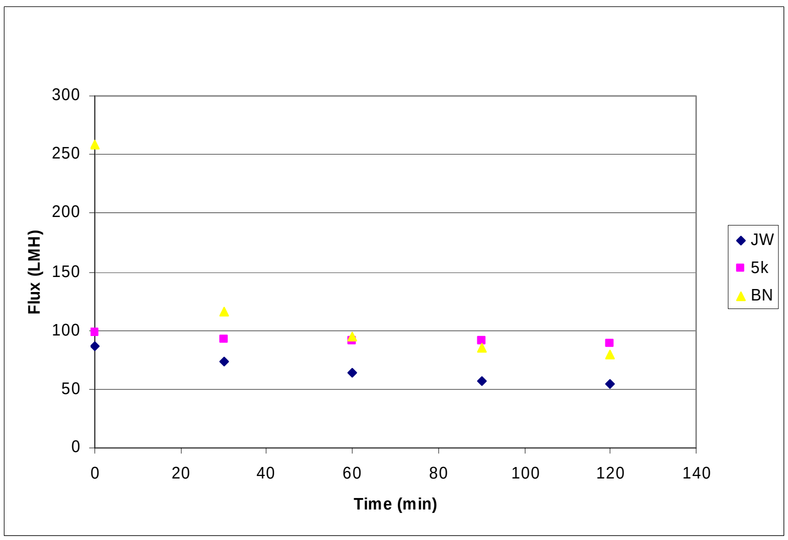
b)

Figure 3. 138 kPa Brine fouling curves, for the two feed flow rates. The flux decay was monitored for the membranes at 298K. (a) 1.9 LPM, and (b) 3.6 LPM.

Figure 3 showed that the flux decays were slight and steady over the time period for the 5k and JW. For the BN membrane, *Figure 3* showed a major drop in the flux within the first 30 minutes followed by a slow decline for the rest of the experiment. *Figure 4* showed similar curves on the membrane types for a 207 kPa TMP. *Figure 4* showed that for the 207 at both flow rates and the JW membrane at the higher flow rate. The figure also demonstrated that only moderate decline occurred for the JW membrane at the low flow rate and for the 5k membrane. *Figure 4* also showed that the flux decay for BN membrane occurred mainly within the first 30 minutes then stabilized.



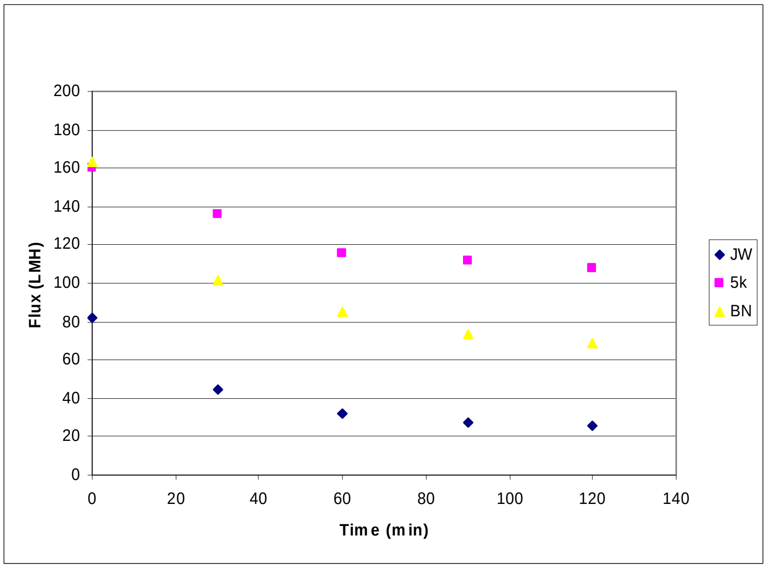
a)



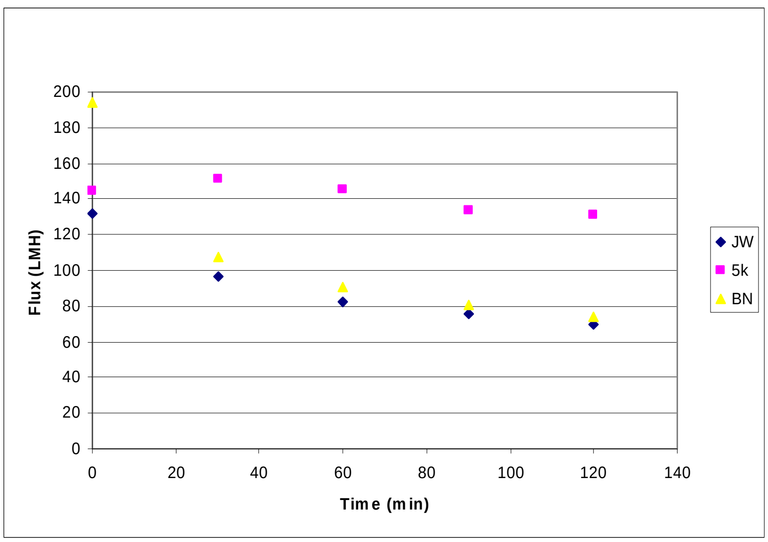
b)

Figure 4. 207 kPa Brine fouling curve, for the two feed flow rates. The flux decay was monitored for the membranes at 298K. (a) 1.9 LPM, and (b) 3.6 LPM.

curves indicate major decay for three membranes during the experiment except for the 5k membrane under the high flow.



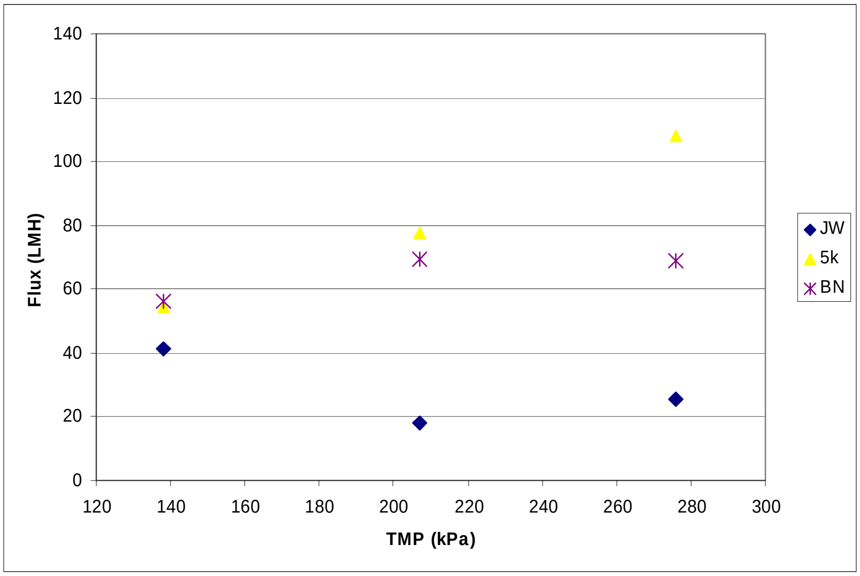
a)



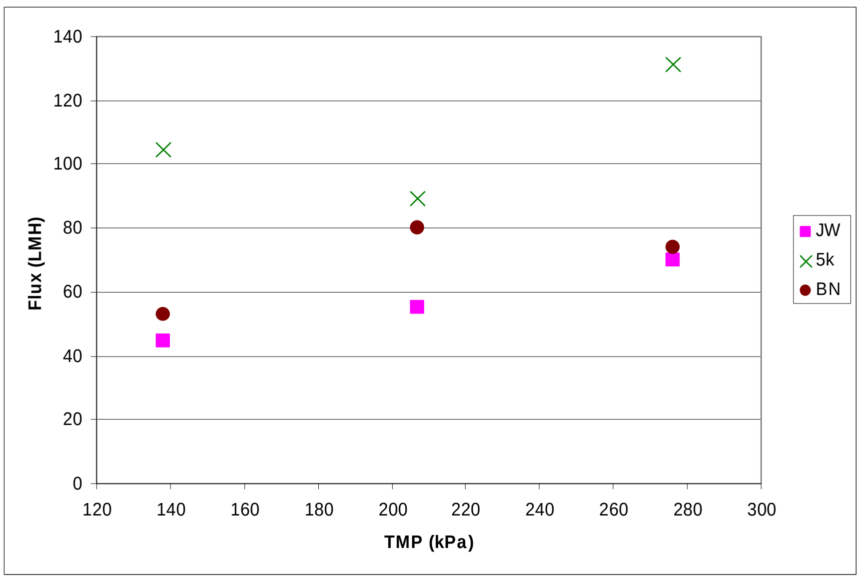
b)

Figure 5. 276 kPa Brine fouling curve, for the two feed flow rates. The flux decay was monitored for the membranes at 298K. (a) 1.9 LPM, and (b) 3.6 LPM.

Figure 5 showed the major decay in flux in the first 30 minutes. After 30 minutes, *Figure 5* showed only a steady slow decline in the flux performance. *Figure 6* showed 120 minute fluxes were the highest for the 5k membrane except for TMP of 176 kPa and 1.9 LPM flow rate.



a)



b)

Figure 6. Brine flux @ 120 min versus TMP, corrected to 298K and for the two flow rates. (a) 1.9 LPM, and (b) 3.8 LPM.

Figure 6 demonstrated that doubling the feed flow rates improved flux for each membrane but only slightly. It also showed that the JW membrane provided the lowest flux at all pressure and flow rates. The data in *Figure 6* showed that increasing pressure yielded higher fluxes than doubling the flow rate provided.

3.4.2. Separation performance

Water quality analyses for turbidity and oil content were computed and averaged for every experiment and shown in *Table 2.*

Table 3 Water quality results

Experiment parameters	Feed Turbidity Average (NTU)	Permeate Turbidity Average (NTU)	Turbidity % Removal	Feed Oil content Average (ppm Oil)	Permeate Oil Content Average (ppm Oil)	Oil content % Removal
JW: 1.9LPM/138kPa	627.8	2.5	99.60%	363.5	34.8	90.43%
JW: 1.9LPM/207kPa	412.2	1.6	99.61%	1927.8	573.3	70.26%
JW: 1.9LPM/276kPa	238.2	1.7	99.27%	1509.0	188.1	87.53%
JW: 3.8LPM/138kPa	252.3	1.1	99.57%	28.0	11.3	59.52%
JW: 3.8LPM/207kPa	1000.0	1.3	99.87%	204.3	47.7	76.64%
JW: 3.8LPM/276kPa	1000.0	1.9	99.81%	156.3	26.9	82.81%
5k: 1.9LPM/138kPa	365.8	3.7	98.99%	43.8	15.6	64.41%
5k: 1.9LPM/207kPa	868.7	1.6	99.82%	48.0	7.9	83.61%
5k: 1.9LPM/276kPa	1000.0	2.4	99.76%	62.8	8.0	87.27%
5k: 3.8LPM/138kPa	565.2	2.6	99.55%	76.0	26.3	65.44%
5k: 3.8LPM/207kPa	954.7	8.8	99.07%	192.2	30.9	83.94%
5k: 3.8LPM/276kPa	832.8	35.4	95.75%	44.2	23.3	47.32%
BN: 1.9LPM/138kPa	1000.0	1.8	99.82%	136.0	7.7	94.31%
BN: 1.9LPM/207kPa	875.8	2.5	99.71%	61.8	7.7	87.60%
BN: 1.9LPM/276kPa	922.5	2.3	99.75%	98.2	7.9	91.92%
BN: 3.8LPM/138kPa	1000.0	1.8	99.82%	121.0	7.3	93.94%
BN: 3.8LPM/207kPa	1000.0	1.8	99.82%	76.8	9.3	87.94%
BN: 3.8LPM/276kPa	974.0	1.8	99.81%	42.5	9.3	78.20%

Table 2 shows that the turbidity and the oil content of the feed was different for each experiment but within the range for produced water. *Table 2* displayed that turbidity of the permeate water samples calculated below 5 NTU. The removal percentage for the turbidity ranged from 95.75% to 99.87%. *Table 2* shows also that the oil content of the water samples were influenced by the feed concentrations. The oil removal percentages for the experiments ranged from 47.32% to 94.31%. The results indicated that all three membranes achieved the turbidity removal less than 5 NTU necessary to meet feed quality requirements for desalination technologies. *Table 2* also showed that the oil removal percentages were the highest for the BN membrane and that the permeate oil content was the lowest concentration achieved by the membranes and averaged below 10 ppm oil. Finally, *Table 2* indicated that increased TMP or feed flow rates did not improve

the oil content separation removal percentages or obtained oil content concentration characteristics of three membranes.

3.5. Discussion

3.5.1. Flux curves

The results indicated that the three membranes were able to provide a high flux to treat the oilfield brine. The fouling curves indicate that the 5k membrane was able to reduce fouling by the produced water over the duration of the experiment. This could be the result of a lower MWCO for the membrane. The lower MWCO could prevent the pores of the membrane surface of being plugged by the suspended and dissolved oils. The JW and the BN membrane or higher MWCO membranes showed large flux decays which were possibly explained by the filling of the larger pores on the membrane surface, but more likely explained by surface fouling.

The flux curves indicated that the increased feed flow rates increase flux performance of the membranes without any loss in water quality. The curves showed that increase TMP typically raised the flux achieved slightly as expected for a membrane system. The flux data indicate that the higher pressure caused faster fouling while significantly decreasing the flux rate of the fouled membrane. The higher pressure caused the formation of the fouling layers to occur at a faster rate by forcing the oil deposits or particles within the produced water feed to plug the membrane pores or increasing the surface fouling of the membrane. The fouling curves also indicated two distinct regions of fouling of the membrane, the rapid initial flux decline during the first 30 minutes and the second gradual flux decay during the rest of the experiment.

3.5.2. Water Analysis

The water analysis indicated that even though the produced water feed samples were taken from the same 10 micron filtered sources the quality of the feed varied significantly for the experiments. This variation led to the treatment of some produced water with higher concentrations of oil and suspended solids and some treatment with lower concentrations of oil and suspended solids in the produced water feed. The analysis showed that even for the feed samples with the higher concentration of contaminates the membrane was able to treat the produced water. The higher concentrations of the suspended solids or oils indicated by the high or maximum turbidity on most feed samples provided no noticeable effect on the water quality of the permeate samples when compared to the lower feed turbidity experiments. The membranes were capable of providing the required suspended solid or oil removal of a turbidity of about 5 NTU for subsequent TDS treatment. The oil separation characteristics provided by the membranes showed that increased pressure and feed flow rate forced oil content through the membrane while also increasing the fouling rate. This indicated that increased pressure reduces the performance of the two of ultrafiltration membranes while increasing the fouling rate of the produced water. The BN membrane showed that the increased TMP while causing the faster fouling did not hinder the water quality of permeate obtained. This suggested that the membrane prevented the oil content for being forced through the membrane by the higher flow rate and pressures.

3.6. Conclusion

The treatment of produced water by ultrafiltration membranes was a logical treatment step for an onsite system before the desalination of the brine. The commercial available membranes were able to treat the produced water to the desire water quality for later desalination. The results indicated that the system would be operated at very low pressure and high flow rates that would provide low capital and operational costs. The testing showed that increased flow rate would provide the necessary throughput while limiting the fouling rate and improving water quality.

The PVDF membranes selected for testing each had different separation characteristics for the produced water. The three ultrafiltration membranes all had a capability of at least 30,000 MWCO. The MWCO generally was not an indicator of the separation capable of the membranes. The BN membrane provided the overall best treatment of the produced water with high flux rate and the best separation characteristics. The 5k membrane was the second effective membrane with the highest flow rates but reduced water quality. The JW membrane was the least effective membrane tested.

The study showed that the treatment of produced water with ultrafiltration membranes onsite could be effective method. The study showed the operation pressure and flow rate affected the treatment of the water with only two of the membranes. The study indicates that the commercially available BN membrane would be a good choice for the onsite application of produce water treatment because the water quality obtained by the membrane was suitable for later reverse osmosis desalination. The study also showed that for the BN membrane the feed flow rate, TMP, feed suspended solids concentration, and feed oil content provided no change in the membrane effectiveness.

4. MEMBRANE CLEANING AFTER PRODUCED WATER TREATMENT WITH A MICELLAR SOLUTION

4.1. Abstract

The second objective of this research was to test the effectiveness of a new type of membrane cleaning agents. A neutral pH and ambient temperature microemulsion cleaning agent has been developed that effectively cleans oily water fouled membranes.. The performance of the cleaning solutions on produced water fouled ultrafiltration membranes was tested on laboratory membrane testing equipment. The micro emulsion characteristics of micelle solutions effect on cleaning performance were examined. Physical cleaning factors on cleaning were studied for the micelle solution along with the multiple membranes of the same PVDF material but different nominal separation or flux characteristics. The results indicated the micellar solution was effective in cleaning the produced water fouled ultrafiltration membrane. Physical factors that influenced the micelle solution cleaning effectiveness included the cleaning flow rate, rinse time, and membrane size were

4.2. Introduction

Membrane filtration has been utilized in various industries for the treatment of water and wastewater. These membrane systems are designed for treatment of a specific known water source and remove the desired contaminates to meet environment regulations or desired water quality for industrial use. These contaminates can have a wide range of characteristics that will allow them to be separated through membrane technology. The concern with using membranes in the treatment of wastewater was to increase efficiency of the treatment system by minimizing the fouling and to efficiently clean the membranes after fouling.

To efficiently clean membrane fouling, the fouling type caused by the wastewater should be known. The degree of fouling is related to the wastewater characteristics and the amount of filtration desired. In typical membrane application the wastewater characteristics are almost constant and have known concentrations, but for produced water treatment the water characteristics will vary from well to well and over time causing additional concerns when developing a cleaning protocol. Also, temperature an important factor for cleaning membranes required additional consideration, especially for remote filtration units for well sites where high temperature cleaning might not be practical. A cleaning solution that will work at ambient conditions would also reduce costs. . An ambient temperature micelle solution would be a possible solution to the temperature limitation. Microemulsions consist of micelles formed by surfactants to create a hydrophobic cell within an aqueous environment.

As explained earlier, produced water has caused all four types of membrane fouling but typically mineral and oil deposits dominate. The mineral and oil deposits on the membrane were the primary concern since they will occur from every produced water source and require a different cleaning approach than biological fouling. Particulate fouling occurred but can be cleaned using physical cleaning or high flow rates to strip the layers from the membrane surface along with the chemical cleaning for the mineral and organic layers. Mineral and organic fouling was cleaned by industry for oily water fouled ultrafiltration by acidic and basic solutions, respectively [11]. The micelle solution created using surfactants were utilized in this study as a solution for cleaning of produced water fouled ultrafiltration membranes. These surface active agents formed micelles that reacted with the mineral and oil droplets to form larger particles that are then removed by the high flow rate. The micelle should improve the effectiveness of dissolving the organic and mineral fouling layer over the acidic and basic solutions currently employed.

This study was testing the feasibility of using such a micelle solution to clean the membrane fouling that was occurring during operation. The specific objective of this research was to examine the feasibility of using micelle chemical solutions with different micro emulsion characteristics for membrane cleaning of produced water fouled ultrafiltration membranes. The research was determining if a micelle solution cleaning cycle at ambient condition can provide better performance than commercial acidic and basic solutions or manufacturers recommended cleaning solutions for produced water. The research evaluated the use of the micelle solution on PVDF ultrafiltration membranes from three manufactures, GE, PTI, and Snyder, used in produced water treatment and to determine whether physical conditions of cleaning time, flow rates, and rinse times affect the cleaning performance to optimize the micellar cleaning solution for these ultrafiltration membranes.

4.3. Materials and Methods

4.3.1. Fouling of membranes samples

The membranes are fouled by using random samples of different produced water obtained from a local disposal well with unknown oil and suspended solids concentrations. The produced water sample obtained is then filtered by a 10 μm depth filter to remove large particles. The membranes are fouled by a 7 liter filtered produce water sample by batch operating the experimental apparatus for 2 hours with concentrated recycle under different operating conditions provided in *Table 3.*

Table 4 Fouling conditions for ultrafiltration membranes

Fouling Condition	Feed Flow Rate (LPM)	TMP (kPa)
1A	1.9	138
1B	1.9	207
1C	1.9	276
2A	3.8	138
2B	3.8	207
2C	3.8	276

The effect of fouling conditions will be assumed to be negligible on cleaning effectiveness. The effect of the conditions under which the membranes were fouled should have no appreciable effect on cleaning the surface of the membranes since the cleaning solution were being design to clean heavily fouled oily membranes. These heavily fouled membranes have a limit on the amount to which they are fouled and can be fouled only to the limiting factor of the cross flow rate or shear rate of the feed across the membrane.

4.3.2. Cleaning of fouled membranes

4.3.2.1. Solution preparation and cleaning procedure

The micelle solutions were prepared using reverse osmosis (RO) water and precise amounts of surfactants and salt concentration to provide the micellar characteristics. The micellar solution consisted of a 1-1.5% surfactant solution of three components A, B, C in a 2-5% sodium chloride solution. The three components consisted of a nonionic A, a nonionic B, and ethyl alcohol C. The surfactants were used to generate Winsor type micro emulsion system with different phase behaviors. *Table 5* below showed the characteristics of the micelle solutions.

Table 5 Micelle solution characteristics

Formula	Surf. Conc., %wa	SL 11, Molar	nC_4OH, %v	NaCL, %w	ME phase	Equilibration
50406A	1.0	0.4M	2.5	2.0	m-phase	2 phase
50406B	1.5	0.4M	2.0	2.0	m-phase	m-phase
50928A	1.0	0.5M	2.0	2.0	2-phase	Slow separation
50928B	1.0	0.1M	2.5	2.0	2-phase	Very slow separation
50928C	1.0	0.5M	2.5	2.0	m-phase	Very slow separation
50928D	1.5	0.1M	2.5	2.0	m-phase	Slow separation
50928E	1.5	0.5M	2.5	2.0	m-phase	Fast separation
50928F	1.5	0.1M	2.5	5.0	m-phase	Fast separation
50928G	1.5	0.5M	2.5	5.0	m-phase	Fast separation

A cleaning experiment test procedure consisted of taking a fouled membrane and using the experimental apparatus diagram in *Figure 1* and running the step by step procedure below:

1. Add RO water to feed tank. Flush membrane system (no recycle) with clean RO water specified rinse flow rate for *t* minutes and minimum pressure (fully open back pressure valve). Record average temperature and pH over specified time.

2. Flush membrane system (concentrate recycle) with clean RO water specified rinse flow rate for *t* minutes and minimum pressure. Record average temperature and pH over specified time.

3. Drain system

4. Add RO water to feed tank. Run system taking clean water flux data over range of pressures at 3.8 LPM flow rate.

5. Record flux data and plot with temperature correction for viscosity.

6. Drain system

7. Add 2L of cleaning solution to feed tank. Run cleaning chemical solution over system (concentrate recycle) for *t* min at specified operating flow rate and minimum pressure. Record average temperature and pH over specified time.

8. Drain system

9. Add RO water to feed tank. Flush system (no recycle) for *t* minutes with clean RO water at specified rinse flow rate and minimum pressure.

10. Flush system (concentrate recycle) for *t* minutes at rinsing flow rate and minimum pressure

11. Drain system.

12. Add RO water to feed tank. Run system taking clean water flux test over range of pressures at 3.8 LPM flow rate.

13. Record flux data and plot with temperature correction and compare to new clean flux data and to Step 4 data.

Step 1 and 9 were performed without any recycling of the RO water to reduce mixing of fouling water or cleaning solution and Step 2 and 10 were performed with concentrate recycle specifying the time and flow rate while monitoring pH and temperature of feed through the instrumentation shown in *Figure 1*. Then, Step 4 and 12 were conducted by using a stopwatch and graduated cylinder for permeate flow rate measurements at the specified TMP and 3.8 LPM flow rate. Permeate flow rate measurements were taken over a range of at least 5 TMP pressures suggested by the membrane manufacturers from 69 to 345 kPa to obtain a pure water flux versus TMP plot. During the permeate flow rate measurements, pH and inlet and outlet temperatures were recorded.

4.3.2.2. Analysis of the cleaning effectiveness.

The cleaning effectiveness was determined by comparing the un-cleaned flux to the cleaned flux, since the fouling conditions were assumed not a factor. To calculate the flux the permeate flow rate is divided by the membrane area. After initial flux calculation, the flux was adjusted or corrected to a specified temperature of 298 K by viscosity for baseline comparisons. Simple linear regressions were used to analyze the corrected flux curves. Linear regressions were used to predict pure water flux rate at three specified TMP for the un-cleaned, cleaned, and the new flux curves. The predicated pure water flux rate were used to calculate ratios of cleaned flux to un-cleaned flux, un-cleaned flux to new clean flux, and un-cleaned flux to cleaned flux at the 3 specified TMP. The ratios obtained at each specified TMP were averaged to provide overall flux ratio for cleaned to un-cleaned, cleaned to new, un-cleaned to new, and the cleaning effectiveness calculated according to *Eq. 2*.

$$Cleaning\ \ Effectiveness\ \ (\%) = \left(1 - Avg(\frac{uncleaned\ \ flux}{cleaned\ \ flux})\right) * 100 \qquad (2)$$

The cleaning effectiveness percentage showed percentage improvement provided by the cleaning solution and procedure over the un-cleaned flux. The percentage calculated the effect of cleaning the membrane while neglecting the amount of fouling that was obtained by the fouling conditions.

4.3.3. Membranes testing

4.3.3.1. Micelle solution formulation experiments

The first series of cleaning tests, Experiments 1-9, were testing the differences between the micelle micro emulsion solutions. This series is conducted using the above procedure with each test being conducted on the same membrane under the identical cleaning parameters of flow rates and time as indicated in *Table 6*.

Table 6 Micelle solution test conditions

Experiment Test	1	2	3	4	5	6	7	8	9
Micelle formula	50406A	50406B	50928A	50928B	50928C	50928D	50928E	50929F	50929G
No recycle Rinse before Cleaning Cycle duration (min)	1	1	1	1	1	1	1	1	1
Recycling Rinse before Cleaning duration (min)	5	5	5	5	5	5	5	5	5
Rinse Solution Flow Rate (LPM)	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8

Cleaning Cycle duration (min)	15	15	15	15	15	15	15	15	15
Cleaning Solution Flow rate (LPM)	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
No recycle Rinse after Cleaning Cycle duration (min)	1	1	1	1	1	1	1	1	1
Recycling Rinse after Cleaning Cycle duration (min)	5	5	5	5	5	5	5	5	5
Membrane	JW	JW	JW	JW	JW	JW	JW	JW	JW

4.3.3.2. Flow rate experiments

The next series of experiments, Experiments 10-18, consisted of using the best two micelle solutions from the first test series and performing threes sets of three flow experiment tests. The first set of three experiments was performed on the JW membrane and used the 50928A formula where three flow rates for the cleaning solution were tested within the set. The second set consisted of the utilization of the same three flow rates and the 50928A formula but were performed on the 5k membrane. The last set was conducted on the 5k membrane and the three flow rates but utilized a different formula 50406B. All three sets were conducted using the same specified cleaning parameters for rinse flow rate, rinse time, and cleaning time as shown in *Table 7*. These sets of experiments tested the effect shear stress or cross flow rate for the cleaning solution effectiveness. This series of tests also considered whether the different formulas had different or corresponding effect on cleaning performance and flow rate effect and whether the different membranes showed similar performance trends.

Table 7 Flow rate Experiments parameters

Experiment Test	10	11	12	13	14	15	16	17	18
Micelle formula	50928A	50928A	50928A	50928A	50928A	50928A	50406B	50406B	50406B
No recycle Rinse before Cleaning Cycle duration (min)	1	1	1	1	1	1	1	1	1
Recycling Rinse before Cleaning Cycle duration (min)	5	5	5	5	5	5	5	5	5
Rinse Solution Flow Rate (LPM)	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Cleaning Cycle duration (min)	15	15	15	15	15	15	15	15	15

Cleaning Solution Flow rate (LPM)	1.9	3.8	7.6	1.9	3.8	7.6	1.9	3.8	7.6
No recycle Rinse after Cleaning Cycle duration (min)	1	1	1	1	1	1	1	1	1
Recycling Rinse after Cleaning Cycle duration (min)	5	5	5	5	5	5	5	5	5
Membrane	JW	JW	JW	5k	5k	5k	5k	5k	5k

4.3.3.3. Contact time experiments.

The next series of tests consisted of two additional cleaning experiments, Experiment 19 and 20. This series tested the cleaning solution contact time or duration. The tests were to evaluate whether time of cleaning solution contact was a factor and can improve performance. The tests were performed following the cleaning procedure and under the baseline cleaning parameters for rinse flow rate, rinse time, cleaning flow rate shown for Experiments 2 shown in *Table 6.* The only test condition that was changed was the cleaning time was doubled to 30 minutes and that the test was repeated. The contact time could cause an increase in effectiveness by increasing the chemical solubilization of the fouling layers.

4.3.3.4. Water rinsing experiments

The last series of cleaning tests conducted evaluated the changing of the rinse duration and flow rates to see if any effect was seen of the micro emulsion solution being maintained on the membrane and reducing the actual effectiveness of the cleaning cycle. The tests were conducted to form sets of experiments to coincide with previous tests, Experiment 17 and 18 shown in *Table 7,* to test the rinse flow rate effect with similar conditions for comparison. The experiments in *Table 8* along with Experiment 17 and 18 tested whether doubling the rinse time and flow rate before and after the cleaning cycle added any notable effect on performance.

Table 8 Water rinsing experimental test conditions

Experiment Test	21	22	23	24	25	26	27	28
Micelle formula	50406B	50406B	50406B	50406B	50928C	50928C	50928C	50928C
No recycle Rinse before Cleaning Cycle duration (min)	1	1	1	2	1	1	2	2
Recycling Rinse before Cleaning Cycle duration	5	5	5	10	5	5	10	10

(min)								
Rinse Solution Flow Rate (LPM)	7.6	7.6	3.8	3.8	3.8	7.6	3.8	7.6
Cleaning Cycle duration (min)	15	15	15	15	15	15	15	15
Cleaning Solution Flow rate (LPM) Reynolds Number	3.8	7.6	3.8	3.8	3.8	3.8	3.8	3.8
No recycle Rinse after Cleaning Cycle duration (min)	1	1	1	2	1	1	2	2
Recycling Rinse after Cleaning Cycle duration (min)	5	5	5	10	5	5	10	10
Membrane	5k	5k	BN	BN	BN	BN	BN	BN

The different sets consists of changing one other variable along rinse flow rate or time to make direct comparisons on performance changes and to notice any trends or slight variation on the rinse effect to the other parameters.

4.3.3.5. Comparison of membrane type effect on cleaning effectiveness

The last set of experiments and analysis consists of analyzing the data to make comparison on which membrane type was cleaned more effectively. The set of experiments consisted of the baseline test conditions of Experiments 1-9 with changing only the membrane type and utilizing the same micelle solution. The analysis also included analysis whether different membranes showed different effects for rinsing affects or cleaning flow rates. This analysis tested the suitability of the micelle solution for wide varieties of PVDF ultrafiltration membranes. The analysis also examines the cleaning solution temperature provided by ambient conditions.

4.4. Results

4.4.1. Micelle solution test series

The flux measurement results from Experiment 1 are shown below:

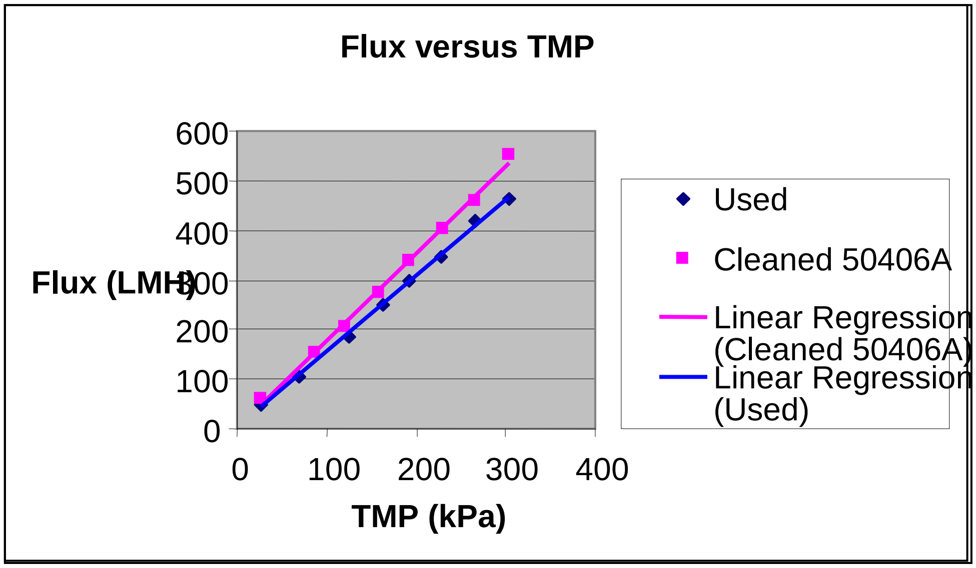


Figure 7 Experiment 1 Pure water flux curves. The flux measurements were measured and adjusted to 298K.

Graphs similar to *Figure 7* were utilized to compare and analyze each individual experiment and to calculate the average ratios of cleaned to used, cleaned to new, used to new, and cleaning effectiveness as percentage of unclean to clean. The ratios are averaged over the 3 different points on the flux curve and provided in *Table 9.*

Table 9 Micelle formula testing results

Experiment Test		1	2	3	4	5	6	7	8	9
Micelle formula		50406A	50406B	50928A	50928B	50928C	50928D	50928E	50929F	50929G
Membrane		JW	JW	JW	JW	JW	JW	JW	JW	JW
Cleaning Solution	Flow Rate (LPM)	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
	Reynolds Number	653	859	875	857	900	932	825	803	792
	Temperature (K)	299	296	297	296	298	299	294	293	292
	pH	6.3	5.9	6.0	6.6	5.8	7.1	6.0	7.0	6.5
Clean flux/ Used flux		1.15	4.86	7.53	2.16	2.78	1.32	2.16	1.34	1.3

Clean flux/ New flux	1.44	1.68	1.62	1.46	0.98	0.96	0.52	0.31	0.62
Used flux/ New flux	1.25	0.35	0.21	0.68	0.36	0.77	0.25	0.25	0.48
Cleaning Effectiveness (%)	12.9	79.3	86.7	53.6	63.8	20.6	52.5	19.4	23.2

Note: All experiments were conducted under rinse flow rate, before and after cleaning total rinse time, cleaning time of 3.8 LPM, 12 minutes, and 15 minutes, respectively

4.4.2. Cleaning solution flow rate test series

The results of the cleaning flow rates tests for formula 50406B and 50928A are summarized in *Table 10* based on linear regression flux curves and averaged ratios as done previously. *Table 10* also shows the effect of different membrane types on the micelle solution performance.

Table 10 Cleaning flow rate effect on performance results

Experiment Test		10	11	12	13	14	15	16	17	18
Micelle formula		50928A	50928A	50928A	50928A	50928A	50928A	50406B	50406B	50406B
Membrane		JW	JW	JW	5k	5k	5k	5k	5k	5k
Cleaning Solution	Flow Rate (LPM)	1.9	3.8	7.6	1.9	3.8	7.6	1.9	3.8	7.6
	Reynolds Number	396	825	1562	418	825	1766	407	770	1606
	Temperature (K)	292	294	292	295	294	297	294	291	293
	pH	6.5	6.5	6.3	6.5	6.5	6.5	6.5	6.4	6.5
Clean flux/ Used flux		1.26	1.64	1.72	1.13	1.00	1.00	1.10	1.33	0.92
Clean flux/ New flux		0.63	0.59	0.70	0.30	0.46	0.28	0.34	0.39	0.35
Used flux/ New flux		0.50	0.36	0.41	0.27	0.46	0.28	0.32	0.30	0.38
Cleaning Effectiveness (%)		20.6	38.9	41.7	11.3	0.0	-0.4	7.8	24.1	-9.1

Note: All experiments were conducted under rinse flow rate, before and after cleaning total rinse time, cleaning time of 3.8 LPM, 12 minutes, and 15 minutes, respectively

4.4.3. Contact time test series

The test series consisted of repeated tests, Experiment 19 and 20, and the results of Experiment 2 to investigate the effect of doubling the contact time for the cleaning micelle solution. The repeated experiments were conducted under Experiment 2 cleaning parameters for rinse flow rate, rinse time, and for cleaning flow rate. The experiments resulted in cleaning effectiveness for Experiment 19 and 20 of 82.7% and 77.2 %, respectively. The clean flux to un-cleaned flux ratios were 5.77 and 4.40, respectively. The clean to new flux ratios for set were 1.38 and 2.80. The unclean to new flux ratios for Experiment 19 and 20 were 0.24 and 0.64, respectively.

4.4.4. Water rinse test series

Water rinse effects on cleaning results are shown in *Table 11*.

Table 11 Rinse water parameter affect on performance results

Experiment Test		17	18	21	22	23	24	25	26	27	28
Micelle formula		50406B	50406B	50406B	50406B	50406B	50406B	50928C	50928C	50928C	50928C
Membrane		5k	5k	5k	5k	BN	BN	BN	BN	BN	BN
Cleaning Solution	Flow Rate (LPM)	3.8	7.6	3.8	7.6	3.8	3.8	3.8	3.8	3.8	3.8
	Reynolds Number	770	1606	848	1529	848	792	792	825	770	814
	Temperature (K)	291	293	295	291	295	292	292	294	291	294
	pH	6.4	6.5	6.5	6.5	6.5	6.0	6.0	6.5	6.5	6.0
Rinse Solution	Flow Rate (LPM)	3.8	3.8	7.6	7.6	3.8	3.8	3.8	7.6	3.8	7.6
	Reynolds Number	765	797	1711	1626	842	765	762	1657	775	1663
Rinse solution Total Contact time (min)		12	12	12	12	12	24	12	12	24	24
Clean flux/ Used flux		1.33	0.92	0.98	1.24	3.62	2.10	2.71	1.95	3.02	2.87
Clean flux/ New flux		0.39	0.35	0.34	0.31	0.87	0.47	0.61	0.87	0.58	0.58
Used flux/ New flux		0.30	0.38	0.35	0.25	0.24	0.23	0.23	0.45	0.19	0.25
Cleaning Effectiveness (%)		24.1	-9.1	-2.2	18.4	71.7	50.5	62.5	48.6	65.9	58.2

Note: All experiments conducted under a cleaning time of and 15 minutes.

4.4.5. Membrane type and ambient temperature effect

The general effectiveness of the micelle cleaning solution for each membrane type, see *Table 2*, was shown under the same test conditions in Experiments 2, 17, and 23. The cleaning effectiveness for this set of experiments was 79.3%, 24.1%, and 71.7%, respectively. Also, Experiments 10-15 indicated that the membrane type was a factor on how changing cleaning flow rates affected cleaning solution effectiveness. The membrane type effect was indicated by the difference in the effect of the cleaning flow rate for Experiments 10-12 on the JW membrane and the effect shown for Experiments 13-15 for the 5k membrane.

4.5. Discussion

4.5.1. Micelle solution test series

The results from the first series of tests were shown in *Table 7* and indicate that Experiment 2 and 3 showed the best results with highest cleaning effectiveness percentage and cleaned to un-cleaned flux ratios. In 1994, Lindau and Jonsson reported acid and basic cleaning of oily water membranes cleaned to un-cleaned flux ratio of 1.3 and 1.4, respectively [11].The data in *Table 7* indicates that the performance of the micelle solution in Experiments 2, 3, and 5 were significantly better than for acid or basic solution cleaning of oily water fouled membranes.

Micelle formulas 50406B, 50928A, and 50928C chemically reacted to the oilfield brine fouled membrane and achieving better cleaning effectiveness by dissolving the oil particulates on the surface of the fouled membrane into the micelle solution. The data shows that cleaning of produced water fouled ultrafiltration membranes with micelle is feasible and more effective than reported in the literature for standard acid and basic cleaning of such fouled membranes. The results also indicate the micelle solution can be optimized to obtain the desired oil and water properties to enhance the performance of the solution.

4.5.2. Cleaning solution flow rate test series

The results of Experiments 10-18 indicated that there might be a maximum or optimum effective cleaning flow rate for the micelle solution for produced water fouled membranes. The change in cleaning effectiveness indicated that increasing cleaning flow rate improves performance for Experiments 10-12 but only to a point shown by Experiments 13-15 for micelle solution 50928A. Solution 50406B and Experiments 16-18 also showed that increased flow rate improves performance to a point that then reduced performance. These experiments indicated the point at which cleaning flow maximizes cleaning effectiveness is dependent on the specific membrane and the micelle solution formula. The membranes affected the cleaning flow rate effect by how tight the membrane was and whether the micelle solution penetrates within the membrane by the increased flow rate.

Experiment 11 and 12 for the micelle solution also indicated that increasing the cleaning flow rate above the rates of the fouling solution flow rates (see *Table 6*) show only marginal cleaning effectiveness improvement from 38.9% to 41.7%. This result along with Experiments 15 and 18 indicates that increasing micelle solution cleaning above the operation flow is not necessary or significantly beneficial to cleaning effectiveness. Cleaning flow rates above the operational flow rates for Experiment 15 and 18 yielded cleaning effectiveness of- 0.4% and -9.1% respectively or a flux reduction due to the cleaning cycle.

4.5.3. Micelle solution contact time test series

Experiment 2 and repeated experiments for doubling the contact time of the micelle solution Experiments 19 and 20 indicated that no significant effect on the cleaning performance was achieved by the increased contact time. The three experiments, Experiments 2, 19-20, resulted in cleaning effectiveness of 79.3%, 82.7%, and 77.2%, respectively. The three experiments showed little if any change in effectiveness between the repeated longer contact time tests and Experiment 2 that would not be expected for repeated experiments. The set of three experiments show the reaction time of the micelle solution is not the limiting factor on the cleaning effectiveness. The experiments indicated the cleaning flow rate described earlier has a greater effect on performance than contact time.

4.5.4. Water rinse test series

Comparison of results obtained between Experiments 17 and 21, 18 and 22, and between Experiment 25 and 26 indicates the effect of doubling the rinse water flow rates from 3.8 LPM to 7.6 LPM. The data indicates that doubling the water rinse flow rate for the cleaning cycle greatly reduces the effectiveness of the cleaning solution unless the micelle solution flow rate was also doubled. Previous experimental series data indicated that increasing the cleaning solution flow rate above the operational condition of fouling was not beneficial. The combined effect of these facts indicate that for the micelle solution, the cleaning flow rate and the rinse flow rate should be the same for the most effective cleaning cycle. These results in the conclusion that turbulent flow effects of higher cross flows had no significant advantage on cleaning effectiveness for the micelle solution. The micelle solution cleaning cycle flow rate should be determined by the membrane specification on size or by the separation flow rate used during operation of the membrane.

Experimental data comparison shows that rinse cycle flow rate does have an effect on the cleaning effectiveness shown in *Figure 8*.

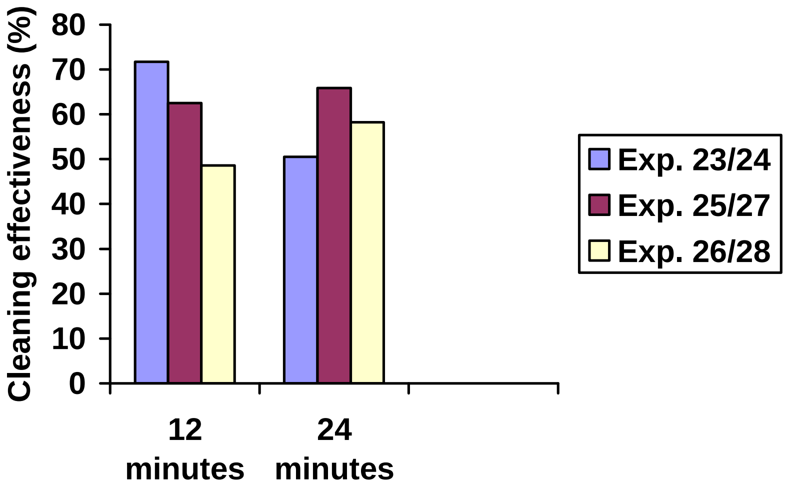


Figure 8 Rinse time comparisons

Figure 8 shows that for the micelle solution the rinse contact time effect depends on the specific micelle formulation and on the actual rinse flow rate. The comparison indicates that for higher rinse flow rates the effect of doubling the duration of the rinse increases the improvement on the cleaning effectiveness. The data indicated that the longer rinse times provided better cleaning effectiveness through improving removal of residual left by the brine and cleaning solutions on the membrane surface.

4.5.5. Comparison of micelle solution general effectiveness on different membranes

Micellar solution cleaning was effective for all membranes tested. The general cleaning performance was better than the standard cleaning with heated acidic and basic solutions. Micellar systems showed better performance on higher molecular weight cutoff (MWCO) ultrafiltration membranes. The systems worked the best on the BN and JW membranes with an approximately 30,000 MWCO. The data showed that micelle solution generally behaved the same for each membrane type. The only effect that was indicated by the different membranes was the limit on cleaning flow rate for the tighter membranes tested.

The average temperature of the micelle solution during cleaning for all experiments was monitored. The temperature of the cleaning solution, a factor in cleaning performance, was not controlled and dictated by ambient test conditions and heat added due to the pump and line friction was within range 10K for all tests conducted.

4.6. Conclusions

Micellar solutions were effective in cleaning the produced water fouled membranes. The results indicated that the micelle solution can be optimized to perform better on the produced water fouled membranes according to micro emulsion properties. The results showed that the micelle solution performed better on 30,000 MWCO ultrafiltration membranes than with the tighter 5,000 MWCO membrane. The study showed that the four cleaning cycle parameters affected the micellar system performance.

The four parameters for optimization of the micelle system were the micelle formula, the cleaning flow rate influenced by the MWCO, rinse duration, and the membrane type. The micelle solution formula had the most effect on performance, followed by the membrane type or size, then the cleaning flow rate, and last the duration of the water rinses. Cleaning flow rate and water rinse duration showed significant improvement on the base level of cleaning effectiveness of the solution on a membrane type.

The micelle solution does provide greatly improved cleaning performance for produced water or oily water fouled membranes over the standard cleaning solution of acid and basic solution typically employed by the membrane industry. The cleaning temperature utilized yielded that a micelle solution can be formulated to operate at ambient conditions and to eliminate the requirement of a heat source for an onsite membrane unit. With optimization, a micelle cleaning solution can provide a very cost effective solution to cleaning oily water fouled membranes at ambient temperature.

5. SUMMARY CONCLUSIONS

The first objective of the study was to evaluate the use of three commercial membranes, JW, 5k, and BN, for the pretreatment of produced water. The study conducted showed that PVDF ultrafiltration membranes could provide treatment to less than 5 NTU for subsequent desalination for an onsite produced water treatment system. The results showed that the turbidity removal ranged for JW, 5k, and BN ultrafiltration membranes were 99.27% to 99.87%, 95.75% to 99.82%, and 99.71% to 99.82%, respectively. The study showed that the oil removal ranged for JW, 5k, and BN ultrafiltration membranes were 59.52% to 90.43%, 47.32% to 87.27%, and 78.20% to 94.31%, respectively. BN membrane would be the best membrane available for the treatment of the produced water to meet feed specification for desalination. The data also indicated that for the BN membrane no effect was shown for operation parameters of TMP and feed flow rate on water quality. The 5k and the JW membranes showed TMP and feed flow rate affected the water quality performance of the membrane.

The second objective focused on the cleaning of produced water fouled membranes by micelle solution. The study consisted of using linear regression to calculate average flux ratios and cleaning effectiveness. The data showed that the use of a micelle solution to clean the produced water fouled membranes was a feasible and effective method. The study show that the micelle solution performed better than acidic and basic solutions reported in the literature for this type of foulant. The study showed with further adjustment of the micelle solution the cleaning effectiveness could be optimized for an ambient temperature cleaning of membranes.

The last objective was to determine the micellar solution cleanup under varying operation parameters. The parameters were the membrane type or size, cleaning flow rate, cleaning duration, rinse flow rate, and rinse duration. The studied showed that for the micelle solution the cleaning effectiveness was not affected by cleaning duration or the rinse flow rate. The study did demonstrate that the cleaning flow rate improved performance but was limited by membrane type or MWCO. The results also indicate that increasing the duration of the rinse before and after cleaning improved the overall effectiveness of the micelle solution cleaning of the produced water fouled membranes.

6. RECOMMENDATIONS

Based on the first study, the use of the BN membrane should be field tested on a pilot plant for the pretreatment of produced water. The BN membrane should be field tested for treatment effectiveness over longer periods. Investigation into the mechanism of fouling of the ultrafiltration membrane by the produced water to explore the two rate of fouling decay observed during the study. Additional studies on the water quality obtained by the membranes should be conducted checking for removal of the other contaminates found in produced water sources. Investigation of hollow fiber membranes for the treatment should be studied and compared to the data obtained for spiral membranes. The micelle solution needs to be field tested on pilot equipment. The micelle solution needs further optimization for cleaning produced water fouled membranes. Studies need to be performed how long the cleaning solution will remain effective in cleaning the membranes. Also, testing of higher pH micelle solutions for improved membrane cleaning effectiveness

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Approved by:

Co-Chairs of Committee,	Roy Hann, Jr.
	David Burnett
Committee Members,	Jean-Louis Briaud
	Ronald Kaiser
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Head of Department,	David Rosowsky

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Major Subject: Civil Engineering

ABSTRACT

Application of Membranes to Treatment of Water Based Exploration

and Production Wastes. (August 2009)

Oluwaseun Alfred Olatubi, B.S., University of Ibadan;

M.S., Texas A&M University,

Co-Chairs of Advisory Committee: Dr. Roy Hann Jr.
David Burnett

Produced water and spent drilling fluids from petroleum operations represent a significant expense to companies developing new energy reserves. These spent fluids, seldom recycled, offer a viable source of water resources for oil-field reuse. A major obstacle to reuse is the presence of suspended solid material in the fluids. Such contaminants, if not removed, will not only prevent any reuse but will also impede disposal. The objective of this project was to evaluate membrane filtration as a way to remove suspended and entrained particles to produce re-useable effluents using membranes. Ceramic and Polyvinylidene Flouride (PVDF) hollow fibre membranes were used in laboratory scale experiments in the investigation of the colloidal filtration of field produced spent drilling fluids and produced water.

Feed parameter and operational parameter evaluation of ceramic and PVDF hollow fibre membrane filtration of spent drilling fluids and produced water showed that feed concentration, solids in the spent drilling fluid and oil in the produced water, is the most important parameter during membrane filtration. Operational parameter variation showed that high cross flow velocity was beneficial in flux maintenance during spent drilling fluid filtration due to its high solids concentration because of the scouring effect on the cake layer on the membrane surface. Pressure regimens were important in flux decline as relatively high pressures accelerate the consolidation of the concentration polarization layer causing flux decline. High temperatures were generally beneficial for increased flux in the filtration of produced water and spent drilling fluids.

Resistance calculations were used to deduce the contribution of individual resistances during the ceramic filtration of produced water and spent drilling fluids and were identified as a real-time tool for monitoring membrane integrity and fouling. Backwashing as a fouling mitigation technique was effective in flux maintenance in ceramic membranes especially in the filtration of produced water; cleaning solutions were effective in flux recovery in ceramic membrane filtration and to a slightly lesser degree in hollow fibre membrane filtration. A methodology in determining the suitability of water based oil field wastes using membranes was developed to help future investigations of this type.

DEDICATION

To my God and my god. God the Almighty, the Father of the fatherless. My god, my mother Agnes Omodunke Olatubi

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CHAPTER I

INTRODUCTION

1.1 Introduction

[1]Exploration and production (E&P) operations in the oil industry are usually large scale operations that produce large footprints ecologically. Over the years the challenge to the oil and gas industry has been to minimize the foot print of its operations to fit the growing public and regulatory environmental consciousness as well as provide good stewardship to the environment. To this end the Department of Energy (DOE), academia, oil producing companies, oil servicing companies, regulatory agencies, environmental groups and other stakeholders formed the Environmentally Friendly Exploration and Production program. This initiative is designed at integrating advanced technologies into systems that significantly reduce the impact of petroleum drilling and production in environmentally sensitive areas.

The objective of this program is to identify, develop and demonstrate cost effective technologies that reduce environmental tradeoffs that may allow operations in environmentally sensitive areas that are currently off limits. The Environmental Friendly Exploration and Production group decided in its first phase to focus on making drilling more environmentally friendly. To this respect the Environmentally Friendly Drilling (EFD) initiative arose as a subset of the Environmentally Friendly Exploration and Production program. The EFD is focused on developing and demonstrating cost effective technologies that reduce the footprint of drilling operations and in doing this defined some broad criteria about the environment and technology. It ruled that every environment is to be viewed as sensitive, that technologies that reduce footprint of drilling operations sustainably shall be investigated and developed.

The issue of water based wastes particularly produced water and water based drilling fluids is an area of interest to the EFD. The management and disposal of these wastes (produced water and water based drilling fluid) creates large footprints in E&P operations and

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This dissertation follows the style of the Journal of Membrane Science.

is of environmental concern due to low amount of recycle and re-use apart from the burgeoning issue of freshwater scarcity. The EFD in tackling these wastes set out to first reduce the footprint of these wastes and also increase the amount of re-use in either oil and gas operations or for non oil field or related non-consumption uses. To this effect this thesis is an investigation into one of the technologies aimed at reducing the footprint of water based wastes and increasing their re-use for oil-field applications.

The objective of this thesis is the investigation of membrane technology in the treatment of produced water and spent water based drilling fluids in order to achieve colloidal and suspended particle filtration. This thesis also aims to achieve volume reduction of the wastes and at the same time produce effluents that could be re-used in oil-field applications. This thesis puts forward the hypothesis that solids (colloids and suspended particles) removal from water based wastes in the colloidal and particle range made possible by using membranes is a key step to re-use and waste volume concentration. It investigates using membrane technology to provide empirical evidence of filtration of water based exploration and production (E&P) wastes in producing effluents that can be re-used.

1.2 Introduction to Drilling

In the exploration and production of oil and gas, the act of drilling commences after various pre-drilling activities such as seismic evaluation, reservoir evaluation, drilling program design, and other well development and production activities needed to ensure successful exploration and production. Drilling primarily entails the use of a drilling bit to make a hole. In drilling for oil and gas the hole could be drilled for various reasons, it could be to discover new petroleum reserves (wildcat) or to exploit known petroleum reserves (development well). Development wells are the types of wells referred to throughout this thesis [1].

Drilling can occur offshore and on-shore. Offshore being in territorial waters notable worldwide offshore drilling locations include the gulf coast in America and the North Sea in Europe. Onshore drilling on the other hand involves drilling on land, there are more onshore drilling operations worldwide than offshore drilling operations for various reasons chief amongst which is cost as considerable resources are mobilized and expended in offshore drilling operations. Offshore exploration and production is primarily executed by multinational corporations and national governments while onshore drilling though capital intensive is relatively inexpensive and is carried out by various interests from independent producers to corporations.

Various equipment are used in drilling operations and could be generally classified based on their function, they include drilling rigs, rig power equipment, hoisting equipment , circulating system equipment and rotary system equipment. A drilling rig is a machine used to drill the wellbore [2], it usually entails every equipment in the drilling process apart from the living quarters. Onshore drilling rig types includes the conventional rig or the mobile rig such as the Jackknife or Cantilever rig while offshore rig types are either the bottom support type rigs such as the Jackup rig or the floating rig type such as the semisubmersible rigs or the drill ships. Rig power equipment consists mainly of the internal-combustion diesel engines which could either be the diesel-electric type or the direct-drive type [2], their basic function is to generate power for drilling operations. Most rig power is consumed by hoisting and fluid circulation system, and total power requirements for most rigs is between 1,000 to 3,000 hp [2].

Rig hoisting equipment include the derrick and the block and tackle which consists of the draw works, the crown block, the travelling line, the anchor, storage reel and the drilling lines. Hoisting equipment function in raising and lowering of drill strings, casing strings and other associated drilling equipment inside and outside the hole. The rig circulating system equipment includes the mud pumps, mud mixing equipment, solids control equipment such as centrifuges, hydrocyclones and other contaminant removal equipment. The circulation system functions primarily to pump drilling mud and for the removal of solids. The rotation of the bit could be achieved using a conventional rotary table and Kelly system which includes equipment such as the Kelly, Kelly bushing, rotary drive, rotary table and swivel or a topdrive system could be used in which hydraulic or electric motors are used for achieving bit rotation. The Kelly systems are more common in most onshore drilling rigs in America. Figure 1.1 shows the schematic of a rotary drilling rig.

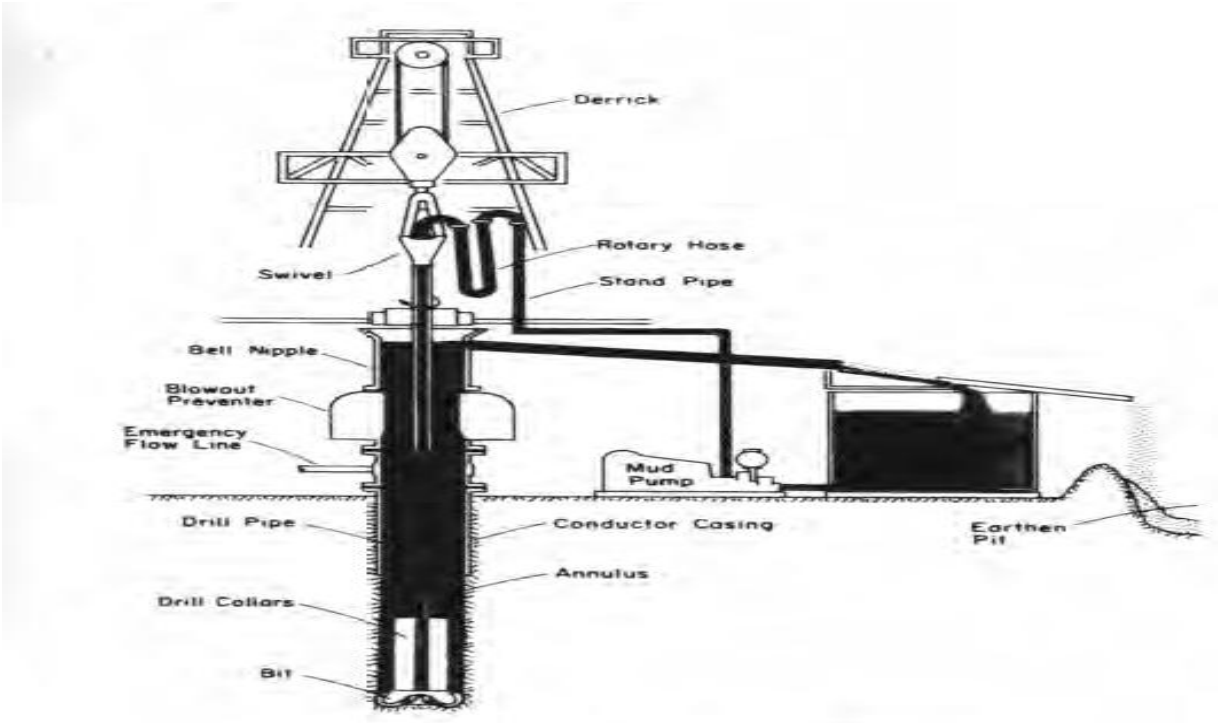

Fig. 1. 1 Schematic of a rotary drilling rig [2].

In the last thirty (30) years drilling technology has gone through significant technological changes resulting in smaller rigs but wider subsurface reach. Innovations such as horizontal drilling i.e. drilling where the well bore is more than eighty degrees (80^0) from the vertical has helped reduced significantly surface disturbance of drilling activities while still enabling the optimization of oil and gas exploitation. Figure 1.2 show us the progress made in rig sizes in the last thirty years, it shows a seventy percent (70%) reduction in rig size and a six thousand four hundred percent (6400%) increase in the subsurface drillable area for wells with about 10,000 ft depth.

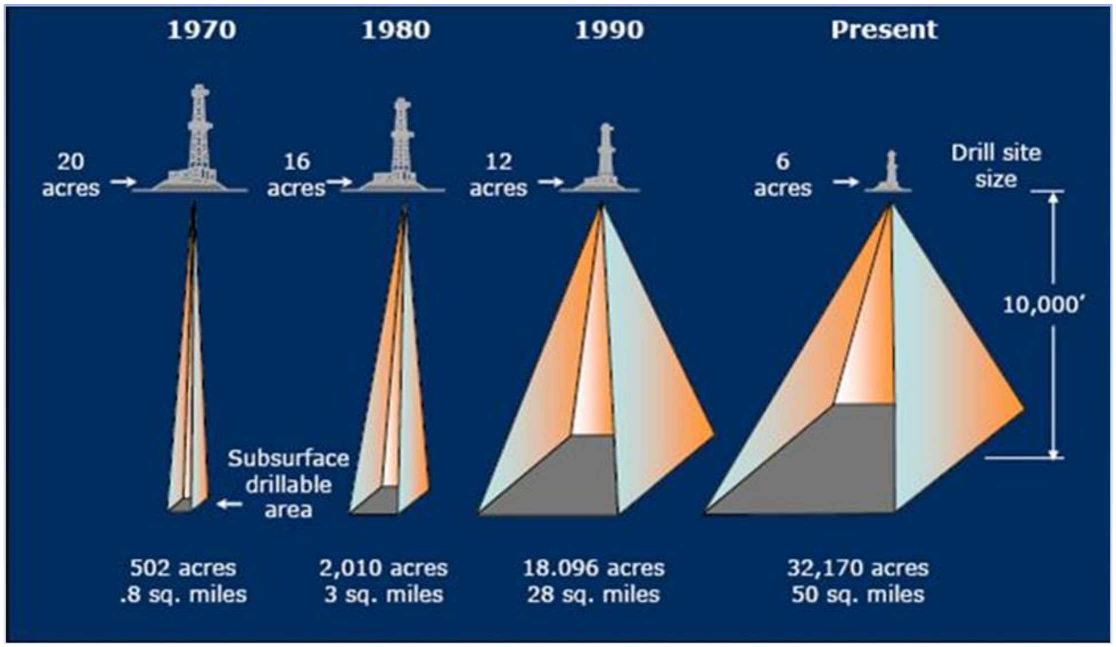

Fig. 1. 2 Subsurface reach and rig sizes in the last thirty years [13].

Though this surface reduction translates to less surface area or ecosystem disturbance in drilling operations, the wider subsurface reach means that there would be an increase in the amount of drilling wastes generated due to increased subsurface reach. In handling wastes generated from this wider subsurface reach the gains made in surface reduction are offset as waste holding, hauling and treatment facilities such as reserve pits increase the total surface area associated with drilling operations significantly impacting the environment in this present age than thirty (30) years ago.

To achieve reduced impact of drilling operations, technological innovations or practices that make rigs smaller would not reduce the impact or footprint of drilling operations alone if there are no corresponding technologies to deal with compacting the waste volume generated by wider subsurface reach. To optimize smart rig technology and drilling practices, there is a need to investigate and develop technologies that promote waste volume reduction, recycling and re-use of water based wastes rather than improving disposal technologies such as slurry or produced water injection.

1.3 Energy and Future Demand

The energy question is increasingly becoming the most important question of this present age, with growing populations especially those of South East Asia and their attendant energy demand the issue of energy has been thrust as a front burner issue globally. The search for energy to meet present demands and future forecasts is becoming more intense and more diversified than ever as alternative energy sources are vigorously investigated. Sources such as renewable fuels, solar energy, wind energy, geothermal energy and hydrogen are being developed to meet the growing energy needs worldwide.

Despite this diversification of sources to meet the global energy demand, wholesale adoption of alternate energy sources have limitations either due to cost, scale, newness of technology, reliability and or efficiency. These challenges faced by alternate energy sources still makes crude oil and coal the prime energy sources today. The relative low cost of coal and crude oil, widespread use and technological advancements in their exploitation makes them very competitive. Despite the huge drive towards alternative sources of energy, exploration and production activities regarding oil has increased dramatically in the past five years with crude oil barrel prices hovering near $100 dollars per barrel in the summer of 2008 compared to about $12-$13 per barrel a decade ago [3].

The Exploration and Production (E&P) industry is expected to witness significant growth through the year 2020. Conservative projections estimate the expected growth not to be less that 1.5 % per year with the most probable projection bordering on 2% per year [4]. Average prices are expected to rise at a higher rate over the next 10-15 years than over the past 10-15 years signifying increased opportunities and capabilities in the oil industry as the opportunity for substantially more revenues per barrel of oil equivalent is produced [5]. Projections for demand for petroleum products is upward, gas consumption in the US will increase by 41% from 2000 to 2025 while oil consumption would increase by a smaller margin i.e. 27% during that same period [4]. Rig count was currently on the rise [6] before the present socio-economic downturn.

Conservative projections show that globally oil demand would continue to rise particularly in South East Asia and developing economies. Social and economic changes would drive demand for more modern conveniences such as automobiles, electrical appliances and travel all fueled by the vast global communication expansion which would result in greater energy usage. It is expected that by the end of the decade the demand for oil will be nearly 100 million barrels per day [7]. For the US, currently the largest energy consumer in the world, these consumption trends translates to increased competition for global energy markets as studies show that oil rich nations are using more energy and cutting exports [4] due to increasing needs in their nations shrinking available exports to traditional customers such as the US.

This increased global energy demand is leading to increased exploration and production activities (E&P) worldwide. Statistics from the American Petroleum Institute (API) show that there are about 1,801 active rotary rigs in the US as of November 2007 compared to a 2006 average of 1,649 [6]. Due to increasing natural gas demand, the Energy Information Administration (EIA) projects that 22,000 gas wells will have to be drilled by 2020 up substantially from the 15,200 wells successfully drilled and completed in 2000 [8]. This increased drilling activity is not confined to the US but is global, as increased drilling activities are evident in all producing regions worldwide. There is also a recognizable growth in increased stimulation techniques for existing oil wells to maximize yield as there continues to be further development and research into stimulation techniques for greater oil and gas recovery.

Increased demand for energy and rising energy prices have renewed interest in unconventional oil resources. Unconventional oil resources is an encompassing term for oil resources that are generally more challenging to extract than conventional oil, examples are tar-sands, heavy-oil, bitumen and oil-shale. Unconventional hydrocarbons are usually situated in tight, low permeability, low porosity, low recovery, difficult to produce rock formations such as shales, chalks, tight sands and coal seams[9]. These rocks require special stimulation, completion and or production technologies to extract their hydrocarbons. Significant improvements have been made in extraction technologies of unconventional reserves. Notable examples of significant unconventional oil extraction are the Orinoco extra-heavy oil belt where

Venezuelan extra heavy oil production grew from about 80 million barrels in 2000 to about 240 million barrels in 2005 and in Western Canada where Canada has boosted its bitumen production from 210 million barrels in 2000 to a little more than 400 million barrels in 2006 [9].

Unconventional oil is projected to play a significant impact in meeting the rising global energy demand. As demand grows in the US and globally it is predicted that unconventional oil resources shall increasingly become important in meeting future energy needs. Current estimates of some 7.5 trillion barrels of in-place bitumen, extra-heavy oil and shale oil are over three times greater than the 2.25 trillion barrels of recoverable conventional oil estimated to have been discovered to date. Estimated in-place resource of unconventional oil is about seven times greater than the estimated recoverable conventional liquids from field growth and yet to find sources. Also with the exception of gas hydrates, estimated in-place volumes of unconventional gas are estimated to be an average of four to five times greater than the estimated recoverable gas from field growth and yet to find sources [9].

These reserves represent significant resources and they also represent a technology dividend. As more interest is generated in these reserves vast technological improvements are needed to expedite exploitation beyond their current state. Though these reserves are estimated to be able to add about 400,000 barrels of annual new production they are still a far cry from the required five to six million barrels a year needed to meet expected rising global demands in the face of depleting existing reservoirs. It is expected that technology would have an increasing role in exploiting newer deposits and also allow the efficient use of resources in the exploitation of new and existing reservoirs.

From figure 1.2 it is clear that though rig sizes have reduced over years, to offset the effect of the impact beneath the surface caused by extended subsurface reach commensurate technological development is needed to handle the wastes generated. In the exploitation of unconventional resources the dynamics are markedly different as copious amounts of resources such as freshwater is needed for their successful exploitation. Also copious amounts of wastes are generated in their exploitation, wastes such as fracture fluid backflow and produced water. In the exploitation of unconventional resources optimal use and recycle of resources and waste is paramount not only to reducing environmental impact but also for financial exploration viability.

For example, hydraulic fracturing, a stimulation technique routinely used on oil and gas wells in low-permeability reservoirs is a widespread stimulation technique used in exploiting some unconventional reservoirs. Hydraulic fracturing involves pumping water and a suitable proppant at high pressure to create and propagate a fracture in the surrounding rock formation downhole. These fracturing operations are known to consume large volumes of freshwater to induce the fracture and they also generate large volumes of fracturing (frac) waste in their flow back after fracturing these formations. Fracturing operations consume millions of gallons of fresh water and generate millions of gallons of fracture fluid backflow in wastes [8,9].

As some unconventional sources require large freshwater resources in their exploitation in some cases such as coal bed methane reservoirs, produced water is generated before they can be exploited. Coal Bed Methane (CBM) is an unconventional oil source where beneath the earth methane is adsorbed to crystalline surfaces of coal due to hydrostatic pressure of overlying water in the coal beds [10]. To strip the methane off the crystalline surfaces the water needs to be pumped out, thus unlike conventional oil fields where produced water is generated as the field matures the reverse is the case with CBM produced waters. Without a doubt unconventional resources are central to meeting the global energy demand, the environmental implication of freshwater use and produced water generation remains the abiding question technology must address to allow for sustainable exploitation of natural resources to meet the global energy demand.

1.4 Waste Description

There are three main categories of wastes associated with exploration and production activities, they are produced water, spent drilling fluid and associated wastes [11]. Produced water is defined by the Environmental Protection Agency (EPA) as "Water brought up from hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water and chemicals added downhole or during oil-water separation process" [12]. Produced water includes components such as organic chemicals, salts, hydrogen sulfide, heavy metals, hydrocarbons and other various components primarily dictated by the geologic features of the reservoir where they are produced. In discussing produced water an associated term used frequently is “water cut”, water cut is defined as the ratio of produced water to the volume of reservoir fluid produced. This ratio could range from less than 1 to about 40 depending on the maturity of the field [13]. Average US cut-out ratio is estimated between 7–10 barrels of produced water for 1 barrel of oil produced [10,13].

Spent drilling fluid is made up of the drilling fluid and rock cuttings. Drilling fluid could either be water based, oil based or synthetic based depending on the continuous phase which could either be freshwater, diesel or synthetic oil respectively. The drill solids are crushed rock formation generated by the drilling bit when drilling the hole. Spent drilling fluids could have solids concentration of upwards of 20,000 mg/L. The nature of the solids is completely dictated by the formation while the sizes of the cuttings are determined by the bit characteristics and rate of penetration of the bit [2]. For a water based mud, the continuous phase is either fresh water or brine, but to facilitate the primary function of the drilling fluids which is primarily to suspend the cuttings and pressure maintenance chemicals are added to the continuous phase to perform specialized functions.

To make the drilling fluid heavy, weighting materials that do not react with the water are added, examples of such materials are barite and galena (galena’s use has been banned). To increase viscosity reactive solids predominantly clays are added, common examples are bentonite, attapulgite and various synthetic polymers [1]. To avoid loss of the fluid to the sub-surface, filter cake forming additives and fluid loss prevention additives are added to the water such as starches, lignosulfonate and carboxymethyl cellulose. Thus, the formulation of a drilling fluid is complex and dependent on the formation being drilled and functions required of the drilling fluid. Significant progress has been made towards environmentally friendly drilling fluids incorporating benign and easily biodegradable fluid constituents.

The final waste category, associated wastes includes various small waste streams that are connected to specialized E&P operations, examples of associated wastes include completion fluids, work over or stimulations fluids, tank bottoms, dehydration or sweetening unit wastes, used solvents or degassers, cooling water, used oils, untreatable emulsions and a host of wastes streams [11]. They are generally not produced as much as other E&P wastes and usually need some form of specialized handling or treatment for their disposal. This research does not focus on associated wastes as they are quite varied and not significant in proportion to the total volume of wastes generated in E&P operations.

1.5 Water Based Wastes Management

Produced water comprises approximately 98% of the total volume of E&P wastes generated [14]. Approximately 18 billion barrels of produced water was produced onshore in the US in 1995, compared to 148.7 million and 20.6 million barrels of drilling wastes and associated wastes respectively produced onshore in the US in the same year [11]. These figures exclude the additionally large volumes of produced water generated in US offshore operations. From disposal statistics available 71% of produced water is used injected for Enhanced Oil Recovery (EOR) and pressure maintenance in the reservoir, 21% is injected into disposal wells while 3% is discharged and 2% re-used. For drilling wastes 47% is evaporated on site, 21% buried on site, 13% is injected into disposal wells, 7% is re-used for drilling, 2% is hauled off-site, 1 % is landspread. For the associated waste streams 52% is sent to treatment facilities, 14% is incinerated, 12% is evaporated from pits and landspread, 7% is disposed by injection and 7% is recycled or reused [11,14]. See figure 1.3.

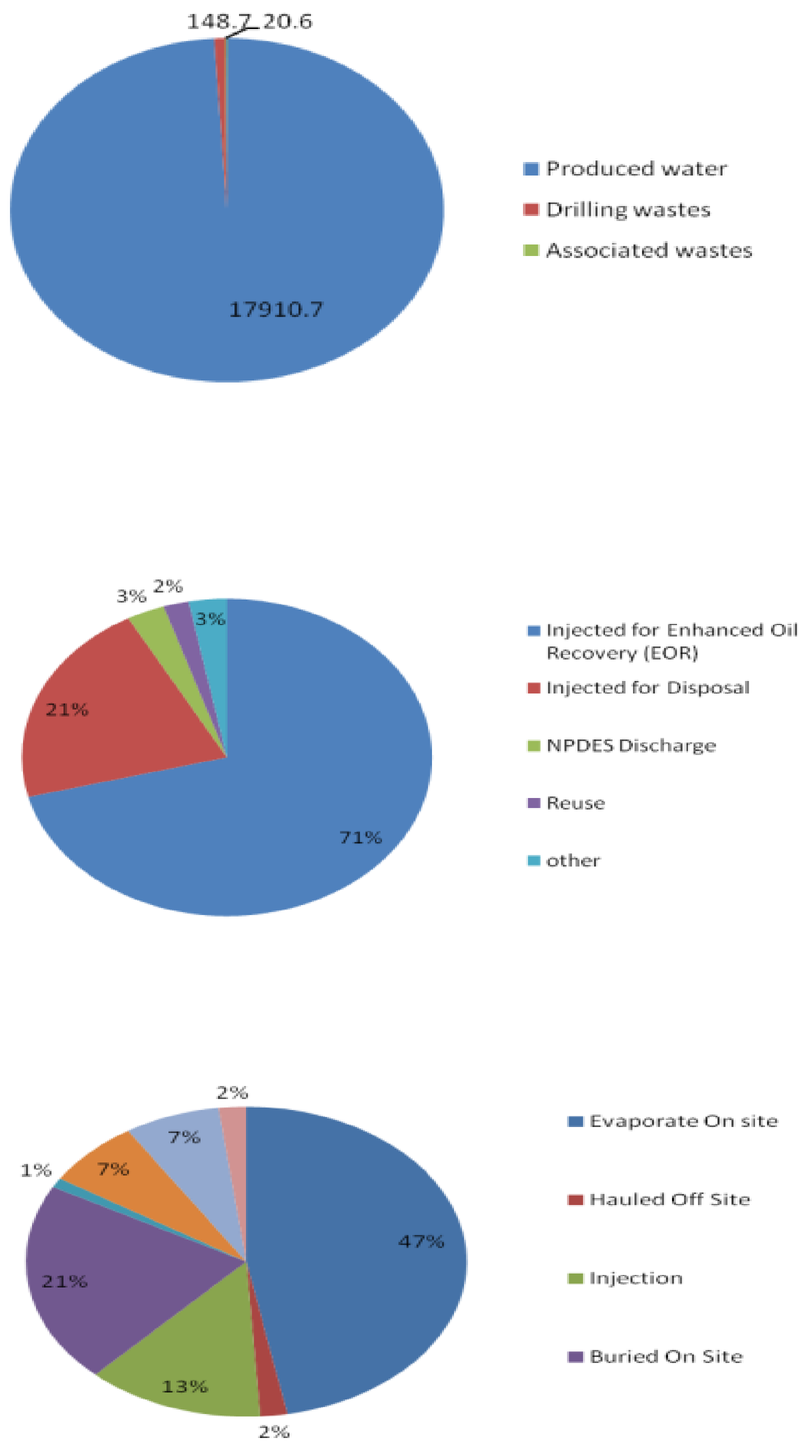

Fig. 1. 3 Waste disposal statistics.

Management of wastes generated from E&P operations represents a significant cost to the industry. Cost of treatment and disposal of produced waters could range from about $0.15 - $15 per barrel of produced water amounting to a global industry cost of $50 billion per year [13]. Commercial disposal of oil based mud cuttings and cuttings disposal range from $2-$40 per barrel and $0.50-$30 per barrel for water based fluids and cuttings disposal. For associated waste such as tank bottom disposal costs range from about $0.85-$40 per barrel [15]. All these costs might not include transportation or trucking costs which could increase the costs of disposal and treatment significantly.

Most of the disposal and treatment costs have to do with disposal methods such as injection (for produced water and drilling waste) and do not in any way recover the produced water and spent drilling fluid for re-use or recycle. Apart from the disposal costs, costs associated with acquiring fresh water resources are increasing as operations such as hydraulic fracturing are straining municipal water supplies [16]. Using the Permian basin as an example, about 390 million gallons (9.3 million barrels) of water per day go into re-injection disposal and less than 1% of this is recycled, such prodigious use of scarce freshwater sources is bound to have socio-political implications evident in "water wars" in places like Colorado and Texas [17].

1.6 Freshwater Sources

Freshwater sourcing is becoming rather difficult especially for the exploration and production of oil and gas. There is an increased awareness about water use in areas where unconventional resources are located as these areas are already challenged for freshwater. Operators in areas exploiting unconventional reserves such as the Barnett Shale in Texas and the Rocky mountains in Colorado are increasingly facing stiff competition from municipal communities and ranchers over freshwater use.

Although agriculture (irrigation) still consumes the largest portion of freshwater in most communities [18], there is an increasing concern over the non-sustainability of fresh water use in E&P operations due to the low-levels of recycle and re-use especially in the light of agricultural practices streamlined to effectively conserve freshwater. For example in Alberta, Canada with approximately 9.7 billion m^3 of freshwater, 4.5 billion m^3 was allocated to irrigation and approximately 0.5 billion m^3 was allocated to the petroleum industry, there was about 0.6 billion m^3 produced water after operations and approximately half was injected for reservoir maintenance and waterflood while almost 0.3 billion m^3 was injected into disposal wells [18].

Freshwater sourcing is increasingly becoming a challenge for E&P operations as freshwater costs are becoming a significant part of operating costs. It is not uncommon for operators in the Barnett Shale to truck freshwater from over one hundred and one hundred and fifty miles to their drilling locations as fresh water prices have increased steadily over the last five years [personal communication]. These challenges are also becoming evident as regulations being promulgated by local communities and regulatory bodies reflect the need to protect freshwater sources not from contamination as it was traditionally framed but also from "excessive use". Regulatory bodies are exploring ways to force behavioral shifts in water use not only by the industry but from all stakeholders [17].

Social issues indirectly related to freshwater sourcing and produced water and water based drilling fluid disposal are also gaining traction amongst stakeholders. Hauling in of freshwater and hauling off of the drilling wastes and produced water for disposal from drilling sites expose communities in areas where drilling operations occur to high levels of noise due to the constant vehicular traffic. For a fracture operation more than three hundred trucks (300) could be used to haul the wastes. Recent social studies by Gene Theodore [19] in the oil producing areas of the Barnett shale show that communities are increasingly becoming exasperated at these "inconveniences" even though royalties from the industry represents a large portion of the tax-base of these communities.

1.7 Conventional Management Options

In the previous sections the classification of water based E&P wastes, volume of the wastes generated, disposal and treatment percentages and freshwater sourcing was highlighted. In this section some general conventional technologies used in the disposal and treatment of this E&P wastes shall be discussed. The discussion shall start with a brief description of each technology, its advantages, limitations, cost implications and an evaluation based on the most important objective of the EFD aside from efficiency i.e. low footprint and increased re-use and recycle. Technologies aimed at spent drilling fluid disposal or treatment shall be discussed first and technologies aimed at produced water disposal or management shall be discussed after.

1.7.1 Spent Drilling Wastes Disposal and Treatment Technologies

1.7.1.1 Burial and Evaporation

Burial merely involves the placement and covering of spent drilling fluids into man-made excavations, such as pits or landfills or into natural excavations. Evaporation on the other hand involves the use of solar energy to evaporate the drilling fluid, the residue (predominantly cuttings) could either be hauled offsite or buried in the pit [20]. From available statistics for the time period within 1985-1995 onsite burial and evaporation was the most common onshore technique used for disposing drilling wastes, according to the report "two-thirds of the drilling wastes (68 percent) were disposed onsite through evaporation and burial" [11]. Table 1.1 is adopted from reference [11].

Table 1.1 Spent drilling waste disposal practices [11]

Comparison of 1985 and 1995 Drilling Waste Disposal Practices		
Drilling Waste Disposal Method	% Drilling Wastes 1985	% Drilling Wastes 1995
Evaporation On site	29	47
Hauled Offsite	28	2
Injection	13	13
Buried on Site	12	21
Discharge to Surface	10	1
Landspread	7	7
Others (Including solidification and incineration)	1	2
Total (%)	100	100

Onsite burial and evaporation is a low-cost, low-technology method. It does not involve waste hauling from the drill site thereby significantly reducing disposal costs making this technology a very attractive technology to most operators especially independent operators. The burial could be done in the reserve pit or in a landfill depending on the site location, soil type, land topography and drilling fluid used; the pits may be lined to avoid leaching into the subsurface. This technology requires no special personnel training as long as issues such as soil type, chemical constituents of the drilling fluid are well characterized and issues such as leaching, soil and freshwater contamination have been already addressed in the drilling plan.

Limitations to this technology are numerous. This technology cannot be applied in areas with high permeability soils such as sands and are consigned to regions with clays. This technology requires a continuous degree of monitoring as the operator must ensure that the constituents of the pit do not leach into the subsurface as liability and clean-up costs are very prohibitive aside from the intangible cost of a damaged reputation. Evaporation is dependent on the sun. When drilling in seasons such as winter or in regions with low sunshine or during heavy rains it becomes unrealistic to evaporate the liquid part of the wastes which could increase dramatically in the event of heavy rainfall. Evaporation as a means of getting rid of the liquids could also introduce Volatile Organic Compounds (VOCs) into the atmosphere [21].

Burial of wastes creates anoxic conditions that do not facilitate favorably the biodegradation of majority of harmful compounds thereby posing a latent source of contamination. Burial into landfills evokes social concerns about sustainability as landfills are viewed as generally unsustainable despite improved lining technology over the years because landfill space is deemed correctly finite. As subsurface reach continues to increase as show in Figure 1.2 waste volumes would continue to increase and assuming all factors favor burial and evaporation such as geological suitability, sunshine and infinite space, the footprint of using burial and evaporation technology shall offset any gains made at reducing footprint as impoundment sizes would increase commensurate to the volume of wastes produced.

Considering the advantages and limitations of on-site evaporation and its impact on the environmentj this technology despite its huge cost advantage presents limitations that greatly outweigh it advantages. A larger footprint would be the outcome of this technology and this technology does very little in addressing the issues of re-use and or recycle of valuable non-toxic water resources that could be put to better use. Though the need for a reserve pit is well understood in the drilling process, onsite burial based on the stated limitations makes this technique rate very low.

1.7.1.2 Land Application

Land application is a widely used treatment or disposal option in the industry. Various technical papers describe treating drilling wastes using land application particularly hydrocarbon contaminated drilling wastes and tank bottoms [22]. Land application involves the controlled application of wastes to the land. It employs the naturally occurring microbial populations in the soil to break down the hydrocarbons or contaminants transforming them to less harmful compounds (biodegradation) or preferably utilizing the contaminants breaking them down to carbon dioxide and water (mineralization).

Land application can be considered a waste treatment option or a waste disposal option or both depending on the intended use. Land application is generally divided into land farming and land spreading although the distinction between both groups is more gray than clear. Land farming generally refers to the repeated application of wastes to the soil surface whereas land spreading describes a onetime application of wastes to the soil surface making the difference between both groups the frequency of application of the wastes. Both groups are lumped up as one in this discussion.

Land application thus involves the controlled one time addition and or repeated application of wastes to the soil surface employing microorganisms in the soil to biodegrade hydrocarbon constituents. Persistent contaminants, heavy metals and other xenophobes are transformed into less harmful compounds or completely mineralized during biodegradation. It is a relatively simple technique and requires more microbial and agricultural knowledge than engineering. This technology strives to create an enabling environment for microbial populations to biodegrade the hydrocarbons and contaminants. Knowledge of soil type, water capacity, weather, nutrients are essential for a successful application of this technology while monitoring is essential to avoid anoxic conditions that would stymie biodegradation and create a hazard.

Land application is a relatively low-cost drilling waste management technique. It is best used in areas where there is an abundance of land. Land applications could be a very effective treatment technique because micro-organisms are very efficient degraders of hydrocarbons and various drilling wastes contaminants. Input into the system is minimal and degradation could be accelerated or optimized through the addition of fertilizers. Studies show that land farming does not adversely affect soils and may even benefit certain sandy soils by increasing their water-retaining capacity and reducing fertilizer losses [23]. Inorganic compounds and metals present in the drilling wastes are diluted in the soil, and may be incorporated into the matrix through chelation, exchange reactions, covalent bonding, or other processes reducing the availability of the contaminants [24].

Land application is limited by available land space and there is also the risk of groundwater contamination in areas with shallow water tables as there exists the risk of percolation or leaching of contaminants. Moderate to high salt concentrations in drilling wastes could be prohibitive to biodegradation and soil structure [24]. Moisture level control is also important in land applications as too much moisture creates waterlogged soils which are not conducive to biodegradation and too little moisture hinders metabolic activity of the micro-organisms thereby causing little or no biodegradation. Land application is not a quick process it may require long periods of time ranging from a few months to a few years to achieve biodegradation and or mineralization depending on the type of contaminants and volume of wastes to be treated. The larger the waste volume the larger the space required and the more recalcitrant the contaminant the longer the biodegradation/mineralization process.

With respect to EFD, land application as a technique poses some challenges with respect to footprint and recycle and re-use. Land application techniques increases the footprint of drilling operations and with increasing subsurface reach the amount of land needed for land applications would continue to increase due to the increasing volume of wastes. So unless there is a compaction of the waste to be treated there shall be a need for increased land space. Limitations are posed by the volume of waste that can be applied over the land causing space constraints apart from residence time on the land. Recycle and re-use gains are moderately significant as the land could be applied for other uses such as farming or allowed to fallow after treatment of the waste. This technology is rated moderate.

1.7.1.3 Bioremediation

Another disposal and or treatment technique also used in the disposal of E&P wastes is bioremediation. The underlying principle in bioremediation is the same as in land application i.e. employing micro-organisms to degrade recalcitrant compounds such as hydrocarbons. Bioremediation differs in practice to land application in that there is an intended objective to accelerate the biodegradation process by actively creating, controlling and managing parameters that affect the microbial biodegradation process, such as oxygen, nutrients, moisture content and pH.

There are basically two common bioremediation techniques in dealing with drilling wastes, composting and bioreactors and there is a third emerging technique –vermiculture or vermicomposting [25]. Though bioremediation is proven to be effective it faces wide adaptation constraints on a large scale in the oil and gas industry due to the large volumes of wastes generated in exploration and production activities. Impoundment size, energy and loading restrictions are common problems associated with adopting bioremediation aside from retention or residence time constraints, monitoring costs and specialized personnel. The three different techniques shall be briefly described and assessed as to their limitations and how they fit into the environmentally friendly drilling concept.

1.7.1.3.1 Composting

During composting waste is mixed with bulking agent such as saw dust, straw or rice hulls and organic amendments such as animal or vegetative wastes under controlled moisture and oxygen levels to attain degradation or transformation of contaminants. Bulking agents serve to increase porosity, reduce soil bulk density, oxygen diffusion and in some cases help to form water stable aggregates [26]. Organic amendments serve to shore up the nutrient base of the soil by enriching the soil enhancing microbial activities. The combination of the soil-waste-bulking agents-organic amendment is called the compost when mixed together and piled. Nutrient ratio, waste loading, aeration and moisture level management are essential to successful composting as waterlogged composts without proper aeration create anoxic environments.

Composting is a very effective process in the treatment of solid drilling wastes as significant reduction of contaminants is achieved in less than two months in some cases (time varies depending on various factors such as contaminant loading)[27]. Compositing requires less land than land farming applications and can handle comparably higher oil content in the waste, initial oil concentration can be as high as 15-25% after bulking agents have been added [26,27,28]. Composting can also be used in cold regions [29] and to reasonable extent it can be used in inclement weather such as during rains as the compost piles may be covered. The end product of composting is of value as the compost can be used for purposes such as agriculture and various other uses where the compost is needed.

Issues with composting lies in regular maintenance, the compost cannot be left to “fallow” as constant monitoring of the temperature, moisture level and pH is essential, lack of which could cause the compost failure and could be toxic in some cases. Aeration during composting could be forced or just by turning the compost periodically, this involves additional manpower or equipment when compared to land farming and this also increases the cost of composting in comparison to land farming.

In the light of EFD principles, composting as treatment or disposal technology has a low-medium footprint. There is also possible re-use of the compost after composting making it more environmentally friendly due to its re-use value. The ease of adaptation of this technology is above average as many operators have used composting in treatment of drilling wastes with very encouraging results and large scale compost operations exist. As with land application higher waste volume generation can affect the long-term viability of using composting due to land constraints and the manpower and resources used in monitoring.

1.7.1.3.2 Vermicomposting

Application of vermicomposting to drilling waste is novel. Vermicomposting has a long but uncommon history in the degradation of organic wastes such as municipal waste and very few vermicomposting plants or projects are known. Vermicomposting involves using worms in the bioremediation of waste, these worms through their burrowing increase aeration, surface porosity and stabilize the compost increasing the microbial activities of the degrading microbes. The activities of the worms also reduce the monitoring required and when they die offer additional organic fuel to the microbes. Paulsen et al [25] were the first to report using vermicomposting on spent drilling fluids.

Their experiment carried out in Norway involved windrows similar to those in composting; they used wood bark and chipping as bulking agents while manure, worm cast and clay were the organic addendum to make the compost. The cuttings used by Paulsen et al were mineral oil contaminated drill cuttings. After approximately 70 days and about four loads of drill cuttings they reported a reduction in the oil content to background levels also showing heavy metals reduction to levels below the Norwegian regulatory limits. Advantages of composting apply to vermicomposting and vermicomposting might hold the additional advantage of requiring less monitoring as the parameters monitored in normal composting is “biologically monitored” in vermicomposting.

From the Paulsen et al study it might be surmised that vermicomposting might take up more land space than actual composting as windrows have vertical limitations. Since literature is scant comparing specifics between vermicomposting of drilling wastes and composting of drilling wastes is quite difficult. For Best Available Technique for drilling waste disposal and treatment especially for environmentally sensitive areas, vermicomposting scores very high though there are practical issues with its adaptation such as drilling waste composition, climatic conditions, volatilization issues and also the limited space rationale in the light of increasing subsurface reach of drilling operations.

1.7.1.3.3 Bioreactors

Bioreactors work on the same principle of bioremediation and land application – employing micro-organism for the break-down or transformation of the contaminants and hydrocarbons in the drilling waste the underlying difference is that biodegradation is carried out in either a closed or opened vessel. The vessel confers a higher degree of control of biodegradation parameters over other techniques that employ bioremediation and this degree of control is intended to optimize biodegradation. Due to this degree of control higher biodegradation rates are encountered in bioreactors than other techniques. In biodegradation micro-organisms could be seeded in the reactors with the drilling waste and stirred, aeration is achieved through intensive mechanical stirring and the major goal in the reactor is the increase of contact between the micro-organism and the contaminants.

The waste is introduced periodically into the system at the start, microbial growth time is allowed for proliferation of the microbes in the system and to allow adaptation of the microbes to the waste. Biodegradation parameters such as oxygen levels, pH, and temperature are monitored usually automatically and they serve to indicate efficiency of biodegradation. Bioreactors can operate in batch, semi-batch and continuous modes. Solids loading in bioreactors on a dry weight basis is usually about 15 to 20 percent although special reactors can handle up to 40 percent [30]. The material which the reactor is made of or how it is protected is of importance due to the abrasive nature of the drilling solids when vigorously mixed. An obvious great advantage of the bioreactor is the ability to use it in any weather or climate condition and the faster biodegradation rates.

Pilot tests are very essential to the successful operation of bioreactors due to the complexities involved in maintaining the biodegradation parameters and reactor environment. Mcmillien and Gray [30] demonstrated the degradation in a bioreactor of mineral oil in oil-based drill cuttings that contained 15 percent oil and grease. The mineral oil was Escaid 110 which is a low molecular weight refined product consisting of normal and cyclic alkanes with less than one percent aromatics, the drill cuttings contained 58 percent solids and 3.5 percent calcium chloride. Using different solids rate in the pilot bioreactor over a 35 day period, they reported impressive reductions in the oil and grease content, using a 5, 15 and 25 percent solids loading they reported oil and grease reduction from about 10 percent to about 100 percent.

Limitations to bioreactors have to do with the sizes of the impoundment, loading rates and the characteristic of the waste and these factors are not mutually exclusive but interrelated. Drilling wastes vary from drilling location to drilling location and in order to use bioreactors for drilling waste treatment a more detailed knowledge of the waste is needed relative to other bioremediation methods. For example most waste can be composted or landfarmed but practical considerations limit what can be biodegraded using a bioreactor. In a bioreactor the aim is to increase contact between the micro-organisms and the waste, the contaminant is bound to the solids and adsorbed to the solids causing a theoretical and practical limitation on how much solids can be loaded on the system.

Since loading limitations cannot be ignored, a larger vessel is needed to increase contact and more freshwater would be needed to dilute the cuttings and more microbial population added. This would also bear on the power needed to mechanically stir the bioreactor constituent and energy needed for forced aeration. Ultimately the residence time of the waste in the bioreactor invariably would be affected and this would be a limiting factor in determining how much waste can be treated. These amongst many problems are issues with adaptation of bioreactors on-site for waste treatment of drilling wastes.

With respect to EFD, bioreactor treatment of drilling wastes is in theory a very environmentally friendly option with bioreactors. Land space is more optimized when compared to other options discussed above and we have the disappearance or transformation of the contaminant. Practical issues with the adaptation of bioreactors for field operations in the light of the volume of waste generated obviate the gains of being environmentally friendly, the use of large vessels and their energy requirements indirectly increase footprint. Impact due to volatilization of contaminants is also worthy of consideration though emissions could be controlled by using control devices such as activated carbon filters to the gas exhaust steam of an enclosed bioreactor [30]. Another indirect issue with bioreactors remain that due to the addition of copious amounts of freshwater the waste volume is increased and when the biodegradation occurs the treated water is still present. So except the operator is allowed to dump the waste, additional costs would be needed to truck the waste to a disposal facility dumping also reduces the ability to re-use the waste.

1.7.2 Produced Water Treatment or Disposal

1.7.2.1 Subsurface Injection

Subsurface injection in the disposal of produced water is a very common disposal option in the oil and gas industry. Subsurface injection is also used for disposal of drill cuttings (slurry made up of drill cuttings) and produced water. Subsurface injection is very common in produced water disposal and the type of subsurface injection used in waste disposal depends on the location of the wastes and injection location. The growing position of subsurface injection and its role as the major disposal option of produced water cannot be overstated and is the major highlight of this section. The discussion starts off describing slurry injection and narrows the discussion to produced water disposal.

Injection is recorded to have begun in the mid-1980 with small volume annulus injection in the Gulf of Mexico [31]. It began to gain broader use in various regions as operators started to use it in Alaska, the North Sea and in limited regions of South America and by the end of the mid 1990's commercial facilities with dedicated injection wells began operation [32]. This was followed by large scale injection operations in Alaska and the Gulf of Mexico [33,34] and today the use of injections as a disposal technology is quite commonplace and increasing. In slurry injection "the two most common sources of waste injected are from on-going drilling operations and from mud cuttings that have been temporarily stockpiled pending some future permanent disposition. Cuttings from an on-going drilling operation are usually retrieved from the shale shaker, mixed with water, processed to an appropriate size and injected downhole" [35].

1.7.2.2 Slurry Injection

There are two common types of slurry injection or two typical wellbore configurations for slurry injection, annulus injection and disposal well injection, these two configurations are shown in figure 1.4.

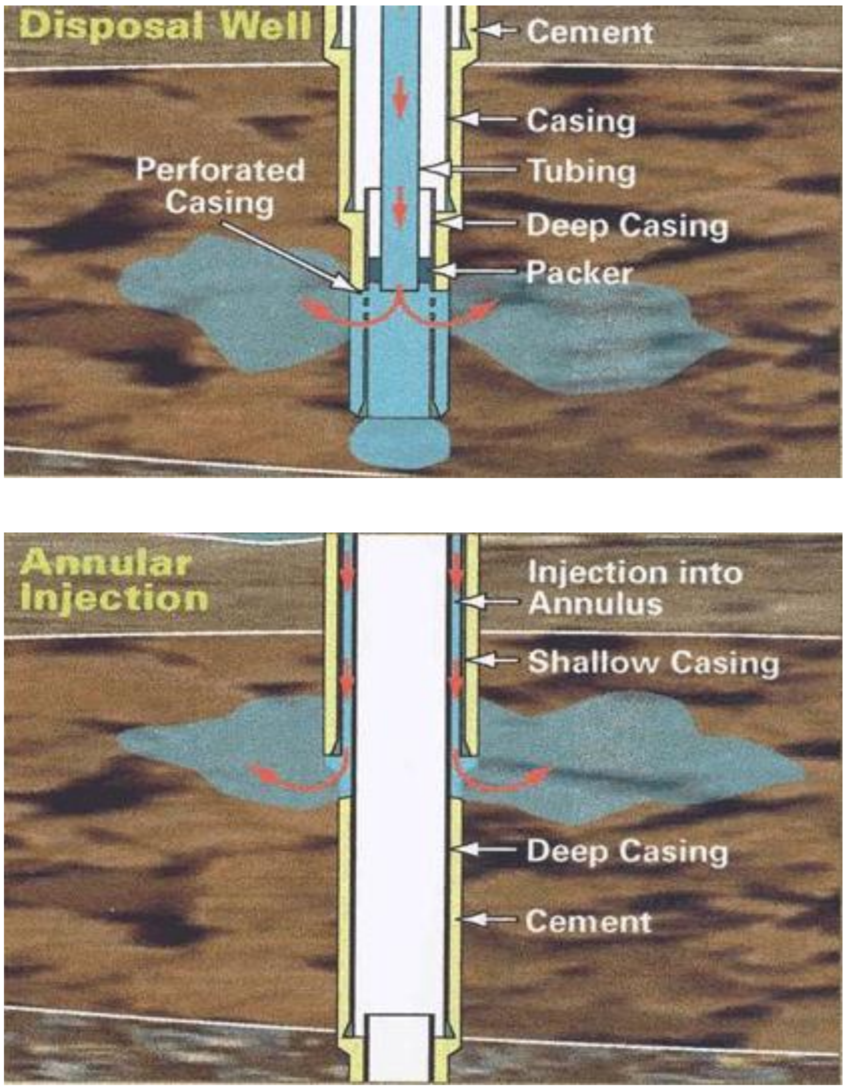

Fig. 1. 4 Schematic of Injection. Top: Disposal well injection. Below: Annular injection [24].

In annulus injection the waste slurry is injected down the annulus (the annulus refers to the space between the two casing strings) between the surface casing and a deeper casing string so the waste slurry enters the formation at the lower end of the deeper casing string. Annulus injection is more common offshore where the cuttings are injected into either the uphole annulus of the well being drilled or into the annulus of the nearby well. Injection rates are typically about 1 to 6 barrels per minute (BPM) and the duration of injection into the annulus is about the drilling time with total slurry volumes injected usually between 10000 – 50000 barrels per well [35].

The second configuration of slurry injection, injection into a disposal well is more typical of longer-term, permanent injection operation. It involves injection to either a section of the drilled hole that is below all casing strings, or to a section of the casing that has been perforated with a series of holes at the depth of an injection formation [24]. In some instances existing producing wells are recompleted as injection wells while in some other instances dedicated injection wells are created and usually the latter wells are functional for long periods of time and can have slurry volumes of about 2 million barrels per well [35]. Injection into disposal wells has typical injection rates of about 5 and 25 barrels per minute (BPM), significantly higher than annular injection primarily due to the tubing having lower friction losses compared to the losses down an annulus.

Implementing the slurry injection involves identification, collection and transportation of solid waste for slurrification. The particles are made relatively homogenous by grinding, a mean particle size of about 300 microns is believed to be about appropriate [36]. This particle size is essential to avoid “bridging and plugging of either the re-injection annulus or disposal fracture in the well region” [36]. The slurry is then transferred to a slurry holding tank to condition the slurry rheology, it is then pumped into subsurface fractures which arise by injecting the slurry under high pressure into the disposal formation. This injection is usually done in batches as this allows the disposal fracture to close unto the cuttings and redistribute any pressure build-up in the formation. Figure 1.5 shows a schematic of drill cutting slurry fabrication and injection system (adapted from [36]). Freshwater or brine is used in the slurry preparation.

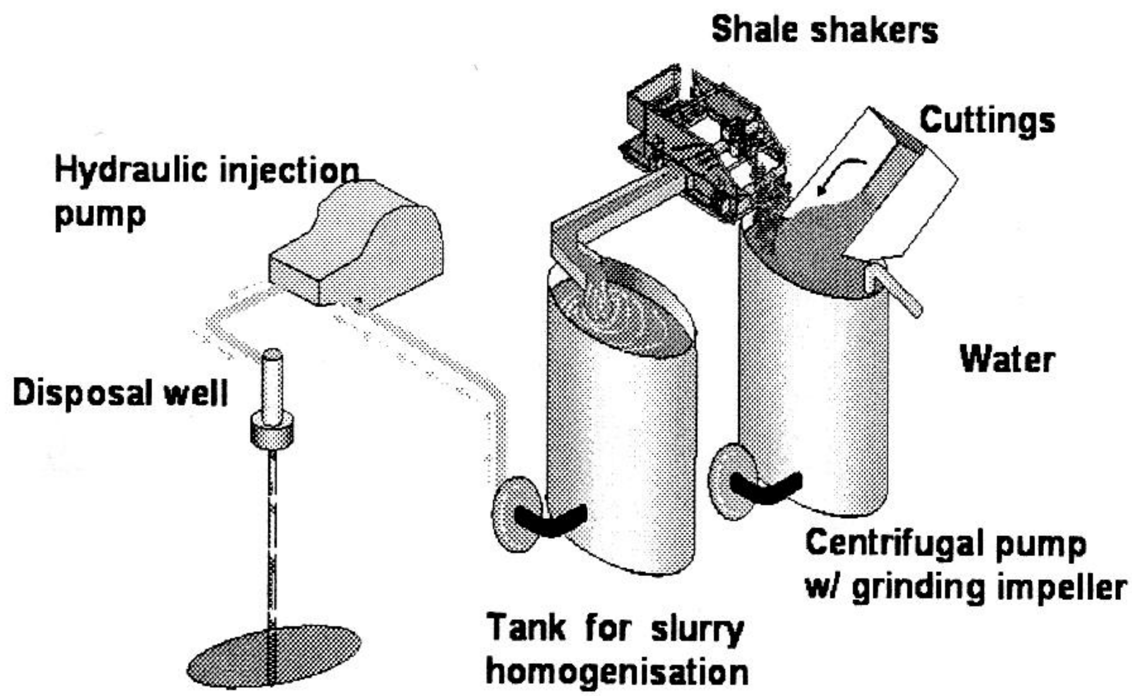

Fig. 1. 5 Schematic of drill cuttings slurry fabrication and injection system [36].

1.7.2.3 Produced Water Injection

Slurry injection pertains mainly to drilling wastes that are predominantly solid in nature (though not excusive), in the disposal of produced water significant amount of produced water is disposed using injection wells usually after de-oxygenation of the produced water. The EPA regulates the injection of produced water using the Underground Injection Control (UIC) regulation and the wells used for injecting produced water are described as Class II injection wells. Wells dedicated to disposal of produced water are termed Class II-D wells because apart from disposal of produced water, produced water is also used for enhanced recovery operations where they are injected into a producing formation to help move crude oil to wells for collection. This stimulation method is generally termed water flooding, and it is designed to increase the yield and productive life of usually mature oil deposits. Recovery wells of this nature are termed class II-R injection wells.

Produced water injection into Class II-D is also similar to slurry injection as it aims to ensure the containment and confinement of the injected water within acceptable injection zones away from any underground source of useable water for drinking or irrigation [37]. Produced water injection could either be by fracture injection (similar to slurry injection explained above) or matrix injection. Matrix injection involves the deposition of the contaminants into the pore spaces of the rock without actually fracturing the formation [37]. Matrix injection involves allowing the contaminant (solid and oil-in-water) deposition and formation plugging to occur in a limited area around the injection well, substantial pilot knowledge and reservoir pressure history is needed to successfully implement a matrix injection.

Injection of wastes has a lot of advantages to operators in the industry as it helps them achieve zero discharge of waste i.e. there are no waste left after the completion of the drilling operation. It also saves on transportation and associated costs as injections are usually done in areas close to or where the waste is generated and If there are no issues with the well integrity there are no clean-up liabilities. The economics of scale makes it economically favorable to inject, from one study for a 20-well program in the Gyda/Ula field in the North Slope, the economic analysis showed that injection costs would be approximately 10 million dollars compared to 18 million dollars for onshore processing [38].

Disadvantages to the use of injection as a disposal primarily revolves around well integrity. The ability to inject depends on the subsurface geology of the formation receiving the waste along with its compatibility to the chemical and physical characteristics of the waste. The protection of groundwater aquifer from contamination is an overriding concern and this has informed increasingly stringent permitting and regulation hurdles which are expected to be more stringent in the coming years. Well failures do occur though they are not very common, for example “excessive erosion wear from long-term slurry injection has caused well integrity failures both in the Gulf of Mexico and in the North Sea operations" [35]. Well integrity issues arising from poor slurry rheology design, overburdening beyond the well capacity, poor monitoring and poor procedures present a large potential for liability for operators.

With respect to Environmentally Friendly Drilling, injection of wastes is not a viable option in fragile ecosystems as regulatory agencies and community stakeholders would balk at the prospect of any breach of the well's integrity. The footprint of equipment needed in the injection such as hydrocylones, centrifuges, crushers, air flotation equipment e.t.c. all add considerable footprint to drilling operations. With respect to footprint on the surface, when compared to other treatment methods injection moderately compares as a small footprint after processing the waste for injection.

With regard to recycle or re-use there is little or no re-use especially in produced water injection (it should be noted that injection for enhanced recover would fall under re-use, the wells referred to in this section are Class II-D wells). The large volumes of produced water disposed represents a huge source of freshwater if desalinated or a large source of water for re-use especially for re-use in oil and gas operations. Possible re-use of injected wastes for drilling or associated operations would go a long way in greatly reducing the pressure for freshwater for oil and gas operations.

Due to greater subsurface reach disposal or treatment options must look towards re-use and recycle to reduce the amount of water resources being disposed. Though the footprint of injection might seem small on the surface, the re-use and recycle level is dismal in the light of the potential for water conservation it poses. Produced water injection remains the prominent disposal option in produced water management and disposal, though other disposal options exists such as thermal treatment they currently pale in comparison to scale and use of produced water injection.

1.8 Technologies Summary

Present disposal and or treatment technologies have shortfalls when the concept of environmentally friendly drilling is used to appraise them, some shortfalls arise because of the need to see land as finite and the need to minimize footprint irrespective of land available. Shortfalls such as low re-use and recycle bedevil technologies that seem to have low footprints and some effective treatment methods are just transference of the contaminant to a different media. The real life adoption of these various technologies are governed by various factors such as cost, existing regulations in areas of operation, public perception, stakeholder involvement, existing technology, adaptability of the existing technology and the cost benefit-ratio.

There are associated issues also with increased waste generation, one being that larger waste volumes due to greater subsurface reach is limiting waste treatment or disposal options. The traditional waste treatment options such as land application, bioremediation, bioreactors, incineration and a host of other treatment options are increasingly becoming uneconomical because of the large volume of wastes to be treated. It is becoming self-evident that treatment technologies aimed at treating drilling waste that are beneficial to the environment are made impractical due to the volume of waste generated. Earlier in this research a preliminary investigation was carried out looking at what it would take to treat drilling wastes using bioreactors, it was concluded that due to the volume of waste generated in drilling operations and assuming above normal improved theoretical biodegradation rates and residence time, bioreactors were simply impractical.

Regulations and liability issues are increasingly making land application technologies obsolete as regulatory bodies are making stricter laws concerning land application as a treatment option to protect groundwater and soil contamination [17]. Public perception is increasingly against disposal or treatment technologies that pose a threat to the environment despite safeguards by operators; these concerns helped accelerate slurry and produced water injection as the most favored disposal technology presently [35]. Injections are seen as the next conducive option because much safer technologies have been impractical to waste volumes and waste composition. Though operators recognize the need for environmentally friendly treatment/disposal technologies as the future, practical issues with the present or upcoming alternatives make them hard to adopt despite good intentions.

Associated issues such as energy demand accelerating the exploitation of unconventional create unique problems with freshwater sourcing and waste disposal forcing a paradigm shift about water use. Considering a conservative estimate of 390 million gallons of produced water injected daily into injection disposal wells [39], the historical daily average use of water in college station as of 2006 is 12 million gallons per day and the United States Geological Survey estimates that the average American uses between 80 - 100 gallons of water per day. Thus the amount of produced water injected daily is approximately the daily water need of about 4 million Americans and 35 times the city of College Station daily use! Though slurry and produced water injection have the semblance of “disappearing waste” present reality dictates that freshwater sourcing could easily become a limitation factor in the exploration and production of oil and gas as operators are increasingly putting pressure on freshwater sources to meet increased E&P needs.

In summary the need for technology that tackles the increasing waste volumes as a result of increasing subsurface reach achieving volume reduction of the waste and at the same time actively increasing the options of recycle and re-use is pressing. This technology would help reduce waste disposal costs by reducing hauling costs through volume reduction and treatment costs. Volume reduction would also reduce the footprint of drilling operations by reducing the size of impoundments needed, allowing for drilling in sensitive ecosystems by significantly reducing the impact of increased wastes. Social gains and positive perception would be sure to follow such concrete steps at environmental stewardship.

Two central issues have been identified; one, that the impact of drilling operations on the environment is bound to increase due to increased subsurface reach as more waste is produced and the footprint of drilling operations increases though rig sizes are reducing. Second, that there exist large volumes of recoverable or re-useable wastes that are disposed off with minimal re-use, especially produced water. In the face of increasing populations and the threat to freshwater sources coupled with environmental concerns there is a need for better stewardship in disposing water based E&P wastes. Associated issues that revolve around these two central issues include the reduced likelihood of permission to exploit the O&G resources in areas deemed sensitive to the public by regulatory agencies, reduction in alternative treatment options due to increased volume of wastes and the increasing associated costs with disposal options and issues with hauling over long distances.

1.9 Membranes

1.9.1 Introduction

Membranes are semi-permeable materials that are used in the separation of particles ranging from bacteria to atoms [40,41]. Membranes acts primarily as a selective barrier in the presence of a driving force allowing the passage of particular particles/components of the stream based usually on size (filtration) and the retention of anything larger. Membranes inadvertently act to enrich one of the streams (permeating or retaining) in one or more constituents. Separation by membranes is not confined to particle separation but extends filtration to include the separation of dissolved solutes in liquid streams and separation of gas mixtures [40]. In membrane terminology the permeate is that part of feed solution that passes through the membrane, while the retentate is that that part of the feed solution that is retained on the side of the membrane.

The driving forces in membranes could either be chemical potential as seen in osmosis, concentration difference as seen in dialysis, voltage or current as seen in electrodialysis or pressure as seen in microfiltration (MF), ultrafiltration (UF), nanofiltration (NF) and reverse osmosis (RO). The membrane processes considered in this thesis are limited to pressure driven processes where the driving force is a pressure difference across the membrane. Pressure driven processes are by far the most common processes and probably the most investigated processes as they find wide use in various industries and in various processes. This being said membranes in general find wide application and serve wide purposes from the pharmaceutical industry to the space industry.

Membranes can be active or passive in the filtration process, according to Cheryan[40] "membranes can also physically or chemically modify the permeating species, conduct electric current, prevent permeation or regulate the rate of permeation (as in controlled release technology). So membranes may either be passive or reactive depending on the membranes ability to alter the chemical nature of the permeating species” [40]. Depending on the type of membrane used and the nature of the driving force significant changes can be made to the product (either the permeate or the retentate depending on the need) and this mandates the investigation into membrane processes and membranes before application to a process.

1.9.2 Classification

There are varied membrane classifications. Some are based on the application of the membrane; gas-liquids, liquid-liquids, solids-liquids separations, some are based on the nature of the constituent material the membrane is made from – natural or synthetic, some are based on the mechanism which the membrane achieves separation –ion-exchange, osmotic, adsorptive or diffusive e.t.c. and some classifications are based on the structure of the membrane i.e. porous or non-porous [42]. Due to these varied classifications there are multiple conflicting terminologies and varied membrane descriptions. Three classifications of membranes pertinent to this thesis shall be used, classification based on membrane materials, classification based on the various pressure driven membrane processes and the classification based on membrane modules.

1.9.2.1 Membrane Materials

Various materials have been used in membrane manufacture, literature surveys of known membrane materials indicates that there are over 130 different materials used in membrane manufacture, though only few have gained commercial status or approval for use in various industrial processes [40]. Table 1.2 shows a few materials used in the membrane manufacture of pressure driven processes, a few of which shall be described here, this description should not been seen as exhaustive of membranes materials rather a highlight of some membranes materials.

Table 1.2 Some membrane materials [40]

Material	MF	UF	RO
Alumina	X		
Carbon–carbon composites	X		
Cellulose esters (mixed)	X		
Cellulose nitrate	X		
Polyamide, aliphatic (e.g., nylon)	X		
Polycarbonate (track-etch)	X		
Polyester (track-etch)	X		
Polypropylene	X		
Polytetrafluoroethylene (PTFE)	X		
Polyvinyl chloride (PVC)	X		
Polyvinylidene fluoride (PVDF)	X		
Sintered stainless steel	X		
Cellulose (regenerated)	X	X	
Ceramic composites (zirconia on alumina)	X	X	
Polyacrylonitrile (PAN)	X	X	
Polyvinyl alcohol (PVA)	X	X	
Polysulfone (PS)	X	X	
Polyethersulfone (PES)	X	X	
Cellulose acetate (CA)	X	X	X
Cellulose triacetate (CTA)	X	X	X
Polyamide, aromatic (PA)	X	X	X
Polyimide (PI)		X	X
CA/CTA blends			X
Composites (e.g., polyacrylic acid on zirconia or stainless steel)			X
Composites, polymeric thin film (e.g., PA or polyetherurea on polysulfone)			X
Polybenzimidazole (PBI)			X
Polyetherimide (PEI)			X

1.9.2.1.1 Polymeric Membranes

Cellulose acetate is a common membrane material used at the onset of modern membrane technology [43]. Cellulose is a polymer of β-1,4 linked glucose units with one primary and two secondary hydroxyl groups and the β- glucosidic oxygen in the equatorial position. Cellulose is derived from cotton linters or wood pulp and in some cases chemically modified wood pulp. To get cellulose acetate, the cellulose goes through acetylation which is a reaction with acetic anhydride, acetic acid and sulfuric acid to give the cellulose acetate.

An important physical property that affects membrane properties and filtration is the degree of polymerization of the cellulose, the optimum appears to be 100-200 or 100-300 which would result in molecular weights of about 25,000-80,000 [41]. Cellulose acetate membranes are widely used for reverse osmosis and ultrafiltration applications [44], they have high hydrophilicity which is essential in minimizing membrane fouling, low production and manufacture cost and they can be produced with a wide range of pore sizes. Disadvantages are narrow temperature and pH ranges, low chemical resistance and they are highly biodegradable [42].

In order to address the short comings of cellulose acetate membranes other polymeric materials where created substituting various classes of materials in the polymer to address the shortcomings such as seen in polyamide membranes. Polyamide membranes have an amide bond in their structure (-CONH-) and were first made by DuPont, polyamide membranes have better resistance to hydrolysis and biological attack than cellulosic membranes and can be operated over a pH range of about 4 to 11. They also have better salt and water soluble organic rejection than cellulosic membranes and can withstand higher temperatures [45].Their shortcomings include low chlorine tolerance, biological fouling and compaction at high pressures and temperatures.

Polysulfone membranes are characterized by having in their structure “diphenylene sulfone repeating units. The –SO2 group in the polymeric sulfone is quite stable because of the electron attraction of resonating electrons between adjacent aromatic groups” [40]. Polysulfone membranes and polyethersulfone membranes are marked improvements over the cellulosic membranes and the polyamide membranes. They have wider temperature limits, wider pH tolerance with considerably better chlorine tolerance and are also easy to fabricate and manufacture [43]. Notable membrane polymeric materials that have excellent properties such as the polysulfone membranes include polyvinylidene fluoride (PVDF), polyetrafluororthylene (PTFE), polypropylene (PP), polystyrene (PS) and polyvinyl chloride (PVC), polyolefin (P) just mentioning a few. These materials confer on the membrane unique characteristics and additional tolerance to exacting operating conditions [46].

1.9.2.1.2 Inorganic Membranes

Inorganic membranes also called ceramic membranes spearheaded the latest revolution in membrane technology starting from the 80s [47]. Ceramic membranes are made from a wide range of inorganic materials and the more common ones are made from alumina, titania, zirconia and silicon oxides. In their manufacture they are often formed into asymmetric, multi-channel elements and normally have an asymmetrical structure composed of at least two, mostly three, different porosity levels. They are a vast improvement both in material characteristics and in technology dividend to membrane filtration over polymeric membranes. They are inert to common chemicals and solvents, can withstand high acidity and alkalinity, have wide temperature, pH, and pressure limits, and their long life and durability increases their appeal significantly. Limitations common to them include brittleness, relatively large energy consumption in running them (explanation is given in membrane module) and pore size limitation in the lower micron range.

1.9.2.2 Pressure Driven Processes

Another description that is of importance to this research are pressure driven membrane processes. There are four pressure driven membrane processes namely - microfiltration (MF), ultrafiltration (UF), nanofiltration (NF) and reverse osmosis (RO). The underlying differences within these pressure driven processes is the different amount of pressure applied to achieve the separation and the size of the separation material; these combined factors determine the retentate and permeate characteristics. Table 1.3 shows the pressure- driven membrane processes and their separation characteristics.

Table 1.3 Pressure driven membrane processes [48]

Process Technology	Separation Principle	Size Range	MWCO	Objective
MF	Size	0.05 – 10 µm	-	Removal of suspended solids, bacteria, cysts and spores e.t.c.
UF	Size, Charge	1-50 nm	> 1000	Removal of both large dissolved solute molecules and suspended colloidal particles including protein, viruses e.t.c.
NF	Size, Charge, Affinity	~ 1 nm	200-1000	Removal of multivalent ions and certain charged or polar molecules such as sugars, pesticides e.t.c.
RO	Size, Charge, Affinity	<1 nm	<200	Removal of inorganic ions, salts and sugars

Reverse Osmosis is the tightest of the membrane types and it retains all components of the feed sample except the solvent (usually water), reverse osmosis is usually used to separate aqueous salts and ions with a molecular weight less than 200 [48]. Reverse osmosis membranes would reject high molecular weight compounds, low molecular weight compounds, glucose, amino acids and a host of different organics. Reverse osmosis finds wide application in different industries and processes, most common of which is desalination where reverse osmosis membranes are used to reduce dissolved solids from feed waters with salinities up to 45,000 ppm TDS (total dissolved solids) or more. Compared to other pressure driven processes reverse osmosis is a high pressure process as the pressure applied is in excess of the osmotic pressure of the dissolved constituents to allow for flow of the permeate across the membrane. Reverse osmosis systems always have operating pressures of between 15-150 bar (217.5-2175 psi).

Nanofiltration is the next tight membrane type following reverse osmosis membranes. It uses charged membranes with pores that are bigger than reverse osmosis membranes but too small to allow the permeation of many organic compounds such as sugars [40]. It would reject high molecular weight compounds, monosaccharides, disaccharides and oligosaccharides, polyvalent negative ions and bigger molecules. It finds wide use in color removal, sugar and dye removal and removing THM precursors and hardness or sulfate from water. It has a pressure rating of between 5-35 bar (72.5 – 507.6 psi) and its mean pore size is also usually rated below 0.003 microns.

Ultrafiltration is the next tight membrane type following nanofiltration. Ultrafiltration is used in the separation of particles in the 0.02-0.2 um range. It finds common use in the retention of macromolecules such as proteins, polysaccharides, viral particles and some pathogens. It is a low pressure membrane system, ultrafiltration systems are rated for pressure between 1-10 bar (14.6 -146 psi). It has wide application in various industries and processes ranging from pharmaceutical, to food and beverage, agricultural and petrochemical processes. Ultrafiltration would be one of the membrane processes that shall be examined in this thesis for the filtration of water based E&P wastes.

Microfiltration on the other hand is the least restrictive pressure drive membrane process. It is used to separate particles in the micron range conventionally between 0.02 – 4 um, it removes bacteria, pigment, clay, suspended particles and larger sized solutes. It is also a low rated pressure process, microfiltration processes are rated for pressure less than 2 bar (29.2 psi). More membrane materials are used in microfiltration than any of the other pressure driven process and microfiltration finds wide use in various industries and processes. Though the delineation of the pore size range in each membrane classification seems clear theoretically, in reality this is not the case as there are usually overlaps in their classifications in different literature and from different membrane manufacturers. The pore size and pressure rating delineation vary from author to author, what is of importance is the graduation in rejection and added pressure as one goes from pressure driven process to another.

1.9.3 Membrane Module

Finally also of importance to this research is the membrane classification based on the module configuration. There are four recognized or common membrane modules [49]; the plate and frame, spiral wound, hollow fibre and tubular membrane modules. These modules can be built with various membrane materials and they are built for various purposes based on the intended need. No single module is deemed best but thorough knowledge of the feed stream to be treated, the economic and operational constraints and membrane filtration characteristics determine the most suitable membrane module for an intended purpose.

1.9.3.1 Plate and Frame

Plate and frame type membranes are amongst the earliest membrane module type. They consist of a rigid, flat plate on which a flat sheet of membrane is placed and a spacer is put between the membrane and the flat plate. The spacer, a netlike material is placed between the membrane sheets and provides channel for permeate flow and this sheet is sealed around the edges with a passage for permeate collection. This “unit” (membrane-spacer-membrane) is then stacked on top of each other or adjacent to one another depending on the decided orientation of the stack. The operation of the plate and frame module involves passing the feed through the plates and the permeate flows though spacer to the collection tube, the retentate goes through the module to the exit. See figure 1.6.

Advantages of the plate and frame include the ability for easy maintenance of the membrane module as replacement of the stack is easy and the cleaning is equally easier and straightforward. In comparison to other modules based on cost of the material and module, the plate and frame module is cheap. The plate and frame module have intermediate energy consumption and packing density when compared against the spectrum of the tubular and spiral wound modules [50]. This module cannot handle high solids feed streams as the passage of the spacers would be easily blocked and are best adapted for low solids streams. Plate and frame modules find wide application in food and beverage industries and some chemical process lines.

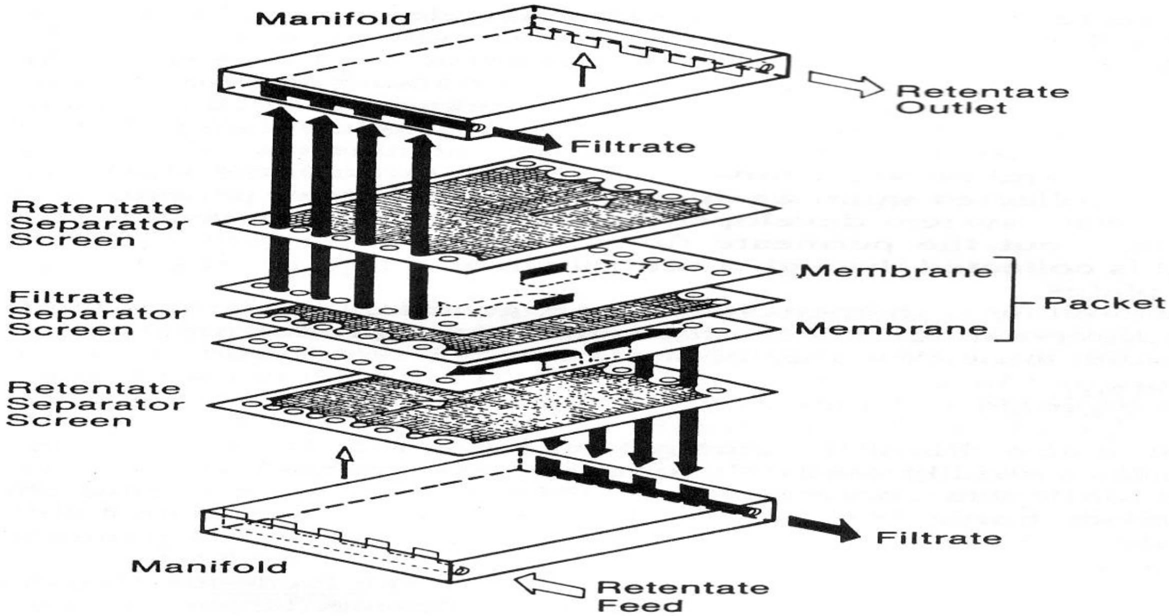

Fig. 1. 6 Schematic of a plate and frame membrane [42].

1.9.3.2 Spiral Wound Membranes

Spiral wound membranes are similar conceptually to the plate and frame module but differ in that the successive layers of membrane are wound around a perforated center tube. They are also designed around two flats sheets, with active sides (filtering sides) positioned opposite each other and separated by the same netlike spacer as in the plate and frame module, glued on the sides. Different from the plate and frame is that another spacer, the feed channel spacer, is placed on "one side of the envelope and the whole assembly rolled around the center tube in a spiral or jelly-roll configuration" [40]. The spiral wound is operated by pumping through the cross section on the module and the spacer channels permeate to the perforated tube in the center for collection. See figure 1.7.

Spiral wound membranes are famed to be the most compressed and economical design of membrane modules available commercially. Spiral wound membranes have the highest membrane area packed into a given pressure vessel with their surface to volume ratio averaging 200-300 ft^2/ft^3 [41,50]. They are reasonably priced and they are seen as membrane workhouses as they find wide applications in different industries, processes and systems. They also have low energy consumption and their capital costs are the lowest amongst most module designs. Their major limitations is similar to the plate and frame module as they cannot handle high solids feed without adequate pre-treatment as suspended particles are sure to block the channels created by the spacers.

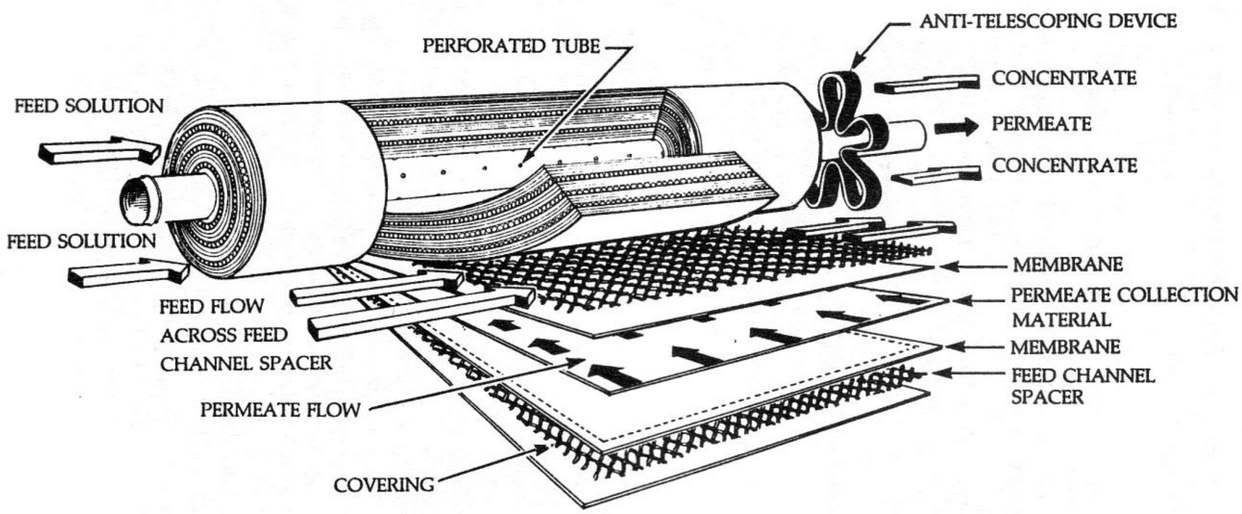

Fig. 1. 7 Schematic of a spiral wound [40].

1.9.3.3 Hollow Fiber

Hollow fibre membranes are basically made up of "spaghetti" like fibers bundled together and sealed by an epoxy resin plug encased in PVC, or acrylic tube or a fibre plastic. They are similar to the tubular membranes (discussed next) differing only in the fact that they stand alone (hollow fibre) and their internal diameter is less than 2 mm. They represent the latest of all membrane modules and have a high surface to volume ratio. They are made in a wide array of diameters from 100 micron to about 2 mm, "their fibers have a cross-sectional thickness of about 100 -400 microns with bundles containing about 50 - 3000 individual fibers sealed into hydraulically symmetrical housings in a shell-and tube arrangement bonded by epoxy at their end" [41]. See figure 1.8.

Advantages of the hollow fibre membrane include a high surface area to volume ratio, they have very low pressure rating with their maximum pressures hovering around 1.8 bar (25 psig), and also their energy consumption is relatively low when compared to other membrane modules. They have good backwash or back flush capacity and hollow fibre systems are usually built to carry out periodic backwash during operation such as seen in the Zenon 300 Unit built by GE. They can also handle moderate solids feeds though the flux would be higher if it had low solids. Disadvantages of the hollow fibre membrane are plugging of the small tube diameter, which could be addressed with an aggressive back flush regimen.

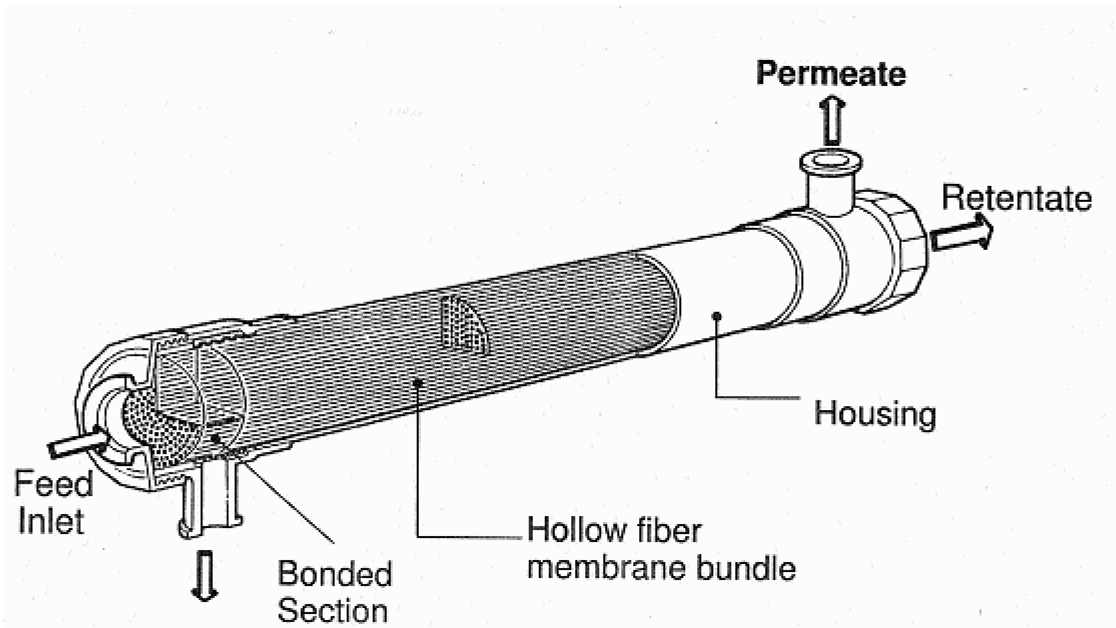

Fig. 1. 8 Schematic of a hollow fibre membrane [40].

1.9.3.4 Tubular Modules

Tubular membranes have the largest diameter of all membrane module types with internal diameters ranging from 0.5 – 1 inch (12.5 – 25mm) with lengths varying from the 2 to 20 ft (0.6 – 6.4m). As explained they differ from hollow fiber membranes in that they are supported along its length and cannot stand alone. Tubular membranes generally operate with the flow going through the internal diameter or lumen of the membranes and the permeate flowing outward from the skin of the membrane collecting in the housing where the membrane in fitted to a permeate collection outlet. Tubular membranes have low membrane densities, and a high flow demand when compared to other modules. See figure 1.9.

Tubular membranes are known to handle high solids feed more than any other membrane module type. They are also easily cleaned and have excellent backwash or back flush capacity like the hollow fibre, thus their tendency to fouling is lowest amongst the membrane modules. They have the lowest surface to volume ratio of all membrane modules and require more energy in their operation due to the high recirculation rates during operation. They are also relatively expensive as ceramic, polymeric and other tubular membrane modules cost more than other modules of the same material. Tubular membranes find wide application in a host of challenging rheological feed streams usually those with high suspended solids or with challenging chemicals such as solvents.

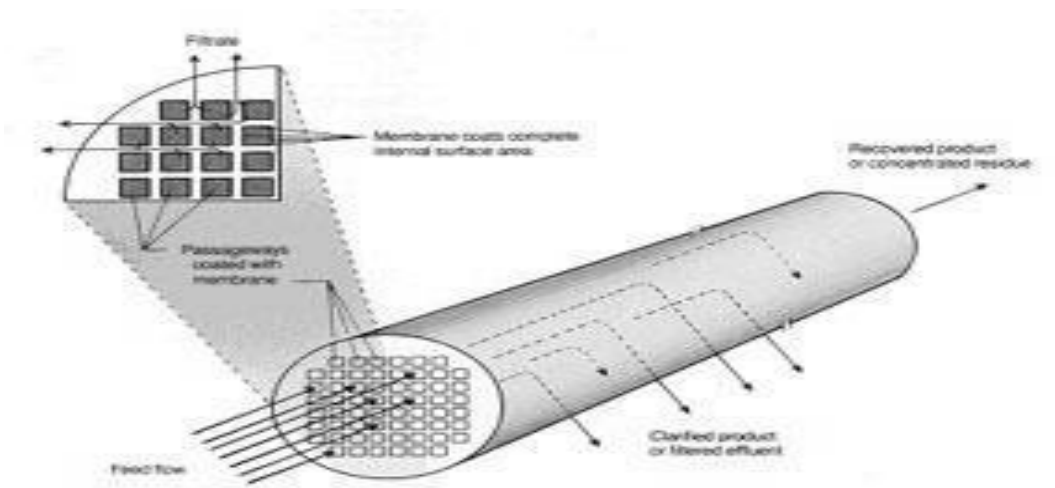

Fig. 1. 9 Schematic of a ceramic membrane.

1.9.4 Membrane Operation

There are two operating modes for membranes, the dead end filtration mode and the crossflow filtration mode. In the dead end mode the feed stream is pumped directly through the membrane. Figure 1.10a depicts the feed going into the membrane and one stream the permeate leaving the membrane. During dead-end filtration all the solvent that enters the membrane surface passes through the membrane while the solid particles or retentate stay behind on the membrane. Inevitably the solvent will experience greater flow resistance as the retentate builds up on the surface of the membrane resulting in flux decrease. Dead end filtration is common in low solids feed such as cartridge filtration of boiler feed or ultrafiltration of apyrogenic pure water production [48].

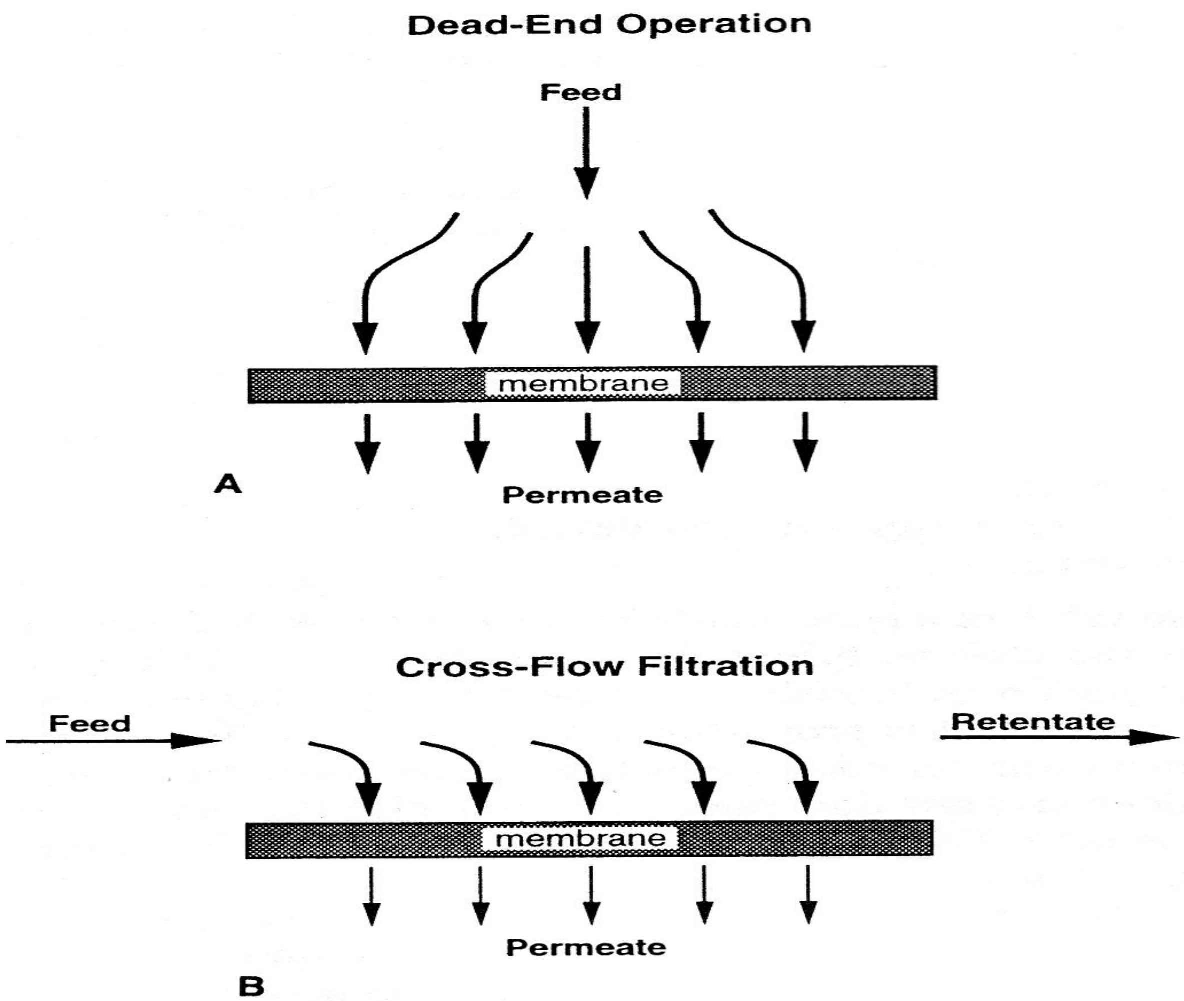

Fig. 1. 10 Dead end and cross flow filtration schematic. a) Dead end b) Cross flow [42].

The second operating mode is called the cross flow operating mode as shown in figure 1.10b. It involves moving the feed stream tangentially across the membrane surface while the permeate flows normal to the surface. In this operation mode there is one stream entering the membrane (feed stream) and two streams leaving the membrane (the permeate stream and the retentate stream). Cross flow filtration is effective against filter cake build up as the suspended solids that would have otherwise accumulated at the membrane surface are removed by the shear caused by cross flow at the membrane surface. Cross flow filtration finds wide use in streams with high solids, though its operation requires more energy. It is effective in filtration of a lot of streams. This thesis is confined to investigations concerning cross flow filtration.

1.9.5 Summary

Membranes find wide application in various industries from the pharmaceutical industry to space research. They are ubiquitous in various filtration and separation processes and have over the years been applied to more applications as membrane material technology improves. This study investigated membrane technology for the separation of E&P wastes due to the versatility of membranes in separating comparable streams in other industries. Streams with more recalcitrant constituents and higher suspended and dissolved solids have been filtered successfully on industrial scales using membranes [51]. This investigation to our knowledge presents the first opportunity where field water based E&P wastes are investigated using different membranes to create effluent that can be re-useable for oil-field purposes. It seeks to filter spent drilling waste to extract re-useable effluent and concentrate the waste volume and to filter produced water as a mechanical pre-treatment upstream of desalination.

Membranes represent the most suitable technology to test the hypothesis that filtration of water based E&P wastes at the colloidal and particle size range produce effluents suitable for re-use. Traditional filtration and or separation system such as hydrocyclones and centrifuges are limited in their filtration size lower limit and filtration using these technologies usually aims at preparing the wastes for disposal not re-use. Also these traditional separation systems are energy intensive in their operation and have a large footprint when deployed to oil and gas sites. In comparison to these traditional technologies, membranes have low energy consumption and they also have very low foot print in comparison, these factors – the filtration size range, low foot print and energy consumption makes membrane investigation the most rational technology for colloidal and particle size filtration of water based E&P wastes.

Waste volume reduction through solids concentration was another integral objective of this investigation especially for spent drilling fluid. Traditional separation technologies available in the oil field have low volume concentration especially in the 50 micron range and below while membranes are effective at concentrating waste volumes when the right pore size is chosen. This ability to effectively separate the waste and at the same time concentrate the waste volume made the investigation of membranes for solids laden-waste such as spent drilling fluids interesting and practical. The benefits of re-use, reduced foot print (through pit size reduction) and reduced waste volume disposal costs are concrete drivers that make this investigation not only of academic value but of practical value to oil and gas industry.

Volume concentration and filtration of colloidal and sand particles is not only essential for re-use wastes in oil-field applications but it also affords the use of environmentally friendly technologies such as bioremediation that are impractical due to the volume of wastes generated. If filtration of water based E&P wastes using membranes is achievable, other water based wastes such as fracture fluid backflow which are generated and disposed without re-use would also be open to similar investigation. This investigation intends to open the discussion at a more practical environmentally friendly look at water based waste management.

CHAPTER II

MATERIALS AND MEMBRANE CHARACTERIZATION

2.1 Introduction

The aim of chapter II is to describe the nature of the water based E&P wastes used in the experiments, how they were defined and how some degree of uniformity was achieved. A description of the experiment design and experimental procedures is also provided including schematics to give better comprehension. Membrane equipment operation procedure and maintenance is also explained along with the cleaning and treatment methods employed on the different membranes. Finally, equations used in calculating the parameters of interest from flux to fouling metrics are also listed in this chapter.

2.2 Sources and Uniformity of Drilling Wastes

The water based E&P wastes (produced water and spent drilling fluids) used in all experiments were procured from the field and were representative of wastes as produced during real operations. Produced water samples were supplied by Advanced Hydrocarbons, Graham Road, College Station, Texas. Advanced Hydrocarbons is a salt water disposal company that hauls salt water, fracture (frac) fluids and specialty chemicals from various oil and gas operations injecting them into underground storage wells (class II D injection wells). Advanced Hydrocarbon receives produced water from drilling and fracturing operations mostly in Texas and adjoining states in the south.

Produced water samples for the experiments were collected freshly when needed from the Advanced Hydrocarbon operation in College station. The samples were pumped directly from the hauling trucks to the 250 gallon collecting tanks for transport to the laboratory. The hauling trucks carried fresh produced water usually from a hundred miles location or more to the disposal site. About a hundred and fifty (150) gallons were collected each time for our experiments and samples were collected twice a week, samples after 72 hours were usually not used for experiments. Produced water when left to sit for a while changes and is markedly different from the original sample from the source, using the samples as soon as possible was an important objective. At the truck collection point the produced water is randomly sampled for temperature, pH, salinity, chloride and calcium to confirm if the sample was within our defined arbitrary range.

The spent drilling fluid was supplied by Newpark Drilling Fluids LLC, Texas, from the Chevron Carthage drilling operation. The drilling fluid used in all the experiments was a lignosulphonate water based drilling mud. This mud was transported from the field to the Texas A&M laboratory from the Carthage field operations in East Texas near the Louisiana state line. The spent drilling mud was from the mud pit and transported in sealed 55 barrel drums. A mud report came with each sample and after each sample was delivered it was sampled for the mud weight, viscosity, gel strength, pH, and salinity. All samples if not used immediately were kept in refrigerated storage rooms at the Texas A&M food protein laboratory till they were used. Samples were mixed vigorously before experiments especially after storage, dilution was necessary for samples allowed to seat for long periods although this was minimal, efforts were made to use the samples as soon as they were delivered.

Uniformity of E&P wastes is a difficult concept to achieve in practice. Produced water from different formations or reservoirs differ in their composition chemically and physically and this also applies to drilling fluids. Spatial and temporal factors account for significant changes in the nature of these wastes. To make uniform the wastes used in the experiments, ranges were specified for the properties of interests and as much as possible samples from the same location with the same properties were sought. Sourcing similar waste from the same location worked in procuring spent drilling fluid as the mud company (Newpark Drilling Fluids) supplied the same operator (Chevron) the same mud type to drill the same type of formation in the same region (Carthage, Texas). For the produced water a range was specified for the parameters of interests namely- salinity, pH, solids concentration and the concentration of some divalent ions. Using portable measuring kits we were able to achieve some degree of uniformity based on our criterion.

Two types of drilling fluids represent about 90% of the water base drilling fluid used in drilling operations [53]. The first drilling fluid is the lignosulfonate drilling mud, this water base drilling mud is treated with lignosulfonate a chemical additive which is a byproduct of papermaking. Lignosulfonate is added as a constituent of the mud to cause deflocculation of solids and clay particles, this drilling fluid is used mostly in drilling wells with high bottom hole temperatures and in wells contaminated by calcium or salts. The second drilling fluid is the KCL polymer mud, the basis of the mud is the normally anionic encapsulating polymer fluid, potassium chloride, which is added to provide potassium ion that assists in stabilizing reactive clays particularly mixed layer clays in the formation [52,53]. Lignosulfonate based drilling muds are by far the most popular and were the mud of choice in this study. It differs from the KCL polymer muds rather slightly and the deflocculation of the solids poses a greater hindrance to filtration so it was chosen because it is the least filterable of both mud types.

2.3 Experiment Design

In the experiment design the first experiment carried out was membrane characterization of all membranes using reverse osmosis water (RO) water. This provided the baseline characteristic of the individual membranes. It shows how the operational parameters of transmembrane pressure (TMP), cross flow velocity (CFV) and temperature interacts with the membrane material and the pore size. This characterization shows us the optimum membrane operation using an ideal feed. Two membrane material types and module type were used in this baseline characterization; PVDF hollow fibre membrane and the ceramic tubular membrane. The hollow fibre membrane pore sizes were 0.1 and 0.2 micron while the ceramic membrane sizes were 0.005, 0.01 and 0.2 microns.

The next step was the determination of the effect of feed characteristics variation on the filtration of water based wastes (produced water and spent drilling fluids) using both membrane types (ceramic and hollow fibre). An arbitrary operational parameter set was determined and feed characteristic varied (an arbitrary feed characteristic set was also defined) during individual runs. The feed characteristics studied and varied were solids concentration for spent drilling fluids and oil concentration for produced water. Using the defined arbitrary operational parameter (pressure, transmembrane pressure and cross flow velocity) a variation of the feed characteristics was made using values above and below the defined feed characteristic to determine the effect variation had on filtration. The objective was to determine a suitable feed characteristic range for filtration of drilling wastes and also for studying the effect of operational parameter variation. This was done using both membrane types.

After the feed characteristic variation of both waste types, the effect of the operational parameters- temperature, cross flow velocity and transmembrane pressure on the filtration of produced water and spent drilling fluid using both types of membrane types was determined. Variations against an arbitrary set of values for temperature, cross flow velocity and transmembrane pressure was carried out by varying a single operational parameter while holding the other operational parameter values constant. This variation of the single parameter was done above and below the arbitrary set value. Uniformity in the waste composition used in the operational parameter evaluation was preserved as humanly possible to ensure balanced comparison. After this set of experiments a suitable operational parameter set that best optimized filtration and reduced fouling was then determined and used for the next set of experiments.

Experiments were carried out to determine to determine the resistance calculation using only the ceramic membrane type, the data generated from flux decline curves was also used to determine if filtration could be explained using the constant pressure blocking laws filtration models [65,68]. Fouling mitigation techniques using clean permeate and or water was also carried out to determine the best method to prolong the onset of flux decline during filtration of these wastes using both types of membranes. Permeate and or clean water was used in backwashing to determine the efficacy of recovering the flux after flux decline. Most of the experiments were carried out three times and the graphs produced are an average of the three data points from each experiment. Experiment duration was usually 65 -80 minutes except during fouling and backwash experiments were experiments had longer durations between four to six hours.

Membrane cleaning studies were also carried out using two different cleaning solutions, the Divos 110 alkaline cleaning chemical and a patented aqueous surfactant solution supplied by a wellbore cleaning company. The cleaning solution effectiveness was compared against each other by determining their clean water flux recovery after filtration at conditions that consolidated fouling most especially after filtration at high transmembrane pressures. The procedure and experiment design used in the resistance calculation and chemical cleaning studies as well as the fouling mitigation studies are provided in the respective chapters where the results are presented.

2.4 Equipment

2.4.1 Filtration Unit

The filtration equipment used was a custom made filtration unit from the separations sciences department in Texas A&M. It has a 15 gallon feed reservoir from which a 5 HP rated centrifugal pump pumped the sample through the membrane filters. Upstream and downstream of the membrane housing are pressure gauges that measure the inlet and outlet pressure respectively. Flow passes through a flow meter at the feed outlet showing the flow through the membrane, a valve is used to control the flow rate from the pump. The flow from the membrane housing passes through a heat exchanger, using steam from the boiler or cool water from the cold water line, the temperature of the sample is kept regulated and there is a thermometer that reads the temperature of the sample.

For backwashing operations the alterations were made to the module where a tube from an exterior pump was used to flow permeate/pure water in reverse flow to the filtration flow at high cross flow velocity, another tube at the other module end leads the flush out. During backwash the permeate valve is shut off. The filtration equipment had the capacity to take three membrane housing in parallel, but only one membrane housing connection was used for all experiments.

For the hollow fibre membranes connections were made that allowed the operation of the hollow fibre membranes to be used in the same filtration system as the ceramic membranes. These connections also allowed for backwash of the hollow fibre membranes. Integrity tests were carried at all connections to make sure there were no leaks during backwash, also pressure readings confirmed if there was a leak present. To run the tests with a different micron size, a different ceramic or hollow fibre module with the pore size rating needed is fixed into the membrane housing. Figure 2.1 shows the schematic of the filtration equipment and figure 2.2 shows filtration when backwashing was used for fouling mitigation.

In the fouling mitigation investigation, backwashing was investigated. For the clean permeate backwash the filtration equipment had to be modified using valves and pipes to channel clean permeate to the membrane in the reverse direction, to do this an additional pump was used (not shown), figure 2.2 shows a schematic of the modified filtration unit to allow for the clean permeate backwash. Some tests were carried out with a 10 micron membrane filter upstream of the membrane housing inlet after the pump to prevent clogging when using the PVDF hollow fibre membrane. This was in cases where feed contained a lot of irregularly shaped solids.

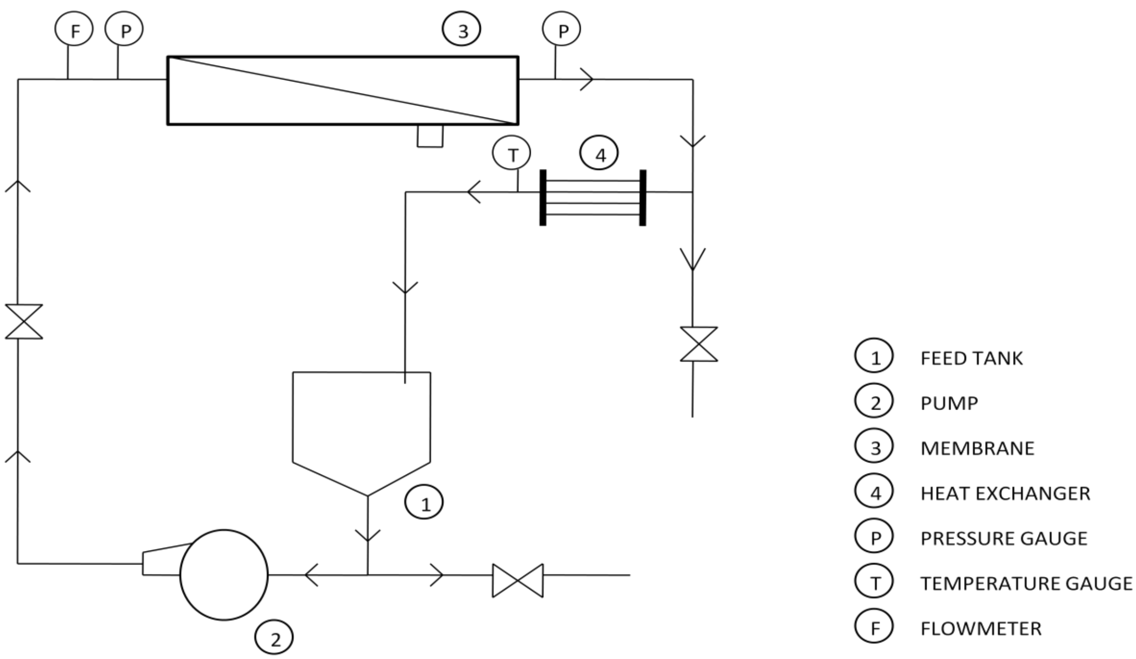

Fig. 2. 1 Schematic of filtration process.

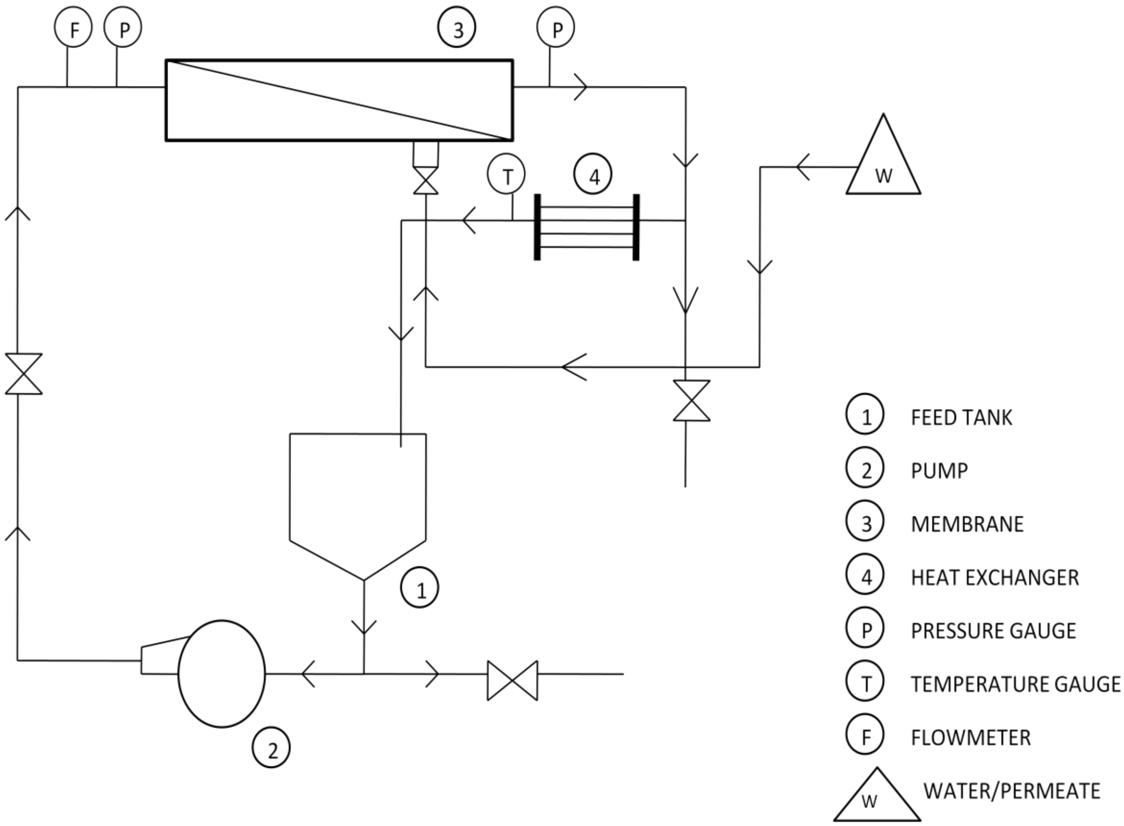

Fig. 2. 2 Filtration process modified for fouling mitigation.

2.4.2 Laser Particle Counter

The Spectrex PC- 2200 laser particle analyzer laser particle counter manufactured by Spectrex, California was used for solids particle analysis. Utilizing the principle of "near angle light scatter", a revolving laser beam passes through the walls of a glass container where it is directed through a central sensitive zone where the equipment not only counts the particles in suspension but tabulates their size as well. The analog signals generated by the light pulses are routed to a computer and digitized. Feed samples of both drilling fluids and produced water were analyzed before each run, permeate samples were also analyzed before each run and retentate samples were also analyzed before each run.

2.4.3 Salinity and pH Reading

The HACH Sension 156 portable multi parameter measurement device was used to read the salinity of the samples by inserting the electrodes into about 100 mL of the sample and the salinity of the sample was read digitally. Feed samples, permeate samples and retentate samples salinity was recorded for the all samples processed. For the drilling mud the salinity was read the same way and the salinity value was checked with that in the mud report that came with the mud samples.

The pH of the sample was also read using the HACH Sension 156 portable multi parameter measurement device. It was used to read the pH of the samples by inserting the electrodes into about 100 mL of the sample and the pH of the sample was read digitally. Feed samples, permeate samples and retentate sample pH was recorded for the all samples processed.

2.4.4 Turbidity Reading

The HACH turbidity meter was used to measure the turbidity of all samples. The samples are put into a 10 mL bottle in the bottle receptacle and covered, then light rays are then passed through the bottle and the deflection of the light rays are then quantified to give a reading. Feed samples, permeate samples and retentate sample turbidity was recorded for each experiment run.

2.4.5 Chemical Analysis Reading of Produced Water

Though ultrafiltration and microfiltration do not affect the separation of dissolved solids, for sample collection at the produced water disposal facility the dissolved solids needed to be measured to determine if the sample was within the arbritrary range set. Ion selective electrodes (ISE) from Laval lab in Canada were procured and electrodes for measuring calcium and chloride were used to determine the concentration of these ions in the samples. The permeate concentration of these ions did not usually change after filtration.

2.4.6 Temperature Reading

The temperature of the sample was read using the HACH Sension 156 portable multi parameter measurement, this was done by inserting the metal electrode into the samples directly and the temperature of the sample was read digitally. Feed samples, permeate samples and retentate samples were read for the all samples processed. It was also used to cross check the accuracy of the temperature gauge on the filtration equipment.

2.4.7 Oil in Water Concentration

The TD 500 oil in water analyzer manufactured by Turner systems was used to measure the oil in water concentration. The TD 500 analyzer measures the oil content in oily waters containing crude oil or gas condensate and it finds wide use in the oil and gas industry. It measures the oil content by UV fluorescence using an easy solvent extraction with high accuracy and reproducibility. The standard procedure of solvent extraction is specified by EPA - 1664A method and the analysis is compatible with common solvents such as hexane, Freon, Xylene amongst others. The TD 500 was calibrated using a San Francisco crude oil with 39 API and a calibration curve was made based on the known concentration response to UV.

2.5 Experimental Procedure

Before each run the clean water flux of the membrane is recorded at a set temperature, transmembrane pressure and cross flow velocity with reverse osmosis water. The feed tank is then filled with the samples and pumped through the membrane, the operational parameters are set blow the required values and filtration is allowed for about ninety (90) seconds. After ninety seconds, the operational parameters are then set to the desired flow rates and filtration of the sample continues. Using steam or cold water, temperature regulation is achieved using the heat exchanger. The pressure of the feed inlet and outlet are recorded manually on the data chart as well as the permeate volume, sample flow rate and temperature of the samples. The permeate volume is manually measured using a stopwatch and a measuring cylinder, the permeate volume is measured three times and the average of the three readings is recorded as the point value.

After each experiment the clean water flux is recorded, then the membrane is flushed at higher cross velocity and low pressure using reverse osmosis water, using the initial temperature, transmembrane pressure and crossflow velocity the original clean water is compared to see how much flux is lost. In the event that considerable flux is lost, chemical membrane cleaning is usually carried out to restore the flux to its original comparable level, clean water flux less than 90% required chemical cleaning. To address fouling propensity due to amount of runs especially during normal filtration and repeats, most filtration experiments were run for not more than seventy (70) minutes and were run for longer duration for the fouling and backwashing experiments. Using the membrane size measurements and manually recorded measurements, the flux, yield, concentration values and fouling parameters were calculated.

2.6 Analytical Formulae

Membrane filtration has different purposes in separation of liquid streams; it might be to concentrate the solute or to reduce the volume waste or to extract a component of the solution. Whatever the purpose of filtration certain metrics are required in measuring if filtration is feasible and to determine methods of improving filtration. With respect to the intent of separation of water based wastes namely the removal of suspended solids and volume reduction, metrics such as permeate flux, rejection, recovery and volume rejection are essential in determining the feasibility of water based wastes membrane filtration.

1. Flux (J)

Filtration feasibility is determined by the amount of membrane area used and the permeate flux produced. The ideal is to use minimal membrane area to produce larger permeate flux, this saves on energy, space and brings good economic return on filtration. The membrane flux is expressed in terms of the unit membrane area with respect to the permeate volume collected in unit time. Flux is defined as

$$Flux = \frac{Permeate\ volume\ collected}{membrane\ area\ \times time}$$

(2.1)

Flux can be calculated in liters per m^2 per hour (LMH) or it can be calculated as it is in this thesis in gallons per ft^2 per day (GFD), the day is not corrected for 8 hour operation and remains a 24 hour day. Pure water flux (J_w) differs from the permeate flux as it measures the permeate flux using RO water as the feed under specified conditions of temperature, pressure and cross flow velocity, it is an essential measurement in membrane fouling studies.

2. Rejection (R)

Rejection relates to the amount of the solute quantity that is left behind in the membrane. Rejection shows the efficiency at which the membrane separates the species of the feed that needs to be separated either to claim permeate or the retentate. In this thesis the species to be rejected would be the solids concentration (spent drilling fluids) oil-concentration (produced water), it is measured as

$$R = 1 - \frac{Cp}{Cf} \qquad (2.2)$$

where R is rejection, C_p is the concentration of the species in the permeate and C_f is the concentration of the species in the feed. Rejection can also be reported in percentage by multiplying by 100.

3. Recovery (Y)

Recovery is defined at the amount of the feed that is treated; it is an estimation of the performance of a membrane system. It measures the volumetric fraction of the permeate to the feed showing how much of the permeate is recovered from the feed.

$$Y(\%) = \frac{Qp}{Qf} \times 100 \qquad (2.3)$$

Where Y is the recovery, Qp the permeate volume and Qf the initial volume of the feed.

4. Concentration Factor (CF) and Volume Reduction (VR)

The concentration factor or the concentration ratio is the ratio of the initial feed volume (or weight or flow rate) to the retentate volume (or weight or flow rate). When volume is considered it is called the volume concentration ratio (VCR)

$$VCR = \frac{Initial\ feed\ volume\ (Vo)}{Retentate\ volume(Vr)}$$

(2.4)

Volume reduction is the amount the feed volume has reduced; it is represented by comparing the volumes of the feed at the end of filtration to the volume initially

$$VR = \frac{V\ (final)}{V(initial)}$$

(2.5)

Using mass balance it is seen that concentration factor, the rejection and recovery are linked

$$CF = 1\ + R(\frac{Y}{1-Y})$$

(2.6)

Equations dealing with fouling and fouling mechanisms are presented in the chapters where the results are discussed.

2.7 Membrane Characterization

2.7.1 Introduction

This chapter is designed to generate a baseline description of the membranes used during filtration experiments using reverse osmosis (RO) grade water. This description illustrates the basic characteristic of the individual membranes and how the operational parameters of transmembrane pressure (TMP), cross flow velocity (CFV) and temperature interacts with the membrane material and pore size to determine the filtration capacity of the membrane when a solids free feed is filtered. RO water is water devoid of any ions; the RO water used in this membrane characterization was made by running tap water through a reverse osmosis filter. This device also ensures the removal of microorganisms through treatment by UV radiation downstream of the filter.

The ceramic membranes were manufactured by Corning Membranes. The membranes were made from α-Alumina (0.2 micron), Silica (0.005 micron) and Titania (0.01 micron). The general properties of membranes are described in chapter I. Three average pore size membranes were used in our investigation; they are the 0.005 micron, 0.01 micron and the 0.2 micron membranes. The dimensions of the ceramic membranes are 305 mm in length, 27 mm in diameter and an effective membrane area of 0.13 m^2. The ceramic membranes are monolith membranes and a pictorial depiction of a ceramic membrane is shown in figure 1.9.

The hollow fibre membranes were procured from Pall microfilters, they are the called the microza membranes and were developed in Japan, they are made from polyvinylidene fluoride (PVDF) and are hydrophobic membranes. Two average pore size membranes were used in our investigation they were 0.2 micron (UMP 153) and 0.1 micron membrane (USP 143). The membranes have a 1.4 mm internal diameter and a 2.2 mm outer diameter. The 0.2 micron filter have bounded hollow fibre bundles giving an effective membrane area of 0.8 m^2 and the 0.1 micron filter have bounded hollow fibre bundles giving an effective membrane area of 0.12 m^2. A pictorial depiction of a hollow fibre membrane is shown in figure 1.8.

Studies [54,55]show that membrane properties such as pore size, membrane material and operational parameters (temperature, TMP and CFV) determine the filtration ability of membranes making feed characteristic the other determinant in the applying membranes to a particular stream. In this ideal feed membrane characterization, the relationship between membrane property and operational parameters (temperature, TMP and CFV) are investigated to describe their relationship. This is designed to serve as a baseline description of the membranes and present a basis for operational parameters used in experiments with the actual feed (water based E&P wastes).

In membrane filtration especially in microfiltration (MF) and ultra filtration (UF), permeate flux is seen to directly increase with increase in transmembrane pressure [56] for cases where there are conditions of low feed concentration and high feed velocity [40]. In the absence of these conditions (low feed concentration and high feed velocity) fluxes becomes independent of pressure and permeate flux is mass transfer controlled, incremental pressure would not bring about an increase in flux. The region where pressure increase directly influences flux by increasing flux is known as the pressure controlled region. Transmembrane pressure is also an important factor in fouling of membranes; pressure regimens control the activities of gel layers on the membrane surface and determine the rate of flux decline.

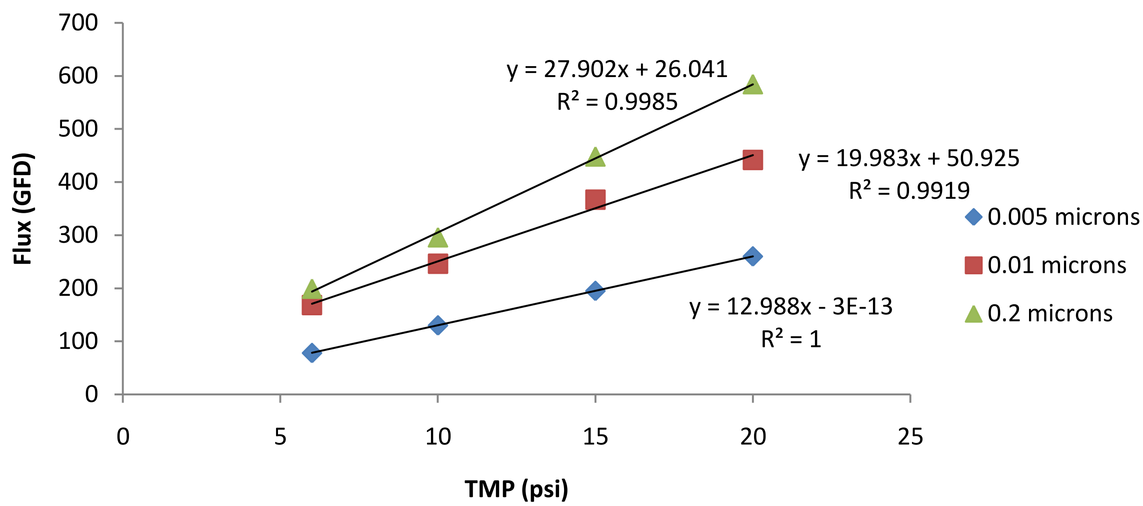

Fig. 2. 3 Effect of TMP on the RO permeate Flux for the ceramic membrane at CFV of 8.04 ft/s at 22 C.

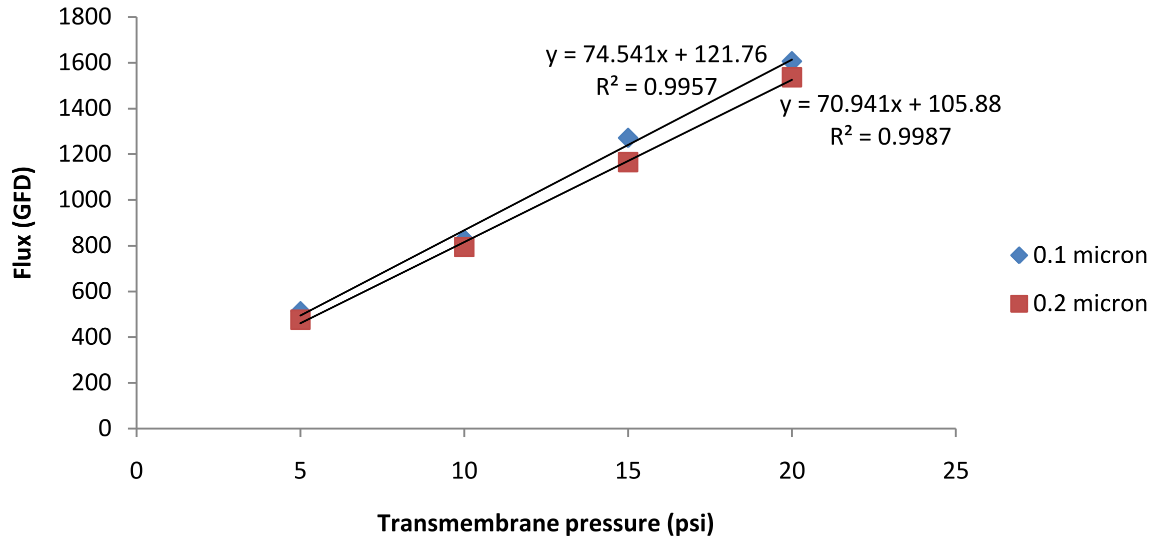

Fig. 2. 4 Effect of TMP on the RO permeate Flux for the hollow fibre membrane at CFV of 3.84 ft/s at 22 C.

As seen from figures 2.3 and 2.4 there is a close to perfect linear correlation between transmembrane pressure and flux in both the ceramic membrane and the hollow fibre membrane at the chosen cross flow velocity and temperature. Flux at additional cross flow velocities and temperatures were also carried out and the same linear correlation was observed. This linear correlation is expected as we have all the requisite conditions – low feed concentration and high feed velocity for filtration to be pressure controlled.

As expected flux is higher in membranes as the pore sizes increase at comparative pressure, cross flow velocity and temperature and this is due to the fact that membranes with larger pores sizes have lower membrane resistance (R_m) and as such would have higher permeate fluxes. At lower pressures (less than 10 psi) at the same cross flow velocity the flux between the 0.2 and 0.01 micron membranes seem to be closer but at higher pressures the increase in flux with pore sizes becomes apparent. This would seem to give an indication of the sensitivity of permeate flux to transmembrane pressure at larger pore sizes. It seems that the larger the pore size the greater the sensitivity transmembrane pressure has on the permeate flux, thus it can be inferred that in pressure controlled region of the flux profile larger pore sizes are more sensitive to increases in transmembrane pressure.

With the hollow fibre membrane results we see that permeate flux increases slightly with pore size at comparative pressure, cross flow velocity and temperature. The flux difference between both micron sizes of the hollow fibre membranes is smaller when compared to the flux difference between proportional pore sizes of the ceramic membranes. The reason for this disparity in the pore size flux difference could due to the fact that the effective membrane area of the 0.1 micron hollow fiber membrane is greater than that of the 0.2 micron hollow fibre membrane due to the higher number of hollow tubes packed in the 0.1 module. Comparing flux of both membrane types, we see that the hollow fibre membranes have higher fluxes at the about the same pressure and lower cross flow velocity, this is due to the large surface area to volume ratio of this membrane compared to the ceramics [50].

Cross flow velocity is the rate at which the feed flows over the membrane area and the cross flow velocity (CFV) at which membranes are run is essential for various reasons as shall be discussed later. CFV has a large effect on the flux in the mass transfer controlled region i.e. the region where pressure increase does not affect the flux. Cross flow velocity is also essential as more feed is pumped through the membrane without fouling higher yields are attained. Also higher cross flow velocities dictate how much pumping energy is expended in operating membranes. Ceramic membranes traditionally have to be run at comparatively high CFV relative to hollow fibre membranes due to the recirculation frequency of the retentate because of its low surface area to volume ratio, therefore running ceramic membranes require more energy than the low cross flow rated hollow fibre membranes.

Most tubular membranes units operate under turbulent conditions with high Reynolds numbers usually greater than 10,000. This translates to a high feed flow through the membrane and a lot of turbulence generated during filtration. In contrast the hollow fibre membranes operate at laminar conditions with Reynolds number of usually less than 3000, though they operate at laminar flow, shear rates are also high in hollow fibre due to a combination of thin channels and high velocity, Cheryan [40] reports that shear rates ay the walls could be between 12,000 – 16000 sec^{-1}.

Ceramic membranes are run at average of about 6 – 16 ft/s while hollow fibre membranes are run at about 2-5 ft/s [49]. CFV also helps in prolonging the onset of fouling as it can be used in controlling the gel-layer as shall be explained later. The ceramic membranes were run at four velocities, 6.04 ft/s, 8.04 ft/s, 11.09 ft/s and 14.11 ft/s all corresponding to flow rates of 6, 8, 11 and 14 gallons per minute. The hollow fibre membranes are rated for low operating velocities, for the 0.2 hollow fibre membranes two cross flow velocities of 3.48 ft/s and 6.59 ft/s were used corresponding to 4.5 and 8.5 gallons per minute respectively while for the 0.1 micron membrane two cross flow velocities of 3.81 ft/s and 6.69 ft/s were used corresponding to 4.0 and 7.0 gallons per minute respectively were used.

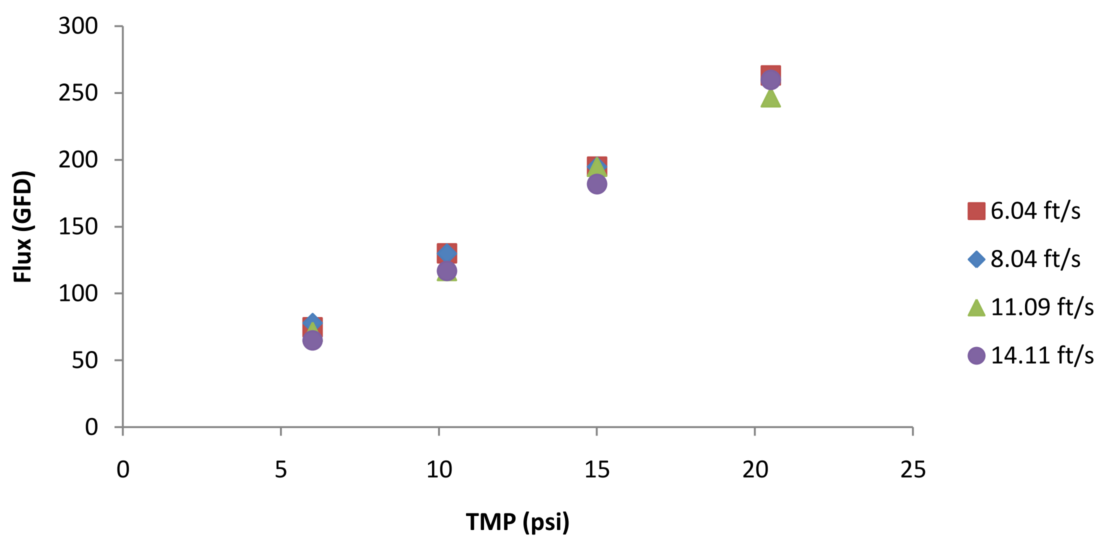

Fig. 2. 5 Effect of cross flow velocity on the 0.005 pore size ceramic membranes .

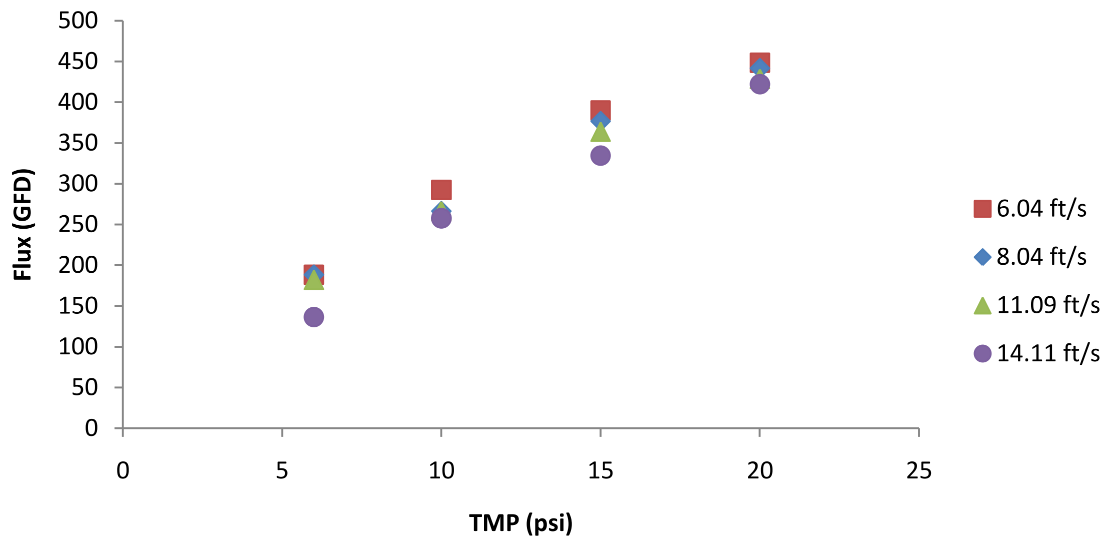

Fig. 2. 6 Effect of cross flow velocity on the 0.01 pore size ceramic membranes.

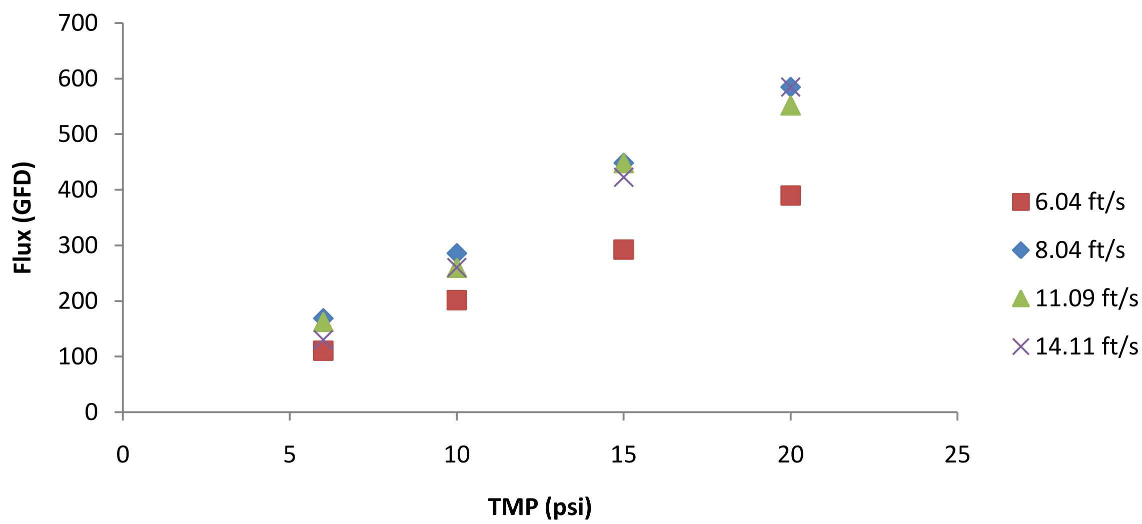

Fig. 2. 7 Effect of cross flow velocity on the 0.2 pore size ceramic membranes .

From figures 2.5-2.7 where the cross flow velocities are varied at different pressures, we can see that there is no significant effect of high cross flow velocities on the flux as the flux remains nearly the same with increases in cross flow velocities. This is because the system is still in the pressured control region and experiences no fouling thus the pressure continues to be dominant in determining flux increase. The nature of the feed (RO water) where there are no solutes being deposited on the membranes or even if there were any deposition of solutes, the cross flow velocity is high enough to prevent fouling of the membrane surface creating a condition where mass transfer has no effect. When filtering drilling wastes that have higher feed concentrations than the RO water, the effect of higher cross flow velocities shall be apparent.

The same observation as noted with ceramic membranes was also observed in the hollow fibre membranes as seen in figures 2.8 and 2.9.

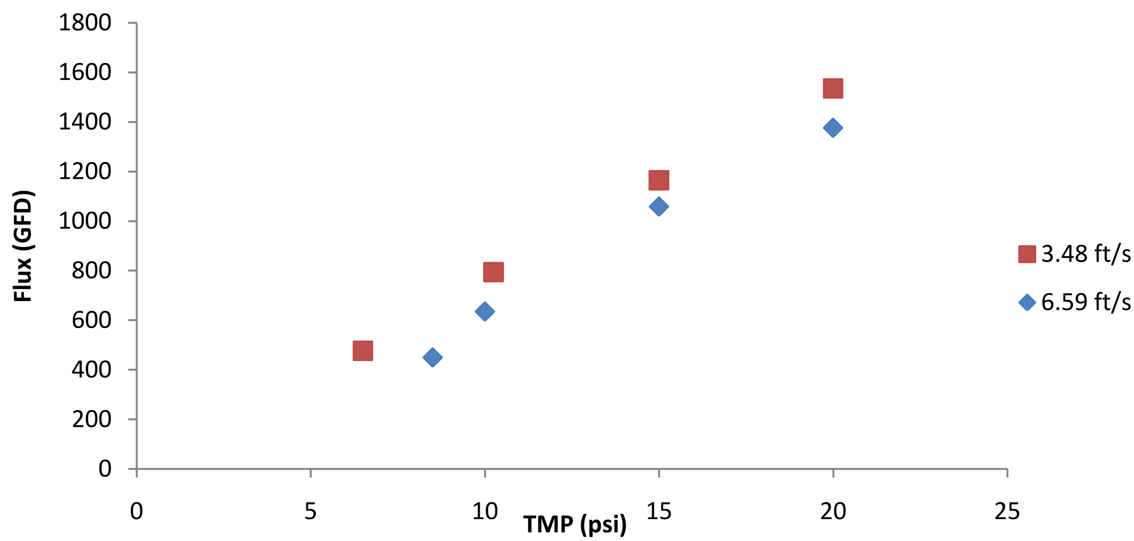

Fig. 2. 8 Effect of cross flow velocity on the 0.2 pore size hollow fibre membrane.

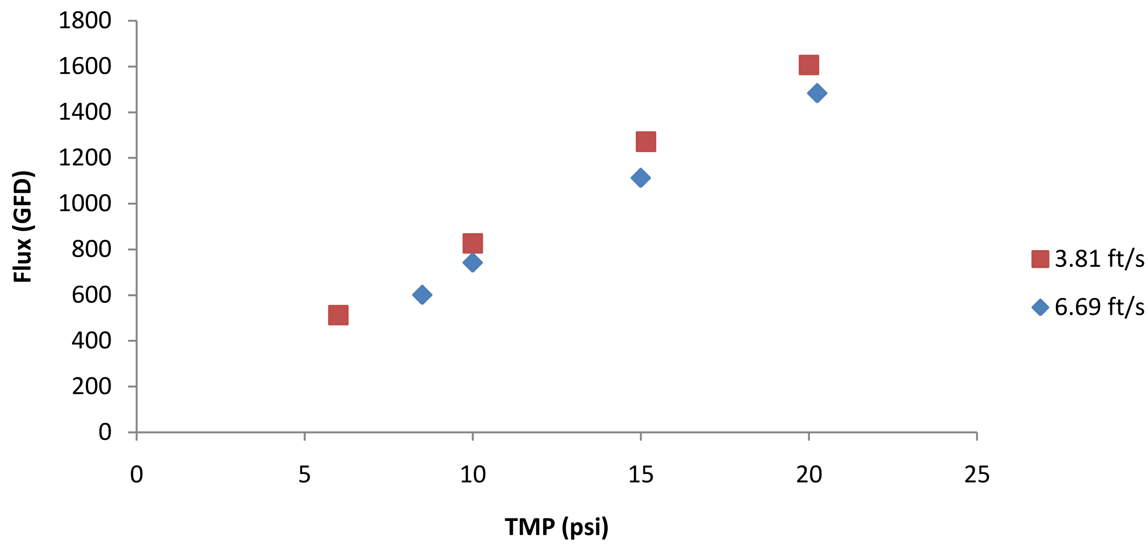

Fig. 2. 9 Effect of cross flow velocity on the 0.1 pore size hollow fibre membrane**.**

Comparing the flux at the different cross flow velocity for the different pore sizes we come up with the same conclusion as in figures 2.5 and 2.6 that flux increases linearly with the pressure and that the effect of cross flow velocity is minimal in the pressure controlled region.

In the absence of fouling and of the membranes or deposition of solutes on the membrane, increase in temperature results in higher fluxes; this increase in flux is attributed to the effect of temperature on fluid density and viscosity [56]. Temperature reduces the viscosity of the feed solution reducing the cohesive molecular forces while simultaneously allowing the greater increase of molecular interchange with the former more pronounced than the latter causing a reduction in the viscosity of the feed [40]. Since this membrane characterization occurs in the pressure controlled region the effect of temperature on the flux is solely due to its effect on fluid density and viscosity.

Figure 2.10 illustrates the effect of temperature on the permeate flux in the membrane characterization using RO water. It was observed that flux increased linearly with temperature. For the 0.2 micron ceramic membrane flux increased from approximately 260 GFD to 345 GFD in a 23 ^{o}C rise in temperature, it is believed that in practical terms, it would take a temperature rise of 30-45 °C to double the flux [40,57] and our observation seems to validate the claim. The same correlation was observed in the different ceramic pore sizes (0.005 and 0.01).

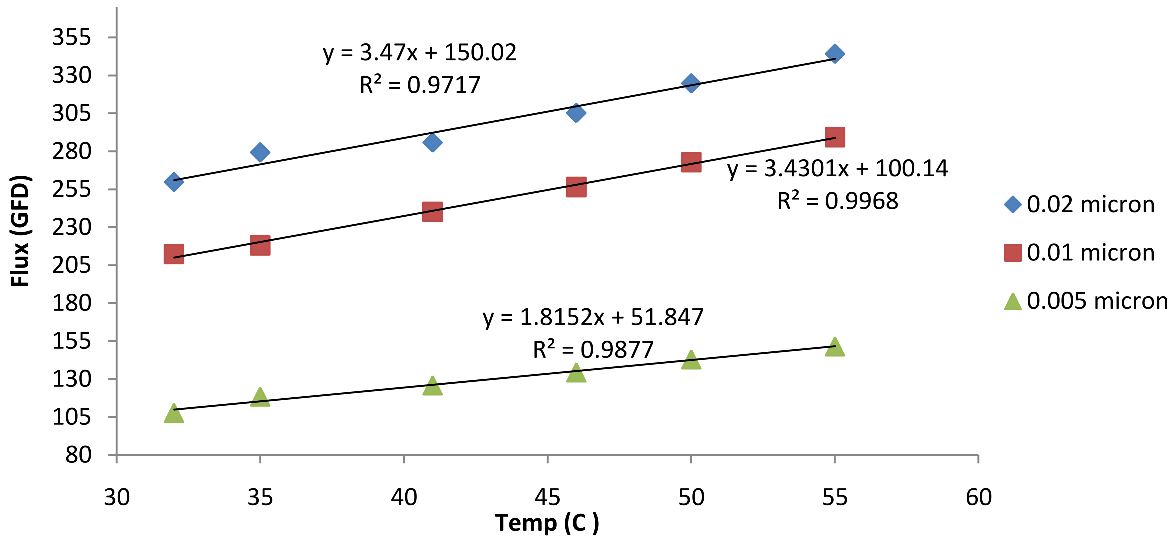

Fig. 2. 10 Effect of Temperature on flux of ceramic membranes (CFV 8.04 ft/s, TMP 15).

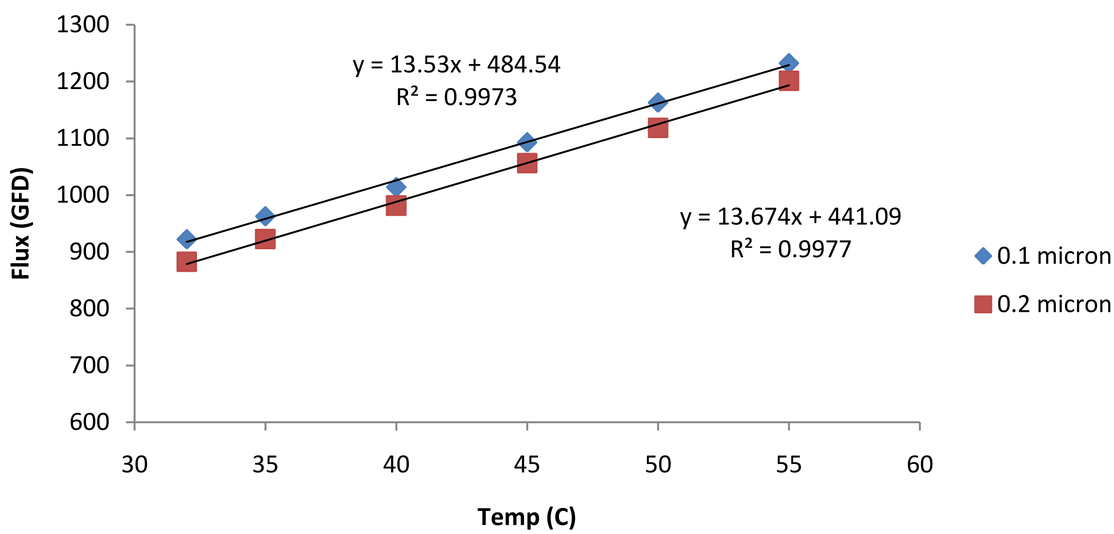

Figure 2. 11 Effect of Temperature on flux of hollow fibre membranes (CFV 3.81 ft/s, TMP 9.5).

The same linear correlation was observed in the relationship between temperature and flux using the hollow fibre membranes as illustrated in figure 2.11.

2.8 Summary

This chapter describes membrane characterizations using the three most important operational parameters in membrane filtration namely transmembrane pressure, cross flow velocity and temperature. The fluxes recorded here would be the maximum achievable fluxes due to the nature of the feed sample, it would be expected that the actual fluxes would be reduced in the filtration of water based E&P wastes particularly the filtration of spent drilling fluids. In the actual filtration of spent drilling fluids the effect of the solids concentration in the feed would affect filtration as mass transfer dynamics would be prominent. With respect to resistance, membrane resistance shall interfere in the filtration process, resistances due to concentration polarization, adsorption, reversible and irreversible fouling shall all affect the operation parameters and ultimately the flux.

It is observed that the larger the pore size the larger the permeate flux. For the colloidal filtration of water based E&P wastes the pore size choice of the membranes needs to be balanced against the needed permeate solids distribution, the propensity of fouling and maintaining the desired flux to make filtration feasible. The permeate solids distribution should be in the range needed for re-use, for example in the pre-treatment of produced water for desalination using reverse osmosis membranes, if the feed can be treated to 5 NTU or less, desalination is optimized thus membranes can serve as a mechanical pre-treatment for desalination. The propensity for fouling should be low when choosing a pore size, if pore sizes are to small permeate flux might not be practical and if pore sizes are too large fouling propensity increases.

The permeate flux also increased linearly with transmembrane pressure and temperature. The nature of the feed masked the complex relationship between pressure and flux in the mass controlled region as it is rarely linear. Pressure rise without subsequent rise in permeate flux is indicative of fouling thus pressure differences are important in membrane filtration fouling analysis. Also the pressures at which membranes are run (depending on their pore size) are important in aiding or delaying fouling. High pressures during filtration using large pore membranes with feed with particles size aggregates a lot smaller than the membrane pores accelerate pore plugging when compared to low pressures [40,49,56]. Temperature effects are dependent on the feed solution especially its viscosity and fluid density, less viscous feed would aid better filtration than a more viscous feed.

The other purpose of the membrane characterization was also to find a way to rationally arrive at some reasonable standard operating parameters for filtration experiments using water based E&P wastes (see Tables 2.1 and 2.2). Experiments shall be carried out where the operational parameters of pressure, cross flow velocity and temperature shall be varied, to determine the effect each parameter on the membrane filtration of the two drilling wastes of interest i.e. produced water and spent drilling fluids. These variations shall be compared to the standard operating parameters from the membrane characterization to determine their effect. From the characterization we arbitrarily with enough reason define the standard operating parameters for the different membrane types as follows.

Table 2.1 Standard operating values for the hollow fibre membrane

Parameter	Arbitrary Standard Value
Transmembrane Pressure (psi)	10
Cross flow Velocity (ft/s)	3.48
Temperature (^{o}C)	38

Table 2.2 Standard operating values for the ceramic membrane

Parameter	Arbitrary Standard Value
Transmembrane Pressure (psi)	15
Cross flow Velocity (ft/s)	8.04
Temperature (^{o}C)	38

CHAPTER III

FEED AND PARAMETER VARIATION

3.1 Introduction

In this chapter the results of the filtration of water based wastes i.e. spent drilling fluid and produced water using ceramic tubular and hollow fibre membranes is reported. Filtration experiments involved varying the feed parameters and the operational parameters of both water based wastes types below and above the arbitrary parameter value to determine their effect using the two membranes types. Observations were made and the description of the results are reported as well as compared against existing literature. Intra and inter membrane filtration results comparison is also made in reporting the results.

3.2 Drilling Mud Filtration

3.2.1 Parameter Variation of Drilling Mud Filtration

Feed samples for filtration of spent water based drilling mud were transported directly from the field and sent to the laboratory, each sample came with a mud report and a mud check was carried out in the mud lab to confirm details of the report. The feed parameter of interest in the filtration of spent drilling waste was primarily solids concentration and volume concentration was the intent of filtering spent drilling waste. The arbitrary spent drilling waste was defined to have 8.8± 0.5% solids per volume (19,000± 7000 mg/L) and a pH of 9.5± 0.3. Initial feed volume was 8 gallons for normal filtration experiments, the experiments were run in a batch mode and at full recycle mode i.e. permeate was channeled back to the feed tank.

Arbitrary operating parameters for ceramic filtration was defined as a cross flow velocity of 10.08 ft/s, transmembrane pressure of 15 psi and temperature of 38 C. Temperature was varied between 20 and 52 C, transmembrane pressure varied between 10 and 20 psi and cross flow velocity varied between 6.04 and 16.12 ft/s. The feed parameter of interests was also varied, solids were varied between 8.8± 0.5% and 10.20± 0.15 % per volume (19,000± 7000 mg/L to 32,000± 4000 mg/L).

Spent drilling mud filtration was carried out using ceramic membranes alone. This was decided because of the particle size concentration of the spent drilling mud, at these solids concentration hollow fibre membranes would be fouled with no appreciable flux. No screening was done upstream of the ceramic filter, the sample was pumped directly through the membranes. The schematic of the filtration process is provided in chapter II, in practical terms this would mean wastes from the mud pits being filtered directly. The results of the filtration process are reported below.

Results

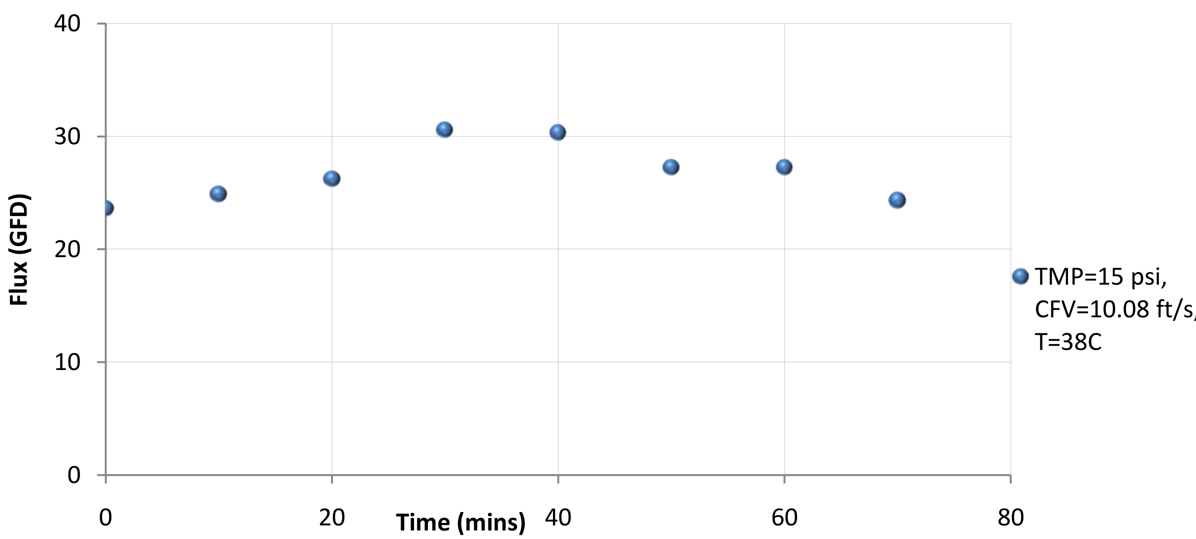

Fig. 3. 1 Ceramic filtration of spent drilling. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.005 micron), transmembrane pressure (15 psi), cross flow velocity (10.08 ft/s) and temperature (38 C).

In the ceramic filtration of spent drilling fluid with solids concentration of 8.8± 0.5% solids per volume and a pH of 9.5, filtering at a transmembrane pressure of 15 psi, cross flow velocity of 10.08 ft/s (corresponding to 10 gallons per minute (gpm)) and temperature of 38 C, the average flux was 26.8 gallons per foot square per day (GFD), maximum permeate flux was 30.57 GFD and the lowest flux was 26.31 GFD, see figure 3.1. Flux decline for the experiment period was less than 20% of the highest recorded flux and there was no significant pressure increase during the experiment. There was 95 % rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 18061 mg/L and 774 mg/L respectively. The volume concentration factor was 1.33 and the volume reduction was 0.75 i.e. the final volume was 75 % of the initial volume. Filtration for this duration and at these condition extracted 25% of the feed for reuse i.e. clean useable effluent for oil-field uses was 25% of the initial waste volume.

In the filtration of spent drilling fluids, like in the filtration of feeds with hydrocolloids and solids, solvent passes through the membranes and particles below the pore size remain on the membrane side where they tend to form a layer on the surface of the membrane. The initial rise in flux (between 0-30 minutes) occurs at the period where the wall is still being formed on the surface of the membrane and resistance to permeate passage is minimal. As filtration proceeds the wall is believed to be taking shape and resistance to the flow of permeate starts to increase with the build-up and it results in the onset of flux decline as less permeate percolates through the membrane. At this stage in filtration (the onset of flux decline) the effect of cross flow is lower than the energy needed to disrupt the formation of the wall; thereby it is believed that the wall layer is getting stabilized. The nature of the wall formed could range from viscous to gelatinous depending on the nature of the constituents of the feed [49].

The alternative explanation is that particles in the feed smaller than the pore sizes of the membrane plug the pores of the membrane. As the pores becomes constricted the flow of permeate is obstructed thereby creating hydraulic resistance to filtration. Progression of pore blockage would create a wall on the membrane surface when there is a saturation of particles in the pore spaces. The particle size distribution of the feed shows no particles smaller than the pore size (0.005 micron) due to equipment (particle size counter) threshold pore plugging cannot be totally ruled out though the nature of the solids in drilling fluids might make this plausible. Most models used in trying to simulate high solids feed filtration use spherical glass beads that retain their shapes and sizes through most of filtration. In reality drilling fluids have varied particle sizes and at high shear would break to form smaller particles especially at high cross flow velocities if they break to sizes below the pore size then pore plugging could be possible.

If the flux decline is due to the cake layer formed at the membrane surface, the layer is known by different names to different authors. It is known as the “gel layer”, “CP layer”, “filter cake”, “particle wall” or “polarization layer” [40,49,64,69]. Concentration polarization (CP) layer shall be adopted in this thesis. The CP layer is assumed not to be chemical in nature but rather of a physical nature with varying degrees of attachment of the particles to the membrane surface. The CP layer can be altered through varying operational characteristics during filtration particularly cross flow velocity; water flushing at higher cross flow velocities reclaims the membrane flux in most degrees of concentration polarization. The inert nature of ceramic membrane materials reduces the reactivity of the membrane to feed dissolved constituents thereby lowering the propensity of chemical fouling but fouling by minerals and organics in the feed can contribute to flux decline apart from particle and colloidal deposition as they can affect the nature of the CP layer.

Concentration polarization can have enormous influence on flux decline. Bruin et al [58] reported a drop to 5% of the initial flux in the ultrafiltration of skim milk using a dead-end cell without agitation in 25 seconds. One of the major advantages of cross flow filtration over dead end filtration is the ability to control the effect of concentration polarization or the formation of the layer, thus if dead end filtration were used for a feed like spent drilling fluids the CP layer would form almost immediately and would be irreversible.

There are two solids phases in water based drilling muds and both phases are suspended in the liquid phase of the mud. One solid phase called the reactive (colloidal) phase consists of microscopic particles that react with the liquid and consists mainly of clays. The other solid phase, the non-reactive phase, consists of finely ground solids such as sand, chert, limestone and some shales [52]. This non- reactive solid are undesirable due to their abrasive nature on rig equipment and reactive solids could be an issue if they cause distortion of the viscous properties of the mud making them non-reusable. The particle sizes of the solids of this reactive phase (colloids) range from 0.005 – 1 micron and the solids of the non reactive phase range from 1-50 microns for silt and barite and 50-420 microns for sand [53]. These are the particles being filtered by the membranes.

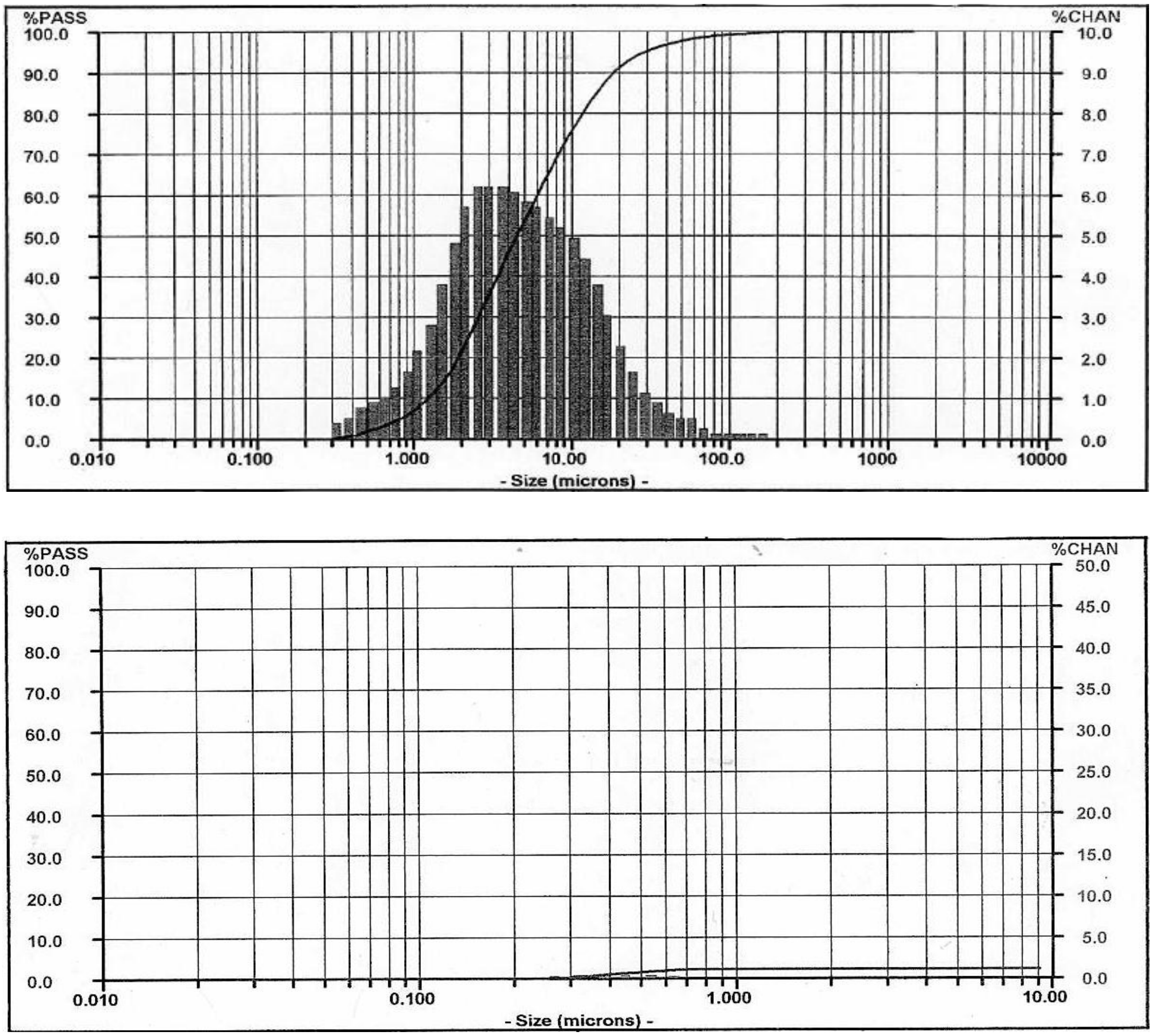

Fig. 3. 2 Shows the particle size distribution of the spent drilling fluid sample filtered using the ceramic. Top is the feed particle size distribution while the bottom is for the permeate.

From figure 3.2 the feed with 8.8± 0.5% vol volume solids has a particle size distribution of solids from between 0.3 microns to 100 microns with mean particle size distribution at 55 microns and median particle size at 11.35 microns. After filtration the permeate particle size distribution is seen to be less than 1 micron and at the threshold limits of particle size analyzer thus it was hard to get a repeatable solids distribution for the permeate. Using turbidity values the turbidity of feed was 1652 NTU and the permeate turbidity at all points was less than 1.16 NTU. These values of the effluent quality exceed the requirement in particle size distribution needed for re-use purposes in oil field applications

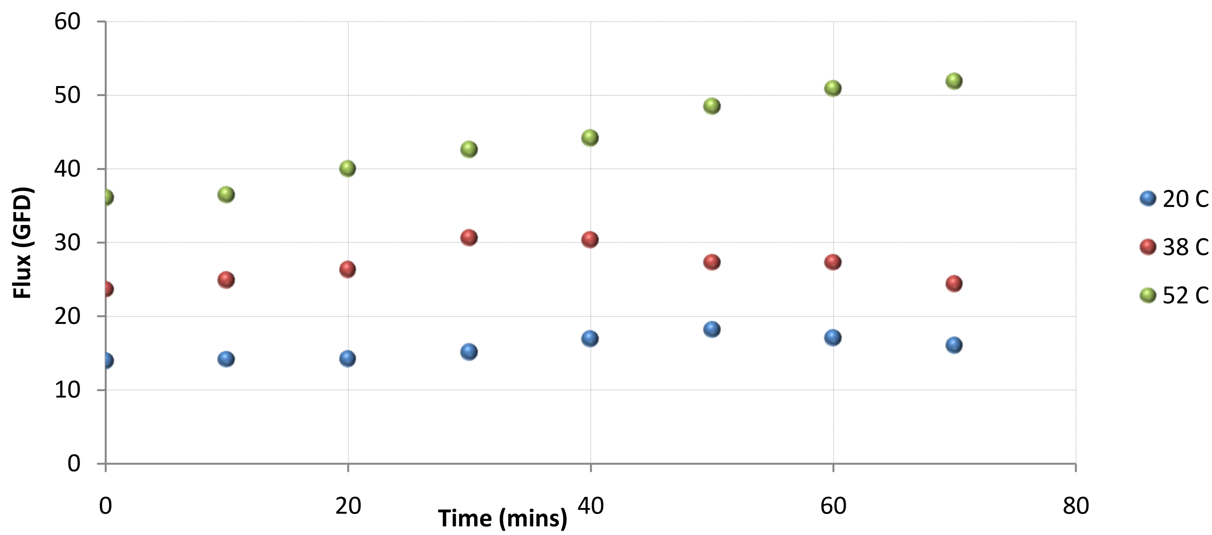

Fig. 3. 3 Temperature variation in the ceramic filtration of spent drilling. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.005 micron), transmembrane pressure (15 psi), cross flow velocity (10.08 ft/s) and temperatures (20 C, 38 C and 52 C).

Temperature in the filtration of the spent drilling fluid was varied from 20 C to 52 C while holding all the other operating parameters constant (transmembrane pressure = 15 psi, cross flow velocity =10.08 ft/s). In the ceramic filtration of the spent drilling fluid at 20 C, the average flux was 15.65 gallons per foot square per day (GFD), maximum permeate flux was 18.14 GFD and the lowest flux was 13.89 GFD, see figure 3.3. Flux decline for the experiment period was less than 20% of the highest recorded flux and there was no significant pressure increase. There was 96% rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 21070 mg/L and 856mg/L respectively. The volume concentration factor was 1.18 and the volume reduction was 0.84 i.e. the final volume was 84 % of the initial volume. Filtration for this duration and at these condition extracted 16% of the feed for reuse.

In the ceramic filtration of the spent drilling fluid at 52 C, the average flux was 43.77 gallons per foot square per day (GFD), maximum permeate flux was 51.84 GFD and the lowest flux was 36.1 GFD. Flux decline for the experiment period was also less than 20% of the highest recorded flux and there was no significant pressure increase. There was 95% rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 19,354 mg/L and 864 mg/L respectively. The volume concentration factor was 1.74 and the volume reduction was 0.572 i.e. the final volume was 57 % of the initial volume. Filtration for this duration and at these condition extracted 42% of the feed for reuse. The values for the results of filtration at 38 C are reported above.

Table 3.1 Flux characteristics of temperature variation in the ceramic filtration of spent drilling fluids

Temperature	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
20 C	18.14	13.89	15.65	1.22
38 C	30.57	26.31	26.80	2.09
52 C	51.84	36.10	43.77	3.42

By increasing the temperature by 22 C the average flux and total extractable permeate all increased by about 40%, see table 3.1. Temperature increase has been reported to increase flux in the absence of anomalies such as chemical precipitation. Temperature generally reduces the viscosity and fluid density of the feed sample, this allows for more flow of the permeate through the pores. Diffusion coefficient is an increasing function of temperature generally increasing by 3-3.5% for every degree increase thereby allowing greater permeation [52]. With increased temperature resulting in reduced viscosity more of the material is passed through the membrane and in practical terms temperature increase of about 30-45 C is believed to double the flux [40]. Costs are also significantly reduced. In the processing of whey milk operating at a higher temperature reduces the viscosity by 50% and reduced the overall pumping costs creating an annual savings of about 40% in a for a 30 C temperature difference [59].

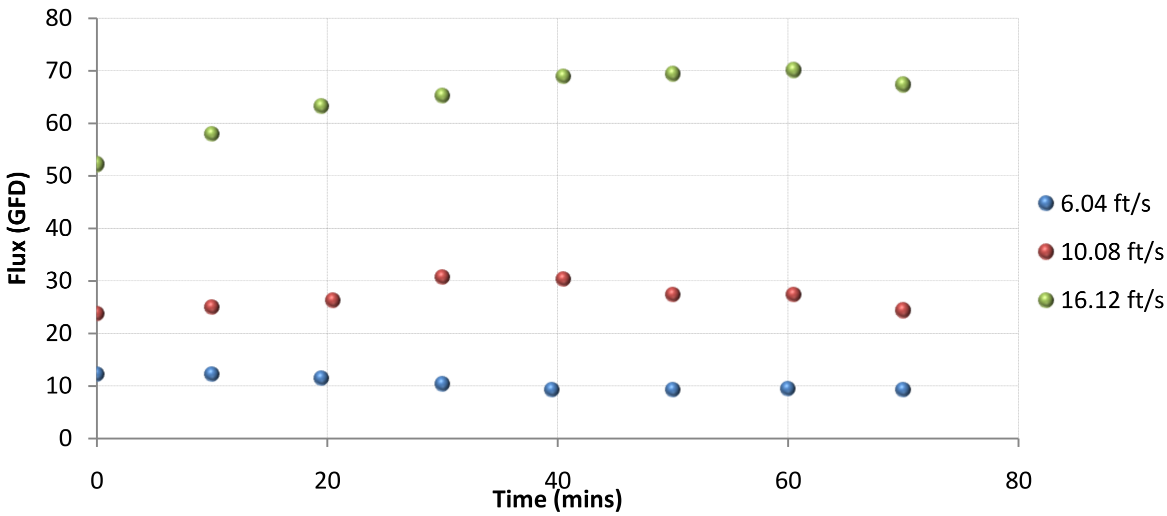

Fig. 3. 4 Cross flow variation in the ceramic filtration of spent drilling. Solids concentration (8.8 ± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.005 micron), transmembrane pressure (15 psi), cross flow velocity (6.04 ft/s, 10.08 ft/s and 16.12 ft/s) and temperature (38 C).

Cross flow variation in the filtration of the spent drilling fluid using ceramic membrane was varied from 6.04 ft/s to 16.12 ft/s corresponding to 6 gpm to 16 gpm, while holding all the other operating parameters constant (transmembrane pressure = 15 psi, temperature =38 C). In the ceramic filtration of the spent drilling fluid at 6.04 ft/s, the average flux was 10.36 gallons per foot square per day (GFD), maximum permeate flux was 12.17 GFD and the lowest flux was 9.2 GFD, see figure 3.4. Flux decline for the experiment period was also less than 25% of the highest recorded flux and there was no significant pressure increase. There was 95% rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 24361 mg/L and y 1112 mg/L respectively. The volume concentration factor was 1.11 and the volume reduction was 0.89 i.e. the final volume was 89 % of the initial volume. Filtration for this duration and at these condition extracted 11% of the feed for reuse.

In the ceramic filtration of the spent drilling fluid at 16.12 ft/s, the average flux was 64.23 gallons per foot square per day (GFD), maximum permeate flux was 70.07 GFD and the lowest flux was 52.13 GFD. Flux decline for the experiment period was also less than 20% of the highest recorded flux and there was no significant pressure increase. There was 96% rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 19,074 mg/L and 733 mg/L respectively. The volume concentration factor was 2.67 and the volume reduction was 0.37 i.e. the final volume was 37 % of the initial volume. Filtration for this duration and at these condition extracted 62% of the feed for reuse. The values for the results of filtration at 10.08 ft/s are reported above.

Table 3.2 Flux characteristics of cross flow variation in the ceramic filtration of spent drilling fluids. CFV=cross flow velocity

CFV (ft/s)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
6	12.17	9.2	10.36	0.81
10.08	30.57	26.31	26.80	2.09
16	70.07	52.13	64.23	5.01

Cross flow filtration involves the flow of the feed tangentially to the membrane surface, there is one stream entering into the membrane and two streams flowing out of the membranes, the permeate stream flows perpendicular to the inlet flow and the retentate flows in the same plane as the feed. Cross flow filtration affects flux decline because it can be used to control concentration polarization especially with feeds that have high solids content [40,60,63]. The flow regimen in the ceramic filtration of spent drilling fluid is turbulent, at 6.04 ft/s, 10.08 ft/s and 16.12 ft/s the Reynolds number were 5762.88 9521.28 and 15388.90 respectively. The turbulence produced by the flow "scours" the membrane surface due to the shear removing the accumulated solids from the membrane surface and reducing the hydraulic resistance of the concentration polarization layer reducing the cake thickness.

At higher cross flow velocities it is observed that flux rate increases, total permeate increased by 100% when the cross flow velocity was increased by 6 ft/s in the ceramic filtration of spent drilling mud, see table 3.2. The turbulence at 16.12 ft/s was effective in controlling the concentration polarization layer and due to the higher flow rate more feed is also processed through the membrane. The shearing action of the flow makes the membrane surface layer "dynamic" as the solids concentration of the spent drilling mud acts to brush the surface.

Increasing cross flow velocity does not always guarantee higher fluxes especially in the pressure controlled region if the solids concentration is too low [40]. Particle size distribution is also seen to affect cross flow velocity effect on flux, Wakeman and Tarleton [60] show that in the filtration of a feed with ground calcite, flux reduced with higher cross flow velocities when the mean particle size of the feed was increased.

Increased cross flow velocity means in practical terms means higher pump energy and higher operational costs in membrane filtration of wastes. The benefits of increasing the cross flow velocity is usually weighed with the cost benefit of increased permeate volume or flux. Pressure regimen at high cross flow velocities is important as pressures contribute significantly to resistances during high cross flow velocity. Using higher cross flow velocities at low pressure regimens would delay the onset of fouling significantly but this advantage has to be weighed with respect to the volume of permeate generated. Low pressures would not generate high permeate volumes relative to permeate volumes at high pressure. Combinations of high cross flow velocity and high temperature would favorably increase permeate flux in a high solids feed as spent drilling fluids.

As would be explained in the discussion on transmembrane pressure variation, during filtration flux equilibrates at the point where convective transportation of the solids to the surface equals the rate of back diffusion of the solids from the membrane surface. High cross flow velocities cause the scouring of the membrane surface but at high pressures the layer at the membrane surface is consolidated. There becomes a time where at increased cross flow velocity and high pressure there is no gain in permeate volume as the solids consolidation at the surface prevents their removal, this is the reason why pressure regimens are important at high cross flow velocities [40,49].

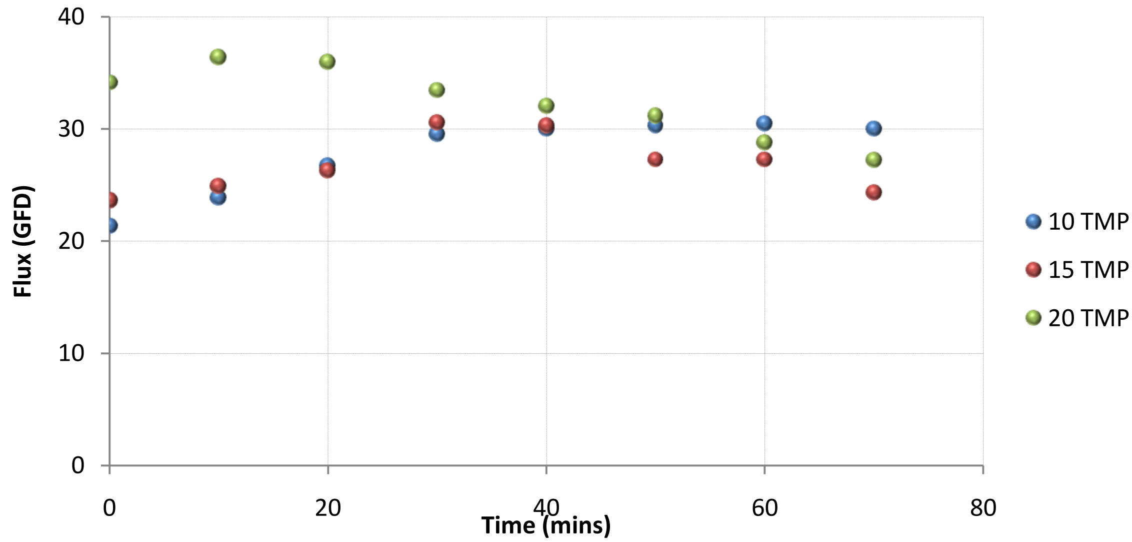

Fig. 3. 5 Transmembrane pressure variation in the ceramic filtration of spent drilling. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.005 micron), transmembrane pressure (10, 15 and 20 psi), cross flow velocity (10.08 ft/s) and temperature (38 C).

Transmembrane pressure variation in the filtration of the spent drilling fluid using ceramic membrane was varied from 10 psi to 20 psi while holding all other operating parameters constant (cross flow velocity =10.08 ft/s, temperature =38 C). In the ceramic filtration of the spent drilling fluid at transmembrane pressure of 10 psi, the average flux was 27.85 gallons per foot square per day (GFD), maximum permeate flux was 30.47 GFD and the lowest flux was 21.35 GFD, see figure 3.5. Flux decline for the experiment period was also less than 15% of the highest recorded flux and there was no significant pressure increase. There was 95% rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 22785 mg/L and 1165 mg/L respectively. The volume concentration factor was 1.37 and the volume reduction was 0.72 i.e. the final volume was 72 % of the initial volume. Filtration for this duration and at these condition extracted 28% of the feed for reuse.

In the ceramic filtration of the spent drilling fluid at transmembrane pressure of 20 psi, the average flux was 32.38 gallons per foot square per day (GFD), maximum permeate flux was 34.11 GFD and the lowest flux was 27.22 GFD. Flux decline for the experiment period dropped rapidly by about 20% of the highest flux. There was 97% rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 21,147 mg/L and 916 mg/L respectively. The volume concentration factor was 1.46 and the volume reduction was 0.68 i.e. the final volume was 68 % of the initial volume. Filtration for this duration and at these condition extracted 32% of the feed for reuse. The values for the results of filtration at 15 psi are reported above.

Table 3.3 Flux characteristics of transmembrane pressure variation in the ceramic filtration of spent drilling fluids. TMP=transmembrane pressure

TMP (psi)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
10	21.35	30.47	27.85	0.81
15	30.57	26.31	26.80	2.09
20	34.11	27.22	32.38	5.01

In the pressure controlled region i.e. when there is a low feed concentration, high cross flow velocity and low pressure regimen it is seen that flux increases with pressure linearly (see chapter II). In the mass controlled region where we have high feed concentration such as in spent drilling mud and medium to high cross flow velocities and pressure the dynamics of filtration in markedly different. In this condition the effect on the concentration polarization layer is a reverse of the scouring seen at high cross flow velocities rather there is a consolidation of the concentration polarization layer due to the effect of pressure on filtration causing an increase in hydraulic resistance hastening the onset of flux reduction. Table 3.3 gives a summary of the fluxes.

As seen in Figure 3.5 where pressure is varied, at 20 psi transmembrane pressure there is an onset of increased flux but after 20 minutes the flux starts to decline rather rapidly. This phenomenon is believed to be due to the consolidation of the concentration polarization layer as observed by Altmann and Ripperger [61]. Convective transport brings solid particles to the membrane surface and a steep concentration gradient develops within the boundary layer, at the same time back transport of the solids occurs due to diffusion. A steady state is soon reached where the convective transport of solids to the membrane surface is balanced by the diffusion back transport of the solids into the bulk. There arises a point where the solute buildup at the membrane surface is saturated i.e. the close packed arrangement of the solids at the membrane surface, at this point additional pressure forces the solids at the membrane surface to squeeze into pore spaces thereby fouling the membranes. At this point operation parameters such as increasing cross flow velocity have no effect on permeate flux.

At 20 psi at a cross flow velocity of 10.08 ft/s the dense close arrangement at the wall seems to build up rapidly, there is an initial increased permeate flow due to the pressure and this would account for more materials reaching the surface of the membrane. At the same cross flow velocity, increasing membrane resistance is observed starting from about 25 minutes, the transmembrane pressure rises by about 3 psi from that moment till the end of filtration indicating fouling and the minimum flux drops below the minimum flux at 10 psi. At the lower transmembrane pressure of 10 psi the reverse is noted, the equilibrium state between the convective and diffusion forces in the transport of the solids takes a longer time, this is evidenced by the increasing flux with time, at about 40 minutes at 15 psi flux decline is setting in and till the end of the experiment at transmembrane pressure of 10 psi no appreciable decline occurs.

Essential to filtration optimization is the balance between the operational parameters especially cross flow velocity and transmembrane pressure, if not properly managed they would accelerate the onset of fouling. High cross flow velocities increase permeation at low pressures for most feeds; Wakeman and Tarleton [60] describe the "tubular pinch" to explain the decrease in flux with increasing high cross flow velocities, a situation where progressively fine particles are deposited on the membrane surface as the larger particles remain in suspension. Higher transmembrane pressures at high cross flow velocities would accelerate the deposition of the finer particles on the membrane surface.

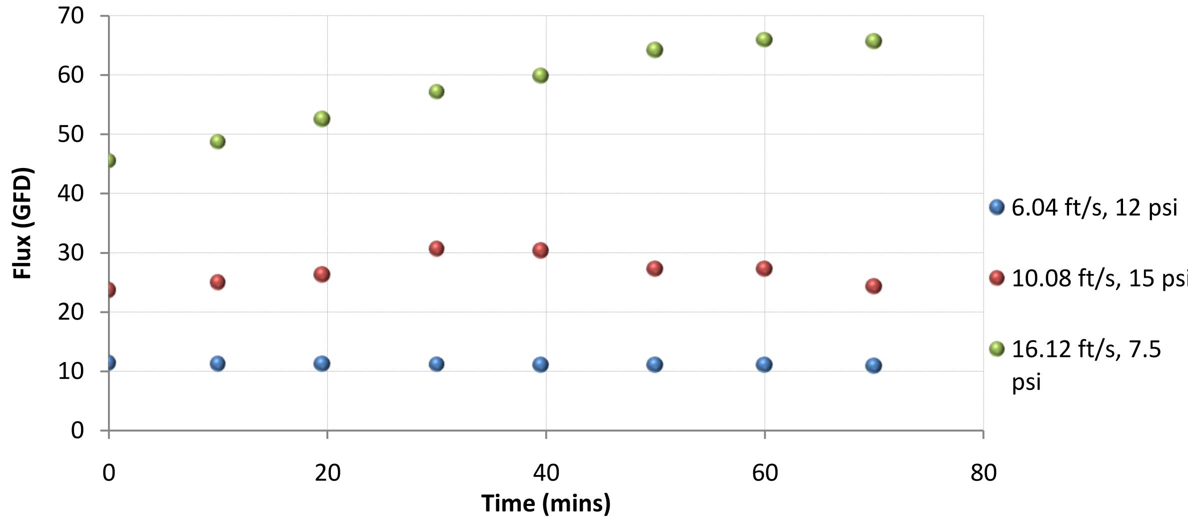

Fig. 3. 6 Varied parameters ceramic filtration of spent drilling. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.005 micron), transmembrane pressure (7.5, 12 and 15 psi), cross flow velocity (6.04,10.08 and 16.12 ft/s) and temperature (38 C).

A mixed regimen of the operational parameters was carried out. A regimen with medium transmembrane with low cross flow velocity (cross flow velocity =6.04 ft/s, transmembrane pressure = 12 psi) and another with a high cross flow velocity and low pressure (cross flow velocity =16.12 ft/s, transmembrane pressure = 7.5 psi) were investigated. In the ceramic filtration of the spent drilling fluid at cross flow velocity of 6.04 ft/s and transmembrane pressure of 12 psi, the average flux was 11.07 gallons per foot square per day (GFD), maximum permeate flux was 11.38 GFD and the lowest flux was 10.85 GFD, see figure 3.6. Flux decline for the experiment period was also less than 8% of the highest recorded flux and there was no significant pressure increase. There was 95% rejection of the solid by the membrane as the feed solids concentration and permeate solids concentration was 19,147 mg/L and 1016 mg/L respectively. The volume concentration factor was 1.10 and the volume reduction was 0.90 i.e. the final volume was 90% of the initial volume. Filtration for this duration and at these condition extracted 9% of the feed for reuse.

In the ceramic filtration of the spent drilling fluid at cross flow velocity of 16.12 ft/s and transmembrane pressure of 7.5 psi, the average flux was 57.39 gallons per foot square per day (GFD), maximum permeate flux was 65.85 GFD and the lowest flux was 45.45 GFD. Flux decline for the experiment period was also less than 20% of the highest recorded flux and there was no significant pressure increase. There was 94% rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 16,332mg/L and 963 mg/L respectively. The volume concentration factor was 2.27 and the volume reduction was 0.44 i.e. the final volume was 44% of the initial volume. Filtration for this duration and at these condition extracted 55% of the feed for reuse.

Table 3. 4 Varied parameter variation in the ceramic filtration of spent drilling fluids. TMP=transmembrane pressure, CFV= cross flow velocity

CFV (ft/s), TMP (psi)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
6.04, 12	11.38	10.85	11.07	2.17
10.08, 15	30.57	26.31	26.80	2.09
16.12, 7.5	68.85	45.45	57.39	2.53

In this mixed regimen filtration we see that by lowering the transmembrane pressure and using high cross flow velocity the onset of the flux decline is prolonged though the total permeate volume is less than the situation with high cross flow velocity and medium transmembrane pressure. This reduced permeate volume is due to the difference in transmembrane pressures from 15 psi and 7.5 psi. It is also observed that when low cross flow velocity is used with medium transmembrane pressure we have stable flux and no discernable flux decline throughout the experiment duration. This regimen comparison shows the operational balance needed in effectively maintaining flux during filtration of any waste stream. Table 3.4 gives a summary of the fluxes.

3.2.2 Drilling Fluid Solids Concentration Variation

The solids concentration of the drilling fluid sample was varied to determine what the effect would be on filtration using the ceramic membrane. To prepare a more concentrated sample than the feed delivered from the field the retentate of previous filtration was mixed with fresh feed and the solids concentration determined. A 10.2 % vol solids concentration feed was prepared using the retentate from previous spent drilling filtration experiments. A more dilute solution than the initial feed solids concentration was not prepared.

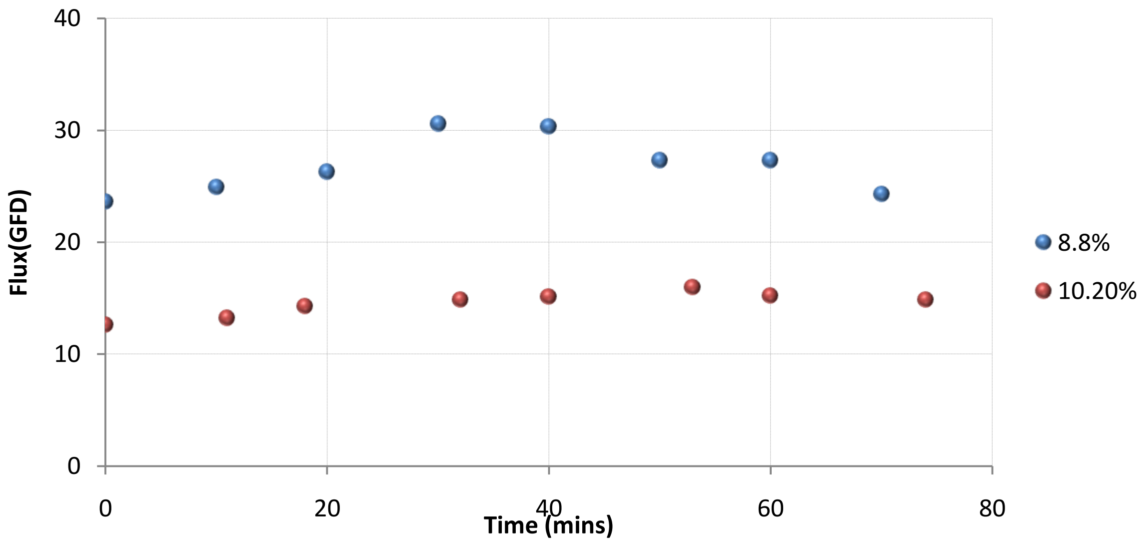

Fig. 3. 7 Solids concentration variation in the ceramic filtration of spent drilling. Solids concentration (8.8± 0.5% and 10.20± 0.15% vol) and pH (9.5). Ceramic membrane pore size (0.005 micron), transmembrane pressure (15 psi), cross flow velocity (10.08 ft/s) and temperature (38 C).

Solids concentration variation in the filtration of the spent drilling fluid using ceramic membrane was varied from 8.8± 0.5% and 10.20± 0.15 % volume while holding all other operating parameters constant (cross flow velocity =10.08 ft/s, Temperature =38 C). In the ceramic filtration of the spent drilling fluid at transmembrane pressure of 8.8± 0.5%, the average flux was 26.8 gallons per foot square per day (GFD), maximum permeate flux was 30.57 GFD and the lowest flux was 26.31 GFD, see figure 3.7. Flux decline for the experiment period was less than 20% of the highest recorded flux and there was no significant pressure increase during the experiment.

There was 95 % rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 18061 mg/L and 774 mg/L respectively. The volume concentration factor was 1.33 and the volume reduction was 0.75 i.e. the final volume was 75 % of the initial volume. Filtration for this duration and at these condition extracted 25% of the feed for reuse i.e. clean useable effluent for oil-field uses was 25% of the initial waste volume.

In the ceramic filtration of the spent drilling fluid at transmembrane pressure of 10.20 ± 0.15% the average flux was 14.5 gallons per foot square per day (GFD), maximum permeate flux was 15.99 GFD and the lowest flux was 12.6 GFD. Flux decline for the experiment period was less than 12% of the highest recorded flux and there was no significant pressure increase during the experiment. There was 90% rejection of the solids by the membrane as the feed solids concentration and permeate solids concentration was 33718 mg/L and 3064mg/L respectively. The volume concentration factor was 1.16 and the volume reduction was 0.85 i.e. the final volume was 85 % of the initial volume. Filtration for this duration and at these condition extracted 14% of the feed for reuse i.e. clean useable effluent for oil-field uses was 14% of the initial waste volume.

Table 3.5 Solids concentration variation in the ceramic filtration of spent drilling fluids. conc. = concentration

Solids conc. % vol	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
8.8± 0.5	30.57	26.31	26.80	2.09
10.20± 0.15	15.99	12.62	14.52	1.13

At higher solids concentration the average flux is about 50% lower than the flux at the lower solids concentration. High solids concentration results in high feed viscosity thus more energy is required to pump the feed through the membrane. At the same filtration conditions the feed with the higher solids concentration has more solids particles and thus the probability for flux decline is higher though the decline was not very steep in this case. The observable hump in filtration when filtering drilling mud is not observed when the solids concentration was increased; this might be because the saturation of the solids on the membrane surface occurs quickly. Flux remains fairly normal during filtration and this might be the base flux achievable under the filtration conditions. Viscosity and solids concentration are the dominant factor at higher solids concentration. Though there are reports in literature of filtering with about 20% solids, the flux and the possibility of abrasion of spent drilling fluid solids on the membrane makes filtering such high concentration seem impractical. Table 3.5 gives a summary of the fluxes.

3.3 Produced Water Filtration with Ceramic Membrane

3.3.1 Parameter Variation in Produced Water Ceramic Filtration

Feed samples for filtration of produced water were procured directly from disposal trucks from the field. Using portable kits concentrations of the oil in water, salinity and some dissolved solids were carried out to see if the feed was within the specified arbitrary range. The feed parameter of interest in the filtration of produced water was primarily oil in water concentration and turbidity. The arbitrary produced water was defined to have an oil concentration range of 250 – 1200 ppm oil in water, turbidity of less than 4000 NTU, pH of 6.5 – 10 and TDS less than 40,000 ppm.

The initial feed volume was 10 gallons for normal filtration experiments. Arbitrary operating parameters for ceramic filtration was a cross flow velocity of 8 ft/s, transmembrane pressure of 15 psi and temperature of 38 C. Temperature was varied between 20 and 52 C, transmembrane pressure varied between 10 and 21 psi and cross flow velocity varied between 4 and 11 ft/s. The feed parameter of interest the oil concentration was varied between 200 and 1200 ppm. The objective of produced water ceramic filtration is to serve as a mechanical pre-treatment of the produced water for removal of oil and turbidity (suspended solids).

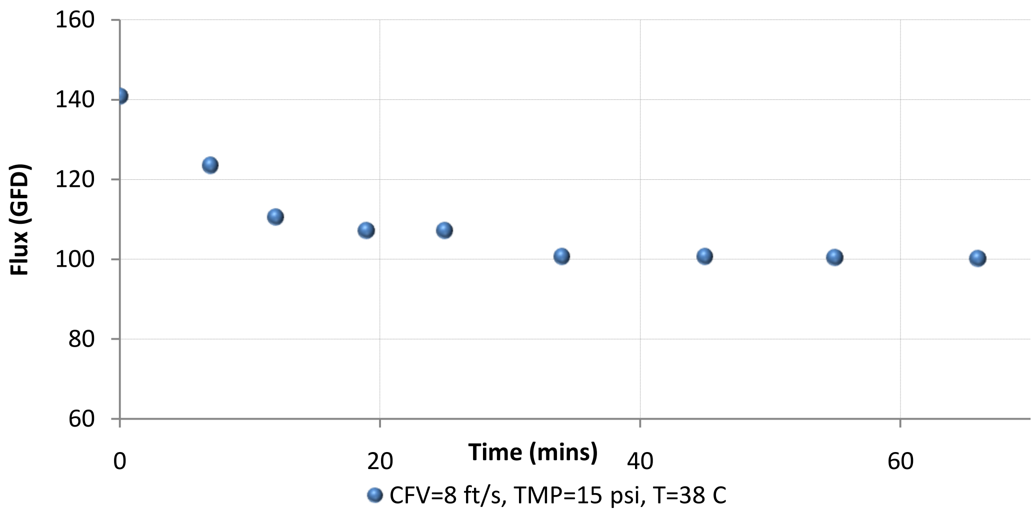

Fig. 3. 8 Ceramic filtration of produced water. Oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.005 micron), transmembrane pressure (15 psi), cross flow velocity (8 ft/s) and temperature (38 C).

In the ceramic filtration of produced water with oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 15 psi, cross flow velocity of 8 ft/s (corresponding to 8 gallons per minute (gpm)) and temperature of 38 C, the average flux was 110.06 gallons per foot square per day (GFD), maximum permeate flux was 140.7 GFD and the lowest flux was 100.11 GFD, see figure 3.8. Flux decline for the experiment period was about 40% of the highest flux and there was no significant pressure increase.

Unlike spent drilling fluid where the concentration of the solids in the feed is important the particle size distribution and sizes are much lower with the median particle size and concentration being 75 microns and 24 microns respectively. Solids rejection was 99% in all cases and turbidity reduction was also 99% in all cases, permeate turbidity at all points was less than 1 NTU. There was 99% rejection of the oil as the feed concentration and permeate concentration was 913 mg/L and 5 mg/L respectively. The volume concentration factor was 4.36 and the volume reduction was 0.23 i.e. the final volume was 23 % of the initial volume. Filtration for this duration and at these condition extracted 77% of the feed as effluent.

Produced water filtration is markedly different from spent drilling fluids as the viscosity, solids concentration and oil content differ significantly. The viscosity of the produced water is less than the viscosity of spent drilling fluids, the solids concentration is also lower and the oil content in produced water is higher than that of spent drilling fluids. The filtration dynamics of produced water differs markedly because the oil concentration and not the solids is believed to be the dominant feed characteristic causing resistance to filtration. In the filtration of oily wastes waters, different authors explain the mechanism of flux resistance in varied ways. One of which is that oil droplets coalesce onto the surface of the membrane creating a gel-polarized layer that creates resistance to filtration [62] while another mechanism is believed to start with internal fouling of the membrane pores (pore blocking) and then an external layer formation (gel layer) [63].

In the filtration of produced water using ceramic membranes there is a rapid flux decline initially between the first 20 minutes of filtration, after this period the flux equilibrates at about thirty minutes and remains constant for the duration of filtration. This rapid flux decline could be due to adsorption of the oil droplets on the membrane surface, pore plugging or formation of a gel layer. Though the mechanism is not ascertained, the role of solids in fouling is limited. Mueller et al [62] showed that the presence of solids helped to enhance flux as the solids act as a dynamic membrane layer preventing oil from fouling the membrane internally and they help to absorb the oil droplet and break up the continuous coalesced oil cake layer. Oil droplets can also plug the pores of the membranes. If the mechanism of pore plugging explains the flux decline, as filtration occurs oil droplets are squeezed into pore spaces constricting the flow of the permeate, the flux equilibrium is achieved at the saturation of the oil concentration/solids in the pore. If a gel concentration theory explains the mechanism of flux decline as filtration occurs oil droplets start to form a layer at the membrane surface and flux equilibrium is achieved when the wall is saturated.

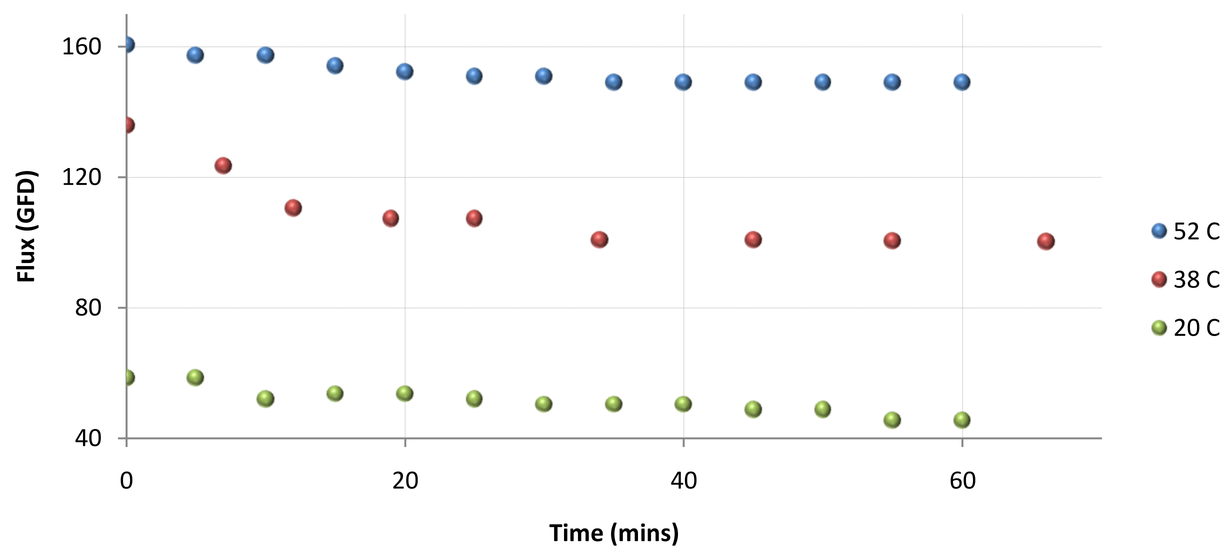

Fig. 3. 9 Temperature variation in the ceramic filtration of produced water. Oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L.. Ceramic membrane pore size (0.005 micron), transmembrane pressure (15 psi), cross flow velocity (8 ft/s) and temperature (20,38 and 52 C).

In the ceramic filtration of produced water with oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 15 psi, cross flow velocity of 8 ft/s and temperature of 20 C, the average flux was 51.32 gallons per foot square per day (GFD), maximum permeate flux was 58.44 GFD and the lowest flux was 45.45 GFD, see figure 3.9. Flux decline for the experiment period was about 46% of the highest flux and there was no significant pressure increase. Solids rejection was 99% in all cases and turbidity reduction was also 99% in all cases and permeate turbidity was less that 1 NTU. There was 98% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 694 mg/L and < 1 mg/L respectively. The volume concentration factor was 1.48 and the volume reduction was 0.67 i.e. the final volume was 67 % of the initial volume. Filtration for this duration and at these condition extracted 32% of the feed as effluent.

In the ceramic filtration of produced water with oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 15 psi,

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cross flow velocity of 8 ft/s and temperature of 52 C, the average flux was 152.05 gallons per foot square per day (GFD), maximum permeate flux was 160.40 GFD and the lowest flux was 149.01 GFD. Flux decline for the experiment period was about 7% of the highest flux and there was no significant pressure increase. There was 99 % rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 761 mg/L and 2 mg/L respectively. The volume concentration factor was 27.77 and the volume reduction was 0.04 i.e. the final volume was 4% of the initial volume. Filtration for this duration and at these condition extracted 95% as effluent. The values for the results of filtration at 38 C are reported on page above.

Table 3.6 Flux characteristics of temperature variation in the ceramic filtration of produced water

Temperature (C)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
20 C	58.44	45.45	51.32	3.52
38 C	140.70	100.11	110.06	7.71
52 C	160.04	149.01	152.05	9.64

Temperature had the same effect on filtration as noticed during the filtration of spent drilling mud i.e. as the temperature increased the flux also increased. The temperature reduces the viscosity of the feed sample and thus with increasing temperature the viscosity is lower and the flux higher. Increasing temperature is known to also reduce viscosity of the oil, this would allow the flow of more oil through the pores prolonging the onset of fouling and reducing the hydraulic resistance to the flow of permeate. The oil content in the permeate was not statistically higher than the permeate under the increased temperature operations.

Using the flux values, it seems the flux doubles with every 16 degree rise in temperature though the difference in flux between the 20 and 38 C is slightly less proportionate to the difference between 38 and 52 C. Low temperature would not only increase the feed viscosity alone but would also affect the nature (viscosity) of the oil, this might accelerate the formation of a gel layer on the membrane surface creating resistance to flow of the permeate. With increasing temperature we also see a delay in flux decline, at 52 C we see that flux decline was just less than 7% of the highest recorded flux compared to 46% at 20 C. Increasing temperature is not only beneficial at increasing the permeate volume it is also beneficial at prolonging the onset of flux decline. Table 3.6 gives a summary of the fluxes.

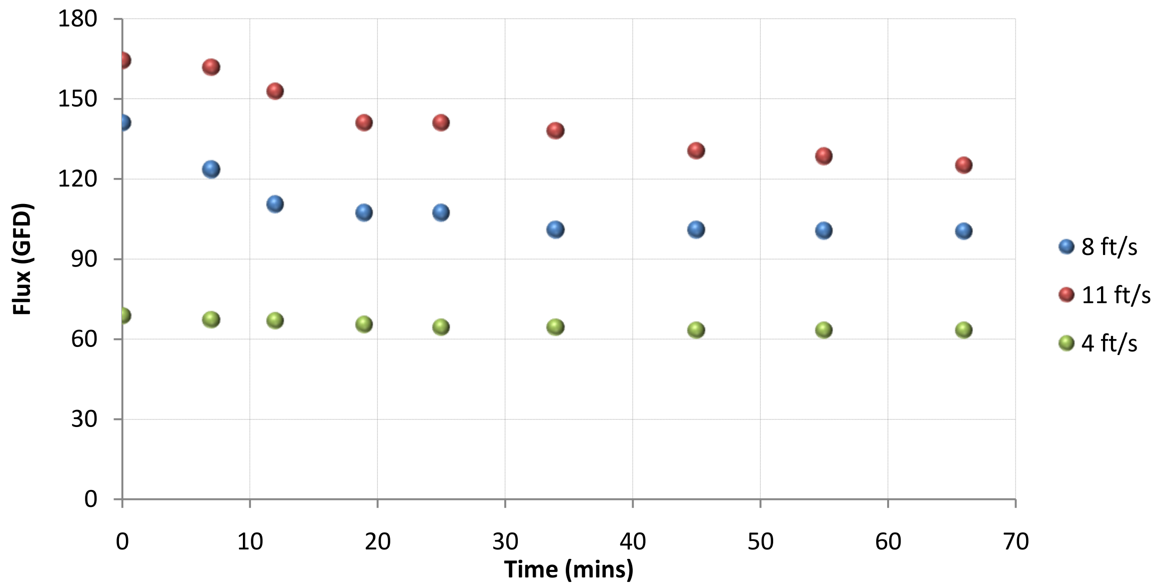

Fig. 3. 10 Cross flow velocity variation in the ceramic filtration of produced water. Oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L.. Ceramic membrane pore size (0.005 micron), transmembrane pressure (15 psi), cross flow velocity (4,8 and 11 ft/s) and temperature (38 C).

In the ceramic filtration of produced water with oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 15 psi, cross flow velocity of 4 ft/s and temperature of 38 C, the average flux was 65.03 gallons per foot square per day (GFD), maximum permeate flux was 68.42 GFD and the lowest flux was 63.10 GFD, see figure 3.10. Flux decline for the experiment period was about 8% of the highest flux and there was no significant pressure increase. Solids rejection was 99% in all cases and turbidity reduction was also 99% all permeate samples had less than 1 NTU. There was 98% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 1104 mg/L and 12 mg/L respectively. The volume concentration factor was 1.85 and the volume reduction was 0.54 i.e. the final volume was 54% of the initial volume. Filtration for this duration and at these condition extracted 45% as effluent.

In the ceramic filtration of produced water with oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 15 psi, cross flow velocity of 11 ft/s and temperature of 38 C, the average flux was 142.42 gallons per foot square per day (GFD), maximum permeate flux was 164.10 GFD and the lowest flux was 124.8 GFD. Flux decline for the experiment period was about 25% of the highest flux decline and there was no significant pressure increase. There was 99% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 885 mg/L and < 1 mg/L respectively. Within the experiment duration most of the feed was treated and the concentration volume factor and the volume reduction were close to 100% i.e. most of the feed was treated, more feed had to be added.

Table 3. 7 Flux characteristics of cross flow variation in the ceramic filtration of produced water. CFV=cross flow velocity

CFV (ft/s)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
4	68.42	63.10	65.03	4.60
8	140.70	100.11	110.06	7.71
11	164.10	124.8	142.42	9.99

With increasing cross flow velocity flux increases though the flux decline profiles at all cross flow velocities are similar. As explained earlier increasing cross flow velocity increases filtration by affecting the wall layer reducing the resistance to permeate flow, this is believed to be the action of the shear caused by flow turbulence aided by the solids in the solution. With a low solids concentration (as in produced water) we see that the impact of increased cross flow velocity is not as dramatic as that of spent drilling fluid filtration as the flux decline profile in produced water filtration remains similar even when velocities are increased. In spent drilling fluids filtration with high solids concentration (Figures 3.4 and 3.6) is it observed that the decline profiles are affected by increasing cross flow velocity as the onset of flux decline is prolonged. Table 3.7 gives a summary of the fluxes.

Shearing action due to turbulence with low solids concentration gives qualified gain from increasing the cross flow velocity. In the presence of increasing oil concentration, it becomes apparent that increasing the cross flow velocity could cease being advantageous as there shall become a point where the fouling dynamics shall overwhelm the shearing action of the flow and cause an acceleration of fouling on the membrane layer or in the pores. As explained earlier increased solids concentration can enhance flux and at higher cross flow velocities or high shear it would be effective at breaking up coalesced oil on the membrane wall.

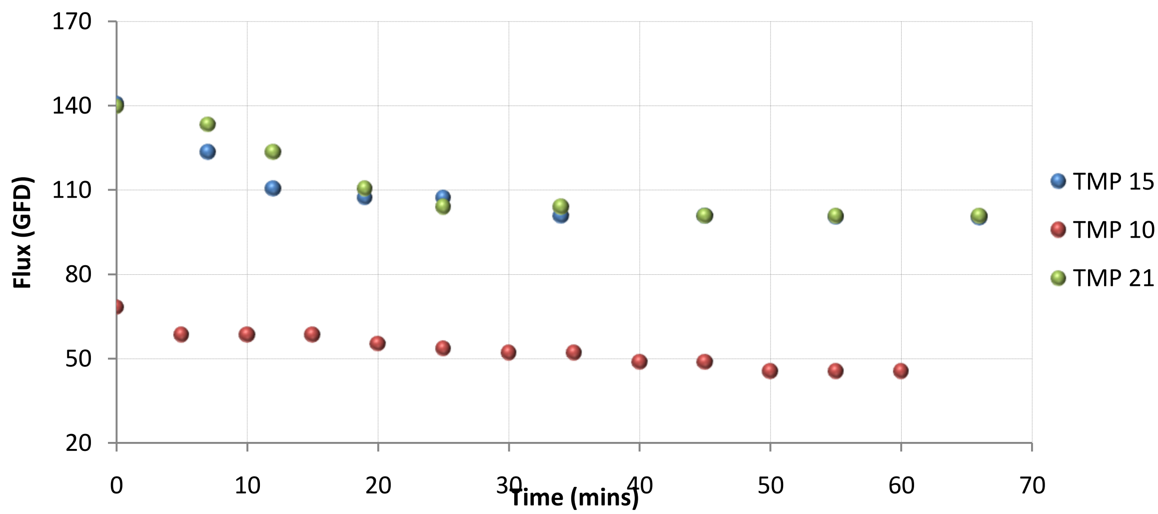

Fig. 3. 11 Transmembrane pressure variation in the ceramic filtration of produced water. Oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.005 micron), transmembrane pressure (10, 15 and 20 psi), cross flow velocity (8 ft/s) and temperature (38 C).

In the ceramic filtration of produced water with oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 10 psi, cross flow velocity of 8 ft/s and temperature of 38 C, the average flux was 53.07 gallons per foot square per day (GFD), maximum permeate flux was 68.18 GFD and the lowest flux was

45.45 GFD, see figure 3.11. Flux decline for the experiment period was about 30% of the highest flux decline and there was no significant pressure increase. Solids rejection was 99% in all cases and turbidity reduction was also 99% in all cases permeate had less than 1 NTU. There was 99% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 901 mg/L and < 1 mg/L respectively. The volume concentration factor was 1.64 and the volume reduction was 0.61 i.e. the final volume was 61 % of the initial volume. Filtration for this duration and at these condition extracted 38% as effluent.

In the ceramic filtration of produced water with oil concentration 700± 500 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 21 psi, cross flow velocity of 8 ft/s and temperature of 38 C, the average flux was 100.65 gallons per foot square per day (GFD), maximum permeate flux was 139.93 GFD and the lowest flux was 112.00 GFD. Flux decline for the experiment period was about 40% of the highest flux decline and there was significant pressure increase. There was 99% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 872mg/L and 3 mg/L respectively. The volume concentration factor was 4.72 and the volume reduction was 0.21 i.e. the final volume was 21 % of the initial volume. Filtration for this duration and at these condition extracted 78% as effluent.

Table 3. 8 Flux characteristics of transmembrane pressure variation in the ceramic filtration of produced water. TMP=transmembrane pressure

TMP (psi)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
10	68.18	45.45	53.07	3.93
15	140.70	100.11	110.06	7.71
21	139.93	112.00	100.65	7.88

Increasing transmembrane pressure increased flux till 20 psi. At 20 psi flux decline is steeper when compared to flux profiles of transmembrane pressures less than 20 psi though the increase in pressure created more permeate volume for the experiment duration. At high pressure the accumulation of oil droplets at the pores or at the membrane surface is accelerated, increasing the resistance to the flow of the permeate. With further increase in pressure the gain in permeate volume would be counterbalanced by high hydraulic resistance caused by increasing consolidation of the concentration polarization layer formed on the wall. It should be noted that membrane flux regeneration after this increased pressure was significantly lower when flushing to clean the membrane. Under this conditions 20 psi seems to be the "threshold pressure" i.e. when the filtration is no longer in the pressure controlled region where increase in the pressure would not bring about a commensurate increase in permeate flow due to the effect of concentration polarization. Table 3.8 gives a summary of the fluxes.

3.3.2. Oil Concentration Variation in the Ceramic Membrane Filtration of Produced Water

The oil concentration in produced water was varied to determine the effect on filtration. To prepare a sample with higher oil in water concentration, crude oil (San Francisco Crude oil 35 API) was added to the sample of produced water and using a laboratory blender was mixed thoroughly. The particle size distribution of the contrived samples was greater than the particle size of the original samples due to the particle size distribution of the oil droplets in the contrived sample. The original sample had oil in water concentration of 560± 163 mg/L and the prepared sample had oil in water concentration of 1200± 186 mg/L. To get samples with less oil in water than the original samples field samples with less oil in water concentrations were procured from the waste disposal site.

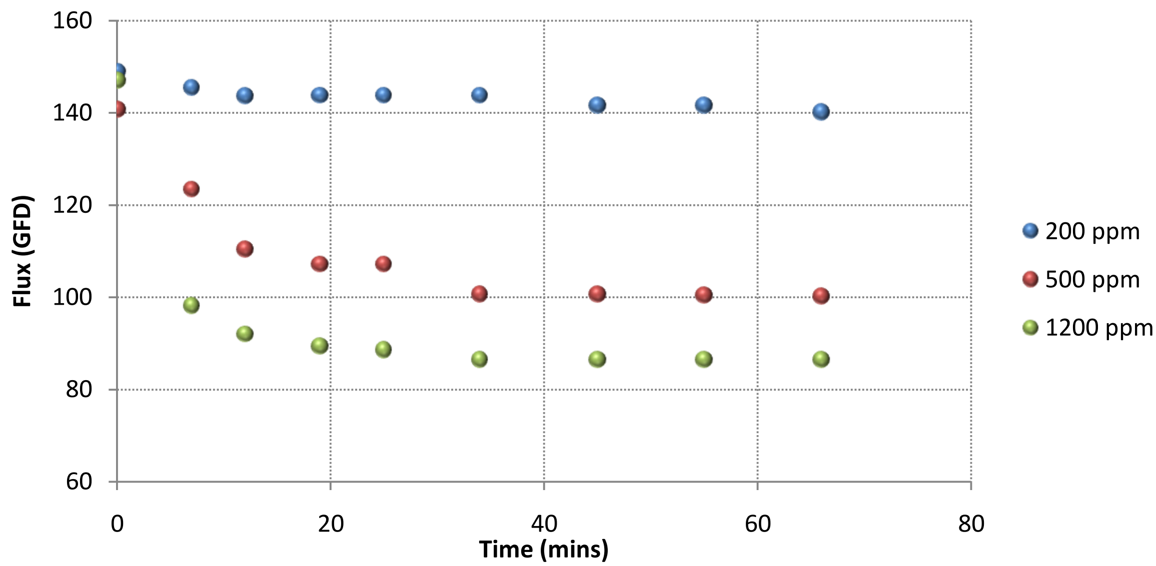

Fig. 3. 12 Oil in water concentration variation in the ceramic filtration of produced water. Oil concentrations are 200± 39 ppm, 560± 163 ppm and 1200± 186 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.005 micron), transmembrane pressure (15 psi), cross flow velocity (8 ft/s) and temperature (38 C).

In the ceramic filtration of the produced water with oil in water concentration of 200± 39 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L with a transmembrane pressure of 15 psi, cross flow velocity of 8 ft/s and temperature of 38 C, the average flux was 143.60 gallons per foot square per day (GFD), maximum permeate flux was 148.94 GFD and the lowest flux was 140.05 GFD, see figure 3.12. Flux decline for the experiment period was less than 6% of the highest recorded flux and there was no significant pressure increase during the experiment. There was 99% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 182 mg/L and < 1 mg/L respectively. Within the experiment duration most of the feed was treated and the concentration volume factor and the volume reduction were close to 100% i.e. most of the feed was treated, more feed had to be added.

In the ceramic filtration of the produced water with oil in water concentration of 560± 163 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L with a transmembrane pressure of 15 psi, cross flow velocity of 8 ft/s and temperature of 38 C, the average flux was 110.06 gallons per foot square per day (GFD), maximum permeate flux was 140.7 GFD and the lowest flux was 100.11 GFD. Flux decline for the experiment period was about 40% of the highest flux and there was no significant pressure increase. There was 99% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 734 mg/L and < 1mg/L respectively. The volume concentration factor was 4.36 and the volume reduction was 0.23 i.e. the final volume was 23 % of the initial volume. Filtration for this duration and at these condition extracted 77% as effluent.

In the ceramic filtration of the produced water with oil in water concentration of 1200 ± 186 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L with a transmembrane pressure of 15 psi, cross flow velocity of 8 ft/s and temperature of 38 C, the average flux was 95.63 gallons per foot square per day (GFD), maximum permeate flux was 146.96 GFD and the lowest flux was 86.45 GFD. Flux decline for the experiment period was about 42% of the highest flux and there was no significant pressure increase. There was 99% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 1180 mg/L and 9.4 mg/L respectively. The volume concentration factor was 3.03 and the volume reduction was 0.33 i.e. the final volume was 33% of the initial volume. Filtration for this duration and at these condition extracted 66% as effluent.

Table 3.9 Flux characteristics in the oil in water concentration in the ceramic filtration of produced water

Oil in water Concentration (ppm)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
200± 39	148.94	140.05	143.60	10.00
560± 163	140.70	100.11	110.06	7.71
1200± 186	146.96	86.45	95.63	6.78

With increasing oil concentration there is a decline in the permeate flux. This correlates to results from the filtration of other oil water wastes [63] from various industries. When the oil in water concentration is lesser than 200 ppm the filtration experiences little or no flux decline compared to higher oil in water concentrations. This is indicative of the role of the oil droplets in the fouling of the membranes. Though the composition of produced water is varied in its physical and chemical properties especially its dissolved components, oil concentration is significant in the fouling of the ceramic membranes. Table 3.9 gives a summary of the fluxes.

At oil in water concentration of 1200 ppm there is a sharp decline in the flux after the initial seven minutes of filtration, by the 15th minute the flux is stabilized and stays that way for most of the experiment duration and this was reproduced almost exactly in repeat runs. The oil particle size also played a role in the flux decline as increased droplet size was an added variable in the contrived sample. Thus the oil concentration and the size of the droplets are important in membrane fouling at high oil concentrations.

3.4 Produced Water Filtration with Hollow Fibre Membranes

3.4.1 Parameter Variation in Produced Water Filtration with Hollow Fibre Membranes

Feed samples for filtration of produced water were procured directly from disposal trucks from the field. Using portable kits concentrations of the oil in water, salinity and some dissolved solids were carried out to see if the feed was within specified range. The feed parameter of interest in the filtration of produced water was primarily oil in water concentration and turbidity. The arbitrary produced water was defined to have an oil concentration range of 50 – 300 ppm oil in water, turbidity less than 4000 NTU, pH of 6.5 – 10 and TDS less than 40,000 ppm. Arbitrary operating parameters for hollow fibre filtration was a cross flow velocity of 3.8 ft/s, transmembrane pressure of 10 psi and temperature of 38 C. Temperature was varied between 20 and 52 C, transmembrane pressure varied between 10 and 21 psi and cross flow velocity varied between at 3.81 and 6.69 ft/s. The feed parameter of interests was also varied; oil in water concentration was varied between 100 to 700 ppm.

The intent of the hollow fibre filtration was particularly to compare the module types i.e. hollow fibre versus the tubular module (ceramic). Unlike the ceramic membranes the hollow fibre membranes are made from polymeric materials, the microza hollow fibre membranes investigated here are made from polyvinylidene fluoride (PVDF). PVDF is hydrophobic i.e. water-repelling and organic and oil attracting, this presented a challenge in the filtration of produced water due to the oil concentration of the feed. At high oil concentration sharp declines in flux was encountered (this is shown in section 3.3.2). Due to the hydrophobic nature of the membrane material the samples used had less oil in the feed than the samples used in the ceramic membrane investigation. The objective of the hollow fibre filtration was to serve as module type comparison. In produced water feed with high turbidity the samples were passed through a 10 micron cartridge filter upstream of the hollow fibre to avoid clogging the membrane.

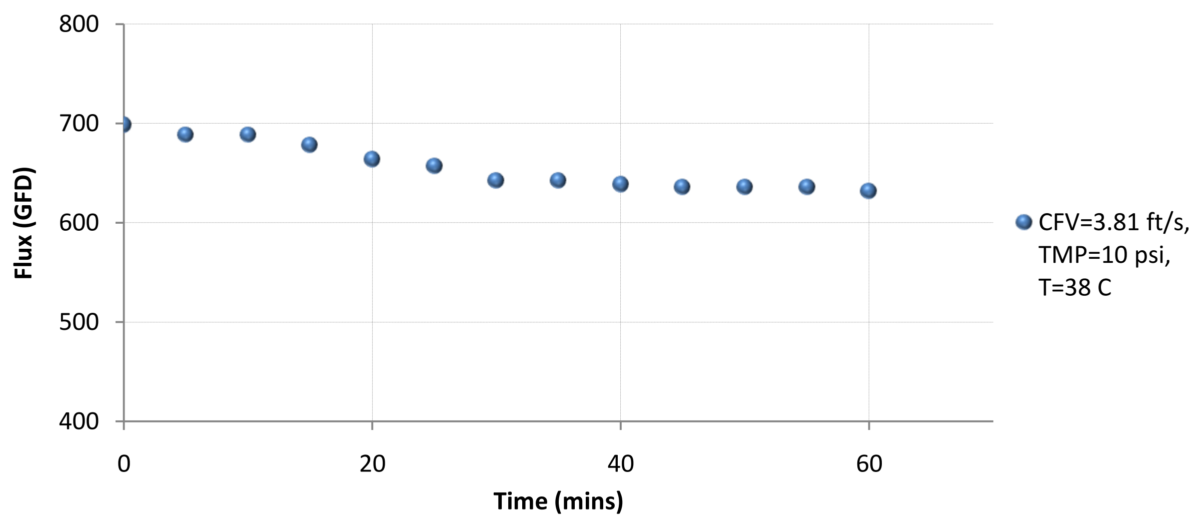

Fig. 3. 13 Hollow fibre filtration of produced water. Oil concentration 155± 100 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.1 micron), transmembrane pressure (10 psi), cross flow velocity (3.81 ft/s) and temperature (38 C).

In the hollow fibre filtration of produced water with oil concentration 155± 100 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 10 psi, cross flow velocity of 3.81 ft/s (corresponding to 4 gallons per minute (gpm)) and temperature of 38 C, the average flux was 656.47 gallons per foot square per day (GFD), maximum permeate flux was 698.82 GFD and the lowest flux was 631.76 GFD, see figure 3.13. Flux decline for the experiment period was about 12% of the highest flux decline and there was no significant pressure increase. Solids rejection was 99% in all cases and turbidity reduction was also 99% in all cases and the permeate at all points had turbidity values less than 1 NTU.

There was 99% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 97 mg/L and < 1 mg/L respectively. The volume concentration factor was 23.5 and the volume reduction was 0.04 i.e. the final volume was 4% of the initial volume. Filtration for this duration and at these condition extracted 95% of the feed as effluent.

Produced water filtration using hollow fiber membranes has a flux that is on average four times the flux of ceramic filtration of produced water with similar feed characteristics. Also, the cross-flow velocity of operation is markedly lower than that of ceramic membrane filtration (3.81 to 8.0 ft/s) and the transmembrane pressures (10 psi to 15 psi). Hollow fibre membranes have large surface area to volume ratio, they operate under low pressure and cross flow velocity and these properties account for the flux superiority of membrane filtration of similar produced water to ceramic membranes. The underlying limitations to hollow fibre membranes is associated with their lower inertness relative to ceramic membranes, their pH ranges are also smaller (though marked improvements have been made), so also is their sensitivity to temperature and chemical solvents are relatively less than ceramics. The PVDF hollow fibre membrane material type was chosen primarily due to its resistance to solvent action allowing better cleaning prospects.

In the filtration of produced water using hollow fibre membranes there is a gradual descent in the flux profile and the flux seems to equilibrate after 40 minutes. This initial decline (10 minute region) could be due to adsorption of the oil droplets on the membrane surface, pore plugging, formation of a gel layer or concentration polarization caused by the oil droplets in the feed. With the hollow fibre the mechanism of fouling is different as there is the possibility of the tube entrance blockage by solids, the fouling on the membrane wall and fouling in the space between individual membrane tubes. These fouling possibilities leave hollow fibre membranes relatively more sensitive to solids concentration and fouling by oil droplets.

Though the fouling mechanism is not ascertained, concentration polarization caused by solids could also be deemed implausible in hollow fibre produced water filtration for the same reasons as in ceramic filtration i.e. the low solids concentration and a higher possibility of oil-membrane interaction. If the mechanism of pore plugging explains the flux decline, then as filtration occurs oil droplets are squeezed into pore spaces constricting the flow of the permeate, the flux equilibrium is achieved at the saturation of the oil concentration. If a gel concentration theory explains the mechanism of flux decline, as filtration occurs oil droplets start to form a layer at the membrane surface and flux equilibrium is achieved when the wall is saturated. Complex fouling possibilities also exist, for example solutes that pass through the membrane pore could accumulate at the passages within the bundles of membranes causing resistance to the flow of permeate. Though the flux rates are impressive long time durability of membrane functioning would require active pre-membrane screens.

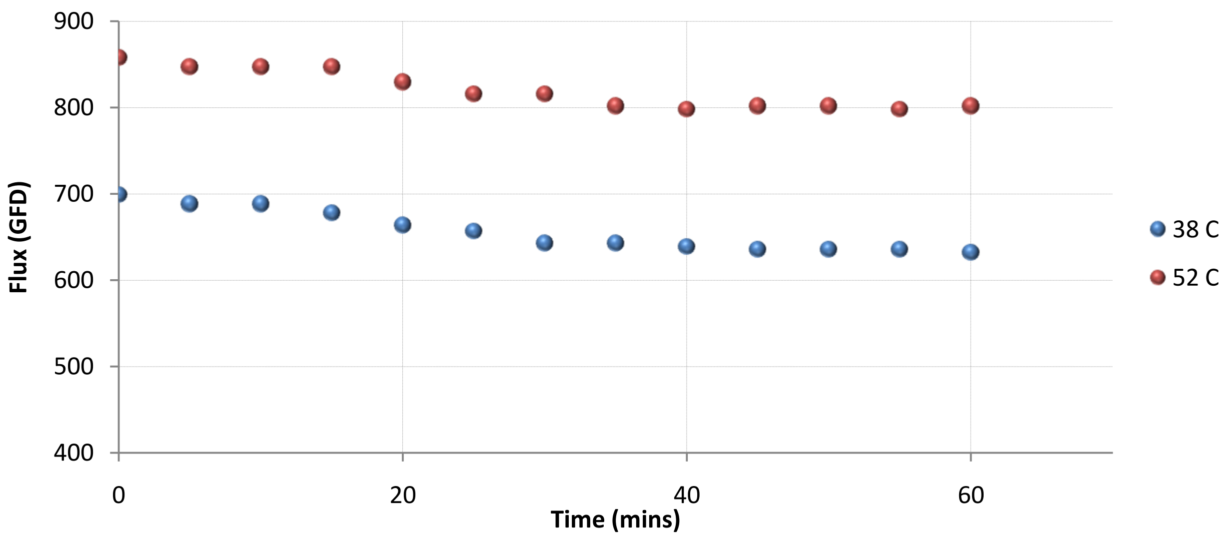

Fig. 3. 14 Temperature variation in the hollow fibre filtration of produced water. Oil concentration 155± 100 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.1 micron), transmembrane pressure (10 psi), cross flow velocity (3.81 ft/s) and temperature (38 and 52 C).

In the hollow fibre filtration of produced water with oil concentration 155± 100 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 10 psi, cross flow velocity of 3.81 ft/s (corresponding to 4 gallons per minute (gpm)) and temperature of 52 C, the average flux was 819.92 gallons per foot square per day (GFD), maximum permeate flux was 857.64 GFD and the lowest flux was 801.17 GFD, see figure 3.14. Flux decline for the experiment period was about 7% of the highest flux decline and there was no significant pressure increase. There was 99% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 168 mg/L and < 1 mg/L respectively Within the experiment duration most of the feed was treated and the concentration volume factor and the volume reduction were close to 100% i.e. most of the feed was treated, more feed had to be added. The fluxes at 38 C are reported above. Table 3.10 gives a summary of the fluxes.

Table 3. 10 Flux characteristics of temperature variation in the hollow fibre filtration of produced water

Temperature	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate(L)
38 C	698.82	631.76	656.47	38.30
52 C	857.64	801.17	819.92	>40

As temperature increases flux increases. There is an average of 11 GFD flux rise per every degree increase in temperature, this is greater than the flux increase per temperature increase observed in ceramic filtration of produced water. The larger proportional flux increase per temperature rise when compared to ceramic membrane filtration could be due to the greater porosity of the hollow fibre allowing more permeate flow when viscosity reduces or the nature of the membrane material. High temperature does not only give high flux rates the flux decline at this high flux is less than 7% of the highest permeate flux during the duration of the experiment. Barring any temperature limitation on the membrane material higher temperatures would be ideal to run hollow fibre membranes successfully.

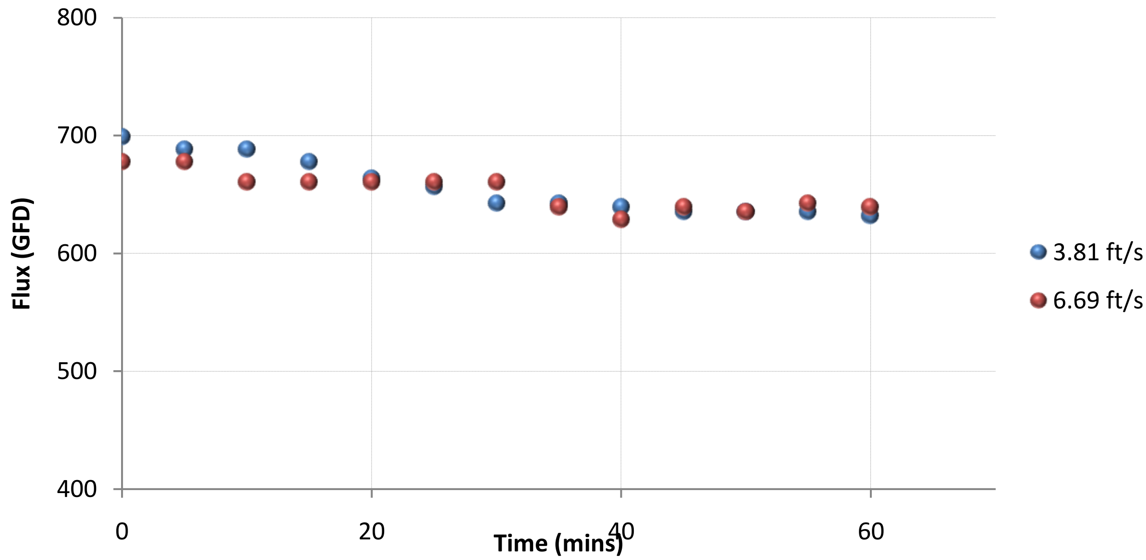

Fig. 3. 15 Cross flow variation in the hollow fibre filtration of produced water. Oil concentration 155± 100 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.1 micron), transmembrane pressure (10 psi), cross flow velocity (3.81 and 6.69 ft/s) and temperature (38 C).

In the hollow fibre filtration of produced water with oil concentration 155± 100 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 10 psi, cross flow velocity of 6.69 ft/s (corresponding to 7 gallons per minute (gpm)) and temperature of 38 C, the average flux was 652.16 gallons per foot square per day (GFD), maximum permeate flux was 677.64 GFD and the lowest flux was 638.82 GFD, see figure 3.15. Flux decline for the experiment period was about 9% of the highest flux decline and there was no significant pressure increase. Solids rejection was 99% in all cases and turbidity reduction was also 99% in all cases permeate turbidity was less than 1 NTU. There was 99 % rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 121 mg/L and < 1 mg/L respectively. The volume concentration factor was 20.4 and the volume reduction was 0.04 i.e. the final volume was 4% of the initial volume. Filtration for this duration and at these condition extracted 95% of the feed as effluent.

Table 3.11 Flux characteristics of temperature variation in the filtration of produced water. CFV= cross flow velocity

CFV (ft/s)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate(gal)
38 C	698.82	631.76	656.47	38.30
52 C	677.64	631.76	652.16	>40

As the cross flow velocity was increased in the hollow fibre filtration of produced water the flux was similar or reduced. This seems abnormal considering that fact that at increased cross flow velocity more of the material should be forced through the membrane but many hollow fibre membranes operate in the laminar flow region. Hollow fibre membranes have a cross flow velocity range specified by the manufacturers, 6.69 ft/s was the upper limit specified by the manufacturer and at this cross flow velocity there was no advantage. The only difference was the lower permeate decline (<3% difference) between both cross flow velocities. It is thus difficult to deduce the effect on fouling. No middle cross flow velocity was possible considering the equipment specifications. Table 3.11 gives a summary of the fluxes.

The implication of filtration with hollow fibre membranes at their low cross flow velocity and low transmembrane pressures is the low cost of operation as less energy is expended for operation. This could also allow for expenses into raising feed temperature and fouling mitigation technologies to increase the viability of filtering difficult waste streams. Using the tubular hollow fibre membranes as the microza membranes used in our investigation could also mean reduced spacing and thus better optimization of space on portable units. All these advantages are dependent on the compatibility of the hollow fibre with the major feed concentrate in the feed and in this case the oil.

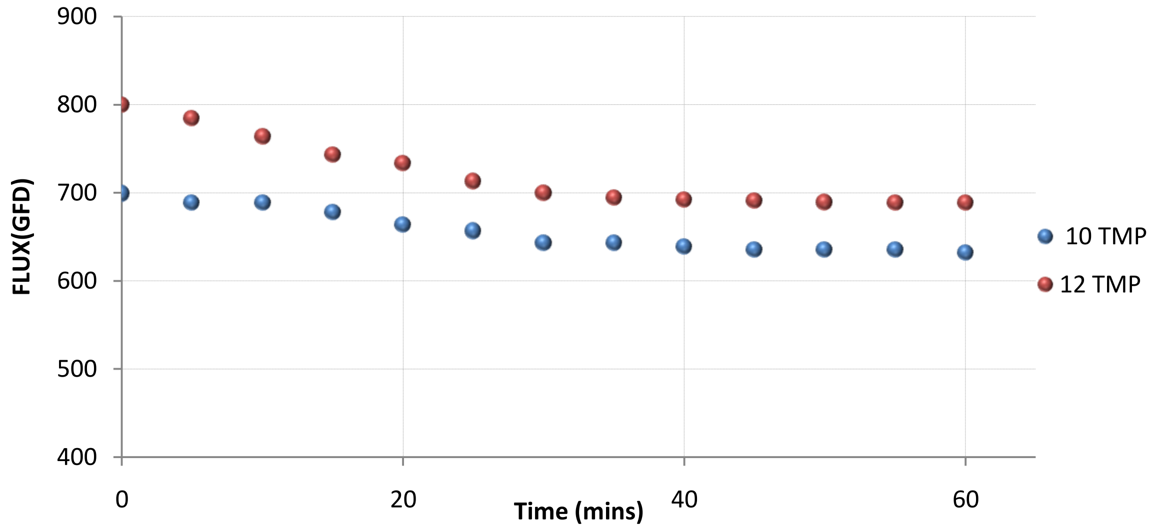

Fig. 3. 16 Transmembrane variation in the hollow fibre filtration of produced water. Oil concentration 155± 100 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.1 micron), transmembrane pressure (10 and 12 psi), cross flow velocity (3.81 ft/s) and temperature (38 C).

In the hollow fibre filtration of produced water with oil concentration 155± 100 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L filtering at a transmembrane pressure of 12 psi, cross flow velocity of 3.81 ft/s (corresponding to 4 gallons per minute (gpm)) and temperature of 38 C, the average flux was 721.42 gallons per foot square per day (GFD), maximum permeate flux was 799.45 GFD and the lowest flux was 688.22 GFD, see figure 3.16. Flux decline for the experiment period was about 14% of the highest flux decline and there was no significant pressure increase. Solids rejection was 99% in all cases and turbidity reduction was also 99% in all cases and permeate turbidity was less than 1 NTU.

There was 99% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 118 mg/L and < 1 mg/L respectively. Within the experiment duration most of the feed was treated and the concentration volume factor and the volume reduction were close to 100% i.e. most of the feed was treated, more feed had to be added. The fluxes at 10 psi are reported above.

Table 3.12 Flux characteristics of temperature variation in the filtration of produced water. CFV= cross flow velocity

TMP (psi)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate(gal)
10	698.82	631.76	656.47	38.30
12	799.45	688.22	721.42	>40

Twelve psi transmembrane pressure was the limit allowable for the hollow fibre membrane type used in the investigation. At this transmembrane pressure there was an appreciable increase in the average flux without the attendant flux decline noticed at higher transmembrane pressures using the ceramic membranes. The reasons could be that at 12 psi filtration is still in the pressure controlled region where increases in flux produce an increase in the flux without increasing fouling. Also the pore size is larger than the pore size filtering with ceramics (0.005 vs.0.1), thus the pressure increase at this pore size does not seem to affect flux noticeably. The effect of pressure is still expected to be the same as seen in the filtration using ceramic membranes i.e. there is a pressure where flux decline is rapid; 12 psi transmembrane pressure is below that pressure in the hollow fibre membrane filtration at the specified conditions. Table 3.12 gives a summary of the fluxes.

3.4.2 Oil in Water Variation in the Hollow Fiber Membrane Filtration of Produced Water

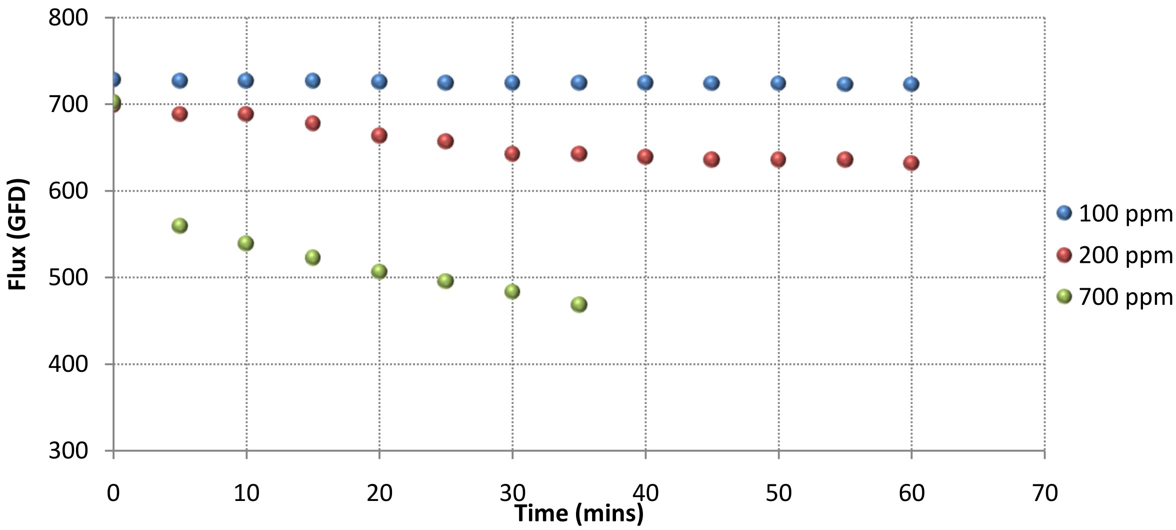

Fig. 3. 17 Oil in water concentration variation in the hollow fibre filtration of produced water. Oil concentrations are 100± 39 ppm, 200± 63 ppm and 716 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.1 micron), transmembrane pressure (10 psi), cross flow velocity (3.81 ft/s) and temperature (38 C).

In the hollow fibre filtration of the produced water with oil in water concentration of 100± 39 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L and transmembrane pressure of 10 psi, cross flow velocity of 3.81 ft/s and temperature of 38 C, the average flux was 724.84 gallons per foot square per day (GFD), maximum permeate flux was 728.23 GFD and the lowest flux was 722.64 GFD, see figure 3.17. Flux decline for the experiment period was less than 2% of the highest recorded flux and there was no significant pressure increase during the experiment. There was 99 % rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 112 mg/L and < 1 mg/L respectively. Within the experiment duration most of the feed was treated and the concentration volume factor and the volume reduction were close to 100% i.e. most of the feed was treated, more feed had to be added.

In the hollow fibre filtration of the produced water with an oil in water concentration of 200± 63 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L with a transmembrane pressure of 10 psi, cross flow velocity of 3.81 ft/s and temperature of 38 C, the average flux was

656.47 gallons per foot square per day (GFD), maximum permeate flux was 698.82 GFD and the lowest flux was 631.76 GFD. Flux decline for the experiment period was about 10% of the highest flux and there was no significant pressure increase. There was 98 % rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 231 mg/L and 1 mg/L respectively. The volume concentration factor was 23.5 and the volume reduction was 0.04 i.e. the final volume was 4% of the initial volume. Filtration for this duration and at these condition extracted 95% of the feed as effluent.

In the hollow fibre filtration of the produced water with an oil in water concentration of 716 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L with a transmembrane pressure of 10 psi, cross flow velocity of 3.81 ft/s and temperature of 38 C, the average flux was 534.30 gallons per foot square per day (GFD), maximum permeate flux was 701.76 GFD and the lowest flux was 467.94 GFD. Flux decline for the experiment period was about 88% of the highest flux and there was significant pressure increase. There was 91% rejection of the oil in water concentration by the membranes as the feed concentration and permeate concentration was 716 mg/L and 62 mg/L respectively. The experiment was run for 35 minutes, the volume concentration factor was 1.74 and the volume reduction was 0.57 i.e. the final volume was 57% of the initial volume. Filtration for this duration and at these condition extracted 42% as effluent.

Table 3.13 Flux characteristics in the oil in water concentration in the hollow fibre filtration of produced water

Oil in water Concentration (ppm)	Max Flux (GFD)	Min Flux (GFD)	Average Flux (GFD)	Total Permeate (gal)
100± 39	728.23	722.64	724.84	>40
200± 63	698.82	631.76	656.47	38.30
716	701.76	467.94	534.30	17.08

With increasing oil concentration there is a decline in the permeate flux just as observed using ceramic filters. When the oil in water concentration is lesser than 200 ppm the filtration experiences little or no flux decline compared to higher oil in water concentrations, the flux decline is less than 2% of the highest reported flux. At oil in water concentration of 716 ppm there is a sharp decline in the flux after the initial five minutes of filtration and by the 35th minute the flux was yet to stabilize and the experiment was truncated. Due to fear of destructive fouling the experiment was truncated and not repeated, the values represent a single experiment. The flux decline at 716 ppm was 88% of the highest reported flux value, representing the highest flux decline in all of the experiments; pressure rose by 3 psi over the normal and fear of rising pressure demanded stopping the experiment. Table 3.13 gives a summary of the fluxes.

Though there was a steep flux decline in the ceramic filtration of produced water at high concentrations the flux decline and pressure increase was mild relative to the hollow fibre membrane considering the pores of the ceramic were smaller (0.005 vs. 0.1). The advantages of ceramic membrane over the hollow fibre in this case would be its ability to filtrate much difficult feeds without the limitations imposed by feed components especially organic constituents.

3.5 Summary

The importance of understanding the feed and operational parameter effects in the filtration of a feed cannot be underestimated. Studies of this nature give a baseline snapshot of the dynamics involved in considering if a feed is suitable for filtration. Process engineers and various experts involved in building membrane systems get insight from these types of studies and use them for basic information in planning for pilot studies which are also inevitable. The laboratory system used in the parameter and feed evaluation is the least optimized; it serves strictly for conceptual understanding of the dynamics involved in the feed filtration. With respect to process engineering, mode of operation and operational parameters optimization is significantly low but the proof of concept, understanding of feed behavior, permeate expectation, membrane foot print and information for pilot studies could be gleaned from such results presented in this chapter.

In the filtration of spent drilling fluids using ceramic membranes, we have solids rejection in the upper 90% range; increased solids above 8.8 % solids per volume (~19000 mg/L) significantly reduced the flux. Increased cross flow velocity increased the permeate flux and also helped to delay the inset of fouling, cross flow velocity had the highest impact of all three parameters tested within the range of parameters defined. The effect of increased temperature was also favorable and operation at higher temperature also increased the flux. Increased pressure above 20 psi was detrimental to filtration, flux decline increased at pressures at and above 20 psi. Permeate quality did not change with operating conditions and apart from minimal turbidity differences the permeate quality did not change with pore sizes. Maximum volume concentration achieved was within half of the initial volume. Most importantly the quality of the permeate as regards to solids was low, permeate from the filtration of spent drilling fluids could be used for field related activities such as mud mixing and rig washing apart from the benefits of reduced waste volume.

In the ceramic filtration of produced water, turbidity and solids removal was above 95% in all cases, oil removal in all cases was between 95% -99%. There was an average of about 40% reduction in the flux during normal filtration. Operation at high temperatures had the highest impact on increasing permeate volume and it also helped to prolong the onset of fouling. Cross flow velocity also increased the permeate volume although to a lesser degree than increased temperature. Increased pressure also reduced the flux and accelerated the flux decline. Ceramic membranes could handle a wider range of oil concentration, from 200 ppm to about 1200 ppm oil in water concentration with above 90% percent oil removal in all cases, concentrations above 1200 ppm were not tested. Mechanical removal of solids and turbidity using ceramic membranes in the filtration of produced water was determined to be effective; the turbidity and oil concentrations in the effluent were good enough for desalination processes. Permeate quality did not differ significantly with different pore sizes.

In the hollow fibe filtration of produced water, turbidity and solids removal was above 95% in all cases, oil removal in all cases was between 95% -99%. There was an average of about 20% reduction in the flux during normal filtration. Operation at high temperatures had the highest impact on increasing permeate volume and it also helped to prolong the onset of fouling. Filtration using hollow fibre membranes are at low cross flow velocity and pressure and thus would amount to significant energy saving, increasing cross flow velocity and pressure did not impact the permeate volume significantly. Hollow fibre membranes cannot handle a wider range of oil concentration, oil in water concentrations from 50 ppm to about 300 ppm was used in the experiments and above 90% percent oil removal was achieved in all cases, concentrations above 700 ppm significantly impacted flux negatively. Mechanical removal of solids and turbidity using hollow fibre membranes in the filtration of produced water with less than 200 ppm oil in water concentration was determined to be effective. Permeate volume at comparative operations conditions to ceramic filtration of produced water was four times higher when compared to ceramic membranes and the permeate quality was of equally quality.

CHAPTER IV

MEMBRANE RESISTANCE

4.1 Introduction

During membrane filtration of any feed apart from pure water there is always a reduction in the flux of the membrane with time. For different feeds based on their feed properties and concentration the onset of fouling varies but flux decline occurs after some time. The mechanism of flux decline occurs has been a subject of intense investigation by various authors during membrane filtration [65,68,69]. An added complexity to this investigation is the variation in feed and membrane types under which flux decline is investigated; feed variation is an issue in this investigation especially with produced water. Membrane filtration models that can aptly describe filtration of the feed are beneficial in developing a sustainable membrane filtration system. Understanding the effect operational and feed parameters have on flux decline would also give a robust assessment of the filtration mechanism. Also, the understanding of fouling mechanism(s) would be useful in the determination of effective cleaning methods to maintain membrane integrity.

Two major components are believed to contribute to permeate flow resistance during microfiltration; the first is associated with the membrane, its properties and the propensity for pore blocking. The second is associated with the membrane boundary layer, the generation and or absence of a fouling layer at the interface of the membrane [64]. The decline of permeate flux is due to the combined effect of these two factors, the real challenge has been the identification of the contributing role or proportion of each individual factor and factors within them. A direct approach to getting a clearer picture is arrived at through investigation of the flux decline curves; an analysis of this curves and their application to existing models or using them to develop totally new models help in the understanding of contributing factors to permeate flux decline.

In this chapter, two different models aimed at describing filtration are considered. The first model, developed by Hermia [68], called the constant pressure blocking filtration laws are presented in their modified linearized forms relating the permeate flow rate, permeate volume and time with the filtration constants for each model. The second model, the resistance in series model, aimed at describing resistances during filtration quantifies the various resistances affecting filtration showing their influence on the total resistance. The results in the resistance in series model are further reported as a ratio of the resistance to the intrinsic membrane resistance to give a better estimate of the resistance magnitude.

4.2. Constant Pressure Filtration Models

Hermia's[68] filtration laws were applied in this section to determine if they could be used to describe the mechanism of filtration during membrane filtration of produced water and spent drilling fluids using ceramic membranes and hollow fibre membranes. Flux decline curves from filtration experiments carried out were matched to the four filtration mechanisms described by Hermia to determine which adequately described the observed flux decline. Hermia attributed flux decline to four mechanisms under constant pressure filtration; complete blocking, intermediate blocking, standard blocking and cake filtration. These blocking models are variants describing possible methods of pore blocking or cake layer formation during membrane filtration.

In the complete blocking model, the underlying assumption is that each particle in the feed reaching the membrane pore actively seals the pores and particles are not superimposed upon each other, in this respect the blocked surface area is deemed proportional to the permeate volume. The rate of change in the amount of open pores is directly proportional to the rate at which particles are transported to the membrane surface. This model also assumes that the formation of a cake or layer at the membrane surface is negligible. Particles in the model as it relates to our feed for water based wastes could be solid particles in the drilling mud or oil droplets in the produced water.

The second model, the intermediate blocking model, is a variation of the complete blocking model. In this model the assumption is also that amount of blocked pores on the membrane is proportional to the permeate volume; it differs from the complete blocking model in that it does not assume that there is no superimposition of the particles. In this less limiting version of the complete blocking model, the assumption is that each particle would not block the pores of the membrane and that there is superimposition of the particles on one another. Here the rate of transport of particles to the membrane is not directly proportional to the volume of permeate. It is assumed in this model that second particle layer has an equal chance of settling on the first layer or the membrane surface and that the suspension is homogenous.

The third model, the standard blocking model concerns itself with the size of the feed particles. In this model it is assumed that most of the feed particle sizes are less that the pore diameter allowing the deposition of the particles in the pores and reducing the available pore volume. In the standard blocking model the pore volume decreases proportionally to the amount of particles in the feed that are deposited in the pore spaces. Other assumptions inherent in this model are that the membrane pores are largely uniform in their diameter and length and that each particle has the same chance of deposition into the pore spaces. This model is used to explain the case for filtration of feed with smaller particles.

The fourth model the cake filtration model concerns itself also with the size of the feed particles. This model is used to explain the case of large particles that cannot enter most of the membrane pores [64]. In the cake filtration model the assumption is that majority of the particles are bigger than the membrane pores and cannot enter the pores but are deposited on the membrane surface forming a filter cake. In this model permeate volume is proportional to the increase in filter cake thickness i.e. as the filter cake thickness increases the permeate volume reduces. Assumptions inherent in this model are that the membrane pores are largely uniform in their diameter and length and that each particle has the same chance of deposition into the pore spaces.

Mohammadi [65] provides the characteristic forms of the equations of these four models as this equations can be expressed in simple linear equations (Table 4.1) relating the permeate flow rate (Q), permeate volume (V) and time (t) with the filtration constants for each model (K_b, K_i, K_s and K_c) and initial permeate flow Q_o. In other to obtain the filtration constants (K_b, K_i, K_s and K_c), the experimental data (Q, V and Qo) were plotted for each form of equation in Table 4.1. According to Mohammadi [65], the initial slope of the curve obtained at the value of V or t equals to zero allowing the calculation of each filtration constant and the intercept is the initial flow Qo. The constants K_b, and K_i are directly related to blocked surface area per unit permeate volume, K_s is dependent on the volume of particles retained per unit permeate volume and K_c depends on both cake resistance and concentration. Q is the permeate flow rate,Q_0 the initial permeate flow, t the time and K_b, K_i, K_s and K_c the filtration constants.

Table 4.1 Constant pressure filtration models

Model	Equation
Complete blocking filtration Model	$Q = Q_0 - K_b V$
Intermediate blocking filtration model	${}^{1}/_{Q} = K_i t + {}^{1}/_{Q_0}$
Standard blocking filtration model	$\sqrt{Q} = \sqrt{Q_0} - (K_s \sqrt{Q_0}\ {}^{V}/_{2})$
Cake filtration model	${}^{1}/_{Q} = {}^{1}/_{Q_0} + K_c V$

4.2.1 Ceramic Filtration of Spent Drilling Fluid

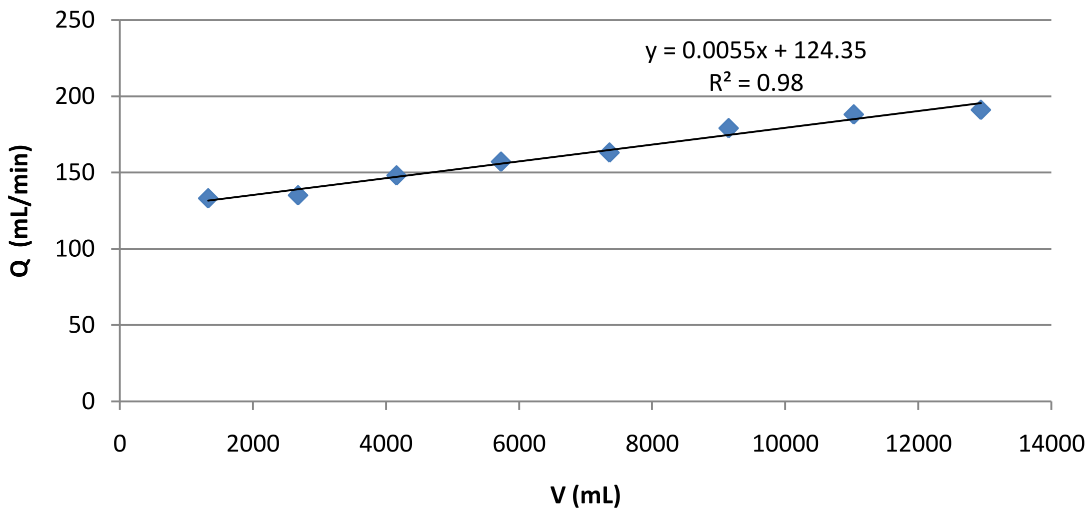

Fig. 4. 1 Plot of Q against V in complete blocking filtration model in the ceramic filtration of spent drilling fluids.

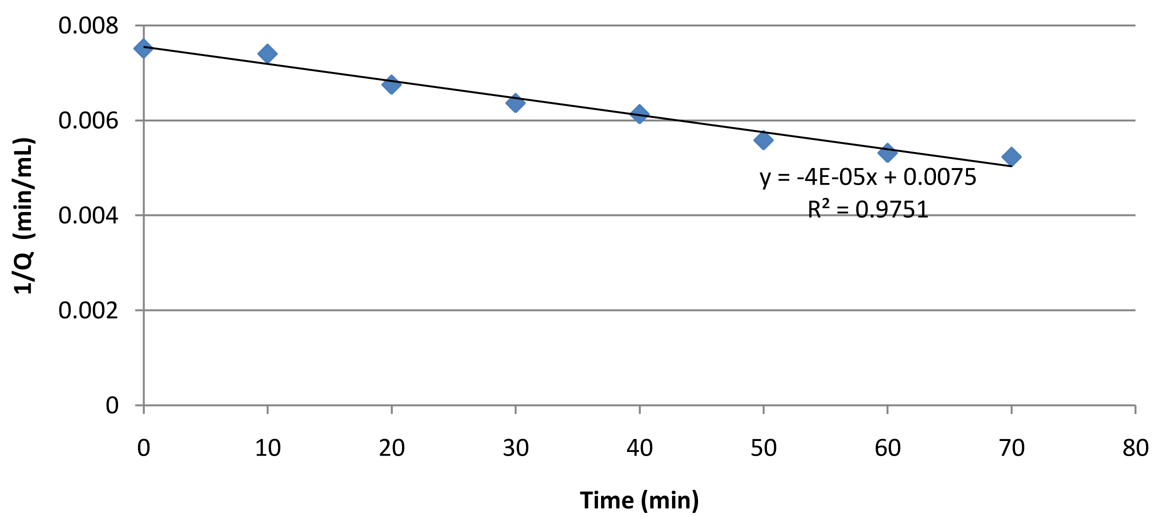

Fig. 4. 2 Plot of 1/Q against t in intermediate blocking filtration model in the ceramic filtration of spent drilling fluids.

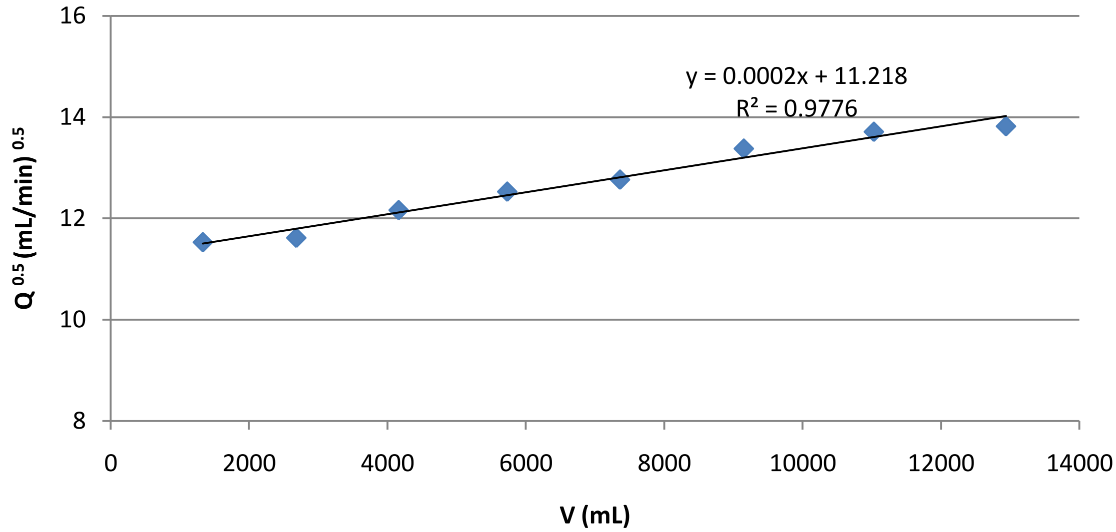

Fig. 4. 3 Plot of $Q^{0.5}$ against V in standard blocking filtration model in the ceramic filtration of spent drilling fluids.

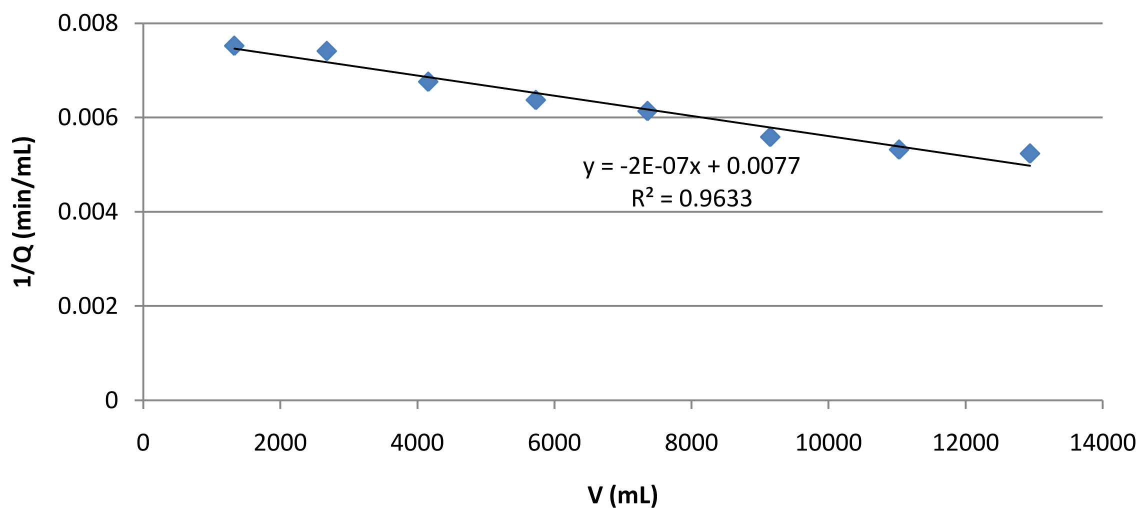

Fig. 4. 4 Plot of 1/Q against V in cake filtration model in the ceramic filtration of spent drilling fluids.

Due to the hump in flux values observed in the filtration of spent drilling fluids (chapter III) the graphs produced were discontinuous except for data at high cross flow velocity and high temperature. The graphs presented here were from using data from the experimental results of filtration of spent drilling fluids at cross flow velocity of 16 ft/s, transmembrane pressure of 15 psi and temperature of 38 C.

The results of fitting the data from the ceramic membrane filtration of spent drilling fluids to the filtration models by plotting the rate of permeate volume (Q or 1/Q or $Q^{0.5}$) with either filtration volume (V) or the filtration time (t) is presented in figures 4.1 -4.4. From the results we see that all models show a high correlation in explaining the filtration mechanism with complete blocking filtration showing a slightly stronger correlation and cake filtration showing the least. From this it seems that using the Hermia models no model adequately explains the filtration in the spent drilling fluids filtration or no model is dominant though the co-existence of different model behavior at different stages during filtration has been reported [48].

The spent drilling fluid samples had a high solids concentration (> 8% solids per volume ~ 19,000mg/L) with a wide particle size range. Most models describing filtration with solids use hard spherical particles that remain a definite size through the model build-up, the nature of the particle in spent drilling mud are markedly different. The particles in the spent drilling mud are earth and they are constantly breaking up into smaller particles due to shear, the distribution is also wide with particles sizes ranging from sand to colloidal barite particles. The data used were generated under high cross flow velocity, thus a high mass flow of the samples is passing through the membrane and the existence of the various models at different periods in filtration is possible though no single model adequately explains the filtration phenomenon.

4.2.2 Produced Water Filtration with Ceramic Membranes

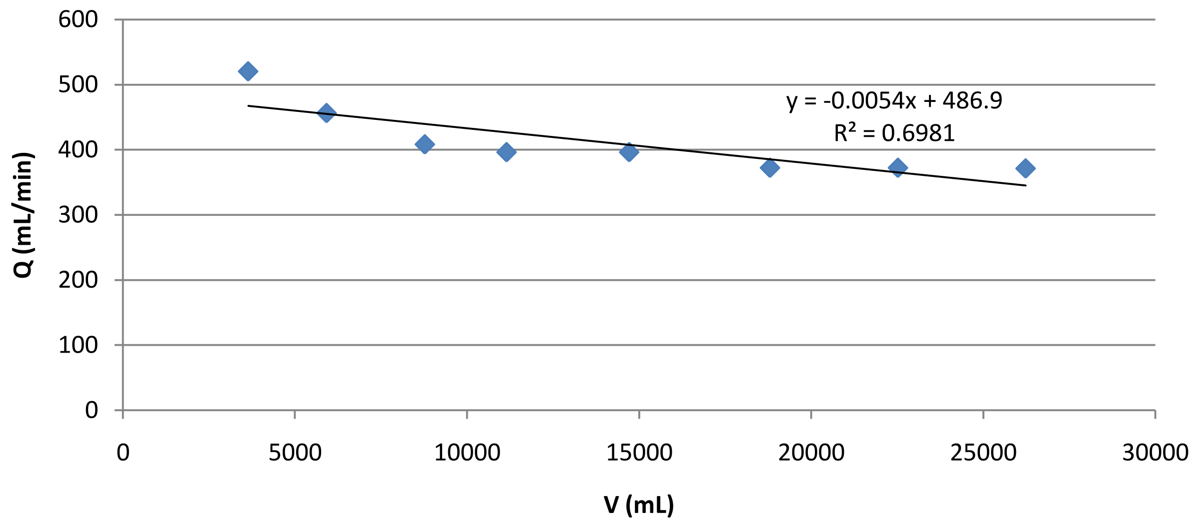

Fig. 4. 5 Plot of Q against V in complete blocking filtration model in the ceramic filtration of produced water.

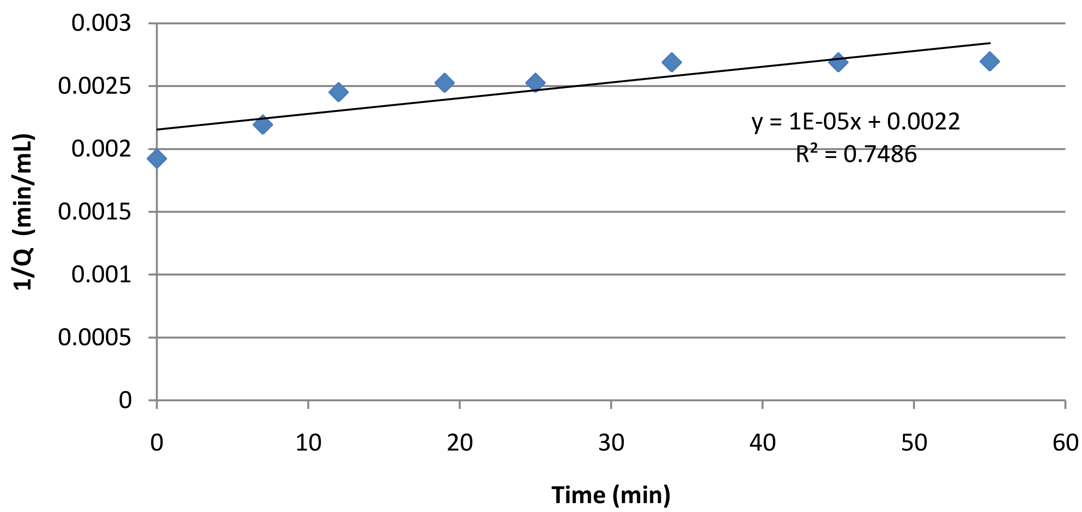

Fig. 4. 6 Plot of 1/Q against t in intermediate blocking filtration model in the ceramic filtration of produced water.

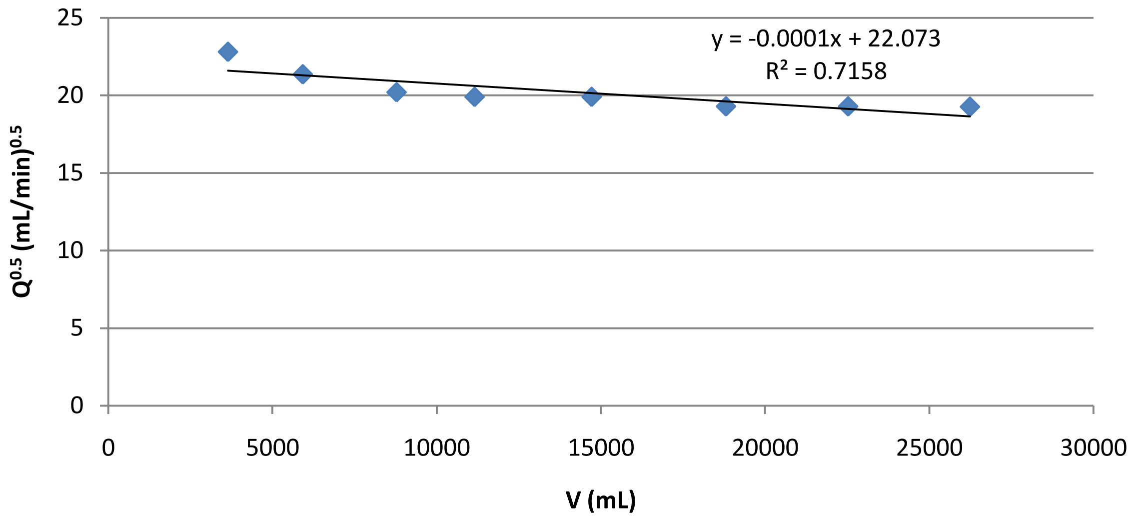

Fig. 4. 7 Plot of $Q^{0.5}$ against V in standard blocking filtration model in the ceramic filtration of produced water.

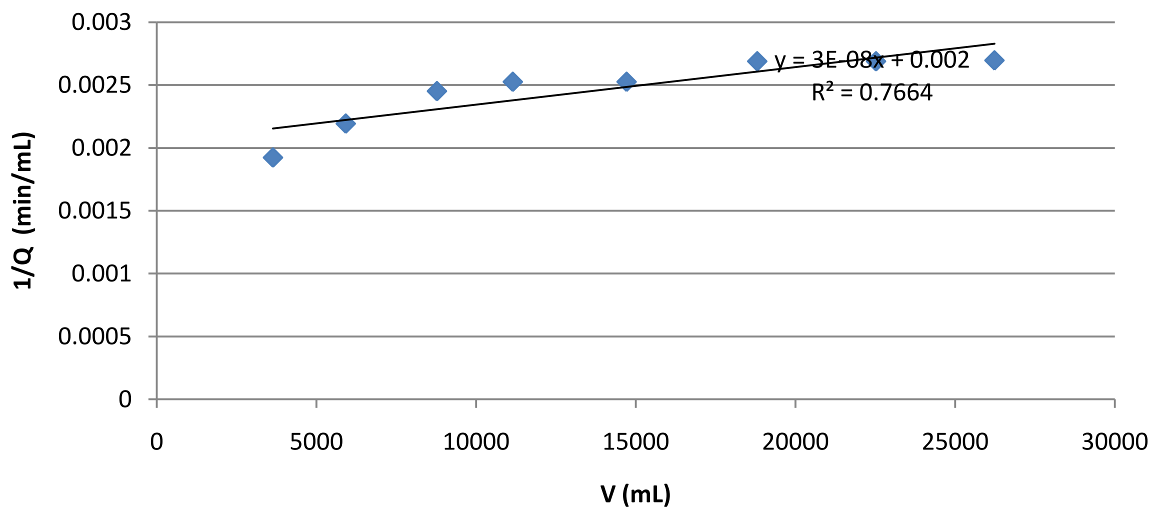

Fig. 4. 8 Plot of 1/Q against V in cake filtration model in the ceramic filtration of produced water.

The results of fitting the data from the ceramic membrane filtration of produced water to the filtration models by plotting the rate of permeate volume (Q or 1/Q or $Q^{0.5}$) with either filtration volume (V) or the filtration time (t) is presented in figures 4.5 -4.8. From the results we see that all models show poor correlation in explaining the filtration mechanism in the filtration of produced water with ceramic membranes. This re-enforces the notion that a complex interaction exists between the oil droplets, membrane surface and membrane pores that is not easily described with the simplified models, using the modifications by Kotuniewicz et al [69] to the Hermia model did not fit either (results not shown). Various authors have described various filtration mechanisms in the filtration of produced water using different membrane and under different conditions. Hu [48] describes different filtration models operating at different periods during produced water filtration, showing the first stage expressing some blocking filtration and the second stage cake filtration while others describe a dominance of a filtration mechanism but usually with simulated oil contaminated water [66,67].

4.2.3 Produced Water Filtration with Hollow Fibre Membranes

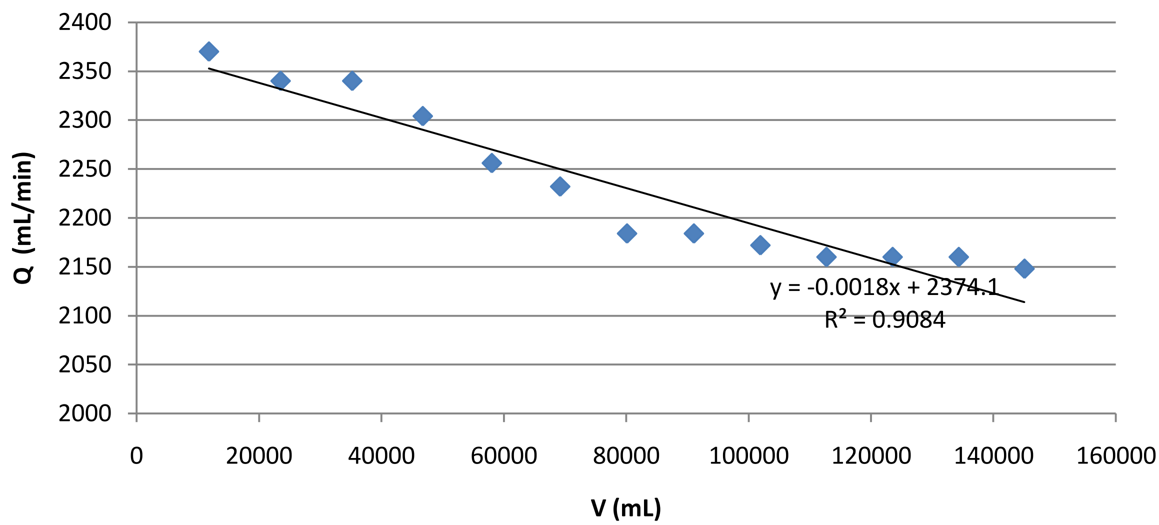

Fig. 4. 9 Plot of Q against V in complete blocking filtration model in the hollow fibre filtration of produced water.

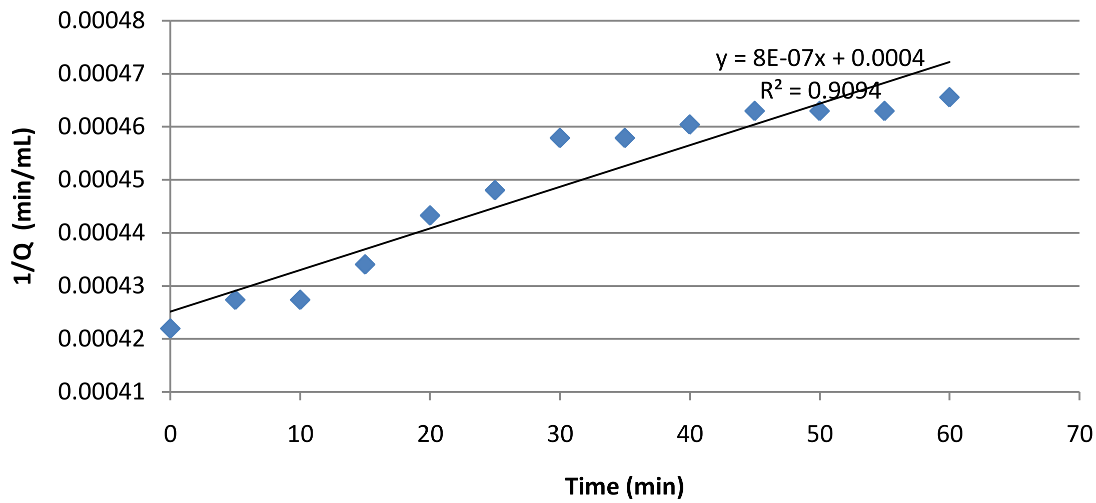

Fig. 4. 10 Plot of 1/Q against t in intermediate blocking filtration model in the hollow fibre filtration of produced water.

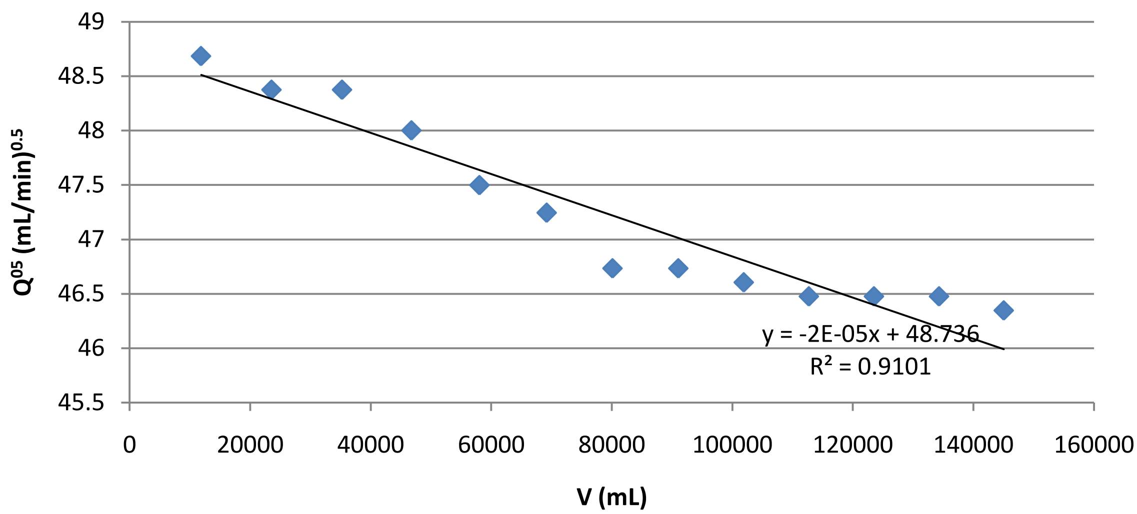

Fig. 4. 11 Plot of $Q^{0.5}$ against V in standard blocking filtration model in the hollow fibre filtration of produced water.

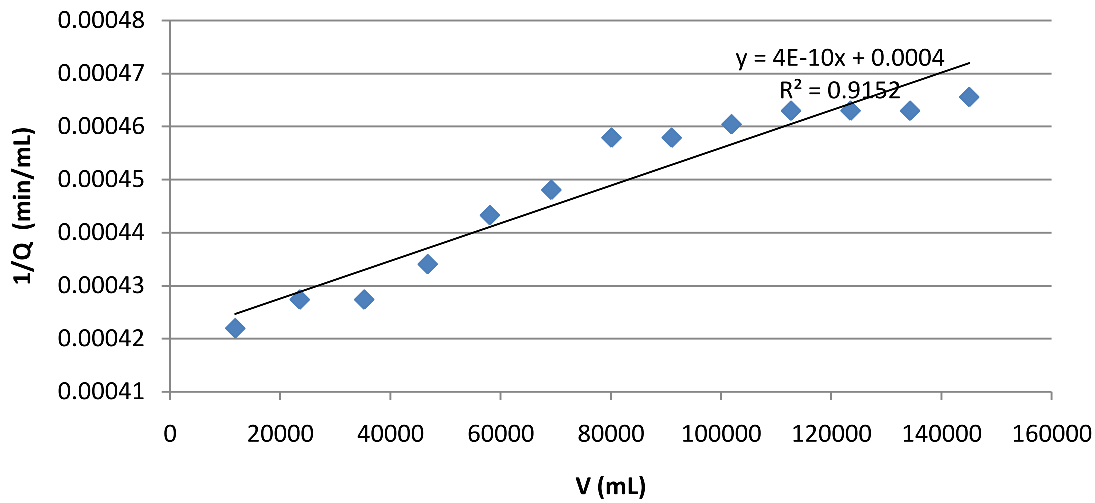

Fig. 4. 12 Plot of 1/Q against V in cake filtration model in the hollow fibre filtration of produced water.

The results of fitting the data from the hollow fibre membrane filtration of produced water to the filtration models by plotting the rate of permeate volume (Q or 1/Q or $Q^{0.5}$) with either filtration volume (V) or the filtration time (t) is presented in figures 4.8 -4.12. From the results we see that all models show a medium correlation in explaining the filtration mechanism with cake filtration showing a slightly stronger correlation and complete blocking showing the least, a reversal of ceramic filtration of spent drilling fluids. From this it seems that using the Hermia models no model adequately explains the filtration in the hollow fibre filtration of produced water, there were no appropriate models found in literature that could suitably be applied to the hollow fibre membrane used.

4.3 Resistance Determination

Due to complexities in describing accurately the filtration mechanism, another beneficial approach would be to use pressure and flux differences to determine the resistances involved in membrane filtration. Another model designed to increase the understanding of membrane fouling is the membrane resistance model and it is one of the most applicable fouling models [64]. This model better describes the entire pressure-flux behavior during ultrafiltration or microfiltration i.e. pressure-controlled at low pressures, pressure-independent at high pressure [40]. The resistance in series model is based on the assumption that there are several distinct resistances in series which affect the transmembrane flux and are indicative of fouling. Central to the resistance model is an understanding of the relative proportion of the various membrane resistances under different filtration conditions, this is crucial to understanding fouling/flux decline. Since the blocking models proposed by Hermia [68] were inadequate to explain flux decline in the filtration of water based drilling wastes the resistance in series model is used here to analyze membrane resistances.

During filtration there are different resistances; there is the resistance solely due to the membrane itself, resistance due to adsorption, resistance due to concentration polarization and resistance due to irreversible and reversible fouling [64]. These resistances are active or passive in the fouling of membranes and are affected to a large degree by the concentration of feed constituent's and operational parameters. Darcy's law is used to determine filtration resistance in permeate transport through porous membranes:

$$J = \frac{P_T}{\mu\, R_t} \tag{4.1}$$

Where J is the permeate flux, P_T is the transmembrane pressure, μ is the viscosity of the permeate and R_t is the total membrane resistance. Different models subdivide the components of total membrane resistance R_t, differently; the definition according to Choi et al [64] is adopted. According to Choi et al

$$R_t = R_m + R_{ad} + R_{cp} + R_f \tag{4.2}$$

Where R_m is the membrane resistance, R_{ad} the resistance due to adsorption, R_{cp} resistance due to concentration polarization and R_f resistance due to fouling. Therefore equation 4.1 can be re-written as

$$J = \frac{P_T}{\mu(R_m + R_{ad} + R_{cp} + R_f)}$$

(4.3)

These resistances are described as follows:

Membrane resistance R_m

During filtration of an ideal feed such as reverse osmosis water which is devoid of solutes the only resistance encountered is the membrane resistance R_m. R_m is the hydraulic resistance of the membrane i.e. the intrinsic membrane resistance determined by using pure water as the feed. R_m is useful for modeling purposes, evaluating the effectiveness of cleaning procedures and for charting the long time stability of the membrane [49]. At a fixed operating pressure, the membrane resistance is a function of the viscosity of the feed water. R_m and the pure water flux J_w are related by

$$J_w = \frac{P_T}{R_m}$$

(4.4)

Where J_w is pure water flux, P_T is the transmembrane pressure and R_m is the membrane resistance.

Resistance due to adsorption R_{ad}

When the membrane is in contact with the feed solution solute molecules interact with the membrane surface and adsorb to the membrane. This physico-chemical interaction between the membrane and the solutes could result in resistances to the flow of permeate and it is independent of the presence of permeate flux. Filtration resistance due to adsorption is thermodynamically unavoidable but its contribution to the total filtration resistance is very small [64,70,71]in most cases. In exceptionally cases such as feed with high solute

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concentration for example ultra saturated brines wastes could make the contribution due to adsorption significant.

Resistance due to concentration polarization R_{cp}

Resistance due to concentration polarization is always confused with resistance due to true fouling, they are different and for the purpose of the different resistances in this model it shall be strictly defined in operational terms. Concentration polarization is fouling where the membrane flux can be recovered by "rinsing" the membrane with de-ionized or reverse osmosis water at the same operational conditions at which filtration of the feed occurs. The concentration polarization layer is believed to be caused by loose accumulation of particles at the membrane surface layer existing at the threshold of hydraulic resistance to permeate flow.

Resistance due to fouling R_f

Resistance due to fouling is the most important of all the resistances as it can be reduced by proper techniques in practical applications [64] or can cause significant losses in filtration operations. According to the classification by Choi et al., the resistance due to fouling is subdivided based on the strength of attachment of the foulants onto the membrane surface. Based on this classification resistance due to fouling is subdivided into reversible and irreversible fouling

$$R_f = R_{rf} + R_{if} \tag{4.5}$$

Where R_f is resistance due to fouling, R_{rf} is reversible fouling and R_{if} is irreversible fouling.

Reversible fouling is fouling caused due to loosely attached foulants and the flux can be reclaimed by "flushing" the membrane at high shear for a specified amount of time with reverse osmosis or distilled water. Cleaning with respect to R_{if} and R_{cp} differ in the magnitude of shear needed to dislodge the foulants predicated on the degree of attachment of the foulants to the membrane surface. Rinsing involves replacing the stream feed with distilled water or reverse osmosis water to filter through the membrane at the same operational conditions during feed filtration. Flushing does not only require using reverse osmosis or de-ionized water to clean the membrane but the filtration at higher cross flow velocity than the operating condition. It involves filtration at low pressure and high cross flow velocity creating a high shear low pressure condition to remove the attached foulants.

Irreversible fouling is fouling where the flux cannot be regained after flushing and or rinsing and would require some form of treatment to regain the flux. In irreversible fouling operational parameter variation to create conditions where reverse osmosis water or de-ionized water can be used to recover flux is largely ineffective. Irreversible fouling can only be treated through chemical means or some special membrane treatment that addresses the root cause of the fouling either physical or chemical. The term irreversible does not connote an irrevocable loss of the membrane filtering capability but rather a loss that requires some form of cleaning aside from operational parameter variation.

The classification of the fouling resistances in better viewed as special cases of concentration polarization where the degree of attachment of the foulants varies progressively. Concentration of particles onto the membrane surface reaches its maximum value after a short period due to high initial flux and then the gel and cake layers start to form. It is assumed that the three layers, the concentration polarization layer, reversible fouling layer and the irreversible fouling layer simultaneously exist on the membrane surface. As filtration progresses, the inner fouling layer near the membrane surface becomes more compacted resulting in a higher density. By the same mechanism the initial reversible fouling layer becomes more dense and attached to the surface of the membrane surface which means higher resistance to shear force and in the same vein the reversible fouling layer is transformed into irreversible fouling layer [64].

The experimental study to determine the various filtration resistances and their corresponding resistance measurements for the resistance in series model was carried out in three phases adopted from Choi et al [64] with slight modifications as shown in Figure 4.13.

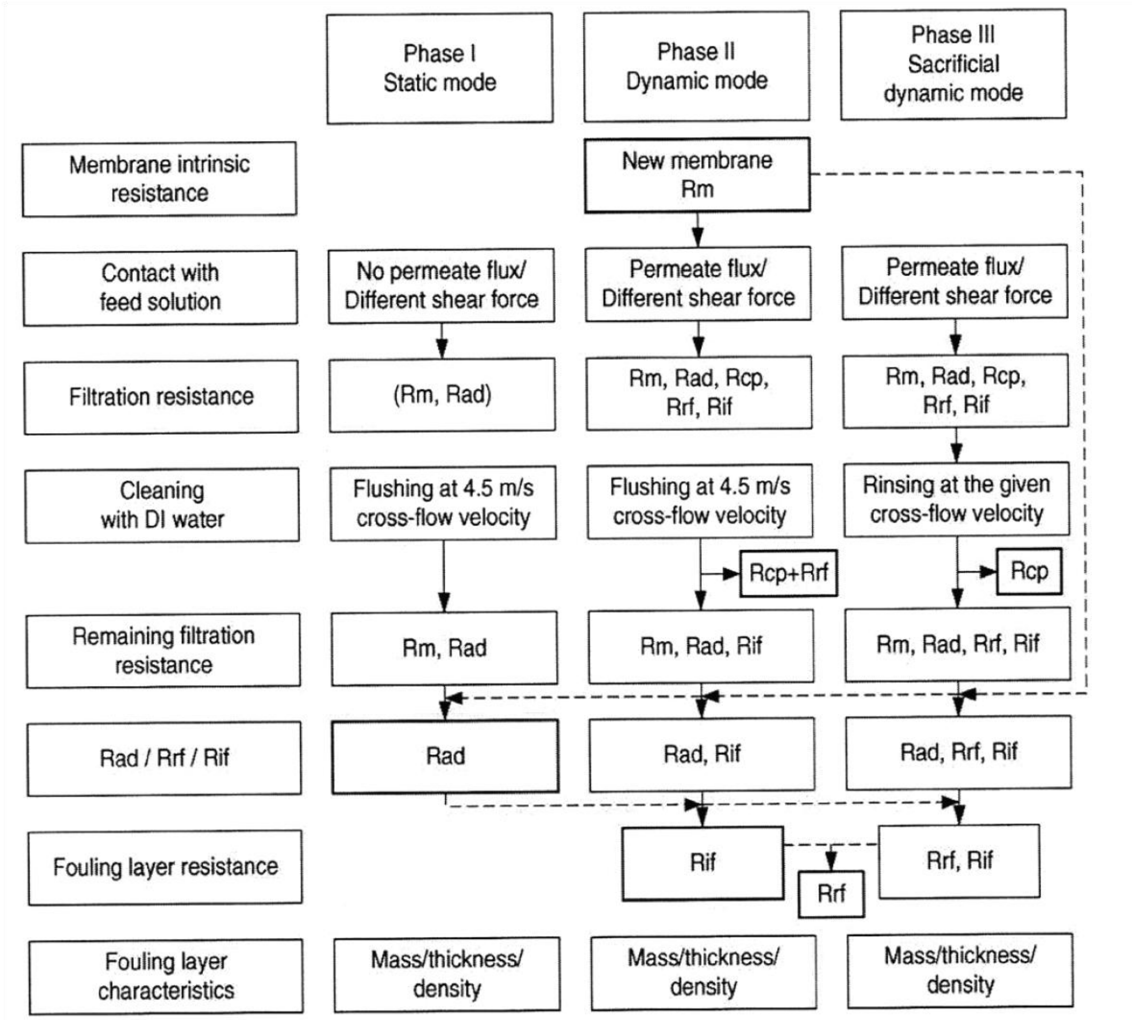

Fig. 4. 13 Test sequence for evaluating the various filtration resistances and their corresponding fouling layers (adopted from [64]).

Phase I

The first phase, called the static mode, is the mode where there is no permeate flux and the transmembrane pressure is 0 psia. In the static mode the feed is contacted with membrane for 4 hours for spent drilling fluids and 6 hours for produced water in the membrane housing, the feed is pumped to fill the membrane housing. After these hours the membrane is then flushed with RO water at high cross flow velocity and low pressure. In this static mode the total resistance of the fouled membrane consists of R_{ad} and R_m, the adsorption and membrane resistances. Therefore

$$R_{ad} = R_t - R_m \tag{4.6}$$

Where R_t is the filtration resistance of fouled membrane in the static mode.

Phase II

Phase II is the dynamic mode, filtration of the feed occurs at the filtration transmembrane pressure of and cross flow velocity for 4 hours uninterrupted for drilling fluids and six hours for produced water. After filtration for four hours the membrane is then flushed for 5 minutes. Flushing in this experimental setup involves cleaning the membrane at high cross flow velocity and low transmembrane pressure for 5 minutes. The total difference in total filtration resistance of the fouled membrane before and after flushing was defined as the sum of R_{cp} and R_{rf}

$$R_{cp} + R_{rf} = R_{t,240} - R_{t,f} \tag{4.7}$$

Where $R_{t,240}$ is the filtration resistance after feed filtration for four hours and $R_{t,f}$ is the filtration resistance after flushing following the four hour filtration, mass and thickness of the fouled membrane after flushing resulted from R_{ad} and R_{if}.

Phase III

Phase III called the sacrificial dynamic mode helps in determining the resistance due to concentration polarization. The same procedure was carried out again as in Phase II but this time after four hours of filtration where the difference in final permeate fluxes between Phase II and Phase III was less than 5%, rinsing instead of flushing was applied. Rinsing involves filtration with RO water at the same filtration condition at which the feed was filtered. Since rinsing removes concentration polarization, R_{cp} is

$$R_{cp} = R_{t,240} - R_{t,r}$$

(4.8)

Where $R_{t,r}$ is the filtration resistance after rinsing. Mass and thickness of the fouled membrane after rinsing resulted from R_{ad}, R_{rf} and R_{if}. R_{rf} was determined by subtracting equation (4.8) from (4.7). Finally the filtration resistance by irreversible fouling was determined as

$$R_{if} = R_{t,f} - R_m - R_{ad}$$

(4.9)

This same procedure was carried out for the ceramic filtration of produced water and spent drilling fluids. This procedure was carried out at the different operational parameters of pressure and cross flow velocities and under the various feed constituents i.e. oil and solids concentration variation.

4.3.1 Resistance in Series Model for Ceramic Membrane Filtration of Spent Drilling Fluid

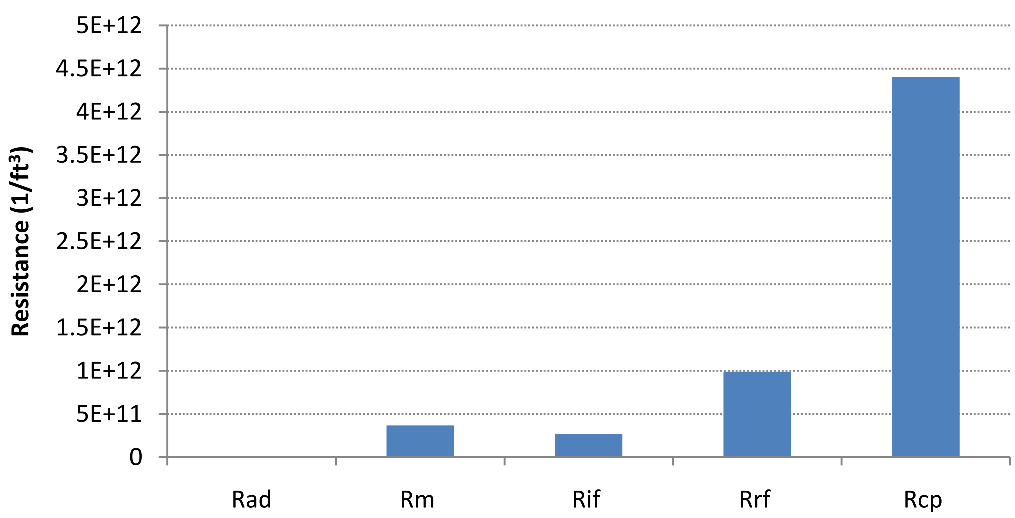

Fig. 4. 14 Different resistances in the ceramic filtration of spent drilling. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressure (15 psi), cross flow velocity (10.08 ft/s) and temperature (38 C).

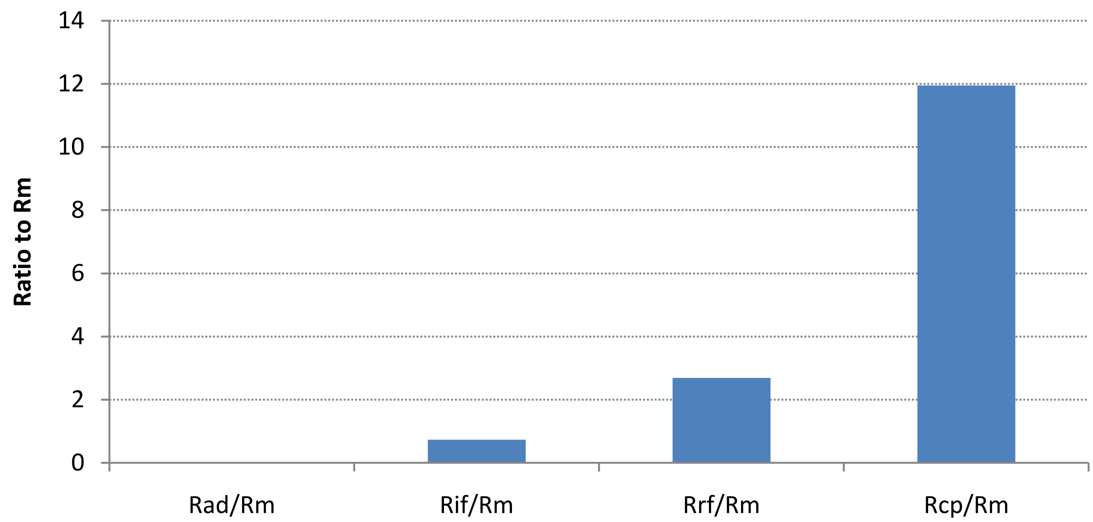

Fig. 4. 15 Ratio of the various resistances to membrane intrinsic resistance in the ceramic filtration of spent drilling. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressure (15 psi), cross flow velocity (10.08 ft/s) and temperature (38 C).

The resistances involved in the ceramic filtration of spent drilling fluids under the chosen arbitrary condition are shown in figure 4.14. At this condition resistance due to concentration polarization R_{cp} is the dominant resistance while other resistances are significantly lesser, resistance due to reversible fouling R_{rf} is the second most significant resistance under this condition. For the fouling studies a brand new ceramic membrane was used in all the experiments. It was noticed that using a new membrane the intrinsic membrane resistance could obscure the contribution of other resistances and the same effect was noticed with fouled membranes (used over two years) as the intrinsic membrane resistance obscured the proportion. Reporting the different resistances as a ratio of the intrinsic membrane resistance gives a more robust assessment of the role of the different resistances and gave an accurate assessment of the contributing membrane resistances.

This ratio comparison allows for the unique development of a practical tool to monitor membrane fouling and integrity by simple tests during membrane filtration and clean-up as would be shown. It also eliminates false fouling representation under various conditions and allows for evaluation of membrane integrity at any point during active membrane use

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especially when the initial pure water flux is not 100% obtainable. Figure 4.15 reports the various resistances as a ratio of the intrinsic membrane resistance and the advantage of reporting in this manner is not apparent but would be apparent other circumstances. From figures 4.14 and 4.15 it is seen that resistance due to adsorption is non-existent in contributing to fouling in the filtration of spent drilling fluids and this supports the findings of [64,70,71] in the filtration of other feeds. Table 4.2 shows the various resistances at different pressures.

Table 4.2 Various resistances in the ceramic filtration of spent drilling fluids at different pressures. Solids concentration (8.8±0.5% vol), pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressures (7, 15 and 20 psi), cross flow velocity (10 ft/s) and temperature (38 C)

Pressure (psi)	R_m (1/ft^3)	R_{if} (1/ft^3)	R_{rf} (1/ft^3)	R_{cp}(1/ft^3)
7	3.684E+11	2.695E+11	9.887E+11	4.402E+12
15	3.684E+11	9.802E+10	7.160E+11	4.486E+12
20	3.684E+11	7.160E+11	1.571E+12	3.373E+12

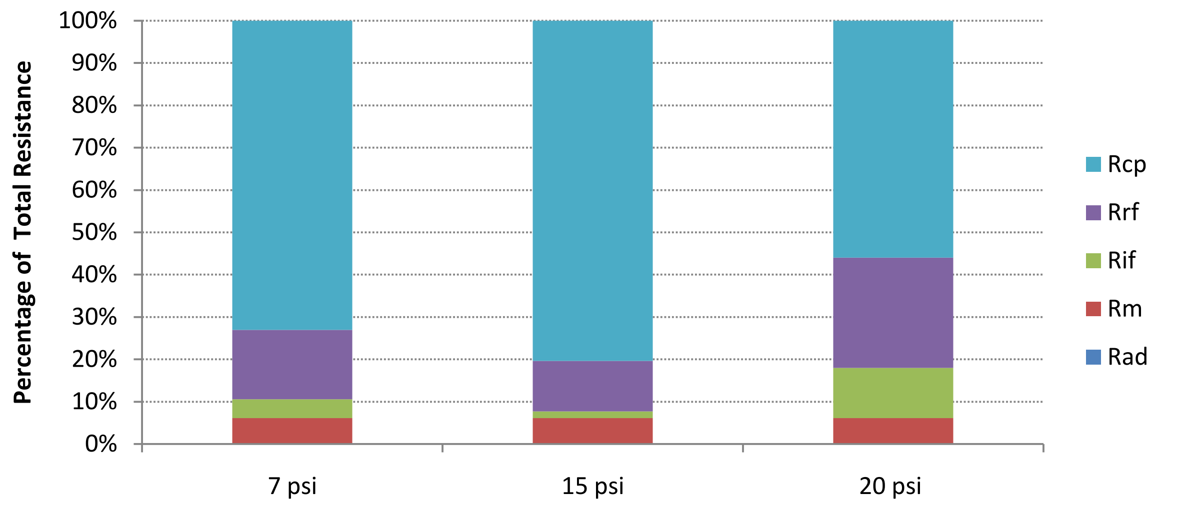


Fig. 4. 16 Proportion of the different resistances in the ceramic filtration of spent drilling. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressures (7, 15 and 20 psi), cross flow velocity (10.08 ft/s) and temperature (38 C).

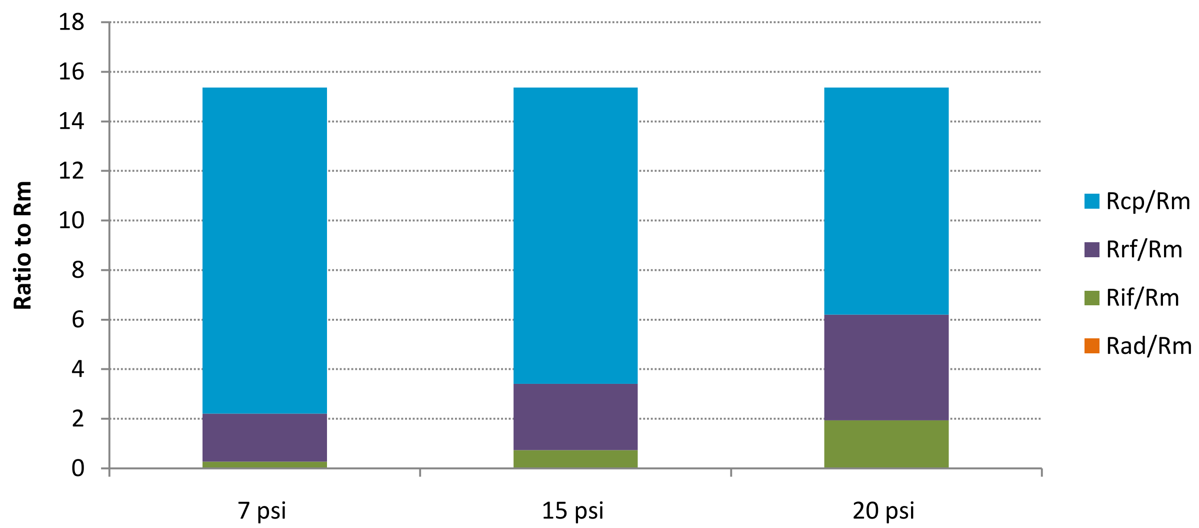


Fig. 4. 17 Ratio of the various resistances to membrane intrinsic resistance in the ceramic filtration of spent drilling fluids at different pressures. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressures (7, 15 and 20 psi), cross flow velocity (10.08 ft/s) and temperature (38 C).

The resistances involved in the ceramic filtration of spent drilling fluids under different pressures are shown in figure 4.16. Increasing pressure as was seen in the filtration of spent drilling fluids caused a rapid decline in flux especially at the transmembrane pressure of 20 psi; this is corroborated by figure 4.16 showing resistance increasing with increased pressure from the figures above. From figure 4.16 it is seen that resistance due to irreversible fouling R_{if} is largest during filtration at transmembrane pressure of 20 psi. This supports the view that at higher transmembrane pressures there is a consolidation of the fouling layer creating greater hydraulic resistance to the flow of the permeate. It is also seen that resistance due to reversible fouling R_{rf} increases with increasing pressure while concentration polarization is lowest at high pressure a possible indication of a more rapid transformation of the concentration polarization layer.

Under closer inspection of figure 4.16 it seems also that resistance due to irreversible fouling R_{if} is larger at transmembrane pressure of 7 psi when compared to transmembrane pressure at 15 psi and this seems contrary to what was observed during filtration when correlated with flux decline. Resistance due to concentration polarization also seems to be greater at transmembrane pressure of 15 psi when compared to 7 psi this intuitively seems contrary. When the resistances are plotted as a ratio of the intrinsic membrane resistance as seen in figure 4.17, the contribution of the different resistances under the different conditions becomes clearer and corroborates what was observed during filtration experiments. Resistance due to irreversible fouling is seen to increase as pressure increases and the same is also noticed for resistance due to reversible fouling. Resistance due to concentration polarization is seen to also decrease with increasing pressure.

Table 4.3. Various resistances in the ceramic filtration of spent drilling fluids at different cross flow velocities. Solids concentration (8.8±0.5% vol), pH (9.5). Ceramic membrane pore size(0.2 micron), transmembrane pressure (15 psi), cross flow velocity (6,10 and 16 ft/s) and temperature (38 C)

Cross flow velocity (ft/s)	R_m (1/ft^3)	R_{if} (1/ft^3)	R_{rf} (1/ft^3)	R_{cp}(1/ft^3)
6	3.684E+11	1.321E+11	6.310E+11	4.896E+12
10	3.684E+11	3.505E+11	6.365E+11	5.205E+12
16	3.684E+11	1.563E+11	4.537E+11	9.507E+11

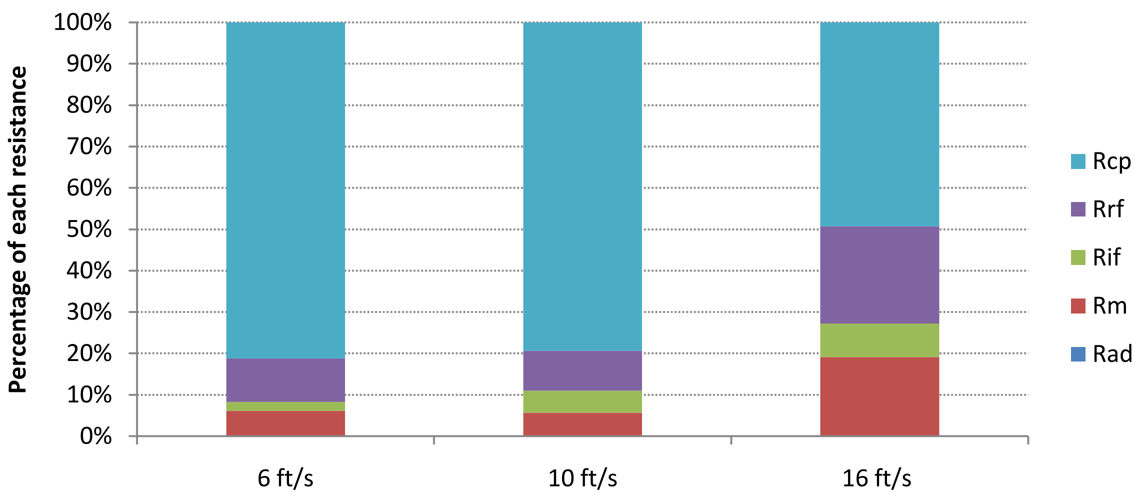


Fig. 4. 18 Proportion of the different resistances in the ceramic filtration of spent drilling fluids at various cross flow velocities. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressure (10 psi), cross flow velocities (6, 10 and 16 ft/s) and temperature (38 C).

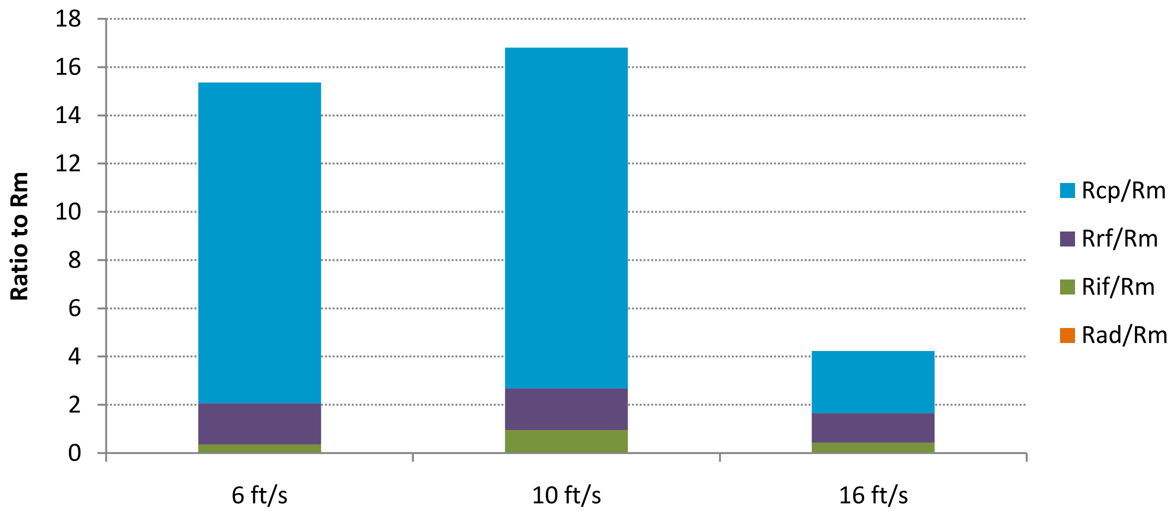


Fig. 4. 19 Ratio of the various resistances to membrane intrinsic resistance in the ceramic filtration of spent drilling fluids at different cross flow velocities. Solids concentration (8.8± 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressure (10 psi), cross flow velocity (6,10 and 16 ft/s) and temperature (38 C).

The resistances involved in the ceramic filtration of spent drilling fluids under different cross flow velocities are shown in figure 4.18. With increasing cross flow velocity it seems that the resistance due to irreversible fouling increases when the percentage of the total resistance is taken into account. But when the resistances are compared to the membrane resistance it is seen that the resistance due to irreversible fouling is lowest at high cross flow velocities and similar to that at low cross flow velocity. Also it is seen that concentration polarization is also lowest at the highest cross flow velocity, this seems to support the concept of scouring of the membrane surface due to shear created by the turbulence at high cross flow velocities. The advantage of the ratio comparison to the membrane resistance is evident in the analysis of the data from different cross flow velocities. Table 4.3 shows the various resistances at different cross flow velocities.

From figure 4.19 the obvious advantages of a cross flow velocity where possible is well shown. This supports findings [64,69]that show increasing cross flow velocities were beneficial to filtration in solids laden wastes as more materials is not only passed through but the onset of flux decline is prolonged. With respect to the description of fouling as special cases of concentration polarization, from figure 4.19 it is evident that at higher cross flow velocities the change in fouling layer develops more rapidly in comparison to lower cross flow velocities. Considering the increased mass of material filtered at high cross flow velocities the rapid change in fouling layer seems intuitive and the role of pressure could also be inferred, at high pressures the change would be much more rapid. This supports the observation during the experiments at lower pressures and high cross flow velocity where the onset of flux decline was further prolonged.

Table 4.4. Various resistances in the ceramic filtration of spent drilling fluids with different solids concentration. Ceramic membrane pore size(0.2 micron), transmembrane pressure (15 psi), cross flow velocity (10 ft/s) and temperature (38 C)

Solids Concentration	R_m (1/ft^3)	R_{if} (1/ft^3)	R_{rf} (1/ft^3)	R_{cp}(1/ft^3)
Low	3.684E+11	1.521E+11	1.420E+12	5.784E+11
High	3.684E+11	1.997E+12	1.971E+12	2.2703E+12

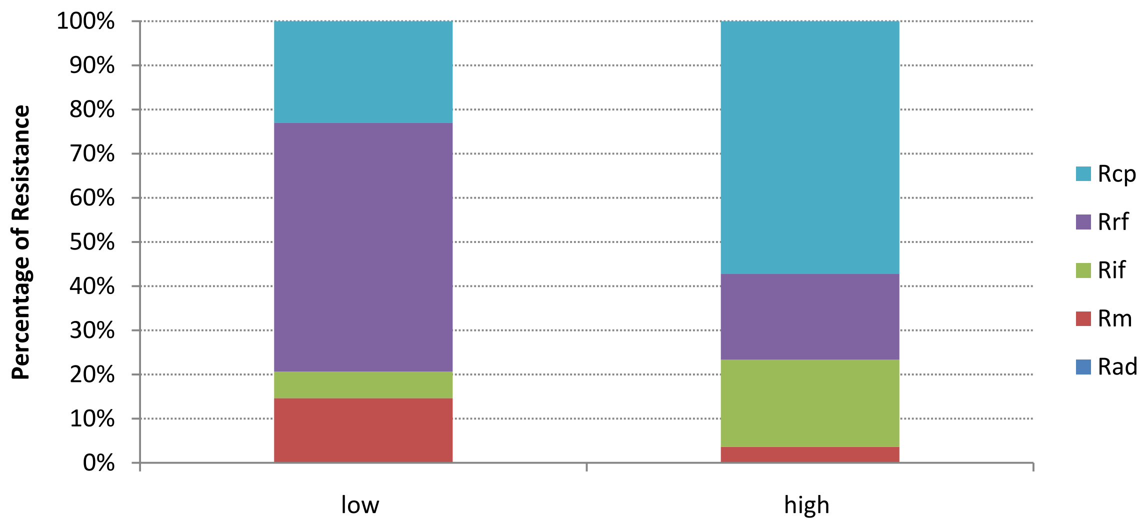


Fig. 4. 20 Proportion of the different resistances in the ceramic filtration of spent drilling fluids at various solids concentration. Solids concentration (8.8± 0.5% vol and 10.20± 0.5% vol), pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressure (10 psi), cross flow velocities (10 ft/s) and temperature (38 C).

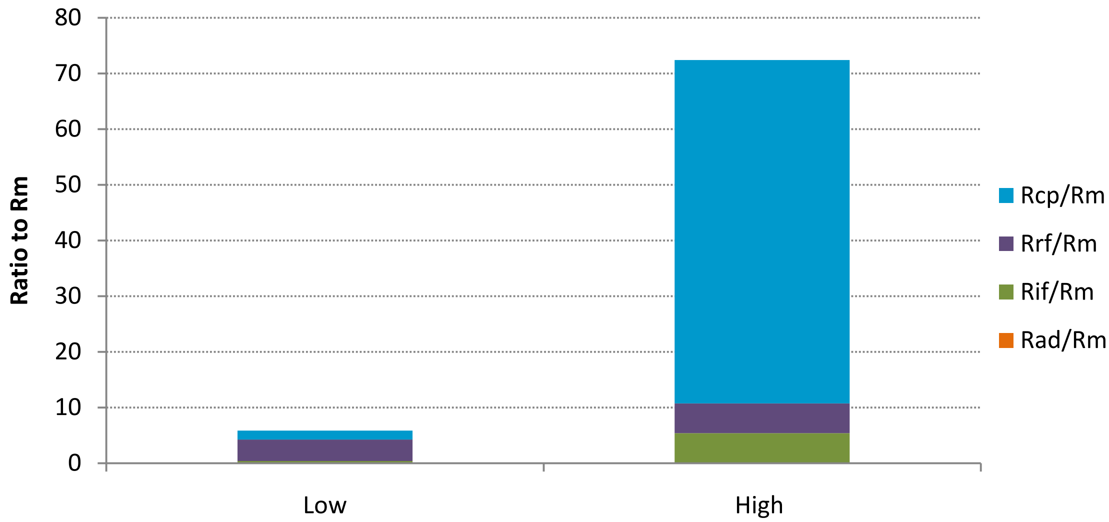


Fig. 4. 21 Ratio of the various resistances to membrane intrinsic resistance in the ceramic filtration of spent drilling fluids at different solids concentration. Solids concentration (8.8± 0.5% vol and 10.20± 0.5%) and pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressure (10 psi), cross flow velocity (10 ft/s) and temperature (38 C).

The resistances involved in the ceramic filtration of spent drilling fluids with different solids concentrations are shown in figure 4.20. The feed with the lower solids concentration showed a high amount of resistance due to irreversible fouling relative to other resistances in the total resistance. In the comparison to the ratio of the resistance due to the membrane, the resistance due to irreversible fouling is still significant at low solids concentration. At high solids concentration the resistance due to irreversible fouling is significant to the total resistance but lesser proportionally than what exists at low concentration. Table 4.4 shows the various resistances at different solids concentration.

When the ratio is compared to the resistance due to the membrane, the resistance ratios are the largest ratios (greater than 10, see figure 4.21) of any of the comparisons. Resistance due to irreversible fouling is 5 times the resistance due to the membrane, thus at higher solids concentration the propensity to foul is significantly greater than at any other operating parameter investigated. In the filtration of spent drilling fluids the feed concentration would be the most important characteristic in determining membrane fouling. This supports the experimental observations.

4.3.2 Resistance in series model for ceramic membrane filtration of produced water

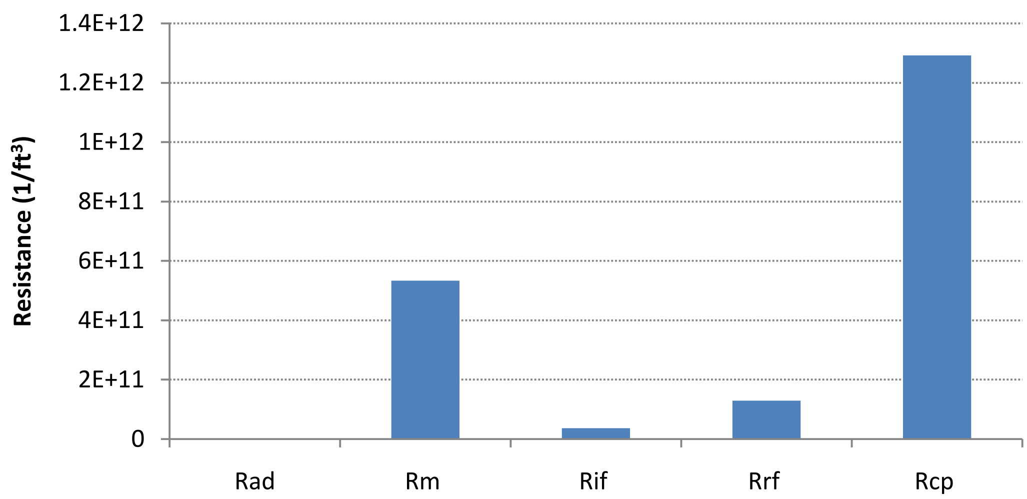


Fig. 4. 22 Different resistances in the ceramic filtration of produced water. Oil concentration 500± 200 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressure (15 psi), cross flow velocity (8 ft/s) and temperature (38 C).

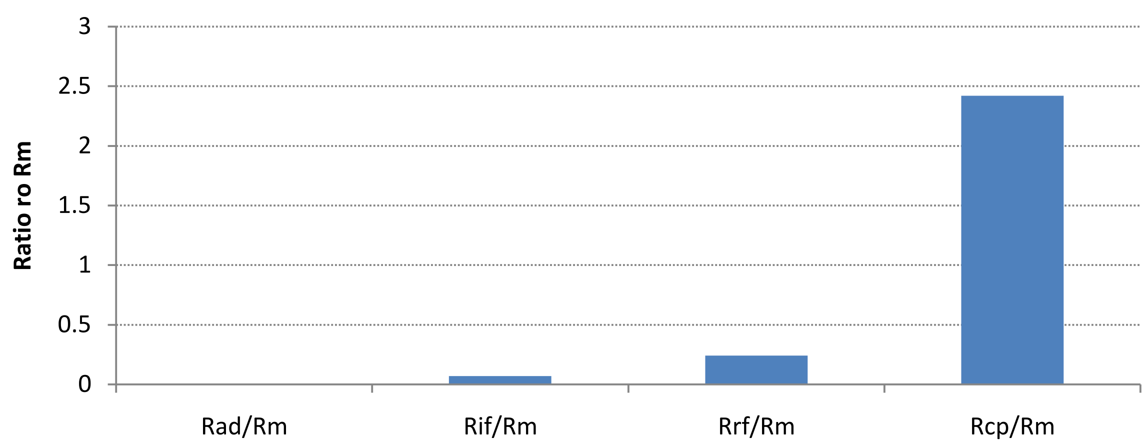
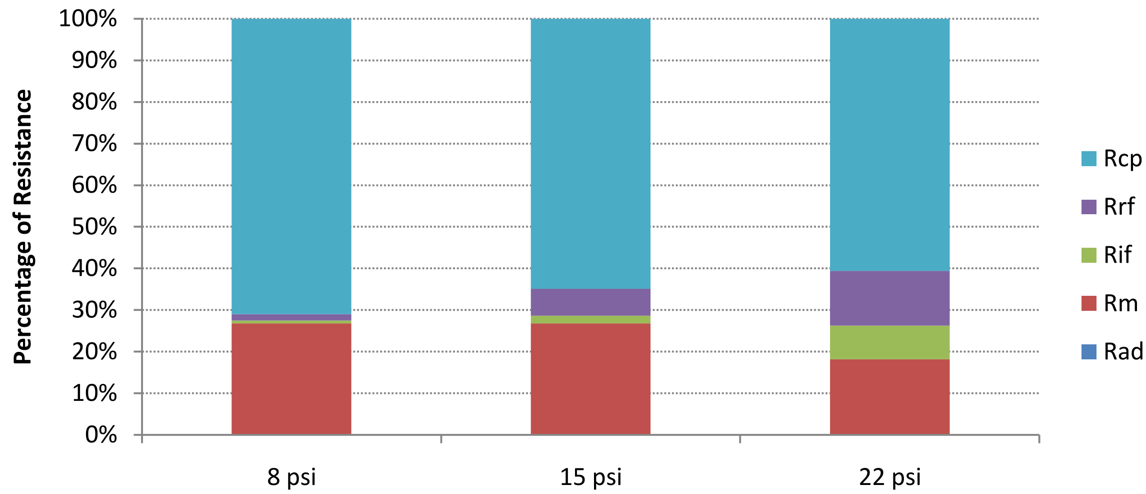


Fig. 4. 23 Ratio of the various resistances to membrane intrinsic resistance in the ceramic filtration of produced water. Oil concentration 500± 200 ppm, pH 7.3± 1.5 and salinity 36,000 ± 5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressure (15 psi), cross flow velocity (8 ft/s) and temperature (38 C).

The resistances involved in the ceramic filtration of produced water under the chosen arbitrary condition are shown in figure 4.22. At this condition resistance due to concentration polarization R_{cp} is the dominant resistance while the fouling resistances R_{rf} and R_{if} are significantly lesser. Intrinsic membrane resistance R_m is the second most significant resistance under this filtration condition, this is indicative of low fouling as membrane resistance is prominent in the total amount of resistance (contrast with figure 4.13). This might be indicative of a lower fouling propensity in the filtration of field produced water than of spent drilling mud. Figure 4.23 shows the ratio of the resistances to the membrane resistance. From figures 4.22 and 4.23 it is seen that resistance due to adsorption is non-existent as in the filtration of spent drilling fluids.

Table 4.5. Various resistances in the ceramic filtration of produced water at different pressures. Oil concentration 500±200 ppm, pH 7.3±1.5 and salinity 36,000±5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressure (15 psi), cross flow velocity (8 ft/s) and temperature (38 C)

Pressure (psi)	R_m (1/ft^3)	R_{if} (1/ft^3)	R_{rf} (1/ft^3)	R_{cp}(1/ft^3)
8	5.336E+11	3.714E+10	1.288E+11	1.292E+12
15	5.336E+11	1.431E+10	3.044E+11	1.413E+12
21	5.336E+11	2.364E+11	6.416E+10	2.101E+12



Fig, 4. 24 Proportion of the different resistances in the ceramic filtration of produced water at various pressures. Oil concentration 500± 200 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressures (8, 15 and 22 psi), cross flow velocity (10.08 ft/s) and temperature (38 C).

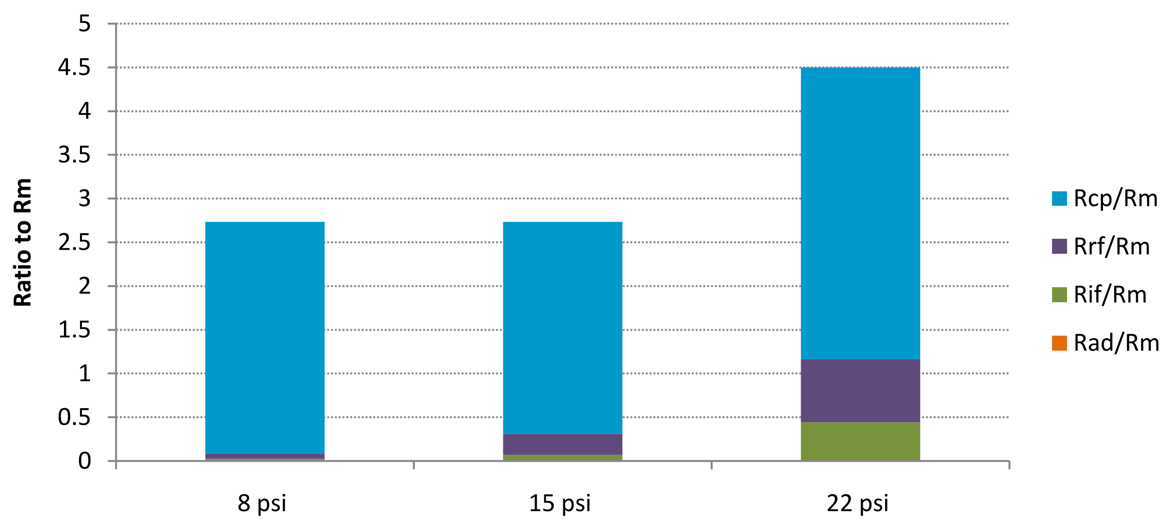


Fig. 4. 25 Ratio of the various resistances to membrane intrinsic resistance in the ceramic filtration of produced water at different pressures. Oil concentration 500± 200 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressures (8, 15 and 22 psi), cross flow velocity (10.08 ft/s) and temperature (38 C).

The resistances involved in the ceramic filtration of produced water under different pressures are shown in figure 4.24. Increasing pressure as was seen in the filtration of produced water caused a decline in flux as higher transmembrane pressures reduced the flux (chapter III), from figures 4.24 and 4.25 increasing pressure increases the magnitude of the fouling layer. This also supports the view that at higher transmembrane pressures there is a consolidation of the fouling layer creating greater hydraulic resistance to the flow of the permeate and the resistance in series model seems to support this view. When compared with the relative magnitude of the resistances during spent drilling fluid filtration produced water filtration is smaller. In spent drilling fluid filtration there seems to be a rapid transformation of the concentration polarization layer (figure 4.17) resulting in a higher R_{rf} layer and lower R_{cp} to R_m ratio at high pressures, this transformation is not seen in produced water filtration as the R_{cp} to R_m ratio at higher pressures is relatively similar. Table 4.5 shows the various resistances at different pressures.

Pressure is one of the most important operational factor in the reduction of permeate flux and fouling of the membrane during filtration of water based wastes. The effect of pressure is more pronounced in filtration of wastes with higher solids concentration than with lower solids concentration. Pressure is also significant to flux values and thereby the productivity of the membrane filtration process. Low pressures though reducing the flux decline and fouling propensities would bring about low flux making filtration uneconomical. Thus a balance needs to be developed between the filtration pressure and fouling and flux decline propensities, and good cleaning or anti-fouling practices are an essential part of this balance.

Table 4.6 Various resistances in the ceramic filtration of spent drilling fluids at different cross flow velocities. Oil concentration 500±200 ppm, pH 7.3±1.5 and salinity 36,000±5000 TDS mg/L. Ceramic membrane pore size(0.2 micron), transmembrane pressure (15 psi), cross flow velocity (5,8 and 13 ft/s) and temperature (38 C)

Cross flow velocity (ft/s)	R_m (1/ft^3)	R_{if} (1/ft^3)	R_{rf} (1/ft^3)	R_{cp}(1/ft^3)
5	5.336E+11	1.660E+11	8.873E+11	5.719E+11
8	5.336E+11	3.714E+11	1.288E+11	1.292E+11
13	5.336E+11	1.547E+11	5.584E+11	4.959E+11

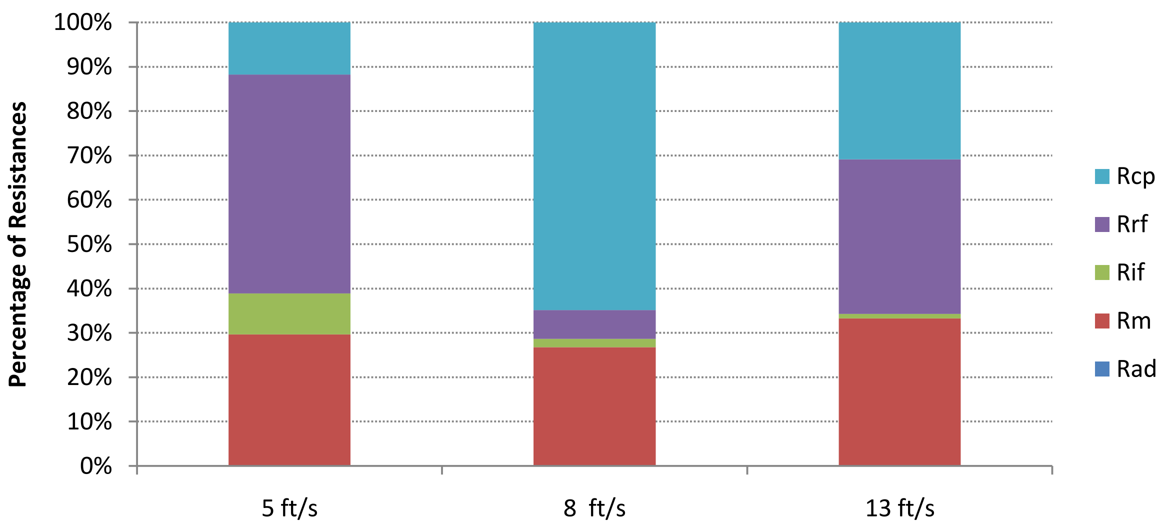


Fig. 4. 26 Proportion of the different resistances in the ceramic filtration of spent drilling fluids at various cross flow velocities. Oil concentration 500± 200 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressure (10 psi), cross flow velocities (5, 8 and 13 ft/s) and temperature (38 C).

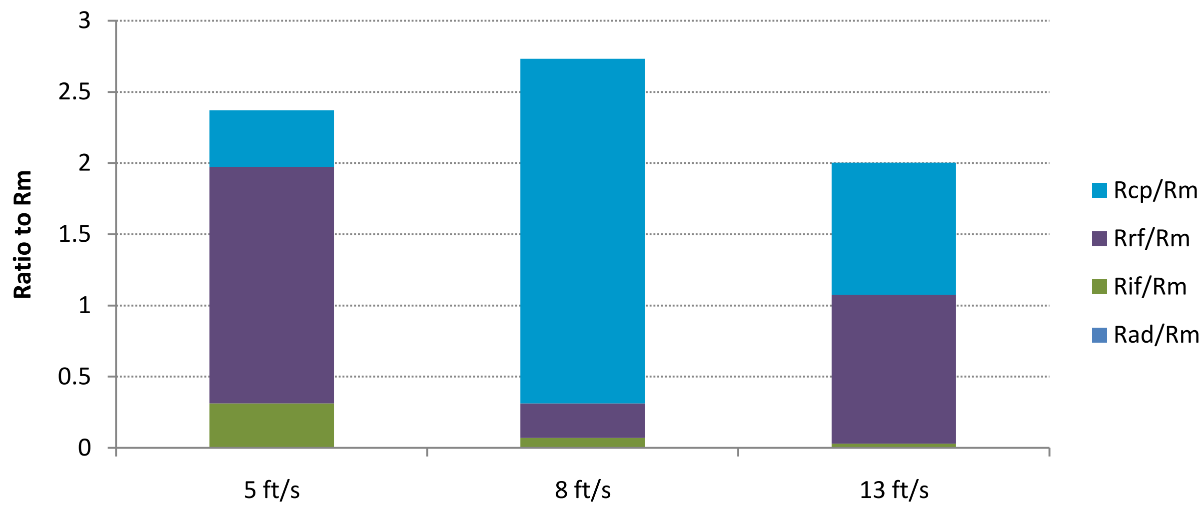


Fig. 4. 27 Ratio of the various resistances to membrane intrinsic resistance in the ceramic filtration of spent drilling fluids at different cross flow velocities. Oil concentration 500± 200 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressure (10 psi), cross flow velocities (5, 8 and 13 ft/s) and temperature (38 C).

The resistances involved in the ceramic filtration of produced water under different cross flow velocities are shown in figure 4.26 and 4.27. The resistances show no clear patterns as the cross flow velocity decreases or increases except that resistance due to reversible fouling decreases as cross flow velocity decreases (figure 4.27). At the lowest cross flow velocity (5 ft/s) there is a rapid change of the concentration polarization layer (much greater than at high pressure) layer and a high magnitude of resistance due to both reversible and irreversible fouling. At the highest concentration where it is expected that fouling layer be minimal, the ratio of R_{cp} to R_m and R_{rf} to R_m are relatively large when compared to filtration of spent drilling fluids under similar conditions. Table 4.6 shows the various resistances at different cross flow velocities.

This observation seems to support the theory that with feeds with low solids concentration such as produced water the advantage of high cross flow velocities is measured relative to feeds with high cross flow velocities. Or more narrowly focused, it is observed that high cross flow velocities is not very effective during filtration as a flux decline mitigation tool in low solids feed. The low solids concentration and particle size distribution do not create enough shear for the scouring of the membrane surface to prolong the onset of hydraulic resistance to the permeate flow.

This is also evidence to show that turbulence generated by the flow through the membrane is aided by the solids concentration in controlling flux decline in ceramic filtration of spent drilling fluids. This resistance observation at different cross flow velocities during produced water filtration could also be indicative of the dominant fouling mechanism during filtration. If cake layer formation were the dominant mechanism, without pressure interference, cross flow velocity should affect the resistances significanlty; this observation seems to lend credence to pore plugging as the dominant fouling mechanism in produced water filtration.

Table 4.7 Various resistances in the ceramic filtration of produced water with different oil concentrations. Ceramic membrane pore size(0.2 micron), transmembrane pressure (15 psi), cross flow velocity (8 ft/s) and temperature (38 C)

Oil concentration	R_m (1/ft^3)	R_{if} (1/ft^3)	R_{rf} (1/ft^3)	R_{cp}(1/ft^3)
Low	5.336E+11	3.714E+10	1.288E+11	1.292E+12
High	5.336E+11	1.170E+11	1.277E+12	1.870E+12

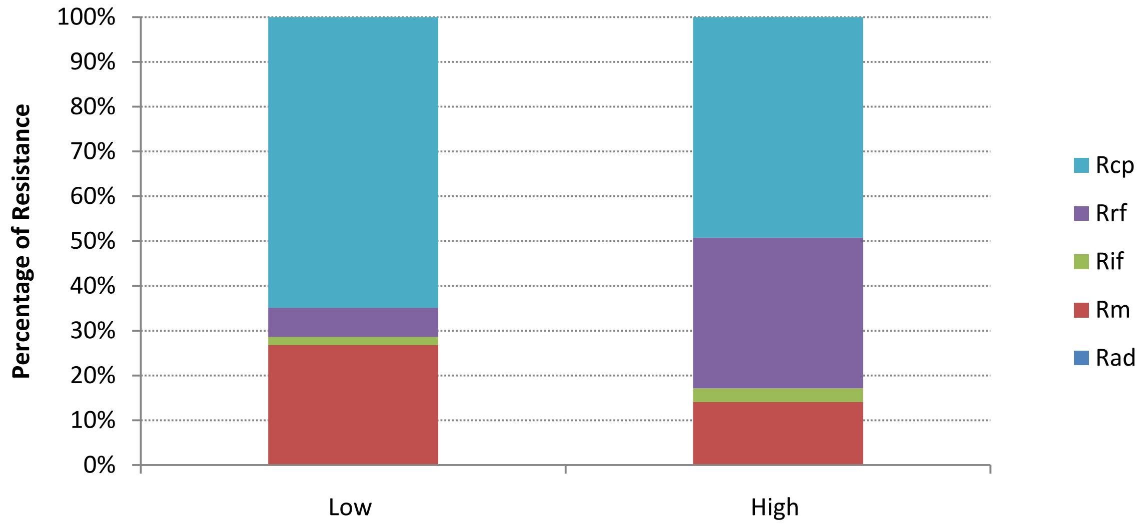


Fig. 4. 28 Proportion of the different resistances in the ceramic filtration of produced water at various oil concentrations. Oil concentration 500± 163 ppm (low) and 1200± 186 ppm , pH 7.3 ± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressure (10 psi), cross flow velocities (15 ft/s) and temperature (38 C).

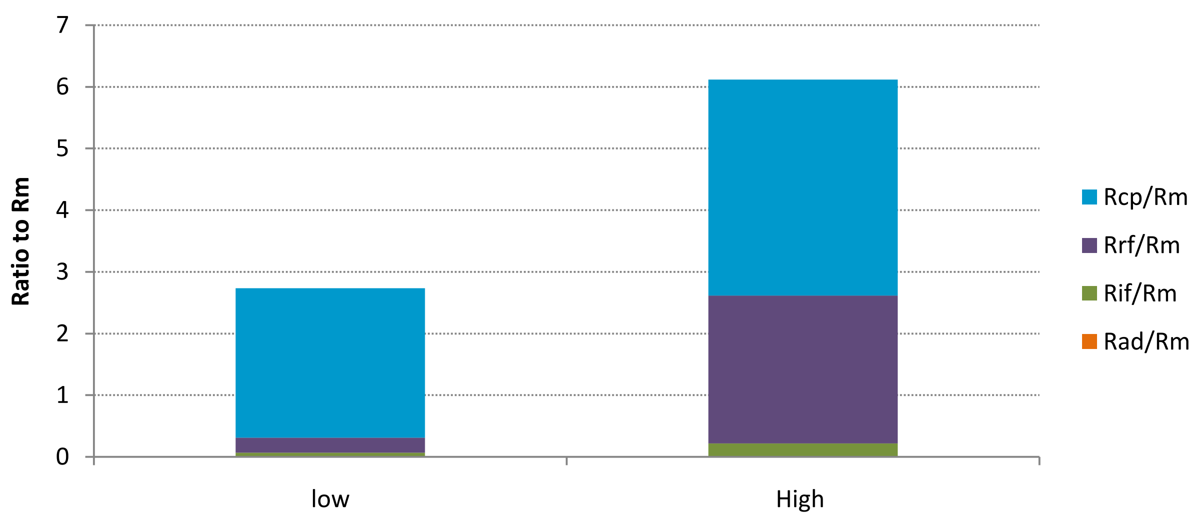


Fig. 4. 29 Ratio of the various resistances to membrane intrinsic resistance in the ceramic filtration of produced water at various oil concentrations. Oil concentration 500± 163 ppm (low) and 1200± 186 ppm , pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressure (10 psi), cross flow velocities (15 ft/s) and temperature (38 C).

The resistances involved in the ceramic filtration of spent drilling fluids with different solids concentrations are shown in figure 4.28 and 4.29. As expected the fouling resistances increased with increasing oil concentration in the feed though it is observed that the resistance due to irreversible fouling is not as significant proportionally to other resistances. The magnitude of the resistances also differs significantly when the solids concentration in the spent drilling fluids is increased than when the oil concentration in produced water is increased. The magnitude of resistances in high solids concentration in drilling mud (60 to 1, R_{cp} to R_m; 6 to 1 R_{cp} to R_{rf} and 7 to 1 R_{cp} to R_{if}) are significantly higher than in high oil concentration in produced water (4.5 to 1, R_{cp} to R_m; 2.5 to 1 R_{cp} to R_{rf} and 0.2 to 1 R_{cp} to R_{if}). Table 4.7 shows the various resistances at different oil concentrations.

It is intuitive that increasing feed concentration parameters would increase not only the flux decline but also the fouling propensity. Investigation into feed parameter variation is most useful in the determination of the optimal feed characteristic for filtration and for fouling studies. Practically, filtration is better optimized at low feed concentrations but this would have to be weighed against feasible flux objectives for filtering the feed. In this study for the feed parameters of solids concentration in spent drilling fluids and oil in produced water, the upper limits of what are practically obtainable were used in our study, thus it is expected that if pre-treatment methods are upstream of the membrane filtration better filtration results would be produced above that which is reported here.

Hollow fibre

Determining the resistances with the hollow fibre membrane was not practical. Hollow fibre membranes due to their low pressure and low cross flow velocity did not affect the resistance calculations to make much of a difference thus it was hard to apply the resistance in series model. Pressure changes are important to the resistance calculation, after determining the fouling period of the hollow fibre membranes pressure differences were not substantial for the equations to be valid. The same applied to cross flow variation where the range was small and the difference in flux not stark in hollow fibre membrane filtration (chapter III).

4.4 Summary

Though there are a plethora of models aimed at describing the filtration of a feed, it is rather difficult to predict with measurable certainty the filtration of most feeds. Empirical data still remains the best method to adequately understand the filtration pattern of the feed. In this chapter the simplified model used was not adequate in predicting the filtration pattern observed when fitted with actual data experiments. It was also difficult to determine the exact mechanism of flux decline as no individual mechanism fully explained the flux decline as the mixture of mechanisms seemed to exist. Though no mechanism rightly explains the flux decline, if fouling is due to physical means the probable reason would be due to either pore plugging or cake formation or a mixture of both of them.

The approach taken in calculating resistance served a central purpose of helping to develop a practical tool in the analysis of membrane integrity during use. Most membrane resistance calculations are done mostly as academic enterprises to explain the different interactions that exist during filtration. The resistance model chosen for calculation resistance was used due to its simplicity and its utility in being an actual tool for the monitoring of membrane integrity during actual operations. Using pressure reading and flux calculation, the membrane state can always be determined by comparing it to its intrinsic membrane resistance. A simplified excel program is being developed to show how an operator either during field pilot programs or actual membrane systems can apply this model to monitor the membrane behavior. More advanced systems can be automated to have this utility.

CHAPTER V

FOULING MITIGATION AND MEMBRANE CLEANING

5.1 Introduction

In the last chapter ways to predict the filtration profile in the ceramic and hollow fibre membrane filtration of water based wastes was examined, no suitable models could aptly describe the filtration pattern adequately. Determining the propensity of fouling through resistance calculation was also investigated and it was determined that it could be used as a simple practical tool in long term membrane integrity monitoring. Knowing the filtration pattern or resistance build-up during membrane filtration is in itself not an end, methods must be devised that address flux decline and membrane fouling for continued filtration. If a membrane system cannot be effectively cleaned and maintained then using membranes should be dissuaded. In this chapter two issues are examined, one, the fouling mitigation technique called backwashing and two, membrane cleaning.

This chapter reports on the investigation of backwashing in the ceramic filtration of both spent drilling fluids and produced water and in the hollow fibre filtration of produced water. As explained in previous chapters flux decline is an inevitable reality in the filtration of any feed that is not ideal (i.e. free of solutes), another reality is that despite rigorous fouling mitigation methods membrane fluxes over time shall decrease. Membrane fouling by minerals, organics, particles, colloids and microbial growth is a major operational concern that warrants periodic membrane cleaning [72,73]. Though flux recovery is possible employing fouling mitigation techniques the subtle accumulation of solutes not removed during mitigation techniques shall increase with time and increasingly intrinsic membrane resistances shall be larger.

To combat flux decline during actual filtration and to arrest gradual membrane integrity decline over time backwashing and chemical membrane cleaning are respectively used to address these issues. In the previous chapter some form of membrane washing was introduced where pure water was used in flushing the membrane at high cross flow velocity and low pressure. Also introduced was the idea of irreversible fouling i.e. fouling that cannot be addressed using operational parameters, to address irreversible fouling or fouling due to chemical interactions membrane cleaning using cleaning materials was investigated to regain flux.

Backflushing involves the flushing of clean permeate/ solids free effluent in reverse direction of the flow of permeate through the membrane outer skin at higher cross flow velocities and low pressure for a brief period during filtration. During filtration using a different pump or the same pump, clean water of solids free permeate is forced in reverse direction to the filtration flow of the permeate dislodging the solutes stuck in the pore spaces from outside. Backflushing forces the clean permeate/solids free effluent from the outer skin of the membrane through the pores to the lumen of the membranes. Terminologies in explaining this concept varies from author to author sometimes backflushing is called backpulsing, backflushing was not investigated but backwashing.

Backwashing involves the flow of clean permeate/solids free effluent in reverse direction of the feed flow through the membrane lumen i.e. the same passage way the feed passes through the membrane. Backwashing happens at higher cross flow velocity than the filtration cross flow velocity and also at lower pressure than the filtration pressure. Backwashing and backflushing are similar in that they occur at higher cross flow velocities than filtration cross flow velocities and they use clean permeate/ solids free effluent. They differ in where the flow is reversed from; backwashing flow is reverse to the feed flow i.e. from the outlet end to the inlet end while backflushing flow is reverse to the permeate flow i.e. from the membrane outer skin to the membrane inner skin.

Backwashing i.e. the reverse flow of the feed is believed to be most effective at the dealing with the concentration polarization layers at the membrane surface and in cases of high shear can unplug pore spaces. At higher cross flow velocity the turbulence of the solids free stream dislodges the cake filter layer at the surface of the membrane thereby reducing hydraulic resistance to the flow of permeate. Backflushing i.e. the reverse flow of the permeate is believed to be most effective at dealing with pore plugging, flow unplugs the pores from the outer layer but the pressure should exceed the pressure of the filter cake (if it exists). At high enough pressure during backflush the force through the pores if high enough should be able to dislodge the solute particles and free the pore space and the filter cake. Both techniques address fouling or flux decline issues that are of a physical nature.

As discussed inevitably chemical interactions between solutes in the feed and the membrane would cause fouling and this fouling cannot be remedied by using any physical process. This type of fouling also includes what was termed irreversible fouling in the last chapter and fouling due to membrane interactions with the feed. Since extensive chemical characterization of the feed was not carried out due to the variability of the feed, it would be impossible to adequately know precisely the chemical nature of the contaminants causing the fouling. This makes it difficult to apply a particular or specific cleaning agent to cleaning the membrane. In situations where the feed is properly characterized the nature of its constituents gives an indication of the chemical nature of the interaction with the membrane. Chemicals that are capable of neutralizing or changing the nature of this interaction are employed to effectively clean the membrane and they are for most part effective. Typical cleaning agents for membrane cleaning are acids, bases, enzymes, surface active agents, detergents, sequestering agents and disinfectants [75].

The approach in this thesis takes a broader path since the luxury of characterizing the wastes is non-existent. The broader approach adopted was a cleaning solution that involved both alkaline and acidic wash and another cleaning solution that is a micellar solution, both solution types were investigated. The cleaning solution that involves an acidic and alkaline wash would address a broad range of chemical interactions between the membrane and the feed while the micellar solution would give insight into cleaning with primarily surfactants. The flux recovery was calculated based on the difference between the flux after fouling and cleaning to the flux before fouling.

5.2 Fouling Mitigation Technologies

5.2.1 Ceramic Filtration of Spent Drilling Fluid

The spent drilling fluids used in these set of experiments were defined to have 8.8$\pm$ 0.5% solids (`19,000 mg/L) and a pH of 9.5$\pm$ 0.3 and the initial feed volume was 8 gallons and the experiment run in recycle mode. Arbitrary operating parameters for ceramic filtration for fouling mitigation experiments were cross flow velocity of 12 ft/s, transmembrane pressure of 12 psi and temperature of 38 C. During the experiment backwashing was initially applied every 15 minutes for 5 seconds at a cross flow velocity of 18 ft/s from an external pump, this was then changed to every 40 minutes to better address flux decline. The flow from the wash was collected outside the system and not reintroduced into the system. The experiments were repeated twice and the result shown is an average of the fluxes.

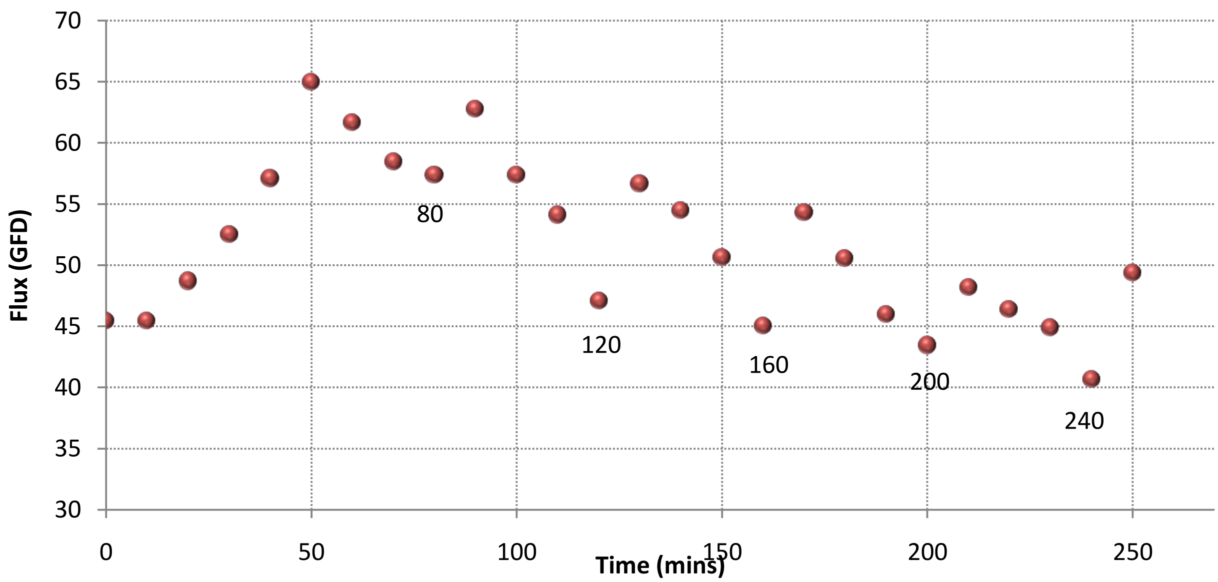


Fig. 5. 1 Backwashing in the filtration of spent drilling fluids using ceramic membranes. Solids concentration (8.8$\pm$ 0.5% vol) and pH (9.5). Ceramic membrane pore size (0.2 micron), transmembrane pressure (15 psi), cross flow velocity (12 ft/s) and temperature (38 C). Backwash cross flow velocity (18 ft/s), backwash duration (30 secs), backwash interval (40 minutes).

In the filtration of spent drilling fluid to see the effect of fouling mitigation technologies, the investigation was initially carried out with backwashing every 15 minutes for one hour. The result showed no significant difference from initial filtration experiments because during the experiment duration there was no significant drop in the flux. After 40 minutes of filtration it was noticed that flux decline was imminent, new experiments were designed to filter longer (four hours) and to have backwashing every 40 minutes. The backwashing regimen included washing with solids free effluent for 30 seconds in the reverse flow of filtration at low pressure and high cross flow velocity of 18 ft/s using an external pump.

The initial volume used for backwashing was made up with some reverse osmosis water to make up for the needed volume. Figure 5.1 is an average of two individual runs and both runs showed a high degree of reproducibility.

From the filtration of spent drilling fluid with 8.8$\pm$ 0.5% solids (~ 19,000 mg/L) and a pH of 9.5$\pm$ 0.3, filtered at 12 ft/s at 15 psi and 38 C with five episodes of backwashing at the 80th, 120th, 160th, 200th and 240th interval the average flux was 51.67 GFD, maximum flux was 64.98 GFD and the minimum flux was 40.66 GFD. The traditional “hump” (rise in flux) noticed in spent fluids filtration occurs till the 50th minute, the cross flow velocity is higher than the arbitrary cross flow velocity used in earlier experiments (12 ft/s vs 10.08 ft/s) and this explains the additional rise in the hump. There is no backwash added in the initial hour of filtration till the 80th minute. At the 80th minute the flux is 57.3 GFD, after the first backwash the flux jumps up to 62.7 GFD, about 10% rise from the last flux before backwashing and just about 3% less than the initial highest recorded flux, this would represent a flux recovery of about 97%. With about 97% recovery of the flux in the initial 80 minutes of filtration it could be assumed that the mechanism of blocking most dominant at this point would be cake layer formation.

In the next 40 minutes (80th -120th) of filtration we see a decline in the flux from its zenith after the first backwashing from 62.7 GFD to 47.1 GFD representing 20% decline in the flux which is about the normal flux decline in the previous ceramic filtration of spent drilling fluid experiments. At 120 minutes another backwash is carried out at the same regimen i.e. 30 seconds with solids free permeate at high cross flow velocity of 18 ft/s and low pressure. At the 120th minute the flux is 47.1 GFD and after the backwash the flux jumps up to 56.7 GFD, about 20% rise from the last flux before backwashing and 13% less than the initial highest recorded flux, this would represent a flux recovery of about 87%. Backwashing at this stage is still rather effective and though the flux rise after backwashing is higher than the initial backwash, overall 10% of the original highest flux is lost after the initial backwash and this is still less than the 20% flux decline observed in previous filtration experiments using the same feed characteristics.

During the next 40 minutes (120th -160th) of filtration we see a decline in the flux after the second backwashing from 56.6 GFD to 45.0 GFD representing 20% decline in the flux which is about the normal flux decline in the previous ceramic filtration of spent drilling fluid experiments. After the backwash at the 120th minute mark the flux climbs up from 45.03 GFD to 54.3 GFD, about 20% rise from the last flux before backwashing and 17% less than the initial highest recorded flux, this would represent a flux recovery of about 83%. The flux pattern at this stage of the third backwash is similar to the second backwash and it is seen that with increasing amount of backwashing and time flux recovery with respect to the highest flux decreases subtly. At this stage backwashing is still an effective fouling mitigation technique.

During the next 40 minutes (160th -200th) of filtration we see a decline in the flux after the second backwashing from 54.3 GFD to 43.5 GFD representing 20% decline in the flux which is about the normal flux decline in the previous ceramic filtration of spent drilling fluid experiments. After the backwash at the 200th minute mark the flux climbs up from 43.5 GFD to 48.2 GFD, about 10% rise from the last flux before backwashing and 26% less than the initial highest recorded flux, this would represent a flux recovery of about 74%. The flux pattern at this stage differs from the last two backwash cycles as the flux gain after backwashing is halved (10%) and the flux after backwashing fell below 20% of the initial highest recorded flux. The final backwash is carried out at the 240th minute and the flux rises from 40.7 GFD to 49.4 GFD representing a 20% rise in flux and a 24% loss of the highest reported flux. In this backwash we see the resumption to gaining 20% of the flux decline after backwash but it seems that the 20% of the highest recorded flux is lost to irreversible fouling.

Backwashing in the filtration of spent drilling fluid was effective in maintaining the flux within the duration of the filtration experiments. The permeate gain by having the flux maintained with backwashing was significant. Comparing the total permeate resulting from the experiments during resistance calculation where there was no backwashing and the backwashing experiment, backwashing gave 54% more permeate for the same duration than when not using backwashing. The backwashing interval chosen (40 minutes) was to show the effect of backwashing, using earlier intervals would have better maintained the flux and increased the gain on the total permeate volume. But increasing the backwash frequency would also have a bearing on the volumes needed for backwashing as significant volumes might be needed to backwash actual systems thereby reducing the available permeate if the permeate is the intended product. Process design of larger system would have to investigate an appropriate balance between the frequency of backwashing and its practicality in the face of filtration endpoints.

The effectiveness of backwashing in addressing the flux decline might be pointing towards cake filtration formation as a dominant membrane blocking mechanism during the operational filtration of spent drilling fluids. Using the Hermia models in chapter IV, the correlation with the cake filtration blocking mechanism was high as well as with other mechanisms such as pore plugging. Backwashing intuitively seems more effective against cake filtration but if enough shear is generated there might be enough to dislodge particles from pore spaces after the removal of the cake filter or in situations where the depth of the plugged pores are superficial. During the first three backwash cycles the percentage gain in the flux was significant though the gain was halved on the fourth backwash, this could be due to plugging of some membrane pores due to incremental deposition into the pores each time the wall is formed.

In conclusion the advantage of fouling mitigation techniques such as backwashing is primarily to prevent significant flux decline during filtration, and this was achieved during the filtration of spent drilling fluids but its effect in reducing the resistances in membrane filtration was mild. It would have seemed intuitive that in reducing the fouling using fouling mitigation techniques this would also reduce the need for cleaning or the amount of total fouling experienced by the membrane. In the end it is seen that the final flux loss is close to what would have obtained if there were no backwash i.e. about 20% loss in the flux overall, this seems to suggest that the fouling mitigation technique is impotent against irreversible fouling. This also seems to suggest that mechanism of fouling or blocking cannot be explained solely by one mechanism for example cake layer formation, that realistically a combination of blocking or filtration mechanism is at play. The major advantage with backwashing is the ability to filter longer and the increase in permeate volume due to longer filtration.

5.2.2 Ceramic Filtration of Produced Water

The produced water used in these set of experiments were defined to have an oil concentration of 700± 200 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Arbitrary operating parameters for ceramic filtration was cross flow velocity of 8 ft/s, transmembrane pressure of 15 psi and temperature of 38 C. During filtration backwashing was applied every 25 minutes for 30 seconds at high cross flow velocity of 16 ft/s from an external pump. The flow from the wash was collected outside the system and not reintroduced into the system. The experiments were repeated twice and the result shown is an average of the fluxes, the reproducibility of the experiments was high.

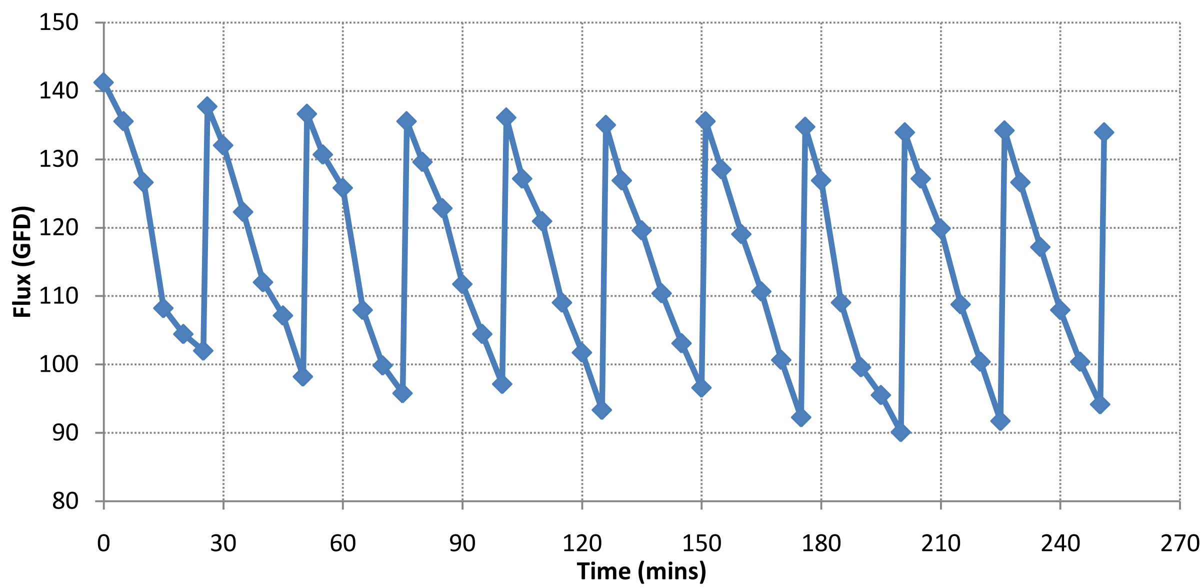


Fig. 5. 2 Backwashing in the filtration of produced water using ceramic membranes. Oil concentration 700± 200 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Ceramic membrane pore size (0.2 micron), transmembrane pressure (15 psi), cross flow velocity (8 ft/s) and temperature (38 C).

The average flux was 115.58 GFD, maximum flux was 141.25 GFD and the minimum flux was 90.10 GFD. The flux decline in the filtration of produced occurs usually after about twenty minutes filtration from previous experiments, this informed the decision to make backwash every twenty five minutes. Before the initial backwash the flux had dropped to 30% of the initial flux volume, after the backwash 96% of the initial flux was recovered. In the next 25 minutes following the initial backwash the flux would also fall below 30% of the initial flux and after backwash 95% of the initial flux was regained. This was repeated throughout the duration of the experiment. The lowest flux gain was 93% of the initial flux and that was after more than four hours of operation. After operation the clean flux after filtration was 94% of the original clean water flux before filtration.

Backwashing is an effective fouling mitigation technique in the filtration of produced water. Backwashing at the interval produced the intended objective of regaining the flux well within initial flux range. Unlike backwashing during the filtration of spent drilling fluids where the flux gained after backwashing reduced progressively with time, the loss of flux with backwashing in ceramic filtration of produced water was negligible. Although the intervals of backwash differed the relative gain after backwash is far less in the filtration of spent drilling fluid compared to produce water backwash.

Also the proportion of the membrane lost to irreversible fouling differed significantly; in the filtration of spent drilling fluid about 20% of the membrane is lost to irreversible fouling while in the filtration of produced water just about 6% of the membrane is lost to irreversible fouling. Thus it would be expected in the filtration of produced water that less chemical treatment shall be afforded the membrane. Not only is the irreversible fouling proportion reduced in the backwashed membrane the permeate volume is about five times the permeate volume if the membrane was not backwashed.

The effectiveness of backwashing during produced water filtration allows some inferences about the nature of the mechanism of fouling or the nature of the fouling layer. The near complete flux gain after backwashing in the filtration of produced water is indicative of either the cake layer that is formed is completely removed by the backwashing or pore plugging is not a major blocking mechanism or that the backwashing at the cross flow velocity also addresses pore plugging. This might indicate that the reduction in flux gain after backwashing in spent drilling fluid filtration could either be due to the fact that the cake layer is not completely removed during backwashing or there is pore plugging at some level during filtration. These differences in the amount of recovery flux depict the complexities involved in membrane-feed interaction and how they affect membrane fouling and filtration.

5.2.3 Hollow Fibre Filtration of Produced Water

The produced water used in these set of experiments were defined to have an oil concentration of 500± 200 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L. Higher oil concentration (but less that 700 ppm) was used as low oil concentrations less than 200 ppm had minimal flux decline. Arbitrary operating parameters for ceramic filtration were cross flow velocity of 3.38 ft/s, transmembrane pressure of 8 psi and temperature of 38 C. During filtration backwashing was applied every 15 minutes for 30 seconds at high cross flow velocity of 7 ft/s and low pressure from an external pump. The manufacturer's limitation on pressure informed the lower pressure for filtration so that membrane transmembrane pressure could rise to 15 psi during backwash. Also the backwash cross flow velocity was limited to 7 ft/s due to the limitation of the allowable cross flow velocity. The flow from the wash was collected outside the system and not reintroduced into the system. The experiments were repeated twice and the result shown is an average of the fluxes, the reproducibility of the experiments was high.

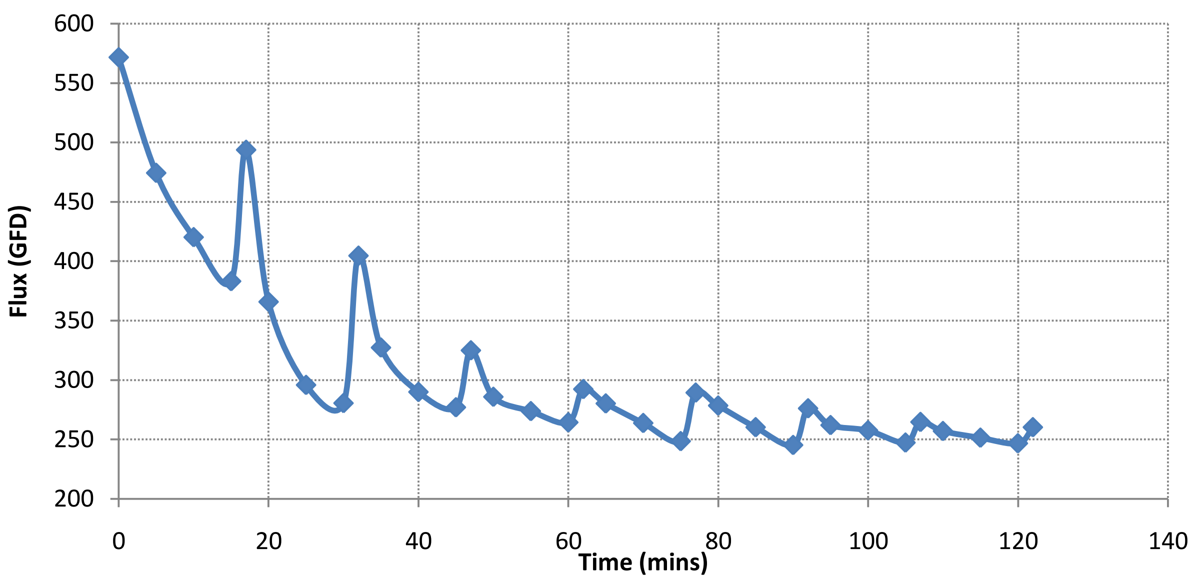


Fig. 5. 3 Backwashing in the filtration of produced water using hollow fibre membranes. Oil concentration 500± 200 ppm, pH 7.3± 1.5 and salinity 36,000± 5000 TDS mg/L.. Ceramic membrane pore size (0.2 micron), transmembrane pressure (8 psi), cross flow velocity (3.8 ft/s) and temperature (38 C).

The average flux was 309.6 GFD, maximum flux was 571.8 GFD and the minimum flux was 246.7 GFD. A sample with a higher oil concentration was filtered in the fouling mitigation study with the hollow fibre membrane to determine if backwash could be an effective method in the reducing fouling in the filtration of samples with high oil concentrations. This explains why the oil content was higher than what obtained in the arbitrary concentration set. Flux decline was most apparent after 15 minutes and this informed the backwash time after 15 minutes. Before the initial backwash the flux had dropped to 33% of the initial flux volume, after the backwash 86% of the initial flux was recovered. This was less than 96% in the filtration of produced water with similar oil content using ceramic membranes.

The next backwash 30 minutes into filtration raised the flux from 280.5 GFD to 404.7 GFD; this was 11% less than highest flux before the second backwash and 30% less than the original highest flux at the beginning of the experiment. The next backwash 45 minutes into filtration raised the flux from 277.1 GFD to 325 GFD; this was 20% less than highest flux before the third backwash and 43% less than the original highest flux at the beginning of the experiment. The next backwash 60 minutes into filtration raised the flux from 264.4 GFD to 292.3 GFD; this was 11% less than highest flux before the fourth backwash and 50% less than the original highest flux at the beginning of the experiment. The next backwash 75 minutes into filtration raised the flux from 248.5 GFD to 289.4 GFD; this was 3% less than highest flux before the fifth backwash and 50% less than the original highest flux at the beginning of the experiment. From this point the backwashing does not increase the flux within 50% of the original flux and the effect of backwashing is nominal and in both trials the experiment is discontinued.

Backwashing is seen to be an ineffective fouling mitigation technique in the filtration of produced water using hollow fibre membranes. Backwashing at the interval used in these experiments did not produce the intended objective of regaining the flux or keeping the flux within 50% of the original initial flux. Unlike backwashing during the ceramic filtration of produced water where the flux gained after backwashing was slightly below the initial, the loss of flux with backwashing using hollow fibre in the filtration of produced water was significant. Using shorter intervals compared to 25 minutes with ceramic filtration of produced water and

40 minutes with spent drilling fluids, the shorter interval with hollow fibre did not improve the outcome. Though the method used in ceramic filtration of produced water to calculate resistances cannot be used to calculate resistances with hollow fibre membrane the loss to irreversible fouling is considerably high during produced water filtration.

At oil concentrations above 200 mg/L it is deduced that produced water filtration using hollow fibre membranes is not advisable. The hydrophobic nature of the PVDF membrane makes it absorb a lot of the oil and thus difficult to maintain the flux during filtration. At oil concentrations less than xxx mg/L it is seen that filtration and loss of flux is not an issue. There are also two dimensions to fouling in the hollow fibre, there is the intra membrane fouling possible in the hollow fibre strand and there is the intra-membrane fouling within the spaces of the hollow fibre strands. Backwashing would have limited effects on the intra-membrane fouling and this might be one of the reasons why its ability to reclaim the flux is limited. Maybe a combination of backwashing and backflushing would be the adequate technique for fouling mitigation in produced water filtration using hollow fibre membranes.

5.3 Membrane Chemical Cleaning

5.3.1 Introduction

The previous section discussed the membrane fouling mitigation technologies aimed at prolonging the onset of flux decline or reclaiming the flux after concentration polarization or reversible fouling. These technologies are designed to address physical fouling of the membranes but are inefficient when the cause of membrane fouling is chemical in nature. Irreversible fouling as defined in this thesis is fouling that exists when the flux cannot be regained by adjustments made during membrane operation such as backwashing or membrane flushing. The cause of irreversible fouling is assumed to also be chemical in nature aside from the possibility of physical fouling which is assumed to be negligible or associated with chemical characteristics of the feed.

The chemical nature of irreversible fouling would be largely due to the interaction between the feed components and the membrane material; it is assumed that this also affects the recalcitrant physical fouling remaining on the membrane. No matter the feed being filtered, there would be a level of fouling after each filtration cycle and continued accumulation of this fouling would eventually cause permanent fouling on the membranes. This section is designed to investigate flux recovery using chemical treatment of the membrane using two chemical cleaning solutions.

The objective of this section is to investigate the efficacy of two cleaning solutions in recovering flux against irreversible fouling. Two different membrane cleaning solutions were used in our investigation, the Divos 110 alkaline detergent for UF membranes produced by JohnsonDiversey, Sharonville, Ohio and a patented aqueous surfactant composition protected by US patent 6130199 from a well bore cleaning company in Texas. The Divos 110 alkaline detergent is described by the manufacturers as a moderately foaming caustic, alkaline detergent liquid for the cleaning of chlorine stable ultrafiltration and microfiltration membranes. When using the Divos 110, Divos Add 3 a detergency booster for oil removal from all membranes is also added. The aqueous surfactant, the second cleaning agent, is described to contain an alkyl polyglycoside, ethoxylated alcohol and a caustic and an alkyl alcohol in specified concentrations to make the cleaning solution. The aqueous surfactant solution is advertised to remove hydrocarbonaceous materials and finely divided inorganic solids from well bore surfaces and other surfaces.

Two membrane "state" types were cleaned in this investigation for the ceramic membranes. Membranes as used in resistance determination and membranes as used in backwashing operations. Membrane as used in resistance determination filtered the feed without any fouling mitigation such as backwashing during the entire filtration carried out on them. The membranes were used to filter the feed for within 4 – 6 hours and the only cleaning done was clean water flushing at a higher cross flow velocity for 5 minutes. The membranes as used in fouling mitigation filtered for between 4-5 hours and they had backwashing at some interval for the entire duration of filtration.

The membranes as used in backwashing operation had lower levels of irreversible fouling compared to the membranes as used in filtration resistance determination and the difference was more significant for produced water filtration than for drilling fluids filtration. The relevance of the comparison is not fundamental but since data was collected for both cleaning processes they are presented here. The membranes as used for resistance determination would represents filtration with the intent to foul while the membranes as used in backwashing represents filtration with to minimize fouling.

The cleaning regimen for both cleaning solutions the Divos 110 and the aqueous surfactant solution was carried out according to the manufacturer's specification. For the Divos 110, two washes where needed; the alkaline wash using the Divos 110 and the acidic wash using 0.5% Nitric acid. For the alkaline wash, 1% per volume of Divos 110 is made with clean water and 0.1% per volume of Divos Add 3 is also added to the water. The alkaline solution has a yellow appearance and a pH of about 6.8. The solution is heated to 120 F and it is circulated in the membrane (recycle mode) for 40 minutes, after 40 minutes the membrane is flushed with RO water for 10 minutes, this is the end of the alkaline wash. After the clean water flush, laboratory prepared 0.5% Nitric acid is circulated in the membrane for 30 minutes and afterwards also flushed with clean water. The clean water flux of the membrane is taken before and after the whole alkaline and acid wash. Volume used is between 3-5 gallons of the solution and wash time is approximately 80 minutes.

For the aqueous surfactant solution, the recipe to make the cleaning solution is specified by the manufacturer, it involves water and four chemical additives, the solution is mixed to be homogenous and it has a slightly viscous but clear appearance. It is not heated and it is circulated at filtration temperature of about 40 C through the membrane for 40 minutes. The clean water flux is recorded before and after the circulation. The membrane clean water flux recovery is the only measure used to determine the efficacy of the cleaning solution. To determine the cleaning efficiency the initial clean water flux (J_i) was recorded before filtration, the clean water flux after filtration and flushing with distilled water (J_f) was recorded and the clean water flux after cleaning with the chemical solution was recorded (J_c). To determine the clean water flux recovery it was calculated as

$$Flux\ recovery = \frac{J_i - J_f}{J_c - J_f} \tag{5.1}$$

Usually after flushing with distilled water i.e. cleaning at high cross flow velocity the membranes are usually retuned to within 40 -70 percent of the original clean water flux depending on the condition of filtration and the amount of flux lost. For example filtration at higher pressures showed high flux loss and lower flux recovery after flushing, the results shown here are for situations where the clean water flux recovery was less than 60% after flushing.

5.3.2 Flux Recovery in Ceramic Filtration of Spent Drilling Fluids

After ceramic filtration of spent drilling fluids the clean water flux, flux after RO flush and flux after cleaning are presented in table 5.1 with the filtration condition under which the feed was filtered.

Table 5.1 Chemical cleaning of ceramic membrane after filtration of spent drilling fluids

Cleaning Agent	Initial water flux (J_i) GFD	Flux after flush (J_f) GFD	Flux after clean (J_c) GFD	Filtration condition
Divos 110	116.57	32.30	110.86	High transmembrane pressure (20 psi), 4 hours filtration, no backwash
Divos 110	115.32	93.69	114.49	Normal transmembrane pressure (12 psi), 4 hours filtration, backwashing
Aqueous Surfactant Solution	118.41	40.33	110.72	High transmembrane pressure (20 psi), 4 hours filtration, no backwash
Aqueous Surfactant Solution	119.17	91.45	117.00	Normal transmembrane pressure (12 psi), 4 hours filtration, backwashing

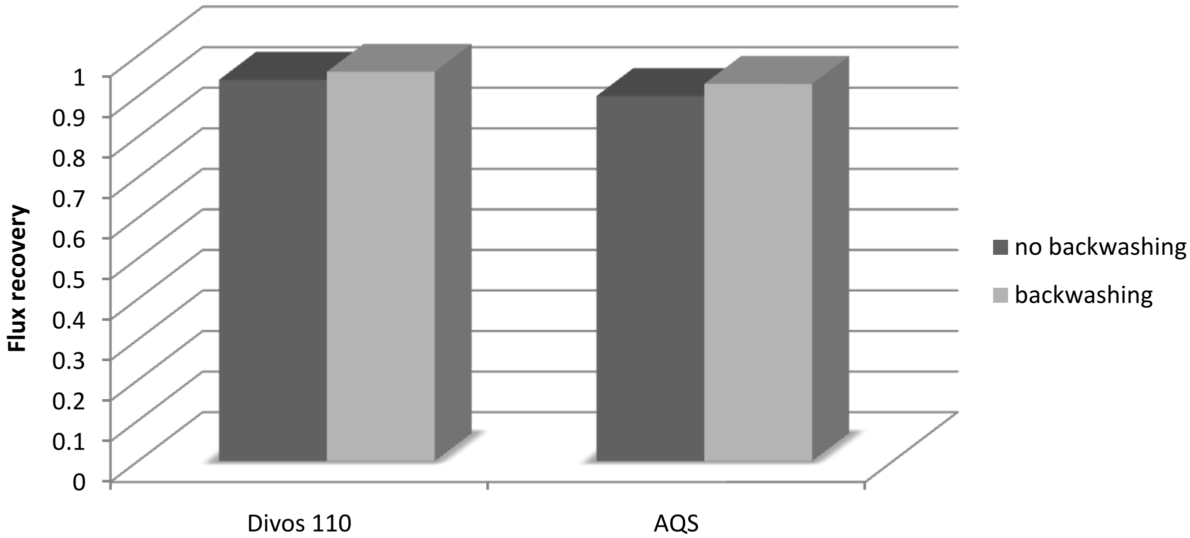


Fig. 5. 4 Flux recovery of ceramic membrane cleaning after filtration of spent drilling fluids. Cleaning agent include Divos 110 and aqueous surfactant solution (AQS).

Figure 5.4 shows the clean water flux recovery using two cleaning solutions Divos 110 (with Divos Add 3) and an aqueous surfactant solution (AQS) for ceramic membrane filtering of spent drilling fluid with and without backwashing. Table 5.1 explains the filtration condition at which the experiments were carried out. In the filtration without backwashing the condition was under high transmembrane pressure of 20 psi a filtration condition certain to induce fouling; the flux before chemical cleaning and after RO flushing is 30% of the clean water flux. 70% of the flux at this condition was not recovered with RO water flux but after cleaning with Divos 110, 94% of the clean water flux was recovered. In the filtration where backwashing was applied to the membrane periodically, the flux before chemical cleaning and after RO flushing is 80% of the clean water flux, after treatment with Divos 110 96% of the flux was recovered.

For the cleaning efficiency using the aqueous surfactant solution, when there is no backwashing and under high transmembrane filtering condition the flux recovered using RO flushing is 34% of the clean water flux i.e. 66% of the clean water flux was unrecoverable. After cleaning with the aqueous solution 90% of the clean water flux was recovered. For the condition with backwashing, after RO cleaning, 78% of the clean water flux was recovered with the RO flushing, after cleaning with the aqueous surfactant solution the clean water flux recovery was 93% of the initial clean water flux. Filtration at the set arbitrary values used to generate flux decline curves (chapter III) for spent drilling fluids would usually after RO flushing recover 60-80% of the clean water flux similar to what obtains during backwashing, but at high pressures the recovery is lower and thus were better suited to determine cleaning efficiencies.

5.3.3 Flux Recovery in Ceramic Filtration of Produced Water

After ceramic filtration of produced water the clean water flux, flux after RO flush and flux after cleaning are presented in table 5.2 with the filtration condition under which the feed was filtered.

Table 5. 2 Chemical cleaning of ceramic membrane after filtration of produced water

Cleaning Agent	Initial water flux (J_i) GFD	Flux after flush (J_f) GFD	Flux after clean (J_c) GFD	Filtration condition
Divos 110	113.14	74.85	109.53	High transmembrane pressure (20 psi), 4 hours filtration, no backwash
Divos 110	117.56	105.14	116.69	Normal transmembrane pressure (12 psi), 4 hours filtration, backwashing
Aqueous Surfactant Solution	114.38	70.19	108.92	High transmembrane pressure (20 psi), 4 hours filtration, no backwash
Aqueous Surfactant Solution	114.31	94.30	112.18	Normal transmembrane pressure (12 psi), 4 hours filtration, backwashing

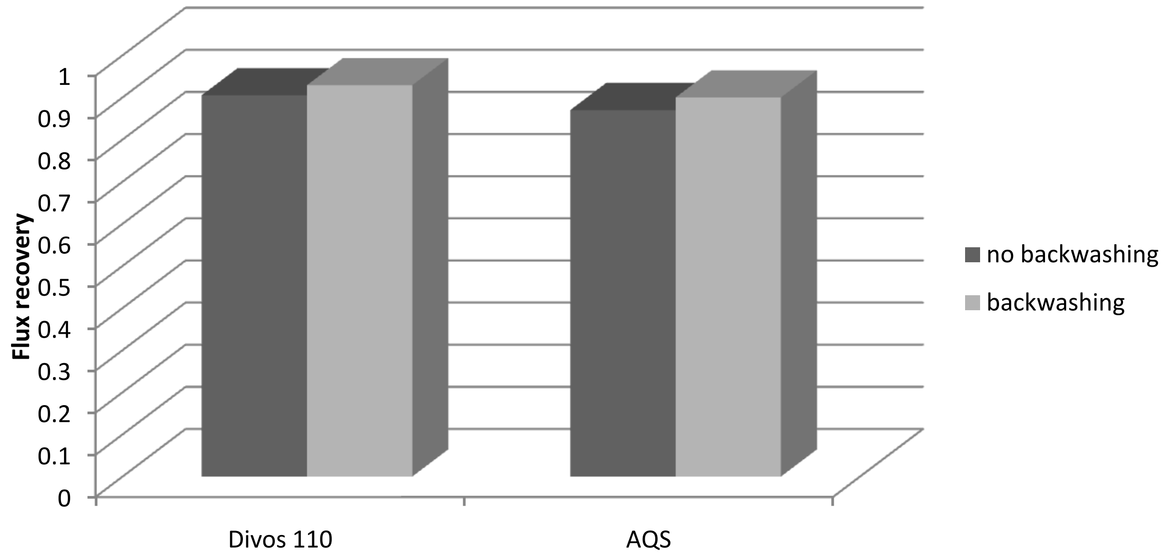


Fig. 5. 5 Flux recovery of ceramic membrane cleaning after filtration of produced water. Cleaning agent include Divos 110 and aqueous surfactant solution (AQS).

Figure 5.5 shows the clean water flux recovery using two cleaning solutions Divos 110 (with Divos Add 3) and an aqueous surfactant solution (AQS) for ceramic membrane filtering of produced water with and without backwashing. Table 5.2 explains the filtration condition at which the experiments were carried out. In the filtration without backwashing the condition was under high transmembrane pressure of 20 psi a filtration condition certain to induce fouling; the flux before chemical cleaning and after RO flushing is 66% of the clean water flux. 34% of the flux at this condition was not recovered with RO water flux but after cleaning with Divos 110, 90.5% of the clean water flux was recovered. In the filtration where backwashing was applied to the membrane periodically, the flux before chemical cleaning and after RO flushing is 90% of the clean water flux, after treatment with Divos 110 93% of the flux was recovered.

For the cleaning efficiency using the aqueous surfactant solution, when there is no backwashing and under high transmembrane filtering condition the flux recovered using RO flushing is 62% of the clean water flux i.e. 38% of the clean water flux was unrecoverable. After cleaning with the aqueous solution 87% of the clean water flux was recovered. For the condition with backwashing, after RO cleaning, 82% of the clean water flux was recovered with the RO flushing, after cleaning with the aqueous surfactant solution the clean water flux recovery was 90% of the initial clean water flux. Filtration at the set arbitrary values used to generate flux decline curves (chapter III) for spent drilling fluids would usually after RO flushing recover 60-80% of the clean water flux similar to what obtains during backwashing, but at high pressures the recovery is lower and thus were better suited to determine cleaning efficiencies.

5.3.4 Flux Recovery in the Hollow Fibre Filtration of Produced Water

After the hollow fibre filtration of produced water the clean water flux, flux after RO flush and flux after cleaning are presented in table 5.3 with the filtration condition under which the feed was filtered. The hollow fibre membrane resistance calculation was not carried out (Chapter IV); the conditions of filtration have only the conditions where the flux decline experiments for 6 hours were carried out. The oil concentration in all cases was less than 300 ppm.

Table 5.3 Chemical cleaning of hollow fibre membrane after filtration of produced water

Cleaning Agent	Initial water flux (J_i) GFD	Flux after flush (J_f) GFD	Flux after clean (J_c) GFD	Filtration condition
Divos 110	986	288	754	Transmembrane pressure (12 psi), 4 hours filtration, no backwash
Aqueous Surfactant Solution	1016	219	918	Transmembrane pressure (12 psi), 4 hours filtration, no backwash

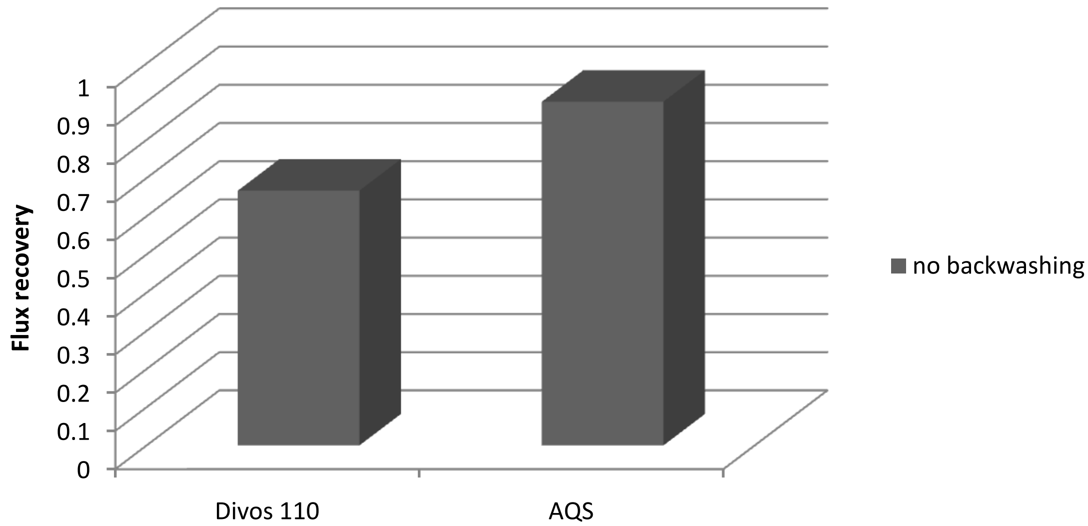


Fig. 5. 6 Flux recovery of hollow fibre membrane cleaning after filtration of produced water. Cleaning agent include Divos 110 and aqueous surfactant solution (AQS).

Figure 5.6 shows the clean water flux recovery using two cleaning solutions Divos 110 (with Divos Add 3) and an aqueous surfactant solution (AQS) for hollow fibre membrane filtering of produced water without backwashing. Table 5.3 explains the filtration condition at which the experiments were carried out. In the filtration without backwashing the condition was under transmembrane pressure of 12 psi a filtration condition certain to induce fouling; the flux before chemical cleaning and after RO flushing is 30% of the clean water flux. 70% of the flux at this condition was not recovered with RO water flux but after cleaning with Divos 110, 76% of the clean water flux was recovered.

For the cleaning efficiency using the aqueous surfactant solution, when there was no backwashing and under transmembrane pressure of 12 psi, the flux recovered after RO flushing was 21% of the clean water flux i.e. 79% of the clean water flux was unrecoverable. After cleaning with the aqueous solution 90% of the clean water flux was recovered. The polymeric membranes when not in use were stored in a cleaning solution because the membrane had to be wet, when left in the sanitizing solution overnight the membrane flux returned to the initial clean water flux at all times.

5.4 Summary

The cleaning solution Divos 110 recovered more of the clean water flux for ceramic membranes above the aqueous surfactant solution and in cleaning the polymeric PVDF hollow fibre membrane the aqueous surfactant solution recovered more of the clean water flux. The Divos 110 cleaning solution has a more robust cleaning cycle as the alkaline cleaning cycle is followed by an acidic cycle, the alkaline cleaning agent are effective in breaking the bonds between the membrane surface and the fouling layer [40,72]. While acids are effective in getting rid of inorganic salts[40], insoluble salts and metal oxides [73 and Nitric acid is a strong oxidant causing nitrification of organic compounds [48]. The aqueous surfactant solution contain hydrophilic and hydrophobic functional groups that enhance the wettability and rinsability, increase contact area between the foulants and the active agents hereby dislodging the foulants easily.

The clean water flux recovery was higher in all cases for the membrane state type where there was backwashing. As explained the backwashing reduced the proportion of irreversible fouling relative to a membrane that filtration occurred without backwashing, intuitively the cleaning process is less tasked in with backwashed membranes as the fouling start point is lower. Recovery was within 90-96% of the initial clean water flux in the ceramic filtration of both feed types using the Divos 110, while it was between 87-93% of the clean water flux recovery when the aqueous surfactant solution was used for both feed using ceramic filtration. More clean water flux recover was achieved in the filtration of drilling fluids relative to produced water; this underscores the variability and complexity in produced waters.

For the cleaning of the polymeric PVDF hollow fibre material the aqueous surfactant solution recovered more of the clean water flux compared to the ceramic membrane, it is not fully understood the reasons for this but surfactant action gave a cleaner membrane compared to the alkaline and acidic wash of the Divos 110 cleaning cycle. Flux recovery of using the aqueous surfactant solution was 91% of the original clean water flux compared to about 70% recovery of the clean water flux when using the Divos 110. Polymeric material membranes cannot be left dry they need to be soaked in some cleaning solvent to keep the membranes wet. After use the membranes are always soaked in ultrasil xxx to sanitize the membrane, when soaked overnight with the sanitizer the membrane returns to its original clean water flux despite the cleaning solution used in most cases.

In comparing the two cleaning chemicals no optimization was done to improve the cleaning regimen. Time, temperature, water quality used, fluid mechanics and pH [48, 49]are factors capable of affecting the cleaning solution efficiency. Though the Divos 110 cleaning agent shows a higher efficiency at cleaning than the aqueous surfactant solution, it has to be heated to 120 F for the alkaline wash and contains two wash cycles and two flushes thereby a longer cleaning regimen. All these factors apart from cleaning efficiency are necessary in selecting a cleaning agent for both pilot and industrial purposes.

CHAPTER VI

CONCLUSION AND RECOMMENDATIONS

6.1 Introduction

Increasing energy demand is spurring exploitation of unconventional resources and conventional resources while increasing subsurface reach would increase the foot print of exploration and production activities, significantly changing the dynamics of environmental impact. Stricter environmental protection demands, fresh water sourcing and waste volume management shall increasingly narrow the availability of reservoirs that can be exploited by the oil and gas industry. Waste volumes generated are increasingly bearing on alternative waste treatments that are environmentally friendly forcing less re-use and recycle of waste streams that can be used for non-consumption purposes. The positioning of exploration and production waste management as a central factor in the decision to exploit oil and gas resources shall amplify with time if the current trend continues.

Water based exploration and production wastes are a substantial portion of oil and gas waste produced, they are also the least recycled or re-used as disposal permits or large scale treatment systems such as injection reduce the incentive for treatment. This class of wastes is expected to increase as water cut increases, subsurface reach increases, unconventional reservoirs exploitation increase, use of environmentally friendly drilling fluids increase and exploration and production activities increase. The need for technologies aimed at making these water based wastes amenable to re-use or pre-treating these wastes so that they can be subjected to other treatment systems such as desalination is increasing daily. Steps at waste management to increase economical re-use of these wastes in fields would go a long way at cost reduction of waste disposal.

Irrespective of the treatment methods aimed at recycle or re-use of these water based wastes a step by step treatment objective should be laid out for the treatment of the wastes after feed characterization. In this thesis solids concentration removal was the treatment objective in the treatment of spent drilling wastes to achieve solids concentration or in oil-field terms dewatering. In the treatment of produced water the treatment objective was mechanical pre-treatment using microfiltration or ultrafiltration in the removal of oil concentration and suspended solids for desalination of produced water. These objectives determined the type of membranes used, the operational objectives set, the fouling mitigation and cleaning procedures adopted and the characterization of the wastes needed.

6.1.2 Spent Drilling Fluids Filtration Using Ceramic Membranes

Membrane filtration of spent drilling fluids using ceramic ultrafiltration and microfiltration membranes was successful, there was between 95-99% solids rejection after filtration. The permeate was mostly solids free and had low concentrations of suspended solids. The dissolved constituent of the feed were unaffected by filtration at the pore sizes used. Flux values were moderate and fouling mitigation and chemical membrane cleaning were effective in reclaiming the clean water flux. Permeate quality differences existed using different pore sizes but were not very significant, the larger the pore size the larger the flux and fortunately within 0.005 to 0.2 microns the fouling pattern was significant. In order words for a pilot scale study using the larger pore size 0.2 micron would be beneficial as it gives a higher flux and the membrane fouling pattern is not significantly greater than the fouling pattern at smaller pore sizes.

High cross flow velocities created the largest gain in permeate volume compared to other operational parameters varied. Operating at high temperature was also beneficial to maintaining and increasing membrane flux, as much as possible using ceramic membranes at high temperatures would be beneficial for higher fluxes and fouling mitigation. The feed solids concentration was the most important parameter in the filtration of the spent drilling fluids, solids above 10.20% solids volume (~30,000 mg/L) gave very low fluxes, solids volume less than 8.8% solids (`19,000 mg/L) gave better fluxes. The solids concentration and distribution would is beneficial to fouling mitigation at the appropriate filtration conditions. Possible pre-treatment would involve the reduction of solids to filterable levels while maintaining a diverse solids distribution. The effect of the dissolved constituents on filtration was not individually characterized and would need to be determined with respect to membrane flux and cleaning for similar feed types.

6.1.3 Produced Water Filtration Using Ceramic Membranes

Membrane filtration of produced water using ceramic ultrafiltration and microfiltration membranes was successful in the removal of oil and suspended solids, there was between 95-99% oil rejection and 99% turbidity after filtration. The permeate was mostly oil free and had low concentrations of suspended solids. The permeate exceeded the 5 NTU needed to optimizes desalination, with an average of 1.16 NTU. The dissolved constituent of the feed were unaffected by filtration at the pore sizes used. Flux values were moderate and fouling mitigation and chemical membrane cleaning were effective in reclaiming the clean water flux. Permeate quality differences existed using different pore sizes but were not very significant, fouling at larger pore sizes was slightly higher than at lower pore sizes. Oil concentration not solids concentration plays the significant role in the flux decline during filtration using ceramic membranes.

High temperatures created the largest gain in permeate volume compared to other operational parameters varied. Operating at high cross flow velocity was also beneficial to increased membrane flux but was qualified in prolonging the onset of fouling. As much as possible high temperatures would be beneficial for higher fluxes and to a lesser extent in fouling mitigation of produced water filtration. The feed oil concentration was the most important parameter in the filtration of the produced water, oil concentration above 1,200 ppm gave the least optimized flux but oil concentration below 500 ppm gave higher fluxes. Pre-treatment to the feed entering the ceramic membrane should be for the removal of large particle size and to reduce oil concentration to optimize filtration. Dissolved solids characterization except for some divalent ions was not carried out, for the concentrations range of divalent ions specified, the effect on filtration was minimal.

6.1.4 Produced Water Filtration Using Hollow Fibre Membranes

Membrane filtration of produced water using hollow fibre microfiltration membranes was successful in the removal of oil and suspended solids, there was between 95-99% oil rejection and 99% turbidity after filtration. The permeate was mostly oil free and had low concentrations of suspended solids. The permeate exceeded the 5 NTU needed to optimizes desalination, having an average of 1.8 NTU. The dissolved constituent of the feed were unaffected by filtration at the pore sizes used. Flux values were high at low oil concentrations, fouling mitigation and chemical membrane cleaning would only be effective in reclaiming the clean water flux at low feed oil concentrations. Feed oil concentration played the major role in the flux decline as oil concentrations higher than 300 ppm caused significant flux decline.

High temperatures created the largest gain in permeate volume compared to other operational parameters varied. Operating at high cross flow velocity and temperature within the manufactures parameter was not beneficial to increased membrane flux and in prolonging the onset of fouling. As much as possible high temperatures would be beneficial for higher fluxes within the membrane specified temperature range and to a lesser extent in fouling mitigation of produced water filtration. The feed oil concentration was the most important parameter in the filtration of the produced water, oil concentration above 500 ppm gave the least optimized flux but oil concentration below 300 ppm gave high fluxes. Pre-treatment to the feed entering the ceramic membrane should be for the reduction in oil concentration and removal of large particle (greater than 10 micron) to optimize produced water filtration. Dissolved solids characterization except for some divalent ions was not carried out, for the concentration range of divalent ions specified, filtration was unaffected.

6.1.5 Membrane Resistance Cleaning and Fouling Mitigation Technologies.

High pressures accelerated the fouling of the membrane during filtration of all types of feed and membrane types. High cross flow velocities were beneficial in prolonging the onset of fouling, in high solids concentration feed like spent drilling fluids, high cross flow velocities were effective in maintaining flux. Temperature effect on resistances showed no clear pattern. The dominant fouling mechanism in the filtration of solids concentration is believed to be cake layer formation though pore plugging plays a role. In the filtration of produced water cake layer formation is also believed to be prominent though pore plugging is apparent, the losses after backwashing could be attributed to blocked pores. From the results of backwashing, the cake layer adhesion in produced water filtration is loose as high cross flow velocity flushing shows a high recovery of the flux. Hollow fibre membrane filtration fouling was not determined in this experiment, inter and intra fibre fouling create an added layer of complexity in determining the fouling mechanism using hollow fibre membranes.

Fouling mitigation using backwashing was very effective in the filtration of produced water using ceramic membranes, flux recovery was high and the recovery with time was fairly constant within the experiment time frame. Backwashing was effective in flux recovery in the spent drilling fluids filtration using ceramic membranes, the recovery rate reduced with time and at one point there shall be a saturation of the benefits of backwashing. Absorption of the oil by the hydrophobic PVDF membrane of the hollow fibre membrane made backwashing of little value especially at oil concentrations above 300 ppm. At low oil concentrations i.e. below 300 ppm, backwashing or fouling mitigation had very limited use in the produced water filtration using hollow fibre membranes.

Flux recovery using the two chemical cleaning agents were effective in the recovery of flux with the Divos 110 alkaline cleaning agent from Johnson diversey showing more recovery in the cleaning of ceramic membranes. The aqueous surfactant solution was more effective in the cleaning of the PVDF hollow fibre membrane. The aqueous surfactant membrane could be a better choice as there is no need to heat though it is less efficacious in ceramic membrane cleaning.

6.2 Recommendations

To apply practically membranes to a particular waste streams these recommendations are deemed useful to make that determination.

6.2.1 Waste characterization

Oil field wastes show significant variability and this poses one of the biggest challenges to membrane filtration. Feed variability hinders the ability to stabilize flux values, reduces the comprehension on foulants subjecting the membranes to fouling. A simple characterization can be done based on the figure 6.1.

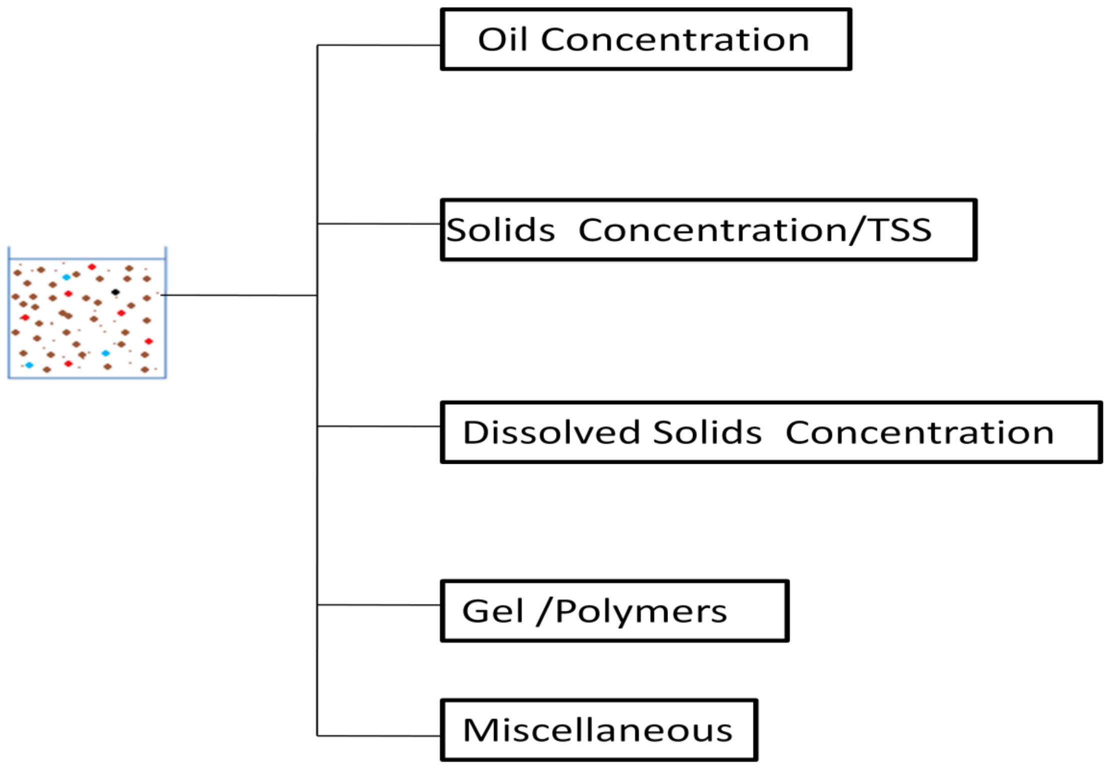


Fig. 6. 1 Waste characterization of E&P wastes to determine membrane filtration compatibility.

A simple waste characterization in the consideration of water based E&P wastes for membrane filtration would be a characterization based on oil concentration, suspended solids concentration, dissolved solids concentration, gel or polymers and miscellaneous categorization. Depending on the intention for filtration, the characterization of the feed allows for better determination of the membrane type most suitable and the membrane system most appropriate.

As much as possible gels and polymers should be removed before filtration through membranes, depending on their constituents they might accelerate fouling, chemically react with the membranes, increase viscosity of the feed thereby reducing the flux. Chemical pre-treatment for the removal of gels and polymers might be essential upstream of membrane filtration. Categorization based on miscellaneous characteristics would be essentially geared towards properties of the feed that would affect membranes such as the presence of corrosive properties, solvents, temperature of the feed, pH of the feed and pertinent information that could be detrimental to membrane functioning. These allow for appropriate pre-treatment before membrane filtration.

High oil concentration > 1200 ppm can go through pre-treatment before ceramic membrane filtration to bring down the oil concentration using treatments such as adsorbents to lower the oil concentration remarkably. Also higher high oil concentration can be accommodated if efficient fouling mitigation and cleaning methodologies are employed in the operation of the membrane, this would be an operational decision. Low oil concentrations (<300 ppm) with low solids concentration (<2000 mg/L) would be great feed for hollow fibre membranes as the flux rate is superior at these conditions to ceramic membranes. Two stage treatments can also be encouraged where ceramic membranes treat feed with high oil concentrations and the hollow fibre are used as a cleaning step either for further treatment or just for re-use.

Ceramic membranes are effective in high solids feed up to 18,000 mg/L as they showed rejection rates up to 99%, low solids (less than <2000 mg/L) would be suitable for both membranes types with the hollow fibre more appropriate due to higher fluxes. Depending on the desired flux rate, pre-treatment of the waste to reduce the total suspended solids could be carried out; solids concentrations lower than the upper limit used here would guarantee better flux in the absence of chemical foulants. Depending on the intended flux high solids in ceramic membranes can be handled if good fouling mitigation techniques are applied. Issues with high solids feed filtration would be abrasion on the membrane surface or the erosion on the entrance of the membrane; these should be factored in determining the life cycle of the membrane under constant use. When there is a high rise in the clean water flux relative to prior reading or quick fouling of the membranes there is possibility of abrasion by solids of the membrane surface, this was not noticed in our testing of the ceramic membranes.

The major effect of the dissolved solids in the ultrafiltration and microfiltration of feeds centers around their effect on fouling. The effects of dissolved solids were not studied in this study due to the variation in their concentrations in the feed sample i.e. the presence of various dissolved solids from sample to sample and the varied concentrations. Specified ranges of dissolved solids were chosen as a criterion to give some form uniformity to the feed. In filtration operations, the effect of dissolved solids interaction with membrane material would be very important, the more inert the material is the lesser the propensity of fouling and the more reactive the membrane material is the greater the propensity of fouling.

Feed variation control would be the most important operational parameter in the filtration of water based E&P wastes. Better characterization of the wastes would allow for determination of upstream treatments needed before microfiltration or ultrafiltration, this would also allow for effective membrane filtration and cleaning strategy. Due to practical limitations in maintaining feed uniformity from diverse oil and gas operations, ranges could be specified as exemplified in this study, above those ranges pre-treatment could be applied to bring the value within range.

6.3 Limitations

The laboratory membrane system used in this study was the most simplistic membrane filtration outlay, it was not optimized for performance and thus the flux rates would be lower than what would be obtained using optimized membrane systems. Feed characterization of produced water was not extensive and thus the roles of completing influences such as dissolved solids was not isolated for contribution to fouling of both feed types. Studies of this nature are designed as proof of concept to determine membrane suitability to the chosen waste types; this does not diminish the need for pilot testing to recognize issues closely associated with scaling. The results presented are best interpreted within the determination of membrane material and module suitability for filtration of the feed and the efficacy of fouling mitigation and cleaning methodologies.

6.4 Recommendations

This study shows the potential of membranes as a waste management tool in the re-use and recycle of water based E&P wastes. Fouling and low fluxes remain the greatest challenges to membrane adoption, investigation into feed characterization and the effect of various components of the feed on membrane fouling would be beneficial. For practical systems investigation into pre-treatments that could help reduce the effect of feed concentration on membrane filtration would yield the highest dividend to water based E&P

wastes filtration. Fouling mitigation technologies and environmentally degradable cleaning solutions would also be another area of interest in the application of membranes to this class of waste. Finally the translation of this laboratory results to pilot scale would enhance a better understanding of issues creating an iterative process that would feed more knowledge into this quest.

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COMMUNITY LEADERS' PERCEPTIONS OF ENERGY DEVELOPMENT IN THE BARNETT SHALE

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ABSTRACT

In recent decades, the production of natural gas from unconventional reservoirs (i.e., tight gas sands, coalbed methane resources, and gas shales) has become commonplace within the U.S. energy industry. The Newark East Fort Worth Basin field–called in the vernacular, the Barnett Shale–in north central Texas is one of the largest unconventional natural gas fields (in terms of production) in the United States. Unlike many conventional energy development projects, which typically occurred in small rural areas, much of the Barnett Shale production is occurring in and around a highly urbanized geographical setting. In spite of recent efforts to assess the economic effects of Barnett Shale production, little attention has been directed toward understanding the social impacts associated with this immense unconventional energy development. In this article we use key informant interview data collected in two Barnett Shale counties to investigate the reported positive and negative outcomes of unconventional energy development, as well as the similarities and differences in perceptions between respondents from each of the study counties. We then discuss practical applications and future research implications of our findings.

The production of natural gas from unconventional reservoirs (i.e., tight gas sands, coalbed methane resources, and gas shales) has become commonplace within the U.S. energy industry in recent decades. In 1990, of the 17.2 trillion cubic feet (tcf) of natural gas produced in the U.S., roughly 16 percent (2.8 tcf) was from unconventional sources (Kuuskraa and Stevens 1995). By 2006, the percentage of unconventional gas production to total domestic production increased to 43 percent (8.5 tcf of the total 18.6 tcf produced) (EIA 2008). Recent projections by the Energy Information Administration (EIA 2008), the statistical agency of the U.S. Department of Energy, suggest that onshore production of unconventional natural gas will increase to 9.6 tcf in 2018 and hold at or near that level for the next dozen

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years. In essence, unconventional natural gas will constitute roughly one-half of the projected 19.6 tcf onshore production in the year 2030 (EIA 2008).

Data reveal that in 2005, nine of the twelve largest U.S. natural gas fields (in terms of production) produced gas from unconventional resources (Kuuskraa, Godec, and Reeves 2007). The San Juan Basin Gas Area, in northwestern New Mexico and southwestern Colorado, topped the list. Natural gas production from coalbed methane and tight gas sands in the San Juan Basin resulted in 3.8 billion cubic feet per day (bcfd) in 2005. The Newark East (Barnett Shale) Forth Worth Basin field in north central Texas, where production averaged 1.4 bcfd, was second on the list that year.

The Newark East field (called hereafter the Barnett Shale) is currently the most productive gas field in the State of Texas. Recent estimates place production in the Barnett Shale at 3.7 bcfd (The Perryman Group 2008). As of last year, natural gas production in the Barnett Shale accounted for 4.3 percent of the total production in the United States (The Perryman Group 2008). From a rural, natural resources sociological perspective, what is most conspicuous about the Barnett Shale is that the core production area is *not* in a rural area (as often happens with onshore energy developments). Instead, this massive, large-scale energy boom is occurring in and around a highly urbanized geographical setting–the Fort Worth and Arlington metropolitan areas.

Geologists and engineers for years have chronicled the development of the Barnett Shale and assessed the amounts of known, undeveloped, and technically recoverable natural gas in the reserve (Ambrose, Potter, and Briceno 2008; Bowker 2003, 2007; Kuuskraa et al. 1998; Montgomery et al. 2005; Pollastro 2007). Most recently, attention has turned to assessing the aggregate economic impact of the Barnett Shale (The Perryman Group 2007, 2008). In 2008, the economic impact of the Barnett Shale activity on the local economy was estimated at $8.2 billion, up from $5.2 billion in 2007. Little attention, however, has been directed toward understanding the social impacts associated with this immense unconventional energy development at the community level. Indeed, the authors are unaware of any published sociological studies on the topic.

In this paper we analyze responses from key informants in two Barnett Shale counties to understand their perspectives regarding the community-level impacts of this unconventional energy development better. Specifically, we examine the responses reported by key informants to three interview questions. Respondents were asked: (1) what community-level benefits have occurred because of increased energy development; (2) what perceived negative impacts have accompanied increased development; and, (3) whether the benefits of development have outweighed the costs. Answers to these questions shed light on some community-level consequences of unconventional energy development that might be considered in future research. Before describing the data and findings, we briefly summarize previous literature on conventional energy development and explain why unconventional energy development is on the rise.

BACKGROUND

Conventional Energy Development

Social impacts of energy production have been studied in the past, generally within the contexts of rural western energy "boomtowns" and offshore drilling communities along the Gulf of Mexico. In these cases, the positive and negative consequences of development, as well as the magnitudes of their effects, were said to be influenced by contextual factors such as community size and rate of population growth.

Much of the onshore energy development of the past several decades has occurred in remote locations and has resulted in rapid population growth (10-15% per year) that triggered various forms of social disruption (Albrecht 1978; Freudenburg 1982; Gilmore 1976; Lillydahl et al. 1982; Little 1977). In spite of some criticism (Wilkinson et al. 1982), there has been a consensus among researchers that the negative consequences of boomtown growth have traditionally outweighed the advantages. The negative impacts encountered have been grouped into three general categories (Albrecht 1978), including social problems, service delivery problems, and environmental problems.

Feelings of alienation and isolation (Gilmore 1976; Lillydahl et al. 1982; Little 1977), integration problems among newcomers (Albrecht 1978), decreased density of acquaintanceship (Freudenburg and Gramling 1992; Lovejoy 1977), and decreased effectiveness of socialization and deviance control (Freudenburg and Gramling 1992) reported in past research were, in part, a function of rapid rural development. Other social problems, such as shifts in friendship selection, social class alignments, and community power structure have also been shown to result from rapid growth, along with added strains on communication patterns and a reported loss of sense of community (Bates 1978).

In western energy boomtowns, planning often failed to keep pace with the influx of new residents, a disparity shown to place burdens on housing supplies, facilities, and services (Albrecht 1978; Gramling and Brabant 1986; Gramling and Freudenburg 1990; Little 1977), as well as on existing medical, educational, and recreational facilities (Cortese and Jones 1977; Gramling and Freudenburg 1990; Little 1977). Any new taxes generated from development were typically subject to a five to ten-year lag between the need for infrastructural enhancements and the tax base increase needed to fund them. Even after this delay passed, additional revenue often failed to cover costs for increased social service needs (Albrecht 1978; Freudenburg 1982, 1984; Gramling and Brabant 1986; Little 1977).

Impacts on the physical environment of rural boomtowns included aesthetic disturbances, loss of access to the outdoors, and limitations to alternative land uses (Albrecht 1978; Leistritz and Voelker 1975; Little 1977). Wildlife habitat resources, typically more abundant in rural than in urban areas, were also highly susceptible to negative impacts of growth and development (Freudenburg and Gramling 1992).

Research on offshore oil development has demonstrated the need for a modified approach to the study of energy-related economic and social impacts. Specifically, with offshore oil drilling in East St. Mary Parish, Louisiana, energy extraction was happening in an urban area, where long-range commuting was common among industry employees and where development had progressed at a relatively gradual pace (Gramling and Brabant 1986). Furthermore, while Gramling and Brabant (1986) were careful to note that adverse social impacts had resulted from this development, Forsyth, Luthra, and Bankston (2007) portrayed the industry's effects as either overwhelmingly positive or benign, based on community members' responses to interviews conducted two decades later in the same parish.

Unconventional Energy Development

The metropolitan communities in the Barnett Shale where unconventional natural gas development is rapidly occurring offer another context in which to examine the positive and negative impacts of energy development. Unconventional energy exploration and production have greatly increased over the last several decades because of several factors (Durham 2006; Forbis 2001; Martineau 2003). First, the onset of horizontal, multidirectional drilling techniques has allowed greater access to natural gas deposits, increased well productivity, and reduced surface intrusion. The advent of hydraulic fracturing technology has also spurred the increase in unconventional energy development by allowing economical access to resources that were once very difficult and expensive to extract. Wells are fractured by flushing large quantities of freshwater into them at extremely high pressure levels to create cracks, or fractures, in the shale. This process overcomes difficulties associated with the limited porosity of the shale by loosening natural gas and allowing it to flow more freely through the rock formation for easier extraction.

Technological advancements continue to make the fracturing process more cost-effective. Meanwhile, rising natural gas prices contribute to the increased profitability of unconventional energy development. It should be noted that natural gas reserves reached through unconventional methods would be inaccessible via traditional extraction methods, due to the characteristics of the geological formations in which they are located. Access to resources in urban areas, however, is especially enhanced by technological advancements that effectively reduce the surface footprint associated with resource extraction.

Because natural resource deposits have been most plentiful in the shale beneath the most metropolitan of Barnett Shale counties, these areas have experienced substantial unconventional energy development. In spite of this, industry activity has not led to the rapid population growth witnessed in the western energy boomtowns of the past.[1] Nor can this development be expected, *a priori*, to closely parallel offshore oil development, which has occurred near–but not in–larger metropolitan areas. As a result, both the positive and negative economic and social impacts of unconventional energy development can be expected to differ in nature and magnitude from those reported in past research.

In contrast to the extant literature addressing the social, economic, and environmental impacts of conventional energy development, little empirical research has been directed at uncovering the potential benefits and/or negative consequences associated with unconventional energy development. We contend that an exploration of the various impacts faced by communities experiencing unconventional energy development is timely and particularly salient. In this article we use key informant interview data collected in two Barnett Shale counties to investigate the reported positive and negative outcomes of unconventional energy development. Moreover, we assess the differences and similarities in perceptions between respondents from each of the two study counties. Policy and resource use decisions associated with this development have important implications for local populations.

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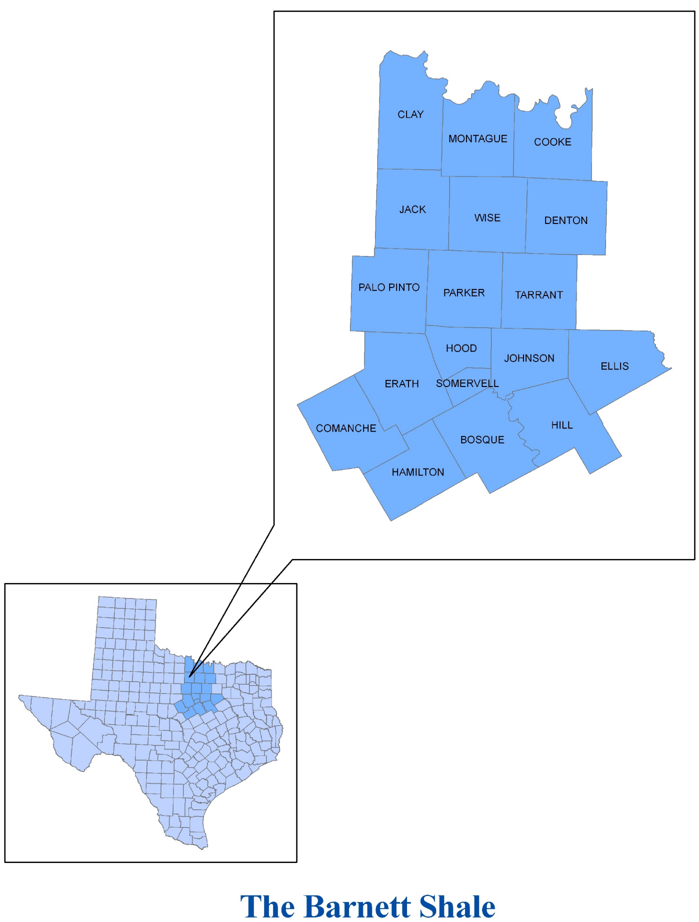
[1]Unconventional energy development also differs from conventional development in that wells in the production stage require limited labor and maintenance, thus workers frequently only remain in one place for between 30 and 90 days before moving on to another drill site (Giraud 2006). This fact may also contribute to lower rates of population growth.

METHODS

Study Area

While conventional oil and gas production throughout the State of Texas has declined during recent years, unconventional energy development in the Barnett Shale region is becoming increasingly more common (Givens, Zhao, and Steward 2004). The geographic boundaries of the Barnett Shale region are not clearly defined. Known limits of the reservoir are constantly expanding as operators continuously explore areas considered on the fringe. For purposes of this paper, the Barnett Shale refers to an 18-county region encompassing Bosque, Clay, Comanche, Cooke, Denton, Ellis, Erath, Hamilton, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Somervell, Tarrant, and Wise Counties (see Figure 1).

FIGURE 1. THE BARNETT SHALE REGION OF TEXAS.



The first commercially successful well in the Barnett Shale was drilled in 1981 near Newark, TX (Forbis 2001), representing the start of a boom that spread throughout Wise and Denton counties in the late 1990s (Durham 2006; Piller 2006). The drilling boom has now extended into surrounding counties and is expected to spread even further. As such, the Barnett Shale constitutes the largest natural gas reservoir, or "play" as referred to in the vernacular, in Texas.

The Barnett Shale is a geologic formation that is located at a depth of 6,500 to 8,500 feet and runs horizontally. The rock formation is 1,000 feet thick in some places and as shallow as 30 to 50 feet thick in others (Hayden and Pursell 2005). The Ellenberger Zone, a water bearing formation that lies directly below the Barnett Shale, must be avoided during drilling to maintain profitable mineral extraction (Sanders n.d.). These characteristics have historically made it difficult to develop the resources in the Barnett Shale economically. The recent advancements in the field of unconventional extraction techniques have made Barnett Shale production much more technologically and economically feasible. The success witnessed in this area begs the question, "In what ways, and to what degree, has energy development positively and negatively impacted communities in the Barnett Shale?"

For answers to this question, we turned to two Barnett Shale counties, Wise and Johnson Counties. Two main reasons prompted the selection of these two particular counties. First, they provide a longitudinal perspective, to a certain degree. Wise County, the county where much of the initial development was performed after the first well completion in 1981, was selected to represent a site with relatively mature energy development. Conversely, Johnson County, the county called an emerging "sweet spot" (Hayden and Pursell 2005) when this research was conceptualized, was chosen to represent a site where large-scale exploration and production activities were just beginning. The second influential factor in the selection of these two counties was the willingness of community key informants to participate in this study. Participants in both Johnson and Wise counties were supportive of this research and enthusiastic about sharing their experiences.

While Wise County is somewhat more metropolitan than Johnson County, both displayed the types of population trends we would expect to occur with unconventional energy development (USBC 2006). According to Census figures, between the years 2000 and 2005, population in Wise County grew by 16.2%, with the largest annual increase occurring between 2000 and 2001 (5.2%). In Johnson

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County, population grew by 15.4% during the same period, with the largest annual increase also taking place between 2000 and 2001 (4.2%). Neither of these rates approaches the threshold for boomtown growth, which is 10-15% per year (Little 1977).

Data Collection

In March 2006, key informant interviews were conducted in Wise County and Johnson County. The utilization of key informants has long been central to the basic methodological techniques used by anthropologists (Campbell 1955; Poggie 1972; Tremblay 1957; Young and Young 1961). As a methodologically acceptable and highly practical means of gaining information, the key informant technique has become relatively common in organization analyses (Seidler 1974) and community sociology (Claude, Bridger, and Luloff 2000; Krannich and Humphrey 1986; Schwartz, Bridger, and Hyman 2001). Key informants provide important knowledge about community characteristics that cannot be measured precisely with secondary data (Claude et al. 2000; Fetterman 1989; Krannich and Humphrey 1986; Schwartz et al. 2001).

Interviews with key informants were conducted either individually or in groups, depending upon logistical constraints and participants' preferences. Key informants in both counties responded to a series of semi-structured interview questions. Interviewed informants included municipal and county leaders as well as concerned and active local citizens. Participants represented convenience samples from each county and were selected based on position and availability, in coordination with a local contact from each site. Below is a table depicting the participants and their positions within the community (see Table 1).

FINDINGS

Interview responses between the two counties showed many similarities as well as some substantial differences. While participants perceived many similar positive and negative consequences, they weighed the effects of those consequences differently. This apparent difference in weighting led to a different overall response pattern for the question regarding benefits versus costs of development.

Respondents in both Wise and Johnson Counties agreed that energy development had stimulated economic prosperity for their communities. The benefits identified included increases in city revenue, property values, and household income. Community leaders also noted the industry's positive impact on the job market and local unemployment rates. The retail sector also benefited from

TABLE 1. STUDY PARTICIPANTS.

Position	Number of People Interviewed: Johnson County	Number of People Interviewed: Wise County
County government official.	3	2
Law enforcement official.	1	0
Criminal judge.	1	0
Congressional representative.	1	0
State representative.	1	0
Newspaper editor/reporter.	1	1
City mayor.	1	0
City manager.	1	0
Director of economic development*.	2	0
Chamber of commerce.	1	0
Business owners/operators.	2	0
Hospital administrator.	1	0
Concerned citizens.	2	3

*One director for each of two Johnson County municipalities was interviewed.

development through the improvement of shopping choices and the presence of new businesses. Respondents in Johnson County differed from those in Wise County inasmuch as they listed improvements in schools and medical facilities among the benefits of energy development, whereas Wise County respondents reported only economic benefits. Overall, however, the responses to this question indicate that leaders in both counties recognized the economic contribution of the energy industry at the community level. This impression has been corroborated by economic impact assessments, including one conducted by the Perryman Group, which attributed $10.8 billion in annual economic output and 108,000 jobs to the development of Barnett Shale resources (King 2007).

Several common themes surfaced among respondents regarding the negative consequences of energy development. These can be generally classified into three categories: potential threats to public health and safety, environmental concerns, and quality of life issues. First, respondents in both counties mentioned several health and safety-related concerns during the interview process. A crucial concern focused on increased truck traffic on county roads as a byproduct of increased energy development. This increase in traffic is largely due to the water transportation needs involved with the well-fracturing process. Freshwater must first be transported to the well site in large quantities, then the saline water that emerges from the fractured well must be transported to a disposal site. Respondents asserted that the sheer number of large vehicles poses a threat to other drivers. Additionally, informants claimed that many truck drivers fail to adhere to legal mandates and customary safety precautions, leading to an increase in traffic accidents and fatalities.

Beyond traffic-related safety concerns, natural gas drilling itself can pose a danger to nearby residents. Gas leaks and explosions, though not frequent, do occur on occasion, forcing the evacuation of surrounding citizens. Such incidences, although rare, can possibly cause severe injury and/or death. The dangers involved with natural resource extraction are not unique to unconventional gas development, though new technologies do allow for drilling within a much closer proximity to residential areas. This places many citizens in a position to potentially be adversely affected by drilling and/or production accidents.

Respondents, specifically those from Wise County, also indicated health and safety concerns involved with injection well placement. As Wise County moves from the initial exploration and drilling phase into the production and maintenance phase, operations have resulted in an increased need for brine disposal. Citizens oppose the placement of disposal wells in their immediate vicinity, because improper well design may allow for potential contamination of groundwater supplies. Several citizens have even expressed concerns that the proximity of these wells to the local population has been the cause of certain cancer cases. While available data neither substantiate nor contradict this assertion, some local residents believe that experts have intentionally avoided researching these cases, fearing the implications of potential findings.

Besides issues related to public health and safety, environmental concerns also surfaced during discussions with key informants. Several informants mentioned a general decline in environmental quality, and one respondent expressed concern about air pollution. By far, though, the greatest environmental concern mentioned in both Wise and Johnson Counties dealt with freshwater supplies. The fracturing process requires enormous amounts of water–as much as five to eight million gallons per fracturing procedure.[2] Sources differ in their reporting of the number of fracturing procedures required per well. It has been reported that each well is fractured three times during the first year of production, then once every six months thereafter (Wilson 2007a). Wilson (2007b) later reported that wells are fractured an average of 17 times each. Either of these scenarios would amount to a substantially large quantity of water use.

While informants in both counties listed water as a major energy-related concern, the availability of freshwater was of greater concern in Wise than in Johnson County. This may be attributable to a combination of factors. First, energy production occurring in Wise County exceeds that of Johnson County, meaning that the amount of freshwater used in extraction procedures is also greater in Wise County. Divergent reports make direct water use calculations difficult, but a higher well count clearly requires greater amounts of water. As early as February 2000, Wise County reported 2,436 regular producing gas wells compared with only two producing wells in Johnson County. Well counts have since increased in both counties, numbering 3,489 in Wise County as of February 2006 and 195 in Johnson County (Texas Railroad Commission 2006). Beyond the differences in water use between the two counties, Johnson County community leaders have arranged for water provision from multiple surface water sources, including Lake Cleburne, Lake Aquilla, Lake Pat Cleburne, and Lake Whitney. Consequently Johnson County municipal leaders, in particular, felt confident about their ability to meet community water needs. County-level officials expressed a deeper concern about the availability of freshwater, citing multiple instances among constituents where private wells had run dry. Thus, concern may be greater for individuals relying on groundwater as opposed to surface water for their ongoing needs.

Besides health and safety concerns and environmental issues, respondents mentioned several adverse impacts on quality of life resulting from increased energy development. These included inconveniences related to both the drilling and production phases. The drilling process typically lasts approximately 65 days (Giraud 2006) and necessarily includes round-the-clock noise and lighting, which can disturb nearby residents. Changes to the aesthetic value of the landscape was also mentioned as a potential quality of life impact.

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[2] This information was obtained via personal communication with David Burnett, Director of the Global Petroleum Research Institute at Texas A&M University.

The primary quality of life concern mentioned by informants in both counties pertained to the condition of the local roads (especially county roads). The quantity of traffic as well as the nature of the vehicles traveling these roads has caused a disruption in the way of life for local people. County roads and, to a lesser degree, municipal thoroughfares are being damaged more quickly than they can be repaired. Revenue from natural gas production helps to abate this situation within city limits, but county officials must rely on money allocated from the State. Many officials see this as only a temporary inconvenience that will disappear once the Barnett Shale's resources have been depleted, but that nonetheless poses a threat to the present quality of life in affected counties.

Informants in both counties stressed the influence of mineral rights ownership as a potential factor in perceived quality of life. They readily acknowledged that many citizens were becoming very wealthy very quickly. A sizeable financial gain from the energy industry presumably often outweighs any short-term inconveniences caused by industry operations for those upon whom such benefits are bestowed. Many social costs associated with development, however, are borne by members of the community who do not benefit directly from the industry's presence. Quality of life disturbances do not accrue only to those for whom increased development has proven lucrative (i.e., mineral rights owners). Thus, while many do benefit from development and believe that the associated costs are warranted, public opposition may arise from those who do not perceive a personal benefit from energy industry activity. Furthermore, sometimes, a shift in the distribution of economic wealth may also lead to drastic changes in the local power structure, as those who have benefited financially begin to seek positions of leadership. In these cases, ensuring that decisions made by those in power continue to reflect the needs of the community as a whole rather than those of the wealthy elite is important.

After itemizing the positive and negative consequences of energy development in their communities, informants in Johnson and Wise Counties were asked to give their overall impressions. Specifically, respondents were asked whether the benefits of energy development outweighed the costs. In Johnson County, the county where the massive, large-scale development was just beginning to occur, respondents unanimously agreed that the benefits of production would outweigh the costs. In contrast, Wise County respondents unanimously reported that the costs outweighed the benefits. These responses may reflect differences in site maturity between Johnson County, where the massive development has only recently begun, and Wise County, where citizens have been exposed to intense development efforts for over a decade. While respondents from both counties acknowledged the benefits of energy development, the enthusiasm of the Wise County respondents may be overshadowed by the daily presence of, and exposure to, the associated costs in relation to health and safety, resource use, and quality of life. It also appears that respondents in Wise County were well aware that their local resources are finite, as expressed by one concerned citizen: "We need energy, but we need water, too. If you had to choose, would you rather be cold or thirsty?"

CONCLUSIONS AND LIMITATIONS

In spite of economic benefits of unconventional energy development that were readily acknowledged by community leaders and concerned citizens in Wise and Johnson Counties, these individuals also expressed apprehension over perceived adverse consequences. Potential threats to public health and safety, such as increased truck traffic, unsafe driving practices, gas leaks, and explosions, were among the concerns mentioned. Environmental concerns were expressed mostly in terms of water resources, as their use is closely tied to unconventional energy development. Temporary disturbances caused by noise, lighting, traffic, and conflicts over mineral rights comprise the quality of life issues addressed by participants. These negative impacts were perceived although much of this development is occurring in and around a metropolitan area. Thus, while rapid population growth has not resulted from Barnett Shale energy development, the region has not been entirely insulated from social costs associated with industry activity.

On the contrary, our findings demonstrate that communities experiencing unconventional energy development in a metropolitan context *do* face negative consequences in addition to positive impacts. In fact, concern regarding negative consequences was greater among respondents in Wise County, the more metropolitan of the two counties studied. This finding suggests that the nature of the energy development itself, rather than population growth, may act as the catalyst for the various forms of social disruption.

To more fully understand the association between unconventional energy development and social consequences, there is a need for additional research on both the positive and negative energy-related impacts experienced in the Barnett Shale as well as in other areas that are beginning to employ unconventional techniques for mineral extraction. Future research should address the types of impacts and concerns outlined here (e.g., increased truck traffic and accidents, freshwater resource depletion, wastewater disposal, etc.). Continued reliance upon the indicators used to measure social disruption in the western energy boomtowns of the past would likely yield misleading results for unconventional energy development, particularly in a metropolitan context. Rather, public health and safety concerns, environmental impacts, and quality of life levels should all be given greater attention.

Future research should also empirically examine the differences in perceptions among diverse stakeholder groups. Municipal leaders and county-level officials, for example, face different challenges and, therefore, may perceive energy-related issues differently. While the present study included both types of officials, the interviews and participant selection processes did not allow for in-depth analyses of their responses. Furthermore, an understanding of the similarities and/or differences between community leaders' perceptions and those of the general citizenry may offer valuable insights. Lastly, examinations of the interpersonal dynamics within energy-producing communities and investigations into the ways in which increased energy development affects wealth and power at the local level are warranted. In closing, this study has introduced indicators of social disruption designed to better reflect the experience and concerns of community leaders and the public in communities facing increased unconventional development of natural gas resources and has demonstrated the need for further research into the community-level impacts of unconventional energy development.

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Public Perception of Shale Plays

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Department of Sociology

Center for Rural Studies: Research & Outreach

Sam Houston State University

Today's Presentation

1) Perception of the natural gas industry
2) Perception of potentially problematic issues associated with natural gas development

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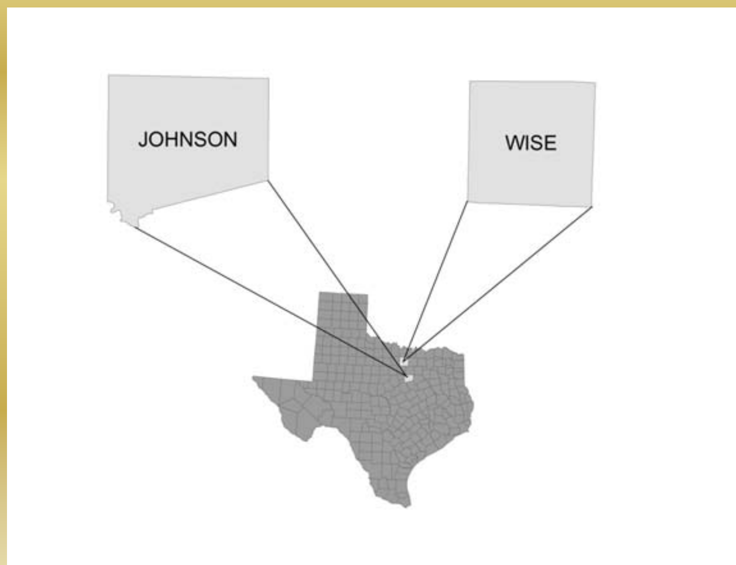
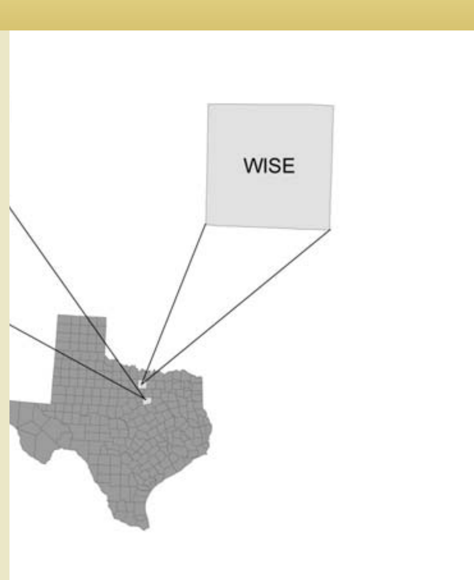
Study Sites



Wise County

- Represented a site with relatively mature development
- Much of the initial development was performed after the first well completion in 1981



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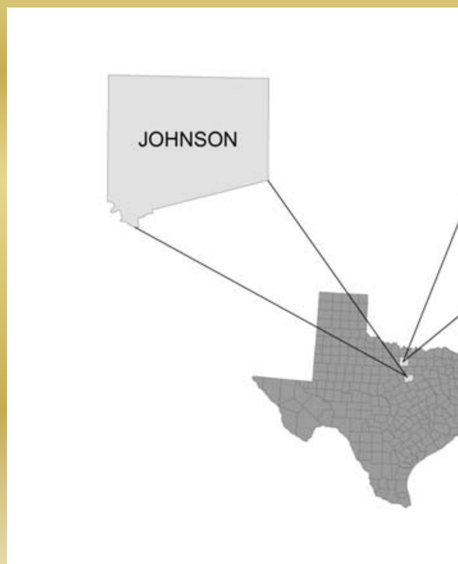
Johnson County



- Represented a site where large-scale E&P activities were just beginning
- Referred to in 2005 (at the time when this research was conceptualized) as an emerging “sweet spot”

Data Collection

- Key informant interviews in both counties (March 2006)
- Household survey questionnaire (late spring, early summer 2006)
- Mailed to 1,533 randomly selected households (749 in JC; 784 in WC)
- 600 returns (301 from JC; 299 from WC)
- 39% response rate

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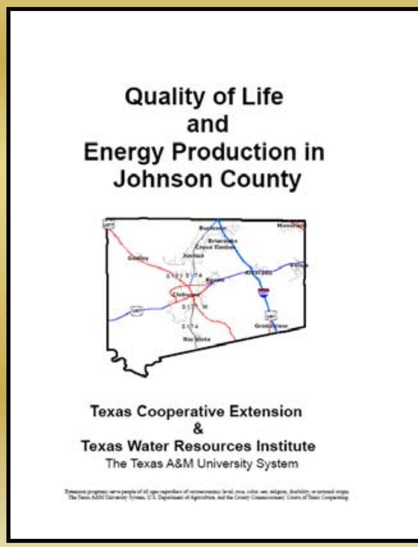
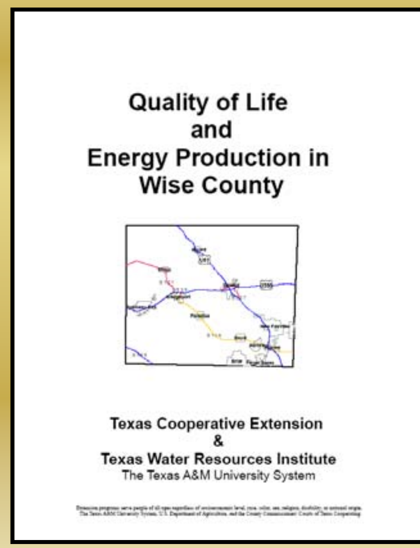
Survey Questionnaires


Quality of Life
and
Energy Production in
Johnson County

Texas Cooperative Extension
&
Texas Water Resources Institute
The Texas A&M University System


Quality of Life
and
Energy Production in
Wise County

Texas Cooperative Extension
&
Texas Water Resources Institute
The Texas A&M University System

Perception of the natural gas industry

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Gallup's Annual Poll

Year	Very/Somewhat positive (%)	Neutral (%)	Very/Somewhat negative (%)
2001	24	21	54
2002	25	28	44
2003	35	22	43
2004	21	18	58
2005	20	17	62
2006	15	7	77
2007	19	14	67
2008	15	8	76

Dependent Variable

Perception of the natural gas industry

- 10 statements
  - Strongly Agree
  - Agree
  - Disagree
  - Strongly Disagree

Dependent Variable

Perception of the natural gas industry

- Natural gas industry operators in this area are too politically powerful.

- 0 = disagreement
- 1 = agreement

Dependent Variable

Perception of the natural gas industry

- Not enough information concerning the development of natural gas is being made available to the general public.

- 0 = disagreement
- 1 = agreement

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Dependent Variable

Perception of the natural gas industry

- Even when carefully controlled, natural gas development is likely to upset the quality of life in a local area.

- 0 = disagreement
- 1 = agreement

Dependent Variable

Perception of the natural gas industry

- Too little attention is being paid to the social costs of natural gas development.

- 0 = disagreement
- 1 = agreement

Dependent Variable

Perception of the natural gas industry

- The natural gas companies have no compassion for our natural environment.

- 0 = disagreement
- 1 = agreement

Dependent Variable

Perception of the natural gas industry

- Natural gas operators MUST adopt and use more environmentally friendly drilling practices.

- 0 = disagreement
- 1 = agreement

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Dependent Variable

Perception of the natural gas industry

- Natural gas companies will do only what's required by law.

- 0 = disagreement
- 1 = agreement

Dependent Variable

Perception of the natural gas industry

- Natural gas operators are drilling and producing too close to homes and businesses.

- 0 = disagreement
- 1 = agreement

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Dependent Variable

Perception of the natural gas industry

- In the long run, I'm sure that people in this area will be better off if our natural gas resources are developed.

- 0 = agreement
- 1 = disagreement

Dependent Variable

Perception of the natural gas industry

- All in all, the benefits of natural gas development for this area are greater than the costs.

- 0 = agreement
- 1 = disagreement

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Independent Variable

County of residence

- 0 = Johnson County
- 1 = Wise County

Control Variables

Mineral rights ownership

- 0 = does not own mineral rights
- 1 = owns mineral rights

Personal / familial ties to NG industry

- 0 = no
- 1 = yes

Length of residence in county

- measured in years

Descriptive Results

Statements	Overall	Johnson	Wise
Natural gas operators MUST adopt and use more environmentally friendly drilling practices.	0.86	0.83	0.89
Natural gas companies will do only what's required by law.	0.79	0.79	0.78

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Descriptive Results

Statements	Overall	Johnson	Wise
Not enough information concerning the development of natural gas is being made available to the general public.	0.77	0.79	0.75
Natural gas operators are drilling and producing too close to homes and businesses.	0.70	0.63	0.78

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Descriptive Results

Statements	Overall	Johnson	Wise
Too little attention is being paid to the social costs of natural gas development.	0.67	0.64	0.70
Natural gas industry operators in this area are too politically powerful.	0.63	0.56	0.69

3 of 5

Descriptive Results

Statements	Overall	Johnson	Wise
Even when carefully controlled, natural gas development is likely to upset the quality of life in a local area.	0.60	0.58	0.61
The natural gas companies have no compassion for our natural environment.	0.53	0.46	0.60

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Descriptive Results

Statements	Overall	Johnson	Wise
All in all, the benefits of natural gas development for this area are greater than the costs.	0.43	0.39	0.46
In the long run, I'm sure that people in this area will be better off if our natural gas resources are developed.	0.30	0.23	0.36

Logistic Regression Results

Statements	Bivariate	Multivariate
Natural gas operators MUST adopt and use more environmentally friendly drilling practices.	1.69	1.37
Natural gas companies will do only what's required by law.	0.92	0.83

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Logistic Regression Results

Statements	Bivariate	Multivariate
Not enough information concerning the development of natural gas is being made available to the general public.	0.78	0.69
Natural gas operators are drilling and producing too close to homes and businesses.	2.07**	1.80*

Logistic Regression Results

Statements	Bivariate	Multivariate
Too little attention is being paid to the social costs of natural gas development.	1.28	1.08
Natural gas industry operators in this area are too politically powerful.	1.73**	1.68*

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Logistic Regression Results

Statements	Bivariate	Multivariate
Even when carefully controlled, natural gas development is likely to upset the quality of life in a local area.	1.12	0.86
The natural gas companies have no compassion for our natural environment.	1.81**	1.60*

Logistic Regression Results

Statements	Bivariate	Multivariate
All in all, the benefits of natural gas development for this area are greater than the costs.	1.32	1.22
In the long run, I'm sure that people in this area will be better off if our natural gas resources are developed.	1.97**	1.93**

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Perception of potentially problematic issues associated with natural gas development

Perception of Potentially Problematic Issues

30 issues

Because of the development of natural gas, the issue is ______________.

- getting worse (-1)
- staying the same (0)
- getting better (1)

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Analyses

Bivariate

- t-test

Multivariate

- Analysis of covariance
  - Mineral rights owners
    - mean = 0.41
  - Personal/familial ties to NG industry
    - mean = 0.19
  - Length of residence in county
    - mean = 21.85

Issues	Overall	Johnson		Wise
Increased truck traffic	-0.73	-0.72		-0.73
Amt. of freshwater used	-0.56	-0.53		-0.59
High tax rates	-0.43	-0.35	*	-0.51
Depletion of aquifers	-0.42	-0.35	*	-0.50
Noise pollution	-0.41	-0.40		-0.43
Water pollution	-0.39	-0.26	***	-0.53
Traffic accidents	-0.38	-0.32		-0.44
Environmental quality	-0.35	-0.31		-0.39
Loss of privacy	-0.35	-0.26	**	-0.44
Cond. of streets and roads	-0.34	-0.43	*	-0.25

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Issues	Overall	Johnson		Wise
Land use conflicts	-0.33	-0.27		-0.40
Air pollution	-0.32	-0.31		-0.33
Odors/fumes from drill. equip.	-0.27	-0.30		-0.24
Population growth	-0.27	-0.36	*	-0.18
Light from gas drill. operats.	-0.26	-0.28		-0.25
Use of illegal drugs	-0.24	-0.19		-0.28
Crime	-0.22	-0.25		-0.19
Fire hazards	-0.21	-0.20		-0.22
Gas well explosions	-0.12	-0.14		-0.10
Respect for law and order	-0.11	-0.11		-0.10

Issues	Overall	Johnson		Wise
Disagree among local res.	-0.11	-0.09		-0.12
Absence of zoning regs.	-0.07	-0.07		-0.07
Effectiveness of County govt.	-0.05	-0.01		-0.08
Effectiveness of City govt.	-0.03	-0.04		-0.03
Poverty	0.05	-0.03	*	0.13
Local police protection	0.06	0.03		0.10
Quality of local schools	0.10	0.03		0.17
Fire protection services	0.10	0.04	*	0.16
Med. and health care services	0.13	0.00	***	0.27
Availability of good jobs	0.36	0.28	*	0.45

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Conclusions

- Wise County
  - more negative perceptions
  - social and environmental issues – ***negatively***
  - economic and service-related issues – ***positively***
- Mineral rights ownership
  - relatively strong and consistent factor

Recommendations

- Fund and promote informational and educational programs
- Communicate openly with the public and enhance involvement

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Thank You

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ENVIRONMENTALLY FRIENDLY DRILLING SYSTEM

SCORECARD

Reference Guide

Version 1.0

First Edition

January 2010

EFD

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- John Hopkins University
- University of Arizona
- University of Texas
- University of Houston

Environmental Organizations

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- Environmental Defense
- The Nature Conservancy
- Conservation International
- Mercer Arboretum
- Bureau of Applied Anthropology/Arizona
- Clinton Climate Initiative
- Rocky Mountain Clean Air
- McFaddin Ranch

Industry

- API
- Ballard Exploration
- BP
- Shell
- Chevron
- StatoilHydro
- ConocoPhillips
- Devon
- King Exploration
- Halliburton
- Huisman
- National Oil Well – Varco
- MI Swaco
- TerraPlatform
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- PTTC
- IADC

State/Federal Agencies

- US Department of Energy
- Bureau of Land Management
- US Park Service
- Texas Railroad Commission
- Texas General Land Office
- Texas Dept. of Agriculture
- Texas Dept. of Transportation
- US Minerals Management Services
- Texas Parks & Wildlife
- Texas Water Board
- Texas Commission on Env. Quality
- US Environmental Protection Agency
- US Fish and Wildlife
- Argonne National Laboratory
- Big Thicket Preserve
- Idaho National Laboratory

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Environmentally Friendly Drilling Scorecard

Project:
Location:
Ecosystem:
Date:

0	Points Achieved	Possible Points: 100

★ 55 - 64 points ★★ 65 - 74 points ★★★ 75 - 84 points ★★★★ 85 - 94 points ★★★★★ 95 - 100 points

0	Air	Possible Points: 10
	Prerq 1	Compliance w/Air Quality Regs	
	Credit 1	Contractual Obligations for Logistics	2
	Credit 2	Site Emissions	2
	Credit 3	Dust Suppression	2
	Credit 4	Alternate Power	2
	Credit 5	Green Completions	2

0	Site	Possible Points: 15
	Prerq 1	Regulatory Compliance	
	Prerq 2	Erosion & Sedimentation Control	
	Credit 1	Pre-Existing Site	3
	Credit 2	Pad Drilling	2
	Credit 3	Protect and Restore Habitat	2
	Credit 4	Contractor Guidelines	2
	Credit 5	Site Restoration Plan	2
	Credit 6	Match Site/Access to Topography	1
	Credit 7	Avoidance of Archeological Sites	1
	Credit 8	Logisitics Plan - Offsite Storage	1
	Credit 9	Planting of Native Vegetation	1

0	Waste Management	Possible Points: 20
	Prerq 1	Waste Management Plan	
	Prerq 2	Pit Design Pre-site Assessment	
	Credit 1	Drilling Fluid Handling System	5
	Credit 2	Evaporation Ponds	3
	Credit 3	Reduction of Fresh Water Needs	3
	Credit 4	Spill Prevention System	3
	Credit 5	Cuttings Reuse	3
	Credit 6	Cuttings Reinjection	3

0	Biodiversity	Possible Points: 20
	Prerq 1	Species Protection	
	Prerq 2	Habitat Protection/Enhancement	
	Prerq 3	Regulatory Requirements	
	Credit 1	Restoration/Interim Reclamation	3
	Credit 2	Reduction of Surface Disturbance	3
	Credit 3	Erosion Prevention	3
	Credit 4	Voluntary Offsite Mitigation	2
	Credit 5	Invasive Species Prevention	2
	Credit 6	Restoration of Fragmented Habitat	2
	Credit 7	Reintroduction of Species, Habitat	2
	Credit 8	Avoidance of High Value Areas	1
	Credit 9	Wildlife Protection	1
	Credit 10	Habitat Enhancement	1

0	Water	Possible Points: 15
	Prerq 1	Stormwater Mangement Plan	
	Prerq 2	Water Management Plan	
	Credit 1	Water Usage Tracking	4
	Credit 2	Setbacks from Streams/Sources	3
	Credit 3	Reduce Water Usage	2
	Credit 4	Reuse of Water/Fluids	2
	Credit 5	Recycling of Water/Fluids	2
	Credit 6	Monitor Nearby Surface Waters	1
	Credit 7	Pressure Testing of Surface Casing	1

0	Societal	Possible Points: 20
	Prerq 1	Community Engagement	
	Prerq 2	Communication Plan	
	Credit 1	Public Outreach	5
	Credit 2	Noise Control	2
	Credit 3	Training of Local First Responders	2
	Credit 4	Remote Alarms for Toxic Releases	2
	Credit 5	Emergency Management Plan	2
	Credit 6	Dispute Resolution Plan	2
	Credit 7	Land Use Plan	2
	Credit 8	Landowner Indemnification	1
	Credit 9	Water Well Mitigation Agreement	1
	Credit 10	Surface Use Agreement	1

EFD Facts

Project:
Location:
Ecosystem:

	Max	Score
AIR	10	0
WATER	15	0
SITE	15	0
WASTE MANAGEMENT	20	0
BIODIVERSITY	20	0
SOCIETAL	20	0
	100	0

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Environmentally Friendly Drilling System Scorecard – *what gets measured, gets done*

Introduction

What Does 'Environmentally Friendly' Mean?

'Environmentally Friendly' has become the shorthand term for the concept of developing energy resources in such a manner as to minimize the impact on the environment. The concept goes beyond environmental impact and takes into consideration societal issues as well as ensuring that technologies are cost effective.

Why Use the Scorecard?

Development of energy resources is important to the economic development and security of our nation. The scorecard enables a methodology to be employed that documents the environmental and societal tradeoffs associated with energy development. The scorecard enables operating companies to make use of the principle of ***what gets measured, gets done***.

Environmentally Friendly Drilling (EFD) practices can substantially reduce negative environmental impacts and promote balance between nature and energy development. In addition, EFD practices may be cost effective, enhance public relations, increase worker productivity and reduce potential liabilities.

Having an operation certified through the use of the Scorecard can demonstrate how an operating company successfully manages operations. In addition, using EFD practices may reduce overall costs, enhance public image, increase productivity and reduce potential liability issues. EFD practices have environmental, economic, and social elements that benefit all stakeholders, including operating companies, service companies, suppliers, contractors, regulators, landowners and the general public.

Who Should Use the Scorecard?

The EFD Scorecard process is designed to enable operating companies to document how they address environmental and societal issues for a specific project. The Scorecard is an adaptive ecosystem services management tool that can assist operating companies in planning and implementing practices to manage operational risks.

The Environmentally Friendly Drilling System Scorecard

The environmental scorecard was developed to determine the tradeoffs associated with implementing low impact drilling technology in environmentally sensitive areas. The scorecard assesses drilling operations and technologies with respect to air, site, water, waste management, biodiversity and societal issues. Low environmental impact drilling and completion operations may reduce the environmental footprint of operations by the adoption of new methods to use in (1) getting materials to and from the rig site (site access), (2) reducing the rig site area, (3) using alternative drilling rig power management systems, and (4) adopting waste management at the rig site.

The scorecard enables a dialog to be established and maintained among all interested, concerned and affected stakeholders. In this manner, the oil and gas industry has a new way of seeing itself within the larger network. Environmental sensitivities and other factors vary between various ecosystems. The EFD scorecard process takes this into consideration and enables operating companies to document how environmental factors are addressed for the different ecosystems.

History of the Scorecard

The Houston Advanced Research Center (HARC) and Texas A&M University through the Global Petroleum Research Institute (GPRI) have been collaborating with industry and environmental organizations to integrate and demonstrate current and new technology into land-based drilling systems for compatibility with environmentally sensitive or off-limits areas. The **Environmentally Friendly Drilling Systems** (EFD) Program, www.efdsystems.com, is taking a systems approach to the integration of currently known but unproven or novel technology in order to develop drilling systems that will have very limited environmental impact and enable moderate to deep drilling and production operations and activity with reduced overall environmental impact.

The EFD Program is identifying and providing the technology to successfully produce shale gas and tight gas sands while appropriately addressing environmentally sensitive issues. The project focuses on developing drilling technologies that can be used throughout the U.S., in particular, unconventional natural gas resources.

Why create something called "Environmentally Friendly Drilling"? Because new technology will help meet the U.S. energy needs for the next century at the same time we reduce the environmental "footprint" of oil and gas operations.

Exploration and production companies are aware that minimizing their environmental footprint is crucial to reducing environmental liabilities, controlling operational costs, and encouraging public acceptance for the sustainable development of the U.S. natural resources. There are certain restrictions for habitat protection, and in some cases complete prohibitions, that prevent drilling in many sensitive areas in the continental United States.

Sustainable development of petroleum resources requires careful planning, monitoring and measurement of operations over the life cycle of a development, from the initial planning through decommissioning and site restoration. According to the recent National Petroleum Council's recommendations, access to indigenous resources is essential for reaching North America's full supply potential. New discoveries in mature North American basins represent the largest component of the future supply outlook. However, the trend towards increasing leasing and regulatory restrictions in the Rocky Mountain region, the U.S. coastal areas and the Outer Continental Shelf (OCS) is occurring in precisely the areas that hold significant potential for natural gas production.[i] The NPC evaluated the effect of removing the OCS moratoria and of reducing the impact of conditions of approval on the Rocky Mountain areas – a potential addition of 3 BCF/D by 2020. This represents more than 25% of the projected growth in natural gas needs of the U.S. by 2020.[ii]

Land-use policies of federal, state, and local governments have not always kept pace with technological advances that allow for exploration and production while protecting environmentally sensitive areas. Technical advances have reduced the number and size of onshore drilling sites and production facilities. The federal government has continued to set federal lands off-limits to development through legislation, executive orders, and regulatory and administrative decisions without always acknowledging these advances.

According to the Texas Independent Oil and Gas Association, "*New technology developed by industry, universities and the Department of Energy is needed to*

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help industry meet our members' goal of producing oil and gas in a safe and environmentally acceptable manner; especially when operating in environmentally sensitive areas." The Independent Petroleum Association of America (IPAA) has consistently stated to Congress that access to more Federal Lands is the primary way to increase domestic oil and gas production. Many of these areas are on Federal Lands currently off-limits to drilling primarily because regulators, Congress and the environmental community are not convinced that technology is sufficient to develop these resources without adversely impacting the environment. For example, there is great concern over oil and gas spills in New York State.[iii] New Yorkers have been producing natural gas since the world's first commercial gas well was developed in Fredonia nearly 190 years ago. Today, the state supports more than 14,000 individual natural gas wells. And over the past 30 years, those wells have delivered more than 800 billion cubic feet of natural gas to consumers in New York and elsewhere. The total number of spills documented in the state's Department of Environmental Conservation database over these 30 years is 354,615, of which only 161 (0.045%) are related to oil and natural gas exploration and production with the top five number of incidents being[iv]:

- 100,929 (28.5%) — commercial/industrial sites
- 69,719 (19.7%) — residential (private dwelling) sites
- 63,121 (17.8%) — transportation (automobile, railroads, trucks)
- 35,072 (9.9%) — institutional sites
- 30,122 (8.5%) – simple spills at gas stations

While there may be technologies available to accomplish environmentally acceptable drilling, technologies have to be proven to be accepted. In response to this need, the EFD project team works with government, industry, academia and public organizations to identify, develop, and provide industry with the tools to develop needed energy supplies. Many of these new and emerging technologies and methodologies can be applied to reduce environmental tradeoffs associated with oil and gas operations.

The US Environmental Protection Agency (EPA), the Bureau of Land Management (BLM), and the Forest Service (FS), are responsible for ensuring compliance with the National Environmental Policy Act (NEPA). During the review of development proposals that encompasses multiple wells in a specific area, the BLM, the surface management agency, or the agency's or operator's environmental contractor conduct an environmental analysis and prepare an environmental document in conformance with the requirements of NEPA and the regulations of the Council on Environmental Quality (CEQ). Regardless of which agency, entity, or individual prepares the environmental analysis document, the BLM (and FS, for actions on National Forest System lands) must concur with the content prior to issuing a decision document. In the case of National Forest System lands, where the environmental analysis is conducted jointly with the BLM, each agency issues its own decision. The extent of the environmental analysis process and the time frame for issuance of a decision depend upon the complexity of the proposed action and resulting analysis, the significance of the environmental effects disclosed, and the completion of appropriate consultation processes.

Conservative estimates of the near term impact of the adoption of low impact drilling technology would increase the immediately accessible resources by more than 10%, just in the Texas Gulf Coast. The Chairman of the General Land Office Jerry Patterson[v] estimated the state's Permanent School Fund received more than $450 million dollars in revenue in 2006. Future revenues will include more than $104 million in royalties from its share of gas production from gas wells on Padre Island. These funds will add to the $22 billion in the Permanent School Fund, royalties from 13 million acres where the state retains an interest in the mineral rights, land office officials said.

Having a program that has the potential to “lighten the impact” of drilling in environmentally sensitive areas such as coastal margins, National Forests and Parks and other public lands is extremely important. Oil and gas leases beneath many of state and national parks and public lands are owned by private companies, not the government. Only by setting environmentally responsible standards can park managers protect the environment while providing access to these resources.

THE MORE YOU KNOW, THE LESS YOU NEED

The drilling process is considered a complex activity composed of a set of processes interrelated by purpose, sequence, and time. Millheim[vi] defined the drilling process as a system in the mid 1980’s. The systems themselves are made up of sub systems. The rig and the surface equipment is a complex subsystem of the drilling process. Pedersen and Essendrop defined the drilling system (Millheim’s rig subsystem) comprised of six subsystems[vii]: drilling control system, drilling machine, pipe handling, blow-out-preventer (BOP) and handling system, mud supply, and mud return[viii]. Though defined for the offshore jack up design environment, many of the concepts have transitioned to the onshore rig design.

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As knowledge has increased, technology has allowed the industry to contact almost 60 times the volume of subsurface rock material that could be accessed in 1970 while occupying only one third the surface area.[ix] Today's technology associated with drilling and production can be unobtrusive and highly efficient if the technologies are used concurrently on the same well. In the past 20 years, technology has been able to significantly reduce the impact that drilling operations have on the environment. According to the Natural Gas Supply Association, some of the key technology developments over this time period have enabled the following.

- 22,000 fewer wells are needed on an annual basis to develop the same amount of reserves as were developed in 1985.
- Had technology remained constant since 1985, it would take two wells to produce the same amount of oil and natural gas as one 1985 well.
- Drilling wastes have decreased by as much as 148 million barrels due to increased well productivity and fewer wells.
- The drilling footprint of well pads has decreased by as much as 70 percent due to advanced drilling technology.
- By using modular drilling rigs and slim hole drilling, the size and weight of drilling rigs can be reduced by up to 75 percent over traditional drilling rigs.
- Had technology, and thus drilling footprints, remained at 1985 levels, today's drilling footprints would take up an additional 17,000 acres of land.

Documented best practices and lessons learned have greatly reduced environmental issues associated with drilling operations. The oil and gas industry just needs to combine these practices into EFD systems, and then demonstrate their effectiveness in real applications.

REDUCE, REUSE, RECYCLE

The energy industry has progressed in taking into consideration environmental issues. Shell Exploration and Production Company established a Rig Waste Reduction Pilot Project in 2001 to identify potential waste reduction strategies.[x] Their preferential hierarchy that they developed is: *reduce, reuse, recycle, recover and dispose.* The majority of the total waste stream was found to be drilling discharges and non-hazardous oilfield waste. Mud use was reduced by 20% and mud component packaging was reduced by 90% through a combination of solids control efficiency, cuttings dryer technology and bulk mixing equipment. In addition, Shell implemented a sorting, compaction and recycling process for solid waste (consumables and trash) to reduce landfill disposal.

Schlumberger has introduced a total waste management program to mitigate rising quantities of landfill waste.[xi] Benefits included an overall improvement in general housekeeping that reduced health and safety exposure and a general increase in environmental awareness and concern. As a result, the recommendation is made to ensure that the operator establishes a waste management program that covers all exploration, drilling and production activities.

Mobil implemented a waste management program for the Hugoton field operations.[xii] The waste management system decreased overall waste-related costs while improving compliance assurance and reducing potential liability. The key element was a mechanical solids control system consisting of a semi-closed loop centrifuge flocculation dewatering process that removes solids for burial on location.

Chevron has published ten years of lessons learned concerning bio-treating exploration and production wastes.[xiii] They have successfully implemented bioremediation in diverse climates and in remote locations. The most common biological treatment techniques in the exploration and production industry are composting and land treatment. Land farming and composting have been successfully used for drilling wastes.[xiv]

There is currently an industry joint venture, sponsored by GPRI and the U.S. Department of Energy – National Energy Technology Laboratory to reduce waste volume of liquids at the rig site. This “Mud Pit Cleanup and Re-Use” project aims at recovering fresh water and solids-free brine at the rig site for re-use in drilling operations.[xv]

RESTORE

Reducing, reusing and recycling are all important. For sustainability, more is required. The relationship between business and a healthy environment is critical to long-term sustainability. Paul Hawken has defined sustainability as a stable relationship between human culture and the living world.[xvi] Business practices need to address life on earth. Ecology and commerce need to be united. As industry weighs various business practices, a systematic methodology of understanding and guiding practices may be implemented to, first, develop an understanding of the tradeoffs. To develop an understanding of what is possible, an understanding of the current situation is required.

Today's industry is accepting costs of environmental stewardship. These costs must be reconciled with commercial interests. Environmental restoration, economic prosperity and social stability may co-exist and do not have to be in conflict.

WHAT GETS MEASURED, GETS DONE

The Nutrition Labeling and Education Act of 1990 mandated that food companies were required to use a new food label on most food products beginning in 1994. This label provides information to enable users to make educated decisions about what they eat.

The US Green Building Council (USGBC) has develop an analogous label for summarizing how a building measures up in their Leadership in Energy and Environmental Design (LEED) Green Building Rating System™. The LEED system encourages and accelerates the use of green building practices through the implementation of universally understood and accepted tools and performance criteria.

The EFD Scorecard, to measure tradeoffs concerning environmental issues related to oil and gas operations, used the nutrition label and the LEED system as analogies.

THERE IS ONLY ONE BUS

In 1963, Buckminster Fuller published his ***Operating Manual for Spaceship Earth***[xvii] where he discusses the limited supply of energy onboard the spaceship and the need to harness the energy being supplied by the sun. Another way of looking at it is to realize that everyone is on the same bus and that there is a limited amount of fuel in the tank. While technologies are being pursued to harness solar energy, technologies need to be developed and implement to ensure that current energy supplies are being used efficiently and that all new fuel supplies that are tapped are done in a manner that will not be detrimental to those onboard.

There are tradeoffs between energy needs and biodiversity values. Many areas that are potentially valuable for energy are also recognized for biodiversity values. Energy development can impact biodiversity. The energy industry needs to meet public demand for energy while at the same time meet society's expectations for corporate, social and environmental responsibility. Conservation organizations need to be a voice for biodiversity protection while appropriately partnering with industry, recognizing that there is a balance to be struck between economic development, energy production and the conservation of biodiversity.

The EFD program is aimed at tapping the fuel supplies in an environmentally sound manner. The scorecard methodology aims to measure that manner that demonstrates its effectiveness.

Everyone on the bus has a vested interest in ensuring that sources of energy are produced using technologies that are not harmful. In developing the tradeoffs scorecard methodology, the decision was made to get as many stakeholders around the same table as possible, including, industry producers and service companies, ecologists, botanists, toxicologists, zoologists, wildlife managers, endocrinologists, environmentalists, regulators, and others. An initial workshop was held with representatives from government, academia, non-profits, industry and environmental organizations with the objective of discussing the tradeoffs associated with producing energy.

The focus of the workshop was the drilling systems and operations, recognizing that there is a need to also consider other oil and gas systems and operations. Environmentally Friendly Exploration and Production scorecards could be developed, as a minimum, for:

- Exploration
- Drilling
- Completion
- Processing
- Refining
- Transportation
- Distribution
- Field Development
- Field Operations

An EFD scorecard for drilling systems and operations was selected as the first scorecard to be developed due to the ease at which a boundary can be established around the time and location for the systems and operations.

WHAT GETS IDENTIFIED, GETS DEALT WITH

The objective of the EFD scorecard is to have a methodology that is meaningful, simple and easy to implement and understand. Six attributes were identified as meaningful to evaluate: site (soil/sediment), water, air, waste management, biodiversity and societal issues.

Each attribute has several layers or sub-attributes. As an example, within biodiversity, the potential threat to wildlife due to proximity or timing of operations could be assessed and minimized. Drilling activities have the potential risk of temporarily interfering with wildlife. The risk can be mitigated through proper planning and monitoring of operations.

The EFD scorecard has two point levels. First are the prerequisites – those items that must be done. Secondly are optional credits – those items that are considered best practices, going beyond minimum operating requirements.

Prerequisites for the various attributes include rules and regulations that govern the drilling locations. Within the United States, regulations vary by state and address various environmental issues by geographic location. Argonne National Laboratory, in conjunction with Marathon and Chevron, has developed an interactive website that summarizes state and federal regulations governing drilling waste. The website also provides descriptions of various technical options as well as case studies and other information.[xviii]

The optional credits include various practices that can reduce the environmental and societal tradeoffs associated with oil and gas operations. There are several references that provide information on various technologies and methodologies that may be employed to address the optional credits, including:

- *The Oil and Gas Industry from Rio to Johannesburg and Beyond*, IPIECA/OGP 2002.[xix]
- *Integrating Biodiversity Conservation into Oil and Gas Development*, The Energy & Biodiversity Initiative.[xx]
- *Reinventing the Well,* Conservation International.[xxi]
- *Environmental Management in Oil and Gas Exploration and Production,* Joint E&P Forum/UNEP Technical Publication.[xxii]
- *Drilling Rig Energy Inventory Engineering Report.*[xxiii]
- *Environmental Impact of Standard Oil Drilling Installations Versus the LOC250.*[xxiv]
- *Assessments of Technologies for Environmentally Friendly Drilling Project: Land Based Operations.*[xxv]
- *Clean Energy-Environment Guide to Action.*[xxvi]
- *Annotated Bibliography of Waste Minimization Technology.*[xxvii]
- *Waste Minimization in the Oil Field.*[xxviii]

- *Guidelines for the Review of State Oil & Natural Gas Environmental Regulatory Programs.*[xxix]
- *Coal Bed Methane Best Management Practices.*[xxx]
- *Texas State Review of Oil and Natural Gas Environmental Regulations.*[xxxi]
- *Manager's Guide to Environmental Regulations.*[xxxii]
- *Considering Ecological Processes in Environmental Impact Assessments.*[xxxiii]
- *Environmental, Health, and Safety (EHS) Guidelines.*[xxxiv]
- *Environmental Management Systems and International Environmental Standards in the Offshore Oil and Gas Industry.*[xxxv]
- *Summation of Potential Technologies for Environmentally Friendly Drilling in South Texas.*[xxxvi]
- *Modern Shale Gas Development in the United States: A Primer.*[xxxvii]

[i] "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy Volume I Summary of Findings and Recommendations," National Petroleum Council, September 25, 2003.

[ii] International Energy Outlook 2007, Energy Information Agency, Chapter 4. "Natural Gas".

[iii] Wilber, Tom: "Natural gas quest: State files show 270 drilling accidents in past 30 years," www.stargazette.com, Nov. 8, 2009.

[iv] "Lies, Damned Lies, and Walter Hang's Statistics," www.energyindepth.org, Dec. 18, 2009.

[v] General Land Office Annual Report, 2006, "Mineral Revenue" page 14.

[vi] Millheim, K.K. and Huggins, R.L.: "An Engineering Simulator for Drilling Part I," paper SPE 12075 presented at 1983 SPE Annual technical Conference and Exhibition, San Francisco, Ca, Oct 5-8.

[vii] Pedersen, Paul and Finn Essendrop: "New Jack-Up Design Improves Drilling Efficiency," *Oil and Gas Journal Online* September 14, 1992.

[viii] Kudsk, Carsten P., G. Lund: "Contractors Long Overdue Focus on Drill Floor and Its Equipment" paper SPE/IADC 23863 presented at 1992 SPE/IADC Drilling Conference, New Orleans, La, Feb. 18-21

[ix] Harrison, William: "Current Environmental Practices in Petroleum Exploration & Production," in *Energy and the Environment: A Partnership that Works: The Actual Impacts of Oil and Gas Exploration and Development on our Environment*, Ed. By Lee C. Gerhard, et al., March 2005 American Association of Petroleum Geologists, Tulsa.

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Environmentally Friendly Drilling System Scorecard – *what gets measured, gets done*

Certification Process

Features

The EFD certification system is a voluntary, consensus-based, rating system based on existing, proven technologies. The process evaluates environmental and societal issues associated with energy development. It is based on accepted principles and seeks a balance between energy development and all living systems.

The EFD Scorecard is organized into six attributes: Air, Site, Waste Management, Biodiversity, Water and Societal. It is a performance-oriented system where points are earned for satisfying criteria. Different levels of certification are awarded based on the total points earned. The system is comprehensive in scope, yet simple in operation.

The EFD Scorecard will vary with various ecosystems. Practices and methodologies vary in importance from one ecosystem to another and the Scorecard takes this into consideration.

Project Registration

xxxxxxxxxxxxxxxxxxxxxx

Submittals

Once a project is registered, the company may begin to collect information to satisfy the prerequisite and credit submittal requirements. The company should appoint a point of contact that can champion the EFD goals, facilitate communication, track progress and compile the components of the final submittal for certification.

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Documentation for submittal should be gathered throughout the process.

Credit Interpretation Rulings

Occasionally the company may encounter difficulties in applying an EFD prerequisite or credit to their project. These problems arise from instances where the Reference Guide may not sufficiently address a specific issue or that there is a conflict that requires resolution. To address such problems, the company may submit an EFD Interpretation Request.

Certification

To earn EFD certification, the applicant project must satisfy all of the prerequisites and a minimum number of points to attain the established ratings.

★	55 – 64 Points
★★	65 – 74 Points
★★★	75 – 84 Points
★★★★	85 – 94 Points
★★★★★	95 – 100 Points

xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx

Environmentally Friendly Drilling System

Attribute: Air

Prerequisite: 1. Compliance with Air Quality Regulations

Intent

Minimize air pollution by complying with air quality regulations as mandated by the Clean Air Act, other EPA, BLM and state regulations.

Benefits

The Clean Air Act (**42 U.S.C. § 7401 et seq.**) governs air quality in the United States. The United States **Environmental Protection Agency** (EPA) is the federal agency responsible for creating and enforcing national air quality regulations under the **Clean Air Act**. The EPA works with its federal, state and tribal regulatory partners to assure compliance with clean air laws and regulations in order to protect human health and the environment.

Congress passed the CAA (42 U.S.C. 85) in 1970 in order to combat air pollution in the United States and protect the health and general welfare of United States citizens against air pollutants. The act prescribes the measures that federal agencies, state and local governments, and polluters in business and industry must take in order to decrease air pollution in the country. The act was last amended in 1990.

Requirements

The project shall comply with the regulations.

Title 40 of the federal regulations deals with environmental protection, and all of the air quality regulations promulgated under the CAA, which are contained in Chapter I, sections 50 through 99 of Title 40, are enforceable solely by the Environmental Protection Agency (EPA).

Perform predevelopment baseline studies of air quality to assist in the development of an air quality management plan. Monitor air quality throughout the program to determine effectiveness of current practices or to justify new strategies.

Potential Technologies & Strategies

The EPA Office of Compliance has published a **Profile of the Oil and Gas Extraction Industry**. This provides an introduction to the oil and gas industry, pollution prevention, compliance and enforcement and a summary of pertinent statues and regulations.

Determine the regulatory requirements for the location of the project. Develop an Air Emissions Control Plan to identify how compliance with the requirements will be met. Implement the plan, recording any deviations and how they were addressed.

Verification (Indicator Monitoring and Analysis)

Project shall have an Air Emissions Control Plan that addresses how compliance will be managed. The Plan will be submitted with the registration form. Adjustments to the plan, documentation of deviations and corrective actions may be audited.

Summary of Referenced Standards

National Primary and Secondary Ambient Air Quality Standards (40 C.F.R. pt. 50 (2007)) – The EPA establishes national primary and secondary ambient air quality standards to regulate pollution in the United States. “National primary ambient air quality standards define levels of air quality which the Administrator judges are necessary, with an adequate margin of safety, to protect the public health,” while “[n]ational secondary ambient air quality standards define levels of air quality which the Administrator judges necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant,” pt. 50.2. The goal of national ambient air quality standards (NAAQS) is to limit levels of “criteria pollutants” like carbon monoxide, sulfur dioxide, lead, nitrogen dioxide, particulate matter, and ozone. Under section 110 of the CAA, each state must develop a State Implementation Plan (SIP) to identify sources of air pollution and reduce air pollution to meet federal standards.

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Of particular interest to oil and gas operations are the following:

- 40 C.F.R. pt. 50.4 – **Primary NAAQS for Sulfur Oxides (Sulfur Dioxide)** – This part establishes the maximum allowable concentration of sulfur dioxide in the atmosphere in a calendar year, and in any single 24-hour period, which may not be exceeded more than once during any calendar year.
- 40 C.F.R. pt. 50.5 – **Secondary NAAQS for Sulfur Oxides (Sulfur Dioxide)** – This part establishes the maximum allowable concentration of sulfur dioxide in the atmosphere during any three-hour period, which may not be exceeded more than once during any calendar year.
- 40 C.F.R. pt. 50.6 – **Primary and Secondary NAAQS for Particulate Matter (PM) 10** (particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers) – This part establishes the maximum allowable concentration of PM 10 in the atmosphere in a calendar year, and in any single 24-hour period, which may not be exceeded more than once during any calendar year.
- 40 C.F.R. pt. 50.7 – **Primary and Secondary NAAQS for PM 2.5** (particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers) – This part establishes the maximum allowable concentration of PM 2.5 in the atmosphere in a calendar year, and in any single 24-hour period, which may not be exceeded more than once during any calendar year.
- 40 C.F.R. pt. 50.8 – **Primary NAAQS for Carbon Monoxide** – This part establishes the maximum allowable concentration of carbon monoxide in the atmosphere during any given 8-hour period and during any given 1-hour period, neither of which may be exceeded more than once during any calendar year.
- 40 C.F.R. pt. 50.9 – **1-hour Primary and Secondary NAAQS for Ozone** – This part establishes the maximum allowable concentrate of ozone in the atmosphere during any given 1-hour period, which may not be exceeded more than once during any calendar year.
- 40 C.F.R. pt. 50.10 – **8-hour Primary and Secondary NAAQS for Ozone** – This part establishes the maximum allowable concentrate of ozone in the atmosphere during any given 8-hour period, which may not be exceeded more than once during any calendar year.
- 40 C.F.R. pt. 50.11 – **Primary and Secondary NAAQS for Nitrogen Oxide** – This part establishes the maximum allowable concentration of nitrogen oxide in the atmosphere during any calendar year.
- 40 C.F.R. pt. 50.12 – **Primary and Secondary NAAQS for Lead** – This part establishes the maximum allowable concentration of lead and its compounds in the atmosphere during any calendar quarter.

National Emission Standards for Hazardous Air Pollutants for Source Categories (40 C.F.R. pt. 63 (2007)) – The EPA establishes national emission standards for hazardous air pollutants (NESHAP) for "specific categories of stationary sources that emit (or have the potential to emit) one or more hazardous air pollutants listed in [part 63] pursuant to section 112(b) of the [Clean Air] Act." 40 C.F.R. pt. 63.1(a)(2) (2007). Major sources and areas sources, the two categories of sources regulation by Title 40, are defined in pt. 63.2. Emissions from oil and gas production and exploration wells cannot be aggregated with emissions from similar units to determine whether such emission points or stations are major sources.

Regulations of interest for the oil and gas industry include:

- 40 C.F.R. pts. 63.160-.183 (Subpart H) – National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks – These provisions apply to pumps, compressors, agitators, pressure relief devices, and other pieces of equipment that are intended to operate in organic hazardous air pollutant service 300 hours or more per year within a source subject to part 63 that references subpart H. Pt. 63.160(a).
- 40 C.F.R. pts. 63.760-.777 (Subpart HH) – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities – These provisions apply to emission points of hazardous air pollutants located at oil and natural gas production facilities that are major or area sources of hazardous air pollutants (i.e., all sources of hazardous air pollutants), as well as "[f]acilities that process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer," and "[f]acilities that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user." Pt. 63.760(a)(1)-(3). For major sources, all glycol dehydration units; storage vessels with the potential for flash emissions; and all ancillary equipment used in volatile hazardous air pollutant service also constitute affected sources. Pt. 63.760(b)(1). For area sources, triethylene glycol dehydration units that meet the criteria of pt. 63.760(a) also constitute affected sources. Pt. 63.760(b)(2).
- 40 C.F.R. pts. 63.1100-.1114 (Subpart YY) – National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology (MACT) Standards – Subpart YY applies MACT standards to eight different source categories and affected sources, including ethylene production emission points located at major sources.
- 40 C.F.R. pts. 63.6080-.6175 (Subpart YYYY) – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines – This subpart applies to stationary combustion turbines located at major sources

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of hazardous air pollutant emissions, including turbines located at oil and gas production facilities. Pt. 63.6085(a)-(b).

- 40 C.F.R. pts. 63.6580-.6675 (Subpart ZZZZ) – **National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines** (RICE) – This subpart applies to RICE located at major sources of hazardous air pollutant emissions, including oil and gas production facilities. Pt. 63.6585(a)-(b).

State Operating Permit Programs (40 C.F.R. pt. 70 (2007)) – Each state and Indian tribe must establish a comprehensive air quality permitting system consistent with CAA Title V, in accordance with EPA regulations and with the approval of the EPA. Pt. 70.1(a). Part 70 defines the minimum requirements that each state must meet for its program, as well as the standards that the EPA uses in approving individual state programs. Pt. 70.1(a). Individual states may establish more stringent requirements that are not inconsistent with the act, but they may not establish less stringent requirements than the CAA or EPA regulations. Pt. 70.1(c). States and Indian tribes with an approved program are responsible for regulating the oil and gas industry within their jurisdictions.

Federal Operating Permit Programs (40 C.F.R. pt. 71 (2007)) – If any state or Indian tribe does not have an operating program that has been approved in full by the EPA, that state will then be subject to the federal permit program under Part 71, in either the whole state or those parts of the state not regulated by the state permit program. Pt. 71.1(a)-(b).

Approach and Implementation

This prerequisite is submitted with the registration form. The project should then implement the plan and ensure that all deviations and corrective actions are documented. There may be an audit to ensure that the project is following the submitted plan.

Considerations

The most cost-effective technologies that will enable the project to comply with the regulations should be identified and implemented. The elimination of greenhouse gas emissions and a comparison to a baseline should be documented as there may be incentives in the future.

Resources

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2. Removal of Acid Gas Emissions Using Hollow Fiber Gas Absorption Membrane Contactors A. Mansourizadeh, SPE, and A.F. Ismail, Advanced Membrane Technology Research Centre (AMTEC), University Technology Malaysia (UTM) IPTC-12481-MS 2008.
3. A Novel Combustion Turbine Inlet Air Cooling System Montaser M. Zamzam (ADCO), Abdalla M. Al-Amiri, United Arab Emirates University SPE 117901-MS 2008.
4. Hydrogen Sulfide Detection in Offshore Platforms Edward Naranjo, General Monitors; and Mads Kornbech, Gassonic SPE 120932-MS 2008.
5. Environmental Considerations Related to Oil Shale Development Emily J. Knaus, INTEK Inc., Anton R. Dammer, U.S. Department of Energy SPE 116599-MS 2008.
6. Investigation of VOC Emission Control by the Use of Clay-Aqueous Foam Sani, A.M., SPE, and Mohanty, K.K., SPE, University of Houston SPE 115900-MS 2008.
7. Facts and Data on Environmental Risks—Oil and Gas Drilling Operations S. Rana, Environmental Consulting SPE 114993-MS 2008.
8. Environmental Requirements for New Projects: Systematic Processes and Performance Requirements Driving Better Environmental Outcomes E. Rogers and S. Spence, BP SPE 111981-MS 2008.
9. Minimizing Environmental Impacts in the Arctic: 30 Years of Oil Development on the North Slope of Alaska Janet D. Platt, BP Exploration Alaska Inc. SPE 111957-MS 2008.
10. ADNOC's Air Quality Monitoring and Management System Hazem Abuahmad, Abu Dhabi National Oil Company (ADNOC) SPE 111856-MS 2008.
11. Fugitive Emissions Management Through Infra Red Monitoring—Full Scale Field Application S. Plisson-Saune, TOTAL E&P Indonesie; S. Suripno, Elf Petroleum Nigeria Ltd.; B. Pradier, TOTAL E&P; A. Cramer and H. Pramono, SPE, TOTAL E&P Indonesie; and R. Camps, SPE, and H. Lacamoire, TOTAL E&P SPE 111584-MS 2008.
12. Improving Accuracy in Calculating NOx Emissions From Gas Flaring Jørn Bakken and Øyvind Langørgen, SINTEF Energy Research, and Geir Husdal and Tonje S. Henriksen, Novatech SPE 111561-MS 2008.

13. Mercury Monitoring and Removal at Gas Processing Facilities M. Abu El Ela, Cairo U., and I.S. Mahgoub, M. H. Nabawi, and M. Abdel Azim, Khalda Petroleum Co. SPE 106900-MS 2007.
14. Can the Existing F&G Detection System Provide Safe Guard Against All Possible Gas Releases? (Case Study) Ashraf E. Shabaka, ZADCO SPE 101422-MS 2006.
15. Developing and Using Technologies to Manage and Reduce Greenhouse Gas Emissions J. Cain, Chevron Energy Technology Co., and A. Lee and A. Mingst, Chevron Corp. SPE 98399-MS 2006.
16. Environmental Impact Factor for Emissions to Air: A Tool for Prioritizing Emission Reduction Measures Based on Environmental Impacts and Benefits T. Larssen, Norwegian Inst. for Water Research; S. Knudsen, Norwegian Inst. for Air Research; I. Bruteig and P.A. Aarrestad, Norwegian Inst. for Nature Research; T. Høgåsen, Norwegian Inst. for Water Research; and S.J. Kinn, S. Engen and S. Johnsen, Statoil ASA SPE 98616-MS 2006.
17. Hydrocarbon Gas Storage Tank Blanketing for FPSOS To Eliminate VOC Emissions M.S. Childs, Riskbytes Inc., and A.W. Sipkema, Shell Intl. EP SPE 98763-MS 2006.
18. A Strategy for the Reduction of Greenhouse Gas Emissions W. Veerkamp and W.K. Heidug, Shell Intl. E&P Co. SPE 98753-MS 2006.
19. Development Regarding Discharge and Emission From Offshore Installations on the Norwegian Continental Shelf B. Jarandsen, I. Skare, and O. Raustein, The Norwegian Oil Industry Assn. SPE 98489-MS 2006.
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21. Measurements of PM2.5 Mass and Species Emissions From Natural-Gas-Fired Reciprocating Internal-Combustion Engines G.C. England, GE Energy; K. Loos, Shell Global Solutions (US) Inc.; and K. Ritter, American Petroleum Institute SPE 94201-MS 2005.
22. Baselining and Reducing Air Emissions from an Offshore Drilling Contractor's Perspective M. Cadigan and K. Payton, Noble Drilling Services Inc. SPE 94432-MS 2005.
23. Quantifying Environmental Benefits of Improved Oil and Gas Exploration and Production Technology M.L. Godec, Advanced Resources Intl., Inc., and N. Johnson; U.S. Dept. of Energy/Office of Fossil Energy SPE 94388-MS 2005.
24. Air Compliance in the U.S.: A Systematic Guide for E&P Service Companies to Evaluate, Establish, and Ensure Ongoing Compliance J. Carley, Schlumberger; K. Malmquist, RETEC; W. Davison, RMT Inc.; and P. VanAllan, Consultant SPE 94381-MS 2005.
25. A Method for Evaluation of Risk of Continuous Air Emissions From Sustained Casinghead Pressure S. Duan and A. Wojtanowicz, Louisiana State U. SPE 94455-STU 2005.

26. Achieving Low Emission Levels in an Internal-Combustion Engine Using Off-Spec Produced Gas R. Cassinis, SPE, Tidelands Oil Production Co., and W. Larson, SPEC Services, Inc. SPE 93993-MS 2005.
27. Estimating Air Emissions for BP's Permian Basin Gas Plants and Oil and Gas Properties James E. Johnstone, Contek Solutions LLC; Alan Stobbe, BP SPE 88444-PA 2004.

2 Points

Environmentally Friendly Drilling System

Attribute: Air

Credit: 1. Contractual Obligations for Logistics

Points Available: 2

Intent

Minimize impacts to air quality due to travel to/from the well site and operations at the site.

Benefits

Minimize oxides of nitrogen emissions, precursor to ozone formation, as well as particulate matter (PM).

Nitrogen oxides (NO_x) are formed when nitrogen (N_2) and oxygen (O_2) are combined at high temperatures and pressure during the combustion of fuel. All fuels, such as gasoline, diesel, biodiesel, propane, coal, and ethanol, emit NO_x when burned. The EPA estimates that 49% of NO_x emissions come from on-road and off-road vehicles, 27% from power generation (electric utilities) and the remaining 24% from industrial, commercial and residential sources. Due to the many compounds that are a part of NO_x (predominantly nitrogen dioxide and nitric oxide), the pollutant contributes to a wide variety of health and environmental problems. NO_x is also a main component of ground-level ozone and contributes to global warming. Since the passage of the Clean Air Act in 1970, all primary air pollutants have decreased - except NO_x, which has increased by 10%. Due to its serious health and environmental impact, the reduction of NO_x in our atmosphere has now become a major focus in the fight against air pollution.

Exposure to diesel PM may result in both cancer and non-cancer health effects. Non-cancer health effects from one or more of these compounds may include irritation to the eyes and lungs, allergic reactions in the lungs, asthma exacerbation, blood toxicity, immune system dysfunction, and developmental disorders.

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Requirements

1 Point

Require all contractors and subcontractors associated with any logistical support or well site operations to use retrofit technology on all on-road vehicles that have Tier I or lower engines.

1 Point

To obtain the full 2 Points, require all contractors and subcontractors associated with any logistical support to use clean Tier II (or higher) engines for on-road vehicles.

Potential Technologies & Strategies

In 2004 the EPA introduced stringent air emission standards for on-road vehicles. Any pre-existing vehicle is not required to comply with these newer standards. Diesel vehicles from older model years will have higher non-methane hydrocarbon and particulate matter emissions.

Typically, diesel retrofit involves the addition of an emission control device to remove emissions from the engine exhaust. Retrofits can be very effective at reducing emissions, eliminating up to 90 percent of pollutants in some cases. Some examples of emission control devices used for diesel retrofit include diesel oxidation catalysts, diesel particulate filters, NO_x catalysts, selective catalytic reduction, and exhaust gas recirculation. Devices to control crankcase emissions also exist.

Significant improvement in diesel emission levels, in both light- and heavy-duty engines, was achieved in the 1970 - 2000 period. PM, NO_x, and HC emissions were cut by one order of magnitude. Most of that progress was achieved by emission-conscious engine design, such as through changes in the combustion chamber design, improved fuel systems, implementation of low temperature charge air cooling, and special attention to lube oil consumption.

However, more progress was still required, as the NO_x and PM emissions from diesels remained higher than those from Spark Ignited (SI) engines. A new series of diesel emission regulations was developed with implementation dates around 2005-2010, which require the introduction of exhaust gas aftertreatment technologies in diesel engines, as well as fuel quality changes and additional engine improvements.

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Technology	Emission Impact	Significance
Engine Design Technologies		
Fuel Injection System Charge Air System Combustion Chamber Electronic Control	~90% PM reduction, ~75% NOx reduction, large reductions in HC/CO emissions achieved in the 1980-1990 timeframe	Combination of these engine design techniques was the major source of diesel emission reduction through the end of 1990s; Potential for further emission reductions in the future
Exhaust Gas Recirculation	30-50%+ NOx reduction	Light duty vehicles; Major heavy-duty engine applications from 2002 (USA)
Fuel, Oil & Additive Technologies		
Fuel & Lube Oil	Only limited direct emission impact in modern engines	Sulfur content remains the critical property due to its effect on catalytic aftertreatment technologies
Alternative Diesel Fuels	Variable, depending on fuel and emission	Short term: emission-driven niche markets; Long term: critical importance due to depletion of petroleum reserves
Fuel Additives	Small emission effect with modern engines and quality diesel fuels	Possible use to assist particulate filter regeneration
Water Addition	1% NOx reduction for every 1% added water	Niche markets: marine and stationary engines; centrally fueled fleets (emulsions)
Exhaust Gas Aftertreatment		
Diesel Oxidation Catalyst	High reduction of HC/CO emissions; PM conversion depends on fuel sulfur, usually limited to maximum 20-30%	Widely used on Euro 2/3 cars and on 1994 and later heavy-duty urban bus engines in the U.S.; Will remain a component of future emission control systems
NOx Adsorber Catalysts	~90% NOx reduction potential	Potential future technology for light duty engines worldwide and for heavy-duty engines in the U.S. (2007/2010)
Urea SCR Catalysts	~90% NOx reduction	Future technology for Euro 5 heavy-duty diesel engines; Currently used in stationary engines and other niche markets
Diesel Particulate Filters	70-90%+ PM emission reduction	Expected widespread use for (heavier) Euro 4 cars and heavy duty US2007 engines; Currently used in retrofit programs and voluntary diesel car applications.
Lean NOx Catalysts	NOx reduction potential of ~10-20% in passive systems, up to 50% in active systems	Uncertain; NOx reduction potential insufficient for long-term regulatory objectives
Plasma Assisted Catalysts	NOx reduction potential up to ~50%	Uncertain; NOx reduction potential insufficient for long-term regulatory objectives.

Available Diesel Retrofit Technologies

Tchnlgy	Emissions Reductions			Fuel Rqrmnts	Additional Information
	HC	PM	NOx		
Diesel Oxidation Catalyst (DOC)	50-90%	25-50%	--	500 ppm sulfur	DOC's have an established record in the highway sector and are gaining in nonroad applications. Sulfur in fuel can impede the effectiveness of DOCs; therefore, the devices require fuels with low sulfur levels. Can be combined with other technologies for additional PM and or NOx reductions.
Diesel Particulate Filter (DPF)	50-95%	>85%	--	CB-DPF – ULSD; active, non-CB-DPF – 500 ppm	DPF's use either passive or active regeneration systems to oxidize the PM in the filters. Passive filters require higher operating temperature to work properly. Filters require maintenance. Can be combined with NOx retrofit technologies.
Flow-through Filter (FTF)	50-95%	30->60%	--	500 ppm sulfur	Filtration efficiency is lower than DPF, but is much less likely to plug under unfavorable conditions, such as high engine-out PM emissions and low exhaust temperatures.
Lean NOx Catalyst (LNC) with a DPF	--	>85%	5-30%	ULSD	Verified LNCs are always paired with a DPF or a DOC.
Selective Catalytic Reduction (SCR)	80%	20-30%	80%	500 ppm sulfur	Common in stationary applications. Require periodic refilling of an ammonia or urea tank. Often used with a DOC or DPF to reduce PM emissions.
Exhaust Gas Recirculation (EGR) with a DPF	--	>85%	40-50%	ULSD	Both low-pressure and high-pressure EGR systems exist, but low-pressure EGR is used for retrofit applications because it does no require engine modifications. The feasibility of low-pressure EGR is more of an issue with nonroad equipment than on-road equipment.
Closed Crankcase Ventilation (CCV)	--	5-10%	--	500 ppm	Usually paired with a DOC or DPF.

The array of emission control methods provides the designer with building blocks which need to be chosen and combined into the emission control system, which in turn is integrated with the engine to achieve a given emission target. A system approach is necessary to develop the clean emission diesel engine. There is no miraculous "plug-in" device available which could be installed on a particular engine and effectively clean emissions. An effective emission control strategy has to combine elements of engine design with the use of appropriate fuels and exhaust aftertreatment methods.

Selective catalytic reduction (SCR) of NO_x by nitrogen compounds, such as *ammonia* or *urea*—commonly referred to as simply "SCR"—has been developed for and well proven in large-scale industrial stationary applications. The SCR technology was first applied in thermal power plants in Japan in the late 1970s, followed by widespread application in Europe since the mid-1980s. In the USA, SCR systems were introduced for gas turbines in the 1990s, with increasing potential for NO_x control from coal-fired powerplants. In addition to coal-fired cogeneration plants and gas turbines, SCR applications also include plant and refinery heaters and boilers in the chemical processing industry, furnaces, coke ovens, as well as municipal waste plants and incinerators. The list of fuels used in these applications includes industrial gases, natural gas, crude oil, light or heavy oil, and pulverized coal.[1]

SCR is the only proven catalyst technology capable of reducing diesel NO_x emissions to levels required by a number of future emission standards. Urea-SCR has been selected by a number of manufacturers as the technology of choice for meeting the Euro V (2008) and the JP 2005 NO_x limits—both equal to 2 g/kWh—for heavy-duty truck and bus engines. First commercial diesel truck applications were launched in 2004 by Nissan Diesel in Japan and by DaimlerChrysler in Europe.

SCR systems are also being developed in the USA in the context of the 2010 NO_x limit of 0.2 g/bhp-hr for heavy-duty engines, as well as the Tier 2 NO_x standards for light-duty vehicles.

The technologies and strategies being developed for the 2007/2010 heavy-duty highway diesel engine and Tier 4 nonroad diesel engine standards may be applicable stationary diesel engines provided adequate lead-time is given. The issue is to match the right technologies to the right applications. Reduction of emissions is influenced by the duty cycle of the engine.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Approach and Implementation

Contractual arrangements could be made to ensure that all trucks associated with supplies and services meet specified requirements.

[1] Cobb, D., et al., 1991. "Application of Selective Catalytic Reduction (SCR) Technology for NOx Reduction From Refinery Combustion Sources", Environmental Progress, 10, pg. 49.

Resources

1. The **Manufacturers of Emission Controls Association (MECA)** is a non-profit association incorporated in Washington, DC. MECA's mission is to provide technical information on emission control technology, thereby facilitating the establishment of strong and effective state, federal, and international air quality programs that promote public health, environmental quality, and industrial progress.

2. **Emission Control Technologies for Diesel-Powered Vehicles, Manufacturers of Emission Controls Association, December 2007:** www.dieselretrofit.org

3. DieselNet (www.dieselnet.com) provides current information about emission standards and regulations.

2 Points

Environmentally Friendly Drilling System

EFD

Attribute: Air

Credit: 2. Site Emissions

Points Available: 2

Intent

Minimize impacts to air quality due to operations at the site.

Benefits

Minimize oxides of nitrogen emissions, precursor to ozone formation, as well as particulate matter.

Requirements

1 Point

Use of clean Tier III/Type III engines for all non-road vehicles. Alternatively, ensure application of retrofit technology to non-road vehicles that are Tier II or lower.

1 Additional Point

Use of Tier IV engines for all vehicles will give a total of two points.

Potential Technologies & Strategies

Tier III/Type III engines are currently the cleanest engines that are most widely available for non-road use. Tier IV engines are being passed in between 2008 and 2015. Use of a Tier III engine results in a 39% reduction of non-methane hydrocarbon and NO_x emissions compared to a Tier II engine. In addition, Tier III/Type III engines reduce particulate matter by over 60% compared to Tier I engines.

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Tier II engines were phased in between 2001 and 2006. This standard reduced NO_x and non-methane hydrocarbons by 38%, CO emissions by 70% and particulate matter by 63%, resulting in reduced overall air emissions and improved air quality. Retrofitting older engines with EPA verified technologies can reduce the emissions and improve air quality.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Approach and Implementation

Contractual arrangements could be made to ensure that rig engines meet specified requirements.

Resources

1. Ritter, K., et al: "Application of the API Compendium to Examine Potential Emission Reduction Opportunities for Upstream Operations," SPE 80576, Presented at the SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, TX, March 10-12. 2003.

2. Goodyear, M.A., et al: "Vapor Recovery of Natural Gas Using Non-Mechanical Technology, SPE 80599, Presented at the SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, TX, March 10-12, 2003.

3. Webb, W.G.: "Vapor Jet System: An Alternative Vapor Recovery Method," SPE 25942, Presented at the SPE/EPA Exploration & Production Environmental Conference, San Antonio, TX March 7-10. 1993.

4. "Contractor Innovation Slashes Pollutants from 2-Stroke Diesel Engines on Drilling Rigs, Buses," **Drilling Contractor**, March/April 1999, pp. 10-11.

5. Ballard, H.N., et al: "An Overview of Exhaust Emissions Regulatory Requirements and Control Technology for Stationary Natural Gas Engines," SPE 24306, Presented at the SPE Mid-Continent Gas Symposium, Amarillo, TX, April 13-14, 1992.

See also Air Credit #1.

2 Points

Environmentally Friendly Drilling System

Attribute: Air

Credit: 3. Dust Suppression
Points Available: 2

Intent

Minimize impacts to air quality due to travel to/from the well site and operations at the site.

Benefits

Effective dust suppression at the well site and on roads to the site can:

- Create a safer work environment
- Reduce exposure to litigation
- Create a cleaner environment for personnel

Requirements

Two points may be obtained by submitting a dust suppression plan and implementing/documenting the plan.

Potential Technologies & Strategies

Because of the relatively short-term nature of activities, some control measures may be more cost effective than others. Wet suppression and chemical stabilization are the most common control methods.

Dust suppression techniques may be used, such as applying water or environmentally friendly dust suppression formulations, during road construction activities and throughout the operations. Also, the plan may require service vehicles to drive slowly over the roads and to adjust their speed, depending on conditions, to avoid creating a dust trail.

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Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Approach and Implementation

Develop and implement a dust suppression plan.

2 Points

Environmentally Friendly Drilling System

Attribute: Air

Credit: 4. Alternate Power
Points Available: 2

Intent

Minimize impacts to air quality due to operations at the site.

Benefits

Minimize oxides of nitrogen emissions, precursor to ozone formation, as well as particulate matter. Rigs powered by natural gas or tied to the electrical grid can provide lower cost operations, emit fewer emissions, are quieter and have a smaller surface footprint than conventional diesel powered rigs.

Requirements

1 Point

Use natural gas from the field to power electric motors to run the drill rig.

1 Additional Point

A total of two points may be obtained by connecting the drill rig to the electric grid.

Potential Technologies & Strategies

A land rig operation requires approximately 4,000 to 8,000 HP or about 3 to 6 MW. Using natural gas from the field to power electric motors to run the drill rig can reduce emissions by 90 percent compared to conventional diesel rigs.

Verification (Indicator Monitoring and Analysis)

Document the power source for the rig.

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Approach and Implementation

Natural gas micro-turbines could be used to generate electricity. In addition, a system to recover energy from the heat generated could also be employed. An analysis of the electric grid would have to be performed in order to determine if the grid could handle the rig demands. In addition, the cost to connect to the grid needs to be considered.

Considerations

Availability of field natural gas or appropriate electric grid that can handle the load along with cost to connect.

Resources

1. Verma, A., Burnett, D.B.: "Alternate Power and Energy Storage/Reuse for Drilling Rigs: Reduced Cost and Lower Emissions Provide Lower Footprint for Drilling Operations," SPE 122885, Presented at the Latin American & Caribbean Petroleum Engineering Conference, Cartagena, Colombia, May 31, 2009.

2. Lowe, D.: "Electronic Engines Drive Growth at Command Drilling," **Drilling Contractor**, September/October 1998, pp. 59-61.

2 Points

Environmentally Friendly Drilling System

EFD

Attribute: Air

Credit: 5. Green Completions
Points Available: 2

Intent

Reduce emissions of methane and other gases during completion operations.

Benefits

Minimizes the release of greenhouse gases to the atmosphere. According to the EPA, Natural Gas program, over $145 million is lost annually due to well completions and workovers that vent or flare natural gas and condensate. This is an estimated 45.5 Bcf of natural gas and 480,000 Bbl of condensate. An estimated 25.2 Bcf of natural gas can be recovered annually using green completions. According to the EPA program, green completion practices can recover 7 – 12,500 Mcf (average of 3,000 Mcf) of natural gas and 1 – 580 Bbl of condensate from each clean-up. Benefits include:

- Minimize the release of Volatile Organic Compounds (VOC's) during completions and workovers
- Sales revenue from recovered gas and condensate
- Improved relations with state agencies and public neighbors
- Improved safety
- Reduced disposal costs

Green completions reduce emissions of methane and other gases during cleanout and flowback operations before the well is placed on production. Green completions may also lead to odor reductions surrounding productions.

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Requirements

Two points may be obtained by submitting a plan to use green completion practices. Plan must be implemented by performing and documenting the use of green completion practices.

Potential Technologies & Strategies

The capital equipment may include portable separators, sand traps, and tanks. This equipment would be moved from well-to-well and can be amortized over the life of the equipment and the number of wells where the equipment is used.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Approach and Implementation

Green completions recover natural gas and condensate produced during well completions or workovers. Portable equipment is used to process gas and condensate suitable for sales. Recovered gas may be directed through a permanent dehydrator and meter to the sales line, reducing venting and flaring.

Truck or trailer mounted equipment may be used to capture produced gas during clean-up:

- Sand trap
- Three-phase separator
- If necessary, a portable desiccant dehydrator

Green completions need planning. Must have permanent equipment on-site before clean-up, including:

- Piping from wellhead to sales line
- Dehydrator
- Lease meter
- Stock tank

The sales line gas can be used for fuel and/or gas lift in low pressure wells.

Portable compressors can be used to start-up the well when reservoir pressure is low. There is, however, higher cost to amortize investment in portable equipment.

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Considerations

May not be applicable to exploration wells where a sales line is not conveniently located.

Resources

1. EPA Natural Gas Program: www.epa.gov/gasstar/documents/greencompletions.pdf

2. Natural Gas Star EPA PRO Fact Sheet No. 703.

3. Regional Air Quality Council (RAQC), *White Paper: Short-Term Ozone Reduction Strategies,* December 4, 2007.

4. Colorado Oil and Gas Association; Noble Energy, Inc.; Anadarko Petro Corporation; *Oil and Gas VOC Emissions and Controls in the DMA*, presented December 14, 2007 at RAQC meeting.

5. ENVIRON, *WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation Phase II Final Report*, September 2007.

6. ENVIRON, Buys and Associates, and IPAMS, *Development of Baseline 2006 Emissions from Oil and Gas Activity in the Denver-Julesburg Basin*, February 7, 2008.

7. Four Corners Air Quality Task Force, *Four Corners Air Quality Task Force Report of Mitigation Options*, Mitigation Option: Implementation of Reduced Emission Completions (Green Completions), November 1, 2007.

8. Coalition of Colorado's Local Governments and Environmental Groups, *Early Action Measures to Help Protect Human Health from Ozone Pollution*, November 1, 2007.

9. Newsom, V.L., Determination of Methane Emissions From Crude Oil Stock Tanks," SPE 37930 presented at the 1997 SPE/EPA Exploration and Production Environmental Conference, Dallas, TX, March 3-5, 1997.

10. Paz, R. et al, "Low Pressure Gs Gathering System: Environmental Solution for Hydrocarbon Emissions in Venezuela," Proceedings of the 4th International Petroleum Environmental Conference, San Antonio, TX September 9-12, 1997.

11. Peavy, M.A. and Braun, J.E., "Control of Waste Gas From a Thermal EOR Operation," SPE 21766 printed in *Journal of Petroleum Technology* (June 1991) 656-661.

Environmentally Friendly Drilling System

EFD

Attribute: Site

Prerequisite: 1. Regulatory Compliance

Intent

Comply with all rules and regulations governing site.

Benefits

Required by law.

Requirements

The project shall comply with all applicable regulations.

Develop and implement plan to address all local, state and federal regulations.

Potential Technologies & Strategies

The Drilling Waste Management Information System, developed and maintained by Argonne National Laboratory, is an online resource for technical and regulatory information on practices for managing drilling muds and cuttings, including current practices, state and federal regulations, and guidelines for optimal management practices.[1] See: http://web.ead.anl.gov/dwm/

Well pad construction may convert plant habitat and cause soil compaction. This could lead to direct loss of habitat, harm to plants and habitat fragmentation.

To limit the long-term impacts of essential oil and gas development on plant communities and sensitive species, industry can:

1 Veil, J.A., Gasper, J.R., Puder, M.G., Sullivan, R.G., Richmond, P.D., Fidler, B.R., Fleming, C.N., Bernier, R.F., and Jones, F.V.: 'Innovative Website for Drilling Waste Management,; SPE 80603, SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, TX, 10-12 March 2003.

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- Avoid disturbance in particularly sensitive or important plant communities
- Minimize disturbance wherever possible (e.g., using smaller well pads, fewer roads, or preventing the introduction/spread of weeds)
- Reclaim areas after disturbance.

In gas and oil drilling sites, conventional roads may disturb a few to over a hundred acres depending on the drilling site. Conventional construction of roads:

- Disturbs natural watersheds.
- Removes vegetation coverage.
- Changes the topography and soil structure
- Removes natural habitat for wildlife.
- Provides a barrier to movement and spread of plants and animals.
- Affects animal behavior.
- Provides further access to sensitive areas off the main highway.
- Creates a visual disturbance to the landscape.

Verification (Indicator Monitoring and Analysis)

Project shall have a site regulatory plan that addresses how compliance will be managed. The Plan will be submitted with the registration form. Adjustments to the plan, documentation of deviations and corrective actions may be audited.

Summary of Referenced Standards

The Endangered Species Act (ESA) regulates management of threatened and endangered wildlife species through critical habitat designations and strict controls on activities that could cause harm to protected species. The U.S. Fish and Wildlife Service administers the ESA as it applies to both private and public entities, but state wildlife agencies play a cooperative role in the listing and management of threatened and endangered species.

Approach and Implementation

This prerequisite is submitted with the registration form. The project should then implement the plan and ensure that all deviations and corrective actions are documented. There may be an audit to ensure that the project is following the submitted plan.

Considerations

The most cost-effective technologies that will enable the project to comply with the regulations should be identified and implemented.

Resources

U.S. Forest Service Plant Profiles provide information on the listed Threatened and Endangered and other critically imperiled (by NatureServe's definition) plants occurring on the national forests and grasslands in each state.

Environmentally Friendly Drilling System

Attribute: Site

Prerequisite: 2. Erosion and Sedimentation Control

Intent

Pad locations should use every method and process available to minimize environmental impacts.

Benefits

- Maintain ecosystem health.
- Community relations.

Requirements

- Develop a soil salvage plan.
- Stockpiling topsoil and installing a silt fence around the spoils pile, the location perimeter, new access roads, and all other locations as needed.
- Lining all pits at the location with an appropriate impervious material and ensuring that all surface runoff and fluids at the location are captured onsite and properly disposed of offsite.
- Exposed or disturbed soil resulting from all pad construction shall be stabilized using native grasses or other vegetation as directed.
- Maintain vegetative cover and retain soils in the construction of drilling pads, roads and facilities.
- Reclaiming the site to its original elevations using the stockpiled topsoil and replanting the entire area with native grasses or other vegetation as directed. Mulch and/or compost trees, brush and other vegetation.

Potential Technologies & Strategies

A soil salvage plan may cover the how top soil is scraped and stockpiled and may result in less dirt work in the field and a faster site restoration.

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Soil erosion may be caused by exposure of soil surfaces to rain and wind during site clearing, earth moving and excavation activities. The mobilization and transport of soil may, in turn, result in sedimentation of surface drainage networks that may result in impacts to the quality of natural water systems and ultimately the biological systems that use these waters.

Sedimentation and erosion control may include:

- Contouring and minimizing length and steepness of slopes
- Mulching to stabilized exposed areas
- Re-vegetating areas promptly
- Designing channels and ditches to control flows
- Lining steep channel and slopes
- Reducing or preventing off-site sediment transport through use of settlement ponds, silt fences and water treatment.
- Segregating or diverting clean water runoff to prevent it mixing with water containing a high solids content to minimize the volume of water to be treated prior to release
- Limiting access road gradients to reduce runoff-induced erosion.
- Providing adequate road drainage based on road width, surface material, compaction and maintenance.
- Providing effective short term measures for slope stabilization, sediment control and subsidence control until long term measures can be implemented.
- Providing adequate drainage systems to minimize and control infiltration

Recontouring is required during both interim and final reclamation. All disturbed surface areas, including the well pad, road areas, and pipeline flows, must be re-worked to sit at the original contour or blend with the original landform. Adequate erosion control will provide for site stability and generally comes with successful revegetation.

Verification (Indicator Monitoring and Analysis)

Project shall have a plan that addresses erosion and sedimentation control. The Plan will be submitted with the registration form. Adjustments to the plan, documentation of deviations and corrective actions may be audited.

Summary of Referenced Standards

On August 8, 2005, the President signed into law the Energy Policy Act of 2005. Section 323 of the Energy Policy Act of 2005 added a new paragraph (24) to section 502 of the Clean Water Act (CWA) to define the term ''oil and gas exploration, production, processing, or treatment operations or transmission facilities'' to mean ''all field activities or operations associated with exploration, production, processing, or treatment operations or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activities.''

On June 12, 2006, EPA published final amendments to the National Pollutant Discharge Elimination System (NPDES) Regulations for storm water discharges associated with oil and gas exploration, production, processing, or treatment operations or transmission facilities (71 FR 894) to implement the new provision in the Energy Policy Act of 2005. In the rulemaking, EPA acknowledged that this rule does not prohibit states from regulating oil and gas earth disturbance activities under state authority.

States may require that best practices concerning erosion and sedimentation control be used.

Considerations

The most cost-effective technologies that will enable the project to comply with the regulations should be identified and implemented.

3 Points

Environmentally Friendly Drilling System

Attribute: Site

Credit: 1. **Pre-Existing Site**
Points Available: 3

Intent

Avoid development of inappropriate site and reduce the environmental impact from the location of a drill site.

Benefits

Using an existing site may reduce the costs associated with site preparation and reclamation.

Requirements

A total of three points may be obtained by performing the following:

- Fully evaluate the possibility of the reuse of an existing drill site. Determine the financial impact on the drilling budget.
- Select and use pre-existing drill site.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

Cost effectiveness should be considered. The bottom hole location(s) and the time and ability to reach the desired location(s) from the existing drill site must be considered.

2 Points

Environmentally Friendly Drilling System

Attribute: Site

Credit: 2. Pad Drilling
Points Available: 2

Intent

Avoid development of inappropriate site and reduce the environmental impact from the location of a drill site.

Benefits

Clustered wells reduce the number of pads constructed, thereby having less surface disturbance.

Requirements

1 Point

Employ pad drilling to drill more than a single well from the drill site.

1 Additional Point

Additional point for having a minimum of eight wells on the drill site.

Potential Technologies & Strategies

Clustered wells result in fewer pads that need to be constructed, disturbing less of the surface, allowing more vegetation cover and reducing wildlife fragmentation.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

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Considerations

The number of wells and well sites that may exist per square mile is dictated by reservoir geology and productivity, mineral rights distribution, and statutory well spacing requirements.

2 Points

Environmentally Friendly Drilling System

Attribute: Site

Credit: 3. Protect and Restore Habitat
Points Available: 2

Intent

Conserve existing natural areas and restore damaged areas to provide habitat and promote biodiversity.

Benefits

An environmental concern associated with oil and gas development is the impact on wildlife habitat. The impact may be reduced by taking into consideration the protection and restoration of the habitat during the planning process.

Requirements

1 Point

Perform a site survey to identify site elements and adopt a plan concerning use and restoration of the site.

1 Additional Point

Use a spill control system and mats to limit surface disturbance.

Potential Technologies & Strategies

Evaluate the possible use of construction/roadway platform systems that could enable transport of large heavy pieces of equipment and supplies without permanent harm to the ecology.

Burying powerlines and pipelines in or next to roads reduces surface disturbances and maximizes the preservation of vegetation.

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A Zero spill system can be installed on any rig in any working environment. It attaches to any rig without tools and requires no structural modifications to the rig. The systems protect the worker and the environment by completely containing drilling fluids released in and around the rig floor when making and breaking pipe connections.

Mats may reduce the need of excavation. Once development is completed, the mats are lifted off the surface and may be reused elsewhere. Typically, vegetation has a faster recovery when mats are used. Measuring about 10 feet by 10 feet and weighing around 2,000 pounds, the mats may protect topsoil from drilling equipment and the treads of heavy trucks, leaving the root systems of plants and grasses intact so they can recover faster. The mats provide a path from roads to gas wells, so that vehicles need not come into direct contact with the soil. The mats are left in place until drilling is completed and then they may be moved to another drill site. A plastic liner below the mats may be used to trap condensation and provide moisture to the vegetation underneath it.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

Cost-effectiveness of the technologies should be considered when developing and implementing the plan.

Resources

1. Khan, F.: "Development of Environmental Operational Controls for Risk Minimization and Environmental Clearance for Onshore Drilling Operations," SPE 73949, Presented at the SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Kuala Lumpur, Malaysia, March 20-22, 2002.

2. Creasey, R., Fischer, L.: "Reduction of Footprint and Restoration of Function: An Approach to Cumulative Effects Management," SPE 86686, Presented at the Seventh SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production held in Calgary, Alberta, Canada, March 29-31, 2004.

3. Haut, R., Fischer, M.W.: "Cooperative Efforts Lead to Safer Operations," **Hart's E&P**, January 2010, pp. 32-33.

4. Clark, M., Hotby, Q.: "Prevention Technology Can Help Drilling, Service Rigs to Minimize Environmental Footprint at the Source," **Drilling Contractor**, November/December 2009, pp. 74-79.

5. Kudia, M.S., McDole, B.W.: "Managing Drilling Operations in a Sensitive Wetlands Environment," SPE 3780, Presented at the International Conference on Health, Safety & Environment, New Orleans, LA, June 9-12, 1996.

6. Smith, R.: "Environmental Issues and Solutions for Exploratory Drilling in Sensitive Areas," SPE 29704, Presented at the SPE/EPA Exploration & Production Environmental Conference, Houston, TX, March 27-29, 1995.

2 Points

Environmentally Friendly Drilling System

Attribute: Site

Credit: 4. Contractor Guidelines
Points Available: 2

Intent

Provide contractors with a descriptive tool that both educates and helps them reduce their environmental footprint while at the drill site.

Benefits

Reduce environmental impacts.

Requirements

1 Point

Publishing an illustrated document that provides contractors with information on how to reduce their environmental footprint related to the drill site.

1 Additional Point

Hold training sessions with all contractors to review the document and the strategies listed in the document.

Potential Technologies & Strategies

Site-specific environmental issues and potential risks associated with the operations should be identified, reviewed and addressed in the document. Informed planning and communication allows tasks to be consistently performed with regards to safety and the environment.

The document may include emergency procedures, spill contingency plans, waste management plans, identification of wildlife and endangered species, and other guidelines concerning reducing environmental impacts.

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Verification (Indicator Monitoring and Analysis)

A copy of the document may be requested.

Considerations

Safety should always be a priority when developing and implementing guidelines. Identifying and adopting best practices related to safety, health and the environment may reduce the potential for personal injury, safety related loses and harm to the environment.

2 Points

Environmentally Friendly Drilling System

Attribute: Site

Credit: 5. Site Restoration Plan
Points Available: 2

Intent

To restore site to as original as possible.

Benefits

Reclamation on oil and gas lands restores site stability and ecosystem functions, returning disturbed lands to their original use or use prior to disturbance, such as crop production or wildlife habitat. The benchmark for successful reclamation typically is the establishment of a native plant community that is self-sustaining and meets standards for density and forage production, and the re-contouring of all disturbed surface areas to match or blend with the original landform.

Requirements

1 Point

Reclaim the site to its original elevations using the stockpiled topsoil and replanting the entire area with native grasses or other vegetation as directed.

1 Point

Use topography to hide structure locations, use low profile structures.

Potential Technologies & Strategies

Operators on federal lands must include a reclamation plan in their surface use plan of operation to be approved by the Bureau of Land Management (BLM) or by the U.S. Forest Service (USFS). BLM and USFS expectations for a reclamation plan can be found in the Chapter 6 of the agencies' **Gold Book: Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development**. The BLM finalizes an operator's final abandonment notice, with final approval being contingent upon reclamation meeting the standards of the

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surface managing agency. Throughout the reclamation process, the operator holds responsibility for monitoring reclamation progress and ensuring its success.

In modern, environmentally friendly field developments, an operator's permit to drill usually includes a limit on the total surface area that can be disturbed at one time. Because of this restriction, interim reclamation is conducted during the construction, drilling, and well production phases of oil and gas development to ensure that surface disturbance is within the limits established in the drilling permit. During interim reclamation, land on a well site that is not being used for production but has been disturbed should be undergoing the reclamation process through recontouring, topsoil replacement, and revegetation.

Final reclamation is also required after a well is depleted or if it proves to be dry. The well must be plugged, and the well site and other areas disturbed by road or pipeline construction must be reclaimed and plant communities must be restored. The timeline for reclamation after a well is plugged varies by state.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

Cost-effectiveness of the technologies should be considered when developing and implementing the plan.

2 Points

Environmentally Friendly Drilling System

Attribute: Site

Credit: 6. Match Site/Access to Topography

Points Available: 2

Intent

Minimize impact on topography.

Benefits

Reduces visual impact and wildlife fragmentation.

Requirements

1 point

Whenever possible, use previously impacted terrain for access routes.

1 point

Build irregularly shaped drill pad to conform to natural topography.

Potential Technologies & Strategies

A road system that is planned to match site and topography may reduce the quantity of roads constructed. Plans should be carefully developed to minimize excavation and loss of habitat.

Linear roads can dissect the landscape and create a significant visual impact. Non-linear roads following the topography can use the natural landscape to shield the location of the road.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

Cost-effectiveness of the technologies should be considered when developing and implementing the plan.

1 Point

Environmentally Friendly Drilling System

Attribute: Site

Credit: 7. Avoidance of Archeological Sites

Points Available: 1

Intent

Prevent, or minimize, the disturbance of archeological sites.

Benefits

Preserve the historical, archeological or cultural aspects of the site.

Requirements

Ensure that all operations are in compliance to protect archeological and historic sites.

Potential Technologies & Strategies

State and federal regulations provide protection of archaeological and historic sites that are discovered during developments. Producers must be fully compliant with the regulations to protect the heritage of the areas where operations are located.

If, during the course of operations, any artifacts, cultural features, or other archaeological remains are discovered operations should be halted and the U.S. Forest Service should be notified so the potential significance of the material can be assessed and a possible plan for mitigation prepared.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

1 Point

Environmentally Friendly Drilling System

Attribute: Site

Credit: 8. Logistics Plan – Offsite Storage
Points Available: 1

Intent

To reduce the amount of traffic to/from the drill site. Also, to potentially reduce the size of the drill site.

Benefits

A concern of any drilling operation is the logistics of supplies and the potential impact that of the supply chain on the environment. Having a central supply location may reduce the amount of travel to and from a drill site. A central supply location would enable suppliers to minimize trips to the specific drill sites.

Requirements

Develop and implement a logistics plan that considers a centralized location for storage of equipment and supplies for various drill pads. The plan may include personnel transportation.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

Cost-effectiveness of the plan should be considered.

1 Point

Environmentally Friendly Drilling System

Attribute: Site

Credit: 9. Planting of Native Vegetation
Points Available: 1

Intent

Ensure that site is restored to original conditions.

Benefits

Native vegetation and rare plants support wildlife, the environment, and people.

Requirements

Develop and implement a plan that includes planting of native vegetation at the appropriate time of the year for the plants to become established.

Potential Technologies & Strategies

The establishment of a self-sustaining plant community is vital in marking reclamation success. Standards for revegetation on oil and gas lands vary by state but typically include a specified level of cover, density, vigor, resiliency, diversity; control of highly competitive non-native species; and freedom from noxious weeds.

There are many approved methods for re-seeding and culturing, including drilling, broadcast seeding, hydroseeding, dozer track walking, mulching, irrigating, and fertilizing. If seed fails due to drought or other extreme conditions, the surface management agency may grant the operator a delayed timeline for re-seeding until the adverse conditions have passed. They may also require additional culturing such as mulching or irrigating.

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Soil type, market availability, wildlife needs, and agency or landowner requirements should all be considered when choosing a seed mix for a site. While the surface management agency or a private landowner may approve select non-native species for reseeding, mixes composed primarily of species indigenous to the area being seeded typically are preferred or required. In some cases, the appropriate agency field office will prescribe an already determined seed mix.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The introduction of non-native species to an area is a growing concern for scientists and conservation organizations. Species that are moved to areas outside their natural distribution may establish viable populations in a short period of time, consuming or displacing populations of native species in the new habitat. While the majority of introduced non-native species will not become invasive or aggressive, those that do may proliferate and can have devastating consequences.

The potential for negative impacts from non-native species can be minimized and avoided by using native species in revegetation programs, keeping equipment clean and free of unwanted plant and animal species, and using quarantine and monitoring programs to reduce the transport of non-native species.

Environmentally Friendly Drilling System

EFD

Attribute: Waste Management

Prerequisite: 1. Waste Management Plan

Intent

Provide guidance to waste managers as they balance business needs, risk, and exposure. Increase environmental protection by reducing the potential for pollution of the site and surrounding land, water and air during the exploration and production of oil and gas.

Benefits

1. Satisfy regulatory requirements under RCRA, CERCLA, TSCA, etc.
2. Minimize waste through on-site treatment, recycling, and/or the reuse of recovered products and materials.
3. Reduce the volume and hazards of wastes generated.
4. Recycle wastes that are generated.

Requirements

Develop and implement a Waste Management Plan that includes the following information:

Part 1: Waste Management Program

Business Stream Responsibilities
Contractor/Subcontractor Responsibilities
Administrator Responsibilities
Performance Reviews
Feedback and Continuous Improvement

Part 2: Waste Minimization and Management Guidelines

Waste Minimization
Classifying Waste Handlers
Determining the Type of Waste Involved
Required Identification for Hazardous Waste Generators

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Accumulating Wastes
Preparing Wastes for Disposal, Treatment, and Recycling
Transporting Hazardous Wastes

Part 3: Waste Disposal Guidelines

Audit Process Description
Annual Audit Plan
Audit Process
Audit Protocol
Site Rating
Audit Frequency and Staffing

Part 4: Waste Management Practices

Asbestos and Transite
Bio Waste (septic tanks)
Construction Debris, Coal Tar and Asphalt, Petroleum Contaminated Materials
Contaminated Absorbent Pads/Booms - used oil, chemicals, petroleum
Contaminated Soils (metals, HC, PCB, Hg, Jet A)
Contaminated Water (salt, benzene, BTEX, etc.)
Drilling Waste and Purge Water
Effluent (tanks draws)
Oil/Water Separator Sludge
Radioactive Waste (NORM and other)
Recovered Product (Gasoline/Distillate Mixtures)
Remediation Waste (Solids)
Spent Carbon
Spill Debris
Tank Bottom Sludge
Tank Bottom Water
Used Oil
Used Solvents and Degreasers

Plan should include a management system of authorized chemicals with a storage system, safety data files and a stock-management program.

Verification (Indicator Monitoring and Analysis)

This prerequisite is submitted with the registration form. The project should then implement the plan and ensure that all deviations and corrective actions are documented. There may be an audit to ensure that the project is following the submitted plan.

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Approach and Implementation

The waste management plan described in this prerequisite is submitted with the registration form. The project should then implement the plan and ensure that actions are appropriately documented. There may be an audit to ensure that the plan was implemented.

Contamination of land should be avoided by preventing or controlling the release of hazardous materials, hazardous wastes, or oil to the environment. When contamination of land is suspected or confirmed at any time, the source of the release should be identified and corrected. Contaminated land should be managed to avoid the risk to human health and the ecology.

Adoption of the Waste Management Hierarchy of Preference endorsed in the federal Pollution Prevention Act of 1990 is the first step in focusing on waste management. Disposal is the least preferred waste management option. The preferred hierarchy is 1) source reduction, 2) recycling, 3) treatment and 4) disposal.

Shell Exploration and Production Company established a Rig Waste Reduction Pilot Project in 2001 to identify potential waste reduction strategies.[2] Their preferential hierarchy that they developed is: *reduce, reuse, recycle, recover and dispose.* The majority of the total waste stream was found to be drilling discharges and non-hazardous oilfield waste. Mud use was reduced by 20% and mud component packaging was reduced by 90% through a combination of solids control efficiency, cuttings dryer technology and bulk mixing equipment. In addition, Shell implemented a sorting, compaction and recycling process for solid waste (consumables and trash) to reduce landfill disposal.

Schlumberger has introduced a total waste management program to mitigate rising quantities of landfill waste.[3] Benefits included an overall improvement in general housekeeping that reduced health and safety exposure and a general increase in environmental awareness and concern. As a result, the recommendation is made to ensure that the operator establishes a waste management program that covers all exploration, drilling and production activities.

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[2] Satterlee, K., van Oot, E. and Whitlatch, B.: 'Rig Waste Reduction Pilot Project,' SPE 80582, SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, TX 10-12 March 2003.

[3] Lawrie, G. and Forbes, D.: 'Introducing a Total Waste Management Program,' SPE 98193, SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Abu Dhabi, U.A.E., 2-4 April 2006.

Mobil implemented a waste management program for the Hugoton field operations.[4] The waste management system decreased overall waste-related costs while improving compliance assurance and reducing potential liability. The key element was a mechanical solids control system consisting of a semi-closed loop centrifuge flocculation dewatering process that removes solids for burial on location.

A novel, new technique for effective drilling waste management is vermicomposting.[5] Vermicomposting uses worms to remediate the cuttings, converting them into a compost material that is useful as a soil enhancer. It was found that this technique not only cleans the cuttings but converts them into a valuable resource. For environmentally sensitive areas, this bioremediation technique may be applicable. It was found that the vermicompost technique, combined with environmentally friendly design of the drilling fluid, is by far the preferred treatment technique compared to thermal treatment of the cuttings.

ChevronTexaco has published ten years of lessons learned concerning biotreating exploration and production wastes.[6] They have successfully implemented bioremediation in diverse climates and in remote locations. The most common biological treatment techniques in the exploration and production industry are composting and land treatment. Landfarming and composting have been successfully used for drilling wastes.[7]

Considerations

Economic Issues – The most cost-effective technologies that will enable the project to comply with the regulations should be identified and implemented in the submitted plan.

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[4] Robb, A.J. and Beaty, T.D.: 'Waste Management and Minimization in the Hugoton Field, Southwest Kansas,' SPE 35914, International Conference on Health, Safety & Environment, New Orleans, LA, 9-12 June 1996.

[5] Paulsen, J.E., Getliff, J., and Sørheim, R.: 'Vermicomposting and Best Available Technique for Oily Drilling Waste Management in Environmentally Sensitive Areas,' SPE 86730, 7th SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Calgary, Alberta, Canada, 29-31 March 2004.

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Resources

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Environmentally Friendly Drilling System

Attribute: Waste Management

Prerequisite: 2. Pit Design Pre-site Assessment

Intent

Ensure that the pit design is appropriate to minimize potential environmental liability issues.

Benefits

Reduce potential liability and provide data for the use of onsite disposal options.

Requirements

Perform a pre-site assessment on the drill site pad, pit and receiving site areas.

Potential Technologies & Strategies

The assessment must include a Phase I ASTM standard assessment, clearance of Clean Water Act (CWA), Endangered Species Act (ESA), and National Historic Preservation Act (NHPA) related issues. In addition, the site must be tested for the following:

1) pH
2) Metals
3) Oil and Grease
4) EC (electrical conductivity)
5) SAR (sodium absorption ratio)
6) ESP (exchangeable sodium percentage)

In order to fulfill the above objectives the pad, pit and receiving site must be designed to perform the following functions:

1) Prevent waste from migrating offsite.

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2) Segregate wastes to minimize impact.
3) Prevent runoff from entering the pad, pit and receiving site.
4) Promote the use of onsite disposal options.

The criteria for approval to construct and use a reserve pit and/or reserve pit system include the following:

1) Notification
   a. Notification requirements are satisfied by an application for a drilling or work-over permit.
2) Specifications
   a. Pits will be protected from surface waters by levees or walls and by drainage ditches, where needed, and no siphons or openings will be placed in or over levees or walls that would permit escaping of contents so as to cause pollution. Authorized surface discharges of pit contents under Federal or State regulatory programs are not considered to be pollution or contamination.
   b. Liquid levels in pits will not be allowed to rise within two (2) feet of the top of pit, levees or walls. Pit levees or walls will be maintained at all times to prevent deterioration, subsequent overfill, and leakage of waste to the environment.
   c. Pits will not be used for storage of produced water, waste oil, trash and/or any other material which would increase the difficulty in closure of the pit or otherwise harm the environment. Any such material will be properly stored and disposed of according to the applicable Federal, State and/or local regulation(s).
   d. Pits will be emptied and closed in a manner compatible with all appropriate regulations (SWO LA29B). The preferred disposal options are annular injection, stabilization/reuse and offsite commercial disposal.
   e. Except where exempted, groundwater aquifer and underground source drinking water (USDW) protection for pits will be provided for by a liner along the bottom and sides of pits which has the equivalent of three (3) continuous feet of recompacted or natural clay having a hydraulic conductivity of $1x10^{-7}$ cm/s. Acceptable liners include but are not limited to:
      i. Natural liner – natural clay meeting the hydraulic conductivity requirements above.
      ii. Soil mixture liner – soil mixed with cement, clay type and/or other additives to produce a barrier which meets the hydraulic conductivity requirements above.

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iii. Recompacted clay liner – "in situ" or imported clay soils which are compacted to meet the hydraulic conductivity requirements above.

iv. Manufactured liner – synthetic material that meets the definition[8] and is equivalent or exceeds the hydraulic conductivity requirements above. Pits constructed with a manufactured liner must have side slopes of 3:1 and the liner at the top of the pit must be buried in a one (1) foot wide by one (1) foot deep trench. A sufficient excess of liner will be placed in the pit to prevent tearing when filled with waste.

Verification (Indicator Monitoring and Analysis)

Project shall perform the assessment described in this prerequisite. The plan to perform the assessment will be submitted with the registration form. Documentation of actions may be audited.

Approach and Implementation

This plan to carry out the assessment described in this prerequisite is submitted with the registration form. The project should then perform the assessment and ensure that it is appropriately documented. There may be an audit to ensure that the assessment was performed.

Considerations

Economic Issues – The most cost-effective technologies that will enable the project to comply with the prerequisite requirement should be identified and implemented.

8 Manufactured liner is defined as any man made synthetic material of sufficient size and qualities to sustain a hydraulic conductivity no greater than 1x10-7 cm/s after installation and which is sufficiently reinforced to withstand normal wear and tear associated with the installation and pit use without damage to the liner or adverse affect on the quality of the liner. The liner must meet or exceed the following standards:

Thickness	> 10 mils (.01 inches)
Breaking Strength (grab)	90 lbs. (ASTM D-751)
Breaking Strength	140 lbs (ASTM D751)
Tearing Strength	25 lbs (ASTM D-751)
Seam Strength	50 lbs (ASTM 5-751)

Resources

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A	S	WM	B	W	SL
Credit 1					

5 Points

Environmentally Friendly Drilling System

Attribute: Waste Management

Credit: 1. Drilling Fluid Handling System
Points Available: 5

Intent

Minimize the amount of drilling wastes.

Benefits

Oil and gas wells cannot be drilled without creating waste. However, with good waste management practices, the amount of waste and the toxicity of waste can be reduced. By far, the greatest volume of waste generated in the drilling process is drilled cuttings. Developing and implementing a plan to handle the drilling fluid can reduce the amount of waste generated and the associated handling and disposal requirements.

Requirements

2 Points
Establish a cuttings management plan

1 Point
Use environmentally friendly drilling fluids

1 Point
Use closed-loop mud system

1 Point
Use a thermal desorption unit to completely remove hydrocarbons from the drill cuttings

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Potential Technologies & Strategies

The overall objectives of a cutting management plan are to ensure that drill cuttings do not pose a threat to the environment, to treat and beneficially reuse the oversize fraction of sand and gravel associated with E&P drill wells, and to reduce the disposal volume of cuttings and associated costs. Included in the plan should be a step to confirm that the cuttings left after treatment will not present a potential for release of metals or other toxic substances to the environment. The cuttings management plan should include how the cuttings will be disposed.

The goal of all modern solids control systems is to reduce overall well costs through the efficient removal of drilled solids while reducing and minimizing the loss of drill fluids. The cuttings management plan should cover the selection and operation of the solids control system.

The plan should also cover the pit construction and operation. Pits used for circulation, water storage, completion, flowback, and reserve may be dug to hold fluids and solids during well development and to dispose of waste from production. Pits may be lined or unlined, and their contents may be disposed of in many ways.

Proper disposal of drill cuttings can mitigate environmental effects. Disposal of inert cuttings may possibly occur at the drill site. The cuttings management plan should cover the drill cuttings disposal.

Drilling fluids introduced in 1887 and used in the period 1887–1901 were basic mixtures of clays and water. Now they are a complex mixture of fluids, suspended or dissolved solids, polymers and chemicals, and thus require an engineered design approach to fulfill their technical performance without having any impact on the surrounding environment, ecosystems and habitats, as well as to ensure the occupational health and safety (OHS) of drilling-fluid testing and handling staff. Using environmentally friendly drilling fluid additives and systems can reduce the impact on the environment.

In a closed-loop drilling fluid system, the reserve pit is replaced with a series of storage tanks that separate liquids and solids. Equipment to separate out solids (e.g., screen shakers, hydrocyclones, centrifuges) and collection equipment (e.g., vacuum trucks, shale barges) minimize the amount of drilling waste muds and cuttings that require disposal, and maximize the amount of drilling fluid recycled and reused in the drilling process. The wastes created are typically

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transferred off-site for disposal at injection wells or oilfield waste disposal facilities.

The tanks represent an additional cost, but overall, pitless drilling may save money because there is no need to construct a pit, there is a reduction in the amount of environmental releases, and the closed-loop system may result in more efficient use of drilling fluid.

Closed-loop systems use a suite of solids control equipment to minimize drilling fluid dilution and provide the economic handling of the drilling wastes. A closed-loop system may include a series of linear-motion shakers, mud cleaners and centrifuges followed by a dewatering system. The combination of equipment typically results in a "dry" location where a reserve pit is not required, used fluids are recycled, and solid wastes can be landfarmed, hauled off or injected downhole.

The removal of hydrocarbons from drilling cuttings for environmentally acceptable disposal can be accomplished with the technique of thermal desorption. The goal of any thermal desorption technology is to produce oil-free (or ultra-low TPH) solids for disposal by distilling off the oils from the cuttings and recovering the oil to be re-used as drilling fluid

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Resources

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17. Barragan, et al, "SIC-System for Identifying Contaminants in Drilling Fluids," SPE 23625 presented at the Second Latin American Petroleum Engineering Conference, II LAPEC, of the Society of Petroleum Engineers, Caracas, Venezuela, March 8-11, 1992.

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24. Longwell III, H.J., and Akers, T.J., “Economic Environmental Management of Drilling Operations,” IADC/SPE 23916 presented at the 1992 IADC/SPE Drilling Conference, New Orleans, Louisiana, February 18-21,1992.

25. Bouse, E.E., and Carrasquero, J.E., “Drilling Mud Solids Control and Waste Management,” SPE 23660 presented at the Second Latin America Petroleum Engineering Conference, II LAPEC, of the Society of Petroleum Engineers, Caracas, Venezuela, March 8-11, 1992.

26. Tapin, T.P., and Blake, L.D., “Dewatering Technology: A Current Overview and SE Asia Applications,” SPE 23034 presented at the ASIA-Pacific Conference of the Society of Petroleum Engineers, Perth, Australia, November 4-7, 1991.

27. Halliday, W.S., et al, “Closed-Loop Operations Using Alternate Dewatering Technology,” SPE 20461 presented at the 65th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, Louisiana, September 23-26, 1990.

28. Sanders, J.M., “Minimized Hauloff While Drilling in a Zero Discharge Area,” SPE 19529 presented at the 64th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, San Antonio, Texas, October 8-11, 1989.

29. Malachosky, E., et al, “Impact of Dewatering Technology on the Cost of Drilling-Waste Disposal,” SPE 16098, *Journal of Petroleum Engineering* (June 1991) 730-736.

30. Lal, M., “Economic and Performance Analysis Models for Solids Control,” SPE 18037 presented at the 63rd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Houston, Texas, October 2-5, 1988.

31. Wojtanowicz, A.K., "Modern Solids Control: A Centrifuge Dewatering-Process Study," SPE 16098, *SPE Drilling Engineering* (September 1988) 315-324.

3 Points

Environmentally Friendly Drilling System

Attribute: Waste Management

Credit: 2. Evaporation Ponds
Points Available: 3

Intent

Eliminate evaporation ponds in order to prevent waste from entering the surrounding ecosystem.

Benefits

Reduces surface environmental footprint. Evaporation ponds sit on the surface waiting for the water to evaporate from the drill cuttings, drilling muds, or other material produced during drilling. Re-injection of wastewater, deep below potable aquifers, is one method of dealing with waste fluids, reducing the surface footprint of disturbed land.

Requirements

Three points may be obtained by developing and implementing a plan to handle water with a tank system and reinjection rather than surface evaporation ponds.

Potential Technologies & Strategies

Injection and/or reinjection wells can eliminate numerous surface water treatment, discharge, and disposal issues, thereby preventing soil and plant damage, degradation of receiving streams and aquatic life, and damages to wildlife ecosystems.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies that consider the site, location, environment and other issues should be identified and implemented.

3 Points

Environmentally Friendly Drilling System

Attribute: Waste Management

Credit: 3. Reduction of Fresh Water Needs

Points Available: 3

Intent

Minimize fresh water usage.

Benefits

May reduce the costs associated with fresh water supply needs.

Requirements

Three points may be obtained by developing and implementing a water usage plan that takes into consideration all possible reuse and recycling of fresh water used on site.

Potential Technologies & Strategies

Water is used at a drill site for many reasons in addition to the drilling fluid. There are various technologies and strategies that can be considered to reduce fresh water needs.

One way to minimize the volume of water used for rigwash is to use high-pressure/low-volume nozzles on the rigwash hose. A rigwash hose left running can contribute significantly to the volume of and the water needs for the drilling operation. If feasible, the rigwash may be collected and treated for reuse.

Improved design and operation of drilling fluid systems can also reduce the need for water. Waste minimization opportunities, such as solids control and detailed system monitoring, have been proven effective in reducing the amount of makeup water needed in a drilling operation.

Water from waste drilling fluids can be reclaimed by using mechanical or chemical separation techniques. Large bowl centrifuges, hydrocyclones, and/or chemical flocculants may be used to dewater waste drilling fluids. The reclaimed water may then be reused, thus reducing the demand on, and cost of, new water sources. Proper application of dewatering can result in a reduction of the volume of drilling waste to be managed, thus saving waste management costs, easing site closure concerns and costs, and reducing future potential liability concerns.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies that consider the site, location, environment and other issues should be identified and implemented.

3 Points

Environmentally Friendly Drilling System

Attribute: Waste Management

Credit: 4. Spill Prevention System
Points Available: 3

Intent

Reduce release of potential hazardous materials to the environment.

Benefits

Spills of any material are a possibility on drill pads, roads and areas of development activity. In some situations bioremediation of spills may be the best way to remove or reduce contamination levels in the soil.

Requirements

1 Point

To minimize the risk of oil/fuel spillage, drip pans and other devices should be used.

1 Point

Ensure that all equipment installed on the site is designed so that any effluent is caught and is not discharged directly in the environment.

1 Point

Develop and implement plan for bioremediation of spills and use of landfarming.

Potential Technologies & Strategies

Impervious containment may be used for materials stored on site.

Tanks, containers, pumps, and engines all have the tendency to leak. A good housekeeping practice that can help reduce the amount of soil and water

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contamination is to install containment devices. Containment devices may save money and may address regulatory compliance concerns. Also, they can capture valuable released chemicals that can be recovered and used. Some examples of containment include: drip pans beneath lubricating oil systems on engines; containment vessels beneath fuel and chemical storage tanks/containers; drip pans beneath the drum and container storage area; and containment, such as a half-drum or bucket beneath chemical pumps and system valves/connections. Numerous companies have implemented good housekeeping programs to reduce the amount of crude oil, chemicals, products, and wastes that reach the soil or water. These companies have found these programs to be cost effective in the long run (i.e., less lost chemical and product plus reduced cleanup costs). Also, their regulatory compliance concerns and potential future liability concerns are reduced.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies that consider the site, location, environment and other issues should be identified and implemented.

3 Points

Environmentally Friendly Drilling System

Attribute: Waste Management

Credit: 5. Cuttings Reuse

Points Available: 3

Intent

Find appropriate alternative reuse of drill cuttings.

Benefits

Reduce the environmental tradeoffs associated with cuttings handling and disposal.

Requirements

Three points may be obtained through the development and implementation of a drill cuttings recovery and reuse plan.

Potential Technologies & Strategies

Cuttings may be used for the maintenance and/or construction of drilling and production pads, roads and other necessary access infrastructure, provided they are properly treated.

Drill cuttings are made up of ground rock coated with a layer of drilling fluid. Before the cuttings can be reused, it is necessary to ensure that the hydrocarbon content, moisture content, salinity, and clay content of the cuttings are suitable for the intended use of the material.

One use of cuttings is to stabilize surfaces that are subject to erosion, such as roads or drilling pads. Not all regulatory agencies may allow road spreading.

Other possible construction applications include use in road pavements, bitumen, and asphalt or use in cement manufacture.

The DOE funded several projects to test the feasibility of treating cuttings and using them to help restore damaged wetlands in Louisiana. The results indicated that properly treated cuttings grew wetlands vegetation as well as the dredged material. Neither the U.S. Army Corps of Engineers nor the EPA have issue a permit to conduct a field demonstration of the approach.

In order to implement beneficial reuse for drilling waste, three issues needed to be dealt with: regulatory requirements; quantification and control of toxic constituents; and perception.

Reuse of a solid waste nearly always raises concerns from regulators and/or special interest groups. Often there is a perception that reuse is intended to circumvent regulatory requirements. Consequently, development of a defensible means to characterize the cuttings and meet regulatory requirements should be addressed.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies that consider the site, location, environment and other issues should be identified and implemented.

Resources

1. "Associated Waste Report: Completion and Workover Wastes," U.S. Environmental Protection Agency, January 2000.

3 Points

Environmentally Friendly Drilling System

Attribute: Waste Management

Credit: 6. Cuttings Reinjection
Points Available: 3

Intent
Dispose of the drill cuttings through reinjection.

Benefits
Eliminates future surface handling of the cuttings.

Requirements
Three points may be obtained by developing and implementing a cuttings reinjection plan.

Potential Technologies & Strategies
Drilling operations produce waste that contains a mixture of drill cuttings and drilling fluid. Re-injection of drill cuttings is attracting considerable attention as a cost effective means of complying with environmental legislation concerning disposal of drilling wastes.

There are usually two choices associated with drill cuttings injection:
- The cuttings are re-injection into a dedicated disposal well, which if newly drilled can be re-completed as a producer or water injector at a later date,
- The cuttings are re-injection through the annulus of a well drilled prior to the current well.

Drilling and cuttings disposal into the same well is possible but to date, because of well control concerns, it is not a preferred option with operators.

Several different approaches are used for injecting drilling wastes into underground formations for permanent disposal. The process involves grinding solids into small particles, mixing them with water or some other liquid to make a slurry, and injecting the slurry into an underground formation at pressures high enough to fracture the rock.

Two other injection approaches — waste injection into salt caverns at relatively low pressure, and injection into formations at pressures lower than the formation's fracture pressure (subfracture injection) — may also be used to dispose of the cuttings.

In certain geological situations, formations may be able to accept waste slurries at an injection pressure below the pressure required to fracture the formation. Wastes are ground, slurried, and injected, but the injection pressures are considerably lower than in the case of slurry injection. The most notable example of this process occurs in East Texas, where the rock overlying a salt dome has become naturally fractured, allowing waste slurries to be injected at very low surface injection pressures or even under a vacuum.

At drill pads, the first well drilled may receive wastes from the second well. For each successive well, the drilling wastes are injected into previously drilled wells. In this mode, no single injection well is used for more than a few weeks or months. Other injection programs, particularly those with a dedicated disposal well, may inject into the same well for months or years.

Slurry injection involves straightforward mechanical processes such as grinding, mixing, and pumping. The technology uses conventional oil field equipment. As a first step, the solid or semi-solid drilling waste material is made into a slurry that can be injected. The waste material is collected and screened to remove large particles that might cause plugging of pumps or well perforations. Liquid is added to the solids, and the slurry (or the oversize material) may be ground or otherwise processed to reduce particle size. Prior to injection, various additives may be blended into the slurry to improve the viscosity or other physical properties. The slurry is injected through a well into the target formation.

Under the Safe Drinking Water Act, the U.S. Environmental Protection Agency (EPA) administers the Underground Injection Control (UIC) program to regulate injection activities. States can apply to EPA to administer the UIC program, and many oil- and gas-producing states have been delegated UIC program authority.

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Slurry injection is currently permitted on a regular basis in Alaska, Texas, and California, and at offshore locations in the Gulf of Mexico and elsewhere in the world.

Some states have formal slurry injection regulations while others approve slurry injection under general administrative authority.

Several states, most notably Alaska, consider annular disposal incidental to the drilling process, and therefore do not require a UIC permit for that activity. Annular disposal in Alaska is carefully regulated by the Alaska Oil and Gas Conservation Commission with criteria similar to the UIC program. Injection cannot contaminate fresh water, cause drilling waste to come to the surface, impair the integrity of the well, or damage an actual or potential producing zone.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies that consider the site, location, environment and other issues should be identified and implemented.

Factors that influence the cost-effectiveness are:

- The volume of material to be disposed of — the larger the volume, the more attractive injection becomes in many cases. The ability to inject onsite avoids the need to transport materials to an offsite disposal location. Transportation cost becomes a significant factor when large volumes of material are involved. In addition, transporting large volumes of waste introduces safety and environmental risks associated with handling, transferring, and shipping. Transportation also consumes more fuel and generates additional air emissions.

The regulatory climate — the stricter the discharge requirements, the greater the likelihood that slurry injection will be cost-effective. If cuttings can be discharged at a reasonable treatment cost, then discharging is often the most attractive method. Regulatory requirements that prohibit or encourage slurry injection play an important role in the selection of disposal options.

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Resources

1. Veil, J., Dusseault, M.B.: "Evaluation of Slurry Injection Technology for Management of Drilling Wastes," Argonne National Laboratory, U.S. Department of Energy, W-31-109-Eng-38, May 2003.

Environmentally Friendly Drilling System

EFD

Attribute: Biodiversity

Prerequisite: 1. Species Protection

Intent

Protection of all Threatened and Endangered (T&E) species as listed on the Federal list (Endangered Species Act) and the State list.

Benefits

- Required by law.
- Maintain ecosystem health.
- Community relations.

Requirements

1. Identify T&E species within regulatory framework.
2. Perform wildlife study and identify potential impacts of energy development.
3. Conduct bird survey(s) to assess whether, and when, raptors are present.
4. Select sites for facilities that limit potential conflict with wildlife
5. Develop and implement plan to reduce impact to species. Plan should include raptor nesting site protection practices around active raptor nests during critical breeding periods. Plan should include raptor monitoring. Plan should include instructions to personnel to limit interaction with wildlife.

Potential Technologies & Strategies

Exploration and drilling activities have the potential risk of temporarily interfering with wildlife. The risk can be mitigated through proper planning and monitoring of operations.

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Interaction between operations and wildlife can vary greatly depending on the area of operation and the kind of wildlife present. There are certain times of the year when wildlife is more sensitive to external influences. Such times include migration, mating, birthing and spawning. Sensitive areas can be clearly displayed on maps and graphs. A plan should be developed that identifies boundaries concerning time and distances – establishing exclusion zones at certain times of the year.

Each proposed pad location and the surrounding area should be field surveyed for the presence of endangered, threatened, and sensitive species and other environmental concerns, including water quality issues, prior to any construction activities.

Where interaction is unavoidable, the following steps may be taken to minimize disruption:

- Scouting the sensitive areas and planning routes likely to cause least disruption.
- Staying clear of wildlife areas marked on the planning map to avoid sensitive areas.
- Banning hunting and fishing at all times.
- Instructing the crew not to intentionally harass or feed wildlife.
- Banning pets on all crew facilities.
- Reporting incidents and any significant problems with wildlife.

Conoco's St. Charles Field, located in the Aransas National Wildlife Refuge, is an example of profitable oil and gas operations co-existing with wildlife and nature.[9] The key learning from their effort is to ensure that operations are sensitive to the wildlife activities.

Verification (Indicator Monitoring and Analysis)

Implement and report on plan. The Plan will be submitted with the registration form.

9 Dumas, D.: 'St. Charles Field: A Culture of Environmental Stewardship,' SPE 66573, SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, TX, 26-28 February 2001.

Considerations

The most cost-effective technologies that will enable the project to comply with the regulations should be identified and implemented.

Environmentally Friendly Drilling System

Attribute: Biodiversity

Prerequisite: 2. Habitat Protection/Enhancement

Intent

Limit degradation of nearby wildlife habitat (quantity and quality).

Benefits

- Required by law, in some instances (Tidal Wetlands).
- Maintain ecosystem health.
- Community relations.
- Protecting other ecosystem services.

Requirements

1. Identify tidal wetlands within regulatory framework.
2. Identify other sensitive habitats near site (within 100 feet).
3. Develop plan to reduce impact to habitats.

Potential Technologies & Strategies

The fewer disturbances of ecosystems during development, the less reclamation and restoration that needs to occur. Plants may take many years to fully establish themselves after disturbances. Protection of native habitats is vital to maintain healthy ecosystems.

If the development area is on public lands, livestock grazing may occur in the area during and after development. If areas are re-vegetated during restoration, enclosing the area for a period of time may prevent some livestock from grazing and promote recovery.

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Verification (Indicator Monitoring and Analysis)

Implement and report on plan. The Plan will be submitted with the registration form.

Considerations

The most cost-effective technologies that will enable the project to comply with the regulations should be identified and implemented.

Environmentally Friendly Drilling System

Attribute: Biodiversity

Prerequisite: 3. Regulatory Requirements

Intent

Comply with applicable laws and regulations.

Benefits

Wildlife management and the protection and restoration of wildlife habitat are a complex endeavor. The development of oil and gas resources on federal, state and private lands requires adherence to both federal and state law and requires the cooperation of federal, state, and local governments as well as industry, conservation groups, landowners and many interested citizens.

Requirements

1. Review all applicable federal, state and local laws and regulations.
2. Develop and implement a regulatory plan that addresses all laws/regulations concerning biodiversity, wildlife management and habitat.

Potential Technologies & Strategies

The Endangered Species Act (ESA) is one of the most powerful of this nation's environmental laws. Passed in 1973, the act's purpose is to both conserve and restore species that have been listed by the federal government as either endangered or threatened (referred to as "listed" species). The act has several provisions that promote those goals:

- First, the act broadly prohibits anyone from doing anything that would kill, harm, or harass an endangered species. Those prohibitions even apply when listed animal species are on private lands.

- Second, federal agencies have a special obligation to ensure that they do nothing that would harm a listed species. That obligation significantly affects activities on federal lands, like grazing, logging, and mining. But it also means that a federal agency has to assess whether its actions could affect a listed species before the agency signs off on projects like a new highway or a dam on non-federal land.
- Third, the act tells federal agencies to develop plans that show how the listed species could be restored—or "recovered"—so that it no longer needs the act's protections ("delisted")

States also designate species of state concern and develop management strategies for those species to prevent a need for federal listing as threatened or endangered.

Understanding and protecting resources on a landscape scale is also important to maintaining the biodiversity.

Summary of Referenced Standards

The Secretary of the Interior has delegated most of his or her duties under the ESA to the U.S. Fish and Wildlife Service (USFWS), which is responsible for all land-based species. The Secretary of Commerce has delegated most of his or her responsibilities for sea life and salmon and steelhead ("anadromous fish" that spawn in inland waters, migrate to the ocean for several years, and then return to their spawning grounds) to the National Marine Fisheries Service (NMFS).

Endangered Species

If an animal or plant species is listed as "endangered," the species is considered to be in danger of extinction throughout a large part of its range. It is possible that a species can be listed as endangered, the highest level of protection the act provides, in one place but not another. The U.S. Fish and Wildlife Service (USFWS) maintains a list of endangered species.

Threatened Species

For a species to be listed as "threatened," there must be a significant risk that the species is going to become endangered. Threatened species have a lower risk of extinction than do "endangered" species. As a result, state and federal agencies may have some greater flexibility in how they manage a threatened species than an endangered species. The USFWS maintains a list of threatened species.

Species

Generally speaking, a "species" is a group of related plants or animals that can interbreed to produce offspring. Under the ESA, the word "species" is used more broadly to include any "subspecies" of fish, wildlife, or plants, and also any "distinct population segment" of fish and wildlife species that can interbreed.

- A "subspecies" is a subdivision of a species, which is genetically different from other subspecies and often is geographically separated. Examples of subspecies are the Mexican and the Northern Spotted Owls.
- A "distinct population segment" is not genetically different from the species as a whole, but it has very specific habitat or reproduction habits. An example of a distinct population segment is a particular group of salmon, which, after spending their formative years in the ocean, return to the same mountain stream in which they were born. Thus, the winter run of the Chinook salmon on the Sacramento River in California is endangered, and many other runs of Chinook salmon are threatened, but the spring run of Chinook up the Clackamas River in Oregon and Washington is neither endangered nor threatened

Listing

"Listing" refers to the process by which a species is formally designated as a threatened or endangered species. Currently there are more than 1,260 species listed as endangered or threatened under the ESA. Anyone can submit a petition to the federal government to have a species listed. However, that petition must include scientific information that explains why listing is necessary. The two federal agencies that receive petitions are the USFWS and the NMFS. These agencies have a year to evaluate the species for listing. Either agency can also start the process without a petition.

After evaluating the species, the agency has three options:

- It can agree that a species should be listed, that is, it concludes that the listing is "warranted" in all or a specific part of its range.
- It can decide that listing is not justified, that is "not warranted."
- It can conclude that while adding the species to the list is justified, other species have a higher priority; that is, listing is "warranted but precluded."

Regardless of what decision the agency makes, it must publish its decision in the Federal Register and explain how it reached its decision.

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Critical habitat

When the federal government lists a species as endangered, it is also supposed to identify that species' critical habitat. Critical habitat includes those areas that are important for the species' survival or recovery and which need special management. While a designated critical habitat area is not intended to include all of the potential habitat of the species, it can include habitat that is not currently occupied by the species. The federal government is required to use the best available scientific information in making a decision about critical habitat. The agency can also consider economics when deciding what areas should be designated as critical habitat, although it does not consider economic impacts when it "lists" a species.

The Secretary of the Interior is not allowed to designate critical habitat at a military site if the Secretary decides that the military site has a resource management plan in place that benefits the affected species. In advocating for this relatively new provision, the Pentagon claimed that this provision is necessary to maintain high standards of military training.

Approach and Implementation

This prerequisite is submitted with the registration form. The project should then implement the plan and ensure that all deviations and corrective actions are documented. There may be an audit to ensure that the project is following the submitted plan.

Verification (Indicator Monitoring and Analysis)

Implement and report on plan. The Plan will be submitted with the registration form.

Considerations

The most cost-effective technologies that will enable the project to comply with the regulations should be identified and implemented.

Resources

1. Endangered Species Act of 1973, 16 USC sections 1531 to 1544.

2. Endangered Species Act Regulations can be found in 50 CFR sections 17.1 to 17.23.

3 Points

Environmentally Friendly Drilling System

Attribute: Biodiversity

Credit: 1. Restoration/Interim Reclamation
Points Available: 3

Intent

To maintain site during operations and to restore site after operations in a manner that promotes biodiversity.

Benefits

Restoration is dependent on successful re-seeding of native plants. Some sites may require different re-seeding techniques in order to establish a strong plant community. There is not a single universal method of re-seeding and an analysis of each site will determine which technique is most appropriate and which will be most successful.

Requirements

1 Point

Study potential beneficial use (for example compost) of necessary cutting of trees and brush.

1 Point

Develop a well abandonment plan before the well is drilled and ensure that the plan is updated during the well's life whenever the well's configuration is changed.

1 Point

Develop an interim restoration plan that includes recontouring to original contour and landforms.

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Potential Technologies & Strategies

Well abandonment – what to do when the life of a well comes to an end – is a concern. A series of best practices has been published to reduce environmental risk associated with abandonment.[10] Operators should consider abandonment requirements during the drilling and completion planning process. An abandonment plan should be developed before the well is drilled and that the plan be updated during the well's life whenever the well's configuration is changed.

Interim restoration may enhance vegetation recovery. Rather than waiting until final restoration, the additional time may assist plant and wildlife habitats to be quickly restored. Any reconoturing of landforms during interim restoration needs to be done correctly to ensure that re-established habitats are not damaged during final restoration. Proper recontouring during interim restoration avoids repetitive dirt work, stripping, recontouring and revegetation when final restoration occurs.

Reclaiming unnecessary roads after initial production phase reduces the visual impact.

Knowledge of soil chemistry in the root zone will increase the restoration efforts. A base-line study of the predevelopment nature of the soil will be crucial to know that the soil needs to return to after development. The soil chemistry study will also be instructive for returning vegetation to the land and provide initial data for what additives might be needed to restore the soil.

A soil salvage plan can be an instructive exercise about where on the proposed well pad viable top soil exists that needs to be scraped and stockpiled. Based on the results of the soil salvage plan, less dirt work could be deemed necessary in the field. Less dirt and less top soil scraped will minimize the disturbed land and require less interim restoration and/or allow for more successful interim restoration.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

[10] Kelm, C.H. and Faul, R.R.: 'Well Abandonment – A "Best Practices" Approach Can Reduce Environmental Risk,' SPE 54344, SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, April 20-22, 1999.

Considerations

The most cost-effective technologies should be identified and implemented.

3 Points

Environmentally Friendly Drilling System

Attribute: Biodiversity

Credit: 2. Reduction of Surface Disturbance
Points Available: 3

Intent

To reduce surface disturbances in order to minimize impact on wildlife and to promote biodiversity.

Benefits

Reduces wildlife fragmentation and promotes healthy ecosystems.

Requirements

1 Point

During construction and drilling, shuttle workers to site.

1 Point

Establish centralized location for hydraulic fracturing and water delivery.

1 Point

Install systems to enable remote monitoring.

Potential Technologies & Strategies

Traffic to and from sites may be reduced by having a logistics plan that includes shuttling of works to and from a central location to the work sites.

Centralized facilities reduce the need for access to a site. Centralized fracturing pads have been shown to be successful in the Piceance Basin with access allowable to wells up to three miles away.[11]

[11] Harrison, Alan. Platts 2nd Annual Rockies Gas & Oil Conference.

Remote monitoring may reduce the amount of traffic in the field.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

3 Points

Environmentally Friendly Drilling System

Attribute: Biodiversity

Credit: 3. Erosion Prevention
Points Available: 3

Intent
Minimize the potential for soil erosion.

Benefits
Promotes biodiversity and ecosystem health.

Requirements
1 Point
Plan and install access roads to avoid erosion.

1 Point
After grading, apply seed or erosion control mats to soil.

1 Point
Armor roadway ditches and leadoff ditches with rock riprap.

Potential Technologies & Strategies
Existing roads should be used to the greatest extent practicable in order to avoid soil disturbances, to keep the length of new roads to a minimum and to minimize the erosion potential. Access roads that need to be constructed should be engineered to avoid or minimize impacts to fragile biodiversity areas. If areas cannot be avoided, then the plan should include the restoration of the area to the extent practicable. Roads should be designed by a professional engineer in such a manner to avoid concentrating overland flow of water. Roads should be designed and placed to avoid drainage areas. If drainage areas cannot be avoided, then the roads should be designed with appropriate spacing of crossing

with energy dispersion structures (i.e, armored low-water crossings). The plan should also cover the maintenance of the roads.

Roads should also be designed to avoid straight lines in order to protect the visual integrity and to take advantage of any topographical features.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

Cost-effectiveness of the technologies should be considered when developing and implementing the plan.

2 Points

Environmentally Friendly Drilling System

Attribute: Biodiversity

Credit: 4. Voluntary Offsite Mitigation
Points Available: 2

Intent
Minimize impact of development.

Benefits
Improve biodiversity and ecosystem health.

Requirements
Two points may be obtained for the development and implementation of an offsite mitigation plan that encourages biodiversity and ecosystem health.

1 Point
One point may be obtained for establishing and implementing a plan that includes passive techniques that encourages biodiversity and ecosystem health, for example, seeding of native plants and constructing topographical features.

1 Point
One point may be obtained for including more active techniques, for example, closing roads and other techniques to limit disturbance by off-road vehicles, developing and implementing efforts to reduce poaching and accidental shooting.

Potential Technologies & Strategies
A variety of techniques may be applied to reduce impacts of oil and gas operations. On occasion, the disturbance to a particular site cannot be avoided. In these instances, a voluntary offsite mitigation plan may be developed and implemented. The plan would cover how a nearby location could be enhanced

to encourage biodiversity and ecosystem health for the overall region. The plan should include the tracking of changes made to the area(s) and how the benefits to the biodiversity and ecosystem are measured.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

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A	S	WM
Credit 5		

2 Points

Environmentally Friendly Drilling System

Attribute: Biodiversity

Credit: 5. Invasive Species Prevention
Points Available: 2

Intent

Preserve health of ecosystem through the protection and restoration of native species. Prevent spread of non-native species.

Benefits

Promote ecosystem health and services.

Requirements

Receive one (1) point for performing three (3) of the following, maximum of two (2) points.

- Site Restoration – use native species to restore site
- Identify and establish no impact zones
- Clean equipment that is moved between sites to prevent transport of invasive species.
- Ensure that materials (soils, mulch, etc.) brought in to site are certified to be invasive free.
- Reseeding of disturbed habitat to prevent encroachment of invasive species.
- Identify and remove invasive species on site.

Potential Technologies & Strategies

If machinery is used in an area containing noxious weeds, either the producer's or contractors' equipment, the equipment should be cleaned by washing or air spraying. This may reduce the spread of noxious weeds outside of the contaminated area.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

2 Points

Environmentally Friendly Drilling System

Attribute: Biodiversity

Credit: 6. Restoration of Fragmented Habitat
Points Available: 2

Intent
Improve the ecosystem and biodiversity of the region.

Benefits
Improved ecosystem and biodiversity health.

Requirements
1 Point
One point may be obtained by operating in such a manner that encourages natural re-vegetation by indigenous flora and fauna and avoids the removal of vegetation, topsoil and seed source.

1 Point
One point may be obtained by developing and implementing a plan to restore surrounding areas that currently have fragmented habitat(s).

Potential Technologies & Strategies
Loops in roads can isolate and fragment habitat and should be avoided. If there are loops that can be restored, a plan may be developed and implemented. Using hand cutting, or selectively using machinery, to clear vegetation can minimize fragmentation.

Pipeline and flowline routing requires special considerations in relation to disturbances and effects. Sensitive habitats should be avoided and the route should go along existing access routes, using spatial planning workshops with relevant stakeholders to design routes. Right of ways should be restored wherever possible to encourage habitat(s).

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

2 Points

Environmentally Friendly Drilling System

Attribute: Biodiversity

Credit: 7. Reintroduction of Species, Habitat
Points Available: 2

Intent

Minimize the impact of development on native plan and wildlife species.

Benefits

Improve biodiversity and ecosystem health.

Requirements

1 Point

One point may be obtained by ensuring that a botanical expert is on site when clearing vegetation occurs. The expert should develop a pre-disturbance species composition list. Then, a restoration/revegatation plan should be developed and implemented based on the pre-disturbance species composition list.

1 Point

A second point may be obtained by ensuring that a wildlife expert is consulted and on site, if necessary, when site construction activities occur. The expert should document various topographical and other features that are conducive to wildlife habitat(s). Then, a restoration plan should be developed and implemented that would encourage the return of native wildlife.

Potential Technologies & Strategies

Techniques and strategies may be developed and implemented to reduce the impact of oil and gas development on native plant and wildlife species. Maps concerning native plants and wildlife habitats can commonly be found at local universities, the US Fish and Wildlife Service offices and elsewhere. These can be helpful in developing appropriate strategies and plans. Landowner(s) and

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land manager(s) may also be a good source of maps that may assist a botanical or wildlife habitat survey. Impacts to plants and habitats of concern may be reduced by placing temporary fencing or other barriers around the footprint of the development in order to discourage vehicles from entering sensitive habitat areas. To avoid attracting activity to rare plant and wildlife habitats and drawing attention to the areas, the edge of the development should be fenced, not the plan and wildlife habitats.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

1 Point

Environmentally Friendly Drilling System

EFD

Attribute: Biodiversity

Credit: 8. Avoidance of High Value Areas
Points Available: 1

Intent

Work with landowners to ensure that various surface areas that are of high value are minimally disturbed.

Benefits

Coexistence of energy production and land use.

Requirements

One point may be obtained by including input from on-site land manager(s) to preserve agricultural land when selecting locations for facilities.

Potential Technologies & Strategies

In developing a Surface Use Plan, consultations with the on-site land manager(s) may identify key areas of high value to current activities. Through these discussions the value of the natural capital may be recognized.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

1 Point

Environmentally Friendly Drilling System

Attribute: Biodiversity

Credit: 9. Wildlife Protection
Points Available: 1

Intent

Exploration and drilling activities have the potential risk of temporarily interfering with wildlife. The risk can be mitigated through proper planning and monitoring of operations. Interaction between operations and wildlife can vary greatly depending on the area of operation and the kind of wildlife present. There are certain times of the year when wildlife is more sensitive to external influences. Such times include migration, mating, birthing and spawning. Sensitive areas can be clearly displayed on maps and graphs.

Benefits

- Maintain ecosystem health.
- Community relations.

Requirements

To obtain one point, the following must be done:

- Establish boundaries concerning time and distances – establish exclusion zones at certain times of the year.
- Scout the sensitive areas and plan routes likely to cause least disruption.
- Stay clear of wildlife areas marked on the planning map to avoid sensitive areas.
- Ban hunting and fishing at all times.
- Instruct crews not to intentionally harass or feed wildlife.
- Ban pets on all crew facilities.
- Report incidents and any significant problems with wildlife.
- Train crews to identify wildlife.

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Potential Technologies & Strategies

Conoco's St. Charles Field, located in the Aransas National Wildlife Refuge, is an example of profitable oil and gas operations co-existing with wildlife and nature.[12] The key learning from their effort is to ensure that operations are sensitive to the wildlife activities.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

[12] Dumas, D.: 'St. Charles Field: A Culture of Environmental Stewardship,' SPE 66573, SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, TX, 26-28 February 2001.

1 Point

Environmentally Friendly Drilling System

Attribute: Biodiversity

Credit: 10. Habitat Enhancement
Points Available: 1

Intent

Manage site in order to minimize effects on wildlife.

Benefits

Promotes biodiversity and ecosystem health.

Requirements

One point may be obtained by developing and implementing a habitat mitigation plan that includes enhancements to the area that encourages biodiversity and improves wildlife mortality rates.

Potential Technologies & Strategies

Surface disruptions, for example, light, sound, roads, traffic, etc. may adversely impact wildlife. The habitat mitigation plan should be developed in consultation with a biologist that is familiar with the wildlife native to the area of interest. Enhancements may include reseeding of areas with native plants and constructing topographical features that encourage wildlife populations.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

Resources

1. Baizan, R.M., Broucke, A.: "Water Runoff Management: A Joint Operator/Drilling Contractor Approach," SPE 27183, Presented at the Second International Conference on Health, Safety & Environment in Oil & Gas Exploration & Production, Jakarta, Indonesia, January 25-27, 1994.

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Environmentally Friendly Drilling System

Attribute: Water

Prerequisite: 1. Stormwater Management Plan

Intent

Limit disruption of natural hydrology by managing stormwater runoff.

Benefits

Stormwater includes any surface runoff and flows resulting from precipitation, drainage or other sources. Typically stormwater runoff contains suspended sediments, metals, petroleum hydrocarbons, Polycyclic Aromatic Hydrocarbons (PAHs), coliform, etc. Rapid runoff, even of uncontaminated stormwater, also degrades the quality of the receiving water by eroding stream beds and banks. In order to reduce the need for stormwater treatment, a stormwater management plan should be developed and implemented.

Requirements

- Develop and implement a stormwater management plan that prevents discharge of stormwater runoff.
- Use acceptable best management practices to eliminate sources of contaminants and to remove pollutants from stormwater runoff.

Potential Technologies & Strategies

A water runoff management program may help to control discharges of waste water to the environment.[13] The program should include collection ditches/berms around all areas and equipment that could discharge contaminated water. An incentive scheme could also be a part of the program

[13] Baizin, R.M. and Broucke, A.: 'Water Runoff Management: A Joint Operator/Drilling Contractor Approach,' SPE 21783, Second International Conference on Health, Safety & Environment in Oil & Gas Exploration & Production, Jakarta, Indonesia, 25-27, January 1994.

with a bonus or penalty based on the volume of water discharged and the hydrocarbon content of the discharged water.

The stormwater program should monitor potential sources of pollution including transport of chemicals and materials, fueling, outdoor storage of chemicals and materials, produced water, drilling fluids, erosion from well pads, roads, and pipelines, leaks and spills, and construction.

The following principles should be applied:

- Stormwater should be separated from process and sanitary wastewater streams in order to reduce the volume of wastewater to be treated prior to discharge.
- Surface runoff from process areas or potential sources of contamination should be prevented.
- Runnoff from process and storage areas should be segregated from potentially less contaminated runoff.
- Runoff from areas without potential sources of contamination should be minimized (e.g., minimize the area of impermeable surfaces) and the peak discharge rate should be reduced.
- Where stormwater treatment is deemed necessary to protect the quality of receiving water bodies, priority should be given to managing and treating the first flush of stormwater runoff where the majority of potential contaminants tend to be present.
- When water quality criteria allow, stormwater should be managed as a resource, either for groundwater recharge or for meeting water needs within the development area.
- Oil water separators and grease traps should be installed and maintained as appropriate at refueling facilities, workshops, parking areas, fuel storage and containment areas.
- Sludge from stormwater catchments or collection and treatment systems may contain elevated levels of pollutants and should be disposed in compliance with local regulatory requirements, in the absence of which disposal has to be consistent with protection of public health and safety, and conservation and long term sustainability of water and land resources.

Verification (Indicator Monitoring and Analysis)

Implement and report on plan. The Plan will be submitted with the registration form.

Considerations

The most cost-effective technologies that will enable the project to comply with the regulations should be identified and implemented.

Environmentally Friendly Drilling System

Attribute: Water

Prerequisite: 2. Water Management Plan

Intent

To protect and preserve the natural condition of the water cycle in the region and to reduce the amount of fresh water used on site.

Benefits

Reduces logistics of water requirements.

Requirements

Develop and implement a water management plan that includes, for example, a freshwater pond that limits contact with live water bodies. Plan should include reuse of water with ongoing drilling and completions to reduce need for new fresh water. Plan should address the Clean Water Act and other regulations.

Potential Technologies & Strategies

Avoid development activities within 500 feet of surface drinking water sources for a distance of five miles upstream of public water supply intakes. Development activities may have the potential to contaminate water with silt, chemicals and other by-products. Keeping activities farther than 500 feet from surface drinking water sources for a distance of five miles upstream of public water supply intakes may protect drinking water quality.

The essential elements of a water management plan include:

- Identification, regular measurement and recording of principal flows.
- Definition and regular review of performance targets, which are adjusted to account for changes in major factors affecting water usage.
- Regular comparison of water flows with performance targets to identify where action should be taken to reduce water use.

- Water measurement (metering) should emphasize areas of greatest water use.

Verification (Indicator Monitoring and Analysis)

Implement and report on plan. The Plan will be submitted with the registration form.

Considerations

The most cost-effective technologies that will enable the project to comply with the regulations should be identified and implemented.

4 Points

Environmentally Friendly Drilling System

Attribute: Water

Credit: 1. Water Usage Tracking
Points Available: 4

Intent

Reduce the amount of water used along with the amount of waste water that is generated.

Benefits

Reduces the cost of water handling and treatment. Reduces the impact on the environment.

Requirements

1Point

Develop and implement a water sourcing/use/discharge survey that includes knowledge of the locations, routes and integrity of supply/drainage/discharge systems and points.

1 Point

Plan and implement the segregation of liquid effluents principally along industrial, utility, sanitary and stormwater categories, in order to limit the volume of water requiring specialized treatment. Characteristics of individual streams may also be used for source segregation.

1 Point

Identify opportunities to prevent or reduce wastewater pollution through such measures as recycle/reuse within the development area.

1 Point

Assess compliance of wastewater discharges within the applicable discharge standard and water quality standard (for reuse, for example, for irrigation).

Potential Technologies & Strategies

Baseline hydrology studies can assist in the planning of water usage at the site. Working with the community to understand risks associated with the management of the watershed and its protection during operations will help to ensure that environmental impacts can be minimized. A program to characterize watershed hydrologic systems may include:

- Identifying key surface discharge and storage features: streams, springs, lakes, ponds, as monitoring stations for the measurement of discharge and water quality parameters
- Delineating and constructing groundwater monitoring wells to characterize groundwater hydrology
- Establishing surface water and groundwater baseline hydrological conditions through sampling and analysis of the inventoried features
- Conducting hydrological field reconnaissance and mapping that will contribute to conceptual flow model development
- Conducting special hydrochemistry studies to support watershed characterization.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

3 Points

Environmentally Friendly Drilling System

Attribute: Water

Credit: 2. Setbacks from Streams/Sources
Points Available: 3

Intent

Protect fresh water sources.

Benefits

Reduce impact of the environment.

Requirements

1 Point

Inform all stakeholders that have water wells, streams, wetlands, or other water sources within 1,000 feet of the proposed operation.

1 Additional Point

Inform all stakeholders that are within 500 feet of 5,000 feet downstream of the operation of any stream that is within 1,000 feet of the proposed operation.

1 Additional Point

Hold a stakeholders meeting will all stakeholders identified to discuss the operation, any risk to the fresh water sources and all risk mitigation efforts that are planned. Discuss with stakeholders how they can assist to ensure that risks are minimized.

Potential Technologies & Strategies

Typically, state rules and regulations require setbacks from municipal water wells, surface water bodies and streams. A meeting with stakeholders could identify what water quality parameters are important to them, enabling these parameters to then be monitored during the operation. Stakeholders may be concerned about cumulative impacts on the environment that multiple projects may have. While any one project might do minimal damage to a water source, the cumulative impact from several projects may cause damage.

Stakeholders may be knowledgeable of sensitive headwaters, floodplains and riparian areas, wetlands, exceptional value and high quality streams and areas that may be home to threatened or endangered species. Operations should work with the stakeholders to ensure that risks are identified and minimized.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

2 Points

Environmentally Friendly Drilling System

Attribute: Water

Credit: 3. Reduce Water Usage
Points Available: 2

Intent

Reduce the volume of water used onsite. Efficiently use the water that is necessary to carry out operations.

Benefits

Reduce/mitigate environmental impact.

Requirements

1 Point

Develop and implement a water use efficiency program to reduce the amount of water used.

1 Point

Develop and implement process to reduce the use of hazardous materials that could increase water treatment requirements.

Potential Technologies & Strategies

There are four basic ways to supply fresh water used in operations:

- Surface water
- Ground water
- Municipal sources
- Recycled water

Mobile water purification units that may be fueled by produced natural gas may be used to treat the wastewater stream for reuse. The use of high efficiency mud treatment systems or closed-loop mud systems can reduce the amount of water required onsite.

Innovative solutions that expand water resource options for the region should be considered. For example, wastewater from other nearby industries may be an option for the supply of water needed for operations.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

2 Points

Environmentally Friendly Drilling System

Attribute: Water

Credit: 4. Reuse of Water/Fluids
Points Available: 2

Intent

Reclaimed water may not be clean enough for potable water sources, however, there may be a use for the water.

Benefits

Reduce overall water needs of the region.

Requirements

Two points may be obtained by reusing reclaimed water within the region.

Potential Technologies & Strategies

Economic development and the increase in population in a region may place an increased demand for the amount of water required to support regional growth. Finding innovative solutions by working with community stakeholders to identify water needs and usage may lead to novel ways to reuse reclaimed water.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

Resources

1. McKay, H. et al, "Minimizing Drilling Fluid Waste Discharges While Drilling an Arctic Exploratory Well," SPE 21765 presented at the Western Regional Meeting, Long Beach, California, March 20-22, 1991.

2. Malachosky, et al, "Impact of Dewatering Technology on the Cost of Drilling-Waste Disposal," SPE 19528, *Journal of Petroleum Technology* (June 1991) 730736.

3. Nordquist, D.G. and Faucher, M.S., "A Case History of Dewatering and Recycling Sump Drilling Mud on 141 Wells in the Midway Sunset Field, California," IADC/SPE 17246 presented at the 1988 IADC/SPE Drilling Conference, Dallas, Texas, February 28- March 2, 1988.

4. Whitney, P.M., and Greer, C.R., "Evaluation and Comparison of Closed-Loop Wash-Water Systems," SPE 23378, Presented at the First International Conference on Health, Safety and Environment, The Hague, The Netherlands, November 10-14, 1991.

2 Points

Environmentally Friendly Drilling System

Attribute: Water

Credit: 5. Recycling of Water/Fluids
Points Available: 2

Intent

Reduce overall water needs onsite.

Benefits

Reduce the amount of water that must be transported to the site.

Requirements

Two points may be obtained by recycling water/fluids onsite. A plan should be developed and implemented that demonstrates effective strategies to recycle water/fluids onsite. A target of having 30% of the water used on site being supplied by recycling may be doable.

Potential Technologies & Strategies

A typical 50,000 person city uses approximately 238,100 barrels of water per day. A hydraulic fracturing operation (in the Bakken formation) uses up to approximately 10 percent of this value, about 12,000 to 23,800 gallons. In the Marcellus Shale operations, typically 14,000 barrels of water may be recycled from a hydraulic fracturing treatment. Reclaiming and recycling water onsite can lower the environmental impact of the operations.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

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Considerations

The most cost-effective technologies should be identified and implemented.

1 Point

Environmentally Friendly Drilling System

Attribute: Water

Credit: 6. Monitor Nearby Surface Waters
Points Available: 1

Intent
Ensure water quality of surrounding surface and ground water is not impacted by the development.

Benefits
Reduce/mitigate environmental impact.

Requirements
One point may be obtained by:

- Performing baseline study of water quality and chemistry of surrounding surface and ground water.
- Monitoring the water quality and chemistry of surrounding surface and ground water during the development.

Potential Technologies & Strategies
Baseline studies of water sources surrounding sites are critical to understand sources of contamination, if contamination occurs during the time of operations. For example, if an algae formation occurs in a surface water source (stream or lake), having a baseline study may assist in understanding how the causes for the algae formation.

Recycling water onsite reduces the total amount of water consumed and reduces the expense associated with hauling wastewater/fluids from a site. Often, it may be more economical to treat wastewater/fluids for recycling onsite than haul it away to disposal wells.

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Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

Resources

1. Cowthran, J.L.: "Technology Used to Improve Drilling Performance and Primary Cementing Success in Katy Field," SPE 10956, Presented at the 57th Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers, New Orleans, LA, September 26-29, 1982.

2. Chaney, M.L.: "Back to the Basics: Planning the Operations for Drilling a Well," IADC/SPE 19930, Presented at the 1990 IADC/SPE Drilling Conference, Houston, TX, February 27 – March 2, 1990.

1 Point

Environmentally Friendly Drilling System

Attribute: Water

Credit: 7. Pressure Testing of Surface Casing
Points Available: 1

Intent

Prevent interaction between groundwater and subsurface hydrocarbons must be prevented.

Benefits

Minimizes probability of contaminating fresh water zones.

Requirements

One point may be obtained by planning and implementing an appropriate surface casing program that includes pressure testing.

Potential Technologies & Strategies

Proper casing of the drill hole can keep water from hydrocarbon layers and hydrocarbons from the water layer. The program should include appropriate well logging to determine aquifer depths.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

Environmentally Friendly Drilling System

Attribute: Societal

Prerequisite: 1. Community Engagement

Intent

Conduct all business in a way that that will not endanger public health.

Benefits

Minimize the effects on the local community.

Requirements

- Engage community early and often in discussions concerning energy development.
- Reach a consensus with community leaders concerning location of facilities that may potentially be visible from public places.
- Develop and implement plan to support regional economic development to attract diverse businesses to the area. Work with tax assessors to ensure accurate taxes are collected.
- Work with community leaders to develop and implement measures to reduce traffic safety hazards.
- Work with community leaders to develop and implement community wide drug and alcohol programs that include screenings, counseling and education.
- Develop and implement a safety and health plan that includes all workers and the surrounding community.

Potential Technologies & Strategies

The oil and gas industry has published various techniques to help manage exploration and production activities in sensitive social environment and ecosystems. Total, for example, has involved local communities and other stakeholders such as NGOs and governmental bodies.[14] They determined that successful solutions involved close communication and educational activities, reaching out to the various stakeholders that may be affected by the activities.

Columbia Natural Resources drilled a well on the football field of the University of Charleston, within sight of the West Virginia State Capitol.[15] The major hurdle was cooperating with a neighborhood that was as close as 501 feet from the wellbore. An observation tent was erected on-site for public viewing, an action that proved to be very much accepted by the residents. Four critical considerations were recommended in their report:

1. Evaluate the drillsite's geotechnical situation to minimize the likelihood of a surface collapse.
2. Work the logistics – figure out how to get all of the consumables for the project to and from the location in the least disruptive way and how to use them on location in the safest possible manner.
3. Research the laws, ordinances and regulations and maintain the highest standards for the community.
4. Strive to make and keep positive relations with the public.

The safety and health plan may include the following items:

- Disclosure of all chemicals used during all operations
- Use of nontoxic alternatives for all lubricants
- Use of nontoxic alternatives for hydraulic fracturing
- Use of Job Safety Assessment forms
- Development and implementation of a Stop-work card program
- Maintenance and testing program for blowout prevention equipment
- Setbacks for well sites and other production facilities
- Spill reporting procedures
- Monitoring procedures
- Leak detection and repair programs

[14] Suripno, S., Hajib, M. and Asmaradewi, G.: 'Management of Oil & Gas Exploration and Production in Sensitive Social Environment and Mangrove Ecosystem,' SPE 86578, 7th SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Calgary, Alberta, Canada, 29-31 March 2004.

[15] Grey, J.E. and Spady, D.W.: 'Minimizing Environmental Impact: Exploration and Production on an Urban University Campus,' SPE 94414, SPE/EPA/DOE Exploration and Production Environmental Conference, Galveston, Texas, 7-9 March 2005.

Verification (Indicator Monitoring and Analysis)

Implement and report on plan. The Plan will be submitted with the registration form.

Considerations

The most cost-effective technologies should be identified and implemented.

Resources

1. "The Rifle, Silt, New Castle Community Development Plan: A Collaborative Planning Document Between the RSNC Defined Area Residents, Antero Resources Corp. and Galaxy Energy," A Project of the Grand Valley Citizens' Alliance, January 1, 2006.

Environmentally Friendly Drilling System

Attribute: Societal

Prerequisite: 2. Communication Plan

Intent

Establish a means of communication among all stakeholders.

Benefits

Develops relationships among all stakeholders.

Requirements

Develop a communication plan that includes:

- Engaging land manager(s) and landowner(s) concerning plans to construct new facilities.
- Developing and implementing a transparent process concerning making decisions about land use and land improvements.
- Being transparent about changes in the program.
- Traffic safety.

Potential Technologies & Strategies

Traffic safety should be promoted during the course of all operations. Prevention and control of traffic related injuries and fatalities should include the adoption of safety measures that are protective of workers, the community and all road users. Road safety initiatives proportional to the scope and nature of the operations may include:

- Emphasizing safety among drivers
- Improving the driving skills and requiring licensing of drivers
- Avoiding overtiredness of drivers
- Regular maintenance of vehicles
- Minimizing pedestrian interaction with vehicles

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- Collaborating with the community to improve signage, visibility and overall safety of roads.
- Collaborating with the community on education about traffic and pedestrian safety.
- Coordinating with emergency responders to ensure that appropriate first aid is provided in the event of accidents.
- Locating associated facilities close to operations and arranging worker bus transportation to minimize external traffic.

During operations, noise and vibration may be caused by the operation of equipment, transportation of equipment and other activities. The community plan may include measures such as:

- Planning activities/operations that have the greatest potential to generate noise/vibrations so that they occur during periods of the day that will result in the least disturbance.
- Using noise control devices, such as temporary noise barriers and deflectors and exhaust muffling devices for combustion engines.
- Avoiding or minimizing transportation through community areas.

Verification (Indicator Monitoring and Analysis)

Implement and report on plan. The Plan will be submitted with the registration form.

Considerations

The most cost-effective technologies should be identified and implemented.

5 Points

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 1. Public Outreach
Points Available: 5

Intent

Manage exploration, drilling and production activities in sensitive social environment and ecosystems.

Benefits

Community relations – make and keep positive relations with the public.

Requirements

One point may be obtained by:

- Evaluating the drillsite's geotechnical situation to minimize the likelihood of a surface collapse.
- Researching the laws, ordinances and regulations in order to maintain the highest standards for the community.

1 Point

Develop and implement a logistics plan to transport all consumables for the project to and from the location in the least disruptive way and how to store and use them on location in the safest possible manner.

1 Point

Develop and implement a public interaction plan, including a communication process that keeps the public informed of planned activities and progress.

1 Point

Develop and implement an emergency response plan that includes communication with the public.

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1 Point

Develop and implement a site visitation plan that enables the public to be informed of operations.

Potential Technologies & Strategies

The oil and gas industry has published various techniques to help manage exploration and production activities in sensitive social environment and ecosystems. Total, for example, has involved local communities and other stakeholders such as NGOs and governmental bodies.[16] They determined that successful solutions involved close communication and educational activities, reaching out to the various stakeholders that may be affected by the activities.

Columbia Natural Resources drilled a well on the football field of the University of Charleston, within sight of the West Virginia State Capitol.[17] The major hurdle was cooperating with a neighborhood that was as close as 501 feet from the wellbore. An observation tent was erected on-site for public viewing, an action that proved to be very much accepted by the residents.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

[16] Suripno, S., Hajib, M. and Asmaradewi, G.: 'Management of Oil & Gas Exploration and Production in Sensitive Social Environment and Mangrove Ecosystem,' SPE 86578, 7th SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Calgary, Alberta, Canada, 29-31 March 2004.

[17] Grey, J.E. and Spady, D.W.: 'Minimizing Environmental Impact: Exploration and Production on an Urban University Campus,' SPE 94414, SPE/EPA/DOE Exploration and Production Environmental Conference, Galveston, Texas, 7-9 March 2005.

2 Points

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 2. Noise Control
Points Available: 2

Intent

Reduce the impact of noise.

Benefits

Noise prevention and mitigation measures should be applied where predicted or measured noise impacts from a site exceed applicable noise level guidelines.

Requirements

1 Point

Work with community leaders to identify noise management plan. This may include the construction of sound/safety walls.

1 Point

Collect noise level readings and take needs of the community into consideration when designing and constructing facilities.

Potential Technologies & Strategies

Topography could be used to minimize noise. Planned development can locate facilities at significant distance from community areas or can use existing topography to reduce noise generated. A plan of development should consider the location of topographical features and areas that are inhabited or used by communities.

Sound barriers may be used to reduce the noise transmitted from a site. Noise reduction mufflers may also reduce the noise associated with the development.

The preferred method for controlling noise from stationary sources is to implement noise control measures at the source. Noise reduction options that may be considered include:

- Selecting equipment with lower sound power levels.
- Installing suitable mufflers on engine exhausts and compressor components.
- Installing silencers for fans.
- Installing acoustic enclosures for equipment casing radiating noise.
- Installing acoustic barriers without gaps in order to minimize the transmission of sound through the barrier. Barriers should be located as close to the source or to the receptor location to be effective.
- Installing vibration isolation for mechanical equipment.
- Limiting the hours of operation (if possible) for specific pieces of equipment or operations, especially mobile sources operating through community areas.
- Taking advantage of the natural topography as a noise buffer.
- Developing a process to record and respond to complaints.

No one should be exposed to a noise level greater than 85 dB(A) for a duration of more than 8 hours per day without hearing protection. In addition, no unprotected ear should be exposed to a peak sound level (instantaneous) of more than 140 dB(C).

Verification (Indicator Monitoring and Analysis)

Noise monitoring may be carried out for the purposes of establishing the existing ambient noise levels in the area of the proposed site, or for verifying operational phase noise levels.

Noise monitoring programs should be designed and conducted by trained specialists. Typical monitoring periods should be sufficient for statistical analysis and may last 48 hours with the use of noise monitors that should be capable of logging data continuously over the time period, or hourly, or more frequently, as appropriate.

Considerations

The most cost-effective technologies should be identified and implemented.

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2 Points

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 3. Training of Local First Responders

Points Available: 2

Intent

Ensure that the community is prepared for any type of emergency that may result from the operations.

Benefits

Improved safety for all.

Requirements

1 Point

Develop and implement plan to train local emergency medical service personnel on issues that may arise during operations.

1 Point

Provide financial support to local public health service providers that could address key public health issues.

Potential Technologies & Strategies

Training of local emergency personnel can ensure that the community knows what to do in any given situation. First responders at the operations level are personnel who are involved in an initial response for the purpose of protecting people, property and the environment from hazardous substances. They should be trained to respond defensively, instead of actually trying to stop the release at the source. Training should include:

- Knowledge of basic hazards and risk assessment techniques.
- Ability to select and use the proper PPE.

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- Understanding basic hazardous material terms.
- Ability to recognize hazardous materials that are present/involved in an emergency.
- Ability to perform basic control, containment and/or confinement operations.
- Ability to implement basic decontamination procedures.
- Understanding relevant standard operations procedures and termination procedures.
- Understanding when additional resources are needed for the response and to make appropriate notifications.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

2 Points

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 4. Remote Alarms for Toxic Releases
Points Available: 2

Intent

Prevent or minimize consequences of catastrophic releases of toxins.

Benefits

Reduce/mitigate environmental impacts.

Requirements

1 Point

Install air quality monitors.

1 Additional Point

Include alarms when toxic substances are detected.

Potential Technologies & Strategies

A written plan of action regarding the catastrophic release of toxins should be developed and made available to the community. The plan should include safety information to enable the understanding of hazards posed by the operations. The plan may include toxicity information, permissible exposure limits, corrosivity data, and other information as applicable.

A hazard analysis may be performed to identify likely potential for catastrophic consequences and to identify engineering and administrative controls applicable to the hazards. Operating procedures that provide clear instructions for responding to alarms should be documented.

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Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

2 Points

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 5. Emergency Management Plan
Points Available: 2

Intent

Encourage positive community relations by ensuring that the community is aware of potential emergency situations.

Benefits

Positive community relations.

Requirements

Two points may be obtained by developing and implementing an Emergency Management Plan that includes engaging the community. The Emergency Management Plan should be a set of scenario-based procedures to assist emergency responders during real life emergencies as well as training exercises. The plan should include an assessment of local support capabilities.

Potential Technologies & Strategies

Any spill or release may threaten or impact the health and safety of the public. When such incidents occur, steps to remediate the impacted area must be undertaken.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

2 Points

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 6. Dispute Resolution Plan
Points Available: 2

Intent

Encourage good communication and the development of good working relationships.

Benefits

Promotes good relationships with landowners.

Requirements

1 Point

Develop a dispute resolution plan that is agreed to with all landowners.

1 Additional Point

Include in the agreement a selected mediator/attorney that would handle any dispute and agree on how the initial costs would be covered.

Potential Technologies & Strategies

Litigation is complicated and expensive. Having a dispute resolution plan in place among stakeholders can promote good working relationships among all parties. Working together prior to operations, a system through which complaints may be made and a process by which complaints may be resolved can be developed and agreed to. Because industry and the community have both participated in the development and design of the plan and have voluntarily agreed to participate in the plan's implementation, few complaints may result.

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A complaint tracking system should be included in the plan. The tracking system should be designed to enable the public to track how complaints are resolved.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

2 Points

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 7. Land Use Plan
Points Available: 2

Intent

Develop a land use plan that is agreed to with all stakeholders.

Benefits

Promotes good relationships with landowners.

Requirements

1 Point

Hold a workshop with all stakeholders that results in an agreed land use plan.

1 Additional Point

Based on the land use plan, establish land use agreements with all landowners.

Potential Technologies & Strategies

A workshop with all stakeholders could assist in documenting the condition of the operations site, including vegetation health, road condition, fencing, water quality/quantity, etc. The workshop could also determine possible impacts and items that are important to landowners and other stakeholders that may be important and may be incorporated into a surface use agreement.

A clear understanding of the social context of an area, including information about historic claims and established customary entitlement of indigenous people, should be obtained early on in a development. Land use agreements may include establishing protected areas to prevent encroachment on traditional lands. Nature preserves may protect cultural identify key to an area.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

1 Point

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 8. Landowner Indemnification

Points Available: 1

Intent

Protect the landowner(s) against any claims for loss, damage or injury that happens on the property from operations.

Benefits

Promotes good relationships with landowners.

Requirements

Include landowner indemnification in an agreed surface use agreement.

Potential Technologies & Strategies

An indemnification clause should address all possibilities, including situations such as someone tripping over equipment, contamination of a neighbor's or the landowners water well, or an explosion caused by the operation. Also, since litigation is expensive, the indemnification clause should include a duty to defend so that the operating company is obligated to hire an attorney for the landowner(s) and pay all other costs and expense of litigation.

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

1 Point

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 9. Water Well Mitigation Agreement
Points Available: 1

Intent

Ensure that water well(s) belonging to the landowner(s) and neighbors are not adversely impacted by operations.

Benefits

Promotes good relationships with landowners.

Requirements

Develop a water well mitigation agreement that is accepted by the landowner(s).

Potential Technologies & Strategies

A workshop may be held with all affected stakeholders located within a half mile of the potential impact of operations. The workshop may result in identifying the issues that can be addressed in a water well mitigation agreement. The mitigation agreement may provide for supplementation or replacement of water from any natural spring, stream or water well that may be adversely affected by operations, as agreed to in the workshop. Mitigation agreements are typically intended to address the reduction or loss of water resources and may exclude mechanical, electrical or similar loss of productivity not resulting from a reduction in the amount of available water.

Mitigation agreements may also address testing and monitoring for the presence of methane or other constituents in the water source(s).

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

1 Point

Environmentally Friendly Drilling System

Attribute: Societal

Credit: 10. Surface Use Agreement

Points Available: 1

Intent

Obtain community involvement and agreement concerning development activities.

Benefits

Promotes positive relations with community.

Requirements

One point may be obtained by developing and implementing a Surface Use Agreement, including the adoption of an environmental mission statement concerning exploration and production activities. Ensure that expectations concerning site remediation and restoration are clearly stated.

Potential Technologies & Strategies

When development occurs on private land, the production company should develop a surface use agreement with the landowner(s). The agreement may cover the placement of infrastructure, location or roads and development schedule.

A surface use agreement may be negotiated at the same that as the mineral lease. Items that may be included in a surface use agreement include:

- Gathering of baseline water quality and quantity data
- Disclosure of the quantity and quality of water that may be discharged or re-injected.

- Repair/mitigation of damage/disruption to irrigation
- Development/operation plans that include locations of roads, wells, etc.
- Proposal of potential development alternatives (siting of well pads, roads, etc.)
- Indemnification bond
- Noise suppression
- Air quality monitoring and emissions reduction equipment
- Reclamation conditions
- Removal of hazardous materials, closing and restoring waste pits
- Breach of contract provisions

Verification (Indicator Monitoring and Analysis)

Have appropriate documentation available if an audit is performed.

Considerations

The most cost-effective technologies should be identified and implemented.

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Overview: The Environmentally Friendly Drilling Systems Program and Disappearing Road Competition

Texas A&M University GPRI
Houston Advanced Research Center (HARC)

Partially Funded
by U.S. DOE Grant DE-FC22-05NT42658
&
DR sponsored by Halliburton

TEXAS A&M THE HAROLD VANCE DEPARTMENT OF PETROLEUM ENGINEERING

David B Burnett
burnett@pe.tamu.edu
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Denver IPAM, 2008

Low Impact Surface Operations

Can you use GIS based hydrologic models developed for agribusiness site selection to optimize surface well site locations?

Can you create a "Disappearing Road" to/from the well?

Is there a way to identify and to quantify optimal mixture of low impact drilling technology for a particular environmentally sensitive area using systems engineering tools?

What is the public view of the O&G industry's efforts to lower their impact on the environment? (first responses to a 6,000 person questionnaire)

2

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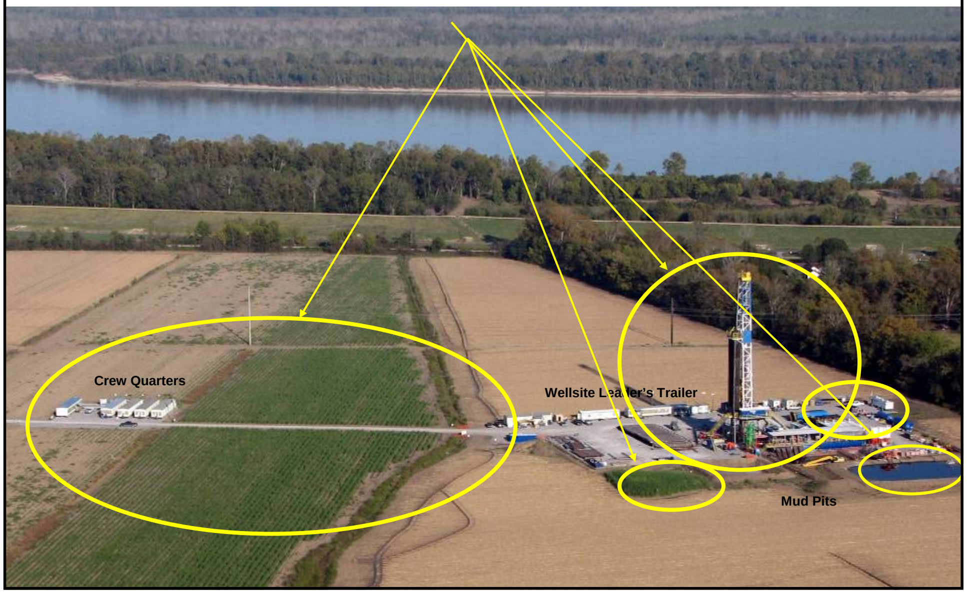
Integrated Low Impact Systems



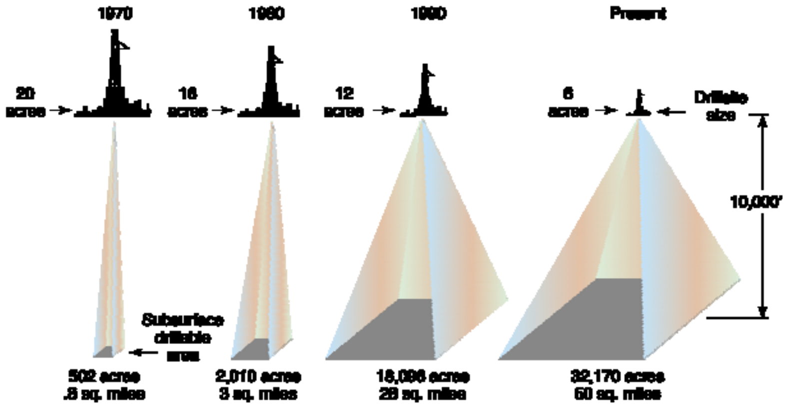
How Much Can We Reduce the Environmental Footprint of O&G Operations?

4

Well Site Access & Drilling Rig

Program Goal is less than one acre

Access to Environmentally Sensitive Areas
- How to access with minimal impact
- How to measure effect of low-impact practices



Source: William Harrison, Kansas Geological Survey

5

Access; Disappearing Road Competition

A competition to design disappearing roads to be used in place of conventional access corridors created to reach O&G drill sites

The goals are to (1) support multi-year competitions and (2) to develop broad public awareness of a campaign to help the environment while seeking to solve our domestic energy needs.

Our first year's competition culminated May 29th, 2008 at our Final Event and Awards Forum.

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Disappearing Roads Competition

Texas A&M University and its partners have created a nation-wide scholastic competition to design a "Roadless" or "disappearing road" system. The competition is endorsed by the American Society of Civil Engineers, the Texas Transportation Institute, and the Global Petroleum Research Institute (GPRI). The first year's contest is being sponsored by Halliburton.

For more Info see:

http://www.gpri.org

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Low Impact Access: Pecos Research and Testing Center Project*

*** Partially Funded by RPSEA Independent Producers Research Programs 2008-'10**

8

Winners/ Judges Disappearing Road - 2008

Winners and judges of the DR competition
Top row (L-R) Alyssa Wechsler, David Carol, Nolan Bray Jacob Olenick, Austin Gaskamp
Middle row (L-R) Juan Uzcategui, Kristen Beck, Tyrel Hulet
Bottom row (L-R) David Moore, Sharon Buccino, John Hall, Guido Deloranttis

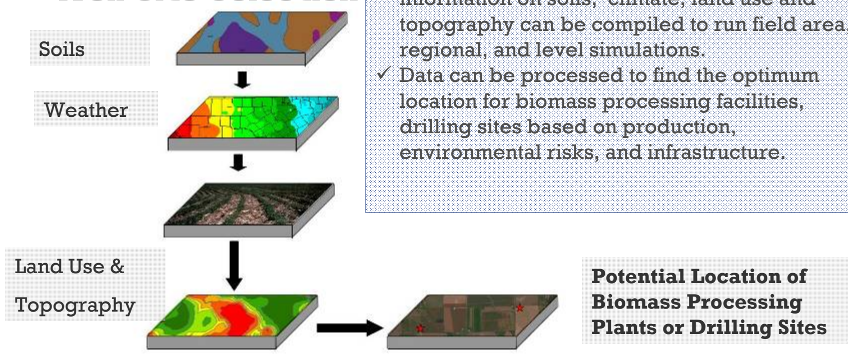
9

Helen O'Connor presents a check to Texas A&M to sponsor DR 2009.

10

2. Access: Decision Support Tools for Surface Well Site Selection

- ✓ Simulation models and spatially distributed information on soils, climate, land use and topography can be compiled to run field area, regional, and level simulations.
- ✓ Data can be processed to find the optimum location for biomass processing facilities, drilling sites based on production, environmental risks, and infrastructure.



- GIS technologies in association with geospatial databases will allow energy and regulatory partners to "optimize" the location of production to maximize recovery while minimizing environmental impact.

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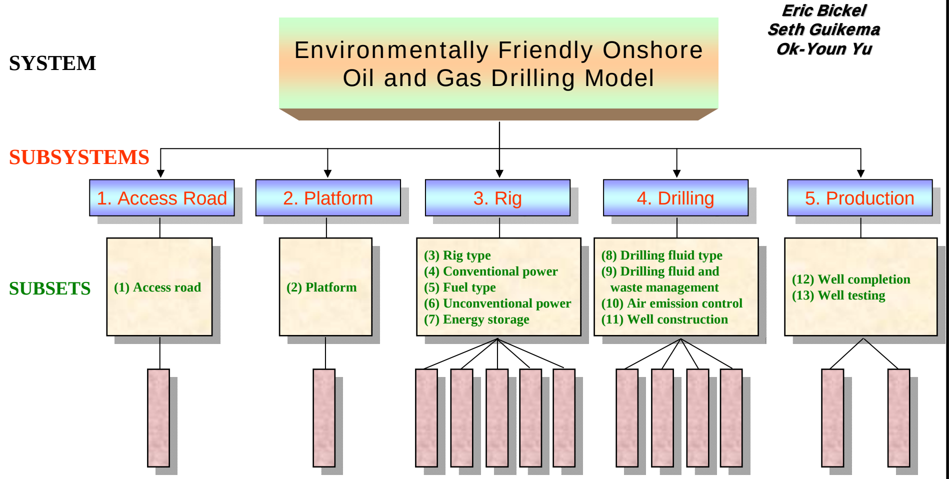
5. Integrated Low Impact Systems

Presented by
Jean-Louis Briaud
Eric Bickel
Seth Guikema
Ok-Youn Yu



12

SYSTEMS APPROACH AND QUANTITATIVE DECISION TOOLS FOR TECHNOLOGY SELECTION IN EFD

Contact information:

Ok-Youn Yu (tg0918@tamu.edu)

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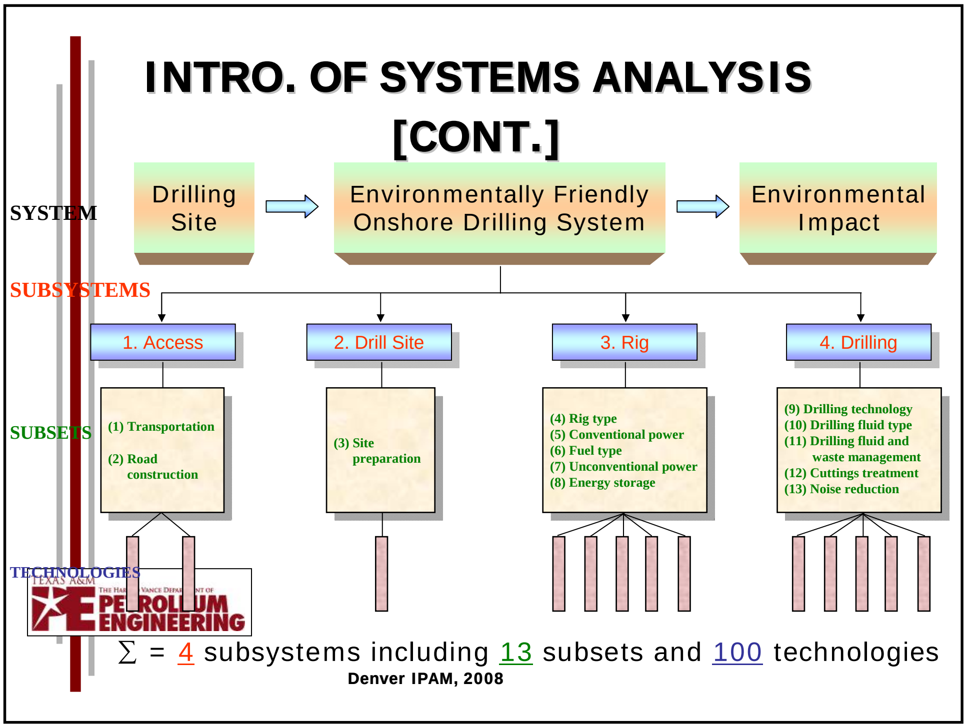
INTRO. OF SYSTEMS ANALYSIS [CONT.]
SYSTEM
Drilling Site
Environmentally Friendly Onshore Drilling System
Environmental Impact
SUBSYSTEMS
1. Access
2. Drill Site
3. Rig
4. Drilling
SUBSETS
(1) Transportation
(2) Road construction
(3) Site preparation
(4) Rig type
(5) Conventional power
(6) Fuel type
(7) Unconventional power
(8) Energy storage
(9) Drilling technology
(10) Drilling fluid type
(11) Drilling fluid and waste management
(12) Cuttings treatment
(13) Noise reduction
TECHNOLOGIES
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∑ = 4 subsystems including 13 subsets and 100 technologies
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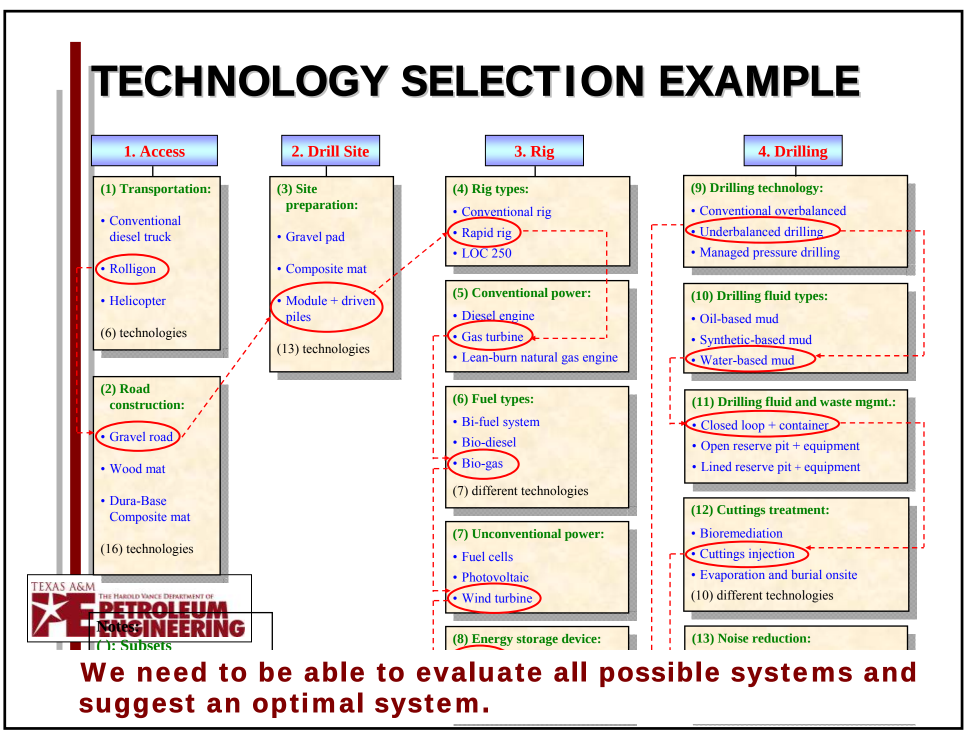
TECHNOLOGY SELECTION EXAMPLE
1. Access
(1) Transportation:
• Conventional diesel truck
• Rolligon
• Helicopter
(6) technologies
(2) Road construction:
• Gravel road
• Wood mat
• Dura-Base Composite mat
(16) technologies
2. Drill Site
(3) Site preparation:
• Gravel pad
• Composite mat
• Module + driven piles
(13) technologies
3. Rig
(4) Rig types:
• Conventional rig
• Rapid rig
• LOC 250
(5) Conventional power:
• Diesel engine
• Gas turbine
• Lean-burn natural gas engine
(6) Fuel types:
• Bi-fuel system
• Bio-diesel
• Bio-gas
(7) different technologies
(7) Unconventional power:
• Fuel cells
• Photovoltaic
• Wind turbine
(8) Energy storage device:
4. Drilling
(9) Drilling technology:
• Conventional overbalanced
• Underbalanced drilling
• Managed pressure drilling
(10) Drilling fluid types:
• Oil-based mud
• Synthetic-based mud
• Water-based mud
(11) Drilling fluid and waste mgmt.:
• Closed loop + container
• Open reserve pit + equipment
• Lined reserve pit + equipment
(12) Cuttings treatment:
• Bioremediation
• Cuttings injection
• Evaporation and burial onsite
(10) different technologies
(13) Noise reduction:
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Notes:
( ): Subsets
We need to be able to evaluate all possible systems and suggest an optimal system.

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AN EXAMPLE SYSTEM

Selected Technologies in Each Subset	Total Cost ($)	Ecological Footprint (Acres)	Emissions			Perceptions			Safety Value
	40%	20%	5%	10%	5%	5%	5%	5%	5%
			Air	*Solid& Liquid*	*Noise*	*Gov.*	*Ind.*	*Public*	
(1) Transportation: Conventional diesel truck	$60,000	0.000	0.000	0.000	0.000	0.500	1.000	0.500	0.750
(2) Road construction: Gravel roads	$148,500	3.030	0.000	0.000	0.000	0.500	1.000	0.500	0.500
(3) Site preparation: Gravel pad	$137,813	2.812	0.000	0.000	0.000	0.500	1.000	0.500	0.250
(4) Rig type: Traditional older vintage rig	$200,000	0.000	0.000	0.000	0.000	0.500	1.000	0.500	0.500
(5) Rig power (Conventional): Internal combustion engine	$80,000	0.000	0.000	0.000	0.000	0.500	1.000	0.500	0.750
(6) Fuel type: Conventional diesel	$94,080	0.000	0.000	0.000	0.000	0.500	1.000	0.500	0.500
(7) Rig power (Unconventional): N/A	$0	0.000	0.000	0.000	0.000	0.250	1.000	0.250	1.000
(8) Energy storage: N/A	$0	0.000	0.000	0.000	0.000	0.250	1.000	0.250	1.000
(9) Fluid type: Water-based muds	$47,940	0.000	0.000	1.000	0.000	1.000	1.000	1.000	1.000
(10) Waste mgmt.: Lined reserve pit + solid control equipment*	$24,000	0.037	0.000	0.000	0.000	0.750	0.750	0.750	0.500
(11) Cuttings mgmt.: Cuttings injection	$60,000	0.000	0.000	1.000	0.000	1.000	0.500	1.000	0.750
(12) Noise reduction: N/A	$0	0.000	0.000	0.000	0.000	0.250	1.000	0.250	1.000
(13) Drilling tech.: Conventional overbalanced	$204,000	0.000	0.000	1.000	1.000	1.000	0.500	0.750	0.500
Σ or minimum value	$1,056,333	5.879	0.000	3.000	1.000	0.250	0.500	0.250	0.250
Utility Values (Risk-neutral)	0.800	0.001	0.000	0.500	0.145	0.250	0.500	0.250	0.250

∴ Multi-Attribute Utility Value = 0.440 (Risk-neutral)

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AN EXAMPLE SYSTEM

Selected Technologies in Each Subset	Total Cost ($)	Ecological Footprint (Acres)	
	40%	20%	5%
			Air
(1) Transportation: Conventional diesel truck	$60,000	0.000	0.0
(2) Road construction: Gravel roads	$148,500	3.030	0.0
(3) Site preparation: Gravel pad	$137,813	2.812	0.0
(4) Rig type: Traditional older vintage rig	$200,000	0.000	0.0
(5) Rig power (Conventional): Internal combustion engine	$80,000	0.000	0.0

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BENEFIT OF THIS RESEARCH

- Provide quantitative basis for suggesting alternative drilling systems.
- Explicitly evaluates alternatives against those criteria that are important in the situation.
- Use best available information – both expert knowledge and data – in a coherent, logical way.
- Can help the system implemented in a given situation to best meet the goals of the sponsor.

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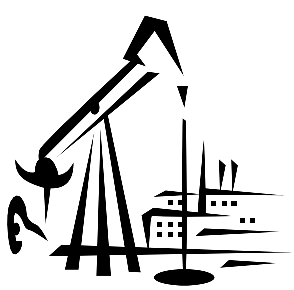
6. Public Acceptance Assimilation

Energy Resources & Natural Environments

A Survey of Texans



Sam Houston State University
A Member of The Texas State University System

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Alternate Rig Power

With emphasis on Peak Shaving Technology

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Alternate Rig Power

With emphasis on Peak Shaving Technology

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Three modes of operation

- Regenerative braking.
- Power grid drilling.
- Diesel engine performance enhancement.

All options incorporate peak shaving by the use of flywheels.

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Containerized switchbox-design procedure

- Energy audit of the rig
  - a.) Based on nameplate rating.
  - b.) Based on rig data.
- Rig data processing and base load determination.
- For grid drilling-design of transformer station as per base load.
- For diesel engines-design is according to the performance curves.
- For regenerative braking-design is according to the power available at the main bus.

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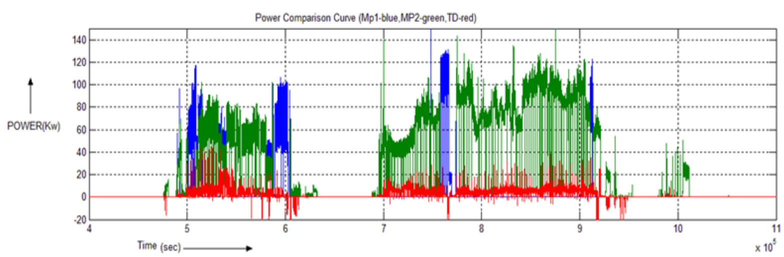
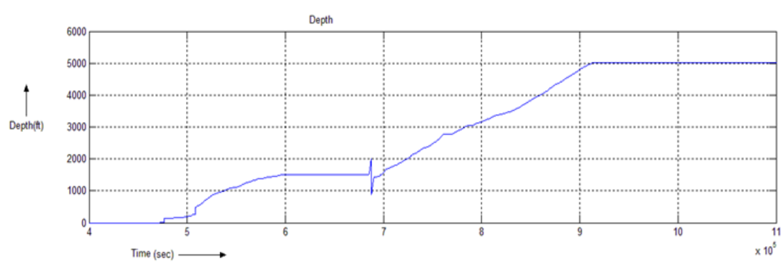
Time stamped rig data measurements- South Texas

Signals Measured by SCADA

Title	Total Headers	Start	End	Continuous	Sample Time(sec)
Gas Unis	51	06-25-07,00:00:00	06-22-2008,23:59:59	Yes	0.5
Auxiliary Pressure	51	06-25-07,00:00:00	06-22-2008,23:59:59	Yes	1
Bit Locaton	51	06-25-2007 00:00:0(	06-22-2008,23:59:50	Yes	10
Block Postion	51	06-25-2007 00:00:0(	06-22-2008,23:59:59	Yes	1
Depth	51	06-25-2007 00:00:0(	06-22-2008,23:59:50	Yes	10
Dexponent	51	05-26-2007 00:00:0(	05-25-2008 23:59:50	Yes	10
Flow Bell Npole	51	05-26-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
GainLoss	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
HookLoac	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
MudPump1GPM	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
MudPump1SPM	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
MudPump1Total strokes	51	4/6/2007 0:00	1/6/2008 23:59	Yes	2
MudPump2GPM	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
MudPump2SPM	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
MudPump2Total strokes	51	4/6/2007 0:00	1/6/2008 23:59	Yes	2
PitTank1Volume	51	06-18-2007 00:00:0(	06-15-2008 23:59:50	Yes	10
PitTank2Volume	51	06-18-2007 00:00:0(	06-15-2008 23:59:50	Yes	10
Pipe Velocity	51	06-25-2007 00:00:0(	06-22-2008 23:59:50	Yes	10
Pt Volume Total	51	06-18-2007 00:00:0(	06-15-2008 23:59:58	Yes	2
Pump Pressure	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
Rate of Penetration	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
ReserveTankVolume	51	06-18-2007 00:00:0(	06-15-2008 23:59:50	Yes	10
RotaryTableRPM	51	06-25-2007 00:00:0(	06-22-2008 23:59:50	Yes	10
RotaryTableTorque	51	06-25-2007 00:00:0(	06-22-2008 23:59:50	Yes	10
ShakerTankVolume	51	06-18-2007 00:00:0(	06-15-2008 23:59:50	Yes	10
SICP	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
SuctionTankVolume	51	06-18-2007 00:00:0(	06-15-2008 23:59:50	Yes	10
TopDriveRPM	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
TopDriveTorque	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
TotalGPM	51	06-25-2007 00:00:0(	06-22-2008 23:59:58	Yes	2
TotalStrokes	51	1/6/2008 23:59	05-21-2007 00:00:00	Yes	10
TripTankVolume	51	06-18-2007 00:00:0(	06-15-2008 23:59:58	Yes	2
WeightOnBit	51	06-25-2007 00:00:0(	06-22-2008 23:59:59	Yes	0.5
WireLineDepth	51	11/6/2007 0:00	06-15-2008 23:59:58	Yes	2
WireLineLoad	51	06-25-2007 00:00:0(	06-15-2008 23:59:58	Yes	2

A processed data set





Depth and Individual Power Consumption

Advantages of Grid Drilling

Sr. No.	Parameter	Diesel Operation	Electric Operation
1	Consumption	3400 L/day or 870 Gal/day and 17400 Gal overall	458461.5 KWh
2	Cost	$73080@ $4.27/Gal for 20 Days	*$45846 for 20 Days
3	Emissions	Noisy operation	Noise free operation (no moving parts of generators)
4	Pollution and Environment	Emissions and pollutants (CO2,CO,NOx,SOx) due to transport and drilling	Environmentally friendly

*www.electricitybid.com

*As per the power consumption profile of rig under investigation.

Share Load of Engines	Operating Time
75%	60%
50%	30%
10%	10%

Thank You

More information:

Dave Burnett burnett@pe.tamu.edu 979 845 2274

http://www.gpri.org/EvironDrilling

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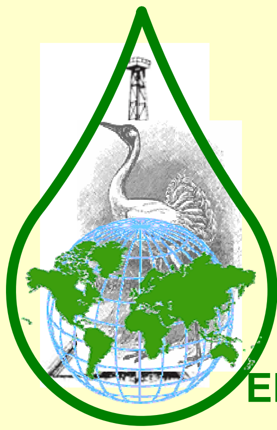
Environmentally Friendly Drilling Systems Background & Current Programs



D.B. Burnett Global Petroleum Research Institute
Texas A&M University

Rich Haut
Houston Area Research Center

Tom Williams
Matagorda Redfish Society

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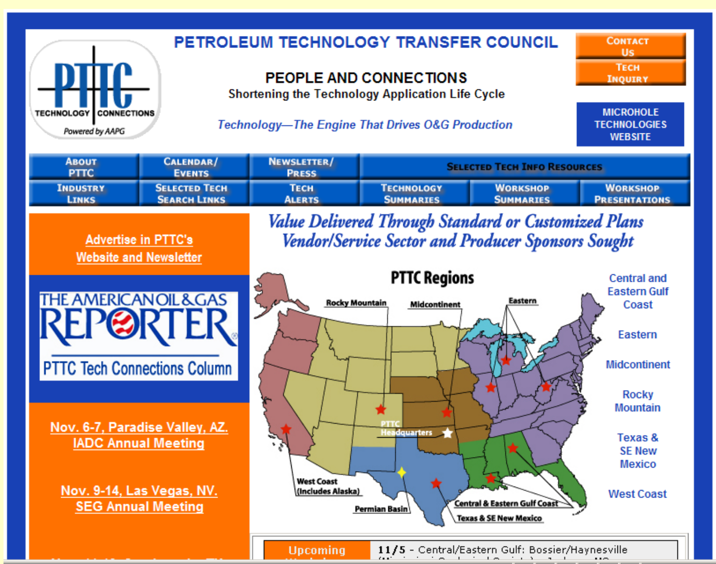
GPRI

HARC

Representing Petroleum Technology Transfer Council



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PTTC Technology Transfer Services

- *The Petroleum Technology Transfer Council (PTTC) is a national not-for-profit organization led by an independent Board of Directors and managed by the American Association of Petroleum Geologists. PTTC was established to provide a forum for transfer of technology and best-practices within the producer community. Local Producer Advisory Groups ensure that PTTC activities in a particular region address the technology needs of producers in that area.*

For more Info see:

http://www.pttc.org

Our Vision

Environmentally Friendly Drilling:

Reducing the Environmental Footprint of O&G Operations

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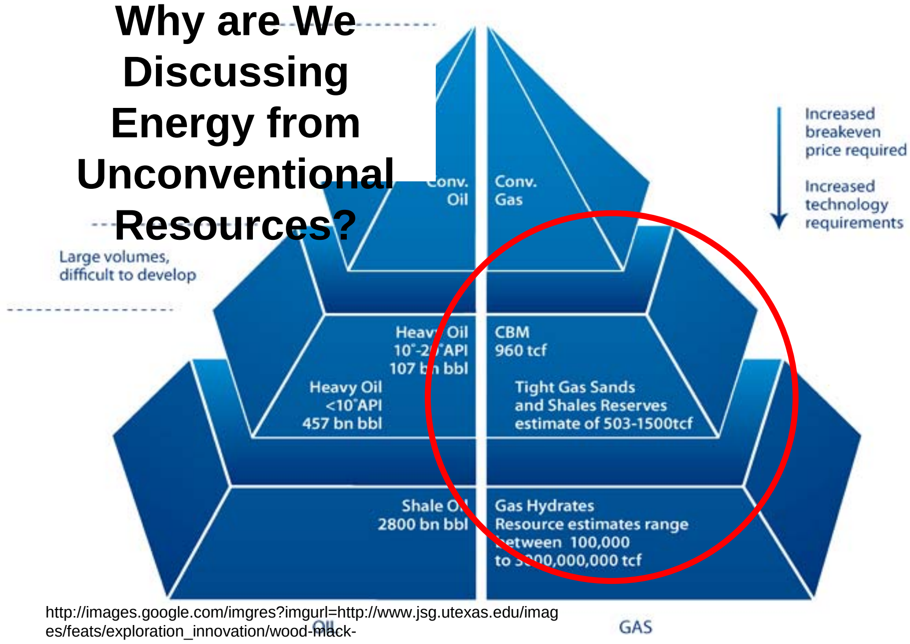
Theodori/Anderson; "Social Cost of Energy"

- *The value of oil and gas resources will increase in the coming decade.*
- *The value of protecting the environment will become more important.*
- *The public's interest in energy development will be more and more significant.*

Why are We Discussing Energy from Unconventional Resources?



http://images.google.com/imgres?imgurl=http://www.jsg.utexas.edu/images/feats/exploration_innovation/wood-mack-pyramid200.jpg&imgrefurl=http

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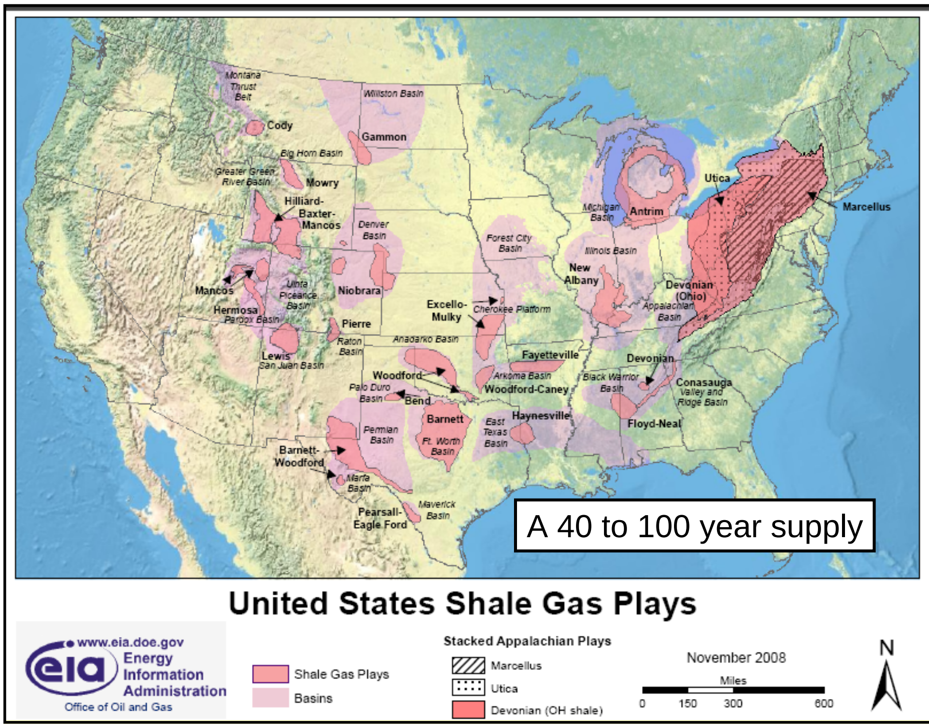

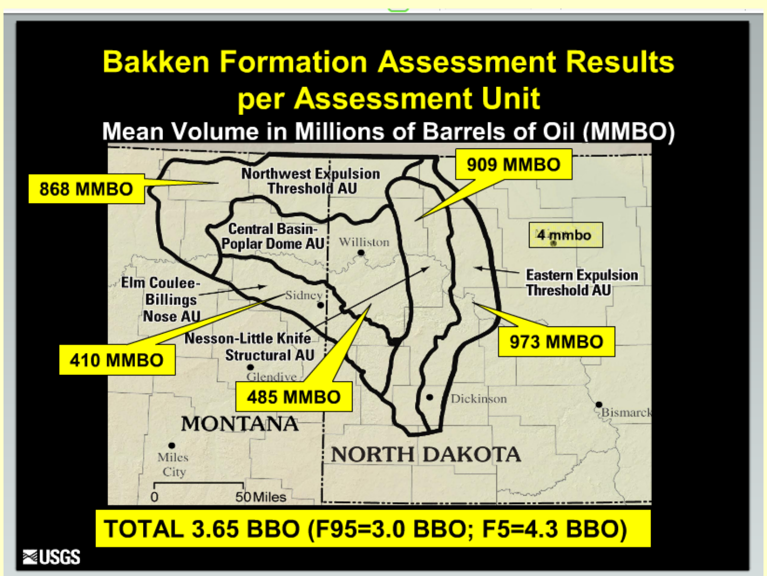

Type Geological formation **Area** 200,000 square miles (520,000 km2)**Age** Late Devonian to Early Mississippian

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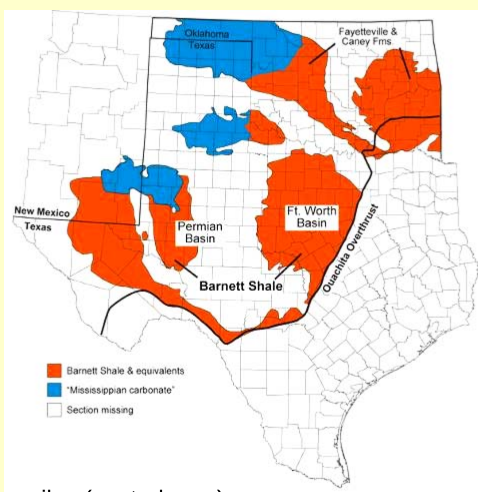
The Barnett Shale Play –
A Comparison*

Analysis of production history from 7000+ wells and an estimation of the ultimate-recovery equivalent of each stimulation treatment showed;
Ultimate production for each 5 mile x 5 mile sub-area
The current cumulative produced gas (3.5 TCF) is about 5.5 % of the ultimate recoverable gas
Production from the Barnett Shale is expected to continue for the next 20 years
Total gas > 50TCF
Total wells > 50,000
Total water used >60 billion gallons

* Valko, P. Crisman Institute Study, Texas A&M University, 2008

Unconventional Resources in Texas



5,000 sq. miles (central core)

Distribution of Upper Mississippian rocks in Texas and Oklahoma. From U.S. Geological Survey Professional Paper 1010 (1979).

- ***The challenge is: we must find ways (1) to produce the gas reserve cleanly and efficiently and (2) to reduce – or perhaps eliminate – the environmental impact of drilling, completion, and production operations***

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Comments Recommend

Town sitting on potential oil jackpot

By JAMES MacPHERSON Associated Press Writer © 2008 The Associated Press
Nov. 9, 2008, 11:02PM

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PARSHALL, N.D. — In this tiny reservation town a hundred miles from the Canadian border where temperatures once hit 60-below zero, a Southern twang is sometimes heard over the din at the local diner and there is talk of Texas tea beneath the streets.

Roughnecks from Texas and Oklahoma have traveled here on hopes that they now share with the town's 1,000 or so inhabitants — that there is oil in Parshall.

About 400 people own mineral rights under homes, businesses, churches, nursing homes or tribal land. All of it has been leased, town officials said.

"We were dying," said Loren Hoffman, a local farmer and the city auditor. "Our town was slipping backward, but now we're on the upswing."

While it is the namesake of the Parshall oil field, which sits in the crude-rich Bakken shale formation, a quarter of Parshall's residents live in poverty.

No one is sure how much oil might lie beneath the town, but with the wells spreading south toward Parshall near the Fort Berthold Indian Reservation, things have begun to change.

"We're seeing an influx of youth that we didn't have before," Hoffman said.

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Assessing Public Awareness & Acceptance

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THE WEB
Heritage Magazine
Huntsville Item
The Houstonian
Huntsville Voice
Newspapers

Sam Houston State University Establishes Center for Rural Studies

Like an old cracked wagon tongue held together by haywire, rural and small-town Texas may not be broke, but there's a lot that needs fixing.

The right tool could be the new Center for Rural Studies: Research & Outreach, at Sam Houston State University. It is housed in the sociology department and directed by Gene Theodori, an associate professor in that department.

We know that as residents of rural areas migrate to the cities to seek more opportunities, the face of Texas, as well as other states, continues to change.

"The social and economic fabric of many rural communities throughout the United States has been progressively weakened by a number of regional, national, and global changes over the past few decades," said Theodori.

"Rural communities in Texas have not been exempt from such structural-level occurrences. Transformations in economic, demographic, and spatial organization have had profound impacts on rural Texas."

The Center for Rural Studies: Research & Outreach, offers a broad range of policy research and recommendations, as well as outreach educational and technical assistance programs. Some of the issues/projects Theodori expects the Center to address include:

Gene Theodori

http://www.shsu.edu/~pin_www/ruralstudiescenter808html

SPE 115917

Public Perception of the Natural Gas Industry: Insights From Two Barnett Shale Counties

G.L. Theodori, Sam Houston State University

This paper was prepared for presentation at the 2008 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA, 21–24 September 2008.

Abstract

Data collected in a general population survey from a random sample of individuals in two counties located in the Barnett Shale region of Texas were used to empirically explore issues associated with public perception of the natural gas industry. Moderate support was found for the hypothesis that individuals residing in places with diverse levels of energy development exhibit dissimilar perceptions of the energy industry. Bivariate and multivariate logistic regression analyses indicate that residents of the county where the natural gas industry is more mature (Wise County) exhibit somewhat more negative perceptions of the energy industry than do residents of the county where natural gas industry is less established (Johnson County). The results also reveal that mineral rights ownership is a relatively strong and consistent factor associated with public perception of the natural gas industry. Possible implications of these findings for the energy industry are proposed, as are suggestions for future research.

For more Info see:

http:/www.spe.org

Society's Perception

Development activities raise concerns about noise, property damage, pollution and safety.

•Local residents within an active unconventional natural gas play surveyed to measure individuals' perception of the energy industry and their interest, knowledge, attitudes, experience, current behaviors, and behavioral intentions with regard to energy exploration and production issues.

•Based on the results of the survey, a plan developed to implement a multimedia effort to familiarize the public with drilling and production and to address concerns.

- **Fact-sheets and other outreach educational materials pertaining to environmentally friendly energy exploration and production practices will be developed, printed and disseminated.**

•A review of potential social impacts documented.

Barnett Shale Well Equivalent to City of 4,000 Population

Water Usage	Well Operations	City Operations(1)	Comments
Water Usage	10 million gal	18 million gal (3 mo.)	5-6 mm gal frac. 1-2 mm gal well ops.
Power Use	7,500 HP	6 MW (8,000 Hp)	Avg. SCR rig
Solid Waste	43,000 cu ft. (wbm, 7,000 ft well)	55,000 cu.ft	3 mo. Ops.
Unit Budget	~$ 2.2 MM	~$1.7 MM	3 mo. Ops.

(1) Based on comparison to Andrews TX city budget (pop.9,600) 2008 FY

U.S. has 100 Years of Resources in Unconventional Petroleum Resources

1908 Ford Model T

2008 Ford Focus

Where will technology lead us in 100 years?

A 2108 Ford?

Where will Battery Technology Be in 100 years?

1908 Exide Lead Acid

2008 100 Hp NiMH

2108?

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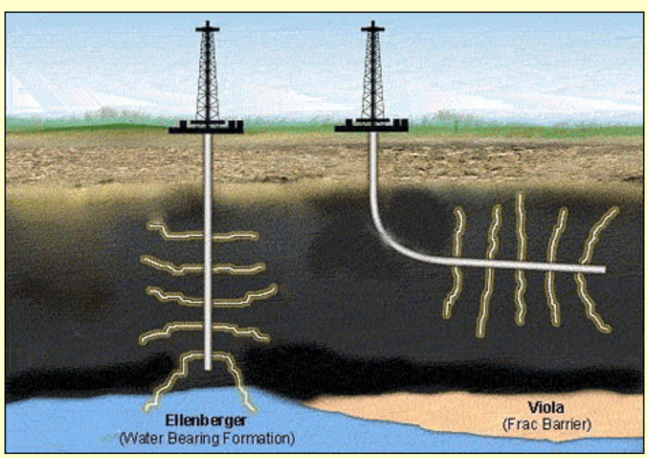
AN ENVIRONMENTALLY FRIENDLY DRILLING PROGRAM FOR NORTH DAKOTA

- **Low Impact Drilling, Completion & Production Operations will:**
  - **Reduce the environmental footprint of the development of the Bakken and other Gas Shales**
  - **Allow more efficient development of the resource**
  - **Promote "green" technologies and companies within O&G sector**
  - **Bring sustainable economic development to North Dakota, Saskatchewan and surrounding Bakken areas**

Schematic of Massive Hydraulic Fracturing Stimulation of Shales



http://www.freewebs.com/mana76016/gaswells1.jpg

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Barnett Shale Well at DFW Airport & In Hamilton County, TX

http://www.freewebs.com/mana76016/gaswells1.jpg

Environmentally Friendly O&G Drilling Systems

Drilling in the Marcellus Shale

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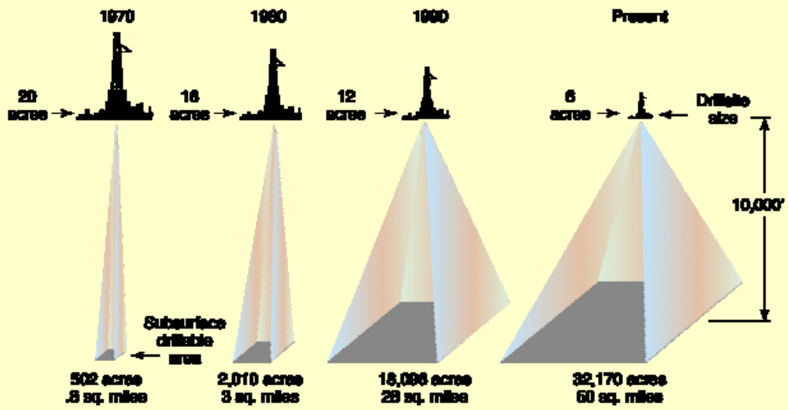
1.4 Platform/Rig Site Options

Well Site Access & Drilling

Questar using "Pod" drilling
(1 acre per well.)

Access to Environmentally Sensitive Areas

- **How to access with minimal impact**
- **How to measure effect of low-impact practices**

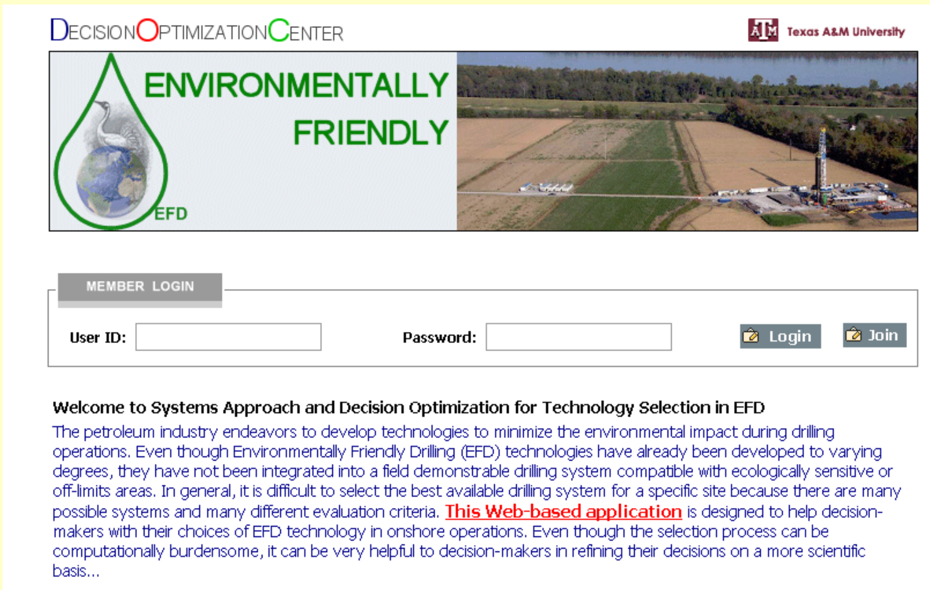


Source: William Harrison, Kansas Geological Survey

Status of Current Programs

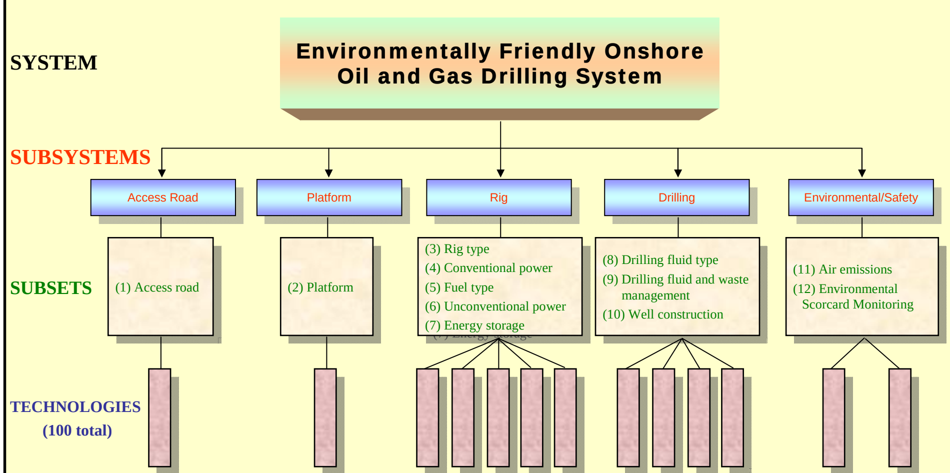
1.1 Systems Engineering
1.2 Waste Management
1.3 Low Footprint Projects
1.4 Platform/Rig Site Options
1.5 Alternate Power
1.6 Society's Acceptance
1.6.1 Perceptions
1.6.2 Scorecard

Selection of Low Impact Technology – Systems Engineering



Systems Approach to Technology Selection

To select the optimal system
(combination of technologies)
to minimize impact and maximize profit



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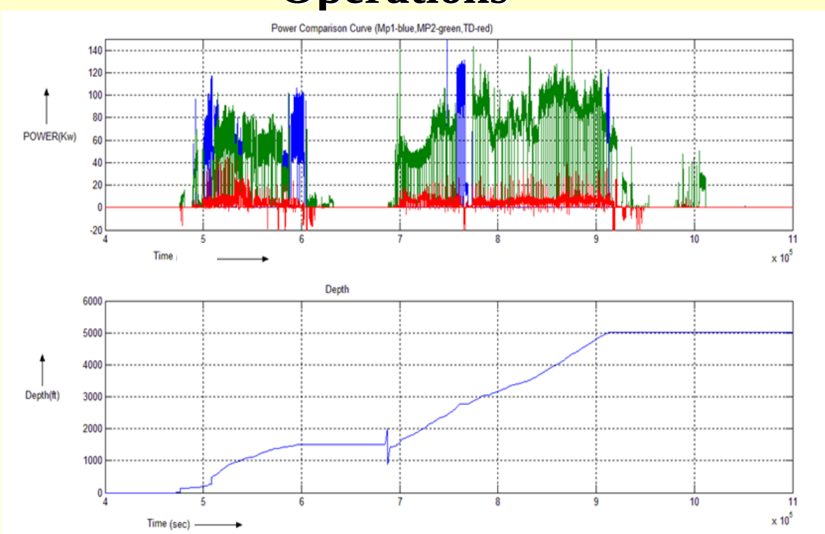
Alternate Rig Power

With emphasis on Peak Shaving Technology

Ankit Verma
MS and Recipient-John C. Calhoun Fellowship
ankitmanit@tamu.edu
979 209 9475

Power Usage During Drilling Operations



Depth and Individual Power Consumption

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Advantages of Grid Drilling

Sr. No.	Parameter	Diesel Operation	Electric Operation
1	Consumption	3400 L/day or 870 Gal/day and 17400 Gal overall	458461.5 KWh
2	Cost	$73080@ $4.27/Gal for 20 Days	*$45846 for 20 Days
3	Emissions	Noisy operation	Noise free operation (no moving parts of generators)
4	Pollution and Environment	Emissions and pollutants (CO_2,CO,NOx,SOx) due to transport and drilling	Environmentally friendly

*www.electricitybid.com

*As per the power consumption profile of rig under investigation.

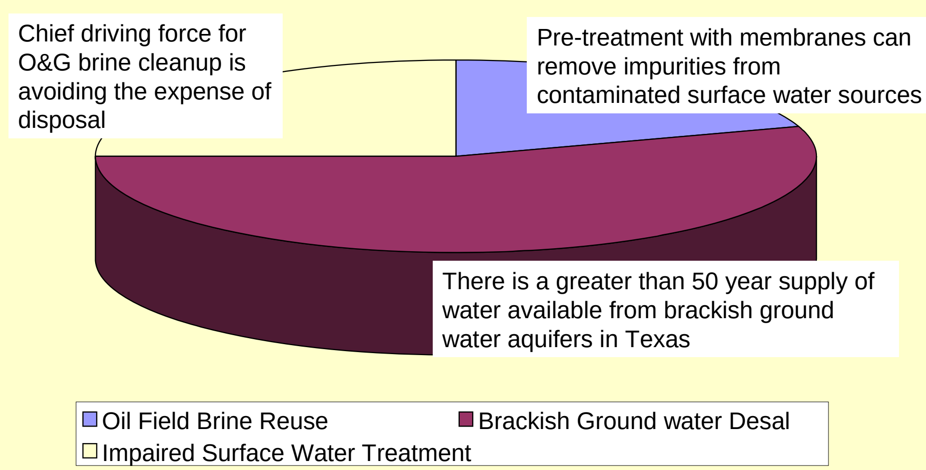
Savings of almost $10,000 per week

Share Load of Engines	Operating Time
75%	60%
50%	30%
10%	10%

New Programs

Low Impact Development Systems

Waste Management



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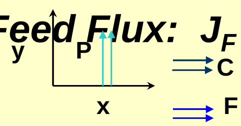
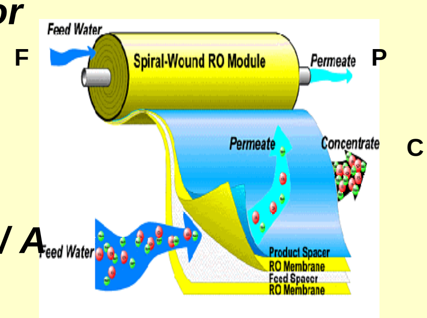
Reverse Osmosis Definitions (RO)

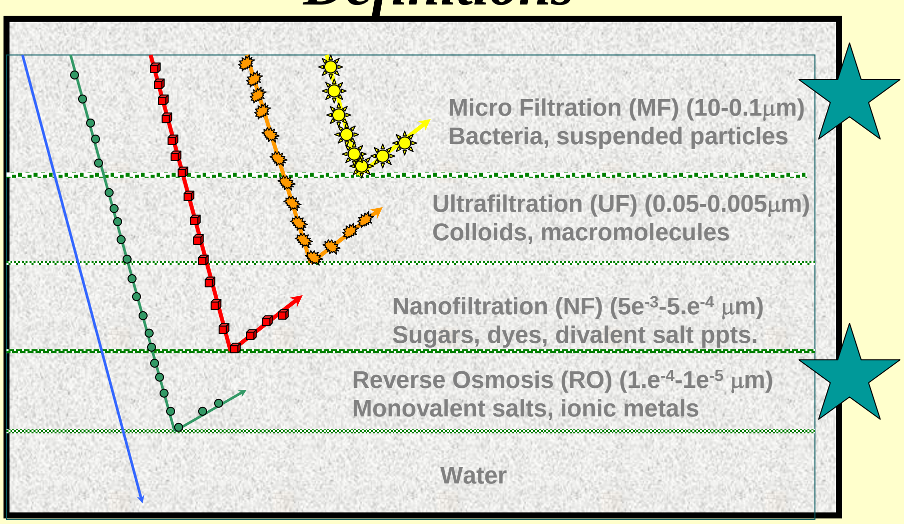
- ***Salt rejection***
- ***Transmembrane pressure***
- ***Feed, permeate, reject or concentrate rates***
- ***Fluxes (volumetric rate/area)***

Feed Flux: $J_F = Q_F / A$





Filtration & Reverse Osmosis Definitions



Water Management at Rig

Mobile Pre-Treatment and Desalination Unit.

Texas A&M GPRI Designs ™ Desalination Process

New Technology

Comparison of Desalinated Produced Water with Municipal

		College Station Municipal Water (1)	Desalinated Produced Water (2)	Desalinated Produced Water (3)
	Substance	Amount	Amount	Amount
Agronomic Properties				
	pH	7.8	7.1	6.2
Physical Properties				
	Conductivity	882	2270	17
	TDS	523	1290	17
	SAR		23	0.1
Major Ions				
	Alkalinity (CaCo3)		34	5
	Bicarbonate (HCO3)	450	41	6
	Chloride	54	706	1
	Sulfate	9	3	ND
	Ca, Mg, K, Na, B	203	94 ppm	1.3
Metals, Dissolved				
	Barium, etc	2 ug/L	0.9 mg/L	ND
Volatile Organics				
	Chloroform, +	14 ug/L	3.4 ug/L	85 ug/L
-1	http://www.cstx.gov/home/index.asp?page=822			
-2	EL Analytical Summary Report Fife # 3 (1/16/2006			
3	EL Analytical Summary Report Neuman well (3/24/2006)			

Water Management at Rig

RO treatment of Barnett Shale Frac Flowback

Analyte	Untreated Water		Final RO Permeate
Alkalinity, Total as $CaCO_3$	160		4.69
Bicarbonate as HCO_3	195		5.72
pH	6.86		6.28
Solids, Total Suspended TSS @ 105 C	4200		<4
Calcium	676		0.662
Sodium	4504		63.6
TPH	1.87		<1.1
Total Dissolved Solids	14,590		191
Chloride	7830		105
Sulfate	396		1.2
bromide	77		1.33
iron	173		0.017
Barium	936		0.0007

Representative power costs of desalination of oil field brine

Salinity of Feed Brine, tds (ppm)	Power Costs Kw Hr per 1,000 gal. Permeate			
	Pre-treatment	RO desalination	Operating Cost, $ per 1,000 gal.	Operating Cost, $ per bbl
Contaminated Surface water ~1,500 tds.	$.65	$1.25	$1.90	$0.08
Gas well produced brine ~ 3,600 tds.	$2.50	$2.00	$4.50	$0.19
Oil well produced brine ~50,000 tds	$2.20	$6.00	$8.20	$0.34

Water Management at Rig

TEXAS A&M
THE HAROLD VANCE DEPARTMENT OF PETROLEUM ENGINEERING

GPRI

Texas A&M University and MI SWACO have announced a long term research services agreement between the University and the oil field service company to integrate advanced membrane filtration technology into MI's world wide drilling waste management products and services.

M-I SWACO, LLC was awarded the 2006 NOIA Safety in Seas Award - in recognition of the company's dramatic overall improvement of the safe capture and disposal of drill cuttings through its CleanCut™ technology in its operations throughout the world

A&M's GPRI Designs™ Desalination team recently won the 2008 World Oil Environmental Science and Safety Award for its industry leading effort to treat and reuse water at rig sites.

MI SWACO

New Programs

Low Impact Development Systems

2.1 Low Impact Access

- ***Conceptual Study – Use hydro-geological models to develop system to minimize impact .***
- ***An example study will be performed for the Fort Worth Nature Center, a potential site for Barnett Shale development.***

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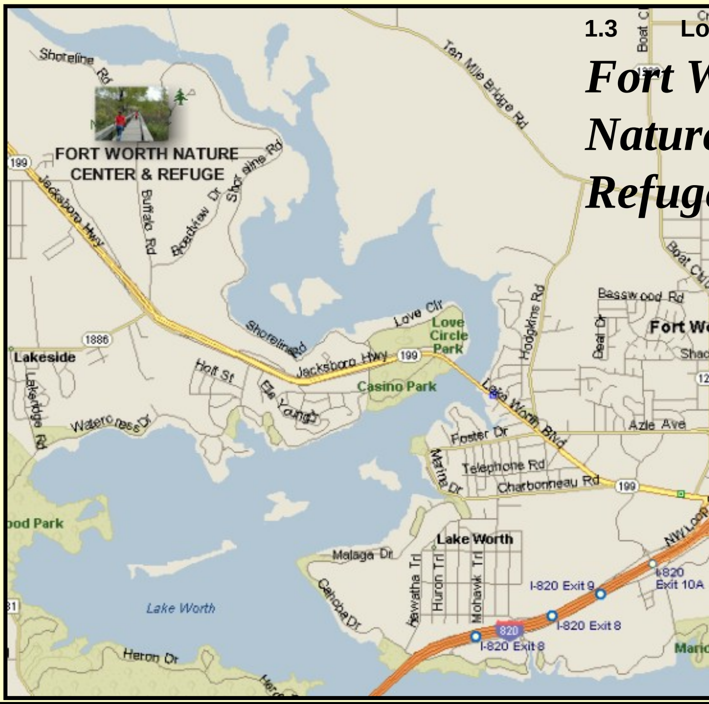
1.3 Low Footprint Projects

Fort Worth Nature Center & Refuge



www.fwnc.org

1.3 Low Footprint Projects

Google Earth Satellite View of FWNCR

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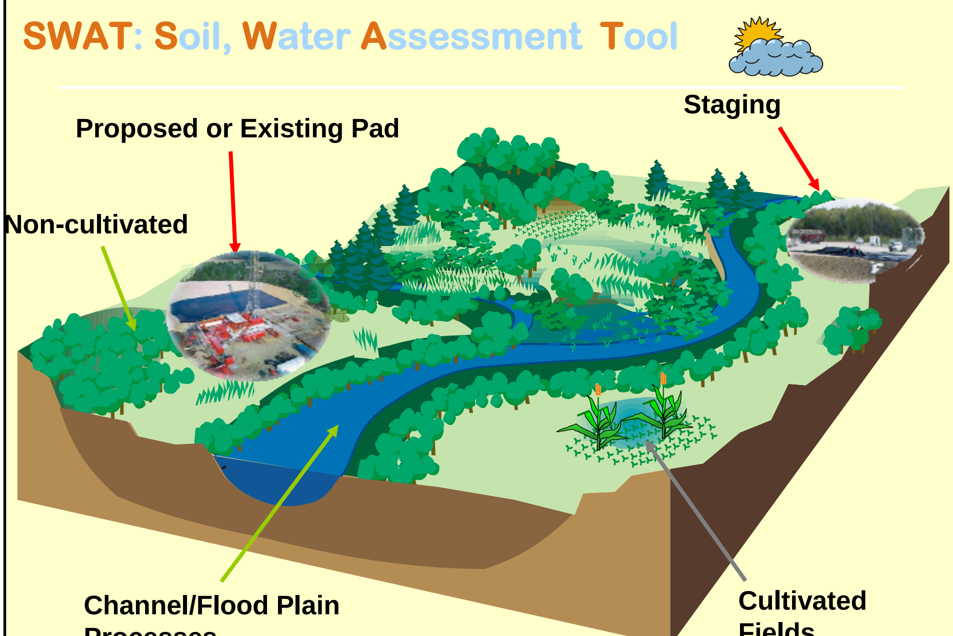
SITING SURFACE ACTIVITIES TO MINIMIZE ENVIRONMENTAL IMPACTS

DECISION SUPPORT TOOLS TO AID THE OIL & GAS INDUSTRY

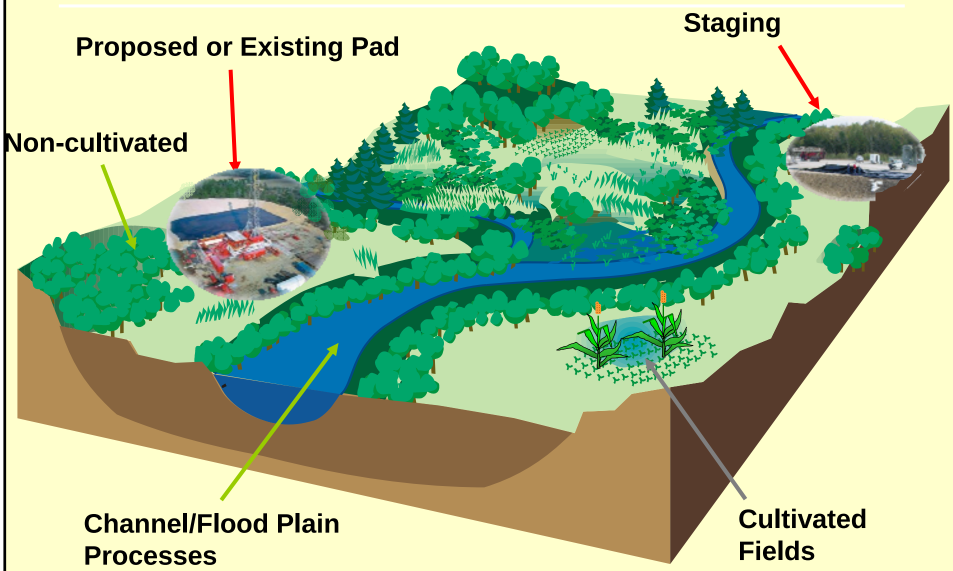
Global Petroleum Research Institute

AgriLIFE RESEARCH
Texas A&M System

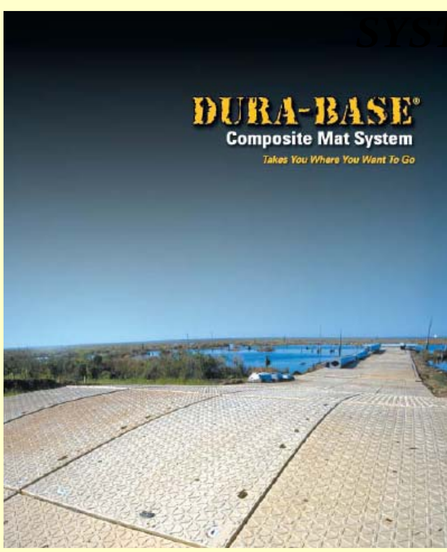
SWAT: Soil, Water Assessment Tool



SWAT: Soil, Water Assessment Tool



DURA-BASE® COMPOSITE MAT SYSTEM



Roadbase Installation

The "Disappearing Road Competition"
2008-2009

http://sites.google.com/a/pe.tamu.edu/disappearing-roads-competition/

Department of Petroleum Engineering
Crisman Institute, GPRI
Department of Civil Engineering
Texas Transportation Institute
Texas A&M University
Houston Area Research Center

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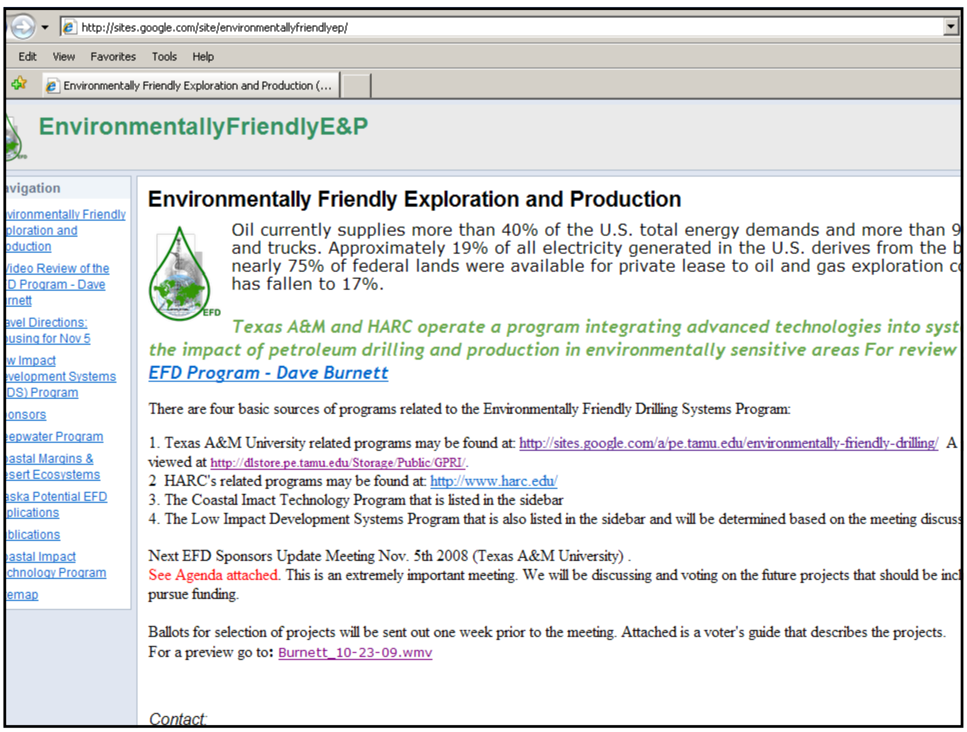
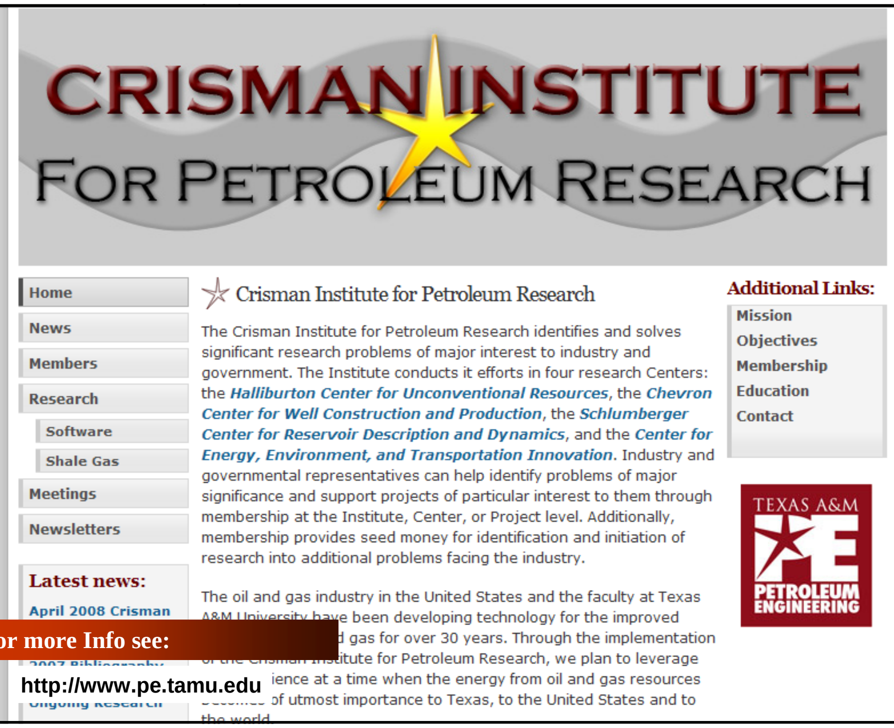
More Information?

http://www.efdsystems.org

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April 2008 Crisman

Crisman Institute for Petroleum Research

The Crisman Institute for Petroleum Research identifies and solves significant research problems of major interest to industry and government. The Institute conducts it efforts in four research Centers: the *Halliburton Center for Unconventional Resources*, the *Chevron Center for Well Construction and Production*, the *Schlumberger Center for Reservoir Description and Dynamics*, and the *Center for Energy, Environment, and Transportation Innovation*. Industry and governmental representatives can help identify problems of major significance and support projects of particular interest to them through membership at the Institute, Center, or Project level. Additionally, membership provides seed money for identification and initiation of research into additional problems facing the industry.

The oil and gas industry in the United States and the faculty at Texas A&M University have been developing technology for the improved ... gas for over 30 years. Through the implementation ... itute for Petroleum Research, we plan to leverage ... ience at a time when the energy from oil and gas resources ... of utmost importance to Texas, to the United States and to the world.

Additional Links:
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For more Info see:

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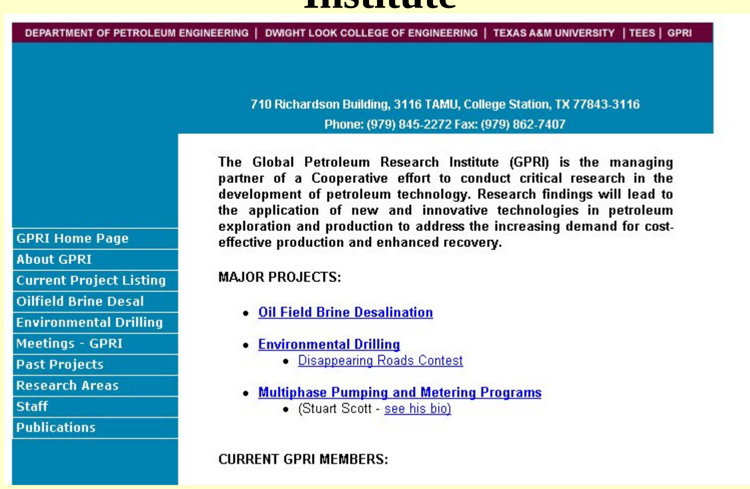
Texas A&M Global Petroleum Research Institute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The Global Petroleum Research Institute (GPRI) is the managing partner of a Cooperative effort to conduct critical research in the development of petroleum technology. Research findings will lead to the application of new and innovative technologies in petroleum exploration and production to address the increasing demand for cost-effective production and enhanced recovery.

MAJOR PROJECTS:

- Oil Field Brine Desalination
- Environmental Drilling
  - Disappearing Roads Contest
- Multiphase Pumping and Metering Programs
  - (Stuart Scott - see his bio)

CURRENT GPRI MEMBERS:

For more Info see:

http://www.gpri.org

Crisman Institute Projects (www.pe.tamu.edu/crisman)

- *1.1.4 – Water fracture treatments: A User's Guide*
- *1.1.10 -The Evaluation of Waterfrac Technology in Low-Permeability Gas Sands in the East Texas Basin (WCP)*
- *1.1.12 - Expert System for Drilling, Completions and Stimulation in TGS*
- *1.1.13 - Using Multilayer Models to Forecast Reserves in Tight Gas Reservoirs (RDD)*
- *1.1.14 -Evaluation of Water Production in Tight Gas Reservoirs in the East Texas Basin*
- *1.1.15 - Evaluation of Water Fracture Treatments in the East Texas Cotton Valley Formation*
- *1.2.4 Natural Fracture Characterization in the Woodford Shale*
- *1.4.2 -Effects of New Technology on Economically Recoverable Coal Bed Methane*
- *1.6.2 - Quantifying Uncertainty in Unconventional Gas Resource Assessments in North America*
- *4.2.9 -Low Impact O&G Activity; Environmentally Friendly Drilling Systems*

Environmental Issues in O&G Operations

For more Info see:

http://www.ead.anl.gov/pub/doc/testimony_veil_final.pdf

TESTIMONY OF JOHN A. VEIL, ARGONNE NATIONAL LABORATORY
BEFORE THE HOUSE COMMITTEE ON SCIENCE AND TECHNOLOGY SUBCOMMITTEE ON ENERGY AND ENVIRONMENT CONCERNING: "RESEARCH TO IMPROVE WATER-USE EFFICIENCY AND CONSERVATION: TECHNOLOGIES AND PRACTICE" OCTOBER 30, 2007

http://www.ead.anl.gov/project/dsp_topicdetail.cfm?topicid=18

Oil and Gas Technology Feasibility Studies
The optimal recovery and use of U.S. oil and gas resources requires energy policies and environmental regulations based on credible scientific data, assumptions, and analyses. Before new technologies can be moved into commerce, their capabilities, cost, risk, and legality need to be determined. Argonne's Environmental Science Division (EVS) conducts independent feasibility studies of the technical, regulatory, economic, and risk aspects of promising oil field technologies to foster technology evaluation and implementation.

http://www.gpri

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Texas A&M GPRI HARC
Environmentally Friendly Drilling Systems

Acknowledging

A&M Crisman Institute
GPRI Sponsoring Companies
EFD Sponsors
U. S. Department of Energy
RPSEA- Independent Producers

Photographs Courtesy CMGC Foundation

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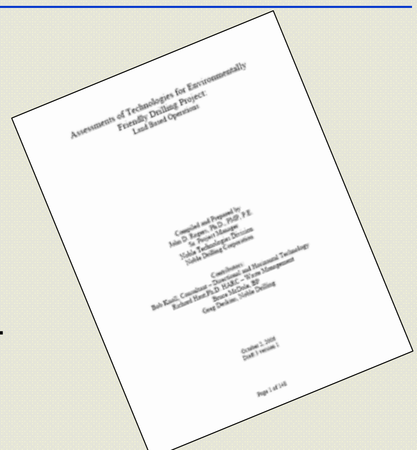
Environmentally Friendly Drilling Systems

David Burnett, GPRI, Texas A&M University
Richard C. Haut, John D. Rogers, Houston Advanced Research Center
Tom Williams, Matagorda Consultants

Acknowledging Funding from U.S. DOE NETL Environmental Program

Environmentally Friendly Drilling Systems Program



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Devon
National Oil Well VARCO
Statoil
Houston Advanced Research Center

Phase I

Prototype Engineering Design EFD Systems.

Phase II

Build and Test components.

Phase III

Let contracts for a Prototype EFD System.
Obtain Drilling Contract for Prototype System.

Slide 2

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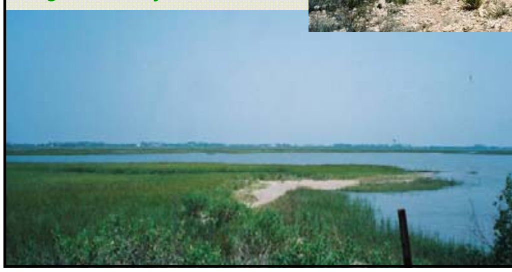
All Areas are Environmentally Sensitive

- *The value of oil and gas resources are increasing.*
- *The value of protecting the environment is becoming more important.*
- *The public's interest in energy development is becoming more and more significant.*
- *The O&G Industry must engage the public in a more significant way.*



- *Identify and develop technologies to get access with minimal impact.*
- *Determine how to measure the effect of low impact practices.*

Outline of Presentation

Program Overview – Sponsorships

Rig and Platform Systems
Access to & from Well sites
Waste Management Issues
Water Management at Well sites
Environmental Issues
Technology Acceptance & Industry Adoption

EFD

Slide 4

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Environmentally Friendly Drilling Systems Program

- Replace Conventional Operations
- Develop Advanced, Low-Impact Technology for Oil & Gas
  - Drilling
  - Transportation
  - Production
- Targets
  - Environmentally sensitive areas
  - Unconventional Gas Shales - CBM
  - Coastal Margins

EFD

Slide 5

Environmentally Friendly Drilling Systems Program

- Sponsorships $100,000 per Sponsor Phase 2
- Deliverables
  - Phase 1 Engineering Design of Low Impact System
  - Phase 2 Design of Low Impact Drilling System & and Testing of Key Components
  - Phase 3 Contracts for EFD Drilling System
- Additional Funding from U.S. DOE NETL Environmental Program
- Pursuing Additional Funding from RPSEA
  - Unconventional Resources, Independent Producers

EFD

Slide 6

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Programs Organized into Task Working Groups and Specific Projects

EFD

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EFD Platform Drilling Onshore Areas

EFD

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CURRENT CIVIL ENGINEERING WORK FOR EFD PROJECT

1. Cost estimate of platform (foundation and platform)
2. 3D Simulation of mats as foundation for platform and road
3. Impact of stacking on the platform foundation (to reduce the number of piles and modules)
4. Web based software development for automation of foundation calculations and cost optimization

EFD

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EFD Rig Operations – Low Impact

EFD

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Rig Energy Efficiency Study: Alternate Power Sources

Wind Turbine Power
Power from Fuel Cells
Power from Grid

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Environmental Issues, Acceptance & Assimilation of EFD Technology

Community Leaders' Perceptions of Energy Development in the Barnett Shale

Economic activity

↓

Population growth

↓

Social Disruption

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Public Perception of Desalinated Water from Oil and Gas Field Operations: Data from Texas*

- Data collected in two counties in north central Texas were used to empirically explore issues associated with public perception of desalinated water from oil and gas field operations.

*Dr. Gene Theodori, TAMU

Ways desalinated water might safely be used:	Yes	No
Re-use by gas and oil industry operators	94%	6%
Industrial use (e.g., manufacturing, etc.)	92%	8%
Municipal uses (e.g., watering golf courses and city parks, etc.)	76%	24%
Home irrigation purposes (e.g., watering lawns and shrubs, etc.)	70%	30%
Irrigation of farmland and/or rangeland	65%	35%
Maintenance of stream flows/reservoir levels	47%	53%
Watering of livestock	44%	56%
Aquifer recharge	42%	58%
People's drinking water	21%	79%

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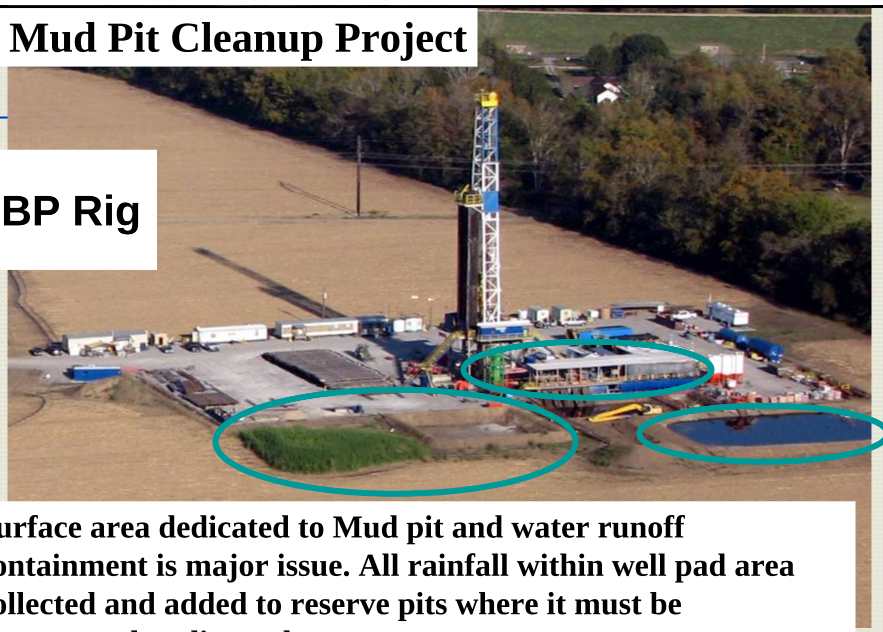
Mud Pit Cleanup Project

BP Rig



Surface area dedicated to Mud pit and water runoff containment is major issue. All rainfall within well pad area collected and added to reserve pits where it must be transported to disposal area.

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EFD Program Waste Management at Well Site

Total Waste Management Programs

- Incorporates other aspects in addition to drilling fluids/cuttings
  - Contaminated water, water runoff
  - Material and chemical packaging
  - Air emissions such as carbon dioxide and oxides of nitrogen
  - Scrap metals
  - Fuel, lubricants and other oils
  - Usual human/industrial wastes associated with operations
- Benefits
  - Overall improvement in general housekeeping
  - Reduced health and safety exposure
  - General increase in environmental awareness and concern

EFD

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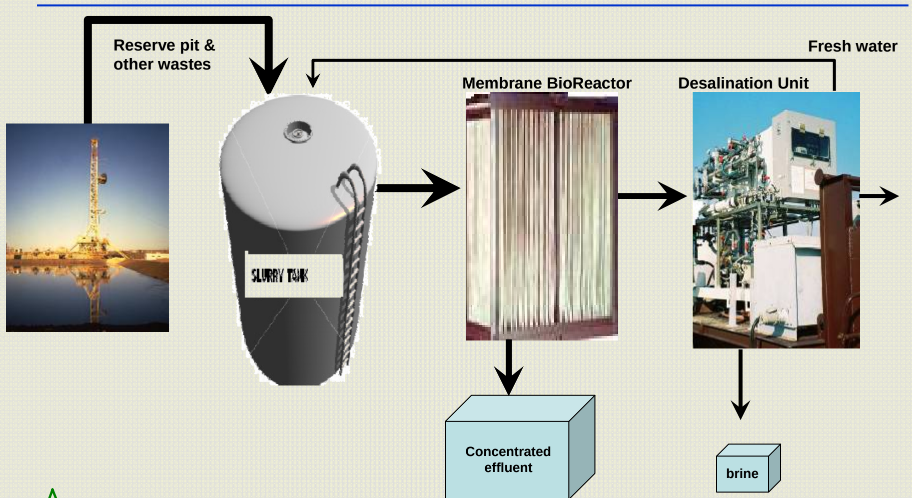
Mud Pit Minimization



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Cross Flow Filtration of Mud Pit Samples; Before and After

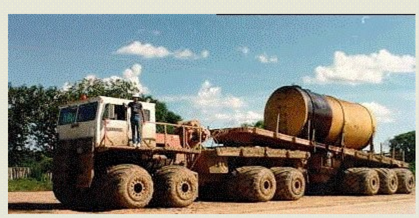
le 17

EFD Well Site Access: Disappearing Roads Competition

Develop innovative concepts for reducing the footprint of transporting equipment and materials to drill sites in environmentally sensitive areas

Rotating Ecosystems

- **Coastal Margin**
- **Desert**
- **Boreal (Arctic)**



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Environmental Issues

EFD

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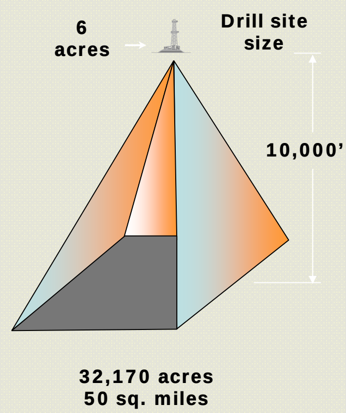
EFD Well Environmental Monitoring

Present

- *Develop a "scorecard" to use as a measure of the cost effectiveness of a new technology*
- *Create a "clearinghouse of technology which can be utilized in a low impact system*
- *Perform "environmental monitoring" of well operations both with and without utilization of low impact technology*
- *Conduct studies of public and O&G industry acceptance of new low impact practices*



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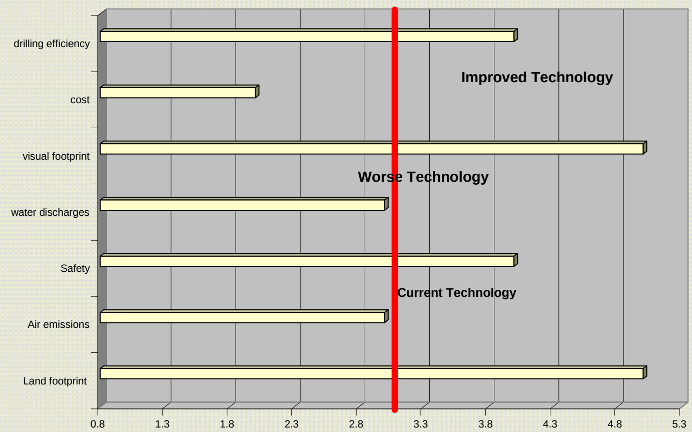
- McFaddin Ranch Drilling Operations Monitoring



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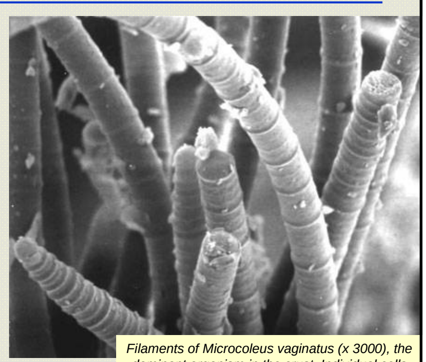
Protect Sensitive Ecologies



Filaments of Microcoleus vaginatus (x 3000), the dominant organism in the crust. Individual cells abut each other to form the filaments.

Cryptobiotic soils in semi arid area

- Found in similar types of environments around the world
- Fix carbon and nitrogen for the semi-arid soil ecologies
- Includes algae, bacteria, lichens, mosses, fungi, liverworts, and cyanobacteria
- Very sensitive and have little mechanical strength. Can be crushed without permanent damage if they are not disturbed or buried or eroded away
- Photosynthetic and cannot be kept in dark
- Increase the stability, fertility, water capture of easily eroded soils
- Challenge is to drill and exploit without significant damage
- Cryptobiotic soils are the essential first step in producing arable soils

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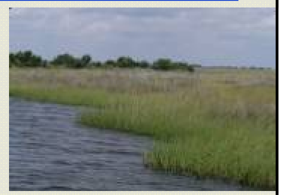
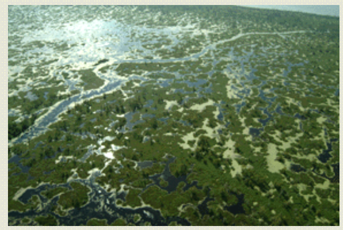
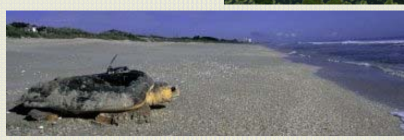
Protect Sensitive Ecologies



Coastal Wetlands

- Transition Zones from fresh waters and land to ocean waters and storms
  - Flow of water, cycling of nutrients and energy of the sun meet
  - Unique ecosystem characterized by hydrology, soils and vegetation
- Usually shallow and require digging canals to explore for oil and gas
  - Creates direct passage of saltwater to damage wildlife habitat





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Site for Disappearing Road Contest 2007 -2008

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Disappearing Roads; Time Schedule

Submission of Phase I Documents	*November, 2007*
Notification to Teams About Outcomes of Phase I Evaluation	*December, 2007*
Submission of Phase II Documents	*March, 2008*
Notification to Teams About Outcomes of Phase II Evaluation *Invitation of the Top Five Winners to Participate in Phase III*	*May 5th, 2008*
Presentations by the Top Five Winners to the Panel Judges	*June 18, 2008*
Awards Banquet	*June 19, 2008*

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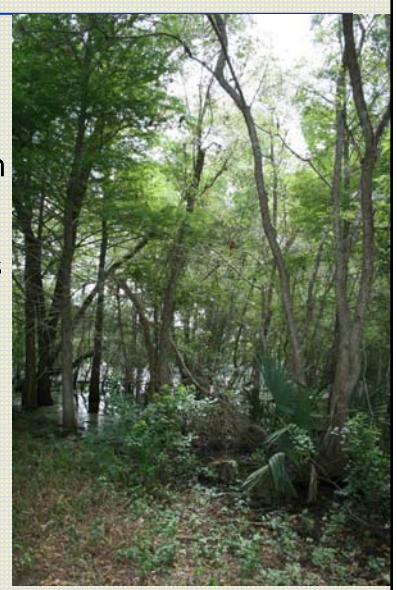
McFaddin Ranch Possibility

- Sanchez Production Company will help with cost share
  - 2 Well AFE
- Pursue additional funding through RPSEA Unconventional Natural Gas Solicitation
- Develop Environmental Tradeoffs Scorecard
- Prioritize of technologies that may be included for drilling operations



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Technical Papers

AADE – Minimizing Waste During Drilling Operations, R. Haut, 2007

IADC Drilling Contractor– Environmentally Friendly Drilling: Responsible E&P Development in Sensitive Ecological Locations Onshore US, J Rogers

IADC - Environmental Friendly Drilling Systems , R. Haut, April, 2007

SPE - Future Trends in Desalination of Oil Field Brine, D. Burnett ACTE September, 2006

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Engineering Reports

"Environmentally Friendly Foundation System for Onshore Oil & Gas Drilling Platforms, Texas A&M Civil Engineering, 2006.

"Technology Assessment Report" – Noble Technology Services, 2006

"Waste Management at Rig Sites," R. Haut, Houston Advanced Research Center

"Quality of Life & Energy Production in Wise County, Texas"- Texas A&M PRTS

"Summary of the Impacts of Oil and Gas Development on Grassland and Barrier Island Ecosystems" Texas A&M DWFS (Wildlife Quality & Conservation) 2007

"Drilling Rig Energy Inventory," Texas A&M PE Department, 2006

"Environmentally Friendly Drilling Systems" – End of Year Report (2006) Texas A&M PE Department

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SYSTEMS APPROACH FOR TECHNOLOGY SELECTION IN EFD

Feb. 7th, 2008

Presented by
Jean-Louis Briaud
Eric Bickel
Seth Guikema
Ok-Youn Yu

INTRODUCTION

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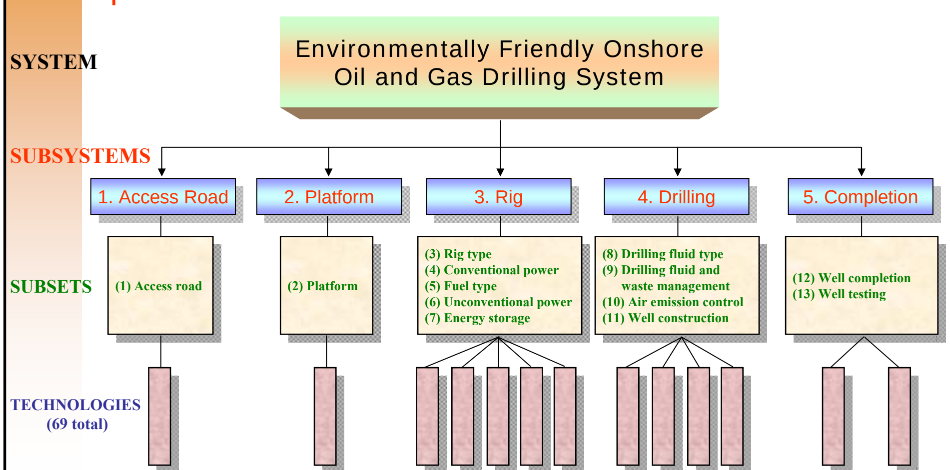
To select the optimal system (combination of technologies) to minimize impact and maximize profit



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INTRODUCTION [CONT.]

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- **Decision situation**: which system (combination of technologies) should be selected for a specific site.
- **Challenge**: there are many possible systems and many different evaluation criteria. How do we handle this in a logical way? How do we measure and select the best system?
- **Approach**: evaluate systems quantitatively and use systems analytic methods to suggest suitable systems to consider.

TECHNOLOGY SELECTION EXAMPLE

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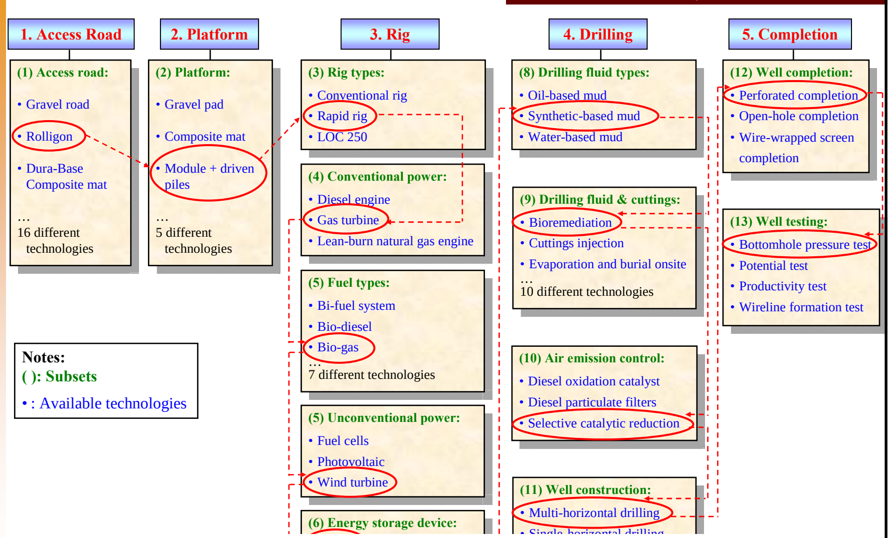

We need to be able to evaluate all possible systems and suggest an optimal system.

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DEFINE ATTRIBUTE & UTILITY FUNCTION

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Attribute: one of the parameters considered in the evaluation of the system (cost, land area, emission, and perception). Each attribute has an attribute scale used to score the technology on how well it meets the objective for this attribute (minimizes cost, land area, emission, and maximizes positive perception).

Utility Function: a relationship between the dimensional attribute score (e.g., $, acres, and grades) and a non-dimensional number (between 0 and 1). The utility function is used to transform all scores into non-dimensional values between 0 and 1. This allows the decision maker to make all attribute scores uniform and comparable.

RESEARCH PROCEDURE

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STEP 1 : Identify main subsystems and subsets for the EFD operation.

STEP 2 : List all technologies within each subset.

STEP 3 : Define attributes and develop attribute scales to evaluate technologies.

STEP 4 : Assign scores to all technologies using the attribute scales.

STEP 5 : For each attribute, calculate the overall attribute score of a system by adding the technology scores or selecting the minimum technology score.

STEP 6 : For each attribute and in order to homogenize the scores, develop a "utility function (u_i)" to convert the overall dimensional score of a system (e.g, $, acres, and grades) into a non-dimensional utility value (between 0 and 1) of the system.

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RESEARCH PROCEDURE [CONT.]

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STEP 7 : Decide on a weight factor (k_i) for each attribute (i).

STEP 8 : Calculate the overall score of the system as "$\sum k_i u_i$" (multi-attribute utility function).

STEP 9 : Use optimization technique to evaluate all systems and to find the best available system for a specific site.

STEP 10 : Conduct sensitivity analysis to examine the impacts of possible changes in the attribute scales, weight factors, and utility functions on the optimal system.

STEP 11 : Suggest a small number of systems that should be particularly attractive for a given site.

AN EXAMPLE SYSTEM

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	Weights						
	0.4	0.2	0.05	0.05	0.1	0.1	0.1
Selected Technologies in Each Subset	Total Cost ($)	Land Area Permanently Lost (acres)	Emissions		Perceptions		
			Air	*Solid/Liquid*	*Government*	*Industry*	*Public*
(1) Hovercraft							
(2) Aluminum modules + driven piles							
(3) Conventional Rig							
(4) Lean-burn natural gas engines							
(5) Natural gas							
(6) Wind Turbine							
(7) Battery							
(8) Synthetic-based muds							
(9) Bioremediation							
(10) Selective Catalytic Reduction (SCR)							
(11) Vertical drilling							
(12) Perforated completion							
(13) Potential test							
Σ or mnimum value							
Utility Values (Risk-neutral)							

∴ Multi-Attribute Utility Value = (Risk-neutral)

OPTIMAL SYSTEM FOR BASE-CASE WEIGHTS

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	Weights						
	0.4	0.2	0.05	0.05	0.1	0.1	0.1
Selected Technologies in Each Subset	Total Cost ($)	Land Area Permanently Lost (acres)	Emissions		Perceptions		
			Air	*Solid/Liquid*	*Government*	*Industry*	*Public*
(1) Hovercraft	$1,268,784.00	0.365	0.600	1.000	0.500	0.500	0.500
(2) Aluminum modules + driven piles	$1,106,581.50	0.021	0.400	1.000	1.000	1.000	0.750
(3) Conventional Rig	$10,000,000.00	1.000	0.400	1.000	0.500	0.500	0.500
(4) Lean-burn natural gas engines	$3,528,000.00	0.020	0.580	1.000	0.500	0.750	0.750
(5) Natural gas	$1,200,500.00	0.000	0.720	1.000	0.500	0.500	0.500
(6) Wind Turbine	$2,184,000.00	0.212	1.000	1.000	1.000	0.750	0.750
(7) Battery	$168,000.00	0.017	1.000	1.000	1.000	0.750	0.750
(8) Synthetic-based muds	$675,000.00	0.500	1.000	0.800	1.000	1.000	1.000
(9) Bioremediation	$500,000.00	0.100	1.000	1.000	1.000	1.000	1.000
(10) Selective Catalytic Reduction (SCR)	$100,000.00	0.000	0.800	1.000	1.000	1.000	1.000
(11) Vertical drilling	$1,500,000.00	0.000	0.400	0.400	0.500	0.500	0.500
(12) Perforated completion	$500,000.00	0.000	1.000	0.800	0.500	0.500	0.500
(13) Potential test	$500,000.00	0.000	1.000	0.800	0.500	0.500	0.500
Σ or mnimum value	$23,230,865.50	2.235	0.400	0.400	0.500	0.500	0.500
Utility Values (Risk-neutral)	0.867	0.916	0.400	0.400	0.500	0.500	0.500

∴ **Multi-Attribute Utility Value = 0.720 (Risk-neutral)**

TOTAL NUMBER OF POSSIBLE SYSTEMS

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1. When "Diesel engine" is selected as a conventional power generation,

Subsets	Subsystems					Π
	1. Access	2. Platform	3. Rig	4. Drilling	5. Production	
(1)	16	5	3	3	3	2160
(2)			2 *	10	4	80
(3)			5	4		20
(4)			3	3		9
(5)			4			4
					Π	124,416,000

* two types diesel engines

2. When "Gas turbine" is selected as a conventional power generation,

Subsets	Subsystems					Π
	1. Access	2. Platform	3. Rig	4. Drilling	5. Production	
(1)	16	5	3	3	3	2160
(2)			1	10	4	40
(3)			3	4		12
(4)			3	3		9
(5)			4			4
					Π	37,324,800

∴ Total number:
124,416,000
37,324,800
24,883,200
Σ 186,624,000

3. When "Natural gas engine" is selected as a conventional power generation,

Subsets	Subsystems					Π
	1. Access	2. Platform	3. Rig	4. Drilling	5. Production	
(1)	16	5	3	3	3	2160
(2)			1	10	4	40
(3)			2	4		8
(4)			3	3		9
(5)			4			4
					Π	24,883,200

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PARAMETER UNCERTAINTY

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Weight scenarios	Total Cost (W_1)	Land Area Permanently Lost (W_2)	Emissions (W_3)		Perceptions (W_4)		
			Air	*Solid /Liquid*	*Government*	*Industry*	*Public*
Maximum	1.00	1.00	0.50	0.50	1/3	1/3	1/3
Minimum	0.00	0.00	0.00	0.00	0.00	0.00	0.00

- enumerated all possible weight combinations within these bounds that summed to one in increments of roughly 0.1. This resulted in 60 weight combinations for further consideration.
- Since there are seven different cases for the unconventional power usage (i.e., 0%, 10%, 20%, 30%, 40%, 50%, and 60% of total power usage), the total number of weight combinations for further consideration is 420 (= 60×7)

SUGGESTED SYSTEMS

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SYSTEM 1 (68%) (Base-case optimal solution)	SYSTEM 2 (3%)	SYSTEM 3 (2%)
(1) Rolligon	(1) Rolligon	(1) Helicopter
(2) Modules + driven piles	(2) Modules + driven piles	(2) Modules + driven piles
(3) Conventional Rig	(3) Conventional Rig	(3) LOC250 from Huisman
(4) Lean-burn natural gas engines	(4) Diesel Engine	(4) Lean-burn natural gas engines
(5) Natural gas	(5) Diesel	(5) Bio-gas
(6) Wind Turbine	(6) Wind Turbine	(6) Fuel cells
(7) Battery	(7) Battery	(7) Battery
(8) Synthetic-based muds	(8) Synthetic-based muds	(8) Synthetic-based muds
(9) Bioremediation	(9) Bioremediation	(9) Bioremediation
(10) Selective catalytic reduction	(10) Selective catalytic reduction	(10) Selective catalytic reduction
(11) Vertical drilling	(11) Vertical drilling	(11) Vertical drilling
(12) Perforated completion	(12) Perforated completion	(12) Perforated completion
(13) Potential test	(13) Potential test	(13) Potential test
SYSTEM 4 (7%)	SYSTEM 5 (12%)	SYSTEM 6 (2%)
(1) Rolligon	(1) Rolligon	(1) Gravel Road
(2) Modules + driven piles	(2) Modules + driven piles	(2) Gravel Pad
(3) LOC250 from Huisman	(3) Rapid rig from NOV	(3) Conventional Rig
(4) Lean-burn natural gas engines	(4) Lean-burn natural gas engines	(4) Diesel Engine
(5) Bio-gas	(5) Natural gas	(5) Diesel
(6) Wind Turbine	(6) Wind Turbine	(6) Wind Turbine
(7) Battery	(7) Battery	(7) Battery
(8) Synthetic-based muds	(8) Synthetic-based muds	(8) Synthetic-based muds
(9) Bioremediation	(9) Bioremediation	(9) Bioremediation
(10) Selective catalytic reduction	(10) Selective catalytic reduction	(10) Selective catalytic reduction
(11) Single horizontal drilling	(11) Vertical drilling	(11) Vertical drilling
(12) Perforated completion	(12) Perforated completion	(12) Perforated completion
(13) Potential test	(13) Potential test	(13) Potential test
SYSTEM 7 (2%)	SYSTEM 8 (2%)	SYSTEM 9 (3%)
(1) Rolligon	(1) Rolligon	(1) Rolligon
(2) Gravel Pad	(2) Modules + driven piles	(2) Modules + driven piles
(3) Conventional Rig	(3) LOC250 from Huisman	(3) LOC250 from Huisman
(4) Diesel Engine	(4) Lean-burn natural gas engines	(4) Lean-burn natural gas engines
(5) Diesel	(5) Natural gas	(5) Bio-gas
(6) Wind Turbine	(6) Wind Turbine	(6) Wind Turbine
(7) Battery	(7) Battery	(7) Battery
(8) Synthetic-based muds	(8) Synthetic-based muds	(8) Synthetic-based muds
(9) Bioremediation	(9) Bioremediation	(9) Bioremediation
(10) Selective catalytic reduction	(10) Selective catalytic reduction	(10) Selective catalytic reduction
(11) Vertical drilling	(11) Vertical drilling	(11) Multiple horizontal drilling
(12) Perforated completion	(12) Perforated completion	(12) Perforated completion
(13) Potential test	(13) Potential test	(13) Potential test

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•

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http://www.gpri.org

Future Trends in Desalination of Oil Field Brine

SPE ACTE September 26, 2006

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Outline of Presentation

- 1. Why is Desalination a Big Deal Now?
- 2. What can the Technology Do?
- 3. Where are Projects Being Established?
- 4. When Will Desalination Allow Companies to Reduce Water Management Costs?
- 5. Example Projects

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Why Des nation Now?

Premise:

Fresh water resources from desalination of wastewater including oil field brine.

Advantages

Demand for fresh water is increasing its value.

Proximity of the water resource to the place of use.

Reuse of byproduct brine in enhanced oil & gas recovery.

Disadvantages

Additional cost of demineralization of water.

The (probable) salinity of the produced brine.

Environmental compliance issues.

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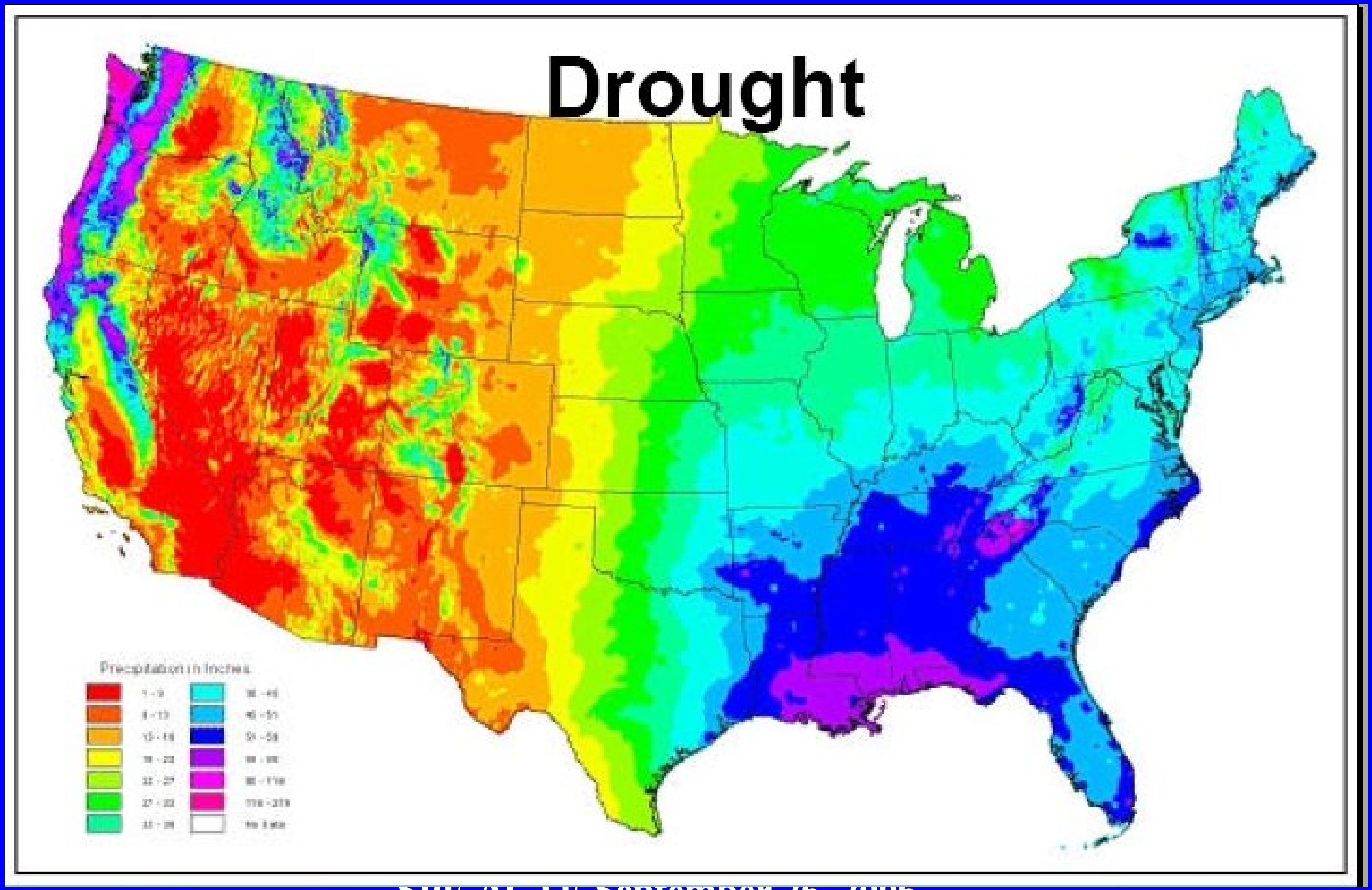
Lack of Fresh Water Resources



Why Desalina on Now?

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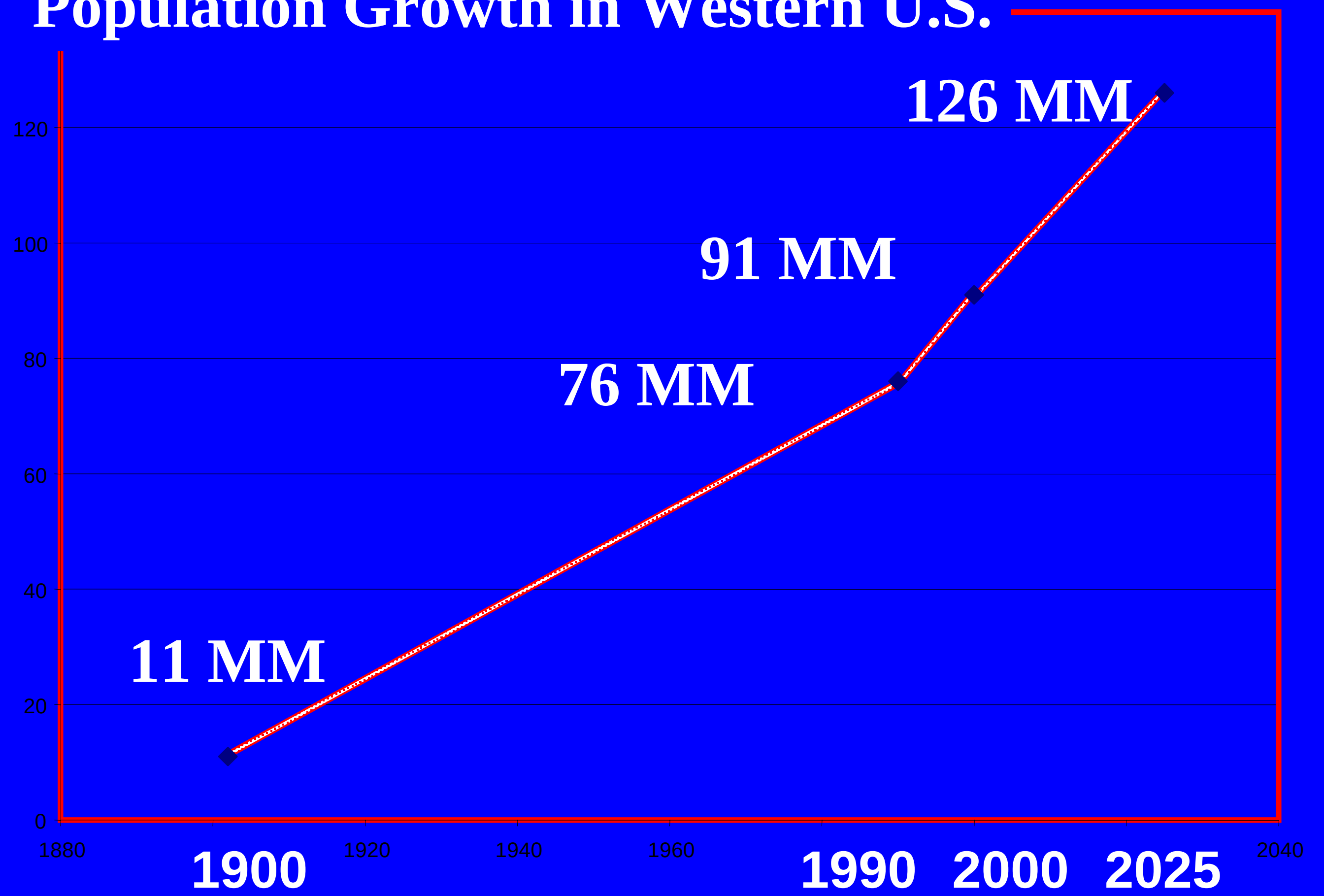
Why the U.S. Worries about Water Resources

Population Growth in Western U.S.



For more Info see:

http://www.wrri.nmsu.edu/

ember 26, 2006

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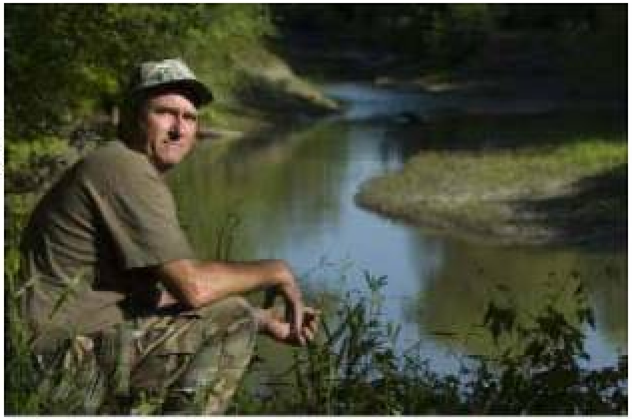

Max Shumake, co-founder and president of the Sulphur River Oversight Society, is organizing the effort to keep the Marvin Nichols project from being built.
AARON STREET: TEXARKANA GAZETTE

May 14, 2006, 11:04AM

Dallas region's reservoir plans irk East Texas

Residents say projects threaten their way of life

By THOMAS KOROSEC

The name Dallas has become a fighting word in some quarters of East Texas.

As the Dallas-Fort Worth region moves ahead on long-range plans to build two new reservoirs in East Texas, landowners, environmentalists and timber interests have united in opposition, pulling many local politicians along.

Miffed at the prospect of job losses in the timber industry and destruction of choice wildlife habitat, opponents have begun calling Dallas a spoiled and selfish bully that wants its swimming pools and green lawns, even in droughts, and has the political muscle to do as it pleases.

Why Desa ation Now?

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Texas Long Range Water Plans call for at Least 7 New Reservoirs

The human dimensions of the issue may prevent timely development.

6, 2006

Coastal Margins
Significant population Growth.
Problem:

How accommodate development with minimal impact.

How to provide fresh water resources.

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Why Desal

Why Des nation Now?

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West Texas

Significant population Growth.

Problem:

- **How accommodate development with minimal impact.**
- **How to provide fresh water resources.**

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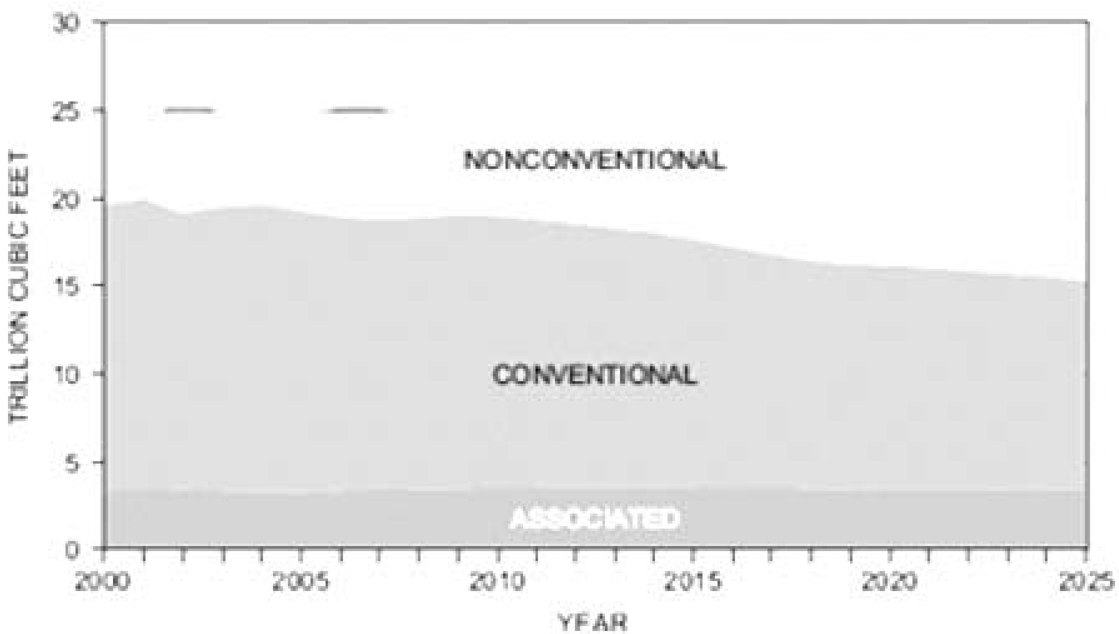
Future Energy Needs to be M by Unconventional Resources



U.S. Lower 48 and Non-Arctic Canadian Gas Production by Type

Future Energy Needs to be M by Unconventional Resources

Resource Triangle

Conventional Reservoirs
Small volumes that are easy to develop

Unconventional
Large volumes that are difficult to develop

Increased pricing

Improved technology

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Outline of Presentation

- 1. Why is Desalination a Big Deal Now?
- 2. What can the Technology Do?
- 3. Where are Projects Being Established
- 4. When Will Desalination Allow Companies to Reduce Water Management Costs?
- 5. Example Projects

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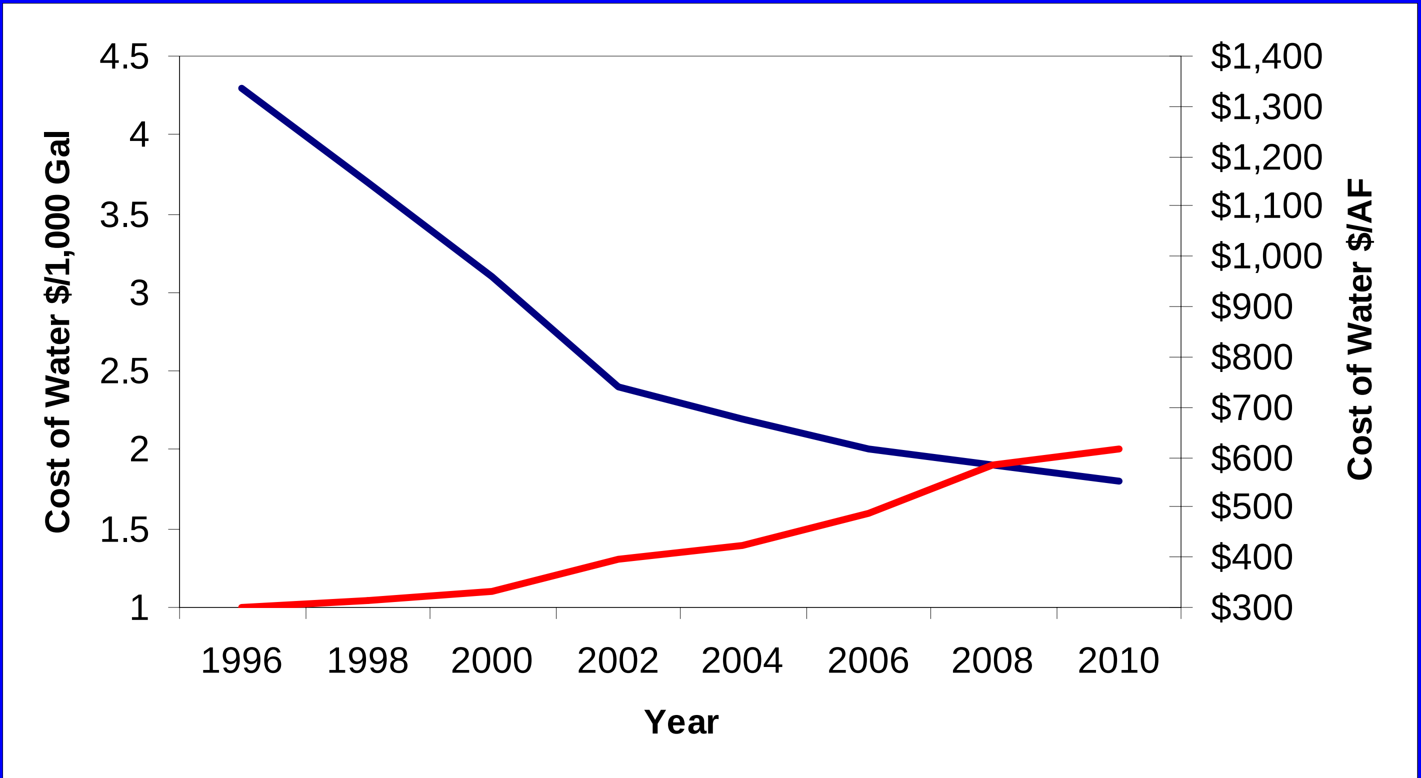
Membrane Desalination Becoming the Technology of Choice



http://www.brazos.org SPE ACTE September 26, 2006

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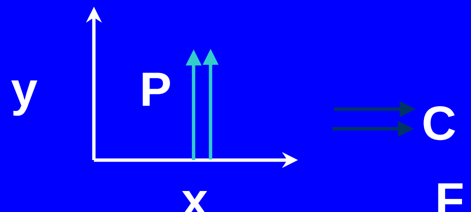
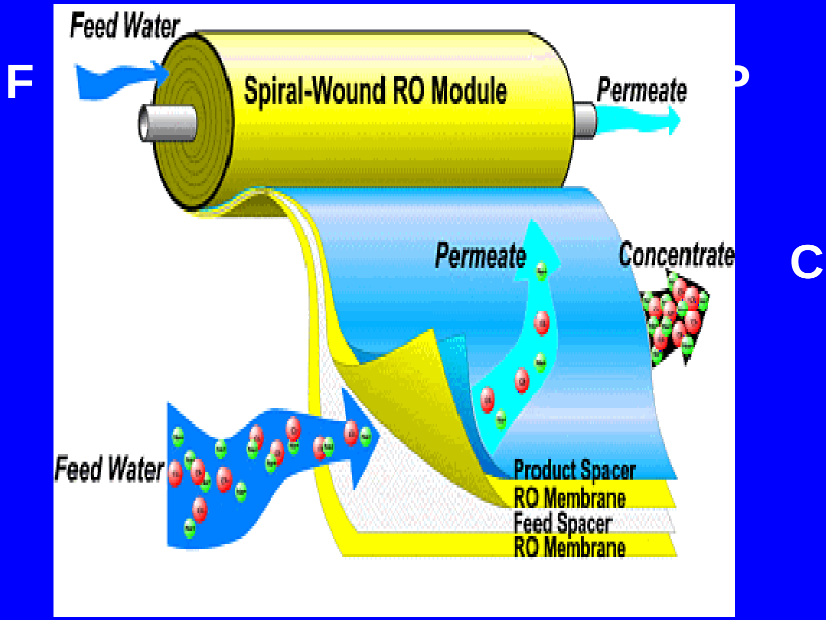
Reverse Osmosis Definitions (RO)

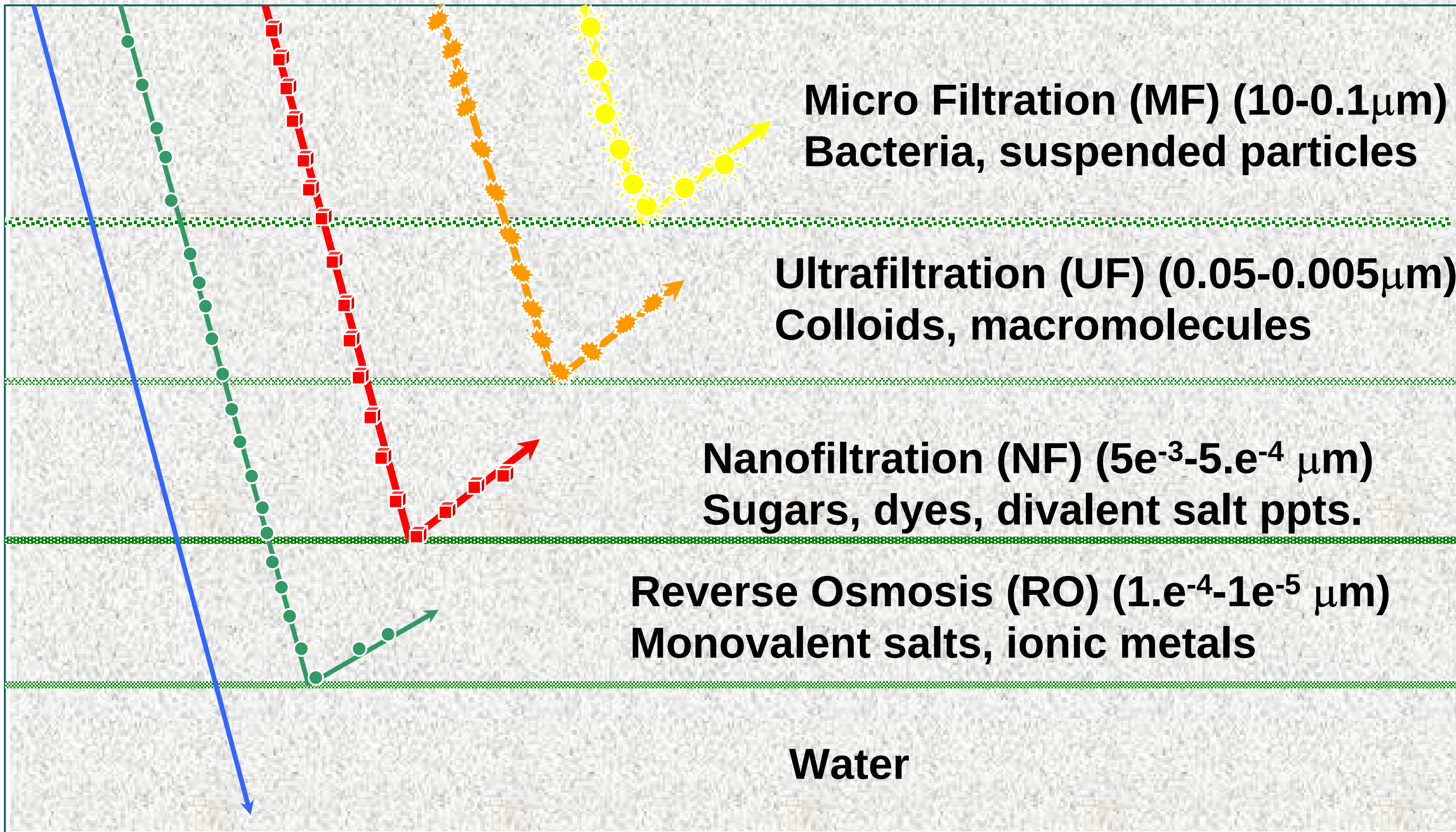
- *Salt rejection* $R = 1 - C_P / C_F$
- *Transmembrane pressure* $TMP = \left[\frac{P_F + P_R}{2}\right] - P_P$
- *Feed, permeate, reject or concentrate rates*
- *Fluxes (volumetric rate/area)*

Feed Flux: $J_F = Q_F / A$





Filtration and Reverse Osmosis: Definitions



N / Resources

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Waste Water Membrane Systems

King County Washington has selected hollow fiber microfiltration to treat wastewater to a high level. It can be used safely as a drought-proof water source for irrigation. Using membrane technology to filter wastewater, the process will be installed at the future Brightwater and Carnation wastewater treatment plants.

For more Info see:

mber 26, 2006

http://www.kingcountyjournal.com/

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Salt Rejection Characteristics of RO

Analyte	Raw Feed	RO filter permeate	Reduction
Alkalinity, Total as CaCO3	188	34	82%
Bicarbonate as HCO3	230	41	81%
Carbonate as CO3	< 1.2	1	n/d
Hydroxide as OH	< 1	1	n/d
Conductivity	33000	2270	93%
Magnesium	73	1	99%
Silicon	78	2	97%
Calcium	1055	23	98%
Potassium	124	5	96%
Sodium	11570	416	96%
Boron	87	34	61%
Silica	1664	4	99%
pH	6.1	7	
Solids, Total Dissolved TDS @ 180 C	38300	1291	97%

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Outline of Presentation

- 1. Why is Desalination a Big Deal Now?
- 2. What can the Technology Do?
- **3. Where are Projects Being Established?**

  4. When Will Desalination Allow Companies to Reduce Water Management Costs?
- 5. Example Projects

Where th rojects Are

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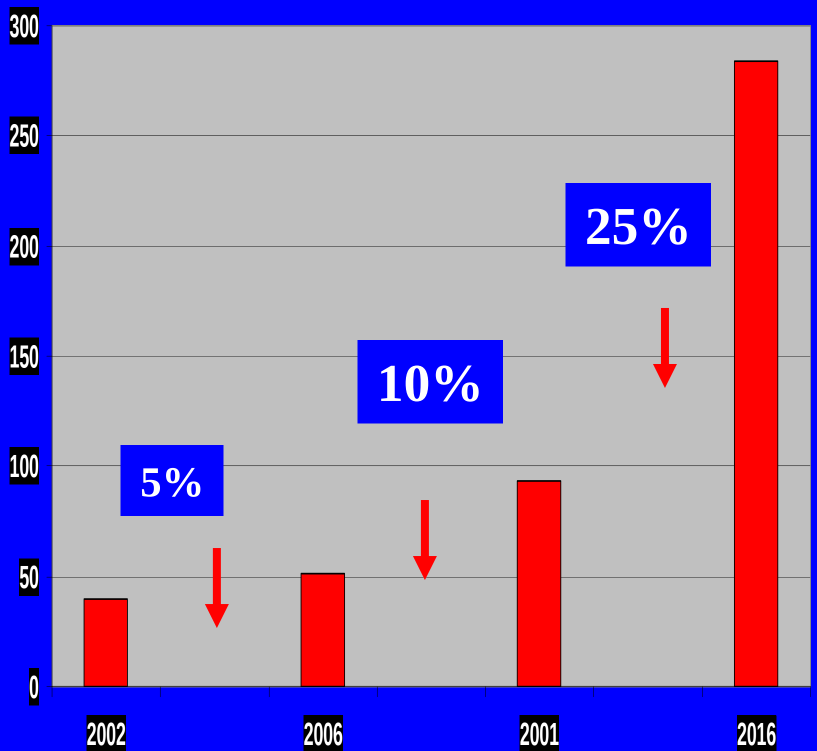
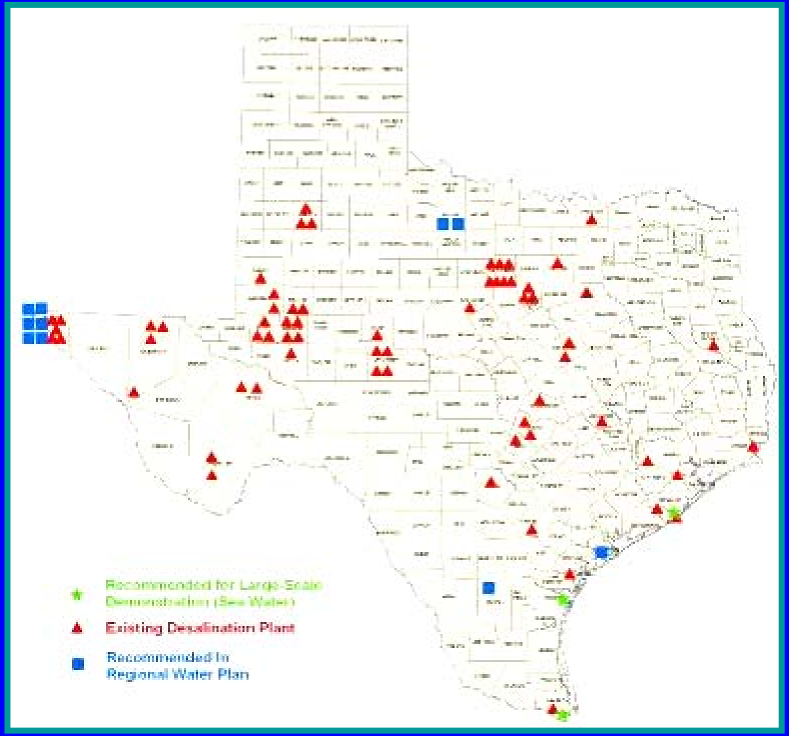
RO Desalination In Texas (2004)

A&M Estimates



Projected Growth of Facilities

Texas Water Development Board



Current Desalination Facilities

SPE ACTE September 26, 2006

Conventional produced brines in Texas

Where e Projects Are

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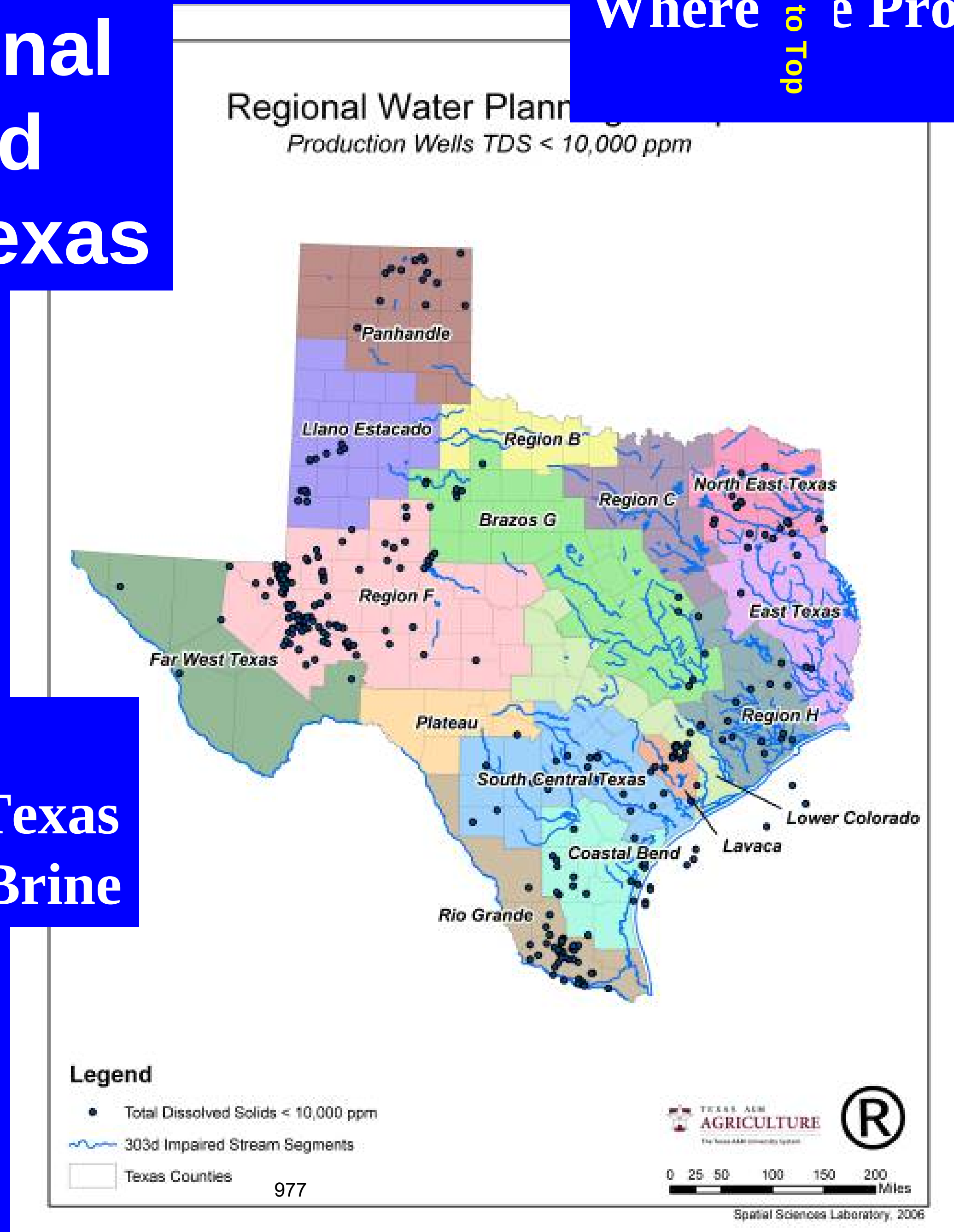
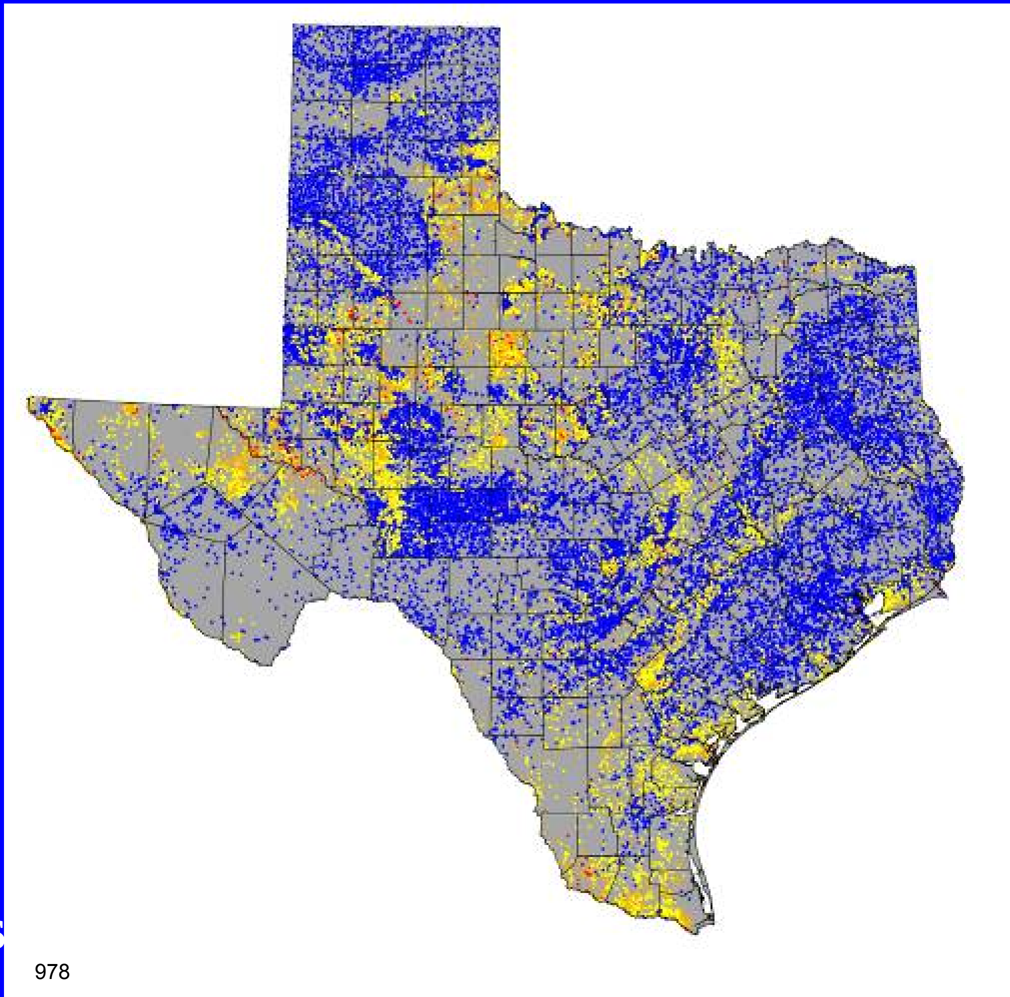


Oil & Gas Wells in Texas Brackish Produced Brine

New Resources: Brackish Groun Water Desalination

Ground water aquifers in Texas. have more than 780 million acre feet* of brackish water amenable to desalination.

*** =6 billion barrels**



For more Info see:

http://www.TWDB.state.TX.us

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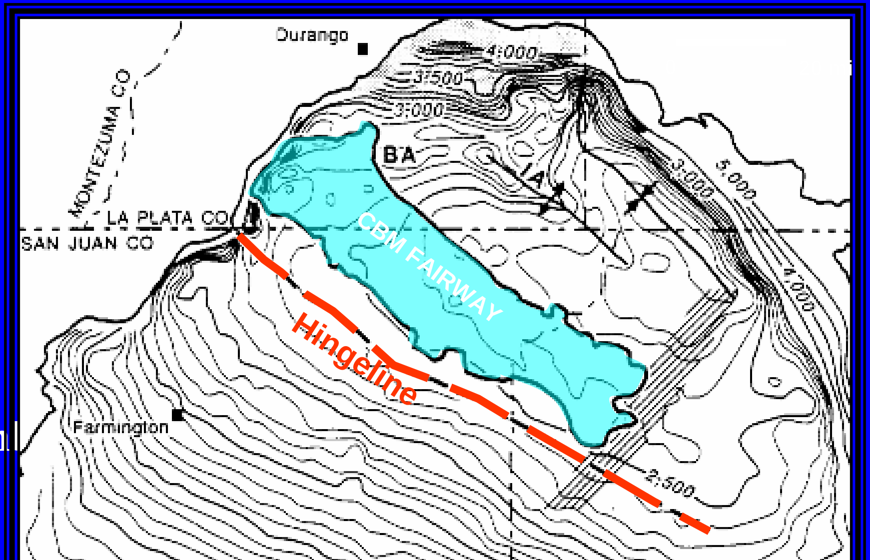
SAN JUAN BASIN

- Fruitland Fm – 50 Tcf Gas in place
- Fruitland produces 80% of U.S. coalbed gas
- Annual Production ~ 1 Tcf
- Giant field – cumulative production ~ 7 Tcf thru 2001
- Many Fruitland wells produce +1 MMcf/d
- *Fairway* – 80% of production is from <10% of the basin
- Geologic and hydrologic settings determine:
  - Gas and water production rates
  - Gas content and composition
  - Water composition
  - Completions and operations



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- 5. Example Projects

Cost Effect Desalination

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Representative power costs of desalination of oi eld brine

Salinity of Feed Brine, tds (ppm)	Power Costs Kw Hr per 1,000 gal. Permeate			
	Pre- treatment	RO desalination	Operating Cost, $ per 1,000 gal.	Operating Cost, $ per bbl
Contaminated Surface water ~1,500 tds.	$.65	$1.25	$1.90	$0.08
Gas well produced brine ~ 3,600 tds.	$2.50	$2.00	$4.50	$0.19
Oil well produced brine ~50,000 tds	$2.20	$6.00	$8.20	$0.34
Gas well produced brine ~ 35,000 tds	$2.00 (est.)	$4.20 (est.)	$6.20 (est.)	$0.26

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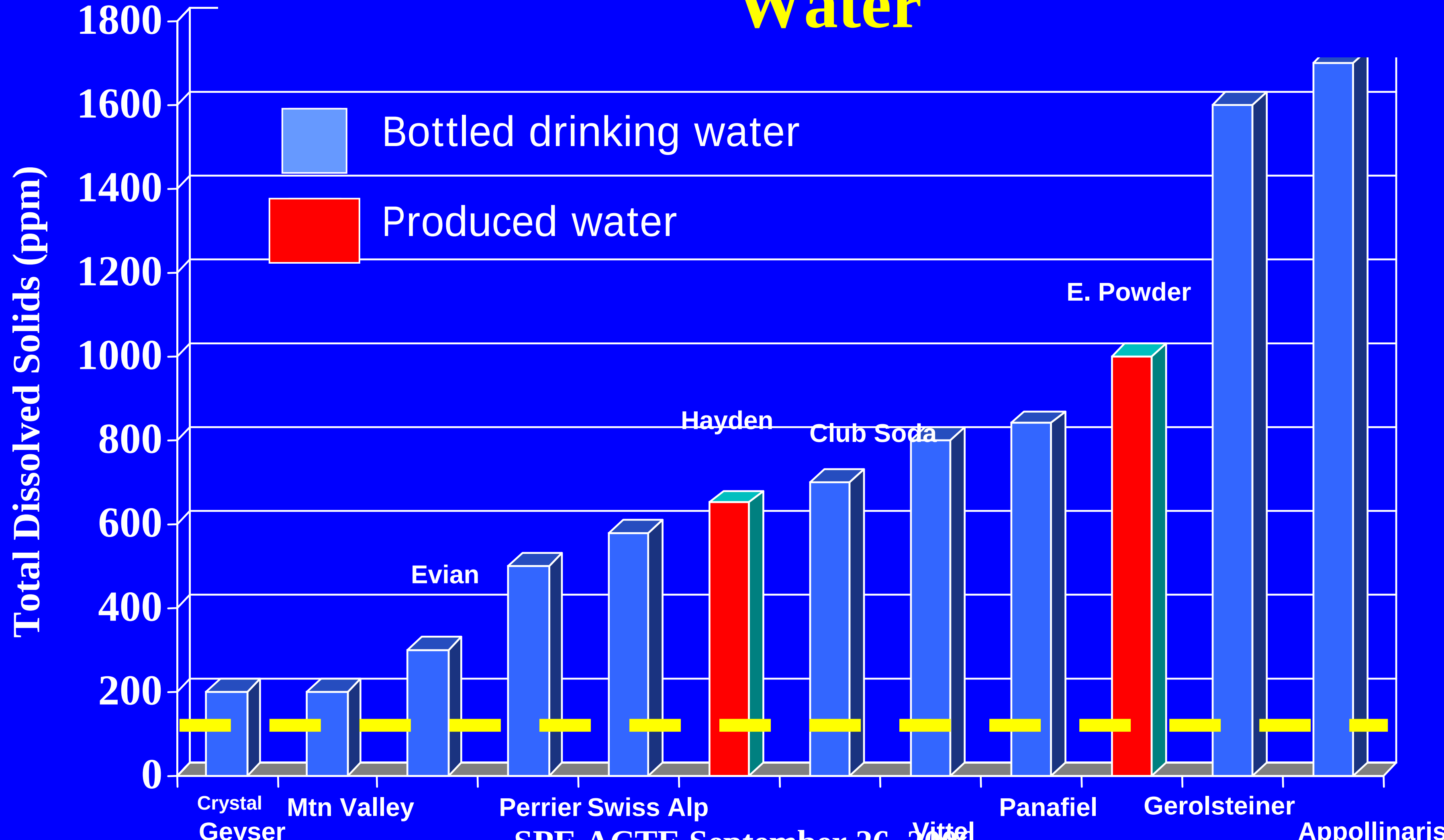
Relative CBM Water Quality vs. Bottled Water



Source: S. DeAlbuquerque, ConocoPhillips

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“Distributed” Desalination

Modular Facilities to Treat Variable Quality/quantity Inlet Streams

Desalination of Water at Point of Use

- **Proximity of the water resource a cost savings**
- **Provides “short term” water supply to fit needs**

Reuse of waste brine into depleted oil & gas zones.

- **Formations represent natural geologic traps**
- **Formations contain brine**
- **Reservoir Compartments already characterized**

urn to Top

Operator Training

urn to Top

Avoiding the Cost of Deep Well Injectic

Deep well Injection - Mickley Table 9.1 Report 069.pdf			
Fixed cost = well 16" at 3,400 ft	4,497,000		
Amortize over 30 yrs 6% interest	6%	$	326,702
Yearly operating costs			
Pumping cost - 150 gpm	per year		$50,000
treatment - corrosion inhibitor 150 gpm	per year	$	7,000
Total yearly for 150gpm			$57,000
Conversion of 150gpm in gallons per day	180000	gallons per day	
Multiple of 150gpm to deal with 5mgd	27.8	times 150 gpm	
Pumping + pre-treatment for 5mgd			$1,583,333
Amortization		$	326,702
Total Yearly Cost			$1,910,035
Number of 1000 gallons in 5mgd			1,825,000
Cost of deep well injection per 1000 gal			$1.05

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Outline of Presentation

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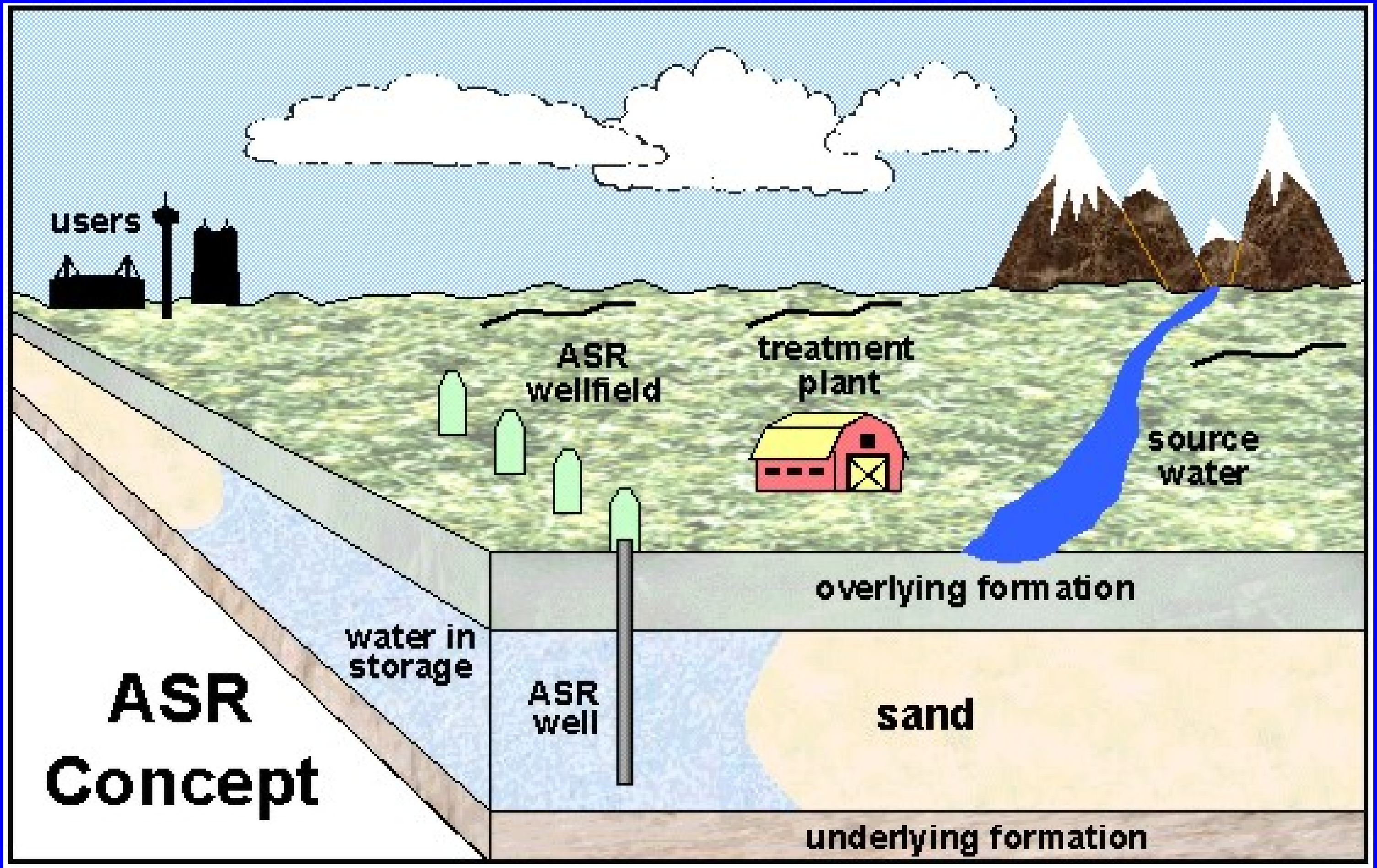
San Antonio Aquifer Storage & Recharge



http://www.edwardsaquifer.net/asr.htm

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Aquifer Storage & Recharge

- **San Antonio Water System Twin Oaks Aquifer Storage and Recovery project lessens impact on the Edwards by storing water during wet times for use during dry times when spring flows and endangered species habitats might be threatened. The $215 million project includes 16 wells spread over 3,200 acres to inject and recover water, 30 miles of pipeline, and the city's first water treatment plant**

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Ex ple Projects

•**Testing in Washington County, Texas** Fife# 3 Well

•40,000 TDS Brine

The Need

Example Projects

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Produced Water in the Permian Basin: Potential for Beneficial Use

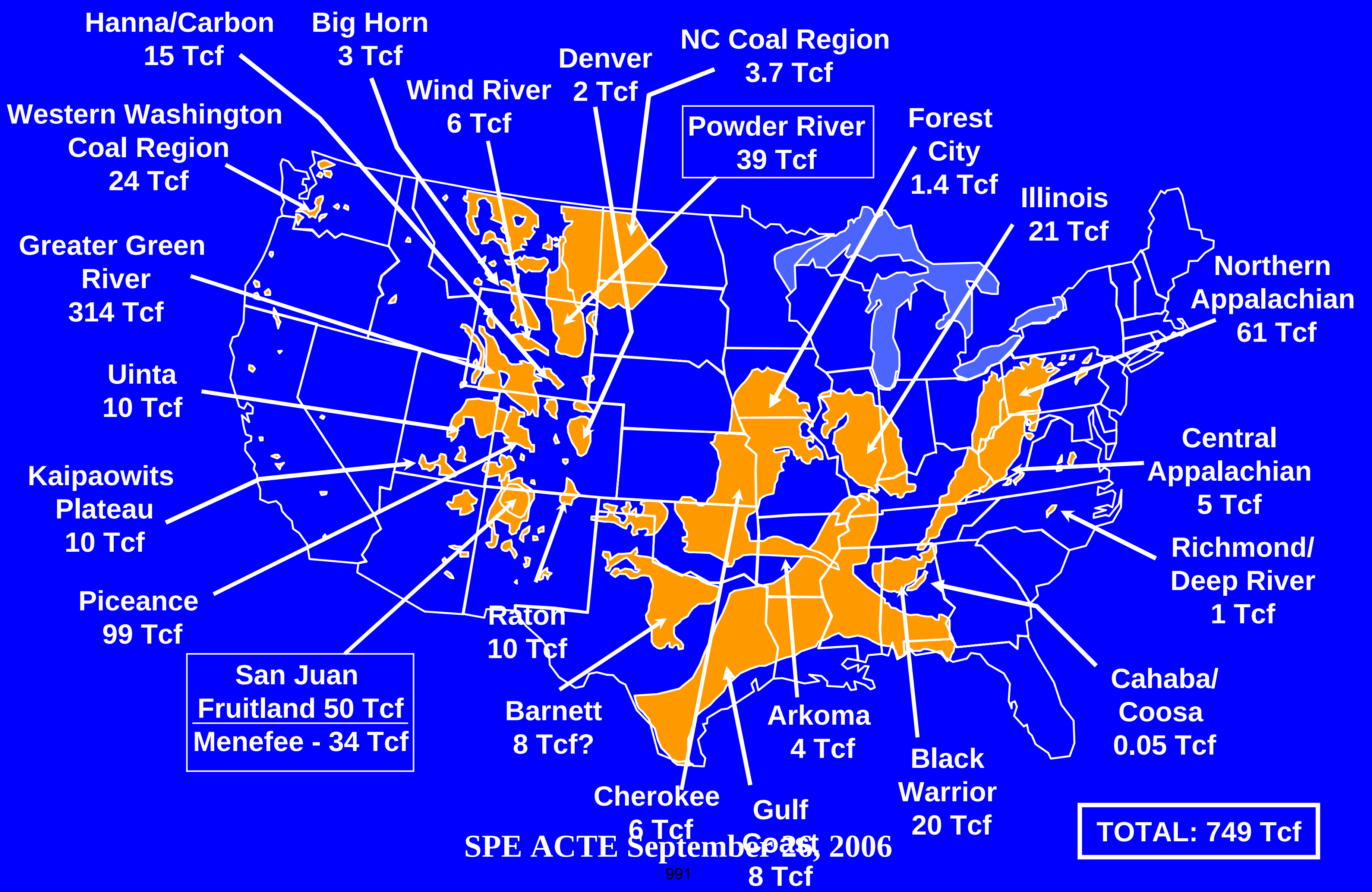
It is estimated that more than 390 million gallons of water per day go to re-injection disposal.

Less than 1% of this brine is re-used.

Where t[h]e Projects Are

Unconventional Gas Resou[rc]es

[Ret]urn to Top



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Natural Gas in Texas;

Unconventional Operations

NATURAL GAS: In contrast to oil, gas production in Texas is up from 4.5 trillion cubic feet a decade ago to about 5.1 trillion cubic feet last year. The growth can be explained in two words: Barnett Shale.
Sophisticated uses of technologies, such as 3-D seismic imaging, hydraulic fracturing and horizontal drilling, have enabled the North Texas field surrounding Fort Worth to become the cleanup hitter of the Texas energy industry. Production from the Barnett Shale reached almost 450 billion cubic feet in 2005, doubling the 220 billion cubic feet it produced in 2002.

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Palo Duro Shale;

Unconventional Operations

NATURAL GAS:

The Lower Pennsylvanian Shale of the Palo Duro Basin is similar in many of its geochemical characteristics to the prolific Barnett Shale of the Fort Worth Basin. Both are organically rich, thick fractured shales. Because the shale is over 300 feet thick in the Barnett Shale Group, publicly disclosed estimates suggest approximately 150-180 BCF of gas in place per section (640 acres per section).

Example Projects

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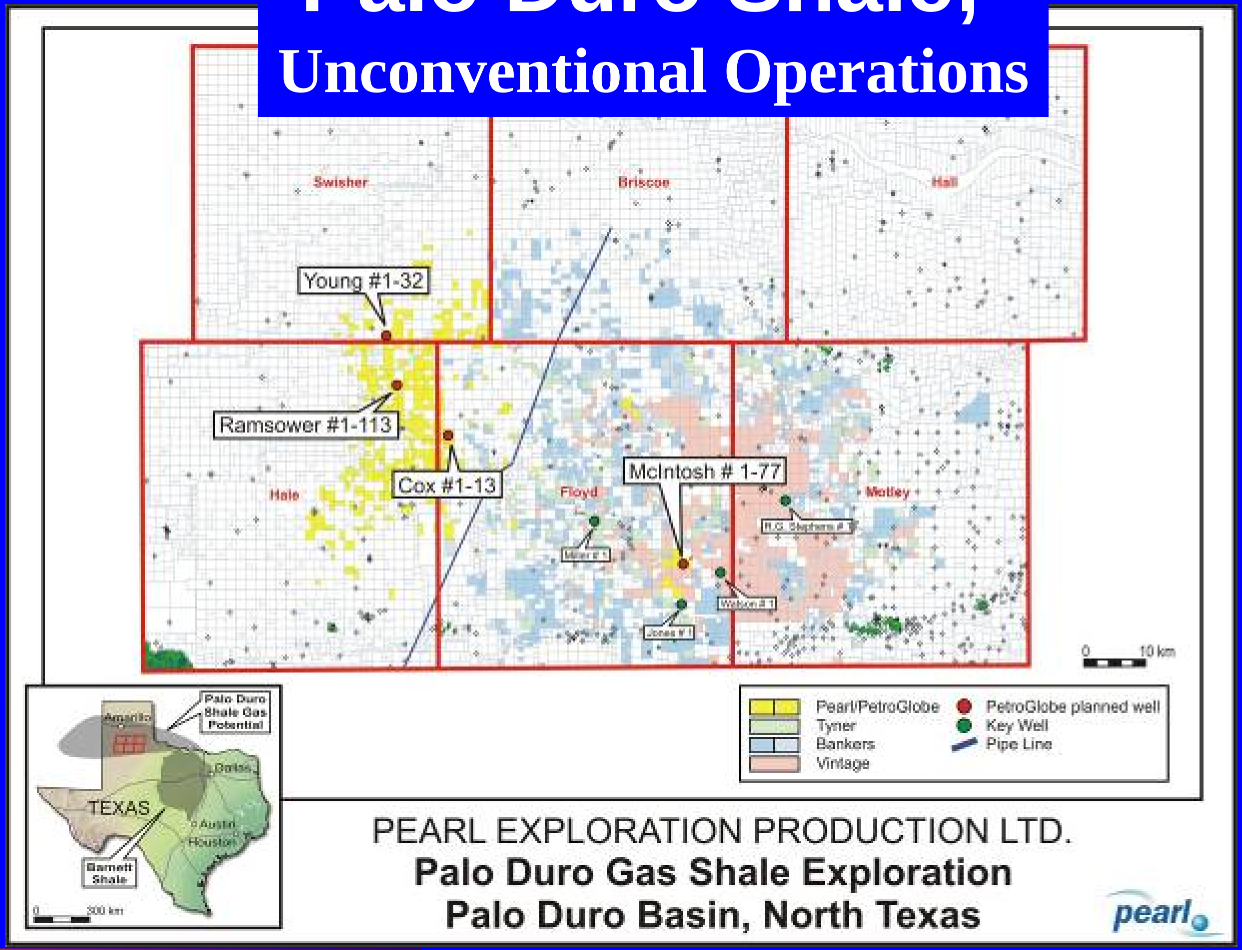
Palo Duro Shale;
Unconventional Operations



For more Info see:

http://www.ccnmatthews.com/docs/pearl1.jpg

SPE ACTE September 26, 2006

Produced Water in the Barnett Shale Play: Potential for Beneficial Use

It is estimated that more than 5 million gallons of water per day are used in fracturing operations. Most then goes to re-injection disposal.

More than 50% of this brine can be re-used in subsequent well fracs. As much as 24% can be recovered as fresh water for beneficial use.

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Desalination Unit: Barnett Shale SWD Wells

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Desalination of Brackish Wat &
Disposal into Waterflood Injection Wells

The City of Andrews Partnership

A Stripper Well Consortium 2005 - 2006 Project

979 845 2274
burnett@pe.tamu.edu

SWC Technology Transfer Meeting ,
Midland, TX 2005

SPE ACTE September 26, 2006

Portable Desalination Unit in McFaddin Texas (pop. 4)

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Thank you!

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The Need

Replacing Conventional Operations

Developing Low Impact
Oil and Gas:
Drilling, Transportation and Production

David Burnett, GPRI Department of Petroleum Engineering
Texas A&M University
Tom Williams, Maurer Engineering, Noble Corporation
Ali Kadastar Anadarko Petroleum
Rich Haut, Jim Lester Houston Advanced Research Center (HARC)
John Hall, Vik Rao, Helen O'Connor, Halliburton Services

Environmentally Friendly Drilling Systems

A Question:

Can you drill for and produce natural gas from environmentally sensitive areas without damaging the environment?

The Goals

A New Program: Integrated Systems for Environmentally Safe Drilling Practices

- *New technology can be adapted to oil and Gas E&P operations. Emissions to air and water and the impact on land forms could be reduced by more than 90% with*
  - *the implementation of new methods of transporting goods and materials through natural terrain.*
  - *New drilling platforms & New drilling practices*
  - *New multiphase fluid transport practices*
  - *New remediation practices*

The Need

Wetlands on Galveston Island.
Potentially significant gas find.
Problem:
How to get access with minimal impact.
How to measure the effect of low impact practices.

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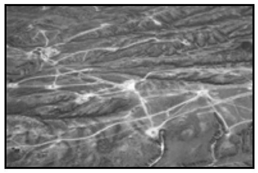
The Need

Addressing Environmental Issues: Development of Powder River Basin CBM



- "The disposal of 1.4 trillion gallons of water over the project's life – over 4 million acre feet; enough water for 16 million people, or all the residents of Wyoming for 30 years."

–http://www.wserc.org/alertsandevents.html

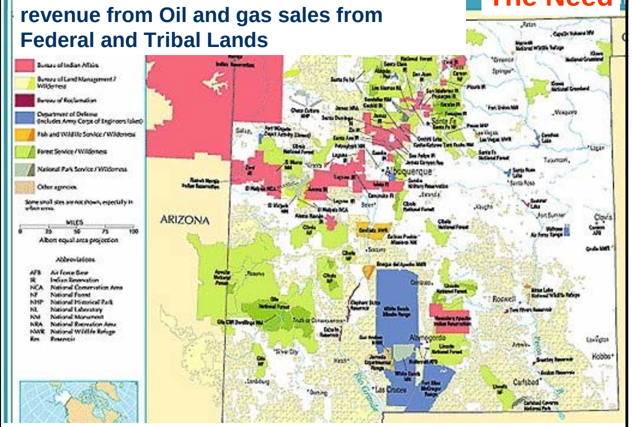
New Mexico Otero Mesa Area Problem:

How to gain access to estimated 2 tcf gas with minimal surface impact?

The Need

New Mexico Gets More than 40% of its tax revenue from Oil and gas sales from Federal and Tribal Lands

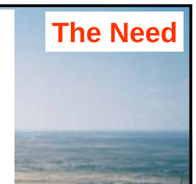
The Need



The Goals

Next Step: Minimal Impact Systems in Environmentally Sensitive Areas

Rio Vista Bluff Ranch, McFaddin Tx.



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The Goals

Objectives of New Program

(1) To incorporate current and emerging technologies into a clean drilling system with no or very limited environmental impact
(2) To demonstrate a viable drilling system used for the exploration and exploitation of oil & natural gas primarily in the lower 48 states (DOE proposal),
(3) To create a team of industry academic and government partners with the knowledge to apply the best drilling systems for use in ecologically sensitive areas, with an understanding of the benefit to the environment.

The Goals

Long Range Payoff

Energy Industry: Argonne National Laboratory estimated that 464 tcf of recoverable gas was placed beyond producers' reach because the regulations implementing the National Environmental Policy Act. In addition, drilling permit delays cost another 311 trillion cubic feet.

Environmental: In 2001 and 2002, more than 7,000 permits were issued for onshore drilling in National Parks. Big Thicket Preserve has more than 200 permit applications currently.

The Goals

Tomorrow's Potential Benefits from Pad / Modular Drilling

- Reduced E&P Risk, Development Cost, Environmental
- Increased Efficiency in Production Operations
- Improved Access to Culturally and Environmentally Sensitive Areas Through Better Technology

The Rationale

Keys to the Problem

Access to potential oil and natural gas resources is limited because of detrimental effect of exploration and production (E&P) activity required to extract petroleum. Enabling technology is sought that would allow "road less" access to remote sites, with pad free drilling, and self contained operations at sites with minimum air or water emissions, and mobilizing/demobilizing practices to employ when activity moves away for the sites.

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The Resources

Low Impact Systems (Anadarko Arctic Platform)

Emerging Technologies, SPI Oct. 2005

Platform Drilling

The Resources

Anadarko/Maurer/DOE HOT ICE well utilizing the Platform on the North Slope in 2003

The Resources

Road Free Access:
Rolligon transportation

The Resources

Arctic Platform Project Summary

Extremely Successful:

- **Protecting Personnel Health & Safety…**
  - No fatalities
  - No lost time accidents
  - No medical treatment cases
- **Protecting the Environment...**
  - No reportable spills
  - No significant environmental damage
  - No notices of violation or fines
  - No damage to tundra

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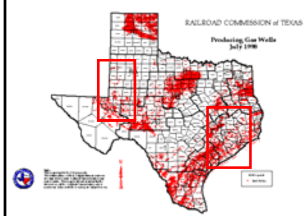
The Resources

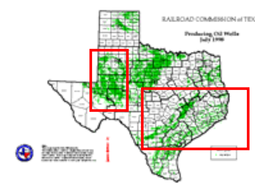
Extended Reach Drilling (ERD) - Drilling 15 to 20 mile lateral wells (current 7 mile technical limit

- Lightweight drillpipe, floating drillpipe, and rotary-steerable tools that reduce hole friction and greatly increase drilling distances.
- More efficient rigs
- Lightweight, gasified and hollow sphere drilling fluids that improve hole cleaning and reduce lost circulation problems.
- Expandable casing that will greatly reduce the casing size and casing weight.
- Systems that allow drilling with casing.
- Retractable bits and motors that eliminate trips.
- Dual-gradient drilling systems that reduce bottomhole pressures.
- Long life bits that drill long distances and eliminate trips.

The Rationale

Oil and Gas Production in Texas Coastal and Desert Regions





Oil Wells

Gas Wells

The Resources

Less damaging transportation: Rolligon

Texas A&M Desert Ecosystem Test Facility

The Resources

The Texas Transportation Institute (TTI) and Applied Research Associates (ARA), Inc., in cooperation with the Pecos Economic Development Corporation, have leased a 5,800-acre research and testing facility in Pecos, Texas. Pecos is located about 90 miles west of Midland-Odessa and is accessible from the Midland International Airport.

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The Resources

Drilling System Test Site

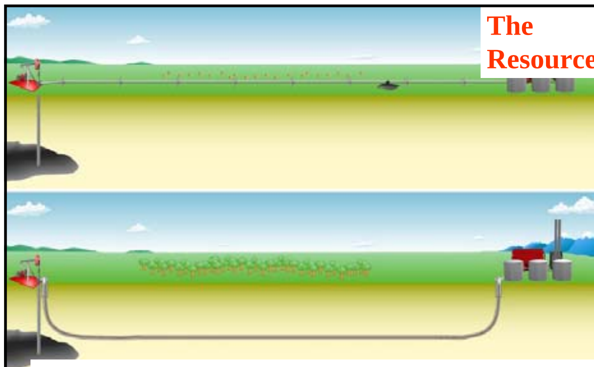
The Need

Access: Can you Create a Disappearing Road?

The Need

Site: Can you Create a Disappearing Well?

The Resources



Landmark Graphics and Sperry Sun in the paper titled "U Tube Wells; Connecting horizontal wells End to End Case Study: Installation and Construction of the World's First U Tube Well"

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The Resources

Hybrid coiled-tubing drilling rig (courtesy of DOE and Tom Gipson – New Force Energy Services, Inc

The Resources

A&M Desalination Rig at McFaddin Store

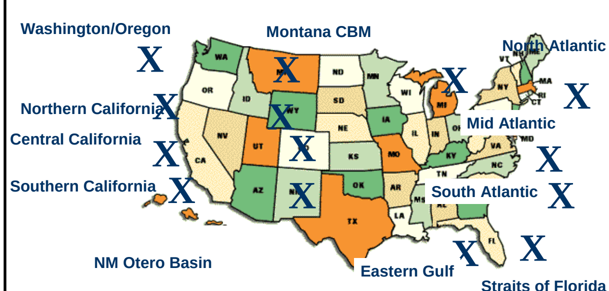
The Organization

Option:

Design, build and deploy scale model to monitor over extended time.

The Need

Environmental Barriers Put Gas Reserves off Limits



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Thank You

Summer 2003

Anadarko Modular, Mobile Drilling Platform

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Texas A&M University
Department of Petroleum Engineering
Global Petroleum Research Institute

Environmental Drilling Systems

TEXAS A&M
THE HAROLD VANCE DEPARTMENT OF PETROLEUM ENGINEERING

GPRI

WHO:

Texas A&M University, Noble Drilling, Anadarko Petroleum, the Houston Advanced Research Center (HARC), and GPRI Industry Advisory Committees.

Home to endangered plant and animals. EIS approval may delay drilling prospects by more than a year.

Padre Island Seashore.

TEXAS A&M PETROLEUM ENGINEERING

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WHAT:

A research collaboration to test and adapt technologies designed for exploiting natural gas resources with a reduced environmental footprint.

Home to endangered plant and animals. Park Superintendent has more than 200 drilling permit applications on his desk.

Big Thicket National Preserve

WHY:

Environmental Issues are going to be more and more important……

The value of oil & gas resources in environmentally sensitive areas is becoming more and more valuable…….

An endangered hardwood forest bottomland and home to endangered plant and animals, Big Thicket has more than 200 drilling permit applications on file.

Big Thicket National Preserve

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HOW:
Innovative technologies have the potential to provide "pad-free" and "road free" acess to oil & gas

Hybrid coiled-tubing drilling rig (courtesy of DOE and Tom Gipson – New Force Energy Services, Inc.

KEY TECHNOLOGIES:

•Platform drilling to eliminate well pads.

Light weight easily deployable CT drilling systems.
Extended reach drilling and multiple well templates from platforms.

Elimination of pipelines roads via horizontal boreholes.

Multiphase Pumping to eliminate surface equipment
Closed systems fluid and materials handling

Other?

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Example: Pad-Free Platform Drilling

Anadarko's platform deployed on the North Slope (Kadaster and Milheim[2]). Field application of the new platform clearly demonstrated the ability to dramatically decrease the footprint and environmental effects of drilling operations in ecologically sensitive areas. This project also showed that a system could be installed "road less" without any adverse impact on the tundra, and that a zero-discharge facility could be operated safely.

Example: Subterranean Pipelines

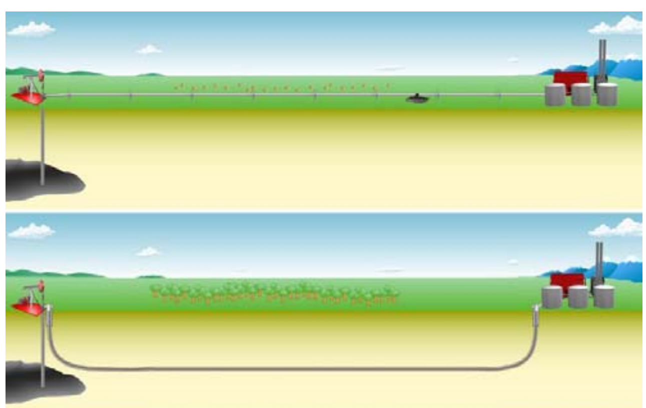
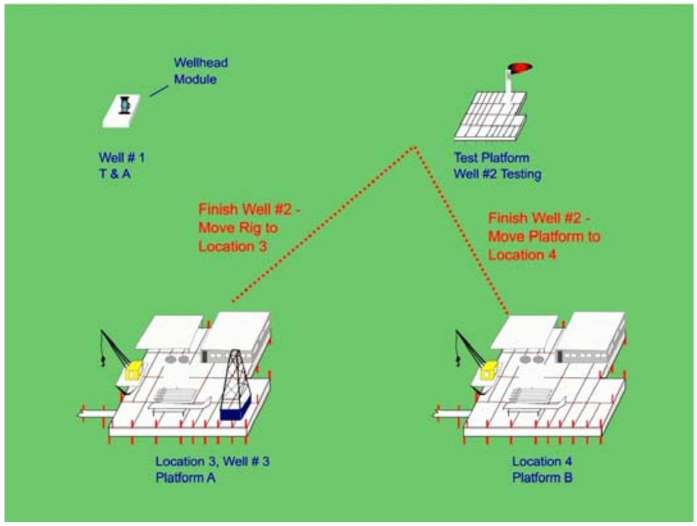


Fig. 9 — Environmentally sensitive or politically hostile environments.

Environmentally sensitive areas where pipeline and well access roads are to be avoided could take advantage of extended reach horizontal borehole construction, such as the technology demonstrated by Landmark Graphics and Sperry Sun, "U Tube Wells; Connecting horizontal wells End to End Case Study: Installation and Construction of the World's First U Tube Well"



"Hop-scotch" drilling procedure enables allows two platforms and one rig to carry out multi-well program to expand the operating window in environmentally-sensitive areas (Anadarko)

Example: Pad Free Drilling

Anadarko's Arctic Platform during operations on the North Slope

Environmental Drilling:
Details

1. Public/private collaborations
2. DOE Funding Request $1.3 MM
3. Anadarko Platform Contribution
4. GPRI Industry Support Phase 1
   $200,000 cash and in kind support

Environmental Drilling:
Scope of Work

1. **Engineering study identifying key components**
2. **Component testing in desert ecosystems**
3. **Component testing in coastal margin**
4. **Environmental Monitoring and socio-economic studies**
5. **Integration into prototype system**
6. **Test prototype system**

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Alternative Access to Well Sites

Early tests of design of spiral legs for platform foundations (UAA, "Tundra Platform Leg Tests," Feb. 2003)

Environmental Component of Program

Deliverables focusing on environmental access:

(1) Explore public perception of access to environmentally sensitive areas for drilling operations.

(2) Assess the potential reduction of environmental impacts on ecological and cultural resources;

(3) Investigate the appropriateness of alternate technical approaches in an environmental domain in which the industry right of access is currently provided.

Engineering Component of Program

Deliverables focusing on low footprint technology:

(1) Pad Free Drilling

(2) No road access

(3) Closed system materials handling

(4) Low intrusion operations (noise, visibility, emissions)

Organization of Program

Phase 1 Engineering Study

Phase 1 Key Component Testing

Phase 2 Integration of Components into Systems

Phase 3 Prototype drilling system drilling system deployed.

An Overview of GPRI Functions

GPRI since 1997 has provided

• A "Fast Track" Path for Funding Oil and Gas Joint Venture Research Projects

What Does GPRI Do?

•Administration of Projects: Implementation,
Distribution of Funding, Project Management
•Research Advocate for GPRI Member Projects
•Coordinates research with other industry activities
•Facilitates A&M researchers contacts with oil and gas industry.

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Examples : GPRI and A&M On-going Programs

Example: Testing in West Texas

West Texas Test Facility, to be operated by A&M. The 6000 acre facility provides an ideal location to test deployment of the Anadarko platform in desert environments and to configure it and other systems for low impact drilling. The West Texas Test Site is less than 100 miles to Lea County New Mexico and oil and gas resources there.

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Example: Coastal Margins

Threatened Species (Endangered: Mexican Breeding Population)

The Olive Ridley turtle was listed as endangered for the "Mexican nesting population" and threatened for all other populations on July 28, 1978.

With pad-free drilling, extended reach drilling and innovative transportation to and from the well site such risks are avoided

A&M Ft Hood Waterways Restoration

Specialized remediation and stabilization studies implemented to mitigate effects of equipment movements.

TEXAS A&M PETROLEUM ENGINEERING

Ft Hood Range Restoration

May 2003

September 2003

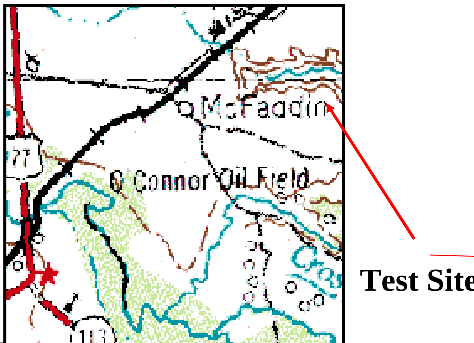
May 2004

Oil and Gas Resource Development Limited by Access

- Unconventional Gas on Federal Lands
- Oil and Gas in Federal and State public lands
- Environmentally sensitive coastal margins

Environmental vs. Oil & Gas Extraction:

Historic McFaddin Ranch & O'Connor Oil Field



Lone Star Land Steward Awards

- Rio Vista Bluff Ranch
- Landowner: Jan K. Wheelis
- 883 Alcalde de la Bahia
- Goliad, Texas 77963
- 361-645-3458

- Jan has owned Rio Vista Bluff for 17 years.
- It has been in her family for 137 years

Environmental vs. Oil & Gas Extraction:

Texas Coastal Margins Development

Wetlands & Riparian Areas

Rio Vista Bluff Ranch

Hardwood Bottomland Forests at Risk

Federal Lands: Powder River Basin Map

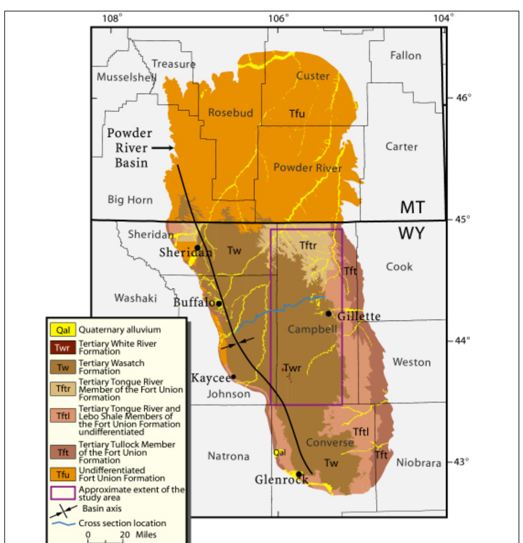


Figure 1. Generalized geologic map of the Powder River Basin,Wyoming and Montana showing the basin axis, counties, major cities, location of cross section (fig. 2), and approximate extent of the study area (modified from Flores and Bader, 1999).

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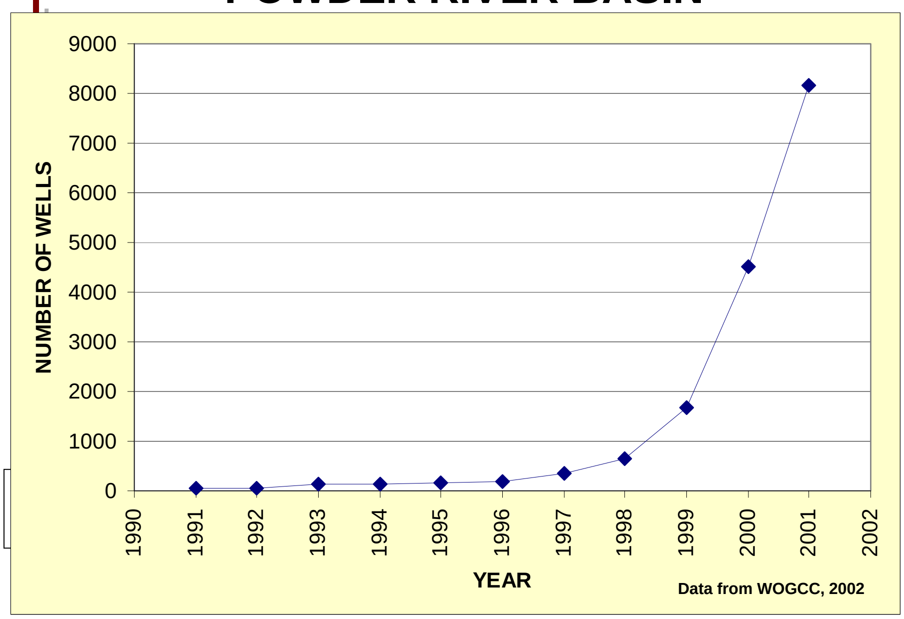
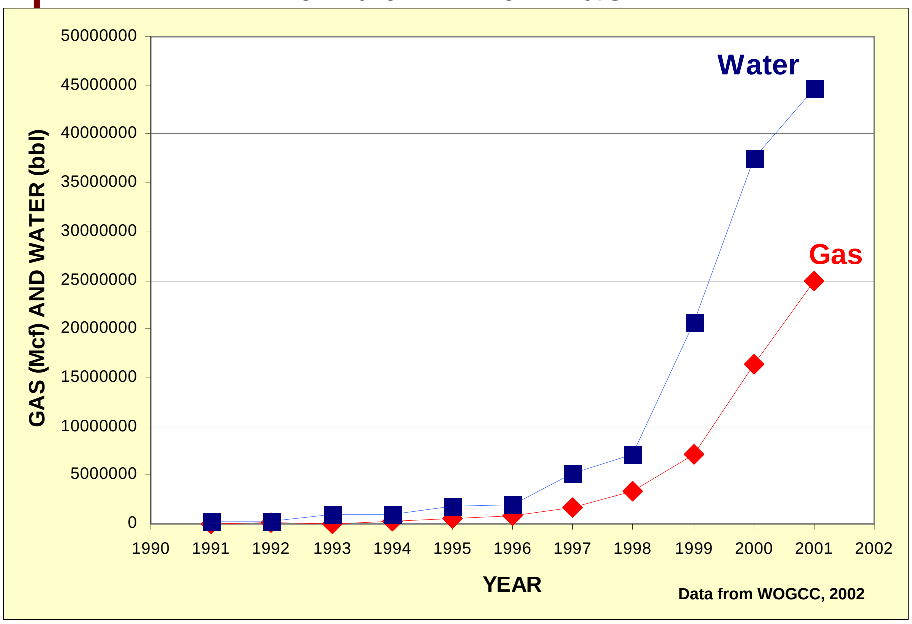
BLM Rangeland at Risk: Powder River Basin Coal Bed Methane Water Discharge

NUMBER OF COALBED GAS WELLS, POWDER RIVER BASIN



COALBED GAS AND WATER PRODUCTION, Powder River Basin



POWDER RIVER BASIN COALBED GAS PRODUCTION

- *Average gas production - 135 Mcf/d per well (August 2000)*
- *1.28 MMbw/d (average 518 bw/d per well; March 2000)*
- *Water/gas ratio is 3-4 bbl/Mcf early, dropping to 1-2 bbl/Mcf*
- *Reserves are 200 - 400 MMcf/well*

Data from Dwight's, after Pratt et al. ,1999; Montgomery, 1999; Rice and others, 2000

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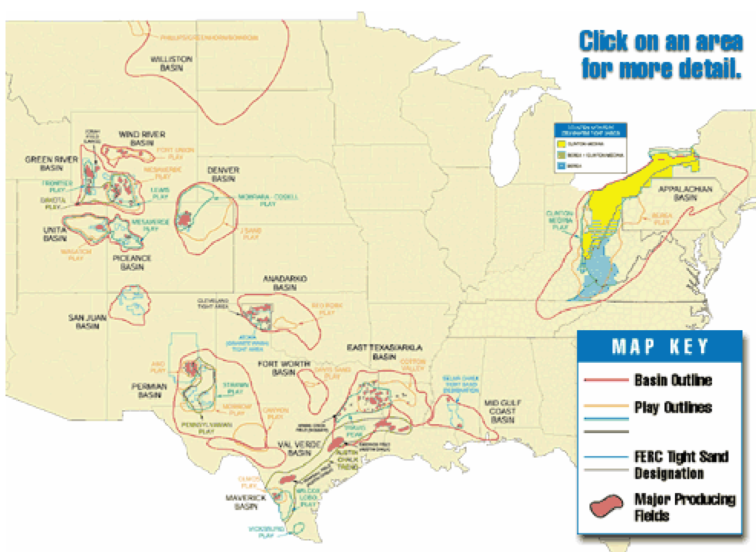
Texas A&M University's Global Petroleum Research Institute prototype oilfield-brine desalination unit in McFaddin Texas. The unit will be tested in August at McFaddin's Rio Vista Bluff Ranch, which will use the fresh water produced



http://www.eandpnet.com/tightgassite/

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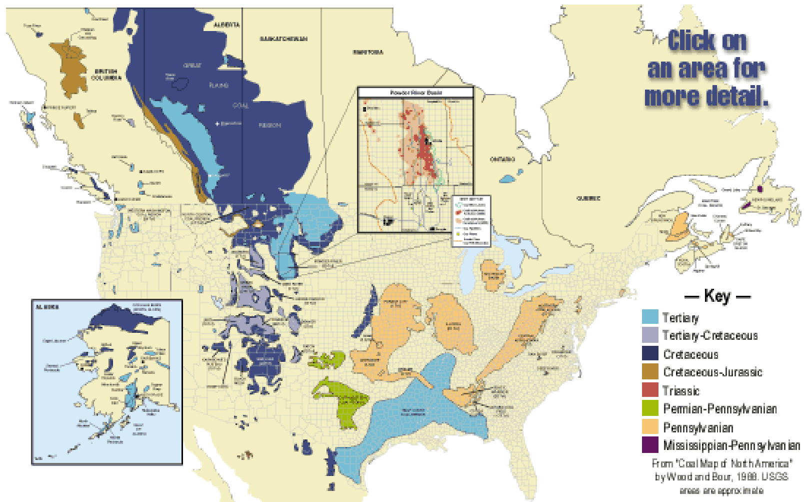
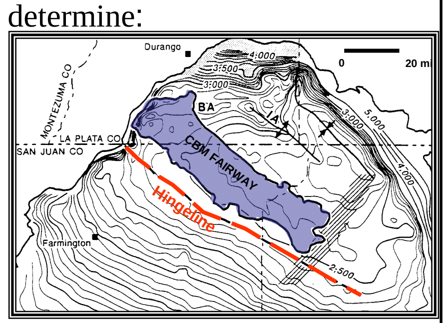
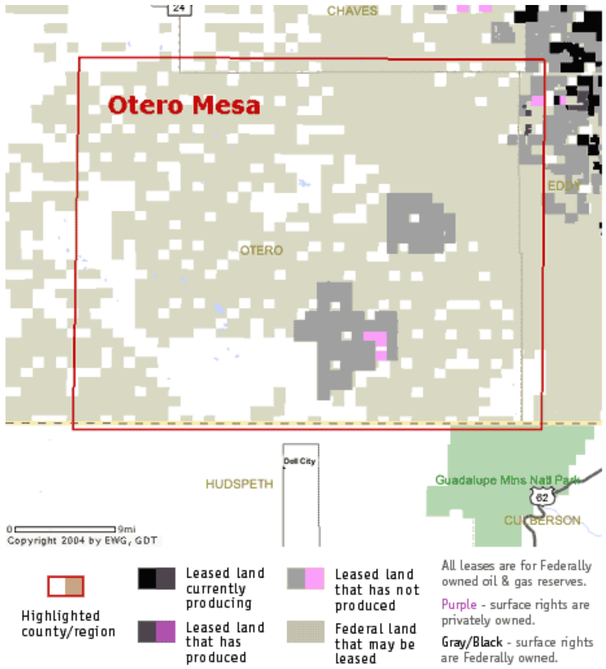


CBM Resources in USA

SAN JUAN BASIN

- Fruitland Fm – 50 Tcf Gas in place
- Fruitland produces 80% of U.S. coalbed gas
- Annual Production ~ 1 Tcf
- Giant field – cumulative production ~ 7 Tcf thru 2001
- Many Fruitland wells produce +1 MMcf/d
- *Fairway* – 80% of production is from <10% of the basin
- Geologic and hydrologic settings determine:
  - Gas and water production rates
  - Gas content and composition
  - Water composition
  - Completions and operations





Example: Limiting Access to Federal Lands in New Mexico

Otero Mesa Landscape

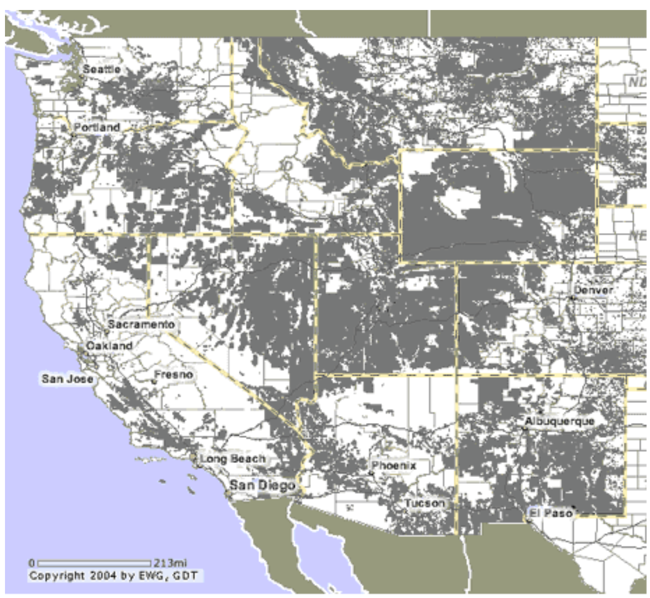
Example: A&M Produced Water Management

Fresh Water Resources from Oil & Gas Field Produced Brines

- *Beneficial Use vs. Disposal*

Allan Jones, Director Texas Water Resources Institute, Texas A&M University

David Burnett, Department of Petroleum Engineering, Texas A&M University



Lands leased or offered for oil and gas drilling, 1982-present

Participants in A&M Produced Water Desalination Program

GPRI Sponsoring Companies
- BP
- Burlington Recourses
- Key Energy
- Tarlton Mfg.
- Total

Contractors
- Polymer Ventures
- Costner Industries Texas
- McFaddin Ranches

Agencies
- Texas Water Resources Institute
- Ground Water Protection Council
- Texas Railroad Commission
- TCEQ
- Stripper Well Consortium
- NYSERDA
- U. S. Department of Energy

TEXAS A&M PETROLEUM ENGINEERING

Maurer Technology — A Noble Corporation Subsidiary

Recreation, Park & Tourism Sciences — Texas A&M University

HARC

TEXAS A&M — The Harold Vance Department of Petroleum Engineering

Contact:
Mr. David Burnett
Texas A&M University
979-845-2274
burnett@pe.tamu.edu

Dr. Joseph O'Leary
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979-845-7324
joleary@tamu.edu

Mr. Tom Williams
Maurer Technology Inc.
281-276-6750
twilliams@noblecorp.com

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- **Thank you!**

GPRI
Harold Vance Department of Petroleum Engineering
Texas A&M University

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Environmentally Friendly Drilling Systems

A Question:

Can you drill for and produce natural gas from environmentally sensitive areas without damaging the environment?

The Need

Replacing Conventional Operations

**Developing Low Impact
Oil and Gas:
Drilling, Transportation and Production**

David Burnett, GPRI Department of Petroleum Engineering Texas A&M University
Tom Williams, Maurer Engineering, Noble Corporation
Ali Kadastar Anadarko Petroleum
Rich Haut, Jim Lester Houston Advanced Research Center (HARC)
John Hall, Vik Rao, Helen O'Connor, Halliburton Services

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The Goals

A New Program: Integrated Systems for Environmentally Safe Drilling Practices

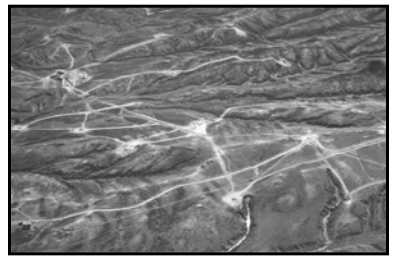
- *New technology can be adapted to oil and Gas E&P operations. Emissions to air and water and the impact on land forms could be reduced by more than 90% with*
  - *the implementation of new methods of transporting goods and materials through natural terrain.*
  - *New drilling platforms & New drilling practices*
  - *New multiphase fluid transport practices*
  - *New remediation practices*

Wetlands on Galveston Island.
Potentially significant gas find.
Problem:
How to get access with minimal impact.
How to measure the effect of low impact practices.

The Need

The Need

Addressing Environmental Issues: Development of Powder River Basin CBM



•"The disposal of 1.4 trillion gallons of water over the project's life – over 4 million acre feet; enough water for 16 million people, or all the residents of Wyoming for 30 years."

–http://www.wserc.org/alertsandevents.html

The Need

New Mexico Otero Mesa Area Problem:

How to gain access to estimated 2 tcf gas with minimal surface impact?

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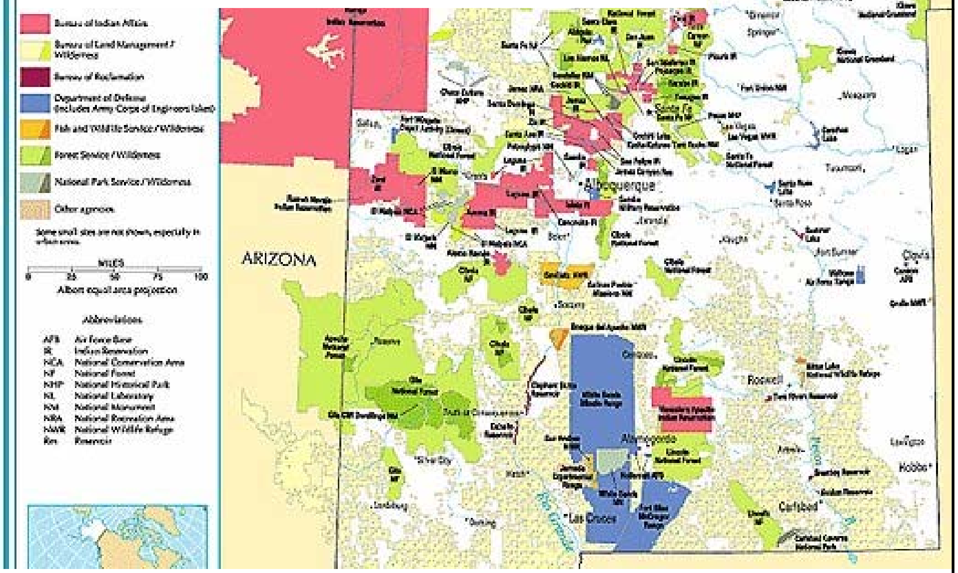
The Need

New Mexico Gets More than 40% of its tax revenue from Oil and gas sales from Federal and Tribal Lands



The Goals

Next Step: Minimal Impact Systems in Environmentally Sensitive Areas

Rio Vista Bluff Ranch, McFaddin Tx.

The Goals

Objectives of New Program

(1) To incorporate current and emerging technologies into a clean drilling system with no or very limited environmental impact
(2) To demonstrate a viable drilling system used for the exploration and exploitation of oil & natural gas primarily in the lower 48 states (DOE proposal),
(3) To create a team of industry academic and government partners with the knowledge to apply the best drilling systems for use in ecologically sensitive areas, with an understanding of the benefit to the environment.

The Goals

Long Range Payoff

Energy Industry: Argonne National Laboratory estimated that 464 tcf of recoverable gas was placed beyond producers' reach because the regulations implementing the National Environmental Policy Act. In addition, drilling permit delays cost another 311 trillion cubic feet.

Environmental: In 2001 and 2002, more than 7,000 permits were issued for onshore drilling in National Parks. Big Thicket Preserve has more than 200 permit applications currently.

The Goals

Tomorrow's Potential Benefits from Pad / Modular Drilling

- Reduced E&P Risk, Development Cost, Environmental
- Increased Efficiency in Production Operations
- Improved Access to Culturally and Environmentally Sensitive Areas Through Better Technology

The Rationale

Keys to the Problem

Access to potential oil and natural gas resources is limited because of detrimental effect of exploration and production (E&P) activity required to extract petroleum. Enabling technology is sought that would allow "road less" access to remote sites, with pad free drilling, and self contained operations at sites with minimum air or water emissions, and mobilizing/demobilizing practices to employ when activity moves away for the sites.

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Oil & Gas Industry Historic Response to Challenges

1964 - 1980

Conventional Technologies

1980 - 1990

Advanced Technologies
- Gravel roads
- Specially designed rigs
- Drilling advances

1990 - 2000

Moving away from the Infra-Structure
- Ice roads & pads
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- Coiled Tubing / Horizontals

2005 - 2015?

Exploration with minimal impact systems in environmentally sensitive areas

The Resources

Low Impact Systems (Anadarko Arctic Platform)

Emerging Technologies, SPI Oct. 2005

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Platform Drilling

The Resources

Anadarko/Maurer/DOE HOT ICE well utilizing the Platform on the North Slope in 2003

The Resources

Road Free Access:
Rolligon transportation

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Arctic Platform Project Summary

Extremely Successful:

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The Resources

Extended Reach Drilling (ERD) - Drilling 15 to 20 mile lateral wells (current 7 mile technical limit

- Lightweight drillpipe, floating drillpipe, and rotary-steerable tools that reduce hole friction and greatly increase drilling distances.
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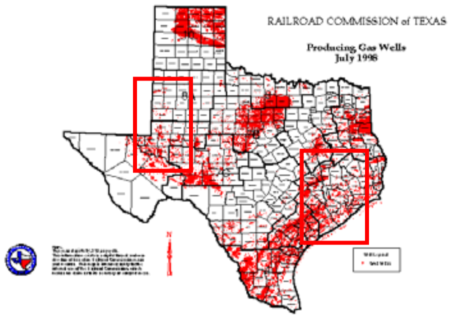
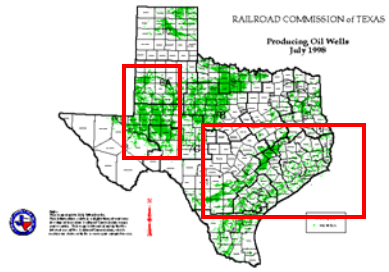
The Rationale

Oil and Gas Production in Texas Coastal and Desert Regions



Oil Wells



Gas Wells

The Resources

Less damaging transportation: Rolligon

Texas A&M Desert Ecosystem Test Facility

The Resources

The Texas Transportation Institute (TTI) and Applied Research Associates (ARA), Inc., in cooperation with the Pecos Economic Development Corporation, have leased a 5,800-acre research and testing facility in Pecos, Texas. Pecos is located about 90 miles west of Midland-Odessa and is accessible from the Midland International Airport.

The Resources

Drilling System Test Site

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The Need

Access: Can you Create a Disappearing Road?

The Need

Site: Can you Create a Disappearing Well?

HARC Blue Water Technology Consortium

The Houston Advanced Research Center (HARC) is collaborating with the Naval Surface Warfare Center, Carderock Division (NAVSEA-Carderock), a 3,000-person Naval research organization, to take existing Navy-developed technology and apply it to the needs of the offshore and maritime industry.

The Resources

Navy Zero Discharge Drilling Systems

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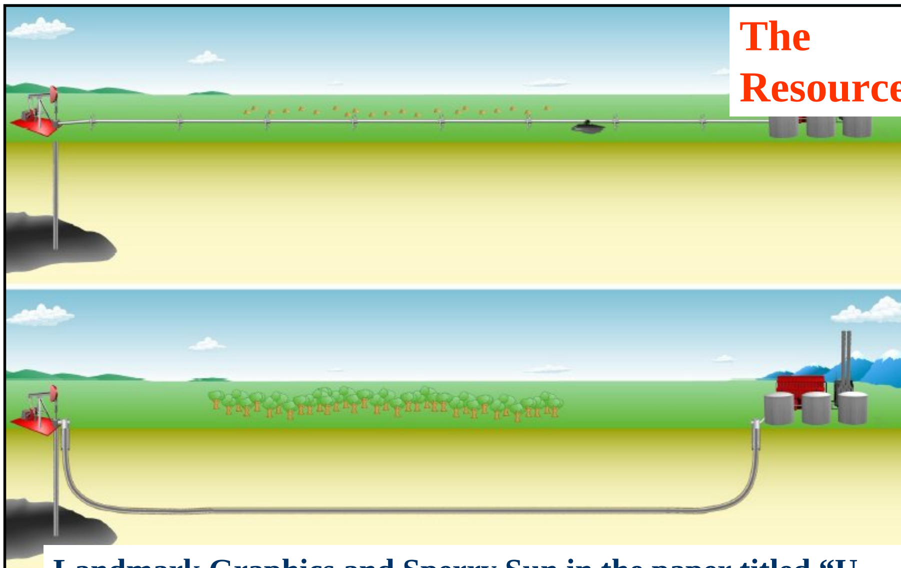
The Resources



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The Resources

Hybrid coiled-tubing drilling rig (courtesy of DOE and Tom Gipson – New Force Energy Services, Inc

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The Resources

A&M Desalination Rig at McFaddin Store

The Organization

Option:

Design, build and deploy scale model to monitor over extended time.

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The Need

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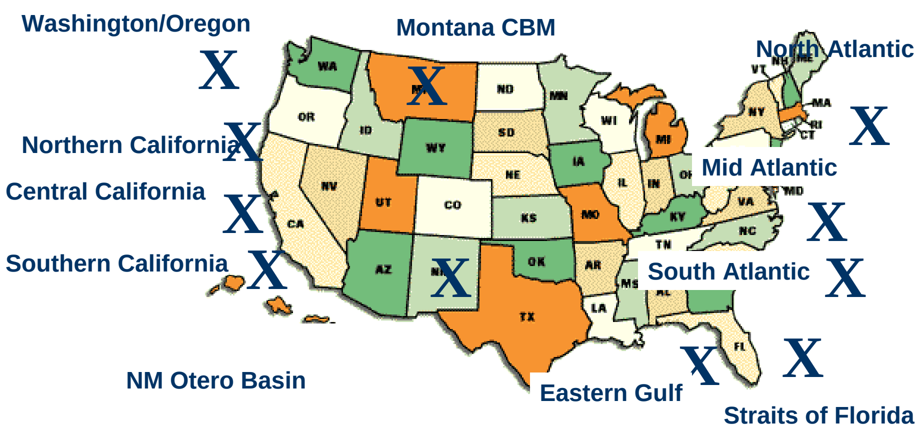

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Thank You

Summer 2003

Anadarko Modular, Mobile Drilling Platform

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Outline of Presentation

- *1. The Need*
- *2. The Goal*
- *3. The Rationale*
- *4. The resources available*
- *5. The organization of the project*
- *6. The Schedule*

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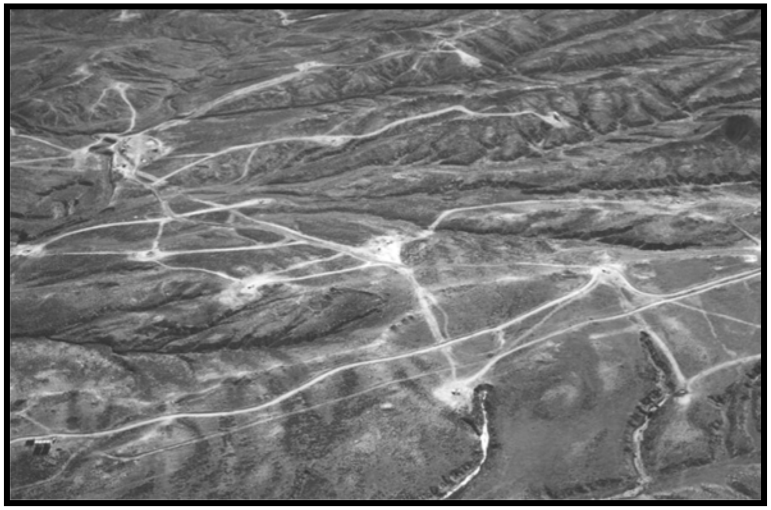

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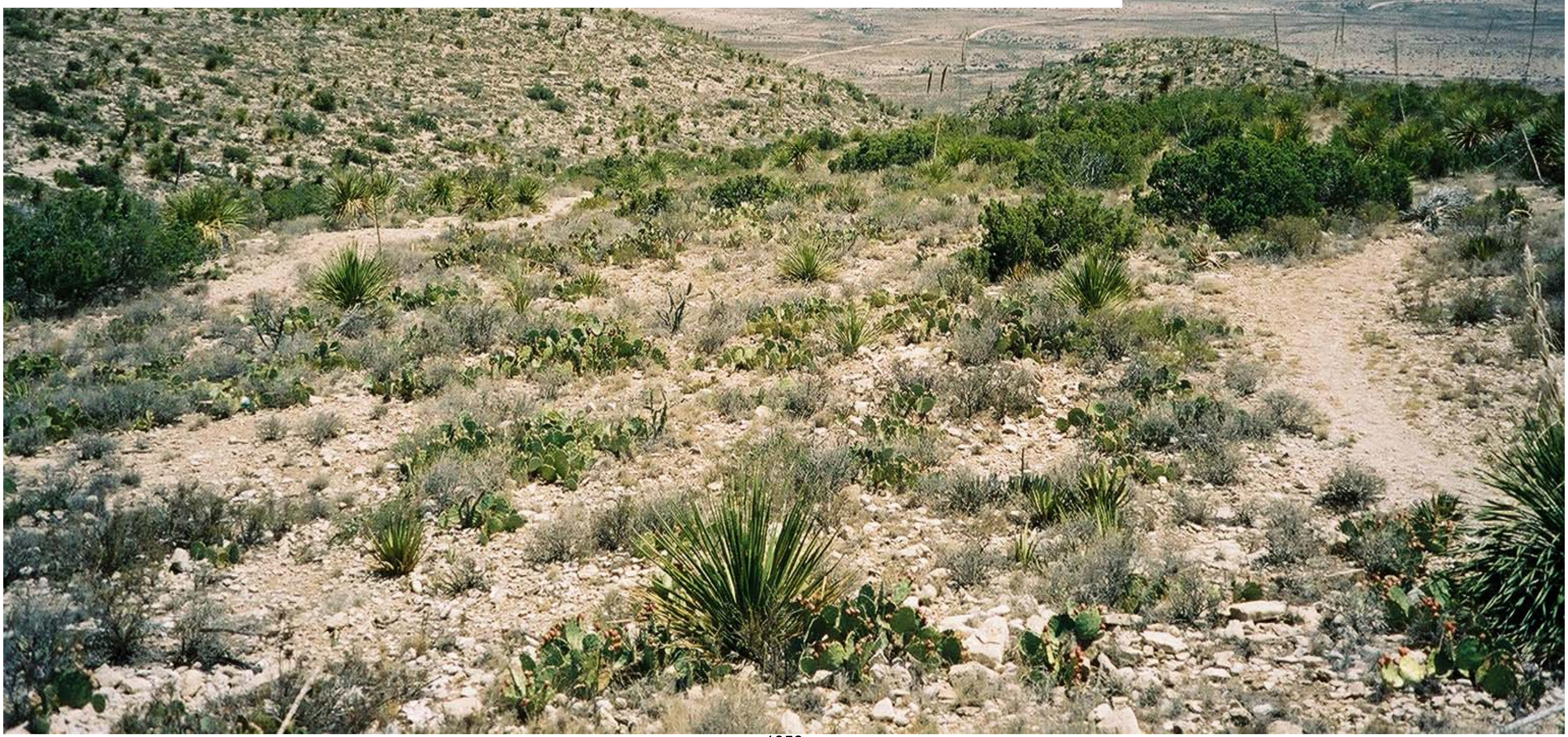

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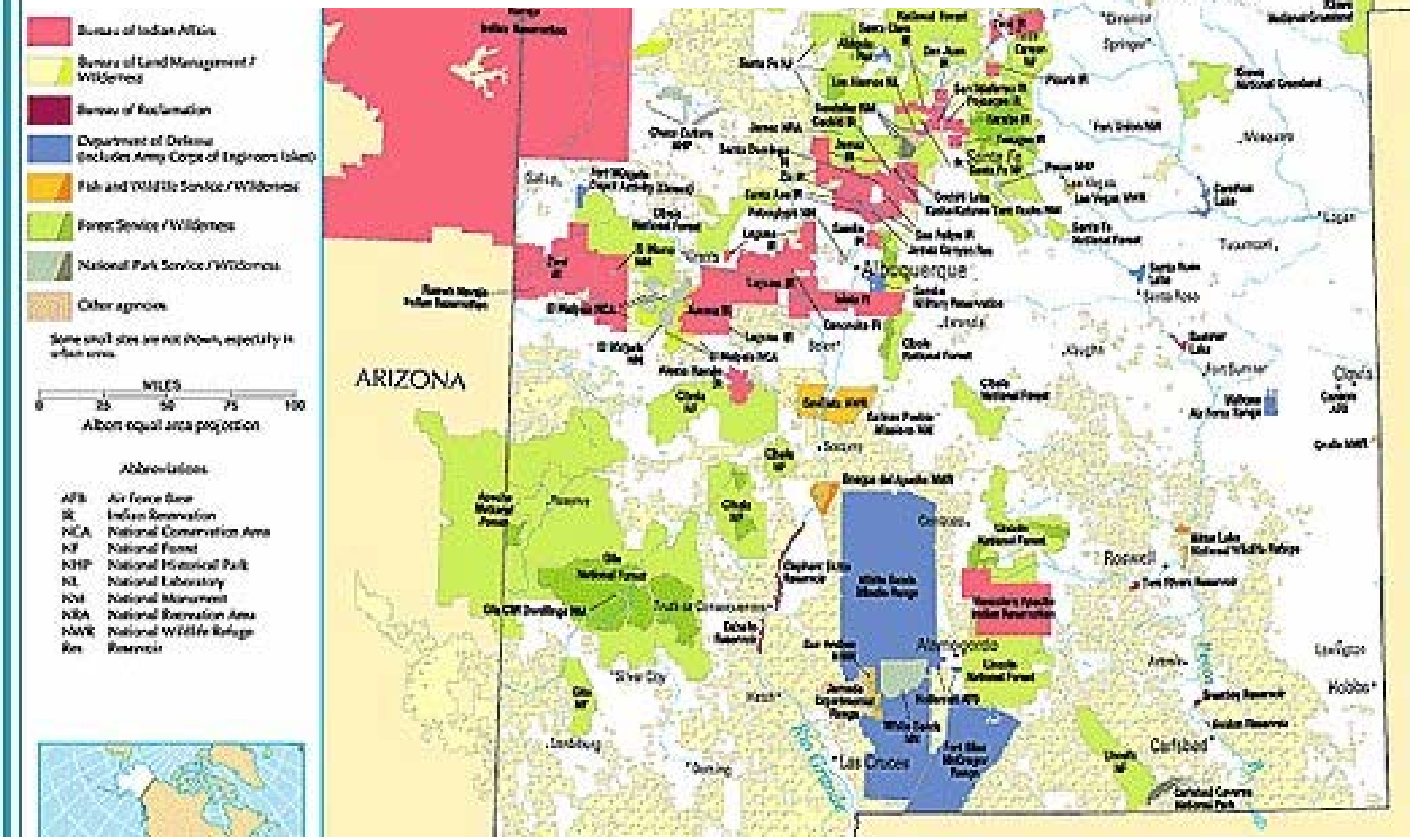

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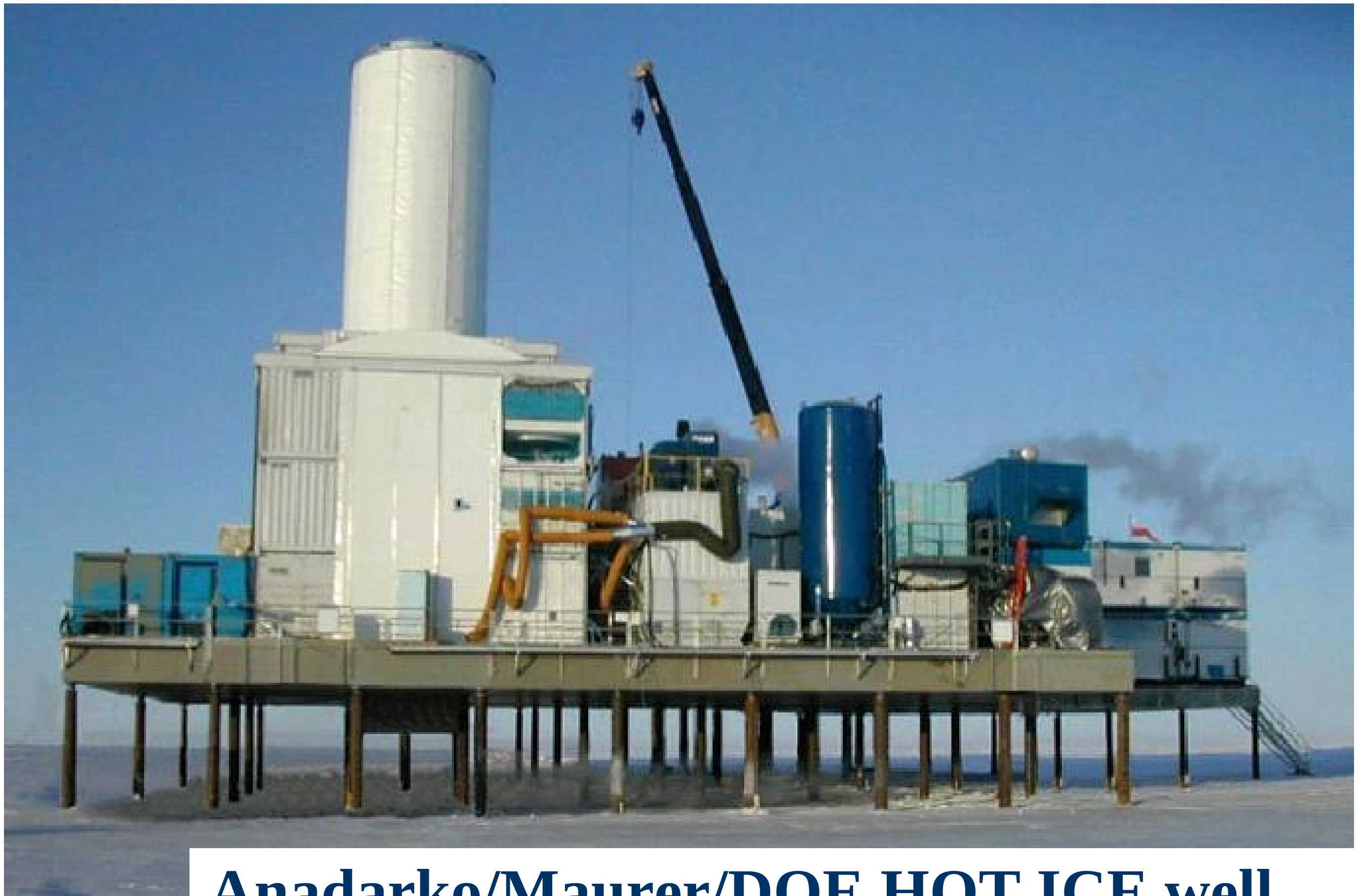
Platform Drilling



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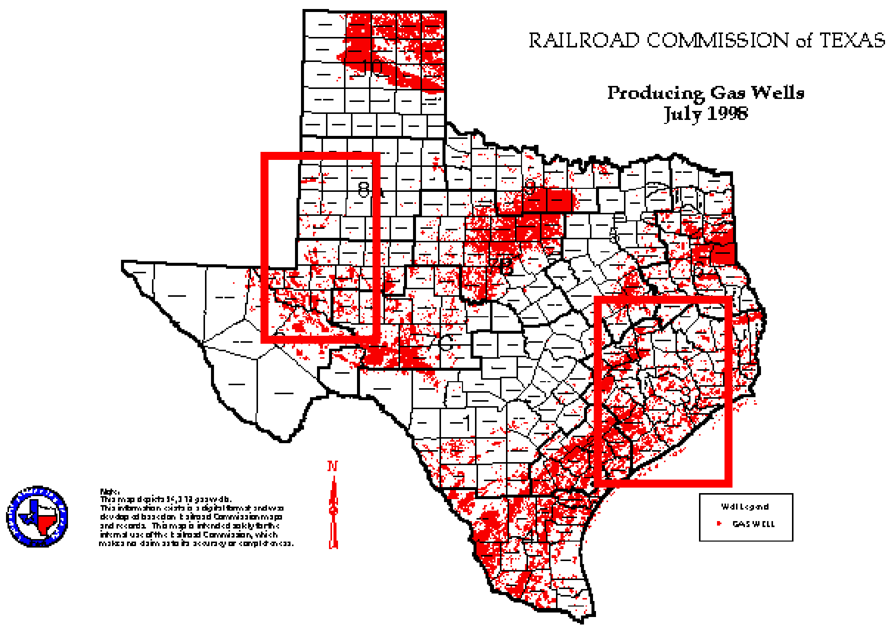

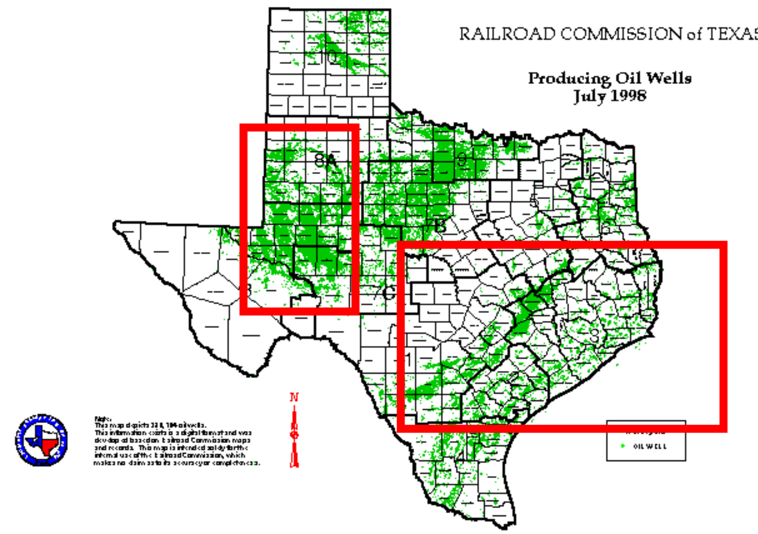

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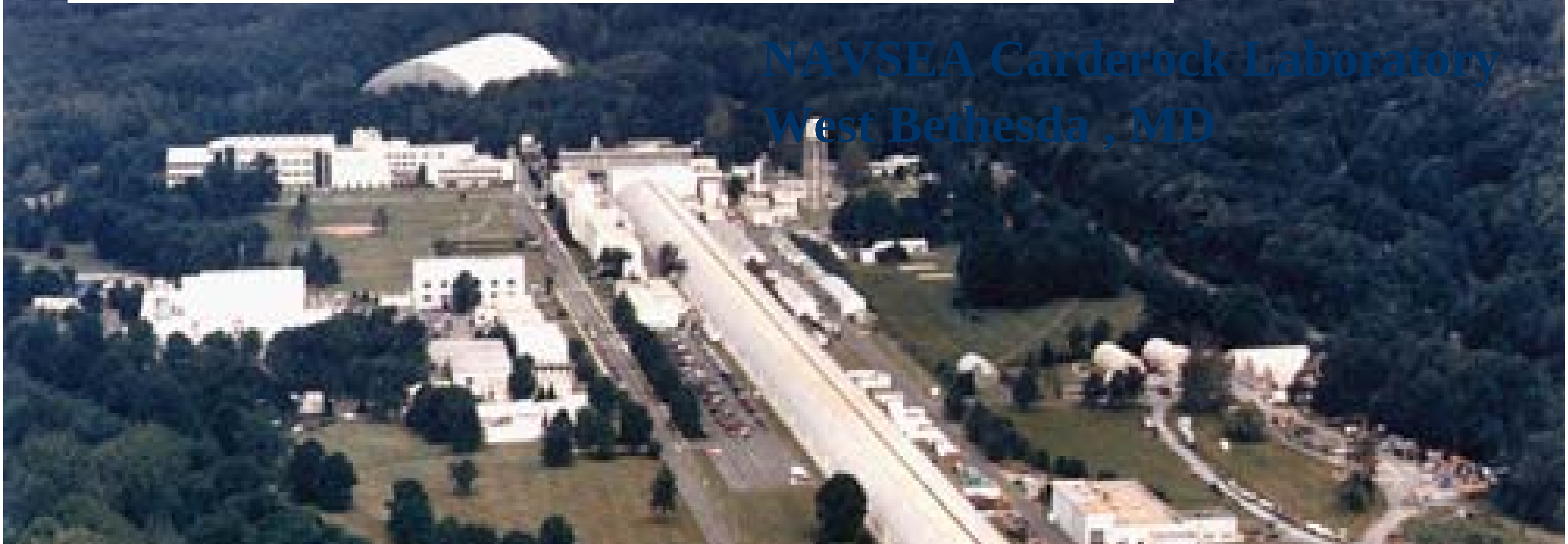

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CARDEROCK
Surface Warfare Center Division

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The Resources

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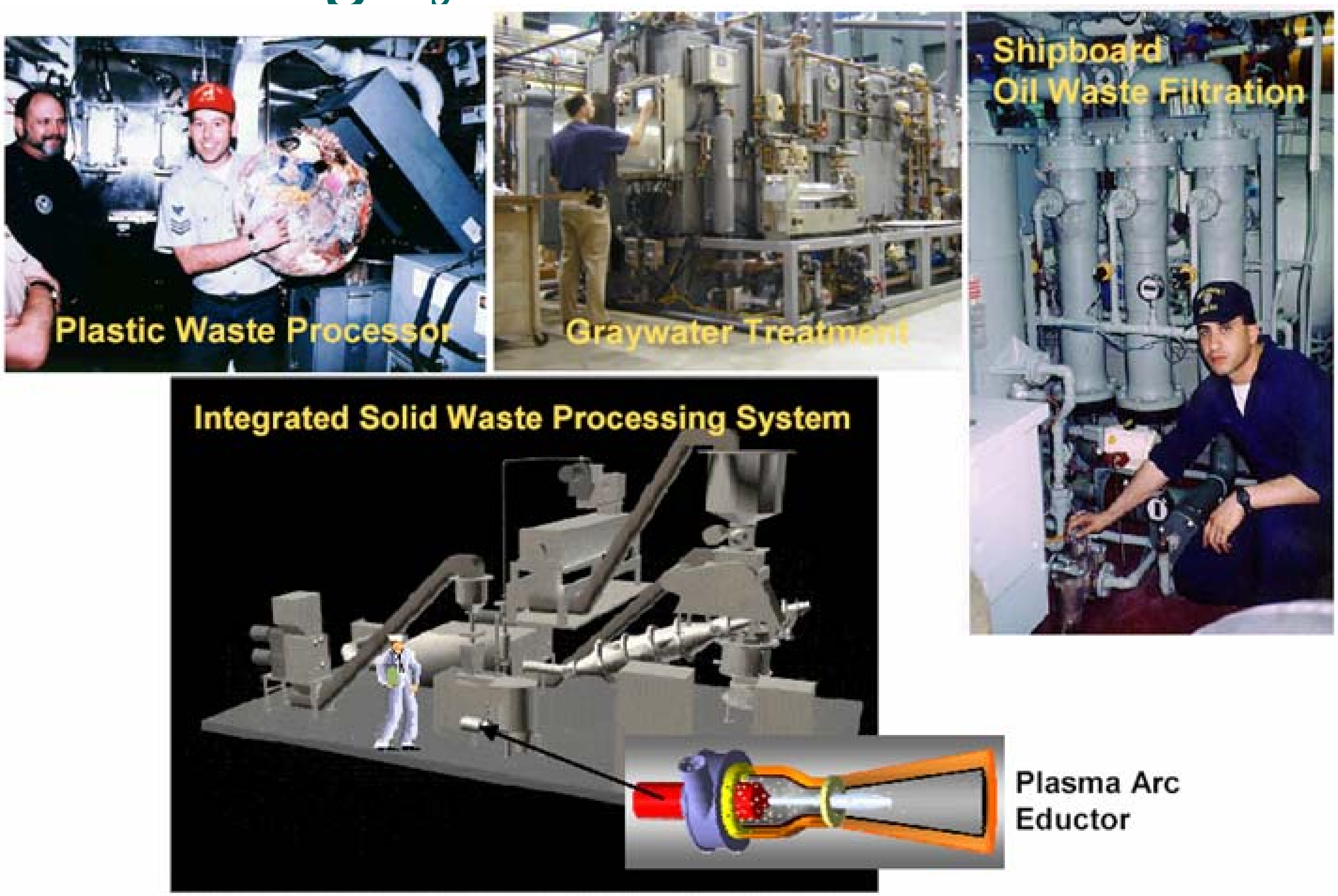

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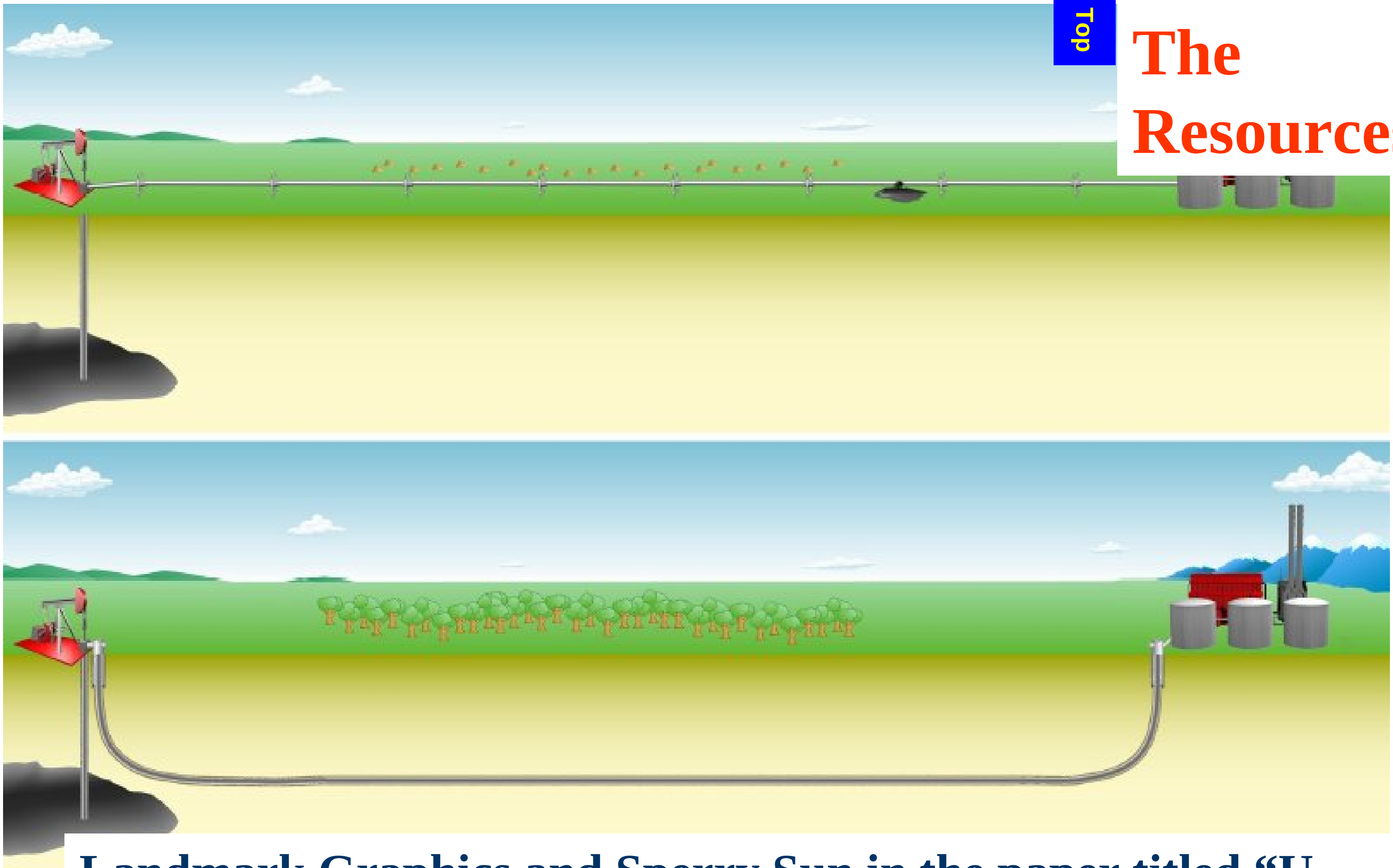

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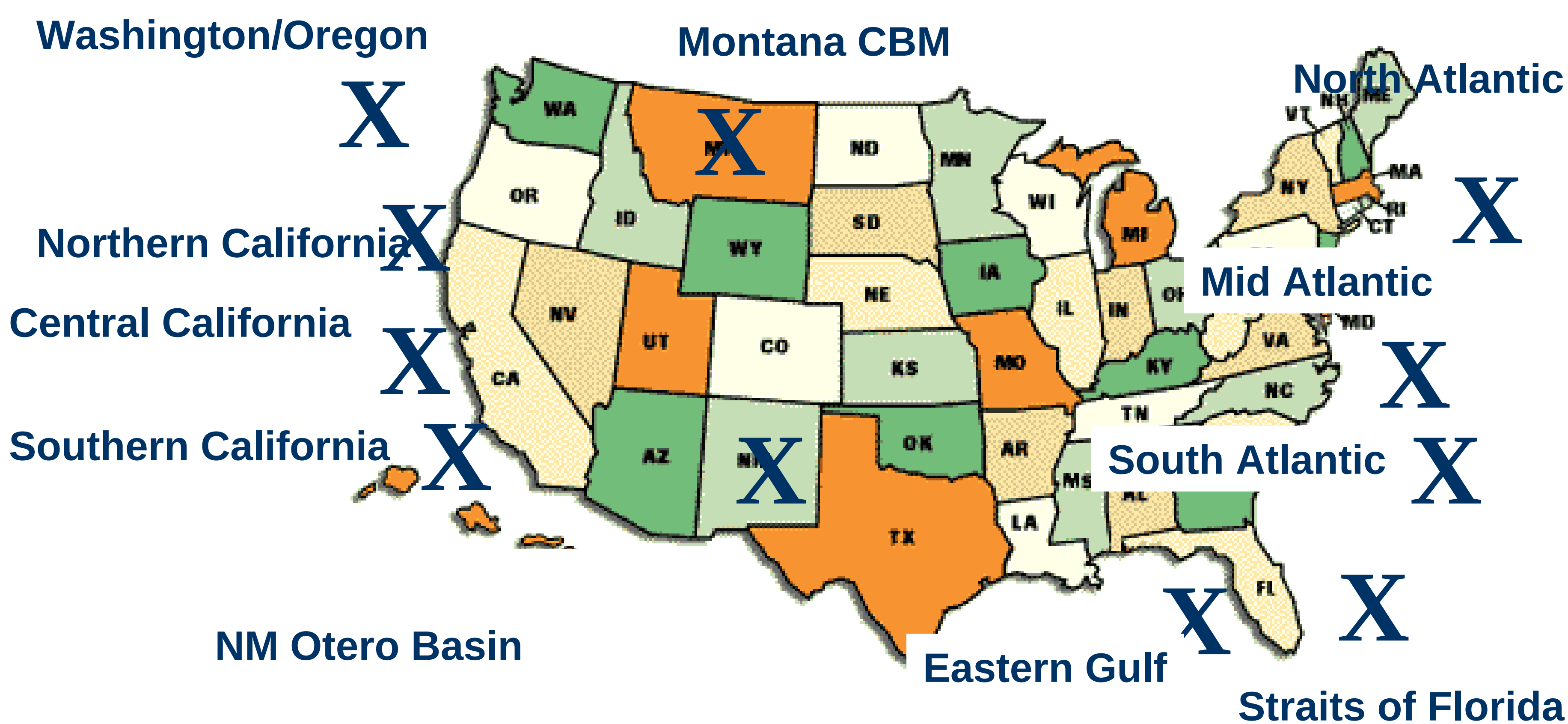

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Thank You

Summer 2003

Anadarko Modular, Mobile Drilling Platform

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TEXAS A&M
THE HAROLD VANCE DEPARTMENT OF
PETROLEUM ENGINEERING

GPRI

Rig Power Efficiency Study: Energy and Emissions Reduction

Chapter based on Report prepared
by
Juan Jose Fernandez Alvarez

Chapter Summary

During the drilling operation all of the designed power of a specific rig is not generally utilized. Now more cost efficient rigs incorporate electric systems with SCR units along with better practices to manage power distribution during the drilling operation. Nowadays, engineers are still trying to develop and come up with better ideas for rig designs that will satisfy the demand of the modern market. Nevertheless, little attention has been put into evaluating different sources of energy to power the rig in a more environmentally friendly way while maintaining the reliability and effectiveness during the entire drilling operation.

This chapter (Alvarez) provides background and evaluates possible alternative energy supplied options to conventional diesel/generator packages. Wind power and solar cells are studied, specifically evaluating the power supplied by both in contrast to specifications that include: equipment size, emissions, installation requirements and footprint. Some advantages were found in the reduction of emissions as compared to internal combustion engines, however both solar cells and wind turbines generate a larger footprint, and they require large cranes that at the same time increase the overall footprint of the drilling site. Fuel cells were considered as one of the most environmentally friendly technologies for power supply. Benefits include high efficiency, unmatched environmental performance, high quality power, fuel flexibility, quiet operation and simplicity (no moving parts). Despite all these advantages the main problem with this technology is the availability of units capable of providing enough energy to the rig, high installation costs and the footprint.

In the next Chapter (Verma) considers the feasibility of connecting the rig to the network or having the prime movers installed in an area that might not be environmentally affected, instead of having them on the rig site. This concept, already employed in the EU was evaluated as an option to reduce diesel/generator package requirements to rig operations, reduce logistical support, lower emissions and noise, and make smoother drilling. Energy storage devices (e.g. flywheels) for peak loading requirements (if powered through grid) are included.

Technical and economic feasibility of these alternatives need to be evaluated and discussed with rig manufacturers, since changes in the electrical system of a rig will be mandatory. Finally a discussion is presented on the feasibility of using Natural Gas and Biodiesel as fuels for prime movers.

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Diesel-electric powered rigs employing silicon-controlled rectifier (SCR) technology provide more precise control of drilling components and greater power efficiency than mechanical rigs and are well suited for horizontal and directional drilling. Having SCR already incorporated into the rig, other energy sources may be used as the prime movers. For example, Encana has used natural gas powered rigs in the Jonah field of Wyoming, reducing emissions. If available, SCR enabled rigs could possibly be connected directly to the grid. Texas A&M University has performed a study to develop an energy inventory of the drilling process from a rig perspective. (This is discussed in the next chapter.) With an energy inventory, technologies that can be used to partially provide power to a rig may be evaluated to reduce fuel consumption and emissions. A study to evaluate the feasibility of adopting technology to reduce the size of the power generating equipment on drilling rigs and to provide "peak shaving" energy through the new energy generating and energy storage devices such as flywheels.

Work in this project was designed to meet the deliverables represented by the NETL SOW Task 2 (*Technology Status Assessment*) and Task 4 (*Planning Prototype Development, Testing and Deployment*)

Research Objectives

This segment of the overall EFD program sought to investigate methods to reduce the environmental footprint of power generation for rig operations. Our goal was to determine the feasibility of adopting technology to reduce the size of the power generating equipment and to provide "peak loading" energy through the use of new energy generating and energy storage devices.

The study focused on developing a system using new technology to power light weight drilling rigs. Such an alternate power system is a significant part of an optimized package of well pad/drilling rig technology that would allow smaller footprints created by access roads and air emissions. The study also included work to develop theoretically and empirically an energy inventory of the drilling process from a rig perspective.

Background

During the drilling operations all of the design power of a specific rig is not needed (roughly 25%) power is needed the majority of the time. Most of the large deepwater offshore rigs being built today need in excess of 40,000 Hp (30 MW). Many are exceeding 50,000 Hp (37.3 MW). To put this into perspective, the average person in the U.S. consumes roughly 13,000 KW-Hrs of energy each year assuming 8,760 hours per year 1.48 KW per person power need equates to approximately 20,000 person community for these large rigs. A land rig operation would be roughly 10-20% of this capacity (4,000 to 8,000 HP) or 3 to 6 MW (about 2,000 to 4,000 person community).

The rig power-system refers to the number and sizes of engines and whether the power transmission is mechanical or electrical (new builds). The rig prime mover must drive the draw works, top drive or rotary table (if applicable), mud pumps, auxiliary equipment, and, in some cases, rig lightning. Horsepower requirements of the prime mover depend to a great extent on calculations already made on the amount of power drawn by the hoist and mud pumps. New rigs with prime movers over 1,000 Hp are diesel-electric, i.e., the diesel engines run generators that convert the mechanical energy to electricity allowing more efficient power allocation between the rig components.

Functional considerations can be based on previous experience with equipment where a 2,000Hp or 3,000Hp rig was specified. In reality this has little meaning and is a carryover from MODU (Mobile Operation Units) or land rig specifications where nominal depth or equipment ratings are used to define an outline tender specification for a rig.

In some other cases the principal drilling equipment is usually sized based on the deepest planned well, yet this may be only one well or a limited number and results in a significant over capacity and higher cost. Reviewing the well designs, determining the most onerous sections and numbers of wells to be drilled, whilst still ensuring the rig is capable of drilling the deepest well usually results in significant cost savings.

After all the essential components have been specified, the electrical power and control system are configured so that a drilling profile study could be performed to determine the peak power and average power along the drilling route including the auxiliary and lightning power requirements.

2.2. Rig Efficiency

During the initial stage of a project it is essential that requirements such as regulatory guidelines, well designs and the appropriate levels of mechanization are understood. This allows a clear definition of the rig equipment selection and functionality to ensure the rig is not over or under rated in order to allow the drilling team to provide a rig that delivers the expected operational efficiency.[4]

Practical methods[6] for evaluating rig performance have been developed to calculate rig efficiencies that include both mechanical performance and the performance of the contractor’s personnel.

The concept of drilling rig efficiency has been associated with a rig’s mechanical capability. Generally a rig’s size, mechanical condition, horsepower rating, and maximum load have been considered by many as determining efficiency. This concept, although it considers all the critical parameters that have a direct influence on field performance, can be considerably put at risk if the rig crew ability to perform routine drilling operations is not taken into consideration. It is because of this relationship that rig efficiency is a function of both the rig and rig crew’s mechanical and operational ability to perform the drilling operation.

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The approach described by Sheikholeslami et al[6] describes the drilling operation as an activity that involves many individual operations influenced by the contractor, the operator, and outside sources. The time required to perform these operations is defined as "total contractor-controlled time" (TCCT) and several contractor controlled categories (CCT) account for routine operations such as rigging up and down, cutting drilling line, lubrication and repairing the rig as well as, drilling, tripping and connection time.

Since problems or non-routine drilling operations are somehow difficult to predict, these factors are not considered in the TCCT relationships. Such problems can be related to time spent on miscellaneous operations like working stuck pipe, pumping soft line, rigging up surface equipment, laying down drillpipe and collars, waiting on service companies, cleaning mud tanks, blowout prevent (BOP) drills, and changing bottomhole assemblies.

Besides evaluating the rig efficiency, costs also play an important role from the contractor or operator point of view. The effective daily rig cost is defined as the rig's actual day work price divided by its efficiency for the particular drilling area. When rigs are compared, the effective daily rig cost can reveal substantial cost differences and can be a useful tool on rig selection. Other daily costs besides rig costs are associated with drilling wells. The other costs are called a rig's daily fixed cost that includes fuel, mud, water and any other drilling expense. This fixed cost is incurred every operating day and is therefore a function of the operating time for each well.

The bottom line in evaluating drilling performance is the overall cost to the operator or contractor. This is defined as the effective daily drilling cost which is often used to compare rigs on a complete cost basis. The relationships used in the analysis presented by Sheikholeslami et al[6] are the following:

- CCT(hours) = total of rig time in:(drill) + (trip) + (lubricate rig) + (repair rig) + (connection) + (nipple - up BOP's) + (nipple - down BOP' s) + (cut drilling line) + (rig up) + (tear down)
- OCCT(hours) = total of minimum times in:(drill) +(trip) +(lubricate rig) + (repair rig) +(connection) + (nipple - up BOP's) + (nipple - down BOP' s) +(cut drilling line) +(rig up) + (tear down)
- Rig efficiency = OCCT / CCT Effective daily rig cost($/ day) = daily rig rate / rig efficiency
- Daily fixed cost($ / day) = (mud) + (supervisory labor) + (contract labor) + (fuel) + (water) + (mud logger) + (rental)
- Total operating days = total operating time(hours) / 24 hours [6]
- Optimal operating time(hours) = total of minimum time in : Eq.2 +
- (summation 7 of minimum time not included in OCCT)
- Optimal operating days = optimal operating time(hours) / 24 hours 8
- Effective daily fixed cost($ / day) = (daily fixed cost × total operating days / 9

- optimal operating days)

Effective daily drilling cost($ / day) = effect. daily rig cost + effect. daily fixed cost

2.3. Rig Power Requirements

The determination of total power required may be done by assuming some condition of greatest demand. Initially it was assumed that this situation could be reached at shallow depths using all mud pumps or when tripping out of the deepest hole with maximum weight pipe. A recent study[7] showed that it is in fact while drilling, that the highest amount of energy is required. Spare capacity may then be supplemented with due consideration for downtime maintenance.

As the well designs are developed each is modeled using commercially available software and the following loads determined.

Torque and drag in all hole sections including casing runs, tripping in / out, with or without rotation.

Hydraulics. During this work the drill string selection and design is verified. At the same time the equivalent circulating densities are checked to ensure that

sufficient margins exist below the formation fracture pressure.

For the torque and drag, sensitivities are run on the friction factors, if field data is available it is used but a range of friction factors is typically run to check sensitivities and to account for both water based and oil based muds. The highest torques will typically be seen during the displacement of the well to a water based completion fluid.

For hydraulic calculations sensitivities are run on the mud weights and increased rheology to allow for the effects of mud going out of specification as well as the potential requirement to increase the mud weight as the inclination increases. The mud volumes in each hole section and an operational breakdown of how the volumes and different fluids that will be handled during cementing are checked in order to determine any restrictions and the ideal pit capacity. Bulk volume requirements for both cement and barites are also calculated.

The final sizing of the mud pits and silos is then based upon the supply period and any minimum stock requirements, such as the minimum cement that should remain on board after completing a casing run. From this work the requirements for setback and the pipe deck capacity are determined. Further optimization of the pipe deck loads are also considered to cater for batch drilling. The offset data is reviewed to determine expected penetration rates with the proposed rig equipment. This information is required to size cuttings disposal systems.

After all these parameters have been estimated, McNair[8] recommends using the efficiency of motors, SCR units and transformers, along with the information related to peak and average kilowatt (Kw) and Kva required from the 600-volt system bus, to then proceed with the selection of the engine-generator set, rating and quantity that will deliver the peak and average Kw and Kwa throughout the drilling cycle. Although dependent upon the overall well distribution, the typical approach is to size the drilling equipment such that it is operating at ca. 75% of maximum load in the most frequently drilled wells and in the deepest wells it is utilized to near capacity. This represents a reasonable compromise of providing sufficient redundancy without over rating equipment.

2.4. Drilling Loads

While a diesel engine at full load operates at constant speed and constant torque, the load demand varies, depending upon the equipment to be driven and the operation involved.[9] To properly select the components for the electric transmission, i.e., generators, motors and controls, it is first necessary to analyze load characteristics.

Driving the rotary table or (top drive nowadays) is a steady load with little variation in torque or speed so long as drilling conditions are uniform. But if gumbo or heavy strata are encountered and the bit begins to ball, more torque and less speed are desirable. If soft strata are encountered, the converse, higher speed and lower torque output is called for.

The draw works has a variety of load patterns, depending upon the particular operation. When used as a hoist mechanism for lowering or raising the drilling stem, it represents a traction load. Raising a long stem requires a high starting torque; handling a single stand requires higher speeds and low torque. Draw works are also used to power the break-out and make-up catheads. Braking-out or making-up is a low speed, light load operation. The transmission must have good deceleration control so that pick-up speed is not excessive. Mud pumps are a constant speed load so long as drilling conditions do not vary. However, speed response is desirable if a cavity or plugged hole is encountered.

In view of the load patterns, the design objective was an electric transmission sensitive to load changes and one that could provide extremely high torque at low speeds and low torque at higher speeds. For each rig there is a particular power system which best fits that rig. In most cases the rig will be configured with diesel-AC generator set for power generation and SCRAC-DC variable speed control for the DC traction motor. Nichols et al4 developed a checklist that helps evaluate the various power systems available, starting with operating parameters such as depth and environment to derive a summary of the electric power loads ratings adjusted according to the required accelerating power factor and use or duty cycle. This information will determine the total kilovolt-amperes (Kva) required by the AC generators and the subsequent Kw or Hp required by the diesel engines.

2.5. Prime Movers in Drilling Rigs

Normally the rig must provide its own source of power. The first source of this generated power must be obtained from a fuel that converts its energy into mechanical speed and torque. Steam used through steam engines was one of the first methods and eventually evolved to the diesel engine and gas turbines as the most popular prime movers.

Gas turbines: Gas turbines are prime movers characterized by their high-speed operation (up to 42,000 rpm), small size and weight, and high audible noise level (Fig.2.1). While several of these units have been used in drilling applications, they have several limitations for this use.
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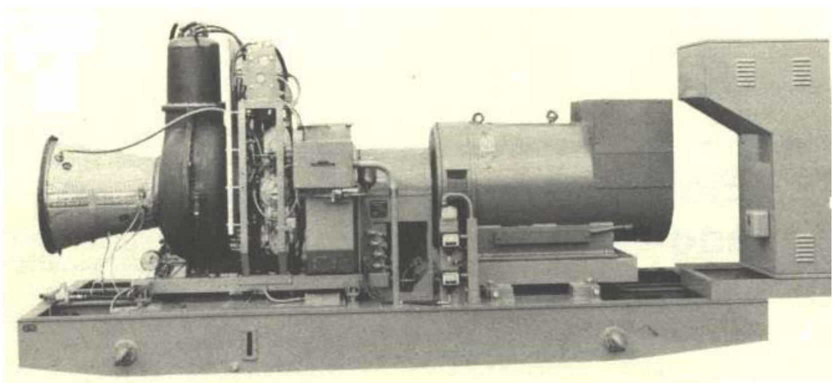

Fig 2.1- Gas Turbine-AC generator system[10]

Most DC generators are 1,200-1,800 rpm units and are mechanically limited to 2,500 rpm maximum speed before damage occurs to the windings/commutator/brushes. Therefore, direct coupling to gas turbines is prohibitive. AC generators must produce of 50 or 60 Hz for the rig load, i.e., AC motors, SCR equipment, and other frequency-sensitive equipment. The speed to produce these frequencies is typically 900, 1,200 or 1,800 rpm depending on the number of generator poles, and direct coupling to gas turbines is prohibitive.

Gear speed reducers could slow the speed from 42,000 rpm to 200 rpm, but the ratio would be 35:1. This gear ratio at high horsepower would be expensive to produce, its gear efficiency would be low, and the gear box would offset some of the weight saving of the turbine. Also, critical alignment from the turbine is important for high-speed operation. The noise level of these turbines requires abatement to allow operation of the drilling rig. Sound-proofing techniques would add expense to the drill rig

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Diesel engines: diesel engines are characterized by their low speed operation, limited speed range, relatively low maintenance, and general availability. Selection of diesel engines to drive electric generators is obvious because their similar operating speeds allow direct coupling, the torque and horsepower of both are compatible, and control of engine-generator speed allows relatively easy control of generator output power.

Operation of a diesel engine differs from a gasoline engine; no spark plug is required to achieve combustion of the fuel. A gasoline engine injects the gasoline and air mixture into the combustion chamber, and then rapidly heats to a combustible temperature with the electrical spark of a spark plug. After the small portion of gas-air mixture around the spark plug starts to burn, it instantly heats and ignites the remaining mixture.

The diesel engine (Fig. 2.2.) uses the principle that compressing any gas at high pressure will heat it to a very high temperature. More importantly, the diesel engine starts the first stroke of its cycle by allowing only air to enter the engine cylinder and then be compressed at a pressure around 500 psi. This pressure heats the air to 1000oF during this compression stroke and shortly afterward mixes with the diesel oil spray to start its combustion. Power is then developed during the power stroke and burnt gases are exhausted at the end of the cycle.

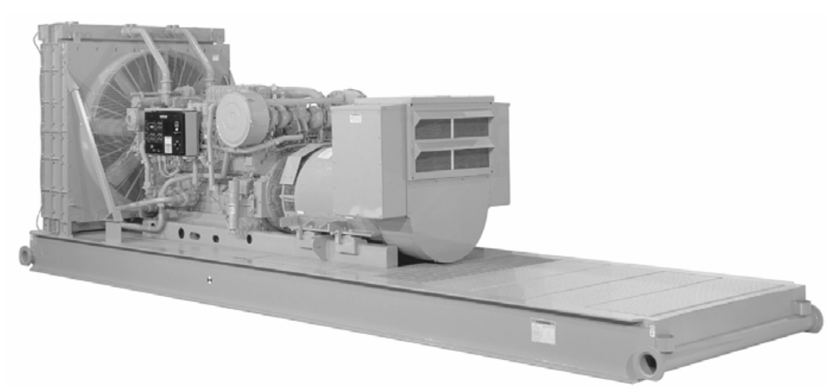

Fig. 2.2- Caterpillar power modules for use as prime rig power on SCR electric drill rigs featuring engine, generator, radiator and base[11]

The operating efficiency of a diesel engine varies with air density and more importantly its load relative to its rating. Fig.2.3 is a typical curve of a diesel engine's fuel economy vs. load. It shows that running diesels near their rating is the most efficient operating method. "Load leveling" refers to techniques whereby diesel engines can operate within their optimum functioning range, relying on alternate power from some external to smooth peak power demands.

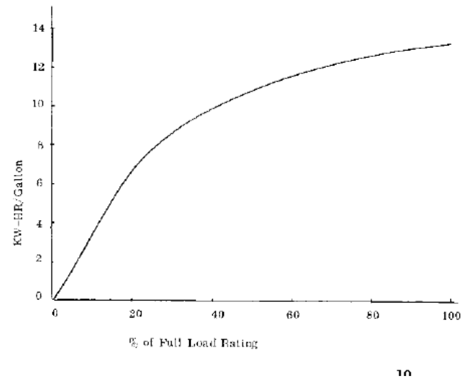

Fig.2.3- Fuel economy vs. Load[10]

The useful life of a diesel engines averages 12 years, depending on the operating care and maintenance it receives. However, operating life of 30 years is possible if proper lubrication, cooling, and repairs are maintained.

2.6. Unconventional Power Generation

2.6.1. Wind Power

Wind power is the process by which the wind is used to generate electricity. Wind turbines convert the kinetic energy in the wind into mechanical power. This mechanical power can be used for specific tasks (such as grinding grain or pumping water) or can be converted into electricity to power homes and businesses.

Modern wind turbine technology takes advantage of advances in materials, engineering, electronics, and aerodynamics to create large wind turbines that can function in a broad range or wind speeds. Small wind turbines are often used in combination with batteries to provide energy to resorts and lodges in remote locations, while larger turbines are usually grouped into wind farms which feed electricity into the electric utility grid.

Because the speed of the wind rises with height, wind turbines are mounted on towers to capture the most energy. Towers on commercial turbines range from 50 meters (160 feet) to as high as 112 meters (more than 300 feet), where they can take advantage of faster and less turbulent wind.

2.6.1.1. Wind Turbines

A wind turbine is the modern version of the windmill. A hollow steel or concrete tower supports a three-bladed rotor which is turned by the wind. The rotation of the turbine generates electricity, which is transmitted through cables to consumers. The towers of modern turbines are 50-100 meters (160-320 ft) high, while the diameter of the rotors is 30-70 meters

(100-230 ft). The maximum rotor speed of large turbines is approximately 20 rotations per minute, and both rotor speed and angle is computer controlled to maximize the power produced under a wide range of wind conditions.

Modern commercial turbines range in size from 750 kilowatts to 4.5 megawatts. Design considerations for wind turbines demand special requirements for a successful and efficient operation.

Some of the parameters in wind turbines design include height because wind speed increases with height above the ground, so the taller the turbine, the better the wind. Fig. 2.4 illustrates wind speed variations with height .

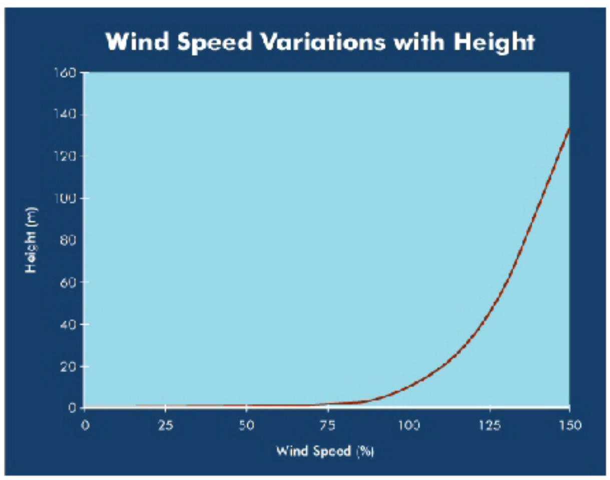

Fig. 2.4- Wind speed variations with height[12]

Rotor diameter: Larger turbine rotors generate more power. To accommodate these large rotors, turbines must be tall. Fig. 2.5 demonstrates the relationship between rotor size and power output - 40 meter rotors generate 500 Kw of power, while 80 meter rotors generate 2,500 Kw of power.

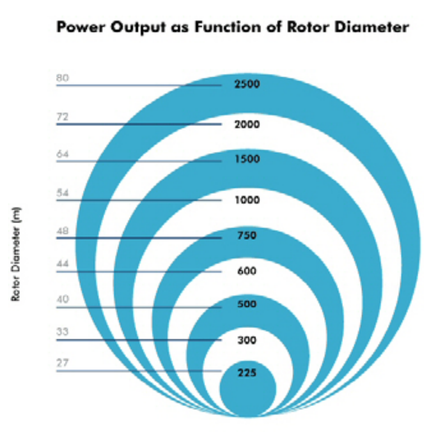

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Fig. 2.5- Power output as function of rotor diameter[12]

Because there are minimal adverse impacts associated with the use of wind for power generation, wind power is environmentally sustainable. Wind turbines do not produce emissions, so they do not contribute to climate change. In fact, they do the opposite by providing a replacement for fossil fuel power generation. Unlike a nuclear plant, a wind farm that is past its productive life can be readily decommissioned and the site returned to its former function.

Wind power is one of the cleanest and most environmentally friendly energy sources available. Bird deaths due to wind development will never be more than a small fraction of those caused by other human activities such as buildings, vehicles, cats and pesticides.

Because wind power replaces fossil fuel power generation, it has additional benefits including:

Insurance against environmental risk with zero emissions reducing greenhouse gases, heavy metals and particulate matter
Reduction in smog and acid rain.
Reduction of hazardous toxins, such as nuclear waste.
Reduction of land and no water use.
Preservation of non-renewable energy resources such as coal and fossil fuels.

2.6.1.3. Wind Requirements to Produce Power

Modern wind turbines will generate power at wind speeds ranging from 3 meters per second (10 km/h) up to 25 meters per second (90 km/h). At speeds higher than 25 meters per second, the turbines stop turning to protect them from damage.

2.6.1.4. Power Production

Every wind turbine has a "rating", often referred to as a "nameplate capacity", which describes the maximum amount of power a wind turbine will produce at any given moment under strong, steady wind conditions. For example, at a wind speed of 10 meters per second (50 km/h), a 1,000 Kw (or 1 megawatt) wind turbine will produce 1,000 kilowatts (or 1 MW) of electricity.

However, wind is rarely constant and seldom blows at 50 km/h, so the actual amount of power that a wind turbine will produce over time will always be less than the maximum power (or "rated capacity") of the turbine. In areas where the wind resource is strong (such as a coastal site) a wind turbine could produce as much as 45% of its rated capacity, while in areas where the wind resource is more moderate, a wind turbine might produce as little as 30% of its rated capacity. Fig. 2.6 demonstrates the power output of a 1 MW wind turbine at various average wind speeds:

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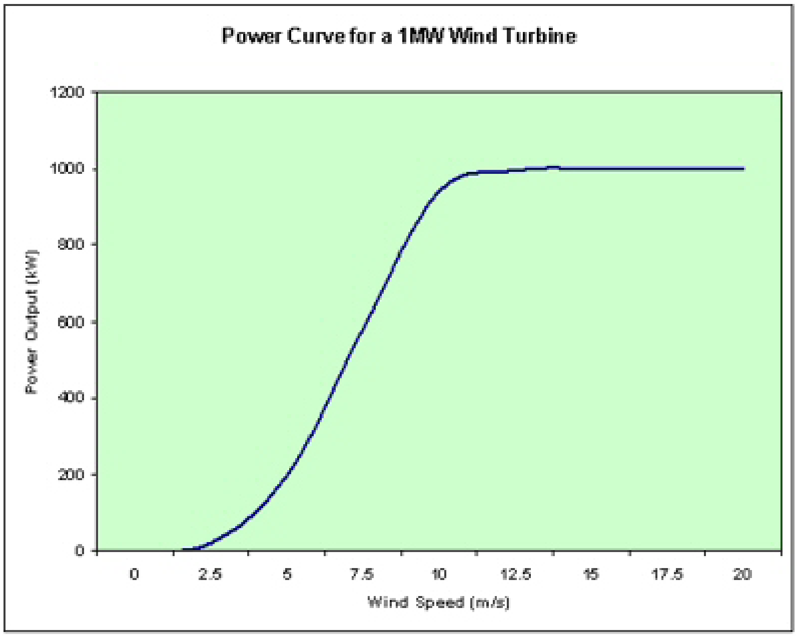

Fig. 2.6- Power output of 1 MW wind turbine[12]

In order to determine the total amount of power produced over a given period (such as a year) by a wind turbine, it is necessary to know the capacity of the turbine, the average annual wind speed and the amount of power produced by the wind turbine at that average wind speed. For example, using the example from the chart above, a 1 MW wind turbine operating in an area with an average wind speed of 15 km/h will produce 2,874,000 kilowatt hours (Kwh) of power in one year (i.e. 325 Kw x 24 hours x 365 days).

2.6.1.5. Costs for Wind Turbines

Generally, the capital cost of wind power is approximately $1.5 million per megawatt of rated capacity. For example, a 50 MW wind farm, (25x2 MW wind turbines, generating enough power for 12,000 to 20,000 Irish homes), would cost approximately $75 million to build.

Table 2.1 shows that coal and nuclear generation facilities are more expensive to build than a wind farm of the same energy production and take longer to commission. The costs in this table are for the latest of each power generation technology. In addition, they do not account for social and environmental costs which are highest for coal, nuclear and natural gas power generation respectively.

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Table 2.1- Capital cost of various types of power generation[13]

Technology	Capital Costs (2001$/Kwhr)	2002 Heat Rates (Btu/Kwhr)	Online Year2
Advanced Combustion Turbine	460	8,550	2004
Conventional Combustion Turbine	409	10,450	2004
Advanced Gas/Oil Combined Cycle	608	7,000	2005
Conventional Gas/Oil Combined Cycle	536	7,500	2005
Scrubbed Coal New 1,154	1,154	9,000	2006
Integrated Gas Combined Cycle 1	1,367	8,000	2006
Fuel Cells 2,137 7,500	2,137	7,500	2005
Advanced Nuclear 2,11	2,117	10,400	2007
Biomass 1,763 8,911	1,763	8,911	2006
Solar Thermal	2,594	10,280	2005
Solar Photovoltaic	3,9515	10,280	2004
Wind	1,003	10,280	2005

[1]Overnight capital cost includes contingency factors, and exclude regional multipliers and learning effects. Interest charges are also excluded. These represent the cost of new projects initiated in 2002.

[2]Online year represents the first year that a new unit could be completed, given an order date of 2002.

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2.6.1.6. Costs for Production

Once a wind farm has been built, the cost of producing power is quite low, and varies with the quality of the wind resource (the more wind, the less the cost per Kwh). Generally, it costs approximately $0.077/Kwh to produce wind power. This amount is comprised of two components: operating costs (the costs of operating and maintaining the wind farm) of $0.0071 per Kwh and capital return costs (the costs of repaying the capital used to build the wind farm) of $0.05 per Kwh. Fig. 2.7 sets out the production costs of various types of power:

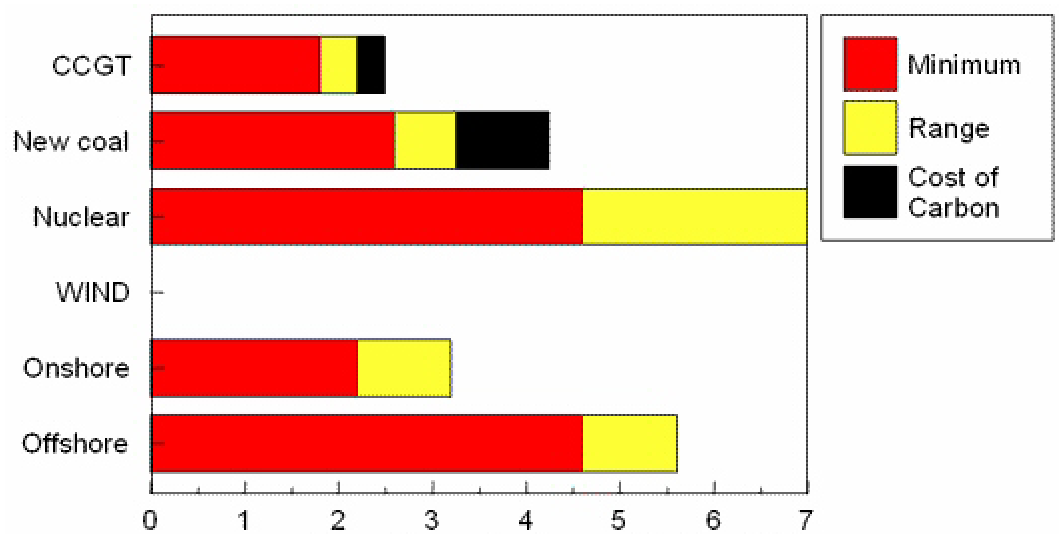

Fig. 2.7- Electricity price for new build, GBP/Kwh[12]

Clearly onshore wind is competitive with coal and cheaper than nuclear. The cost of natural gas has increased since 2004, so that the cost of gas-fired power plants would now be considerably higher also. This chart also ignores environmental (or societal) costs of gas power. Fig. 2.8 also shows the cost for fuel for electrical utilities.

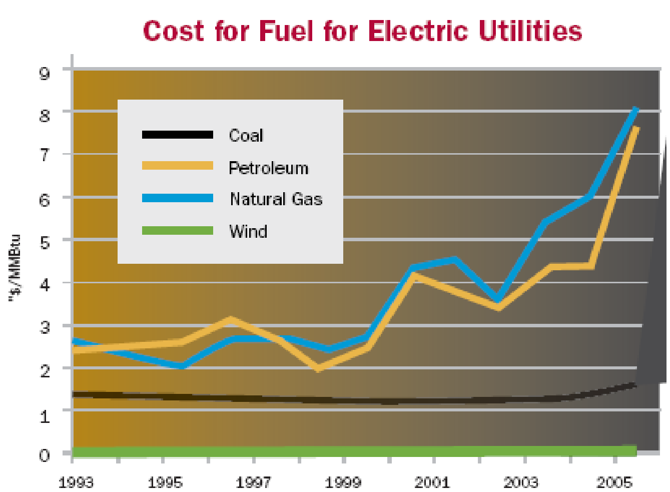

Fig. 2.8- Cost for fuel for electric utilities[14]

2.6.2. Solar Cells (Photovoltaics)

A solar cell (or a photovoltaic cell) is a device that converts photons from the sun(solar light) into electricity using electrons without either chemical reactions or moving parts. In general, a solar cell that includes the capacity to capture both solar and non-solar source of light (such as photons from incandescent bulbs) is termed a photovoltaic cell. Fundamentally, the device needs to fulfill only two functions: photogeneration of charge carriers (electrons and holes) in a light-absorbing material, and separation of the charge carriers to a conductive contact that will transmit the electricity. This conversion is called the photovoltaic effect, and the field of research related to solar cells is known as photovoltaics.

Solar cells have many applications. Historically they have been used in situations where electrical power from the grid is unavailable, such as in remote area power systems, particularly used in assemblies of solar modules (photovoltaic arrays) connected to the electricity grid through an inverter, often in combination with a net metering arrangement.

2.6.2.1. Structure

Modern solar cells are based on semiconductor physics; they are basically just P-N junction photodiodes with a very large light-sensitive area. The photovoltaic effect, which causes the cell to convert light directly into electrical energy, occurs in the three energy-conversion layers.

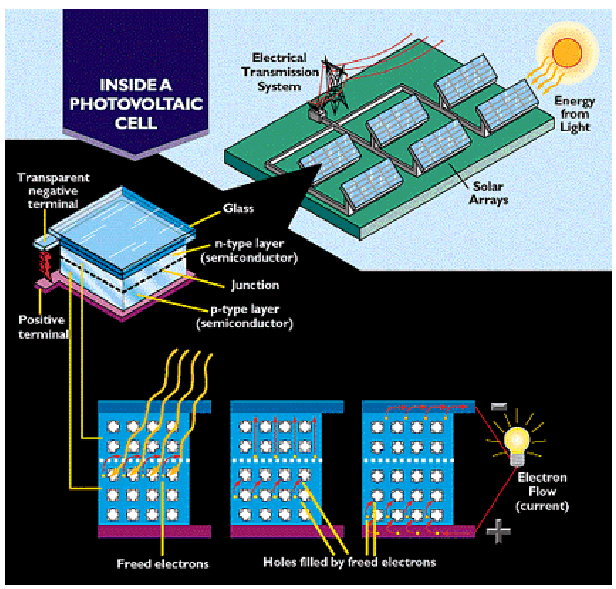

Fig. 2.9- Diagram courtesy U.S. Department of Energy [21]

The first of these three layers necessary for energy conversion in a solar cell is the top junction layer (made of N-type semiconductor). The next layer in the structure is the core of the device; this is the absorber layer (the P-N junction). The last of the energy-conversion layers is the back junction layer (made of P-type semiconductor).

As may be seen in the above diagram, there are two additional layers that must be present in a solar cell. These are the electrical contact layers. There must obviously be two such layers to allow electric current to flow out of and into the cell. The electrical contact layer on the face of the cell where light enters is generally present in some grid pattern and is composed of a good conductor such as metal. The grid pattern does not cover the entire face of the cell since grid materials, though good electrical conductors are generally not transparent to light. Hence, the grid pattern must be widely spaced to allow light to enter the solar cell but not to the extent that the electrical contact layer will have difficulty collecting the current produced by the cell. The back electrical contact layer has no such diametrically opposed restrictions. It need simply function as an electrical contact and thus covers the entire back surface of the cell structure. Because the back layer must be a very good electrical conductor, it is always made of metal.

2.6.2.2. Mode of Operation

Solar cells are characterized by a maximum Open Circuit Voltage (Voc) at zero output current and a Short Circuit Current (Isc) at zero output voltage. Since power can be computed via this equation:

$P = I \times V$ [11]

Where: P = power

I = current

V = Voltage

Then with one term at zero these conditions (V = Voc / I = 0, V = 0 / I = Isc) also represent zero power. As you might then expect, a combination of less than maximum current and voltage can be found that maximizes the power produced (called the maximum power point). Many BEAM designs (and, in particular, solar engines) attempt to stay at (or near) this point. The difficult part is building a design that can find the maximum power point regardless of lighting conditions.

2.6.2.3. Applications and Implementations

Solar cells are often electrically connected and encapsulated as a module. PV modules often have a sheet of glass on the front (sun up) side with a resin barrier behind, allowing light to pass while protecting the semiconductor wafers from the elements (rain, hail, etc.). Solar cells are also usually connected in series in modules, creating an additive voltage. Connecting cells in parallel will yield higher amperage. Modules are then interconnected, in series or parallel, or both, to create an array with the desired peak DC voltage and current.

The power output of a solar array is given in watts or kilowatts. In order to calculate the typical energy needs of the application, a measurement in kilowatt-hours (or kilowatt-hours per day) is often used, which accounts for changes in insulation. One process solution is;

1. Photons in sunlight hit the solar panel and are absorbed by semi-conducting materials, such as silicon.

2. Electrons (negatively charged) are knocked loose from their atoms, allowing them to flow through the material to produce electricity. The complementary positive charges that are also created (like bubbles) are called holes and flow in the direction opposite of the electrons in a silicon solar panel.

3. An array of solar panels converts solar energy into a usable amount of direct current (DC) electricity.

Alternative solution:

1. The DC current enters an inverter.

2. The inverter turns DC electricity into 120 or 240-volt AC (alternating current) electricity needed for home appliances.

3. The AC power enters the utility panel in the house.

4. The electricity is then distributed to appliances or lights in the house.

5. The electricity that is not used will be recycled and reused in other facilities [23]

2.6.2.4. Energy Conversion Efficiency

A solar cell's energy conversion efficiency ("eta"), is the percentage of power converted (from absorbed light to electrical energy) and collected, when a solar cell is connected to an electrical circuit. This term is calculated using the ratio of Pm, divided by the input light irradiance under "standard" test conditions (E, in W/m2) and the surface area of the solar cell (Ac in m^2). At solar noon on a clear March or September equinox day, the solar radiation at the equator is about 1000 W/m2. Hence, the "standard" solar radiation (known as the "air mass 1.5 spectrum") has a power density of 1000 watts per square meter. Thus, a 12% efficiency solar cell having 1m2 of surface area in full sunlight at solar noon at the equator during either the March or September equinox will produce approximately 120 watts of peak power.

2.6.2.5. Comparison of Energy Conversion Efficiencies

Silicon solar cell efficiencies vary from 6% for amorphous silicon-based solar cells to 40.7% with multiple-junction research lab cells. Solar cell energy conversion efficiencies for commercially available mc-Si solar cells are around 14-16%. The highest efficiency cells have not always been the most economical. To make practical use of the solar-generated energy, the electricity is most often fed into the electricity grid using inverters (grid-connected PV systems); in stand alone systems, batteries are used to store the energy that is not needed immediately. A common method used to express economic costs of electricity-generating systems is to calculate a price per delivered kilowatt-hour (Kwh).

The solar cell efficiency in combination with the available irradiation has a major influence on the costs, but generally speaking the overall system efficiency is important. Using the commercially available solar cells (as of 2006) and system technology leads to system efficiencies between 5 and 19%. As of 2005, photovoltaic electricity generation costs ranged from ~ 50 eurocents/Kwh (0.60 US$/Kwh) (central Europe) down to ~ 25 eurocents/Kwh (0.30 US$/Kwh) in regions of high solar irradiation.8 The cost can be compared to prevailing retail electric pricing (as of 2005), which varied from between 0.04 and 0.50 US$/Kwh worldwide. (Note: in addition to solar irradiance profiles, these costs/Kwh calculations will vary depending on assumptions for years of useful life of a system. Most c-Si panels are warranted for 25 years and should see 35+ years of useful life.)

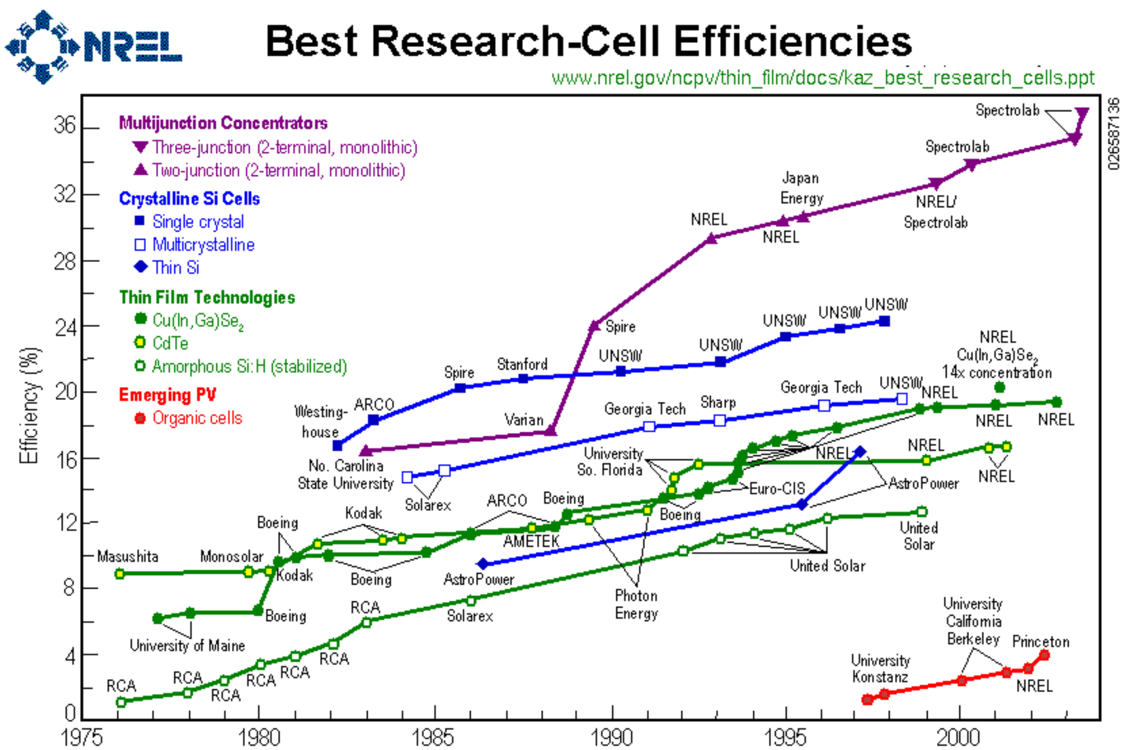

Fig. 2.10 illustrates the various commercial large-area module energy conversion efficiencies and the best laboratory efficiencies obtained for various materials and technologies.

2.6.2.6. Current Research on Materials and Devices

There are currently many research groups active in the field of photovoltaics universities and research institutions around the world. This research can be divided into three areas: making current technology solar cells cheaper and/or more efficient to effectively compete with other

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energy sources; developing new technologies based on new solar cell architectural designs; and developing new materials to serve as light absorbers and charge carriers.

2.6.3. Fuel Cells

A fuel cell is an energy conversion device that converts the chemical energy of a fuel directly into electricity without any intermediate thermal or mechanical processes. Fuel cells are a clean, quiet and efficient energy conversion technology and have been considered to be an advanced alternative to conventional combustion technologies for power generation.[16]

2.6.3.1. Mode of Operation

A fuel cell combines hydrogen-rich gas with air and converts the chemical energy of this mixture into electricity directly with no intermediate combustion step (Fig. 2.11). Its construction is similar to the familiar dry cell battery. Unlike a battery, however, a fuel cell does not undergo a material change. Consequently, it does not run down or require recharging; it operates as long as fuel and air are supplied. A typical fuel cell produces a high current and low voltage. Practical voltages are obtained by connecting many individual cells into what is referred to as a cell stack. A fuel cell produces direct current (DC power), which usually requires a power conditioning unit, called an inverter, to convert the output to alternating current (AC power). Depending on the type of fuel that is to be used, the fuel cell system may also require a fuel processing unit, known as a reformer, to convert the input to a hydrogen-rich gas.

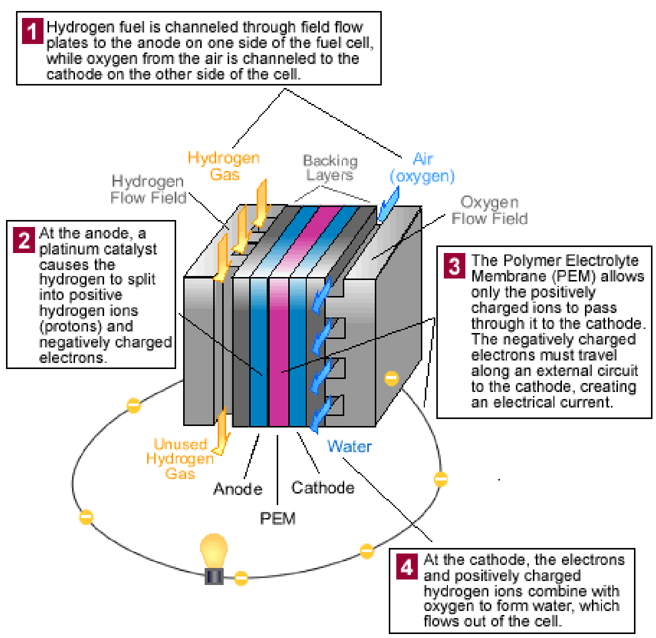

Fig. 2.11- Mode of operation of a fuel cell[17]

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Because a fuel cell transforms fuel directly to electricity without an intermediate conversion to heat, less waste heat is produced, and very high conversion efficiencies; in the range from 40 to 60 percent; are achieved. Additionally, the constant temperature operation of a fuel cell allows the heat liberated by the electrochemical reaction to be used for space heating, water heating or industrial heat. When a fuel cell is used in this cogeneration mode, producing both power and heat, it can achieve overall efficiencies as high as 80 percent.

2.6.3.2. Types of Fuel Cells

The general design of most fuel cells is similar except for the electrolyte, which also determines their operating temperature, the type of fuel and range of applications. The five main types of fuel cells, as defined by their electrolyte, are alkaline fuel cells, proton exchange membrane fuel cells, phosphoric acid fuel cells, molten carbonate fuel cells, direct methanol fuel cells, and solid oxide fuel cells. Table 2.2 summarizes the characteristics of various fuel cell types.

Table 2.2- Summary of fuel cell types and their present characteristics18

Fuel cell type	Operating temperature (oC)	Applications	Electrical power range (Kw)	Electrical Efficiency (%)
Proton exchange membrane	60-110	Mobile, portable, low power generation	0.01-250	40-55
Direct methanol (DMFC	60-120	Portable, mobile	0.001-100	40
Phosphoric acid (PAFC)	175-210	Medium to large-scale power and CHp	50-1,000	40-45
Molten carbonate (MCFC)	550-650	Large-scale power generation	200-100,000	50-60
Solid oxide (SOFC)	500-1,000	Medium to large-scale power and CHp, vehicle APUs, off-grid power and micro-CHp	0.5-2,000	40-72

Alkaline and solid polymer fuel cells operate at lower temperatures and are mainly designed for use in transportation applications, while the other three operate at higher temperatures and are being developed for use where the waste heat can be used (cogeneration) or in large central power plants.
Alkaline fuel cells (AFC), used by NASA, have very high power generating efficiencies, and discharge only pure water. Unfortunately, only very pure hydrogen and oxygen can be used and the electrolyte, alkaline potassium hydroxide i s expensive. It is expected that these types of fuel cells will be used only in niche markets and applications.

Proton-exchange membrane (PEM) fuel cells are the most common type of fuel cells for light-duty transportation use, because they can vary their output quickly (such as for startup) and fit well with smaller applications. Chief advantages of PEMs are that they react quickly to changes in electrical demand, will not leak or corrode, and use inexpensive manufacturing materials (plastic membrane).

Phosphoric acid fuel cells (PAFCs) are the most commercially developed type and are being used in hotels, hospital, and office buildings. The PAFC plant also makes use of the waste heat for domestic hot water and space heating.

Molten carbonate fuel cells (MCFCs) operate at high temperatures which mean that they can achieve higher efficiencies and have a greater flexibility to use more types of fuels. Fuel-to-electricity efficiencies approach 60%, or upwards of 80% with cogeneration.

Solid oxide fuel cells (SOFCs) also operate at higher temperatures and have demonstrated very good performance in combined-cycle applications. SOFCs are a promising option for high-powered applications, such as industrial uses or central electricity-generating stations.

Direct methanol fuel cells (DMFC) use methanol instead of hydrogen and are being considered for use in the transportation industry. DMFCs differ from the other types of fuel cells in that hydrogen is obtained from the liquid methanol, eliminating the need for a fuel reformer.

2.6.3.3. Comparison of Fuel Cells with Internal Combustion Engines

Fuel cells and internal combustion engines share similarities of form.[19] Both fuel cells and internal combustion engines use gaseous fuel, drawn from an external fuel storage system. Both systems use hydrogen-rich fuel. Fuel cells use pure hydrogen or a reformate gas mixture. Internal combustion engines typically use hydrogen-containing fossil fuels directly, although they could be configured to operate using pure hydrogen.

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Both systems use compressed air as the oxidant; in a fuel cell engine the air is compressed by an external compressor. In an internal combustion engine, the air is compressed internally through piston action. Both systems require cooling, although engines operate at higher temperatures than fuel cells.

In some respects, fuel cells and internal combustion engines are fundamentally different. Fuel cells react the fuel and oxidant electrochemically whereas internal combustion engines react the fuel and oxidant by combustion. Internal combustion engines are mechanical devices that generate mechanical energy while fuel cells are solid state devices that generate electrical energy (although the systems used to support fuel cell operation are not solid state). Fig. 2.12 shows a comparison between Fuel cells, batteries and internal combustion engines.

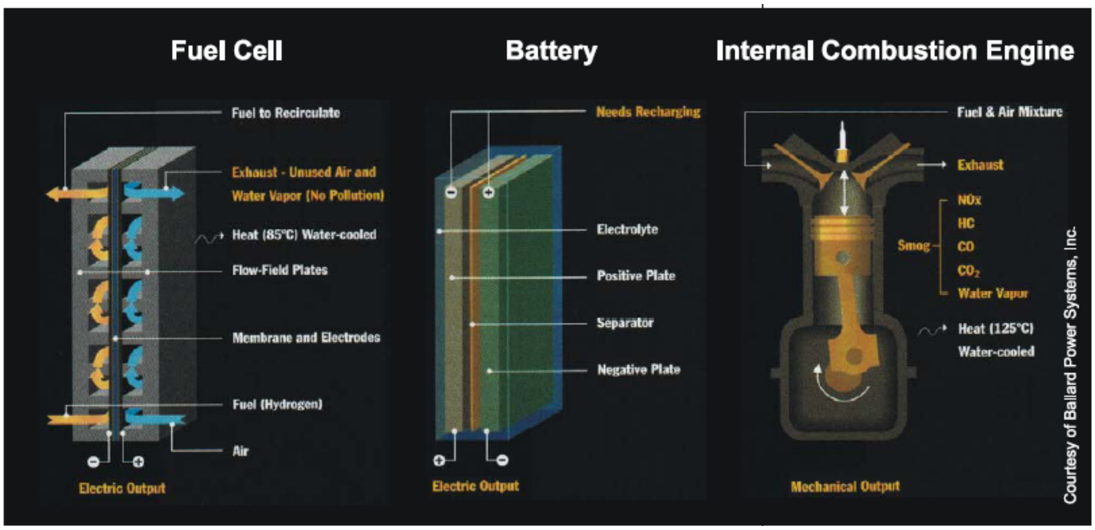

Fig. 2.12- Fuel Cell, Battery and Internal Combustion Engine Comparisons[19]

Pollution is related to the fuel composition and the reaction temperature. Fuel cell engines operating on pure hydrogen produce no harmful emissions; those that operate on hydrogen-rich reformate produce some harmful emissions depending on the nature of the process. Internal combustion engines operating on pure hydrogen can be designed to produce almost zero harmful emissions; those that run on conventional fuels produce significantly more pollution. [29]

2.6.3.4. Advantages of Fuel Cells

A key point is the wide range of applications of fuel cell power, from systems of a few watts up to megawatts. In this respect, fuel cells are quite unique as energy converters; their range of application far exceeds all other types.[19]

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Fuel cell systems are usually compared to internal combustion engines and batteries and offer unique advantages and disadvantages with respect to them. Fuel cell systems offer the following advantages:

Fuel cell systems operate without pollution when run on pure hydrogen, the only by-products being pure water and heat. When run on hydrogen-rich reformate gas mixtures, some harmful emissions result although they are less than those emitted by an internal combustion engine using conventional fossil fuels. To be fair, internal combustion engines that combust lean mixtures of hydrogen and air also result in extremely low pollution levels that derive mainly from the incidental burning of lubricating oil.

Fuel cell systems operate at higher thermodynamic efficiency than heat engines. Heat engines, such as internal combustion engines and turbines, convert chemical energy into heat by way of combustion and use that heat to do useful work. The optimum (or “Carnot”) thermodynamic efficiency of a heat engine is known to be:

T 13 Efficiency max = 1 - 2 T1

Where: T1 = Absolute temperature of inlet (hot) gas (in ^{o}R or K)

T2 = Absolute temperature of outlet (cold) gas (in ^{o}R or K)

This formula indicates that the higher the temperature of the hot gas entering the engine and the lower the temperature of the cold outlet gas after expansion, the higher the thermodynamic efficiency. Thus, in theory, the upper temperature can be raised an arbitrary amount in order to achieve any desired efficiency, since the outlet temperature cannot be lower than ambient.

However, in a real heat engine the upper temperature is limited by material considerations. Furthermore, in an internal combustion engine, the inlet temperature is the operating temperature of the engine, which is very much lower than the ignition temperature.

Since fuel cells do not use combustion, their efficiency is not linked to their maximum operating temperature. As a result, the efficiency of the power conversion step (the actual electrochemical reaction as opposed to the actual combustion reaction) can be significantly higher. The electrochemical reaction efficiency is not the same as overall system efficiency. The efficiency characteristics of fuel cells compared with other electric power generating systems are shown in Fig. 2.13.

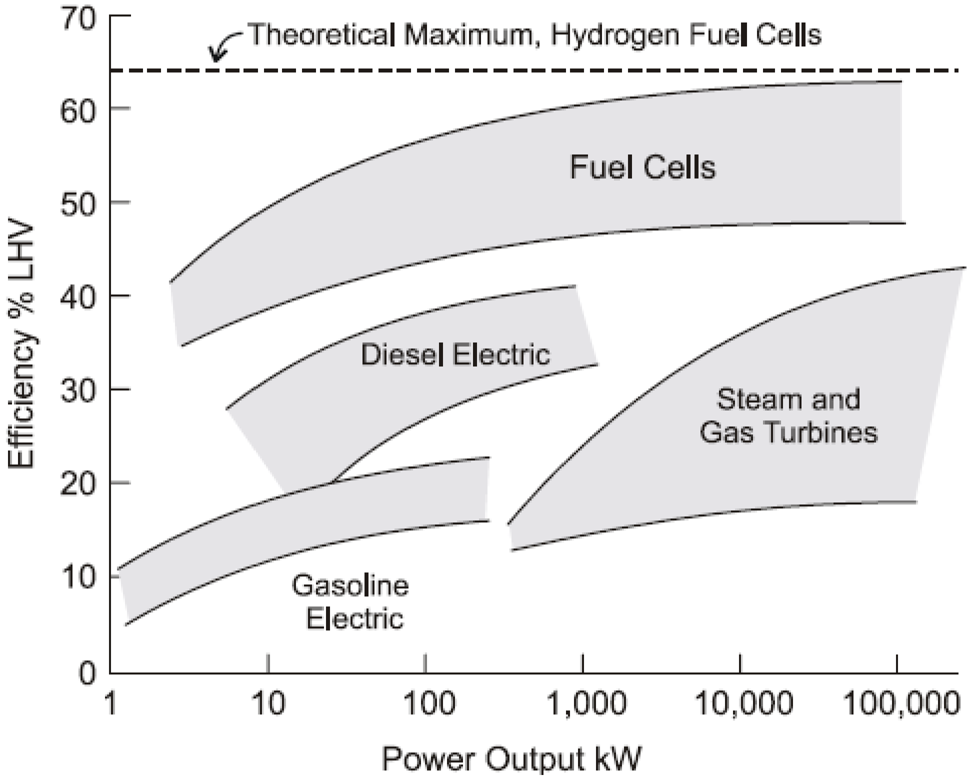

Fig. 2.13- Power Generating Systems Efficiency Comparison[19]

One of the fuel cell's most important characteristics is its ability to operate efficiently at part-load and to respond rapidly to sudden increases or decreases in power demands. The fuel cell's ability to increase output quickly is known as its spinning reserve capability, and its ability to decrease output quickly is known as its load following capability. These capabilities make fuel cells attractive as peak-load facilities. When used as an electrical energy generating device, fuel cells require fewer energy transformations than those associated with a heat engine. When used as a mechanical energy generating device, fuel cells require an equal number of conversions, although the specific transformations are different.

Every energy transformation has an associate energy loss so that the fewer transformations there are, the better the efficiency. Thus fuel cells are more ideally suited to applications that require electrical energy as the end product, rather than mechanical energy. Comparative energy transformations for fuel cells, batteries and heat engines are shown in Fig. 2.14.

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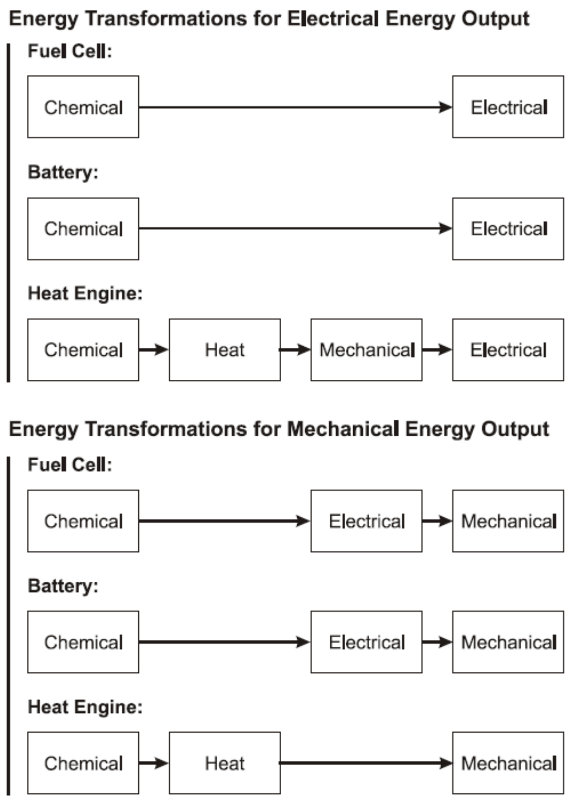

Fig. 2.14- Comparative Energy Transformations[19]

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Fuel cell systems can be used in cogeneration applications. In addition to electrical power, fuel cells generate pure hot water and medium-grade heat, both of which can potentially be used in association with domestic or industrial applications. When this is done, the overall efficiency of the combined systems increases.

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Fuel cell systems do not require recharging. Rather, fuel cell systems must be refueled, which is faster than charging a battery and can provide greater range depending on the size of the storage tank.

A fuel cell employs a hydrogen rich gas to produce electricity. Thus, it can use any fuel source that can supply this gas. At present, sources of such gas include petroleum, naphtha, natural gas, and methanol. Several other sources may be developed to varying degrees. In places where biomass and solid waste produce natural gas economically, they can be used as fuel sources. Additionally, where hydrogen storage is feasible, renewable power sources could drive an electrolysis process to produce hydrogen during off-peak periods that can be used to operate fuel cells during peak demands.

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Fuel cells are expected to attain performance reliability near 85 percent. Furthermore, their modular construction should facilitate repair when they are scheduled for maintenance or are forced out of service by a technical difficulty. Consequently, a utility that installs a substantial number of them may be able to reduce its reserve margin capacity requirements while maintaining a constant level of system reliability. By reducing the need for capacity construction, cost savings may be realized.

2.6.3.5. Disadvantages of Fuel Cells

Fuel cell systems suffer the following disadvantages:

Ironically, hydrogen which is of such benefit environmentally when used in a fuel cell, is also its greatest liability in that it is difficult to manufacture and store. Current manufacturing processes are expensive and energy intensive, and often derive ultimately from fossil fuels. An effective hydrogen infrastructure has yet to be established.

Gaseous hydrogen storage systems are large and heavy to accommodate the low volumetric energy density of hydrogen. Liquid hydrogen storage systems are much smaller and lighter, but must operate at cryogenic temperatures. Alternatively, if hydrogen is stored as a hydrocarbon or alcohol and released on demand by way of an onboard reformer, the storage and handling issues simplify, but some of the environmental benefits are lost.

Fuel cells require relatively pure fuel, free of specific contaminants. These contaminants include sulfur and carbon compounds, and residual liquid fuels (depending on the type of fuel cell) that can deactivate the fuel cell catalyst effectively destroying its ability to operate. None of these contaminants inhibit combustion in an internal combustion engine. Fuel cells that use proton exchange membranes must not dry out during use and must remain moist during storage. Attempts to start or operate these fuel cells under dry conditions can lead to membrane damage.

Fuel cells require complex support and control systems. Fuel cells themselves are solid state devices, but the systems required to support fuel cell operation are not. Of particular note is the requirement for compressed air; this necessitates a high-speed compressor that imposes a large parasitic load on the overall system. System complexity increases significantly when the fuel cells are operated in conjunction with an on-board reformer.

Fuel cell systems are heavy. Fuel cells themselves are not excessively heavy, but the combined weight of the fuel cells, their support systems and their fuel storage is presently greater than for a comparable internal combustion engine system. Systems that include an on-board reformer are heavier still. Fuel cell systems are generally lighter than comparable battery systems even though the battery systems require less support equipment. System weight will likely continue to decrease as the technology develops.

Fuel cells are an emerging technology. As with any new technology, reductions in cost, weight and size concurrent with increases in reliability and lifetime remain primary engineering goals.

2.6.3.6. Technical Problems

There are some uncertainties about whether fuel cell can achieve technical, performance and cost objectives. Although technical and operational feasibility have been established, there are still concerns about water purity, durability, heat rates and alternative fuel use that may be difficult to attain. Ensuring that water of an acceptable purity and quality is fed into the system may pose one technical barrier for phosphoric acid fuel cell commercialization. Another hardware concern involves durability improvements that require extending the life of fuel cell stacks and other commercially available components used in the fuel cell system. Also, private sector commercialization goals depend on expected reductions in fuel cell heat rates, which would translate into improved fuel efficiency and, thus, reduced operating costs. Perhaps the most important technical barrier involves the use of alternative fuels.

2.6.3.7. Environmental Considerations

Air quality: Because fuel cells do not rely on a fuel-burning process, their air pollution emissions are projected to be 1000 to 10000 times smaller than those of new fossil-fuel plants, even if the fossil plants employ the most advanced pollution control equipment. Air quality benefits would be improved further when the fuel cell is operated as a cogeneration facility. Also, the expected reductions in sulfur and nitrogen oxides could enable fuel cells to reduce suggested acid rain conditions.

Water quality: The use of fuel cells is also expected to provide significant benefits related to water use and water quality. Because the fuel cell's electrochemical reaction produces water as a byproduct, little, if any, external water is required for its operation. In contrast, conventional power plants require massive amounts of water for system cooling. Additionally, fuel cells' limited water demands may allow them to be located in remote sites.

Noise level: The quiet electrochemical conversion process of fuel cells eliminates many of the noise sources associated with conventional steam power plants. This feature reduces community concerns, enabling sitting close to the load, and decreases the cost of noise control. It also improves the work environment.

2.6.3.8. Present and Projected Future Costs of Fuel Cells

The biggest drawback presently associated with fuel cells is their cost. Today, the most widely marketed fuel cell for stationary power generation costs for small, medium and large scale applications is in the $3,000 - $5,000 per Kw, depending upon the type of fuel cell and end-use application.[20,21,22,23] By contrast, a diesel engine costs $800 to $1,500 per kilowatt, and a natural gas turbine even less. Costs are expected to decrease in the future (projections are for around $400/Kw) as more fuel cells are produced and utilized. Techniques have also been developed to

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separate hydrogen from natural gas inside the fuel cell ("internal reforming"), eliminating the expense of a separate system.

CHAPTER III TECHNICAL AND ECONOMIC FEASIBILITY

3.1. Adaptation of Unconventional Sources of Energy to Power Drilling Rigs

It is necessary to know the total power required for the drilling operation to evaluate the technical and economic feasibility of using unconventional sources of energy to provide energy to the rig. Obviously the power demand by a particular rig may with the target depth, geology, well planning; among others parameters (see topic 2.1.). The best approach would be to provide all the critical information to the rig manufacturer therefore an optimum design could be developed for the specific situation. Unfortunately this approach is neither economic nor practical since rig manufacturers design and build drilling rigs suitable for a variety of loads and power demands based on worst case scenarios and most important on the experience gained from previous projects. As a consequence different companies produce rigs to cover several ranges in depth and loads respectively and normally a rig will be over-rated for the conditions encountered. A more realistic option would be to consider a fully manufactured rig (National Oilwell Varco’s Rapid Rig) and evaluate further consequences of using these technologies as its prime movers. This “power audit” was undertaken by Verma (Section 2) and will be basis of future studies.

3.2. National Oilwell Varco’s Rapid Rig

National Oilwell Varco’s new Rapid Rigs is an efficient “single” land rig that delivers maximum speed, safety and performance in a compact, road legal drilling package. It was developed with a 250 ton hook load capacity for shallow to moderate well depths. Its small size and self deploying design allows for ease of transport and faster onsite rig-up. The rig floor is fully automated coupled with a revolutionary pipe handling system, reducing crew size and accident exposure while providing a comfortable, efficient work environment. The Rapid Rig’s compact components and AC powered primary systems further reduce environmental impact at the well site. Fig. 3.1 and Table 3.1 show dimensions and some features of the Rapid rig’s design.

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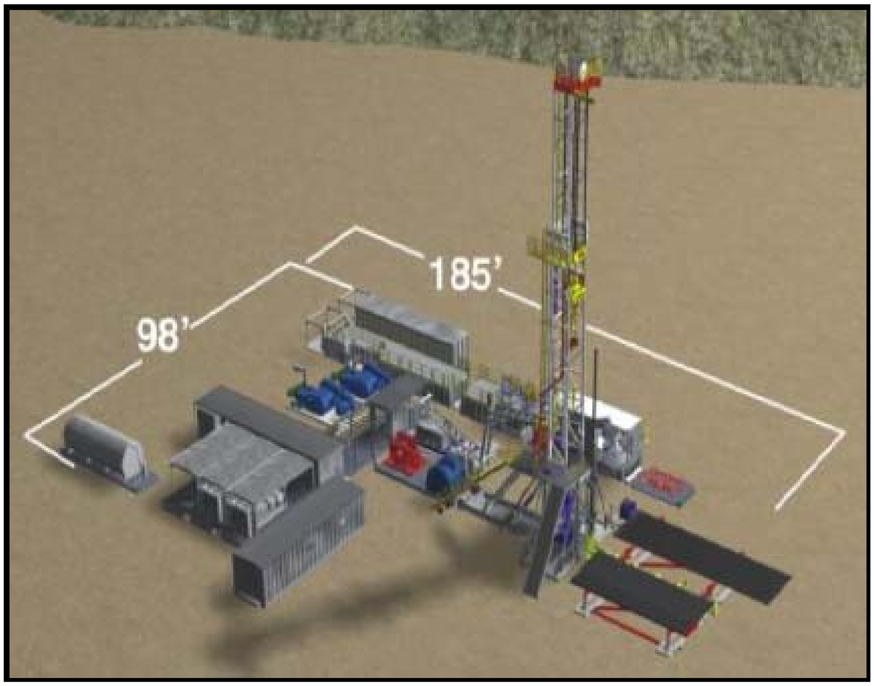

Fig. 3.1- The Rapid Rig[24] visualized on a compact well pad. This site (less than ½ acre) represents the new capability of drilling operations.

Table 3.1- Rapid Rig Specifications[24]

Footprint area	18,500 ft^2 (0.42 acres) - see Appendix A.1
Power system	VFD-AC system w/MCC, Generator Control and two (2) 1350 bhp, 1800 rpm, 1750 Kva Generator sets - see Appendix A.2
Depth rating	11,000 ft (drillpipe) – 15,000 ft (casing)
Hook load	500,000 lbs
Mast Height	80 ft Telescoping
Drill Floor Height	20 ft Slingshot
Clear Height	17 ft

3.3. Technical and Environmental Parameters for Rig Design

Portability: A drilling rig is a machine that has been designed to perform a job (drill a well) for a finite period of time. This means that this machine will be moved frequently from location to location as soon as the targets are reached in every situation. All land rigs are portable.25 Portability may not seem to be an important factor until some parameters are considered. The builder of the rig may have designed it to drill to depths from 10,000 ft to 20,000 ft or more. While not all rigs can drill this deeply, the amount, the size, and the weight of the tools and equipment required to drill a well are nevertheless large. This heavy and cumbersome equipment must be easily disassembled and moved to a new location. This location may be several miles away in entirely different terrain. At the new site, crew members then have to be able to put the rig together, or rig-up, fairly rapidly and start drilling again. Over the life of the rig, crew members may rig it down, move it, and rig it up hundreds of times.

Installation requirements: Rig manufacturers are working hard to come with better designs to facilitate the installation of the rig on site, so the time needed to have the rig available for operation is an important parameter crucial for the final evaluation of the rig efficiency.

Weight: As indicated before, designing and building parts that reduce the weight of the entire system will have a positive influence on the rig's capability to be transported and located on site with less equipment such as cranes or trucks.

Height: This characteristic is also related to the ease of transportation and final rig-up time. (May not be an important parameter in self-erected rigs)

Footprint: This parameter is critical for the purpose of this project as goals have been set to design and conduct operations reducing the footprint left behind by the drilling activities, minimizing disturbance and promoting protection of the environment.

Emissions: This represents another critical parameter to consider since diesel combustion engines used as prime movers have high ratings of contaminants and they also produce high levels of noise.

Installation and operation costs: Costs play a decisive role when alternatives are evaluated against current designs. This does not represent a constraint for this project.

3.3.1. Wind Turbines

As described in the literature, wind turbines can be found in the market in different sizes and capacities depending on the power required. Since we know that the Rapid rig uses two engines each providing 1350 Hp, i.e., 2700 Hp (2.013MW), we would then need a wind turbine that could be capable of providing at least 2.013 MW. GE manufactures wind turbines with capacities of 1.5, 2.5 and 3.6 MW, this means that it is technically possible to adapt a wind turbine as a prime mover for a drilling rig. Fig. 3.2 shows a 1.5 MW turbine.

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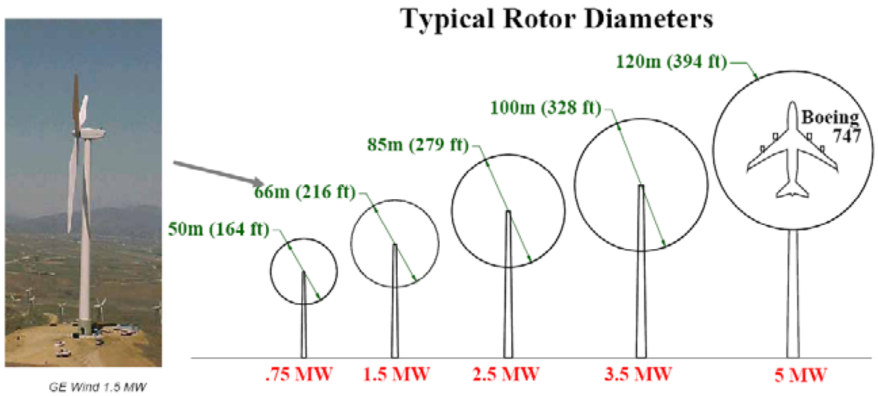

Fig. 3.2- Typical rotor diameters[26], with blades from 80 to 200 ft. in length.

When we evaluate the portability of a wind turbine and the equipment required for its installation, it is evident that this technology is not appropriate for drilling power. A 2.5 MW wind turbine will be characterized by a rotor diameter of 328.083ft (100m) and a hub height of 459.317ft (140m) (1.4 times the rotor diameter27) demanding the use of large conventional cranes which become a significant part of the installation cost. (See Fig. 3.3 and 3.4)

a

b

Fig. 3.3- (a) Blades raised for assembly, (b) Big cranes required for installation

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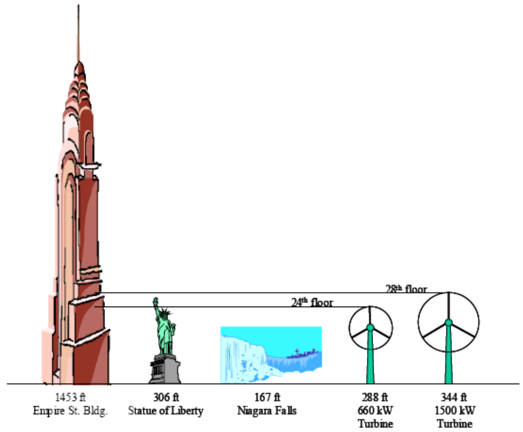

Fig. 3.4- Height Comparison of Wind Turbines[28]

Besides the footprint left by the large cranes used for their assembly, wind turbines should ideally be placed about ten times their diameter apart in the direction of prevailing winds and five times their diameter apart in the perpendicular direction for minimal losses due to wind park effects. As a result, wind turbines require roughly 0.1 square kilometers of unobstructed land per megawatt of nameplate capacity increasing the overall footprint of the drilling site.[27]

Wind turbines were not designed to be mobile machines in contrast to drilling rigs; therefore they require strong concrete foundations (Fig. 3.5) for proper ground settlement.

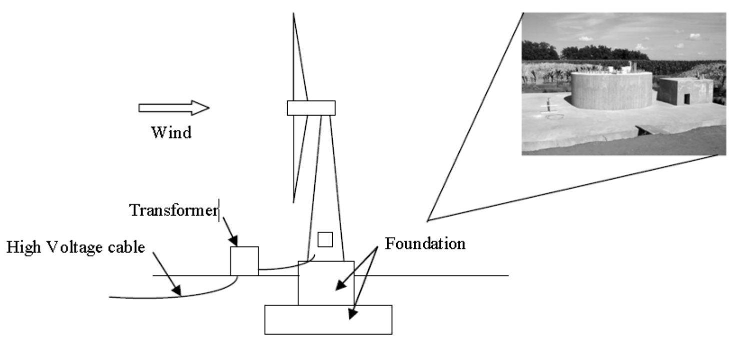

Fig. 3.5- Ground foundations for wind turbines

Additionally, wind turbines rely on availability on wind forces, so their power generation can be considered as intermittent, and as so, their use would not be appropriate in areas with low wind activity. Despite all these disadvantages, wind turbines do reduce emissions to the environment and produce less noise compared to diesel engines; however their adaptation for powering land rigs is not feasible in the near term.

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3.3.2. Solar cells (Photovoltaics)

Today's commercial PV systems are still under development to try to overcome high installed costs (>4500 &/Kw) and the power they can provide (25-35Kw/unit) compared to their size and weight. For example, a 25 Kw unit (Fig. 3.6) will be characterized by dimensions of 45ft x 55ft x 2.5in, 6,000 lbs (2.7 ton) in weight and average land requirements of 0.01 acres/Kw.

Fig. 3.6- Four-25Kw solar cell units

Like wind turbines, solar cells provide energy depending on the amount of sunlight available at the site, do not produce emissions and in contrast, they do not produce noise. Despite these positive environmental features, their overall size (increase in footprint), weight and intermittence (sun availability) represent constraints to consider them as possible providers of energy as prime movers on drilling rigs.

3.3.3. Fuel Cells

Fuel cells are considered as one of the most environmentally friendly technologies for power supply. Benefits include high efficiency; unmatched environmental performance; high quality power; fuel flexibility; quiet operation; simplicity (no moving parts); modularity/scalability, which lead to high reliability, flexible sitting and ease of maintenance; and adaptability to specialized application. Unlike solar and wind technologies, fuel cells operate continuously regardless of time of day or weather conditions and can be sited in any terrain.

According to the literature [20,21,22,23] installed cost of power generators for small, medium, and large-scale applications is in the $3,000-$5,000 Kw per range, which is quite higher than the price of conventional power generation units. For instance, the installed cost of a 200-Kilowatt unit have varied depending on the particular installation, but values at or above $3,000/kilowatt have been reported. However, a recent study20 estimated that a significant market for these cogeneration units will require installed costs in the $2,000- to $1,500-/kilowatt range. The goals

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for advanced fuel cell units for power generation are below $1000/Kw, and this value is also expected to decrease substantially as sale volumes increase and improvements are made in the product and manufacturing methods.

Cost of hydrogen: Even though the chemical reaction is performed combining hydrogen with oxygen (air), fuel cells do not necessarily need to be fueled with hydrogen. Since the 1990's a stronger emphasis has been made on the utilization of natural gas as a primary energy source for all types of fuel cells. This approach was later reinforced by the increased attraction for its use in fuel cell/gas turbine hybrid systems.

Further, since natural gas is considerably a cleaner fuel for fuel processors than petroleum or coal and the hydrogen content is higher for the former than for the latter two fuels, the main goals of the major worldwide fuel cell programs are to use natural gas or natural-gas derived fuels.

That is why all the manufacturers for stationary power generation units have designed fuel cells to be powered with natural gas (standard) and anaerobic digester gas ADG (optional). The cost of natural gas would then depend on the total amount of gas needed and the prices in the market. This situation brings a constraint for the EFD project, because if fuel cells were to be considered as an alternative source of energy for the rig (hypothetically), the need for a gas pipeline would be present, as hydrogen is not being commercially used as fuel for fuel cells for several problems including storage and transportation.

Some values indicating fuel consumption are indicated in Table 3.2.

Table 3.2- Fuel and flow rate required by fuel cells

Fuel cell	Fuel type	Flow (scf/hr)
Purecell 200Kw	Natural gas	2050
	ADG with 60% CH4	3500
FCE 300Kw	Natural gas	2340 @930 BTU/ft^3
FCE 1200Kw	Natural gas	9360 @930 BTU/ft^3
FCE 2400Kw	Natural gas	18720 @930 BTU/ft^3

Table 3.2- Fuel and flow rate required by fuel cells

Expected life of a fuel cell: The life of fuel cells is related to the maintenance needed by the units. However the expected lifetime of fuel cells varies with the intended application. Lifetimes are the longest for continuous power generation/cogeneration (40,000 hrs). Because of the problems with stability of component materials in the electrolyte environment, there is degradation in the performance of an electrochemical cell stack. In this case, they will have to be periodically replaced (5 years for power generation/cogeneration). The cost of the electrochemical cell stack is approximately one third of the whole power plant. This will have to be taken into account in asserting the operational costs.

Footprint: In the United States; UTC Power (200Kw-268Hp) and Fuel Cell Energy (300Kw-402.3Hp/1200Kw-1609.2Hp/2400Kw-3218.45Hp) manufacture units each having specific requirements for fuel (Natural gas) and water supply. Considering the hypothetical scenario of powering the Rapid Rig with fuel cells, we would then need: 11 x 200Kw units from UTC Power (Fig. 3.7).

Fig. 3.7- UTC Purecell 200 -200Kw[29]

It is evident from this information that despite the advantages fuel cells have compared to diesel engines in efficiency, reliability, low acoustic noise level and reduction of emissions (See Table 3.3), the size and weight of the units are not appropriate since the footprint of the overall drilling operation would be greatly compromised.

3.3.4. Summary Comparison of Power Generation

The ability to utilize unconventional technology to produce energy to power a drilling rig may be limited by the footprint and costs involved. This is strongly emphasized in some cases for the lack of available commercial units with enough power or the need of heavy duty equipment to install the equipment. Table 3.4 shows a comparison between the different power generating technologies.

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Table 3.4- Characteristic comparison of power technology[31]

Feature		Internal combustion engine with SCR	Wind turbines	Solar cells	Fuel cells
Rated power (Kw)		10-5,000	1-5,000	1-1,000	100-3,000
Installed cost ($/Kw)		700-1,000	1,000-1,600	>4500	550-5,000
Fuel		Diesel	Wind	Sunlight	Natural gas
Operation & Maintenance cost ($/Kwh		0.008-0.018	0.005	Negligible	0.020-0.04
Electrical efficiency (%)		30-40	20-46	15-30	36-50%
Noise		High	Low	None	Low
Footprint (ft^2/Kw)		0.22-0.7	5-100	200-600	0.9
Emissions (lb.Mwh)	NOx	4.7	0	0	0.03
	SO_2	0.454	0	0	0.006
	PM	0.78	0	0	0
	CO_2	1432	0	0	1,078

3.4. Alternatives

3.4.1. Connecting the Rig to the Network

Results show that it is practical to drill with electric power and that the larger the rig, the better the economy.[8] The use of AC to DC power combines the advantages and conveniences of both the electric utility power system and DC variable-voltage drive. The improved performance at both high speeds and high torques means faster operation when coming out of or going into the hole, so that more time is spent at the bottom. Improved efficiency reduces lost time and simplified and greatly reduced maintenance all result in greater economy in drilling a well.

The electrical setup is very easily taken down and made up. Verma discusses this in the following section. All electrical circuits can be reestablished in an 8-hour working day by three men, since polarized plugs and receptacles are used on all control cables. The cables are transported in place when the rig is moved.

Available power: Depending on the site where the rig will be placed, an existing network should be available for grid connectivity. For example, in the Ventura Oil field, there was a network of 16,500 VAC power lines and in that place drilling was expected to continue for many years, so this means that if a all electric rig is to be used for an environmentally sensitive area it should be appropriate to have an estimate of the drilling forecast within the vicinity therefore efforts for a successful grid connectivity can be accomplished.[32]

In the Ventura field drill site, a 1500 Kva trailer mounted substation took power from the AC network at 16500 volts and step it down to 2300 volts (In our case, the rapid rig is equipped with two 1350 Hp-1750 Kva generators) so if the rapid rig was to be connected to the network, capacities of 3500 Kva or higher should be available to provide the energy required by all the equipment included in the rig configuration.

During the drilling operations in the Ventura field, the only rigs available at the time were mechanical. After the substation had taken the power down from the network, then the energy was induced to drive induction motors, which were shaft connected to DC variable-voltage generators. From these generators, DC power was fed to the 4 motors driving the drilling equipment. These motors were: draw works motor, mud pumps and mud mixing pump motor.

Controlling parameters: Depending on the rig design and the specifications in the electrical equipment, an evaluation of the network power available should be carefully studied before considering the use of the rig in that specific area. One additional aspect should be to consider having backup equipment maintained on a standby basis, to protect the hole in event of power failure.

Today what seems to be the best choice is to use diesel engines despite their negative impacts on the environment, however based on the experience that drillers have had in previous operations, it has been noticed that a large amount of power is needed while drilling instead of other operations like tripping,[7] this gives an advantage for energy efficiency usage in which an electric rig could have energy storage devices (flywheels, batteries, etc) being charged during low power needs and then be used for high power demands depending on the time the operation will last, because it is well known that energy storage devices can supply energy for specific periods of time.

As a summary a successful connection involves the following:

Grid protection

Electrical protection of the equipment in the rig (restrictions on low power factor and harmonics put back onto the line)

Additional equipment to be installed to adapt rig to the network (installation costs)

. Electricity "loads profile" evaluation

Cost of electricity from the grid vs. Cost of electricity from diesel

engines (fuel consumption on a time basis)

Availability of grid support within the vicinity of the rig operation Support systems as a backup in case of grid problems

3.4.2. Prime Movers off Site

As we have seen during this study, to employ an unconventional source of energy in the near term is unlikely to happen. An alternative to approach our goals of reducing the effects of the drilling operation in the field would be to evaluate the technical feasibility of drilling without the diesel engines on site. Instead they could be installed somewhere in the vicinity where the impacts on the environment may be minimized.

However, it is well known that drillers like to have the prime movers on site for versatility in operations and quick access in cases of any malfunctions or just for routine maintenance jobs. Besides looking at this option from a driller’s point of view, this idea requires further economic studies to evaluate the increase of installation costs (longer cables, $/ft) and the consequences in

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safety procedures to ensure proper protection of the connection system from the prime movers all the way to the rig site.

3.4.3. Alternative fuels for Current Prime Movers

3.4.3.1. Natural Gas

Increasing level of oil and gas drilling has caught the attention of a major operator elevating their concern about how this activity is affecting air quality. EnCana is fueling some of its drilling rig engines with natural gas as a way to reduce air quality impacts associated with its operations.[33] Natural gas is a cleaner fuel. Fig. 3.11 illustrates the reduction in oxides of nitrogen (NO_x) anticipated by switching from diesel to natural gas fired engines.

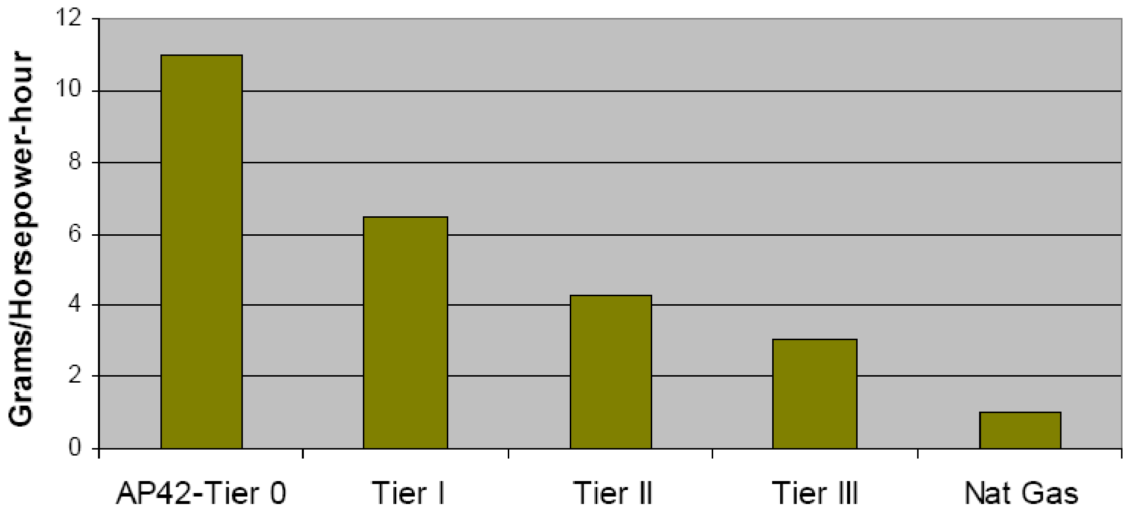

Fig. 3.11- Rig engines – Typical NOx emission levels[3]3

Natural gas fueled engines appear to be the most effective mean to achieve emission reduction commitments. Compared to similar diesel-fueled rigs, natural gas rigs produce less tons/well of NOx. Large HP natural gas engines raise overall fleet tier rating substantially. Average NOx reduction of ~85% vs. Tier I, and ~90% vs. Tier 0). EnCana is building 5 new 1000 Hp Fit for Purpose Rigs with natural gas engines with small footprint (1.5 acres).

EPA regulations concerning emission standards refer to "Tiers" as a way to categorize different pollutants. Manufacturers have begun producing Tier 1 and Tier 2 engines in all size categories and will begin manufacturing engines that meet the more stringent tiers in next several years. However we still see how diesel engines are being used to power drilling rigs without any concern on their impact on the environment. Table 3.5 shows an emissions comparison between Tier I and Natural Gas engines in an assessment conducted by Encana. Economic benefits can also be seen in Fig. 3.12.

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Table 3.5- Emissions comparison between Tier I and natural gas emissions[33]

Features	Ensign 88 2-3516 LE NG	Ensign 89 2-3512 Tier I	Ensign 85 2-3512 Tier I
Average depth (ft)	12,422	12,329	12,389
Average days Total Fuel (g)	29.75 6,621	37.25 59,965	29.25 47,888
Average fuel (g/day)	223	1,610	1,637
NOx (g/Hp/hr)	1.00	6.6	6.6
NOx (ton/well)	0.92	6.8	5.4
CO (g/Hp/hr)	3.5	1.3	1.3
CO (ton/well)	3.2	1.4	1.0

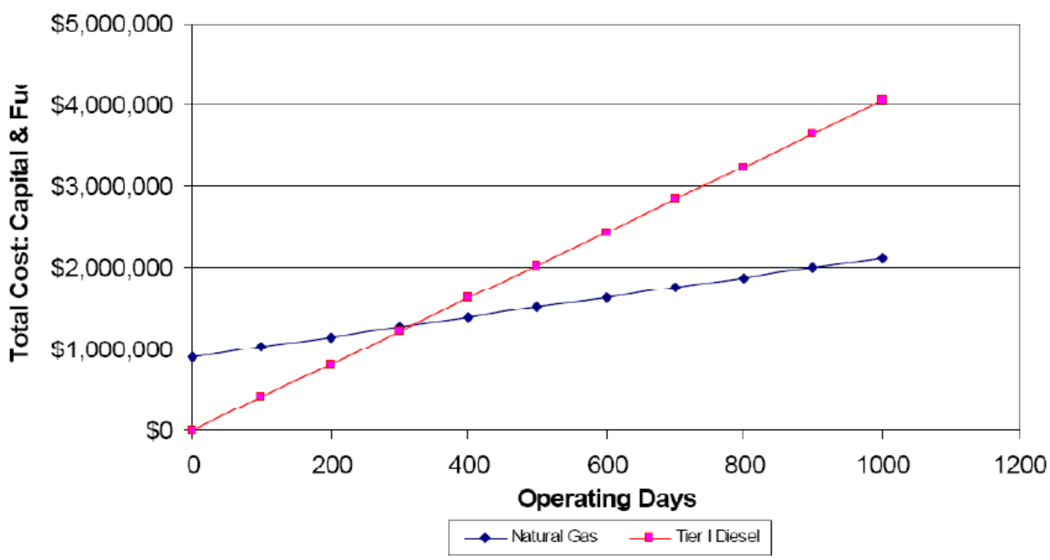

Fig. 3.12- Natural Gas vs. Tier I diesel engines[33]

Further studies are being performed by Encana[33] including Selected Catalyst reduction (SCR), combustion catalyst, bi-fuels and feasibility of using biodiesel.

3.4.3.2. Biodiesel

Biodiesel is a fuel made from vegetable oil that runs in any unmodified diesel engine. Biodiesel can be made from any vegetable oil including oils pressed straight from the seed (virgin oils) such as soy, sunflower, canola, coconut and hemp. Biodiesel can also be made from recycled cooking

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oils from fast food restaurants. Even animal fats like beef tallow and fish oil can be used to make biodiesel fuel.

Biodiesel runs in any unmodified diesel engine.[34] There is no "engine conversion" typical of other alternative fuels. The diesel engine can run on biodiesel because it operates on the principle of compression ignition whereby air is compressed and then fuel is sprayed into the ultra-hot, ultra-pressured combustion chamber. Unlike gasoline engines, which use a spark to ignite the fuel/air mixture, diesel engines actually use fuel to ignite hot air.

Biodiesel Benefits. Biodiesel runs in any conventional, unmodified diesel engine. No engine modifications are necessary to use biodiesel and there is no "engine conversion." In other words, "you just pour it into the fuel tank." Biodiesel can be stored anywhere that petroleum diesel fuel is stored. All diesel fueling infrastructure including pumps, tanks and transport trucks can use biodiesel without modifications. Biodiesel reduces Carbon Dioxide emissions, the primary cause of the Greenhouse Effect, by up to 100%. Since biodiesel comes from plants and plants breath carbon dioxide, there is no net gain in carbon dioxide from using biodiesel. Biodiesel can be used alone or mixed in any amount with petroleum diesel fuel. A 20% blend of biodiesel with diesel fuel is called "B20," a 5% blend is called "B5" and so on.

Biodiesel is more lubricating than diesel fuel, it increases the engine life and it can be used to replace sulfur, a naturally occurring lubricating agent in petroleum based diesel that, when burned, produces sulfur dioxide - the primary component in acid rain. Biodiesel is safe to handle because it is biodegradable and non-toxic. According to the National Biodiesel Board, "neat biodiesel is as biodegradable as sugar and less toxic than salt."

Biodiesel is safe to transport. Biodiesel has a high flash point, or ignition temperature, of about 300 ^{o}F compared to petroleum diesel fuel, which has a flash point of 125 ^{o}F. Engines running on biodiesel run normally and have similar fuel mileage to engines running on diesel fuel. Auto ignition, fuel consumption, power output, and engine torque are relatively unaffected by biodiesel. Biodiesel has a pleasant aroma similar to popcorn popping in comparison to the all-too-familiar stench of petroleum diesel fuel.

Biodiesel Emissions: Overall, biodiesel emissions are lower than gasoline or diesel fuel emissions (with the exception of NO_x). Compared to diesel, biodiesel produces no sulfur, no net carbon dioxide, up to 20 times less carbon monoxide and more free oxygen. Biodiesel has the following emissions characteristics when compared with petroleum diesel fuel:

Biodiesel offers the following:

Reduction of carbon dioxide emissions (CO2) by 100% (net emission reduction)

. Reduction of sulfur dioxide (SO2) emissions by 100%

. Reduction of soot emissions by 40-60%

. Reduction of carbon monoxide (CO) emissions by 10-50%

. Reduction of hydrocarbon (HC) emissions by 10-50%

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. Reduction of all polycyclic aromatic hydrocarbons (PAHs) and specifically the Reduction of the following carcinogenic PAHs:
. Reduction of phenanthrene by 97%
. Reduction of benzofloroanthene by 56%
. Reduction of benzapyrene by 71%
. Reduction of aldehydes and aromatic compounds by 13%

Reduction or increase in nitrous oxide (NOx) emissions by 5-10% depending on the age and type of engine. So far biodiesel has been carefully studied and it is considered as one of the most environmentally friendly alternatives in automotive and marine applications. Nevertheless, ongoing studies33 could help extrapolate their use as fuels for conventional diesel engines in drilling operations.

CONCLUSIONS AND RECOMMENDATIONS

4.1. Conclusions

1. The use of unconventional sources of energy has several advantages from an environmental point of view compared to conventional internal combustion diesel engines, specifically in efficiency, reduction of emissions and reducing noise levels.

2. Some of these technologies are still under development, therefore in some cases, such as in the case of solar cells, there are not units commercially available capable of supplying the amount of energy for drilling purposes.

3. Fuel cells and wind turbines do provide the power required for drilling operations, however, the amount of units (fuel cells), the heavy equipment required for installation (wind turbines and fuel cells) and the inadequacy for land rig mobility purposes represent a big constraint for their near term adaptation in oil and gas land base drilling systems.

4. An economic analysis to evaluate the feasibility of unconventional energies was not conducted since they resulted neither technical nor environmentally suitable for land-based drilling applications.

4.2. Recommendations

Connecting the rig to power grids seems as a good option as it proved to be technically and economically feasible during the drilling operations in the Ventura Field. This idea needs to be evaluated in electric rigs to determine the changes required in the system, the costs for connection to the grid, and the overall impact on the rig footprint. Additionally, it would be necessary to verify the availability of networks in future drilling sites, their power rating and capacity of withstanding variations of power while drilling.

If this option turns out to be feasible, the addition of energy storage devices could also be analyzed. The use of Natural Gas in prime movers for drilling operations has been available for a while and positive results for the reduction of emissions to the environment have already been seen, however new builds are still being designed to use diesel as the fuel of choice. This situation has to be carefully reviewed in order to identify the main constraints that have avoided the use of Natural Gas as a general practice by all rig manufacturers.

Finally, Biodiesel should also be studied to evaluate the feasibility of not just using this fuel for marine and automotive application but as for drilling applications as well.

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SPE 86526

Decision and Risk Analysis Study of the Injection of Desalination By-products into Oil- and Gas-Producing Zones

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Abstract

When reverse osmosis (RO) is used to desalinate brackish water feed streams, a small but significant amount of the brine is discharged as a "reject" stream from the RO unit. This brine contains concentrated dissolved salts and other materials. Disposing of this brine concentrate for traditional RO processes can represent a significant fraction of the cost of operating the unit to recover fresh water. Coincidently, in the oil and gas industry, high salinity brines are routinely injected into formations for pressure maintenance and secondary recovery by water flooding. If water from desalination operations could be injected into these oil- and gas-containing formations, the estimated cost savings could be as much as 30% of the cost of operating the desalination unit. This represents a significant cost savings for RO technology that would make fresh water available to communities in need of this valuable resource.

To provide a comprehensive assessment of the perceived benefits compared to the possible hazards of this practice, we use risk analysis theory to define this process in more detail. The potential for formation damage, reduced injectivity, produced water scaling, and environmental impact is evaluated through comparison with traditional waterflood compatibility studies. We also provide an analysis of how state and federal Underground Injection Control (UIC) rules may be used to regulate injection of RO reject brines. The risk analysis study goes beyond classical decision analysis theory to address the "triple bottom line" economic, environmental, and societal benefits afforded by the process and provides a roadmap to gather quantifiable information for regulators, businesses, and community leaders who might consider this technology.

Introduction

Environmentalists, regulators, industry personnel, and concerned citizens have a basic interest in how to set or negotiate environmental priorities given limited and possibly changing resources. When a new technology or process is being introduced into society, setting these priorities is a problem, especially if the technology has the potential to impact a significant part of the local community. Desalination of brackish ground water, oil field produced brine, or even seawater is one of those technologies. Those who study history have seen that water resources dictate the development of civilizations.[1, 2]

Historically, one of the major impacts of the desalination process to create fresh water resources has been the problem of the disposal of the salts (RO "concentrate") and other materials removed from the source water. Assessing the impact of RO concentrate disposal requires knowledge of the physical, biological, or social conditions associated with various risks. Placing this relatively new process among a host of other environmental priorities of our society requires not only ranking risks but also finding solutions to risk problems. Priority-setting entails trade-offs among competing values when resources are inadequate to do everything; resource consumption demands prudence; or additional resources require negotiation.

Our Texas A&M group is working in fresh water resources research.[3] One of the processes the group has been testing is the desalination of oil field produced brine to make it available for beneficial use. The technology is based on waterflood process designs routinely used by the industry for decades (Figure 1). We need to answer the following questions: Is this process viable? Can fresh water resources be recovered from oil field brine? What is the impact of this new technology?

Engineers are accustomed to evaluating *technical* options when considering the development of a new project.[4] Assessing the uncertainty and comparative *economic* risk of a drilling prospect is also common. What is not common, however, is an effort to quantify the *qualitative* aspects of a project. It is uncommon for a proposed engineering program to address public and other stakeholder issues that might be important in considering the impact of the project on society and the environment.

Aware of this need to connect the engineering effort to the social implications from the beginning of our project, we have been addressing not only the technical problems but also the non-technical issues that arise when a material that is normally considered to be a waste by-product is taken from the oil and gas production facility and converted into a new resource. We view the concentrate disposal issue as one part of the entire infrastructure of desalination and creation of fresh water resources for beneficial use.

Scope of Work

The Texas A&M salt-water desalination program includes both a technical study of the issues involved in treatment of produced water and ground water and the non-technical public and environmental issues that arise as the technology is being developed.

The goal of this technical paper is to offer a process to identify, quantify, and integrate the risks involved in developing new technology – in this case, the desalination of oil field brine and the disposal of desalination concentrate, with the intent of using the recovered fresh water for beneficial purposes.

Our scope of work includes the following:

- A study of the technical risks involved in establishing and operating a facility to desalinate oil field brine.
- A study of the environmental impact that would be created if the technology were to be offered as a commercial venture.
- A study of the regulatory issues that must be considered before a process could be permitted to operate.
- The description of a risk analysis process that considers each of the attributes of the system individually.
- The integration of the risks into quantitative factors that can be used to compare the value or utility of the suggested process with alternate practices.

The Need for New Fresh Water Resources

The need for water in the Western United States is critical. The part of the country dismissed by early American explorers as the “Great American Desert” supports almost 10 times as many people in the 21st century as 100 years ago.[2] Population growth in the Western United States is depicted in Figure 2. The need to supply this population growth is being limited by access to freshwater. U.S. Geological Survey (USGS) projections of water needs in the Western United States show a growth of more than 100% in the next 50 years, as shown in Figure 3**.**

The drought in the United States is aggravating what is already a serious situation. Drought-affected areas of the United States (Figure 4) cover a significant portion of the country. The search for new fresh water resources has led to investigation of seawater desalination processes for states bordering the Gulf and the West Coast and to proposed desalination of brackish groundwater for inland populations.[5] The name of the game in the West is identifying alternative fresh water resources. Figure 5 shows a map of brackish ground water resources identified by the Texas Water Development Board.[5] The study found more than 780 million-acre feet of brackish aquifers that would be amenable to desalination**.**

Description of RO Process

Commercial desalination technology came of age in the 1990s. It is an efficient and environmentally friendly technology that removes all of the pollutants from impure water. World-wide, more than 400 million gallons of fresh water per day are made from RO desalination. In Texas, there are currently more than 40 facilities; most of them are modest in size.

A diagram of an RO process is shown in Figure 6. The key technology utilized in an RO desalination process includes (a) pretreatment, (b) membrane filtration, and (c) disposal of concentrate. The technology can provide fresh water resources from brackish ground water for less than $5.00 per 1,000 gallons[3]. Figure 7 shows a number of desalination sites in Texas that plan to provide services to more than 1,000,000 people by 2005. More facilities will be constructed if the cost of desalination can be lowered.

Pretreatment Issues. For brackish water and oil field produced water systems, pretreatment is critical because of the impurities that the water can contain. Even the most sophisticated RO facility can experience poor flux and high maintenance costs if pretreatment is inappropriate for the feed water being treated. The most recent example of this is the highly publicized Tampa Bay desalination project that has failed to perform as designed (Naples, Florida *Daily News*, September, 25, 2003). This system was troubled by solid material in the feed water that plugged pretreatment filters and reduced throughput and by growth of fouling mussels in the feed lines.

For the treatment of oil field produced water, it is necessary to have more extensive pretreatment than would be required for typical water desalination. In the past, expensive pretreatment has prevented the development of commercial projects with produced water. Recently, new types of treatment and new procedures have been developed to reduce costs. The Texas A&M system uses powered centrifuges to remove any sediments and reduce oil content to low values. The resulting saline water is then treated to remove the remaining hydrocarbon before passing through to the RO filter portion of the process train.

Membrane Filtration. The RO section of the unit consists of a bank of reverse osmosis membranes of a particular type to exclude dissolved salts, heavy metals, and other species. Different types of filters can be chosen on the basis of the components in the water to be removed and the quality of the output water to be delivered. The number of units is selected to allow optimum flux across the membranes. Provisions are made to backwash these units and to protect them in case of a shutdown of operations. As the salinity of brackish water or produced water increases, the osmotic pressure across the desalination membranes increases. New types of microfilters and multistage RO filters have been developed to increase yield and lower operating pressures.

Disposal Issues. The material separated from the fresh water is contained in the RO concentrate or reject stream. This material is not hazardous, only higher in salinity than the feed water. The A&M program is planning on injecting this concentrate into oil- and gas-producing zones at lower depths than the depths of fresh water aquifers.

The technical issue related to the disposal of the concentrate is similar in nature to the process of water treatment used for secondary recovery of oil by waterflooding. Water quality must be maintained in waterflood operations to ensure injectivity is optimal into the oil-bearing formation. Oil must be removed, precipitates must be prevented from forming, and pH must be kept in a range compatible with the formation so that the injectivity does not deteriorate with time. Texas has more than 300,000 oil and gas wells (Figure 8), many of them in mature fields nearing the end of their economic lives.

In RO processes, it is actually easier to maintain concentrate quality because pretreatment has already remove those materials that might plug filters. The concentrate stream, in effect, is already filtered to a higher standard before it is directed to the disposal well. The technical requirements needed for a candidate zone are therefore related to favorable reservoir properties such as specific capacity (formation thickness and good porosity). Formation structure must be covered by a tight caprock with areal integrity, since disposal issues can scuttle many potential projects

Desalination of Brackish Water or Produced Water: Identifying Environmental Issues

Locations in the United States that have difficulty meeting U.S. Environmental Protection Agency (EPA) ozone and other air emission standards can reduce transportation of produced brine by trucks to disposal wells.[6] Figure 9 shows a 160-barrel (bbl) truck. In the North Texas project being developed by Texas A&M, more than 70 trucks like these travel rural roads each day to dispose of return water from produced gas wells from the Barnett Shale development.
Environmental issues that arise from desalination must be considered along with the environmental impact of present operations of produced water from oil and gas production.

Regulatory Considerations Impacting Brackish Water/Produced Water Desalination

This section of the paper discusses some of the possible regulatory requirements that would come into play if the RO concentrate is injected for either secondary recovery of hydrocarbon resources or for disposal. This analysis gives some indication of the uncertain nature of the regulatory environment and the fact that different regulators may use different regulatory mechanisms.

The EPA administers the Underground Injection Control (UIC) program. The UIC regulations define injection well as "a well into which fluids are being injected." A well is "a bored, drilled, or driven shaft whose depth is greater than the largest surface dimension; or, a dug hole whose depth is greater than the largest surface dimension; or, an improved sinkhole; or, a subsurface fluid distribution system." The UIC regulations place injection wells into five classes. Most Class I wells are used to inject hazardous wastes, but some Class I nonhazardous wells are used for disposal of nonhazardous materials. For Class I wells, this injection must occur below any formations that have an underground source of drinking water (USDW) within one-quarter mile of the well bore. Class II wells are used in the oil and gas industry and are particularly relevant to reinjection of RO concentrate when the source water is produced water. The EPA defines them as wells that inject fluids:

> (1) "Which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection.
>
> (2) For enhanced recovery of oil or natural gas; and
>
> (3) For storage of hydrocarbons which are liquid at standard temperature and pressure."

Class III wells are used for solution mining. Class IV wells are used to inject hazardous or radioactive wastes into or above a formation that includes a USDW within one-quarter mile of the well bore – these are banned. Finally, Class V wells include all other injection wells not placed in any of the other classes.

States can apply to the EPA to gain authority to administer the UIC program. Approved state programs do not need to look exactly like the EPA's federal program but must provide an equivalent degree of protection of USDWs. Most oil- and gas-producing states have received UIC program authority. To get a sense of how states might regulate injection of RO concentrate, we asked several states in arid parts of the country and also EPA headquarters under which UIC Class would they regulate the following scenarios:

1. Source water is produced water; injection used for enhanced recovery.
2. Source water is produced water; injection used for disposal.
3. Source water is saline groundwater; injection used for enhanced recovery.
4. Source is saline groundwater; injection is for disposal.

Table 1 indicates the responses from several states and the EPA. All are consistent on scenarios 1 and 2, and all but Texas are consistent on scenario 3 – these would unequivocally be regulated as Class II wells. This follows directly from the Class II well definition above. Because produced water is used as source water in scenarios 1 and 2, subsequent injection of the concentrate is consistent with the first category of Class II wells (injection of fluids brought to the surface in connection with oil and gas production). Under scenario 3, the concentrate is used for enhanced recovery, thereby matching the second category of wells under the Class II definition (injection for enhanced recovery). Texas does not rule out permitting these wells as Class II, but suggests that it would need to review the determination of class type between its Railroad Commission (the oil and gas regulatory agency) and the Commission on Environmental Quality (regulates all other environmental issues).

Scenario 4 presents a different situation because neither the source water nor the injectate meet the definition of a Class II well. Some agencies suggest that injection of the concentrate would be made into a Class I well, and the chemical characteristics of the well would determine if the well would be a hazardous or nonhazardous well. Utah suggested that injection could be made into a Class V well. The difference between Class I and Class V is quite significant. Class I wells are subject to very stringent design, construction, operation, and monitoring requirements, whereas Class V wells are regulated in a less stringent manner. The costs of constructing and operating a Class I well are much higher than comparable costs for a Class V well.

In general, the two key factors used to determine which well class would be assigned for concentrate injection under scenario 4 are the depth of the injection zone in relation to the depth of the lowermost USDW and whether the constituents of the concentrate are considered to be hazardous materials or not. If the injection occurs above or directly into a USDW and the concentrate is nonhazardous, the well could be permitted as a Class V well. Injection of hazardous concentrate into or above a USDW is prohibited. If the injection occurs below the USDW, the well would be a Class I well, and the nature of the concentrate would determine if the well would be Class I hazardous or Class I nonhazardous.

To further complicate the picture for scenario 4, California reports that if the RO concentrate is not hazardous, the Department of Oil, Gas, and Geothermal Resources may try to permit the injection as part of a Class II well. They acknowledge that in the past, the agency has occasionally authorized injection of non-oil-field wastes into Class II wells with the caveat that the permit had restrictions on total volume and the duration of the injection. If the concentrate is hazardous, its injection would require a Class I well.

Presently, injection of RO concentrate is not a common practice. If the practice becomes more common in the future, states or the EPA may adopt new policies or regulations to govern concentrate injection.

Assessing Public Perceptions of Risk

A new research project is under consideration by the EPA within that agency's Market Mechanisms and Incentives (MM&I) for Environmental Management. The goals of the project submitted by Theodori[7] are: (1) identify and evaluate the individual, institutional, technical, legal, and regulatory obstacles to successful implementation of MM&I for produced water management; (2) provide empirical estimates of MM&I cost-savings relative to existing produced water regulatory programs; and (3) show how the MM&I approach to produced water can be transferred or generalized to other environmental problems and/or geographic/political scales.

The project will be gathering quantitative data for the issues arising when new technology is offered to local communities, but at a cost to the community. Will it be accepted or dismissed? The public's view or risk versus economic benefit will determine the answer to this question.

Definitions of Risk

For the purpose of this study, we use the following specific definitions. These definitions are from reference 9. In the context of environmental issues, the term *risk* is defined as the probability of occurrence of a particular adverse effect on human health or the environment as a result of exposure to a *hazard*. Hazards may be a hazardous chemical in the environment, a natural hazard, or a hazardous technology. *Risk assessment* refers to a formal or informal procedure producing a quantitative estimate of environmental risk. *Risk analysis* includes quantitative and qualitative evaluation of all relevant attributes of environmental hazards, risks, adverse effects, events, and conditions that lead to or modify adverse effects. It includes populations or environments that influence or experience adverse effects. *Risk management* is the process of deciding what should be done about a hazard, the population exposed or adverse effects, implementing the decision, and evaluating the results. It also refers to decision making at the program or agency level, for example, deciding which hazards should be managed and in what order. Comparative (or relative) risk analysis and cost-benefit analysis are aids to risk management.

Risk Analysis Using Utility Models

The EPA has been given a mandate to increase the use of risk analysis to provide a systematic evaluation of hazards and their possible effects. Risk, the possibility of loss damage, or any other undesirable property should be evaluated for a range of possible eventualities. Utility theory for a number of attributes of the process can be used to set the common denominator. For example, a potential buyer can evaluate a new automobile on the value dimensions of cost, performance, image, and availability. Each of these characteristics is an attribute of the automobile, and the individual purchasing a vehicle will maximize the value of the attributes, on the basis of his or her perception of the automobile.

Identifying Four Key Attributes

Identifying all of the attributes representing the process of disposal of brine into a depleted oil or gas formation is, of course, subjective. It is relatively simple, however, to pick out the most important issues if safety, environmental compliance, and economic benefit are paramount. We have selected four key attributes to weigh in order to evaluate the risk of utilizing the process compared to the inherent risk of an alternative process. We anticipate that these attributes can be more easily incorporated into surveys and interviews with individuals who are stakeholders involved in the programs under consideration.

The first attribute is utility or usefulness. A process that produces fresh water would have a positive attribute. The issues associated with the desalination and creation of fresh water include (a) pretreatment, (b) membrane filtration, and (c) the injection of the salt water into the formation.

Pretreatment affects membrane filtration, which in turn affects disposal. Produced concentrate characteristics affect the injectivity of the receiving formation. This is an issue, for it determines the amount and the pressure at which the disposed fluid is injected into the formation. Formation damage can best be defined as any obstruction or barrier in the near-wellbore region that reduces the flow capacity of the rock. Formation damage can be in the form of migration of fines, clay swelling, emulsion block, water block, scale, and others. An area that is often overlooked is formation plugging caused by solids in the injection brine. Efficient cleaning of the wellbore fluids before injection operations begin can have a dramatic effect in reducing formation damage.

The second attribute is environmental risk. Surface discharge of salt water is an issue or related attribute that has an adverse effect on the environment. Subsurface leakage from the petroleum formation is another aspect of environmental risk. In petroleum formations, there is no natural path for fluids to escape wells that have been poorly abandoned, however, can provide a path to other porous zones, including USDWs. When the receiving formation is pressured up, fluids can escape through the failed wellbore seal and migrate to USDWs or to the land surface.

The third attribute is public safety. The trade-off for RO facilities will be the risk incurred if no facility is built versus the risk incurred if RO were implemented.

The fourth attribute is economic impact. In this case, the trade-off is between a scenario where measures are imposed to limit water consumption to match current capacity versus a situation in which increased water resources are provided that allow for economic development and enhanced public satisfaction (but at an increased cost).

In summary, the following four attributes are used to evaluate the process:

- Usefulness
- Environmental Risk
- Public Safety
- Economic Impact

These attributes lend them selves to qualitative evaluation by the use of polling tests of involved parties and the public. Appendix 1 discusses a program where questions are poised to individuals and their responses combined with engineering data describing the process technology being introduced into public programs. The process of data collection will be managed by Theodori.[7] During the fall of 2003 and spring of 2004, an on-line questionaire[8] will be used to collect information from those interested in the program.

Comparative Risk Models

The comparative risk of implementing a system to provide new fresh water resources is established by (a) evaluating the risk to provide a higher quality resource in more plentiful supply against (b) the risk of using current water supplies with no alternative treatment system operating. The EPA suggests the following for a comparative risk assessment.

- Address environmental (i.e., ecological and natural resource) as well as health impacts.
- Consider the social and economic impacts associated with different risks

- Make a connection between technical knowledge and policy judgments that may be value-laden.
- Provide the means for addressing views of multiple stakeholders.
- Consider solutions such as pollution prevention as well as more traditional approaches

The environmental impact of implementing the alternative disposal strategy can be positive if the fresh water resources it creates can be utilized effectively. The impact is negative if the brine injection creates an environmental problem because of a surface spill or a subsurface discharge into an unintended zone.

For comparison purposes, we used a *three-level risk model* that considers the four attributes of the two scenarios and gives estimates of the effect of an event occurring. From engineering models and records of past operations we develop estimates of how often an event might occur, that is:

- Often
- Occasionally
- Remote
- None

Table 2 shows how the relationship among the three factors are considered. The impact of an event upon the population, the environment, and the economic well-being of the parties involved are determined through a number of methods.

Tables 3 and 4 show a comparative risk analysis (CRA) for a real situation, using valid, but incomplete information to populate the table entries. Appendix 1 discusses an example of a specific situation in North Texas and uses results from a sample poll to select the perceived impact of an event.

For instance, if a desalination facility shutdown were to occur, the relative effect of the event can be evaluated by classifying each of the attributes. The *severity* of the event can be classified as slight, minimal, serious, or catastrophic. Likewise, the *exposure* created by the event is classified as frequent, occasional, remote, or none. In the CRA Table 4, these factors are equivalent to the "weighting factors" used in classic risk analysis models.[9] Finally the *impact* of the event occurring is classified as negligible, unlikely, possible, or probable. The table's entries (impacts) are shown with the classifications "low," "moderate," or "high." These impacts represent the perceptions of stakeholders who are affected by events.

Decision Analysis Using the Risk Model

We wanted to provide a study that would be a typical example of how risk models could be used to compare the effects of alternate courses of action. Two scenarios are examined. Both are based on a real situation in North Texas where a field project is planned to test prototype desalination units. Figure 10 shows the location of the Chico salt water disposal (SWD) system operated by Key Energy Inc. The first scenario depicts the current practice of transporting fresh water to a central SWD facility for disposal in deep isolated aquifers. The second scenario depicts a new desalination program established in the Barnett Shale Gas Field development.

The first scenario represents "business as usual". In the Barnett Shale play, more than 24,000 bbls per day (1,000,000 gallons) of brine water is transported to deep well disposal facilites. The Key Energy facility receives more than 70 trucks a day, each carrying salt water to be injected into the disposal well. The operator of the gas wells pays more than $1.20 per barrel to dispose of the brine. The risk analysis table of this operation is shown in Table 3. The system may be down, it might be operating but with some inefficienies, it might be experiencing concentrate disposal problems, or it might have an actual salt water discharge. For each event, the table considers the risk impact based on the frequency of the event and which attribute is impacted the most severely.

As the scenario we have constructed shows, an accidental salt water discharge has the most severe consequences. The environmental and economic consequences are rated as "high" as well as the risk to the usefulness of the facility itself. It should be noted that the "system" is defined as including the transport of the salt water to the facility. Any accident to the transporting vehicles would be a risk included in this scenario.

The location of the scenario we have been discussing was actually the scene of a salt water spill in September of 2003.[10] A small SWD facility had begun operations, when surface discharge of water was noted by a neighboring landowner. Unfortunatly, even though the well was permitted, there was an improperly abandoned well nearby dating back more than 70 years. The wellbore offered a way for the salt water from the disposal zone to flow to the surface once the zone began to pressure up. Operations had to be stopped and a remediation project had to be extablished.

Concentrate disposal problems have the second most important effect on the operation. In the case of the SWD facility example we have chosen, the concentrate disposal problems are defined by (a) injectivity and (b) volume. Either an increase in the volume of salt water for disposal or an increase in pressure experience by injection would have adverse impact on the system.

The second scenario considers the use of modular, skid-mounted units placed at strategic locations in the Barnett Shale operations area. The units would be used to treat water produced from completion and production operations and recover fresh water for beneficial use.

The operation of the desalination units provide benefits for the area. Some important benefits would be:

- Reduced truck traffic on rural roads;
- Less pollution from hauling operations;
- Reduced deep well disposal volumes;

- Increased fresh water resources for beneficial use;
- High quality, solids-free brine for oil field operations.

Counterbalancing these reasons to employ such a process are the potential risks associated with the desalination facility. Table 4 shows the risk table completed for the desalination scenario. Four important risks are identified. The system might be *offline* and not providing fresh water. The unit might be having *concentrate disposal* problems, or be *inefficient*, or might be prone to *salt water spills*.

The risk of an event resulting in the system being offline in terms of usefulness and economic impact is judged to be high if the events were frequent, and moderate if the events were infrequent. On the other hand, environmental and public safety issues are correspondingly low. As can be seen, the risk of a salt water spill, like discussed before, has the most severe impact. In the desalination case, however, the usefulness of the system is compromised less because it is decentralized and other operations can be continued. In both scenarios, the environmental risk of a salt water spill is serious, if such events were frequent. The entries in the table thus reflect the quantitative engineering estimate of an event occurring, combined with the public's perception as to the effect of the event.

Concentrate disposal problems would be related to the transportation and injection of the saline material in the same manner as salt water would be handled in the traditional case. The compatibility of the RO concentrate with other salt water was considered to be minimal. The RO concentrate, while more saline than the salt water feed water, has actually been subjected to pretreatment to remove solids and residual oil. This residual oil has been returned to the tank battery. The resulting cleaned water is less likely to cause injectivity problems than "normal" produced water.

Results of Study

Comparative risk assessment was used to identify key issues that affect decisions to implement new desalination technology in locations needing water resources. *Quantitative estimates* of an events probability are combined with the perceived effects of the event on four specific areas.

Risk assessment of the alternative treatment of water resources shows that the benefits of new desalination procedures significantly outweigh the potential problems.

The study shows that the economic value of the new procedures depends strongly upon the location of the proposed facility.

The selection of a new technology is shown to depend upon the need of the local communities and the willingness of the industry to work with citizens and public officials.

A "true to life" example shows that the perceived risk of new desalination programs is less than that of continuing "business as usual."

Acknowledgements

Mr. Burnett would like to thank Texas A&M University for permission to publish this study. The authors extend their appreciation to people who made contributions to this work. We also wish to thank members of the Texas Water Research Institute, the Texas Water Development Board, and the Texas Railroad Commission for their support and aid. Mr. Veil's work on this paper was funded by the U.S. Department of Energy, National Energy Technology Laboratory, under contract W-31-109-Eng-38.

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Appendix

The A&M program expects to find application of the new desalination technology in small communities and rural areas of West Texas with water shortages. The communities in question are being asked to participate in the decision to encourage new economic development through the acquisition of new sources of fresh water for agricultural, industry, and community operations.

Only when policy makers, risk managers, the public, and the media fully understand the influence of value judgments in risk analyses can the critical issues in environmental protection and public health and safety be debated. It must be determined what society is willing to pay to reduce or avoid risks that society recognizes have been identified and estimated using scientifically influenced value judgments rather than science alone. These risks may or may not actually exist. If they do exist, they may be relatively small or indistinguishable from other risks. If risks are too small or indistinguishable, it likely will be impossible to know whether regulation can produce any benefit. The open debate of the value and priority of regulating these types of risks will enable policy and regulatory decisions to be made on a fully informed basis, but cannot guarantee it.

With this in mind, Texas A&M University, through the Department of Rural Sociology is working to engage the local community to obtain quantifiable information on the perceptions of this populace with respect to new technology for water resources. Because of the gas development in Wise County and its neighboring communities, north Texas offered a test of the need to engage the community. A group of individuals was asked to evaluate two types of operations described in this paper. They were given the choice of ranking the importance of a possible event. A total of 12 individuals were polled. Their responses were classified into three categories as shown in Table 2 (high impact, moderate impact, and low impact). Low impact equated to 2 or less responses. Moderate impact was equated to 3 to 7 responses, while high impact was greater than 7 responses.

This criterion was selected to show the process of quantifying information and has not been subjected to rigorous statistical validation. Further work is planned in this area.

An online survey form is available at http://www.gpri.org/survey. It will be used to query stakeholders and to serve as a model for subsequent client-to-client interviews and mail survey forms in selected geographic areas.

Table 1 – Possible Regulatory Requirements for Injection of RO Concentrate[a]

State	Source Water Is Produced Water		Source Water Is Saline Groundwater		Reference (based on e-mails to or phone conversations with John Veil, Argonne National Laboratory, on the dates indicated)
	Enhanced Recovery Scenario	Disposal Scenario	Enhanced Recovery Scenario	Disposal Scenario	
California	Class II well	Class II well	Class II well	If concentrate was not hazardous, permitting as a Class II well would be considered. If hazardous, it would be permitted as a Class I well.	Michael Stettner, California Division of Oil, Gas, and Geothermal Resources, October 6, 2003
New Mexico	Class II well	Class II well	Class II well	Depending on the characteristics of the concentrate, the well would be permitted as Class I hazardous or Class I nonhazardous.	Roger Anderson, New Mexico Oil Conservation Division, October 2, 2003
Oklahoma	Class II well	Class II Well	Class II well	Class I nonhazardous well that would be regulated by the Oklahoma Department of Environmental Quality	Tim Baker, Oklahoma Corporation Commission, October 6, 2003; Hillary Young, Oklahoma Department of Environmental Quality, October 6, 2003
Texas	Class II well	Class II well	In both cases, the Railroad Commission (regulates oil and gas activities) would confer with the Texas Commission on Environmental Quality. Depending on their decision, the wells could be Class II or Class I.		Fernando De Leon, Railroad Commission of Texas, October 6, 2003
Utah	Class II well	Class II well	Class II well	Class V well that would be regulated by the Utah Department of Environmental Quality	Dan Jarvis, Utah Division of Oil, Gas, and Mining, October 2, 2003
EPA	Class II well	Class II well	Not certain, but could probably be a Class II well	Not certain but would depend on the characteristics of the concentrate and whether the injection zone was above or below a USDW.	Bruce Kobelski, EPA headquarters, Office of Groundwater and Drinking Water, October 2 and 3, 2003

[a] These are informal opinions offered by officials in different agencies. They do not necessarily represent official agency policy.

Table 2. Example of Three-Factor Comparative Risk Analysis Model

1. Event	Process Reliability				Water Cost			
2. Frequency =>	Often	Occasional	Remote	None	Often	Occasional	Remote	None
3. Perceived Impact								
Usefulness Economic Effect Environmental Public Safety	Choice of "High," "Moderate," or "Low" Rate of Occurrence							

Perceived Impact

1. Event	Brine Disposal				Salt Water		
2. Frequency =>	Often	Occasional	Remote	None	Often	Occasional	Remote
3. Perceived							
Usefulness Economic Effect Environme Public Safety	Choice of "High," "Moderate," or "Low" Rate of Occurrence						

Table 3. Transport & SW Disposal Operations: Comparative Risk Analysis

1. Event	Water System Offline				System Inefficiency			
2. Frequency =>	Often	Occasional	Remote	None	Often	Occasional	Remote	None
3. Perceived								
Usefulness	High	High	Moderate		High	High	Low	Low
Economic Effect	High	Moderate	Moderate		Moderat	Moder	Low	Low
Environmental	Moderate	Low	Low		Low	Low	Low	Low
Public Safety	Low	Low	Low		Low	Low	Low	Low

Perceived Impact

1. Event	Concentrate Disposal Problems				Accidental SW Discharge			
2. Frequency =>	Often	Occasional	Remote	None	Often	Occasional	Remote	None
3. Perceived Impact								
Usefulness	High	High	Moderate		High	High	Moderate	
Economic Effect	High	High	Moderate		High	High	Moderate	
Environmental	Moderate	Moderate	Low		High	High	Moderate	
Public Safety	Low	Low	Low		Moderate	Moderate	Low	

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Table 4. Desalination Facility Operations: Comparative Risk Analysis

1. Event	SWD System Offline				System Inefficiency			
2.	**Frequent**	**Occasional**	**Remote**	**None**	**Frequent**	**Occasional**	**Remote**	**None**
3. Perceived Impact								
Usefulness	High	Moderate	Moderate		Moderate	Moderate	Low	
Economic Effect	High	Moderate	Moderate		High	Moderate	Low	
Environmental	Moderate	Moderate	Low		Low	Low	Low	
Public Safety	Low	Low	Low		Low	Low	Low	

1. Event	Concentrate Disposal Problems				Accidental SW Discharge			
2.	**Frequent**	**Occasional**	**Remote**	**None**	**Frequent**	**Occasional**	**Remote**	**None**
3. Perceived Impact								
Usefuln	Moderat	Moderate	Moder	Low	Moderat	Moderate	Low	Low
Economic	Hig	Hig	Moder	Low	High	High	Moderate	Low
Environme	Low	Low	Low	Low	High	High	Moderate	Low
Public	Low	Low	Low	Low	Moderat	Moderate	Low	Low

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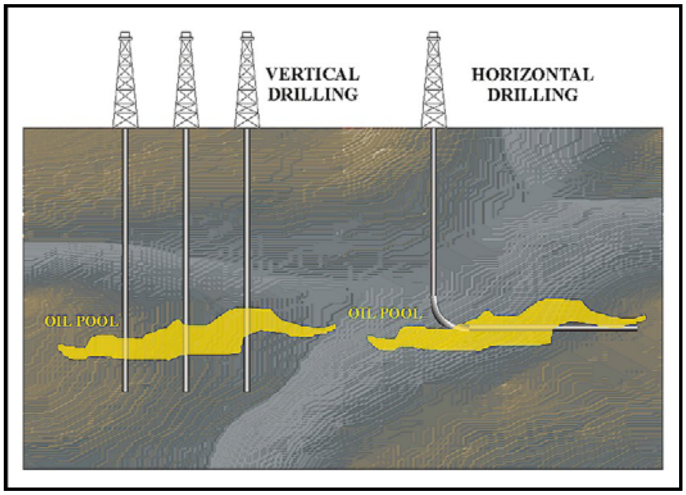

Figure 1. Brine concentrate disposal can represent a significant fraction of the cost of operating a desalination facility. In the oil and gas industry, high salinity brines are routinely injected into formations for pressure maintenance and secondary recovery by water flooding.

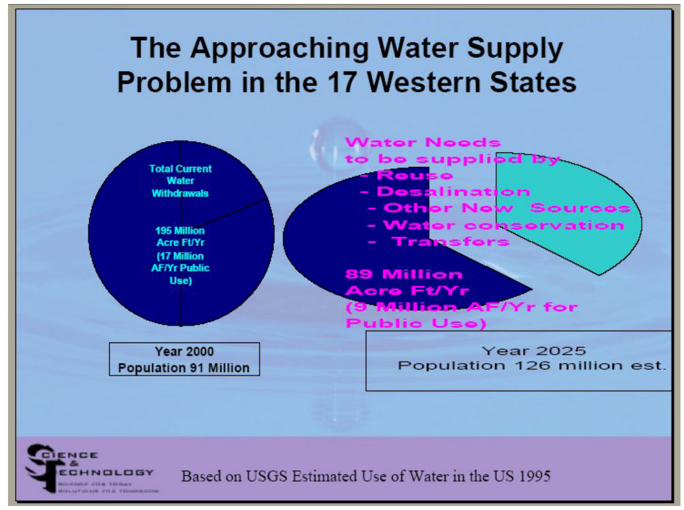

Figure 3. BOR tracks Western population growth, water demand, and environmental impacts on water quality, and looks at long-term weather patterns and drought conditions.

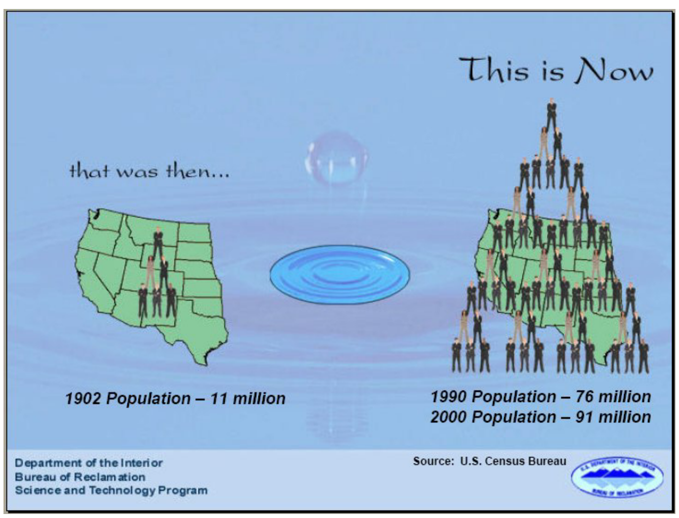

Figure 2. Population growth and water resource needs were projected by the U. S. Bureau of Reclamation (BOR) and presented by Holz in Hobbs, New Mexico, at the Produced Water Workshop.[2]

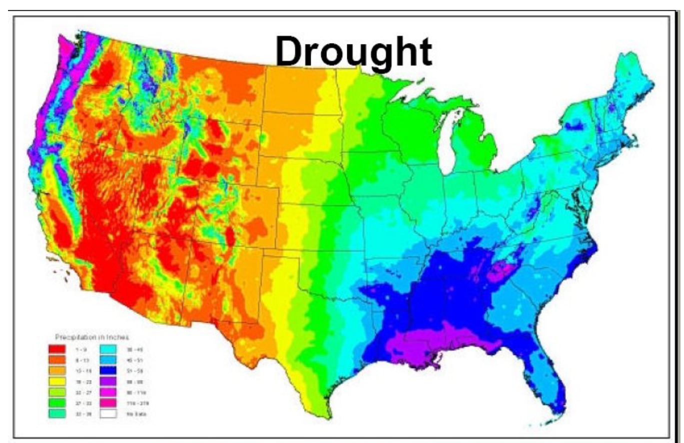

Figure 4. Drought-affected areas of the Western areas of the country are facing severe short-term and long-term shortages of fresh water resources. The most severe impact is seen in the West.

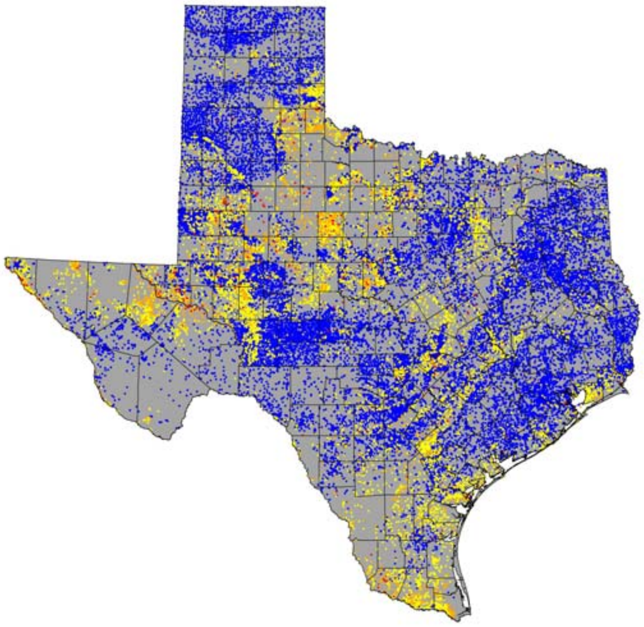

Figure 5. A study commissioned by the Texas Water Development Board[5] identified the saline ground water aquifers in Texas. The study discussed the applicability of desalination technology of brackish ground water to provide fresh water for the citizens of the state, identified the aquifers in the state, and addressed the technology and capital required to exploit the resource. The study found more than 780 million acre-feet of brackish aquifers that would be amenable to desalination**.**

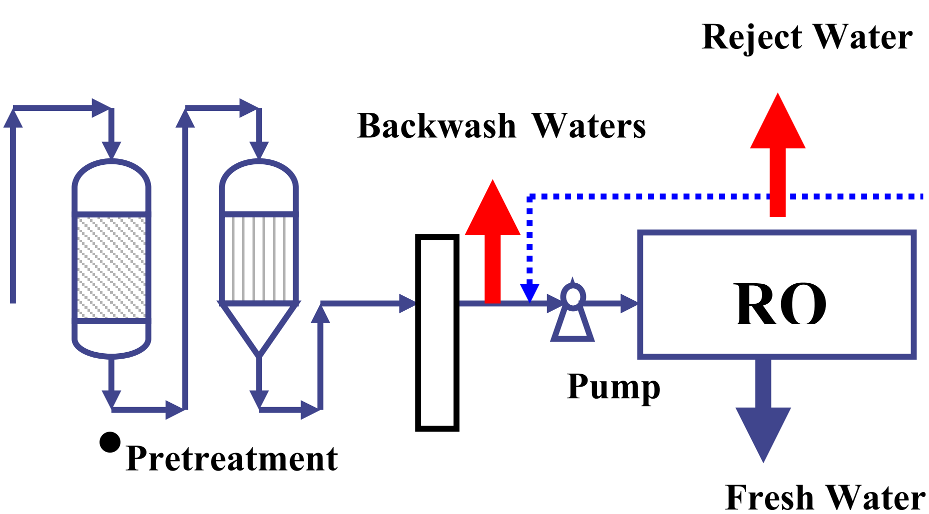

Figure 6. A schematic of a portable RO desalination unit is shown as part of the process train required to treat oil field brine and brackish ground water to recover fresh water resources. Pretreatment has turned out to be one of the keys to a cost-effective treatment. The other critical parameter is the disposal of the saline concentrate rejected by the RO filters.

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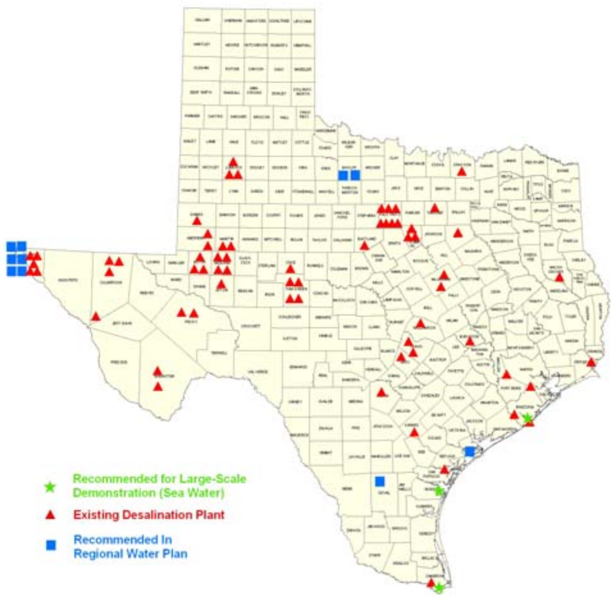

Figure 7. Planned and potential desalination facilities are shown across Texas. (Information from the Texas Water Development Board). If constructed, the facilities would provide services to more than 1,000,000 people by 2005.

Figure 9. Oil field water transport trucks carry the brines produced from gas well completions and operations in the Barnett Shale play in North Texas. As many as 70 truck loads per day will discharge brine at salt water disposal wells in Wise and surrounding counties.

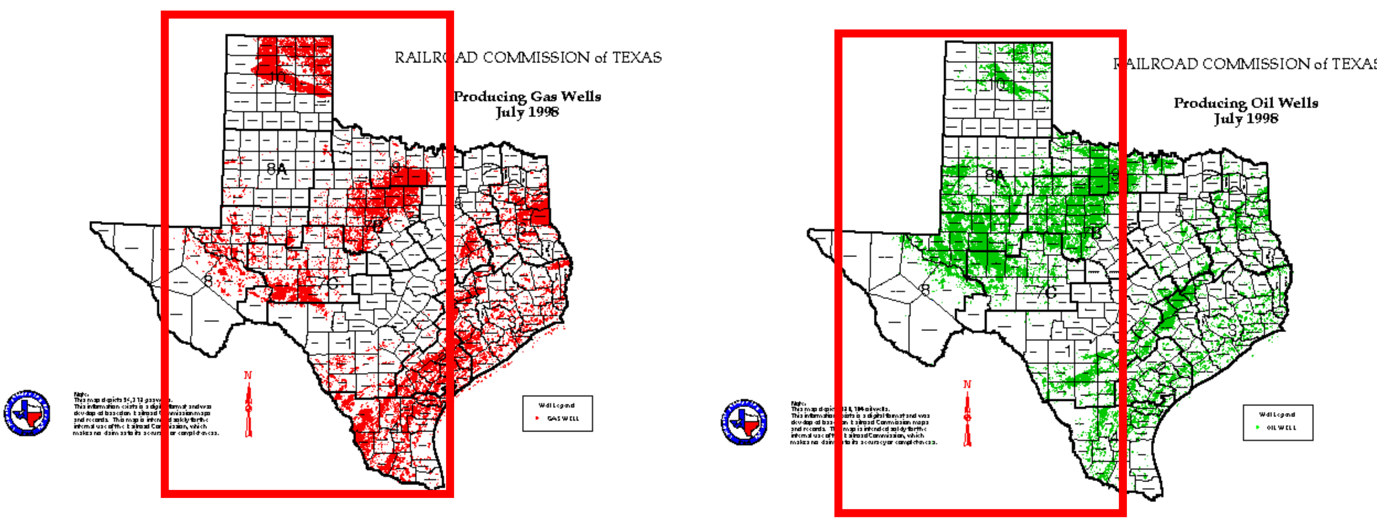

Figure 8. Texas has more than 300,000 oil and gas wells (Railroad Commission Data). The area highlighted in West Texas, showing producing oil wells, is also the area of the state most affected by the lack of fresh water resources. Many of the mature fields are nearing the end of their economic lives and are candidates for saline water disposal.

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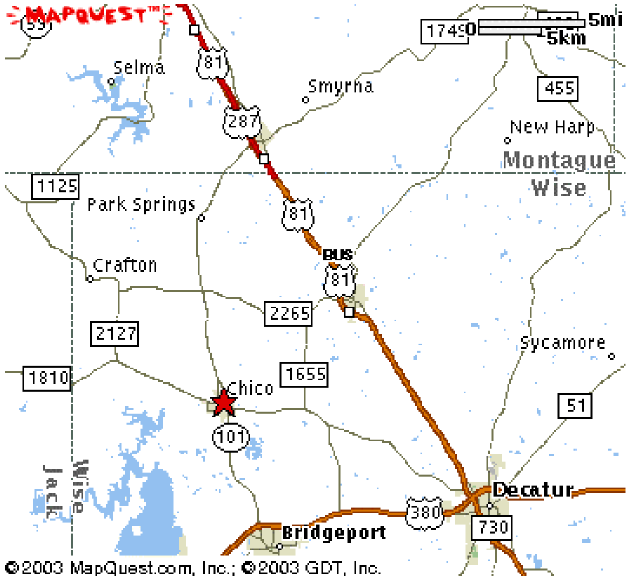

Figure 10. Key Energy operates a state of the art SWD disposal operation in Chico Texas. Gas development from the Barnett Shale in Wise and surrounding counties in Texas have increased significantly with the advent of new completion technology using fresh water fracturing operations. More than 30,000,000 gallons of water a month is transported for the operators in this area.

SPE 98616

Environmental Impact Factor for Emissions to Air: A Tool for Prioritizing Emission-Reduction Measures Based on Environmental Impacts and Benefits

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Abstract

Emission of nitrogen oxides and other air pollutants from the petroleum industry causes concerns regarding impacts on sensitive aquatic and terrestrial ecosystems. In order to optimize strategies for emission reductions according to environmental benefits, an integrated modelling tool has been developed (Environmental Impact Factor for Emissions to Air, EIF-Air). The approach takes into account different emissions to air (nitrogen, sulphur, and organic compounds) and different related environmental impacts based on the concept of critical loads and levels. The model currently takes into account four environmental impacts (acidification of surface waters and soils, nutrient effects on terrestrial ecosystems and vegetation damage from elevated ozone concentrations), but is general in it's formulation and can easily be extended to included other relevant impacts. The approach includes atmospheric dispersion modelling of the emissions, a database for current total deposition and models for the different environmental impacts. Results from three case studies are presented. The first shows that nitrogen emission reductions at an offshore installation in the North Sea have larger environmental benefit than a similar reduction in the Norwegian Sea. In the second case the tool is ised to rank different technology options at a Norwegian onshore petroleum facility. The third case compare the environmental benefits of reducing nitrogen emissions at supply ships compared to offshore installations, showing that measures at ships gives larger benefit per unit nitrogen reduced.

Introduction

The petroleum industry has emissions to the atmosphere of gaseous pollutants, including nitrogen oxides (NO_x), sulphur dioxide (SO_2) and volatile organic compounds (VOCs). Atmospheric transport of gaseous pollutants may contribute to environmental impacts long distance (up to several hundred kilometres) from the emission sources, even though the highest concentrations and deposition fluxes are found relatively close to the emission source.

Emissions to air from a single source will contribute to the air concentration and deposition flux in a large area, but typically with quite low concentration or flux compared to the total air concentration and deposition flux. With exception of the immediate vicinity of the emission source, the contribution to the total air pollution level from a given single source is usually small, commonly between less than one and a few percent. This can be challenging when having to prioritize between measures to reduce emissions, as the environmental impacts from a single emission source can be virtually impossible to measure.

A main principle in the development and application of the modelling tool is to combine emissions, deposition as well as environmental impacts in the assessment of a given emission. As a part of the assessment of potential measures, environmental benefits of the reductions are considered in order to implement the best measures from an environmental and socio-economic point of view. Important questions the modelling tool can help answer are: Does an investment for an emission reduction give any environmental improvement, or is it only fulfilling a political goal? Where is the best location to reduce emissions and which measure should be preferred at the actual facility? What is the best solution/measure from a cost benefit point of view? Should the authorities allow for third party measures in order to comply with the best environmentally and socio economic best solution? In order to be able to answer such questions, we developed a method for assessing the environmental benefits of possible emission reduction measures. The method summarizes the environmental improvements in a single factor, called Environmental Impact Factor for Emissions to Air, EIF-Air.

An Environmental Impact Factor for produced water is already well established and is much in use in assessments (1). Similar approaches are also being developed for other environmental issues related to oil and gas production, including discharges from drilling operations and acute spills. The aim is that the development of EIF-Air will become a tool for assessing and prioritizing between measures related to emissions to air and that the factor together with other similar factors for other environmental issues can form a total system for optimizing between mitigation measures.

The methodical approach presented here was initially developed for assessing measures for reductions in NOx emissions to air from the Norwegian offshore petroleum activities. Even though the installations can be located several hundred kilometres offshore, they are contributing to the overall pollution load on shore (2,3). As a part of the action plan of the Norwegian Government to reduce the national nitrogen emissions to air in compliance with international agreements (i.e. the Gothenburg protocol (4)), all industry sectors must reduce the nitrogen emissions. The most important environmental impacts of nitrogen emissions to air are acidification of waters and soils, changing plant communities from excess nutrients and production of ozone with subsequent potential damage to vegetation (5).

A challenge when assessing the environmental impacts of nitrogen emissions from a specific source is that the total deposition is much larger than the deposition originating from the source to be assessed. This is because nitrogen can be transported over long distances in the atmosphere so that the deposition at a given location originates from many different sources from many different regions. In the EIF-Air approach, the total deposition and the ecosystem sensitivity at each geographical location within the influenced area are taken into account together with the calculated deposition from the point source(s) to be evaluated. To describe the environmental sensitivity the concept of critical loads and levels is used. Critical loads and levels are developed and used as effect targets in international negotiations for emission reductions in Europe under the Convention on Long-range Transboundary Air Pollution of the United Nations Economic Commission for Europe (UNECE) (5,6). The concept of EIF-Air is complying with established principles under this Convention.

Although the EIF-Air approach was designed for evaluation of measures to reduce offshore NOx emissions, it has been developed to include assessment of emissions from onshore plants as well as large mobile sources (ships). The approach is so far developed for emissions of NOx, SO_2 and VOC. Regarding the environmental effects, the focus has been to estimate the effects on vegetation and surface water in the areas where these emissions have their impact. It is developed in such a way that differences in impacts from measures to reduce emissions can be evaluated.

In this paper we describe the rationale behind the EIF-Air approach and how it is developed. We describe the different components of the approach and show with examples how they contribute. Finally, we show some case studies for different types of applications of the approach, including assessments of offshore (drilling platforms), onshore (refinery) and moving (supply ship) emissions sources.

Development of the EIF-Air approach

The EIF-Air approach is based on data sets and models developed for different air pollution aspects in Europe and North America. This includes:

- a model for calculating atmospheric deposition from the emissions
- data sets based on observations for the total current atmospheric deposition
- models and empirical approaches for the quantification of environmental impacts. In this chapter these models and data are described.

Deposition from a specific emission source

It is not possible to distinguish the deposition originating from one source only through measurements, since this deposition will mix with the deposition from other sources (the current total deposition, sometimes also called "background"). The nitrogen deposition originating from emission of NO_x from a single source must be estimated by applying an atmospheric dispersion/deposition model. In our applications we use the puff trajectory model INPUFF (7), which is an extensively used atmospheric dispersion model for point sources.

INPUFF is a trajectory model, meaning that the emissions are moved in the atmosphere according to local wind speed and direction. The model takes into account that the meteorology varies in time and space, and is book-keeping the emissions as long as they are within the geographical area considered. In order to estimate deposition of nitrogen with the precipitation, the model includes a chemical description of the oxidation of NOx to nitrate in the air. Nitrate is dissolved in rain water and deposited with the precipitation.

Different geographical resolution can be applied, according to the influence area to be evaluated. Typically, a grid cell size of 50 × 50 kilometres is used for applications for offshore sources and 10 × 10 kilometres for onshore sources. The model is usually run with hourly time steps, driven by the meteorology. For use in our applications with EIF-Air, accumulated annual nitrogen deposition is calculated.

The current total deposition

The total atmospheric input of pollutants can be determined from atmospheric dispersion models or from measurements combined with geographic interpolation. In areas where topographical features cause large variations in depositions, use of measured concentrations and precipitation amounts makes it possible to determine the inputs by precipitation more directly and with more detailed spatial resolution than is available from models. Dry deposition may also be inferred from measured airborne concentrations.

The total atmospheric inputs have been calculated for Norway using measurements of air and precipitation chemistry (8). Total deposition of nitrogen, sulphate, as well as other compounds, has been estimated for all of Norway based on data available through the national air- and precipitation monitoring program, combined with information about precipitation amounts from the national meteorological network. In the EIF-Air calculations, the latest available

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annual average data have been used, which is based on the period 1997-2001 (Figure 1). Because of natural fluctuations in deposition amount between years, it is better to use a five-year average, than a single year.

Ozone formation and concentrations

Ozone is a secondary pollutant, which means there are no direct emissions of ozone into the atmosphere, and thus the ozone found has been formed by sunlight-driven chemical reactions in the atmosphere. These photochemical reactions involve nitrogen oxides (NO_x=NO+NO_2) and volatile organic compounds (VOCs). Because of the complex photochemistry of ozone formation, models for calculating ozone concentrations are much more computation intensive than the model for nitrogen deposition. In order to reduce the computation time for applications, a library of ozone formation under different emission scenarios is being developed.

For comparison with critical levels for ozone, either long term average concentrations, or accumulated hourly values must be calculated.

Estimation of impacts – critical loads and levels

Critical loads and critical levels define threshold values for the effect of air pollutants (9,10). By definition, these are measurable quantitative estimates showing the degree of tolerable exposure to one or more pollutants. According to present knowledge, when this exposure remains below the critical load and level thresholds, significant harmful effects on specified receptors do not occur. The application of the critical load and levels concept is suitable to describe the limit to which a receptor system may be exposed to pollution without detectable damage, or alternatively, as the threshold below which present loadings and concentrations have to be reduced for recovery. The critical loads and levels approach have been used in development of the European protocols for reduction of long range transported air pollutants (4,11).

The critical loads represent tolerable, long-term deposition rates of pollutants. The increased acidification through the deposition of sulphur and nitrogen compounds and eutrophication through the deposition of nitrogen are two observed effects. In the evaluation of the acidifying potential, both pollutants must be taken into account. Changes due to acid deposition, which are responsible for damage to the structure and function of ecosystems, can be identified using parameters of the chemical composition of surface water or the soil solution. Eutrophication will occur when nitrogen inputs result in nutrient imbalances. When natural nutrient supply becomes unbalanced, the ecosystem is affected by climatic and other stresses. Additionally, eutrophication often affects the biodiversity of terrestrial and aquatic ecosystems because existing plant and animal communities are unable to adapt to the changes in chemical conditions. The magnitude of any critical load depends on the characteristic and condition of the target ecosystem and receptor, e.g. the buffer capacity at a given location. Thus, critical loads are different for eachsurface water quality, plant community, forest and soil type, etc. The Norwegian critical load maps for surface water and for vegetation (based on habitat- and vegetation types) are shown in Figure 2.

The critical levels are effect thresholds of air pollutants based on the estimated or measured ambient concentrations and observed direct effects on different receptors. High concentrations of pollutants in ambient air directly cause harm to leaves and needles of forests and other plant communities. Elevated ozone concentrations may have acute toxic effects to plant communities and direct effects on public health. Ozone has a cumulative effect over the plant growth period, which is considered in the critical levels for ozone.

Critical loads for surface water are usually given in units of acid equivalents per area and time unit. Here we use meq m^{-2} yr^{-1} (milli-equivalents per square meter per year). It is necessary to use equivalents in order to include both nitrogen and sulphur. Critical loads for vegetation are usually given as nitrogen deposition amount per area and time unit. Here we use mg N m^{-2} yr^{-1} (milligrams of nitrogen per square meter per year), which can be divided by 14 in order to get the unit meq m^{-2} yr^{-1}. The nitrogen critical load for vegetation types has been established within a range, with an upper and lower limit value, due to uncertainty in the critical loads (12). In the EIF-Air calculations the lowest values have been used. The critical level for ozone is given as an accumulated flux over a threshold concentration of 40 ppb hourly average (10). The accumulated flux for the three summer months is used for agricultural vegetation and six months for forest. The accumulated dose is called AOT_{40} (Accumulated Over Threshold 40 ppb) and has the unit ppb·h (parts per billion times hours).

Deposition of nitrate from air to sea is not included in the current version. However, deposition from air contributes significantly to nitrate concentrations in sea water in some areas, and will be considered included in EIF-Air in the future.

Calculation of EIF-Air

When establishing the EIF-Air concept it was important to take into account the sensitivity of ecosystems to air pollutants and the total air pollution pressure from all sources when assessing the impacts of a changing emission source. Through the early phases of the EIF-Air project, an equation for calculation of EIF-Air was established and selected, among several other suggested approaches (13-15).

Calculation of EIF-Air integrates the four environmental effects acidification of surface waters, acidification of forest soils, eutrophication of terrestrial ecosystems and damage to forest and other vegetation from elevated tropospheric ozone concentrations. A critical load for all these impact categories has been established for each grid cell. The EIF-Air is calculated on grid cell basis for a given geographical region and summarised over all grid cells within the influenced area for calculation of an overall EIF-Air value. In order to account for grid cells not fully covered by land (i.e. along the coast line), the area of each grid cell is multiplied with the grid cell value before summarized to the overall value for EIF-Air. It is important that the same area is covered for different emissions to be compared.

The formula for calculating the grid cell value is:

$$GridCellValue_i = \frac{Tot.dep_{S+N}}{Crit.load_{water}} \bullet \frac{Additnl.dep_{S+N}}{Crit.load_{water}} + \frac{Tot.dep_{S+N}}{Crit.load_{soil}} \bullet \frac{Additnl.dep_{N}}{Crit.load_{soil}} + \frac{Tot.dep_{N}}{Crit.load_{vegetation}} \bullet \frac{Additnl.dep_{N}}{Crit.load_{vegetation}} + \frac{Tot.conc_{O_3}}{Crit.level_{AOT40}} \bullet \frac{Additnl.conc_{O_3}}{Crit.level_{AOT40}}$$

where:
$Tot.dep_{S+N}$ is the current total deposition of sulphur and nitrogen
$Additnl.dep_{S+N}$ is the modelled additional deposition from the emission source to be evaluated
$Tot.dep_N$ is the current total deposition of nitrogen
$Tot.conc_{O_3}$ is the current total concentration of ozone (accumulated AOT_{40} values)
$Additnl.conc_{O_3}$ is the additional ozone from the emission source to be evaluated (accumulated AOT_{40} values)
$Crit.load_{water}$ is the critical load for acidification of surface water
$Crit.load_{soil}$ is the critical load for acidification of forest soil
$Crit.load_{vegetation}$ is the critical load for eutrophication of vegetation
$Crit.level_{AOT40}$ is the critical level for ozone concentration (as accumulated AOT_{40} values)

This formulation takes into account that a change in deposition in a sensitive area will give a larger environmental response than the same deposition change in a less sensitive area. Further, it takes into account that a deposition change in an area with a large exceedance of the critical loads will be more important than a similar change where the critical loads are not exceeded.

This description of EIF-Air assumes that an exceedance of the critical load for one pollutant is of similar importance as the exceedance for another pollutant. Hence will a given exceedance of the critical loads for surface water be equally important as an equally large relative exceedance of the critical loads for vegetation.

When the contribution from the emission source to be evaluated is multiplied with the total deposition, the importance of the extra deposition/concentration is larger than when using the traditional approach where the extra emission is simply added to the total deposition. The approach implies the following general conclusions:

- If the total deposition is high and the critical load low (i.e. we already have large exceedance), then even a small additional deposition/concentration will be of importance.
- If the total deposition is low and the critical load high (i.e. below exceedance in current situation), a relatively large additional deposition will have low importance.

In the following some calculation examples of EIF-Air are presented.

Case studies

In order to illustrate how the EIF-Air calculation works in practical use, two illustrative assessments are shown here. The first case is an assessment of environmental benefits of reducing the nitrogen emissions at an installation in the Norwegian Sea (Heidrun), compared to an equivalent reduction at an installation at Tampen in the North Sea. The second case is an evaluation of different measures for nitrogen emission reduction at an existing and a new emission source at an onshore installation on the Norwegian west coast. The third case is a comparison of the environmental impacts of nitrogen emissions from a supply vessel and an offshore platform. As mentioned previously, it is important when calculating EIF-Air that the geographical area included is same for the cases to be compared. The cases presented in the following are calculated for different influence areas and the resulting EIF-Air values should hence not be directly compared with each other.

Comparing measures at different offshore installations

In this case study, we compare a nitrogen emission reduction at a platform located in the Norwegian Sea (Heidrun) with a similar reduction at a platform in the North Sea (Tampen area) (see map in Figure 3). In order to demonstrate the methodology, the same emission reduction was used at both locations. For total deposition, the values shown on the map in Figure 1 were used. For critical loads, the values shown in the maps in Figure 2 were used and as critical level for ozone, an AOT_{40} value of 3000 ppb·h was used.

Four different combinations of emissions at the two installations were used:

1. Current emission at both installations
2. 75% reduction of the emission at the Heidrun installation combined with the current emission at Tampen
3. Reduced emissions at Tampen equivalent to the 75% reduction at Heidrun in combination with current emission at Heidrun
4. Reduced emissions (equivalent to 75% reduction at Heidrun) at both locations in combination

The nitrogen deposition for the four different scenarios was calculated using the INPUFF model. The resulting deposition fields are presented on maps in Figure 3. The highest deposition on the Norwegian mainland occurs under the current deposition (1). Reducing the emissions at Heidrun (2), results in reduced nitrogen deposition in Mid-Norway, while reduced emissions at Tampen (3) give reduced deposition in West-Norway.

The ozone concentrations caused by the different nitrogen emission scenarios were correspondingly calculated using a photochemical eularian model.

Values for the calculated EIF-Air are shown on maps in Figure 4 and the overall EIF-Air values for each of the four scenarios are compared in Figure 5. As expected from looking at the maps of nitrogen deposition, the maps of EIF-Air show higher values where the deposition is higher. The largest values for

EIF-Air are found for the case with current emissions at both installations, and the lowest values for the case with reduced emissions at both sites. The interesting case, where the strength of the EIF-Air approach is illustrated, is when scenarios with reduction at either Heidrun, or Tampen are compared: The overall EIF-Air is higher for case 2 (reduction at Heidrun) compared to case 3 (reduction at Tampen), meaning that the environmental benefit is larger for the reduction at Tampen (case 3) compared to Heidrun (case 2).

The reason for the differences in EIF-Air for reduction at Heidrun compared to Tampen can be seen from the illustrations in Figure 5. The figure shows how the different environmental effect terms of the EIF-Air calculation contribute to the overall EIF-Air values. Surface water acidification contributes the most to the total EIF-Air, followed by the nitrogen effects on vegetation. The ozone effects only have a minor contribution and the contribution from the soil acidification term is negligible in this case (and hence not shown in the figure). For surface water acidification there is a large difference between scenario 2 and 3, while for the nitrogen effects on vegetation, scenarios 2 and 3 are almost similar. The reason for this is that the critical loads for surface water in south and south-western Norway are considerably exceeded, favouring measures to reduce deposition in this area. For vegetation, the difference in current exceedance of the critical loads is smaller and the two different scenarios have almost similar impact. The difference in the overall EIF-Air between scenarios 2 and 3 suggests that a measure for nitrogen emission reduction at Tampen should be given priority to a similar measure on Heidrun.

The current calculation only takes into account impacts in Norway since only critical loads data for Norway were readily available. Since the deposition model domain, especially for the Norskehavet deposition source, also covers a part of Sweden, the results may be slightly different if also including Swedish critical loads data. The importance of including Swedish data will be evaluated in the future.

Comparing measures at an onshore installation

In this case, the EIF-Air approach is applied for comparison of different options for nitrogen emission control at an onshore refinery with a potential adjacent gas fired boiler. The site is located on the Norwegian west coast, in an area with considerable long range transported nitrogen and sulphur deposition in addition to the deposition of local origin. Both the surface water and the vegetation in the area are rather sensitive to acidification and nitrogen deposition, and the critical loads are currently exceeded in a large part of the surrounding area (Figure 6).

The calculations of EIF-Air were done as a part of a regional environmental impacts assessment related to emission changes. The emission scenarios shown here were among the options for emission changes evaluated. Although they may not be representative for the final choice, the calculations illustrate the capability of the EIF-Air approach in evaluating different options.

The assessment included scenarios for installing low NOx emission equipment on the existing emissions (in 2008) and different emission options for building a new energy plant with new emissions.

Seven scenarios were analysed, comprising different combinations of emissions from the existing source and an additional source: one baseline scenario for 2008 and six combinations of emissions from the current source and the new power plant. For the existing source, two scenarios were used: without (called SM 2008) and with installation of SNCR technology. For the new installation three scenarios were used with the following emissions:

- 5 ppm NOx + 2 ppm NH_3
- 9 ppm NOx
- 15 ppm NOx

The modelled nitrogen deposition from the different emissions separately is shown in Figure 7 and Figure 8 under the different emission scenarios. Ozone concentrations were not calculated for the different scenarios in the assessment as ozone was assumed to be low and having minor impact. In the calculation of EIF-Air, the ozone term in the equation was ignored.

Table 1 presents the results from the calculations of EIF-Air together with the nitrogen deposition for the grid cell receiving the highest deposition from the plant. The numerical values for EIF-Air range from 1141 for the scenario with SNCR cleaning on the existing stack and 5 ppm NOx + 2 ppm NH_3 emissions from the new energy plant to 1364 for the scenario without SNCR and 15ppm NO_x from the energy plant. As in the previous case, a higher value for EIF-Air means higher environmental impacts, subsequently meaning that the alternatives with the lower EIF-Air values should be preferred from an environmental impact point of view.

The scenario for SNCR + 15 ppm NO_x gives a considerably lower EIF-Air value than the scenario with current emissions combined with the addition emission of 5 ppm NOx +2 ppm NH_3. This suggests that higher priority should be given to reducing the current emissions rather than investing in equipment for the lowest possible emissions at the new emission source. If comparing the maximum grid cell deposition, i.e. using a more traditional assessment method, the result would be the opposite, with slightly higher maximum grid cell deposition for SNCR + 15 ppm NO_x case (Table 1).

Obviously, the combination of SNCR on the current emissions and one of the low emission options for the new installation will give the lowest EIF-Air values and hence the lowest environmental impact of the scenarios analysed. However, the EIF-Air values are very similar for the scenarios with 9 ppm NOx and those with 5 ppm NOx and 2 ppm NH_3, although the maximum deposition is considerably higher for the 9 ppm NOx scenarios. This difference appears because of the different deposition pattern for NOx and NH_3 in combination with more sensitive ecosystems closer to the emission source.

Table 1. Maximum nitrogen deposition contribution for a single grid cell and values for EIF-air for the different scenarios. N deposition given as g m^{-2} yr^{-1}.

Scenario	Max N deposition	EIF-air value
Baseline 2008	14.0	1253
SM 2008 + 5 ppm NO_x +2 ppm NH_3	13.5	1271
SM 2008 + 9 ppm NO_x	14.5	1272
SM 2008 + 15 ppm NO_x	16.5	1364
SNCR+ 5 ppm NO_x +2 ppm NH_3	10.6	1141
SNCR + 9 ppm NO_x	11.6	1141
SNCR + 15 ppm NO_x	13.6	1227

Comparing measures at a supply vessel and an offshore installation

In this case, the EIF-Air for NOx emissions from a supply vessel is compared with the emissions from an offshore installation. The case study illustrates how emissions from a supply vessel have larger environmental impact per unit NOx emission than emissions from an offshore installation and hence, reductions from such a vessel give more environmental benefit compared to the same reduction on the platform. The calculations were done for a platform located at Tampen and a supply vessel in traffic between the Norwegian west coast and the offshore platform at Tampen.

A supply vessel has a typical pattern of movement. For supply vessels that are servicing the Tampen area a typical pattern per round trip will be, 30 hours in port loading etc., 7 hours to get to the standby position, 12 hours in standby/loading/offloading and 7 hours transit back to port. The vessel does this trip three times a week 50 weeks per year.

As the emissions from one supply vessel is considerably smaller than from an offshore installation, the EIF-Air calculations used in the comparison have been done per unit (ton) NOx emission. The emission for the vessel is 116.6 tons NOx per year, and from the example platform at Tampen it is 2050 tons NOx per year. Calculations were done for situations with today's emission levels (0-alternative) and with reduced emissions for the vessel (25 tons) and the platform (513 tons).

The results show clear differences between the EIF-Air per ton NOx for the vessel compared to the platform (Figure 9). The overall EIF-Air value per ton NOx for the vessel (without emission reduction) was 0.76 and for the platform 0.27. Hence, the value for the vessel is 2.8 times higher for the vessel than for the platform. The corresponding ratio for the scenarios with reduced emissions was 2.2. This means that, based on the EIF-Air calculations, it is between 2.2 and 2.8 times more environmental beneficial to reduce one ton NOx on the supply vessel compared to a similar reduction on the platform.

Concluding remarks

The EIF-Air approach is promising as a tool to prioritise between different measures for reducing emissions of nitrogen and other air pollutants to air from point sources. Through several illustrative case studies, the approach has shown to be a useful tool in selecting the most environmentally beneficial scenario or measure among different alternatives. The method takes environmental impacts into account in a quantitative manner, using models and information gathered through a long term, widely accepted European network of scientist and policy makers.

The method is so far developed for applications in Norway and the Norwegian shelf, with the most important environmental impacts on the Norwegian mainland as priority focus. Given that sufficient data for main impacts are available, however, the method is widely applicable also for other geographical regions and environments.

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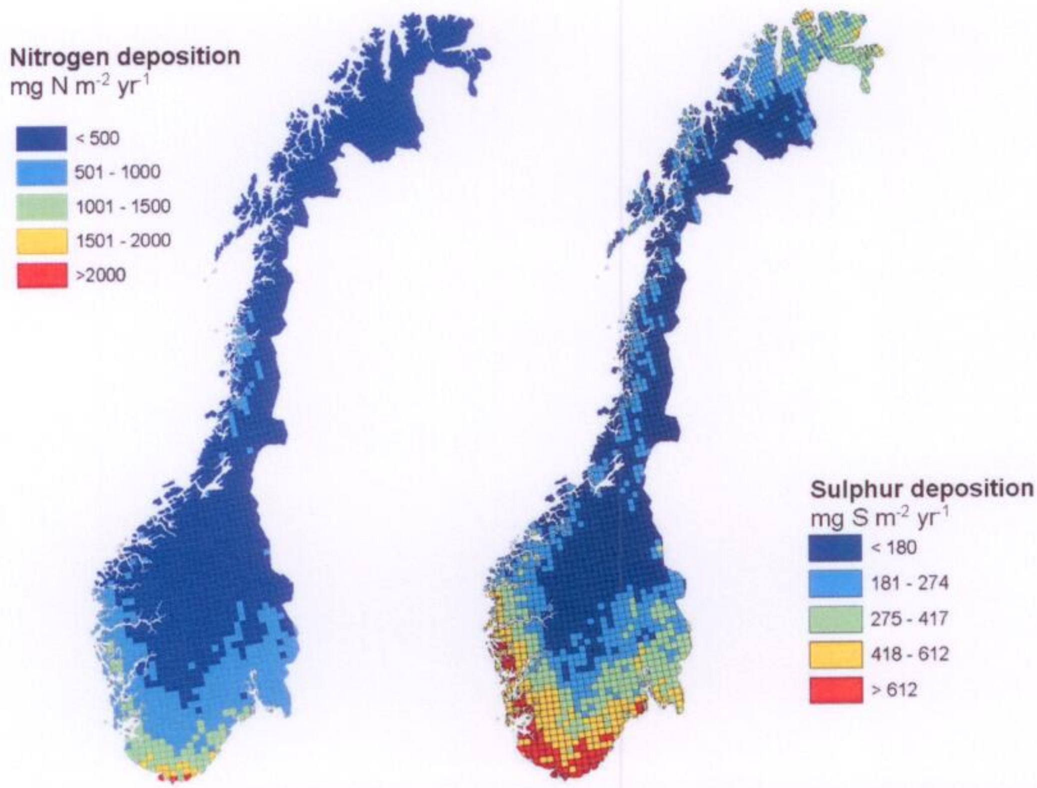

Figure 1. Annual average total nitrogen (left) and sulphur (right) deposition in Norway for the period 1997 to 2001 (1).

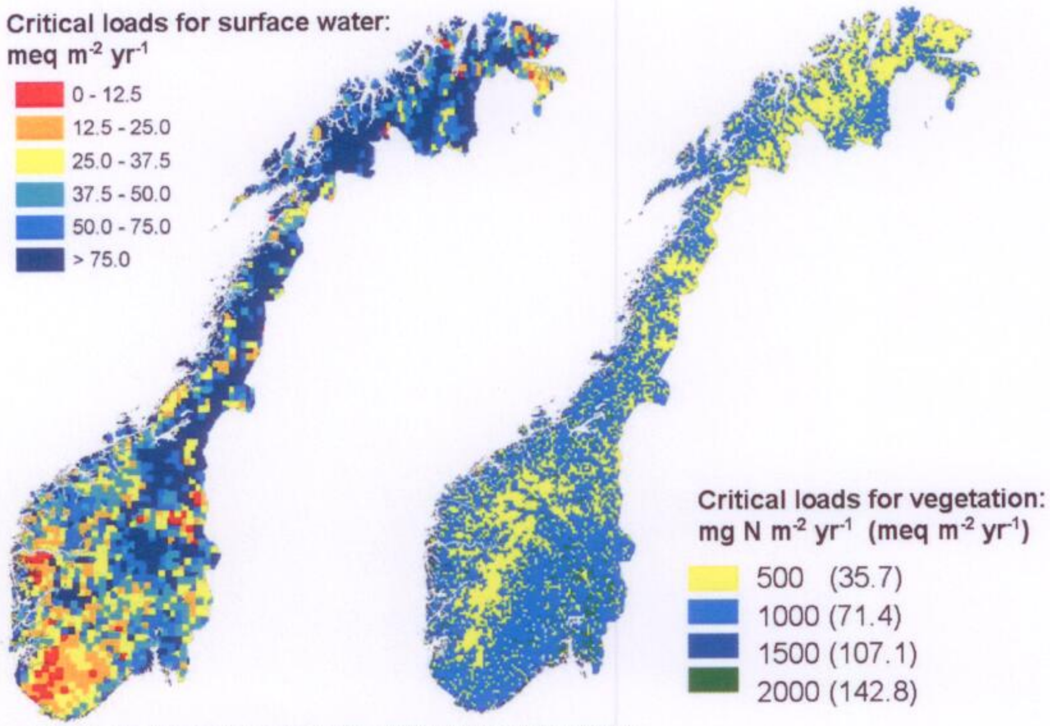

Figure 2. Critical load maps for surface water (left) and vegetation (right).

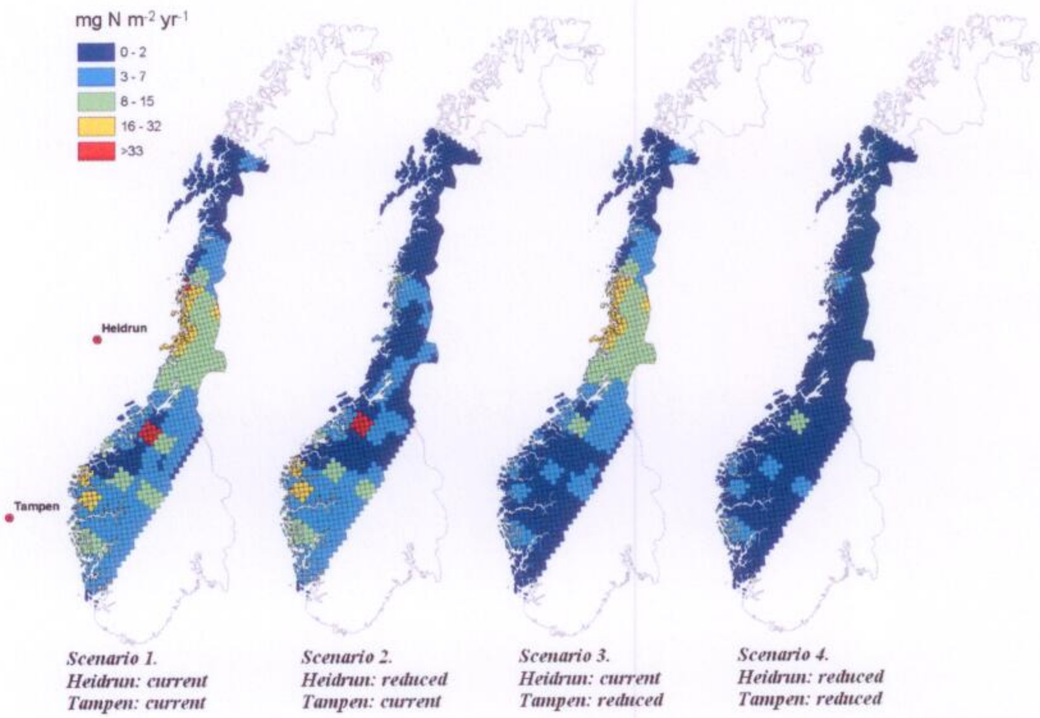

Figure 3. Modelled nitrogen deposition originating from the two installations assuming either current or reduced emission for both locations. Unit: mg N m^{-2} yr^{-1} (milligram of nitrogen deposition per square meter per year).

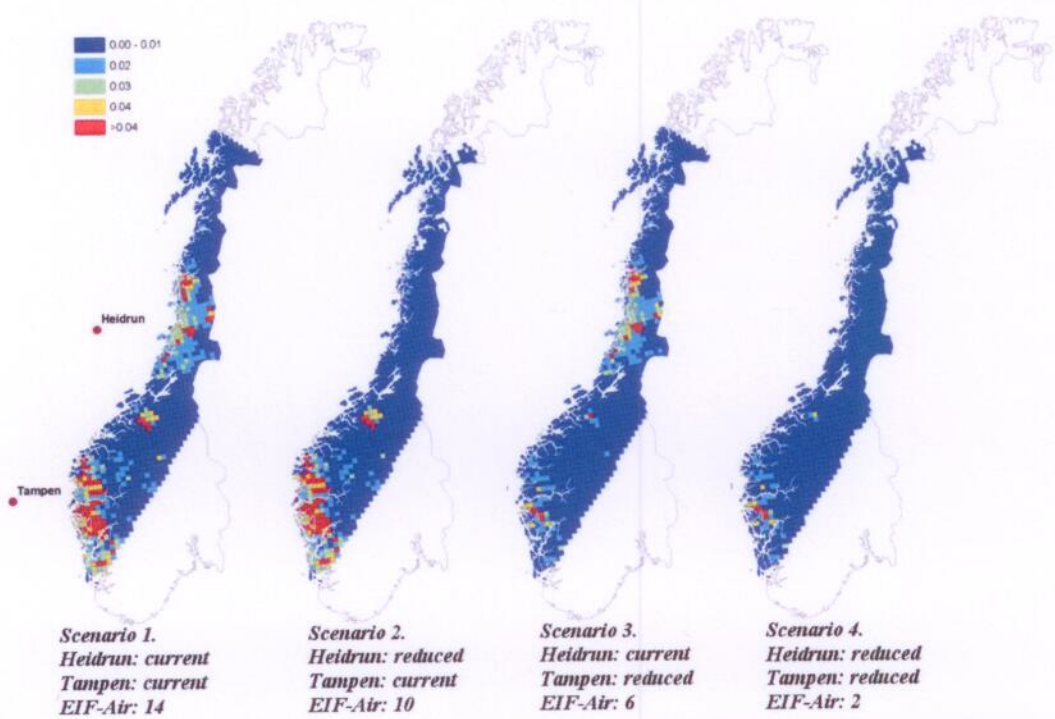

Figure 4. Maps with grid cell values for EIF-Air for the four different scenarios. The overall EIF-Air values are shown for each case. For simplicity, all values are divided by a factor 1000 in these figures.

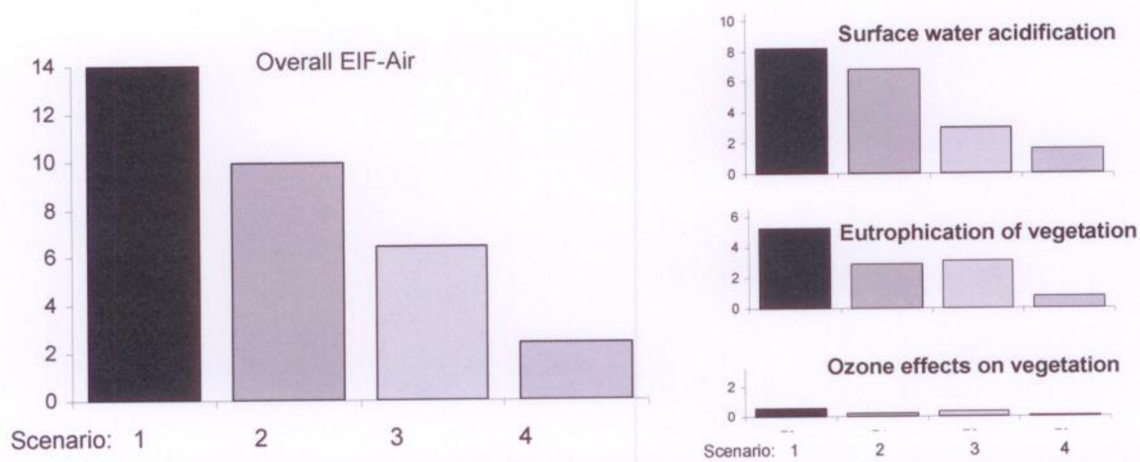

Figure 5. Comparison of the EIF-Air values for the four different scenarios (1 to 4) and the contribution from the different effects to the overall EIF-Air. The left figure shows the overall EIF-Air. The figures to the right show the contribution from surface water acidification, eutrophication effects on vegetation and ozone effects. Contribution from acidification of soils is not shown, since the contribution in all cases was 0. For simplicity, all values are divided by a factor 1000 in these figures.

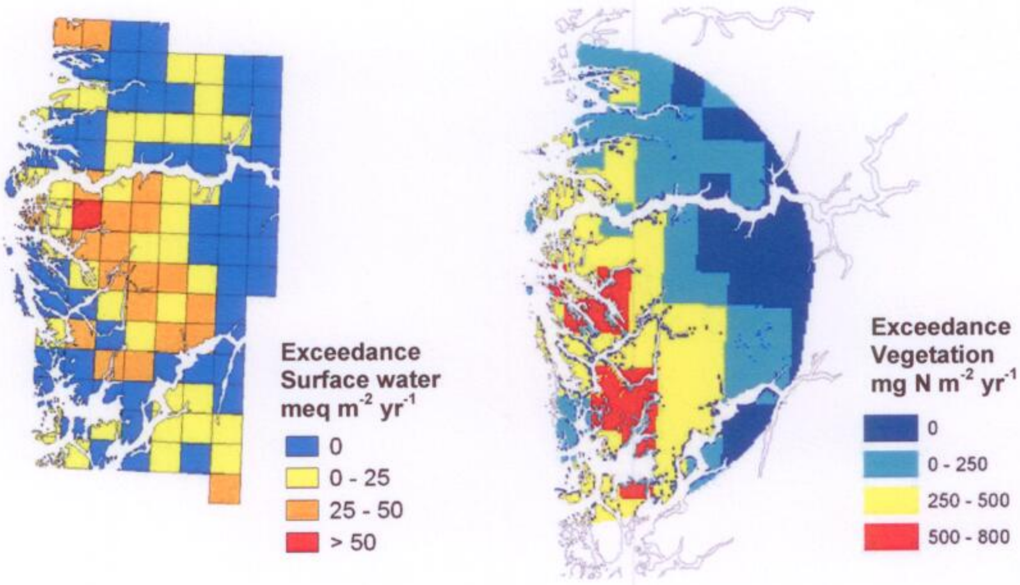

Figure 6. Exceedances of critical loads for surface water (left) and vegetation (right) in the area.

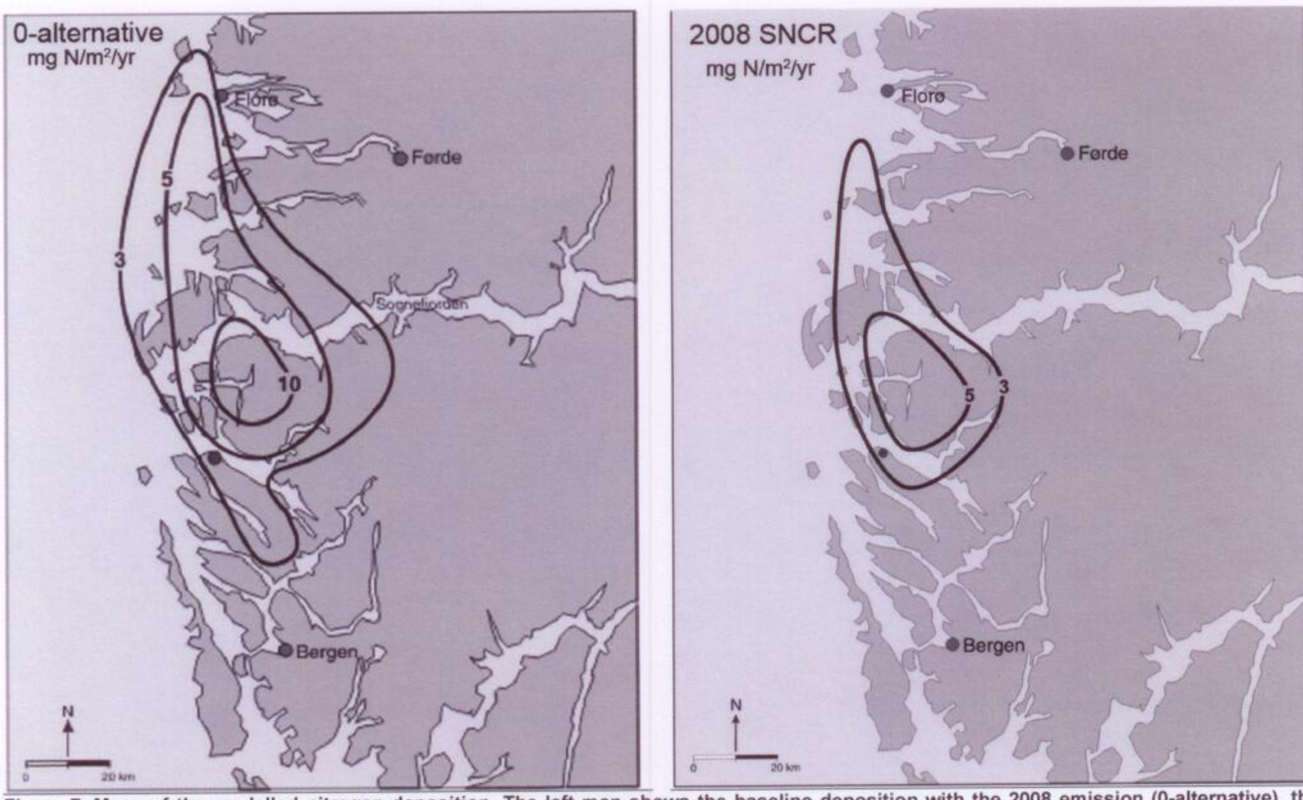

Figure 7. Maps of the modelled nitrogen deposition. The left map shows the baseline deposition with the 2008 emission (0-alternative), the right map shows deposition from the existing stack after implementing SNCR.

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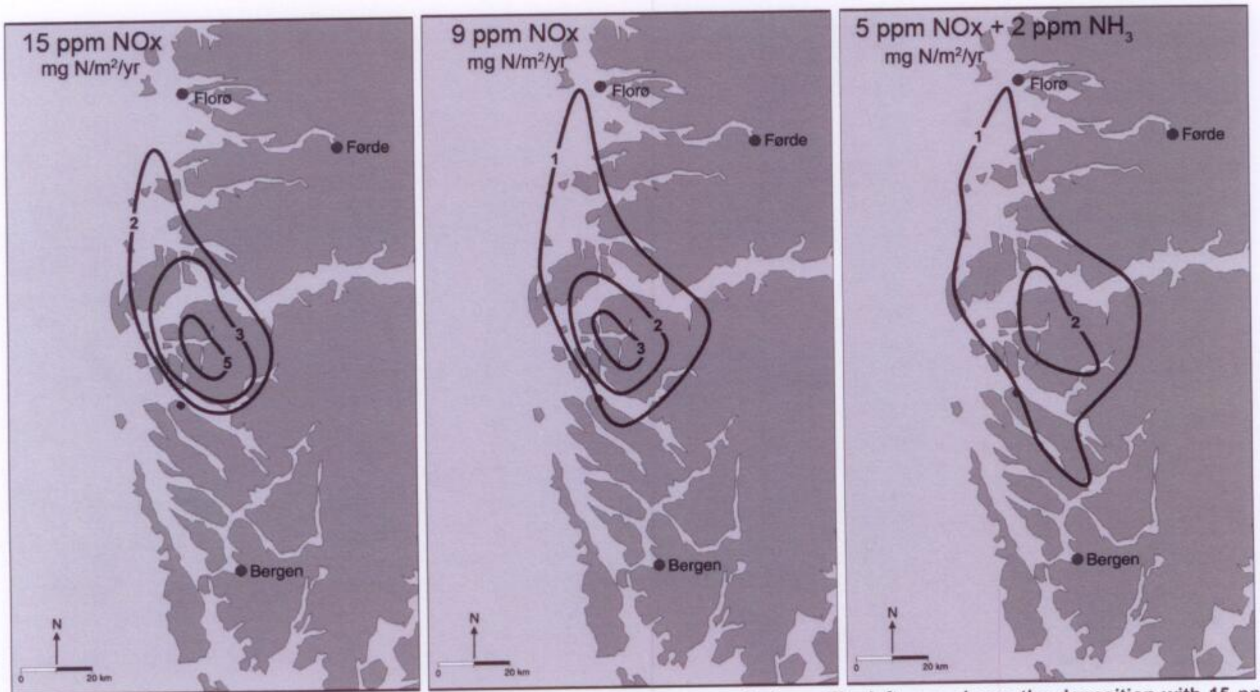

Figure 8. Maps of the modelled nitrogen deposition from the planned new emissions. The left map shows the deposition with 15 ppm NOx emission; the middle map 9 ppm NOx emission and the right map 5 ppm NOx and 2 ppm NH_3 emission.

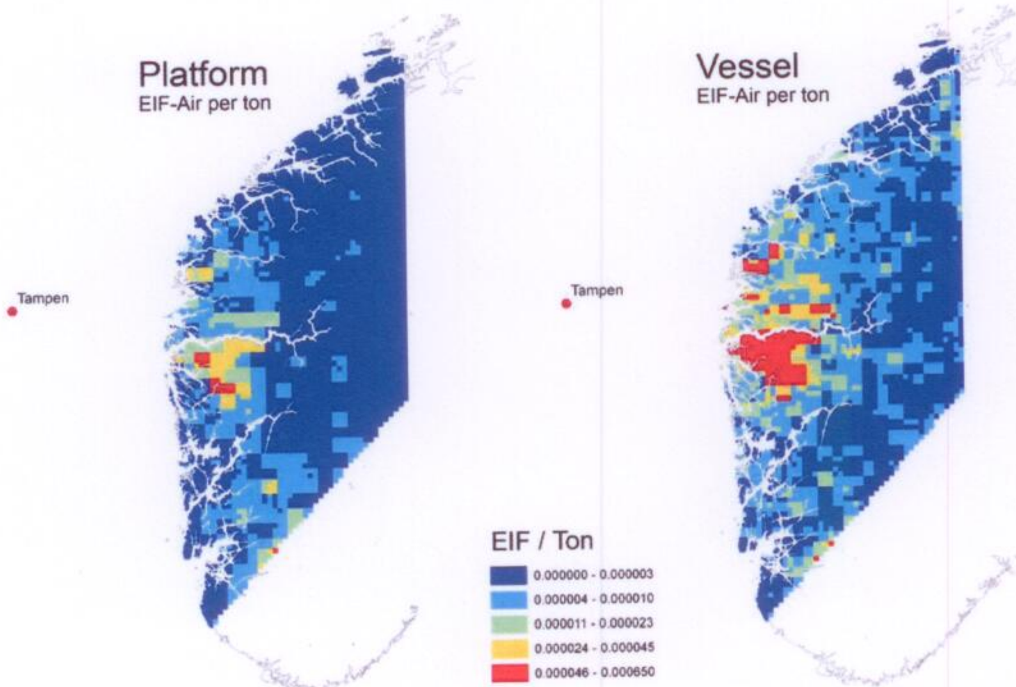

Figure 9. EIF-Air grid cell values per ton NOx emission for the emission at a platform at Tampen (left) and a supply vessel going from the Norwegian west coast to Tampen (right).

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Alternative Management and Mitigation for Potential Impacts of Oil and Gas Operations in the World's Largest and Most Productive Ecologically Sensitive Site

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Abstract

Sundarbans mangrove ecosystem, the world largest mangrove forest in Bangladesh, is one of the most productive and biologically diverse wetlands in the world. This unique coastal tropical forest is among the most threatened habitats on earth. Its importance lies in its floristic composition, resource and economic value and precious wildlife reserve. It is a habitat of some 40,000 wildlife species including endangered royal Bengal tigers, rare freshwater dolphins, and crocodiles. It is a nursing and breeding ground of over 340 fish species and 250 bird species and many others.

This paper critically examines the present status of the Sundarbans and assesses the potential threat of oil and gas exploration. Every aspect of the exploration and development of oil and gas is analyzed and the magnitude of the impact quantified. In addition detailed guidelines and mitigation plans that will minimize potential impacts are addressed. A case study is done in the Sundarbans mangrove and it shows that by undertaking proper protection and mitigation measures, oil and gas operations can be developed by preserving ecological quality and protecting wildlife. Since there is limited research that focuses on environmentally sensitive areas, this work can serve as a basis for understanding the potential effects and required remediation of oil and gas in an environmentally sensitive ecosystem.

The findings of this case study are applicable in any environmentally sensitive area. This work is not intended for use in deciding whether or not to allow oil and gas development in the Sundarbans but rather, to aid in the identification of potential problems, to increase the manager's awareness of the implications of development, and to provide information that may facilitate minimization of harmful effects.

Introduction

Mangrove ecosystems are one of the most productive and biodiverse wetlands on earth. However, these unique coastal tropical forests are among the most threatened habitats in the world [1]. Due to commercial exploration they may be disappearing more quickly than the island tropical rainforest, and so far, with little public notice [1, 2].

The Sundarbans is the largest single-tract mangrove ecosystem in the world with an area of about 10,000 square kilometers [3]. It contains a large variety of genera and species of plants, wildlife and astonishing biodiversity [4]. It stretches across two countries Bangladesh and India, over the northern part of the Bay of Bengal (see Figures 1 and 2). Due to its great significance the Sundarbans was declared a World Heritage Site and Biosphere Reserve. However, the future of the Sundarbans remains uncertain due to logging, human settlement and other numerous exploitation activities [4].

In order to improve a struggling economy, the Bangladesh government has been looking into using the oil and gas resources in the country. After the recent discovery of huge amount of proven gas reserves in the country, Bangladesh got attention by many multinational oil companies. It is considered that the future of the oil and gas is brighter and its reserves are placed at 15.3 trillion cubic feet (TCF), while the US Geological Survey estimates that Bangladesh contains additional 32.1 TCF ''undiscovered reserves'' [5]. The most terrestrial and offshore areas of Bangladesh have been divided into twenty three blocks and are gradually being leased to multinational oil and gas companies.

The Bangladeshi government recently completed the initial signing of a production sharing contract with two multinational oil giants to begin oil and gas exploration in block number five within the Sundarbans. The companies plan to conduct seismic and aerial surveys. In Bangladesh, the gas and oil exploration business is in its infancy and, therefore, environmental impacts have not yet been felt. However, the impact of hydrocarbon pollution has been clearly reported in many other parts of the world [6, 7, 8, 9]. Oil and gas exploration might pose a new and, for the most part, unknown threat to the Sundarbans ecosystem.

There has been a very limited amount of research done so far to determine the effects of oil and gas exploration in mangroves ecosystems except for the preliminary work of [6, 7].

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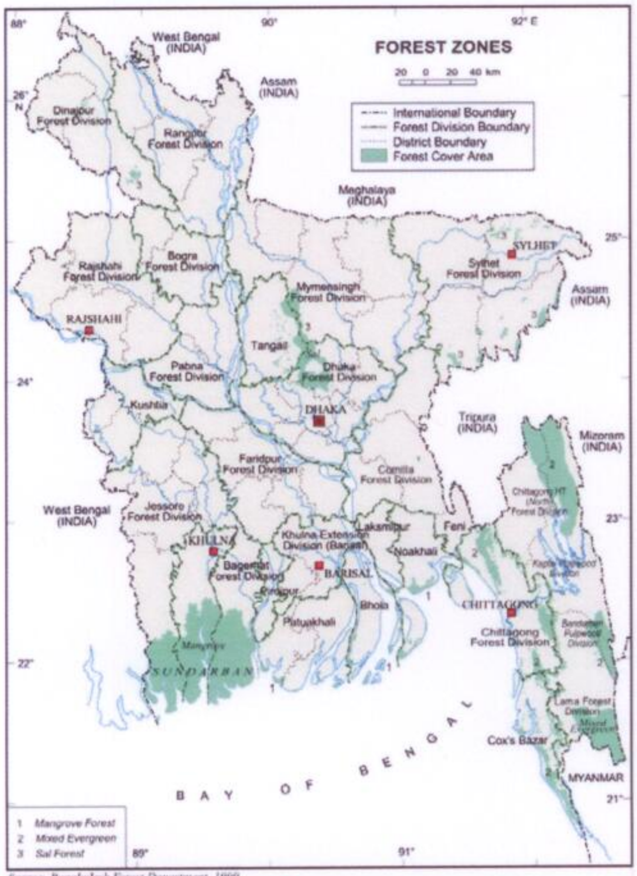

Source: Bangladesh Forest Department, 1999

Figure 1 - Forest zones map of Bangladesh (Source: *[41]*)

The main objective of this paper is to critically examine the potential threat of oil and gas exploration and production on the Sundarbans mangrove ecosystem and provide guidelines to avoid or minimize effects. This paper initially provides a brief description of the present resources status of Sundarbans, followed by detailed analyses of different oil and gas exploration and development activities. Then, the impacts of these activities are quantified. Finally, different measures, mitigation plan, and guidelines are discussed.

Table 1: The Population of the large Terrestrials Mammals of Sundarbans

Name	Population
Spotted Deer	80 000
Wild Boar	20 000
Tiger	350
Rhesus Macaque	40 000
Otter	20 000

Source: [10]

Figure 2 - Wildlife distribution map of Bangladesh (Source: *[41]*)

Environmental Engineering Planning and Impact Analysis

The environmental engineering planning and impact analysis for oil and gas activities in a certain area should consider its physical, social, economic, and environmental impacts as a whole in order to foster a healthy and efficient society in the investigated region.

Environmental engineering planning is a continuous process. It is composed of the following stages (see Figure 3):

1. Goals statement.
2. Data collection and analysis.
3. Program establishment.
4. Resources allocation.
5. Actions implementation.
6. Evaluation.

The environmental impact assessment of an oil and gas activity comprises of the following steps (see Figure 4):

1. Site location.
2. Activity type.
3. Impacts identification.
4. Proposal.
5. Mitigation and impact management.
6. Evaluation.

Impact assessment is based on oil and gas activity nature and substances released while performing such activity.

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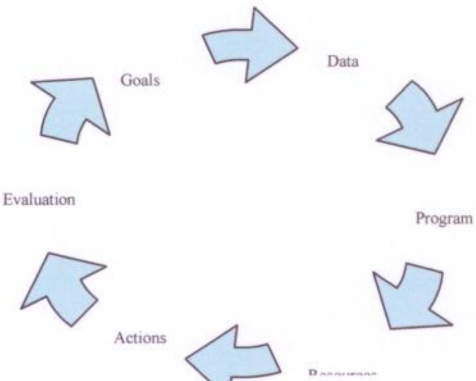

Figure 3- Environmental engineering planning stages

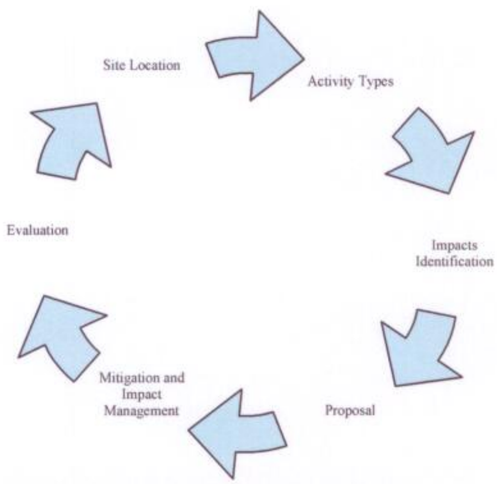

Figure 4 -Environmental impact analysis steps

Sundarbans

The world's largest mangrove ecosystem, 'Sundarbans' locally means beautiful forests (see Figures 1 and 2). It is a dynamic, fragile, complex, and productive ecosystem in delicate balance with the factors of soil, water, and the environment. It has the characteristics of marine and terrestrial, water and land, forest and sea, and a unique habitat of thousands of species, such as fish, shrimp, birds, royal Bengal tiger, crocodile, other wildlife species and numerous flora and fauna [4, 11, 12, 13]. The major wildlife species are shown in Figure 5 and Table 2. This habitat has a unique position, not only in forestry but also in the culture and heritage of Bangladesh [12, 13]. As a forest, Sundarbans constitutes about 44% of the forest area of the country and generates major revenue.

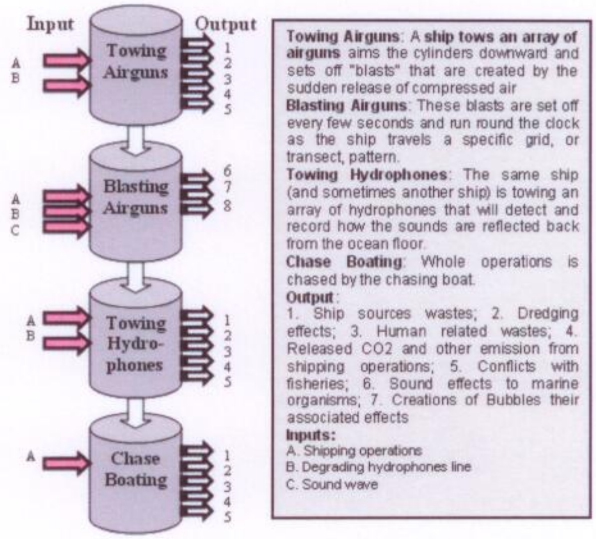

Figure 5 - Schematic Seismic Activities in offshore exploration involving towing airguns, blasting airguns, towing hydrophones and chase boat operations (source: 14)

Oil and Gas Exploration and Development Activities

Seismic Exploration

Seismic study provides primary information about geological formation of a study area [14]. Using airguns, sonar waves are transmitted to subsurface and these waves travel back and are received by hydrophones. Technological details of seismic operations for the offshore oil and gas operations are reported by Khan and Islam [14]. There are different types of technologies used for seismic study, such as 2D, 3D and 4D [15]. The Sundarbans consist of land and water. As a result, offshore and onshore seismic operations are needed. Considering the environmental condition of Sundarbans potential exploratory activities are shown in Table 2.

Drilling

Once the seismic study indicates the possible occurrence of oil, drilling of an exploratory well may be initiated to determine if oil and gas of commercial quantity and quality exist [16, 17]. The actual drilling operation normally uses a rotary drill bit and drill string, consisting of the drillpipe, the bottomhole assembly, and other tools used to make the drill bit rotate and gradually bore into the earth. Drilling is considered the most destructive phase among total oil and gas operations [6, 14, 16]. The drilling activities and their waste generation are shown in Figure 6 and Table 2.

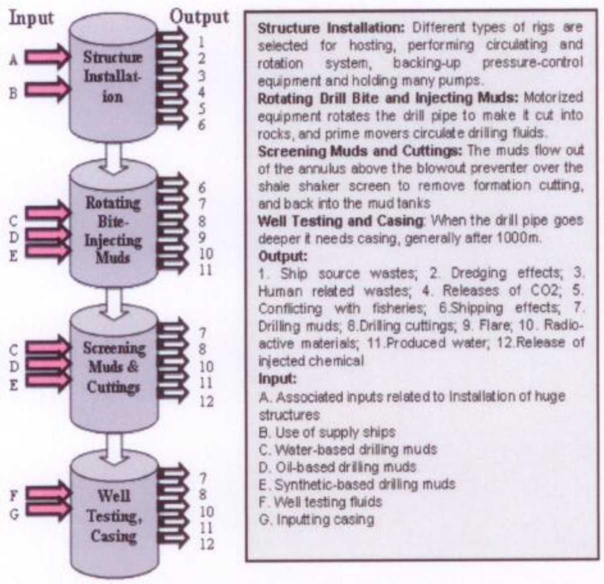

Figure 6 - Systematic diagram of drilling activities and associated waste releases

Development and Production

Oil and gas field production begins if a commercially feasible amount of oil and gas is discovered in drilling. It starts by constructing many production and transportation facilities and replacing temporary facilities. Based on the size of the oil reservoir, an immense amount of materials is necessary to erect production facilities. For example, the Sable Island offshore energy project in Canada used more than 900 kilometers of pipe, 109,000 tonnes of steel, 53 kilometers of chrome tubing, and 160,000 tonnes of concrete [17]. The potential development and production activities for the Sundarbans mangroves are shown in Table 2.

Decommissioning

Decommissioning is the last step of oil and gas operations. However, in every phase some decommissioning activities take place (dry holes and depleted producing wells are plugged with cement). Drilling rigs and support equipment are removed from an unsuccessful well [14, 18, 19]. When the entire lease is completed, all structures must be decommissioned. The activities related to the Sundarbans project are shown in Table 1.

Valued Ecosystem Components of Sundarbans and Potential Impacts

Many studies report that mangrove ecosystems especially are unique among the most productive ecosystems. To identify the potential impact of oil and gas development, the valued ecosystem components (VEC) of Sundarbans are identified. Considering the values and services provided by Sundarbans five VECs are selected which are discussed in this section.

Wildlife

The Sundarbans is a unique habitat for wildlife and it supports a very rich and diverse fauna [4]. There are 315 species of birds, 400 species of fish, 53 species of reptiles, and 8 species of amphibians in Sundarbans [20, 21, 22, 23]. Species diversity and wildlife population are shown in Tables 1 and 3.

Table 2: Potential Environmental Disruptions Resulting form Oil and Gas and Development Activities in the Sundarbans

Activities	Potential Development						
	Noise	Aircraft	Human intrusion	Traffic & access	Struct-ure	Habitat Altert	Harmful material
Land Survey		+	+	+			
Seismic trail clearing	++		+	+		+	
Seismic wave production	+++	+	+				
Clearings Vegetation	++		+			+	
Road Construction	+		++	+		+	
Mobilization of truck/equip.	+	+	+	+			
Site Development	++	+	++	+	+++	++	+
Drill pad construction	+		+			+	
Excavation of storage/mud pits	+						
Drilling and related activities	+		+		+		
Water supply	+				+		+
Borrow pit excavation	+		+				
Wellhead/pump until installation							+
Construction of process plant & storage facilities	+		+++	+	++	++	+
Installation of flow lines			+			+	
Erection of power lines	+		+		+		
Communication system					+		
Drainage facilities			+		++	+	
Operation of process facilities	+					+	
Pipe string	+						
Trenching and pipe installation	+		+		+		
Pipe burial and backfill	+		+				
Maintenance and inspection	+		+				
Accidents	+					++	+
Secondary recovery		+	+			+	
Air trip/helipads		+					
Worker Accommodations	+		+				
Increase in local population	+		+++		+++	+++	
Development of ancillary - Industry	+		+	++	+++	+++	
Well plugging			+				
Site restoration/renegotiation			+				

Table 3: Species Diversity in the Sundarbans

Group of Species	No of Species
Mangroves	27
Mangrove Associate Plants	69
Phytoplankton and Algae	37
Ichthyoplankton	200
Fish and shrimp	400
Shark	3
Shrimp	24
Skates and Rays	5
Crab	7
Lobster	3
Molluscs	26
Mammals	49
Reptiles	53
Amphibians	8
Birds	310

Sources: [20, 21, 24, 25]

Oil and gas operations can cause numerous impacts on the wildlife of Sundarbans. Oil and gas development causes problems [26]. For example, the presence of development-associated structures may interfere with movement (see Table 4). If it is severe or prolonged, it may result in reduced reproductive success or loss of available habitat [26]. Increased human/wildlife encounters may cause animals to avoid an area. It is also reported that the effects on courtship behaviour reduce existing stock and permanent loss of habitat use [26]. The noise of helicopters and other crafts will be a

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serious threat to the huge winter migration of birds. A detailed impact on wildlife is shown in Table 4.

Species at Risks

There is an amazing number of wildlife throughout the forest, but a good number of valuable animals have become extinct [22]. For example, out of the 49 mammal species no less than four major species, the Javan rhinoceros (*rhinoceros sonadacius*), wild buffalo (*Buhalus huyabails*), swamp deer (*Cervus duvauecli*) and hog deer (*Axis porcinus*) have become extinct since the beginning of the century [22].

The tiger is one of the most endangered species in the world. Today, there are only about 7,000 tigers left in the wild, down from more than 100,000 a century ago [23]. Almost 550-600 tigers reside in the Sundarbans. The following Sundarbans species are those considered to be globally threatened as of late 1993 according to the IUCN status categories: White-bellied Heron *(Ardea insignis)*, Lesser Florican (*Eupodotis indica*), Tiger (*Panthera tigris*), Hispid Hare (*Caprolagus hispidus*), Hoolock Gibbon (*Hylobates hoolock*), Green Turtle *(Chelonia mydas)*, Hawksbill Turtle (*Eretmochelys imbricata*), Olive Ridley (*Lepidochelys olivacea*), Batagur (*Batagur baska*).

Oil and gas developments can further endanger the species which are already in risk. Some studies from different parts of the world show that oil and gas development activities have negative impacts on species at risk [6]. Table 4 shows the detailed impacts of oil and gas operations on the Sundarban wildlife. Similar effects are also discussed in the wildlife section.

Special Habitat

Sundarbans provide a critical habitat for diverse marine and terrestrial flora and fauna (Table 3). It provides ecological services and works as an essential habitat, nutrient producer, water purifier, nutrient and sediment trap, storm barrier, shore stabilizer, aesthetic attraction and energy storage unit [12, 13]. Mangrove sediments appear to be efficient in retention and accumulation of phosphorus [28].

Mangroves have a significant importance for fisheries. Many species use the mangrove ecosystem in various ways [12, 13]. Some fish, obligatory species, spend their entire lifecycle in this environment. Migratory species spend a crucial part of their life (e.g., peneaid prawns) using it as a shelter or as a source of food. Others, facultative, survive and reproduce even in the absence of mangroves but show a preference for the habitat and the nutrient provided therein [29].

Healthy mangrove forests are a key to healthy marine ecology. Deterioration of the Sundarbans Mangrove due to oil and gas exploration might directly and indirectly cause declines of fisheries, degradation of clean water supplies, salinization of coastal soils, erosion, and land subsidence (12, 13]. This coastal ecosystem is so specialized that any minor variation in its hydrological quality causes noticeable mortality [30]. Potential impacts of oil and gas exploration and development are presented in Table 4.

Mangrove Forests

The Sundarbans comprises 45% of the productive forest of the country. It contributes half of the forest-related revenue and is an important source of wood and no-wood resources [27]. A wide range of forest products such as timber, fuelwood, pulpwood, matchwood and thatching materials are obtained from the Sundarbans. In 1992-93, US$ 7.0 million revenue was earned from the Sundarbans [28]).

The natural vegetation of the Sundarbans is composed of halophytic tree species commonly termed as mangrove. There are 56 species of mangroves and mangrove associates in the Sundarbans (see Table 3) (39, 38, 11]. The major predominant tree species are Sundaries (*Heritiera fomes*) and gewa (*Exocoecaria agallecha*) followed by minor proportions of passur (*Caraoa obovata*), keora (*Sonneratia apetala*), baen (*Avicennia officinalis*), kankar (*Pruguiera gymorhiza*), and a few other species like goran (*Ceriaps rexburghias*), hantal (*Pheoenix paludosa*), shingra (*Cynometra remiflora*), khalisi (*Ameiceras maius*), bhola (*Hibiscus tiliaceus*).

Oils can have a significant impact on the mangroves. Potential impacts on mangrove forest are shown in the Table 4. If an oil slick were to enter the mangrove forest when the tide is high, it would be deposited on the aerial roots and sediment surfaces as the tide proceeds. Oil that covers the breathing pores of the trees can asphyxiate the surface roots and lead to the death of the mangrove [30]. Trees can also be killed by the toxicity of the hydrocarbon. It is reported that a lighter fraction of the oil, considered to be the most toxic, generally evaporates or degrades rapidly and the heavier fraction is the cause of most of the chronic impacts [40].

Chronic exposure to hydrocarbons results in damage to aerial roots, 25-64.5% defoliation depending on the species, 100% mortality in seedling, reduction in propagate density accompanied by atrophy and malformations, and finally a serious reduction in basal area [37]. Recovery from the effects of oil spills begins 10 years after an incident. It is reported that an oil spill in 1994 near the Sundarbans spread about 15 km downstream from the ship and caused the instant mortality of seedling of Heritiera, Exoecaria, and many species of grasses [35].

Coastal Fisheries

In the Sundarbans mangroves, an average of ten thousand tons of fish and shellfish was caught annually in the late seventies and early eighties [31]. With 169908 km^2 of waterways, approximately 53 kg/ha of fish are being caught within the mangrove area itself [32, 33, 31]. To this figure should be added the portion of the offshore fisheries of mangrove development species. Whereas over 120 species of fish and shellfish are known to be caught of mangrove-dependent species in the Sundarbans area (see Table 3), the main portion consists of shrimps and hilsha (*Tenolosa* and *Hilsha* sp.).

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Table 4 Potential Impacts of oil and gas development activities on the Sundarbans' VECs

Activities	Potential Impact Levels on VECs						
	Wild-life	Species at Risk	Especial habitat	Forest	Fish-eries	Aqua-culture	Solar salt
Land Survey	2	2	2	1	0	1	1
Aerial Survey	2	2	2	0	0	2	0
Seismic trail clearing	2	3	3	5	3	3	0
Seismic wave production	7	7	2	1	5	7	0
Clearings Vegetation	5	7	7	6	6	3	0
Road Construction	4	5	6	3	3	1	1
Mobilization of truck/equip.	3	4	3	1	1	1	1
Site Development	5	5	5	3	3	0	1
Drill pad construction	4	4	5	3	2	1	0
Excavation of storage/mud pits	4	3	4	3	1	1	1
Drilling and related activities	7	7	6	2	8	6	7
Water supply	0	2	4	5	1	3	2
Borrow pit excavation	2	2	2	1	1	1	2
Wellhead/pump until installation	2	2	2	1	1	0	0
Construction of process plant & storage facilities	3	3	3	2	4	0	0
Installation of flow lines	4	3	3	2	2	1	0
Erection of power lines	2	3	4	3	0	0	0
Communication system	1	2	1	2	0	0	0
Drainage facilities	5	2	5	3	3	2	7
Operation of process facilities	6	3	4	2	5	3	7
Pipe string	4	3	3	2	2	2	1
Trenching and pipe installation	2	4	3	6	1	3	2
Pipe burial and backfill	2	3	2	3	1	2	2
Maintenance and inspection	2	4	1	1	2	1	2
Accidents	7	10	10	7	8	9	10
Secondary recovery	5	5	7	5	3	3	4
Airstrip/helipads	3	3	4	2	1	2	0
Worker Accommodations	4	4	4	1	1	1	0
Increase in local population	5	5	7	3	3	1	0
Development of ancillary industry	5	6	5	3	2	1	1
Well plugging	2	3	2	1	2	1	2
Site restoration/ renegotiation	2	4	2	2	2	2	3

A recent estimate of the total yield from the inshore-estuaries and offshore fishery of the Sundarbans reserved forest records 11700 tons in the year 1993 [31]. Penn [32] estimated the potential annual production of demersal finfish in the offshore waters of Bangladesh to be 10,000 to 20,000 tons, and that of the shrimps to be 200 to 4,000 tons. He mentioned that available yields per unit length of the coastline were relatively high by world standards. One of the main reasons for this high yield is the influence of the Sundarbans.

Potential impacts of oil and gas operations are shown in Table 4. Some of them are:

- Reproduction of fish species;
- Damage to fish eggs and larvae;
- Reduced fish stock;
- Change in the quality of fish and shrimp due to tenting;
- Effects on the fish migration;
- Depletion of nutrient form the fish nursing ground through reducing litter fall.

Coastal Aquaculture

Coastal shrimp farming is one of the major economic activities in Bangladesh and shrimp ponds are generally developed in the mangrove areas. Chakaria Sundarbans, the southeast mangrove areas of Bangladesh, are almost (90%) destroyed due to shrimp farming [33] (see Figure 6). Shrimp farming is not permitted in the southwest Sundarbans reserve forests but recently several aquaculture farms have been established at the border of the forest [28]. Frozen food export is the second largest commercial sector in Bangladesh. The major portions of the earnings come from farmed shrimp export. Every year, around 30,000 tons of tiger shrimp is exported to Japan, North America and Europe.

Exploration and development of oil and gas may cause environmental problems, such as tainted product quality, increased disease rate due to oil pollution, closure of aquaculture production if pond soil is affected, and transfer of hydrocarbon to the human body. Details of the impacts are shown in Table 4. In the table, predefined schematic scale is followed. The degree of importance is within the range of 1 to 10, where 10 highest score and 1 lowest.

Salt Production

Solar salt production is a traditional and important industry in Bangladesh and produces edible salt. Traditionally, salt is produced in the muddy coastal land (where water retention power is high) by evaporating the seawater (salinity 35 ppt). In 1997 from December 12 to the end of March about 500,000 tonnes of refined salt were already produced in the coastal areas of Bangladesh [34]. A total of 50,000 acres has been brought under salt production in the coastal areas [34].

Oil and gas operations in the Sundarbans as well as surrounding coastal areas can impact salt production causing quality deterioration of edible salt, hydrocarbon transfer to human body, salt bed contamination, closing of production, and pressure on the foreign currency (US dollar) to import salt. More detailed impacts are shown in Table 4.

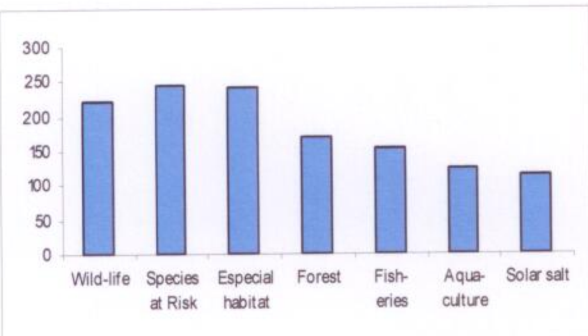

Figure 7 - Impacts levels of oil and gas development on the VECs

Special Measures for Minimizing Effects on Sundarbans

From the above discussion, it is revealed that oil and gas activities have different impacts on the valued ecosystem of Sundarbans. Figure 7 shows the total score of each valued ecosystem components. Fisheries and especial habitat can be highly affected, because they got highest scores. Solar salt got lowest scores, which represents minimal effects. In addition, the mangrove ecosystem is different from any other resource. It is a very complex and dynamic ecosystem [12, 13]. It is composed of multiple resources. Therefore, the Sundarbans need special kinds of measures to minimize the effects of oil and gas development. Guidelines for spatial, temporal and operational management are discussed in the following sections.

Spatial Management Guidelines

- Infrastructure development must be avoided in the places that are sensitive and critical to wildlife, fisheries, flora and fauna, and other resources. In particular, highly detrimental activities, which are shown in Tables 1 and 2, must be avoided.
- Some of the activities are roads, facilities, dikes, and structures.
- The critical places that should be taken into account are wildlife breeding and nursery areas, fish breading ground, habitat of important species such as crocodiles and dolphins, and critical habitat for the species at risks.
- Sufficient and much wider buffer zones can be created to reduce wildlife visual contact with roads and development activities. Buffers may include topographic barriers, vegetation, and/or distance. Fences can also be used as a barrier to control the human movement in the ecologically critical areas.
- Provision for security areas, especially for ungulates, which contain necessary habitat elements and are shelter from disturbance. This may be accomplished by restricting road activities to one out of two adjacent drainages at any one time. Ridgelines should not be developed in any way.
- Considering the impacts of aircraft activities (see Tables 1 and 2) the use of helicopters should be restricted. There should be restriction of aircraft activity to defined flight paths which avoid sensitive areas.

Temporal Management Guidelines

- Sundarbans is multi-resourced ecosystems and different species have different breeding seasons. Restriction of activities to seasons and times of noncritical wildlife, fisheries, aquaculture, and other resources use.
- Oil and gas companies should compile a list of dates when the development activities should be prohibited in certain locations due to specific needs, such as breeding, migration or local movements, etc.

Operational Management

- Avoid making any dikes or embanking in the important habitats, such as crocodile grounds, dolphin channels.
- Avoid road construction, which will minimize clearing and cutting of mangrove vegetation.
- Worker shade should be constructed outside of the mangroves. Temporary water barge houses can be used.
- Waste disposal should be controlled by reusing or minimizing the wastes.
- Oil spill significantly damage the mangrove vegetations, because their respiratory root system is clogged by the oil. There should be a proper contingency plan for the oil spills.
- Seaward mangrove should be maintained as buffer to prevent erosion and cyclone intensity.
- Sundarbans has huge networks of rivers and channels. Using the riverian facilities the aircraft uses and piled roads construction can be avoided.
- Most of the Sundarbans soil is acid sulfated. It will need proper spoil disposal. Dredging should be avoided in the acid sulfate soil.

- Tidal and freshwater flow is vital for the mangrove vegetation. Therefore, water flow off should not be blocked through road construction and other development activities.

Conclusions

In this study, Sundarbans mangroves ecosystem is identified as a unique, productive, diverse, and precious wildlife habitat, in particular the rare tiger habitat, and areas suitable for estuarine crocodiles, and fresh water dolphins. It has huge ecological, economic and societal benefits. Historical uses of Sundarbans, such as shrimp farming, created many problems. Oil and gas operations are being considered as a new economic activity.

To identify the potential impacts of oil and gas operations different development and technological phases, such as seismic exploration, drilling, production and development, and decommissioning, are analyzed. The magnitude of impacts is quantified with the respect of different valued ecosystem components, such as wildlife, fisheries, and mangroves. This work is not intended for use in deciding whether or not to allow oil and gas development in Sundarbans but rather to aid in the identification of problems, to increase the manager's awareness of the implications of development, and to provide information that minimizes harmful effects. Multidisciplinary and long-term research work is needed, which will take into account the concerns detailed in this paper regarding the impacts of oil and gas operations on mangrove forests, fisheries, wildlife, and other resources of the Sundarbans.

Acknowledgement

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Determining Environmental Tradeoffs Associated with Low Impact Drilling Systems

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ABSTRACT

An environmental scorecard is being developed to determine the tradeoffs associated with implementing low impact drilling technology in environmentally sensitive areas. The scorecard will assess drilling operations and technologies with respect to air, site, water and biodiversity issues. Low environmental impact operations will reduce the environmental footprint of operations by the adoption of new methods to use in (1) getting materials to and from the rig site (site access), (2) reducing the rig site area, (3) using alternative drilling rig power management systems, and (4) adopting waste management at the rig site.

The scorecard enables a dialog to be established and maintained among all interested, concerned and affected stakeholders. In this manner, the oil and gas industry has a new way of seeing itself within the larger network.

The scorecard presented in the paper provides the means to demonstrate the connectivity between energy production and the affected ecosystem.

The Houston Advanced Research Center (HARC) and Texas A&M University have been leading an industry consortium effort to investigate the development of low impact drilling systems.

The work originated in 2005 and funding was obtained by the U.S. Department of Energy for 2006 through 2008.

The goal of the low impact drilling systems project is to reduce the environmental impact of rig operations through integration of low-impact site access and site operations. The paper will discuss the scorecard that is being developed. The scorecard methodology presents an ecological understanding of the tradeoffs associated with producing energy. The EFD scorecard will be developed in detail for a coastal margin ecosystem and the methodology will be documented to enable the scorecard to be replicated at other ecosystems wherever reservoirs are produced. This scorecard methodology is being developed through a series of workshops being held with ecologists, botanists, wildlife management experts and others in addition to oil and gas industry experts.

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INTRODUCTION

The Houston Advanced Research Center (HARC) and Texas A&M University through the Global Petroleum Research Institute (GPRI) have been collaborating with industry and environmental organizations to integrate and demonstrate current and new technology into land-based drilling systems for compatibility with environmentally sensitive or off-limits areas. The **Environmentally Friendly Drilling Systems** (EFD) Program is taking a systems approach to the integration of currently known but unproven or novel technology in order to develop drilling systems that will have very limited environmental impact and enable moderate to deep drilling and production operations and activity with reduced overall environmental impact.

The EFD Program is identifying and providing the technology to successfully produce shale gas and tight gas sands while appropriately addressing environmentally sensitive issues. The project focuses on developing drilling technologies that can be used throughout the U.S., in particular, unconventional natural gas resources as illustrated in Figure 1 and Figure 2.

The work described in this paper is focused on the development of a methodology to determine environmental tradeoffs that are related to such issues as air, water, site, and biodiversity. This methodology was developed through a series of workshops to identify what needs to be measured and how the measurements should be made to determine environmental tradeoffs. Workshops were attended by representatives from government, academia, industry and various environmental organizations.

Why create something called “Environmentally Friendly Drilling”? Because new technology will help meet the U.S. energy needs for the next century at the same time we reduce the environmental “footprint” of oil and gas operations.

Exploration and production companies are aware that minimizing their environmental footprint is crucial to reducing environmental liabilities, controlling operational costs, and encouraging public acceptance for the sustainable development of the U.S. natural resources. There are certain restrictions for habitat protection, and in some cases complete prohibitions, that prevent drilling in many sensitive areas in the continental United States. Stakeholders desire to improve energy independence and to understand the environmental tradeoffs necessary to secure energy.

Sustainable development of petroleum resources requires careful monitoring and operations over the life cycle of a development, from the initial planning through decommissioning and site restoration. According to the recent National Petroleum Council’s recommendations, access to indigenous resources is essential for reaching North America’s full supply potential. New discoveries in mature North American basins represent the largest component of the future supply outlook. However, the trend towards increasing leasing and regulatory restrictions in the Rocky Mountain region the U.S. Coastal /Margins and the Outer Continental Shelf (OCS) is occurring in precisely the areas that hold significant potential for natural gas production.[1] The NPC evaluated the effect of removing the OCS moratoria and of reducing the impact of conditions of approval on the Rocky Mountain areas – a potential addition of 3 BCF/D by 2020. This represents more than 25% of the projected growth in natural gas needs of the U.S. by 2020.[2]

Land-use policies of federal, state, and local governments have not kept pace with technological advances that allow for exploration and production while protecting environmentally sensitive areas. Technical advances have reduced the number and size of onshore drilling sites and production facilities. The federal government has continued to set federal lands off-limits to development through legislation, executive orders, and regulatory and administrative decisions without acknowledging these advances.

According to the Texas Independent Oil and Gas Association, “*New technology developed by industry, universities and the Department of Energy is needed to help industry meet our members’ goal of producing oil and gas in a safe and environmentally acceptable manner; especially when operating in environmentally sensitive areas.*” The Independent Petroleum Association of America (IPAA) has consistently stated to Congress that access to more Federal Lands is the primary way to increase domestic oil and gas production. Many of these areas are on Federal Lands currently off-limits to drilling primarily because regulators, Congress and the environmental community are not convinced that technology is sufficient to develop these resources without adversely impacting the environment. While there may be technologies available to accomplish environmentally acceptable drilling, they have to be proven to be accepted. In response to this need, this project team will work with government, industry, academia and public organizations to identify, develop, and provide industry with the tools to develop needed energy supplies.

The Bureau of Land Management (BLM), and the Forest Service (FS), is responsible for ensuring compliance with the National Environmental Policy Act (NEPA). During the review of development proposals that encompasses multiple wells in a specific area, the BLM, the surface management agency, or the agency's or operator's environmental contractor conduct an environmental analysis and prepare an environmental document in conformance with the requirements of NEPA and the regulations of the Council on Environmental Quality (CEQ). Regardless of which agency, entity, or individual prepares the environmental analysis document, the BLM (and FS, for actions on National Forest System lands) must concur with the content prior to issuing a decision document. In the case of National Forest System lands, where the environmental analysis is conducted jointly with the BLM, each agency issues its own decision. The extent of the environmental analysis process and the time frame for issuance of a decision depend upon the complexity of the proposed action and resulting analysis, the significance of the environmental effects disclosed, and the completion of appropriate consultation processes.

Policies concerning biofuels, fossil fuels and greenhouse gases are being discussed and debated across America. A recent edition of ***Science*** summed up their view about the issues as follows[3]:

> 'If the prime object of policy on biofuels is mitigation of carbon dioxide–driven global warming, policy-makers may be better advised in the short term (30 years or so) to focus on increasing the efficiency of fossil fuel use, to conserve the existing forests and savannahs, and to restore natural forest and grassland habitats on cropland that is not needed for food. In addition to reducing net carbon dioxide flux to the atmosphere, conversion of large areas of land back to secondary forest provides other environmental services (such as prevention of desertification, provision of forest products, maintenance of biological diversity, and regional climate regulation), whereas conversion of large areas of land to biofuel crops may place additional strains on the environment. For the longer term, carbon-free transport fuel technologies are needed to replace fossil hydrocarbons.'

Scharlemann and Laurance have concluded that production of various biofuels, including U.S. corn ethanol and soy diesel, Brazilian sugarcane ethanol and soy diesel, and Malaysian palm-oil diesel, have sacrificed natural forest and grassland habitats on cropland that is being converted to energy biomass fuels. The authors recommend against such conversion.

Preventing loss of habitat provides other environmental services (such as prevention of desertification, provision of forest products, maintenance of biological diversity, and regional climate regulation) and avoids the biomass environmental impact costs that represent greater costs than do fossil fuels.[4]

Conservative estimates of the near term impact of the adoption of low impact drilling technology would increase the immediately accessible resources by more than 10%, just in the Texas Gulf Coast. The Chairman of the General Land Office Jerry Patterson[5] estimated the state's Permanent School Fund received more than $450 million dollars in revenue in 2006. Future revenues will include more than $104 million in royalties from its share of gas production from gas wells on Padre Island. These funds will add to the $22 billion in the Permanent School Fund, royalties from 13 million acres where the state retains an interest in the mineral rights, land office officials said.

Having a program that has the potential to "lighten the impact" of gas drilling in environmentally sensitive areas such as coastal margins, National Forests and Parks and other public lands is extremely important. Gas leases beneath many of state and national parks and public lands are owned by private companies, not the government. Only by setting environmentally responsible standards can park managers protect the environment while providing access to these resources.

How can advancements in drilling systems and technologies reduce environmental impacts? Several new practices and processes are being developed.

THE MORE YOU KNOW, THE LESS YOU NEED

The drilling process is considered a complex activity composed of a set of processes interrelated by purpose, sequence, and time. Millheim[6] defined the drilling process as a system in the mid 1980's. The systems themselves are made up of sub systems. The rig and the surface equipment is a complex subsystem of the drilling process. Pedersen and Essendrop defined the drilling system (Millheim's rig subsystem) comprised of six subsystems[7]: drilling control system, drilling machine, pipe handling, blow-out-preventer (BOP) and handling system, mud supply, and mud return[8]. Though defined for the offshore jack up design environment, many of the concepts have transitioned to the onshore rig design.

As knowledge has increased, technology has allowed the industry to contact almost 60 times the volume of subsurface rock material that could be accessed in 1970 while occupying only one third the surface area[9] (Figure 3). The technology of drilling and production can be unobtrusive and highly efficient if the technologies are used concurrently on the same well. In the past 20 years, technology has been able to significantly reduce the impact that drilling operations have on the environment. According to the Natural Gas Supply Association, some of the key technology developments over this time period have enabled the following.

- 22,000 fewer wells are needed on an annual basis to develop the same amount of reserves as were developed in 1985.
- Had technology remained constant since 1985, it would take two wells to produce the same amount of oil and natural gas as one 1985 well.
- Drilling wastes have decreased by as much as 148 million barrels due to increased well productivity and fewer wells.
- The drilling footprint of well pads has decreased by as much as 70 percent due to advanced drilling technology.
- By using modular drilling rigs and slim hole drilling, the size and weight of drilling rigs can be reduced by up to 75 percent over traditional drilling rigs.
- Had technology, and thus drilling footprints, remained at 1985 levels, today's drilling footprints would take up an additional 17,000 acres of land.

Documented best practices and lessons learned have greatly reduced environmental issues associated with drilling operations. The oil and gas industry just needs to combine these practices into EFD systems, then demonstrate their effectiveness in real applications.

REDUCE, REUSE, RECYCLE

The energy industry has progressed in taking into consideration environmental issues. Shell Exploration and Production Company established a Rig Waste Reduction Pilot Project in 2001 to identify potential waste reduction strategies.[10] Their preferential hierarchy that they developed is: *reduce, reuse, recycle, recover and dispose.* The majority of the total waste stream was found to be drilling discharges and non-hazardous oilfield waste. Mud use was reduced by 20% and mud component packaging was reduced by 90% through a combination of solids control efficiency, cuttings dryer technology and bulk mixing equipment. In addition, Shell implemented a sorting, compaction and recycling process for solid waste (consumables and trash) to reduce landfill disposal.

Schlumberger has introduced a total waste management program to mitigate rising quantities of landfill waste.[11] Benefits included an overall improvement in general housekeeping that reduced health and safety exposure and a general increase in environmental awareness and concern. As a result, the recommendation is made to ensure that the operator establishes a waste management program that covers all exploration, drilling and production activities.

Mobil implemented a waste management program for the Hugoton field operations.[12] The waste management system decreased overall waste-related costs while improving compliance assurance and reducing potential liability. The key element was a mechanical solids control system consisting of a semi-closed loop centrifuge flocculation dewatering process that removes solids for burial on location.

Chevron has published ten years of lessons learned concerning bio-treating exploration and production wastes.[13] They have successfully implemented bioremediation in diverse climates and in remote locations. The most common biological treatment techniques in the exploration and production industry are composting and land treatment. Land farming and composting have been successfully used for drilling wastes.[14]

There is currently an industry joint venture, sponsored by GPRI and the U.S. Department of Energy – National Energy Technology Laboratory to reduce waste volume of liquids at the rig site. This "Mud Pit Cleanup and Re-Use" project aims at recovering fresh water and solids-free brine at the rig site for re-use in drilling operations.[15]

RESTORE

Reducing, reusing and recycling are all important. For sustainability, more is required. The relationship between business and a healthy environment is critical to long-term sustainability. Paul Hawken has defined sustainability as a stable relationship between human culture and the living world.[16] Business practices need to address life on earth. Ecology and commerce need to be united. As industry weighs various business practices, a systematic methodology of understanding and guiding practices may be implemented to, first, develop an understanding of the tradeoffs. To develop an understanding of what is possible, an understanding of the current situation is required.

Today's industry is accepting costs of environmental stewardship. These costs must be reconciled with commercial interests. Environmental restoration, economic prosperity and social stability may co-exist and do not have to be in conflict.

WHAT GETS MEASURED, GETS DONE

The Nutrition Labeling and Education Act of 1990 mandated that food companies were required to use a new food label on most food products beginning in 1994. This new label, as illustrated in Figure 4, provides information to enable users to make educated decisions about what they eat.

The US Green Building Council (USGBC) has develop an analogous label, as illustrated in Figure 5, for summarizing how a building measures up in their Leadership in Energy and Environmental Design (LEED) Green Building Rating System™. The LEED system encourages and accelerates the use of green building practices through the implementation of universally understood and accepted tools and performance criteria.

The methodology being developed to measure tradeoffs concerning environmental issues related to oil and gas operations can use the nutrition label and the LEED system as analogies.

USGBC LEED PROGRAM

The USGBC LEED program can serve as a model for the methodology to measure tradeoffs concerning energy production. The LEED program is a nationally accepted benchmark for the design, construction and operation of green buildings, providing a tool to measure a building's performance and impact. The LEED program measures performance in five areas: sustainable site development, water savings, energy efficiency, materials selection and indoor environmental quality. The rating systems were developed through a consensus-based process involving a diverse group of practitioners and experts representing a cross-section of the building and construction industry. The various LEED rating systems that are administered by the USGBC are illustrated in Figure 6. Figure 7 illustrates a completed scorecard for a newly constructed building.

THERE IS ONLY ONE BUS

In 1963, Buckminster Fuller published his ***Operating Manual for Spaceship Earth***[17] where he discusses the limited supply of energy onboard the spaceship and the need to harness the energy being supplied by the sun. Another way of looking at it is to realize that everyone is on the same bus and that there is a limited amount of fuel in the tank. While technologies are being pursued to harness solar energy, technologies need to be developed and implement to ensure that current energy supplies are being used efficiently and that all new fuel supplies that are tapped are done in a manner that will not be detrimental to those onboard.

There are tradeoffs between energy needs and biodiversity values. Many areas that are potentially valuable for energy are also recognized for biodiversity values. Energy development can impact biodiversity. The energy industry needs to meet public demand for energy while at the same time meet society's expectations for corporate, social and environmental responsibility. Conservation organizations need to be a voice for biodiversity protection while appropriately partnering with industry, recognizing that there is a balance to be struck between economic development, energy production and the conservation of biodiversity.

The EFD program is aimed at tapping the fuel supplies in an environmentally sound manner. The scorecard methodology aims to measure that manner that demonstrates its effectiveness.

Everyone on the bus has a vested interest in ensuring that sources of energy are produced using technologies that are not harmful. To develop the tradeoffs scorecard methodology, the decision was made to get as many stakeholders around the same table as possible, including, industry producers and service companies, ecologists, botanists, toxicologists, zoologists, wildlife managers, endocrinologists, environmentalists, regulators, and others. An initial workshop was held with representatives from government, academia, non-profits, industry and environmental organizations with the objective of discussing the tradeoffs associated with producing energy.

The focus of the workshop was the drilling systems and operations, recognizing that there is a need to also consider other oil and gas systems and operations. Environmentally Friendly Exploration and Production scorecards could be developed, as a minimum, for:

- Exploration
- Drilling
- Completion
- Processing
- Refining
- Transportation
- Distribution
- Field Development
- Field Operations

An EFD scorecard for drilling systems and operations was selected as the first scorecard to be developed due to the ease at which a boundary can be established around the time and location for the systems and operations.

WHAT GETS IDENTIFIED, GETS DEALT WITH

The objective of the EFD scorecard is to have a methodology that is meaningful, simple and easy to implement and understand. Five attributes were identified as meaningful to evaluate: site (soil/sediment), water, air, biodiversity and societal issues.

Each attribute could have several layers or sub-attributes. As an example, within biodiversity, the potential threat to wildlife due to proximity or timing of operations could be assessed and minimized. Drilling activities have the potential risk of temporarily interfering with wildlife. The risk can be mitigated through proper planning and monitoring of operations.

The EFD scorecard has two point levels. First are the prerequisites – those items that must be done. Secondly are optional credits – those items that are considered best practices, going beyond minimum operating requirements.

Prerequisites for the various attributes could be rules and regulations that govern the drilling locations. Within the United States, regulations vary by state and address various environmental issues by geographic location. Argonne National Laboratory, in conjunction with Marathon and Chevron, has developed an interactive website that summarizes state and federal regulations governing drilling waste. The website also provides descriptions of various technical options as well as case studies and other information.[18]

Interaction between operations and wildlife can vary greatly depending on the area of operation and the kind of wildlife present. There are certain times of the year when wildlife is more sensitive to external influences. Such times include migration, mating, birthing and spawning. Sensitive areas can be clearly displayed on maps and graphs. The recommendation is made to establish boundaries concerning time and distances – establishing exclusion zones at certain times of the year.

Where interaction is unavoidable, the following steps may be taken to minimize disruption:

- Scouting the sensitive areas and planning routes likely to cause least disruption.
- Staying clear of wildlife areas marked on the planning map to avoid sensitive areas.
- Banning hunting and fishing at all times.
- Instructing the crew not to intentionally harass or feed wildlife.
- Banning pets on all crew facilities.
- Reporting incidents and any significant problems with wildlife.

Conoco's St. Charles Field, located in the Aransas National Wildlife Refuge, is an example of profitable oil and gas operations co-existing with wildlife and nature.[19] The key learning from their effort is to ensure that operations are sensitive to the wildlife activities.

There are other best practices to minimize disturbances on wildlife populations that can be followed during drilling operations, including:

1. Pad locations should not be within 1,000 feet of the perimeter of an active wildlife location or within 1,500 feet of an endangered species' nest.
2. Each proposed pad location and the surrounding area should be field surveyed for the presence of endangered, threatened, and sensitive species and other environmental concerns, including water quality issues, prior to any construction activities and for final approval.
3. Pad locations should use every method and process available to minimize environmental impacts including, but not limited to:

   - A closed drilling fluid system shall be used.
   - Stockpiling topsoil and installing a silt fence around the spoils pile, the location perimeter, new access roads, and all other locations as needed.
   - Lining all pits at the location with an appropriate impervious material and ensuring that all surface runoff and fluids at the location are captured onsite and properly disposed of offsite.
   - Exposed or disturbed soil resulting from all pad construction shall be stabilized using native grasses/vegetation.
   - Reclaiming the site to its original elevations using the stockpiled topsoil and replanting the entire area with native grasses/vegetation.
   - Containment areas shall be constantly maintained and shall be periodically pumped clear of fluids and rainwater to minimize long-term soil contamination.

Texas A&M University has just announced creation of a Desert Research and Testing Center on the edge of the Chiuahua Desert near Pecos, Texas (reference). This center, created with the support from the Research Partnership to Secure Energy for America (RPSEA) aims at testing examples of low impact drilling systems in a real life demonstration, but in a controlled environment where performance can be measured more effectively with less harm to the environment.[20]

The first systems to be tested will be low impact access roads. Part of this project is a "Disappearing Roads" competition established by Texas A&M University with the support of Halliburton to identify ways to move people and material to and from drill sites with minimal impact.

Another example would be the sub-attribute of aquifer protection under the water category. During the drilling operation, several strings of casing of reducing diameter are run and cemented in place. The critical casing string with respect to potential damage to an aquifer is the casing string that is set across the aquifer. The critical issues are related to 1) the drilling through the aquifer – following best practices to ensure that the drilled hole is in the best possible condition prior to running the casing, 2) the outer surface of the casing – to enable the cement to have adequate adherence to the casing, and 3) the cementing operation – again, following best practices to mitigate potential cement column degradation during the life of the well.

For Texas, state wide rules relative to oil and gas operations fall under the jurisdiction of the Texas Railroad Commission and are found in Title 16 (Economic Regulation), Part 1 (Railroad Commission of Texas), Chapter 3 (Oil and Gas Division) of the Texas Administrative Code.[21] Rule §3.8 covers Water Protection and provides for various disposal methods that do not require a permit. These include:

- Disposal of inert wastes by a method other than disposal into surface water**;**
- Disposal of certain categories of low-chloride drilling fluid by land farming**;**
- Disposal of other drilling fluid down the annulus of a producing well or down the well bore of a dry and abandoned well prior to plugging, so long as the wastes are generated at that specific well site**;** and
- Disposal of completion workover pit wastes by burial **i**n a completion/workover pit.

Texas Railroad Commission Rule §3.8 also governs pit and surface waste management standards including standards for short-term pits such as drilling pits and completion/workover pits.

Texas Railroad Commission Rule §3.13 governs casing, cementing, drilling and completion requirements. The rule states that sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. This rule implies that all aquifers will have cement across the interval. Cement quality is governed by the rule. Alternative methods of fresh water protection may be applied for to the appropriate district director.

The operator is responsible to be in compliance with the Texas Railroad Commission rules. Rule §3.13 is intended to ensure that all usable-quality water zones are isolated and sealed off to effectively prevent contamination or harm and that all potentially productive zones are isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. Surface casing must be set and cemented to protect all usable-quality water strata. Sufficient cement must be used to fill the annular space outside the casing from the shoe to the ground surface.

Various publications[22,23,24,25,26] discuss best practices associated with drilling operations to protect aquifers. Key items include:

- Install and cement a sufficient amount of casing from the base of the aquifers to the ground surface.
- Use pipe rotation or high annular velocities to increase the flow energy of the cement during to ensure mud displacement.
- Communication is a key – ensure that all are informed and understand daily goals and objectives. Use a cement formulation that minimizes shrinkage during setting.

Another sub-attribute related to water is surface contamination. During drilling operations, best practices need to be followed to minimize risks associated with potential surface contamination. Minimizing potential surface contamination will lower the risk of damaging artesian springs or aquifers. Large volumes of drilling fluids need to be handled correctly. In addition, rain runoff from the site must be properly contained.

A water runoff management program may be developed to control discharges of waste water to the environment.[27] Current practices typically include a moat (levy around the entire drill pad site. Any fluids collected in the moat are pumped into the reserve pit. All fluids collected in the reserve pit are then hauled off location for proper disposal. Controlling run off is one of the top environmental concerns. The program could include collection ditches/berms around all areas and equipment that could discharge contaminated water. An incentive scheme could also be a part of the program with a bonus or penalty based on the volume of water discharged and the hydrocarbon content of the discharged water.

Other industry practices were reviewed. Key best practices include:

- Whenever possible, use previously impacted terrain for access routes[28]
- Use close-looped and containerized mud system[28]
- Use 'environmentally friendly' substitutes for hydraulic fluids and lubricating compounds[28]
- Use integrated waste minimization practices and innovative restoration alternatives[28]

- Ensure that all equipment installed on the site is designed so that any effluent is caught and is not discharged directly in the environment[29]
- Use environmentally friendly drilling fluids[29]
- Establish a management system of authorized chemicals with a storage system, safety data files and a stock-management program[29]
- Reduce waste volumes at the source: water consumption, optimized recycling of mud, reduction of cuttings volumes[29]
- Establish a cuttings management plan[29]

The initial workshop identified the various attributes and sub-attributes. Based on the workshop, the need for continue dialogue among all stakeholders was strongly recognized. The scorecard development team is in the process of reviewing best practices, the literature, regulations and facilitating meetings and dialogue with various experts in order to develop the scorecard as well as how to implement the measurement process for the various credits. An initial draft of the scorecard is illustrated in Figure 8.

NOW WHAT? THE SYSTEMS APPROACH TO SELECTION

With the prototype scorecard methodology in hand, it is now time to fully develop an EFD scorecard for a given location and test it out.

The scorecard team will be working with stakeholders to apply the methodology to develop ecosystem-specific scorecards for semi-arid and wetland ecosystem locations. Over the coming year the EFD scorecard will be used to investigate the tradeoffs associated with drilling operations in a coastal margin ecosystem.

Concurrently with development of the EFD scorecard, Texas A&M, HARC and their partners are developing a number of other low-impact technologies. We expect to demonstrate these systems in upcoming field trials by our sponsors.

Finally as part of the A&M/HARC EFD program, researchers at Johns Hopkins University and Texas A&M are developing a new approach to identify the environmentally friendly technology that could be included in an EFD system. The systems approach works with matrices of many possible solutions to assist in choosing the system (or combination of technologies) that should be selected for specific drill sites. This quantitative approach to evaluate systems is being used to design preliminary plans for well sites along the Gulf Coast in Texas.[30]

A prototype web-based systems optimization program is available for industry sponsors to choose among the more than 70 technologies identified by the EFD team that reduces the environmental footprint of drilling operations.

ACKNOWLEDGEMENTS

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Figures

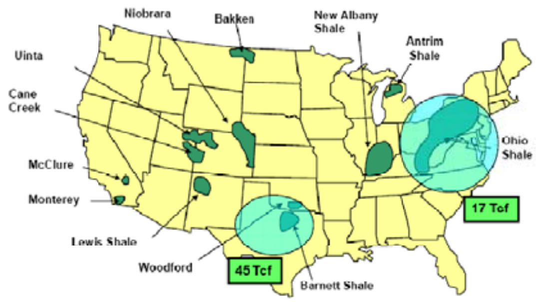

Figure 1. Shale Gas - 69 Tcf Technically Recoverable.

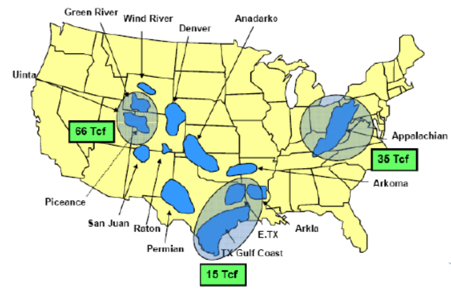

Figure 2. Tight Gas Sands - 159 Tcf Technically Recoverable.

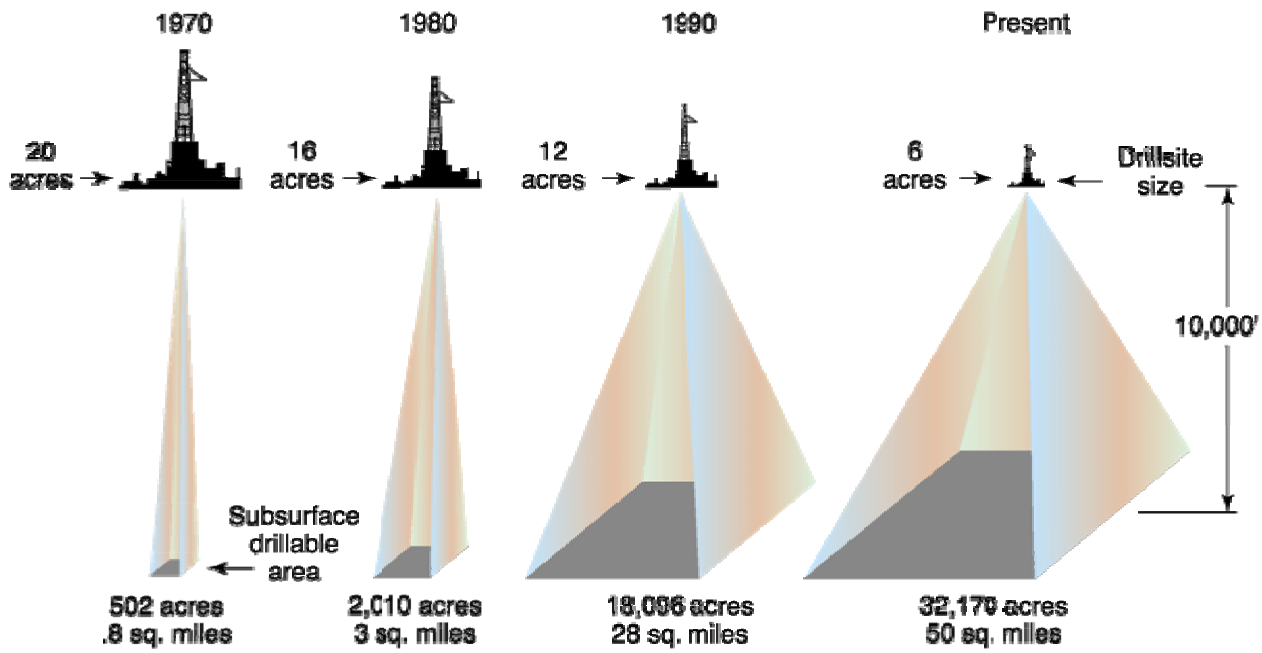

Figure 3. Technology Advancements - Decreasing Environmental Tradeoffs.
(source: William Harrison, Kansas Geological Survey)

Figure 4. Typical Food Label.

Figure 5. Typical USGBC LEED Summary.

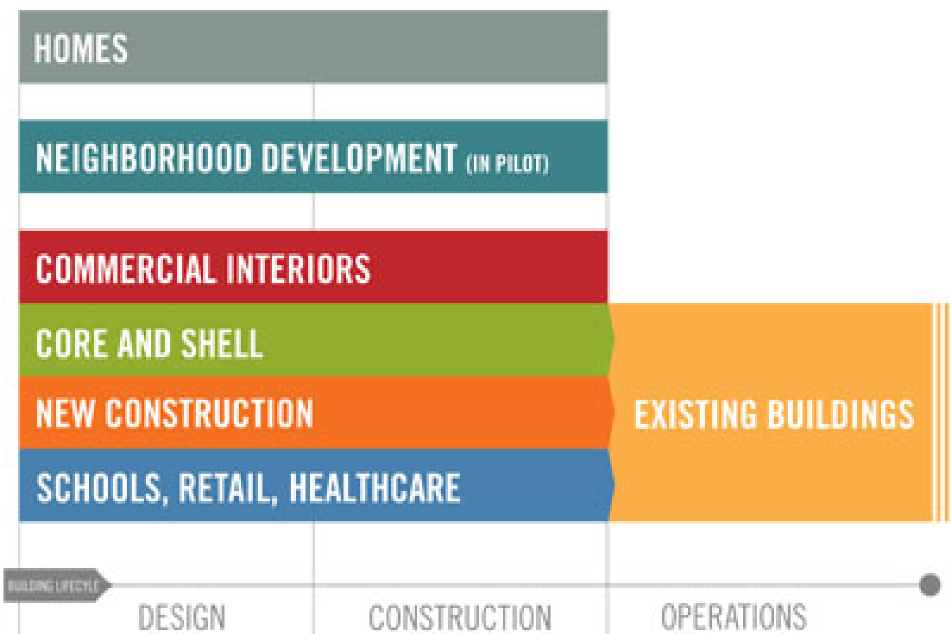

Figure 6. USGBC LEED Rating Systems.

LEED-NC

Bldg. 27 Astronuat Quarantine Facility
LEED® Project # 1486
LEED Version 2 Certification Level: CERTIFIED
2/24/2006

28	Points Achieved	Possible Points:	69

Certified 26 to 32 points Silver 33 to 38 points Gold 39 to 51 points Platinum 52 or more points

6	Sustainable Sites	Possible Points:	14
Y			
Y	Prereq 1	Erosion & Sedimentation Control	
1	Credit 1	Site Selection	1
	Credit 2	Urban Redevelopment	1
	Credit 3	Brownfield Redevelopment	1
	Credit 4.1	Alternative Transportation, Public Transportation Access	1
1	Credit 4.2	Alternative Transportation, Bicycle Storage & Changing Rooms	1
	Credit 4.3	Alternative Transportation, Alternative Fuel Refueling Stations	1
	Credit 4.4	Alternative Transportation, Parking Capacity	1
	Credit 5.1	Reduced Site Disturbance, Protect or Restore Open Space	1
1	Credit 5.2	Reduced Site Disturbance, Development Footprint	1
	Credit 6.1	Stormwater Management, Rate and Quantity	1
	Credit 6.2	Stormwater Management, Treatment	1
1	Credit 7.1	Landscape & Exterior Design to Reduce Heat Islands, Non-Roof	1
1	Credit 7.2	Landscape & Exterior Design to Reduce Heat Islands, Roof	1
1	Credit 8	Light Pollution Reduction	1

1	Water Efficiency	Possible Points:	5
Y			
1	Credit 1.1	Water Efficient Landscaping, Reduce by 50%	1
	Credit 1.2	Water Efficient Landscaping, No Potable Use or No Irrigation	1
	Credit 2	Innovative Wastewater Technologies	1
	Credit 3.1	Water Use Reduction, 20% Reduction	1
	Credit 3.2	Water Use Reduction, 30% Reduction	1

4	Energy & Atmosphere	Possible Points:	17
Y			
Y	Prereq 1	Fundamental Building Systems Commissioning	
Y	Prereq 2	Minimum Energy Performance	
Y	Prereq 3	CFC Reduction in HVAC&R Equipment	
1	Credit 1.1	Optimize Energy Performance, 20% New / 10% Existing	2
	Credit 1.2	Optimize Energy Performance, 30% New / 20% Existing	2
	Credit 1.3	Optimize Energy Performance, 40% New / 30% Existing	2
	Credit 1.4	Optimize Energy Performance, 50% New / 40% Existing	2
	Credit 1.5	Optimize Energy Performance, 60% New / 50% Existing	2
	Credit 2.1	Renewable Energy, 5%	1
	Credit 2.2	Renewable Energy, 10%	1
	Credit 2.3	Renewable Energy, 20%	1
1	Credit 3	Additional Commissioning	1
1	Credit 4	Ozone Depletion	1
	Credit 5	Measurement & Verification	1
1	Credit 6	Green Power	1

5	Materials & Resources	Possible Points:	13
Y			
Y	Prereq 1	Storage & Collection of Recyclables	
	Credit 1.1	Building Reuse, Maintain 75% of Existing Shell	1
	Credit 1.2	Building Reuse, Maintain 100% of Existing Shell	1
	Credit 1.3	Building Reuse, Maintain 100% Shell & 50% Non-Shell	1
1	Credit 2.1	Construction Waste Management, Divert 50%	1
	Credit 2.2	Construction Waste Management, Divert 75%	1
	Credit 3.1	Resource Reuse, Specify 5%	1
	Credit 3.2	Resource Reuse, Specify 10%	1
1	Credit 4.1	Recycled Content	1
1	Credit 4.2	Recycled Content	1
1	Credit 5.1	Local/Regional Materials, 20% Manufactured Locally	1
1	Credit 5.2	Local/Regional Materials, of 20% Above, 50% Harvested Locally	1
	Credit 6	Rapidly Renewable Materials	1
	Credit 7	Certified Wood	1

7	Indoor Environmental Quality	Possible Points:	15
Y			
Y	Prereq 1	Minimum IAQ Performance	
Y	Prereq 2	Environmental Tobacco Smoke (ETS) Control	
	Credit 1	Carbon Dioxide (CO_2) Monitoring	1
	Credit 2	Increase Ventilation Effectiveness	1
1	Credit 3.1	Construction IAQ Management Plan, During Construction	1
1	Credit 3.2	Construction IAQ Management Plan, Before Occupancy	1
1	Credit 4.1	Low-Emitting Materials, Adhesives & Sealants	1
1	Credit 4.2	Low-Emitting Materials, Paints	1
1	Credit 4.3	Low-Emitting Materials, Carpet	1
	Credit 4.4	Low-Emitting Materials, Composite Wood	1
	Credit 5	Indoor Chemical & Pollutant Source Control	1
	Credit 6.1	Controllability of Systems, Perimeter	1
	Credit 6.2	Controllability of Systems, Non-Perimeter	1
1	Credit 7.1	Thermal Comfort, Comply with ASHRAE 55-1992	1
1	Credit 7.2	Thermal Comfort, Permanent Monitoring System	1
	Credit 8.1	Daylight & Views, Daylight 75% of Spaces	1
	Credit 8.2	Daylight & Views, Views for 90% of Spaces	1

5	Innovation & Design Process	Possible Points:	5
Y			
1	Credit 1.1	Innovation in Design	1
1	Credit 1.2	Innovation in Design	1
1	Credit 1.3	Innovation in Design	1
1	Credit 1.4	Innovation in Design	1
1	Credit 2	LEED® Accredited Professional	1

Figure 7. Typical Completed USGBC LEED Scorecard.

Environmentally Friendly Drilling Scorecard

Project:
Location:
Ecosystem:
Date:

0	Points Achieved		Possible Points:	100

★ 55 - 64 points ★★ 65 - 74 points ★★★ 75 - 84 points ★★★★ 85 - 94 points ★★★★★ 95 - 100 points

0	Air		Possible Points: 10
	Prerq 1	On-site Power - Tier 3 Engines	
	Prerq 2	Contractual Obligations for Logistics	
	Credit 1	Site Emissions - Stationary	2
	Credit 2	Site Emissions - Temporary	2
	Credit 3	Site Emissions - Logistics/Transport	2
	Credit 4	Dust Supression	2
	Credit 5	Electric Rig	1
	Credit 6	Green Completions	1

0	Site		Possible Points: 15
	Prerq 1	Regulatory Compliance	
	Prerq 2	Erosion & Sedimentation Control	
	Credit 1	Pre-Existing Site	3
	Credit 2	Pad Drilling	2
	Credit 3	Protect and Restore Habitat	2
	Credit 4	Contractor Guidelines	2
	Credit 5	Site Restoration Plan	2
	Credit 6	Match Site/Access to Topography	1
	Credit 7	Avoidance of Archeological Sites	1
	Credit 8	Logisitics Plan - Offsite Storage	1
	Credit 9	Planting of Native Vegetation	1

0	Waste Management		Possible Points: 20
	Prerq 1	Waste Management Plan	
	Prerq 2	Title	
	Credit 1	Closed Loop Mud System	5
	Credit 2	Title	2
	Credit 3	Title	2
	Credit 4	Title	2
	Credit 5	Title	2
	Credit 6	Title	2
	Credit 7	Title	2
	Credit 8	Title	1
	Credit 9	Title	1
	Credit 10	Title	1

0	Biodiversity		Possible Points: 20
	Prerq 1	Species Protection	
	Prerq 2	Habitat Protection/Enhancement	
	Prerq 3	Regulatory Requirements	
	Credit 1	Restoration/Interim Reclamation	3
	Credit 2	Reduction of Surface Disturbance	3
	Credit 3	Erosion Prevention	3
	Credit 4	Voluntary Offsite Mitigation	2
	Credit 5	Invasive Species Prevention	2
	Credit 6	Restoration of Fragmented Habitat	2
	Credit 7	Reintroduction of Species, Habitat	2
	Credit 8	Avoidance of High Value Areas	1
	Credit 9	Wildlife Protection	1
	Credit 10	Habitat Enhancement	1

0	Water		Possible Points: 15
	Prerq 1	Stormwater Mangement Plan	
	Prerq 2	Water Management Plan	
	Credit 1	Water Usage Tracking	4
	Credit 2	Setbacks from Streams/Sources	3
	Credit 3	Reduce Water Usage	2
	Credit 4	Reuse of Water/Fluids	2
	Credit 5	Recycling of Water/Fluids	2
	Credit 6	Monitor Nearby Surface Waters	1
	Credit 7	Pressure Testing of Surface Casing	1

0	Societal		Possible Points: 20
	Prerq 1	Community Engagement	
	Prerq 2	Communication Plan	
	Credit 1	Public Outreach	5
	Credit 2	Noise Control	2
	Credit 3	Training of Local First Responders	2
	Credit 4	Remote Alarms for Toxic Releases	2
	Credit 5	Emergency Management Plan	2
	Credit 6	Dispute Resolution Plan	2
	Credit 7	Land Use Damage Plan	2
	Credit 8	Landowner Indemnification	1
	Credit 9	Water Well Mitigation Agreement	1
	Credit 10	Surface Use Agreement	1

EFD Facts

Project:
Location:
Ecosystem:

	Max	Score
AIR	10	0
WATER	15	0
SITE	15	0
WASTE MANAGEMENT	20	0
BIODIVERSITY	20	0
SOCIETAL	20	0
	100	0

☆ ☆ ☆ ☆ ☆

Figure 8. Prototype Environmentally Friendly Drilling Scorecard.

SPE 115587

Application of Membrane Filtration Technologies to Drilling Wastes

Oluwaseun, Olatubi, SPE, Burnett, David, SPE, Hann Roy, Texas A&M University, and Rich Haut, HARC

This paper was prepared for presentation at the 2008 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA, 21–24 September 2008.

Abstract

The Environmentally Friendly Drilling (EFD) program is taking a renewed look at dealing with the issue of waste management and re-use particularly with regards to produced water and water based drilling wastes, developing solutions that would possibly reduce the size of reserve pits needed in drilling operations and achieve significant waste volume reduction through the extraction of water from drilling wastes encouraging reuse of the extracted water in drilling operations and the concentration of suspended solids.

The EFD is investigating the use of membrane-filtration technologies in the aforementioned aim of waste volume reduction and water extraction from drilling wastes. The investigation involves processing actual drilling wastes using various membrane types and configurations in developing solutions to challenges facing membranes particularly fouling. We are investigating the ability of these membranes to effectively remove the suspended solids from waste streams and refine the waste to levels where they could be used in drilling operations or sent for further treatment such as desalination. Our aim is to develop a mobile treatment unit made of a suitable membrane system that could be deployed to drilling sites to be used as an onsite option aimed at recycle or re-use of water resources.

We are currently investigating in our laboratories various membrane-filtration technologies with water based oilfield wastes and coupling this with our prior development of field deployed technologies in developing a cost efficient membrane filtration system for field application. We show in this report how membranes have been used in the filtration of actual solids laden field supplied water based muds and a solids simulated laboratory water based mud, highlighting the compatibility of membrane systems with water based muds.

In light of the evolving stringent regulatory standards and in demonstrating good stewardship of the environment, the Oil and Gas industry is expected to be active in reducing the footprint of its various activities on the environment and in showing optimal use of resources. This approach to dealing with drilling wastes confers the two-fold advantage of optimal use of water resources through re-cycle and the reduction of the footprint of drilling operations well within reasonable economic costs by saving significant waste treatment, hauling and freshwater costs.

Introduction

The energy question is increasingly becoming the most important question of this present age, with growing populations especially those of South East Asia and the attendant energy demand of these teeming population the issue of energy has become a pressing issue globally. The search for energy to meet present demands and future forecasts is becoming more intense and more diversified than ever, despite this diversification of sources to meet the energy demand globally, crude oil remains the prime energy source today and probably in the foreseeable future. This increased demand for energy and rising energy prices have renewed interest in unconventional oil resources as unconventional resources are estimated to play a major role in providing energy for the future(1).

Parallel to increasing energy demand is the increasing awareness about environmental issues especially as they pertain to E&P operations. The last decade has witnessed increasing environmental regulation imposed by federal, state and municipal authorities on the industry in other to protect environments where exploration activities occur particularly during drilling.

With the projected rise in E&P operations there is an increasing environmental awareness and activism especially as new terrain is expected to be explored for their resources which could culminate into more stringent protective regulations. Emphasis is increasingly placed on reducing the impact or footprint of E&P operations on the environment to minimal levels, issues such as resource conservation, waste minimization (or waste reduction), recycling, re-use are becoming topical issues and metrics in the regulatory toolbox in determining where exploration activities can be carried out in the USA and worldwide. Increasingly environmental concerns are becoming the major determinants to future drilling concessions by the government and landowners.

In the last thirty years drilling technology has gone through significant technological changes resulting in smaller rigs such as Helmerich &Payne and innovations such as horizontal drilling and these changes have resulted in significant reduced surface disturbance during drilling while significantly increasing the subsurface reach (subsurface drillable area) of drilling operations. From Figure 1 we see that rig size has been reduced by 70% in the last thirty years while subsurface drillable area has increased by 6400% in the same period. This shows that the dynamics of impact of drilling operations has shifted considerably in the last thirty years from top to bottom, though surface reduction translates to less surface area or ecosystem disturbance in drilling operations – on the surface, the wider subsurface reach means that there would be an increase in the amount of drilling waste generated subsurface which is usually brought to the surface thereby increasing footprint, thus due to increasing subsurface reach the total impact of drilling operations on the environment is actually increasing despite marked reduction in rig sizes.

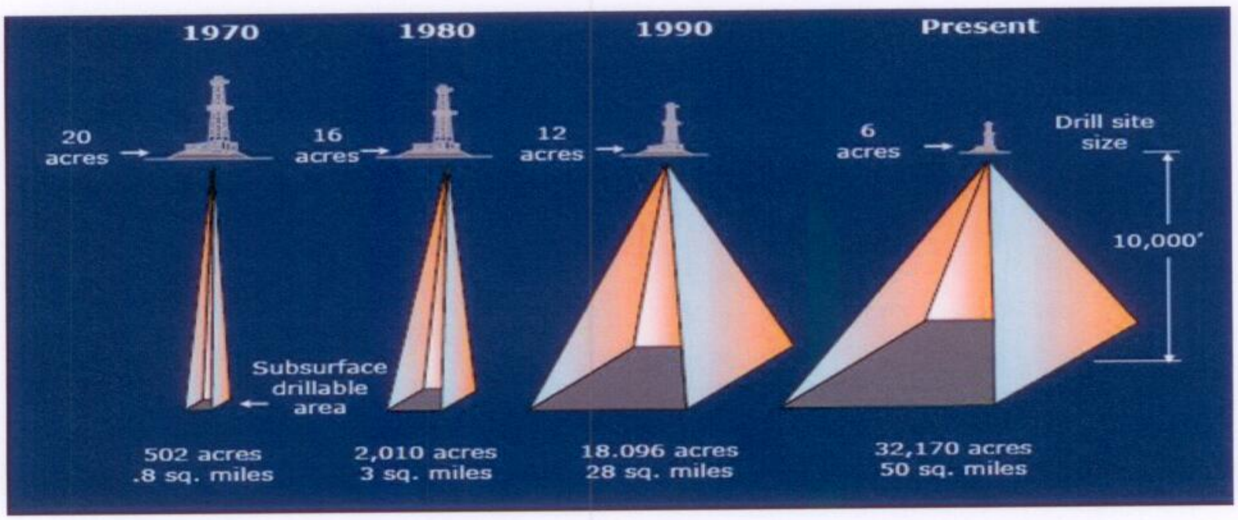

Figure 1: Rig size and subsurface drillable area in the last thirty years (2).

Freshwater sourcing is becoming a limitation factor in the exploration and production of oil and gas as operators are increasingly putting pressure on freshwater sources to meet increased E&P needs especially in the exploitation of unconventional resources. Copious volumes of produced water and water based wastes are disposed without re-use and recycle, from the last industry published study on fates of waste about 4 billion barrels of produced water per year is disposed into disposal wells and over 70% of water based drilling wastes are not recycled or re-used (3). Although the agricultural industry consumes the largest portion of freshwater resources present, industry disposal practices presents unsustainable disposal of scarce water resources especially produced water and water based drilling wastes. An early look into increasing re-use would be of benefit to all stakeholders and society as a whole.

The Environmentally Friendly Drilling (EFD) program is taking a renewed look at dealing with the issue of waste management and re-use particularly with regards to produced water and water based drilling wastes. The EFD is investigating the use of membrane filtration systems for removing suspended solids from water based drilling wastes to achieve the dual purpose of extracting water from these wastes and reducing or concentrating the volume of these wastes with the belief that this would help in reducing the footprint of drilling operations and conserve scarce water resources.

Theory

The objective of our investigation is to develop a treatment option that deals with reducing the impact or footprint of drilling operations specifically by looking into ways of minimizing wastes associated with increasing subsurface reach which we have identified as the largest contributor of footprint. In tackling the issue of these wastes, the perspective has been to critically look into the constituents of these wastes to determine what the "useable" constituents of the waste are and what constituents are "non-useable and if a separation could be made of the waste based on this delineation. If such delineation can be made and executed this would fortuitously help at achieving volume reduction while the useable constituents could be re-used.

Volume reduction of drilling wastes portends a veritable tool to reducing the overall footprint; if the waste volume could be reduced to a factor of the whole this would then augment rig size reduction in reducing the total impact or footprint of drilling operations. Volume reduction would also expand the choice of treatment options available to deal with wastes, current audits show that increasing waste volumes due to higher subsurface reach are making uneconomical preferred waste treatment and or disposal options, even options deemed environmentally friendly. Re-use and recycle have always been envisioned on a larger scale such as desalination of brine as a source of freshwater for agriculture or potable use, such expectations of recycle and re-use sometimes fall short of expectations due to extraneous issues such as public perception of recycled waste or market for the recycled waste. The EFD aim is first localized to encourage recycle and re-use in drilling operations to optimize the use of water resources, this gives room for more flexibility in waste recycling as the burden of greater polishing of the waste is reduced and the lessons from such localized recycling can be used as fodder for more ambitious re-use programs.

Produced water and drilling wastes are the major contributors to drilling wastes. For water based drilling wastes the presence of suspended solids hinders most attempts at recycle and re-use amongst other contending issues, while in the desalination of produced water periodic fouling of reverse osmosis membranes due to suspended particles has also been a major hindrance raising the costs of desalination, the problem associated with suspended solids could be identified in various wastes such as wastes from fracturing operations like the frac fluid backflow. Any successful approach at reclaiming these wastes for re-use or recycle must deal with removal of suspended solids in these wastes before other issues such as toxicity, salinity and other secondary issues are treated.

In this study we set out to show that it is possible to removal of suspended solids and water from water based drilling wastes which are solids laden is possible and that with proper engineering and maintenance, field deployable equipment could be created to achieve this first step in the reclamation process. We began by investigating the use of membrane filtration technologies for solids removal from these wastes. Membrane filtration technologies offer advantages over traditional suspended solids removal equipment such as centrifuges and hydrocyclones because the particle size removal limits of traditional solids removing equipments are well above the limit needed to make re-use or recycle possible.

Traditional solids removal equipments have limits on particle size separation and are less efficient than membranes which have a wide range of separation from bacteria to atoms (4, 5). The separation range of the membrane filtration technologies we investigate make it possible for total removal of all suspended solids thereby changing significantly the wastes making re-use or recycle possible either in its solids free state or in preparation for secondary treatment such as desalination. The major challenge in the adaptation of membranes is fouling (6). We investigate but not report extensively (as our investigation is ongoing) the positive effect that fouling mitigation techniques have on reducing the impact of fouling and how these could be incorporated into field deployable systems.

Procedure and Equipment

There are four common membrane filtration modules or configurations common to membrane systems; they are tubular, plate and frame, spiral and hollow fibre membrane modules. Our investigation was carried using the tubular and hollow fibre configurations. The plate and frame and spiral wound modules were not investigated due to practical issues with adopting them to drilling wastes and or actual drilling operations. Two water based drilling mud types were used in our investigation; a field supplied lignosulphite based mud supplied from actual field operations in East Texas by an operator (was taken from the mud pit) and salt type mud that was made in the lab using mud software and simulated cuttings were added into the lab prepared mud. Each mud type was run using both membrane filtration modules.

For the tubular configuration experiments, a simple in-house built filtration unit (schematic in Figure 2, appendix) fitted with a titania honeycomb ceramic membrane with mean pore size of 0.005 microns was used, the membrane length was 305 mm and had a surface area of 0.13 metres square. The transmembrane pressure (TMP) was controlled by an adjustable valve, the fluid velocity was measured by a flow meter and tests were run in the recycle mode i.e. the filtrate from the membrane was passed back to the feed reservoir. The ZW-10 Zenon® hollow fibre demonstration unit was used for the hollow fibre configuration tests (Figure 3, appendix). It has a nominal surface area of 0.93 metres square, and a nominal pore size of 0.04 microns. The Zenon unit has an air blower that continuously scours the surface on the membrane and also mixes the feed. The system has micro pumps which are set to automatically backwash at periodic intervals using permeate from a backpulse tank, suction was also controlled automatically. A typical run in the ZW-10 consists of a period of suction for a set interval followed by a brief period of backwash using greater pressure; this helped to unclog the pores of the membranes. Both units (tubular and ceramic) carry out filtration in the ultrafiltration range with the ceramic module having finer pores. Before and after each run membranes were cleaned as prescribed by the manufacturers and RO water flux was recorded at the start and end of all experiments and clean-up.

The lignosulphite based mud from the field had a mud weight of 10 pounds per gallon, 10.20 % solids by volume ratio, funnel viscosity of 37 sec/quart and had 92% water by volume. The recipe for the lab made mud is shown in Table 1, mud weight was 9.4 pounds per gallons, solids ranging from 0.762- 3.81 mm (762 -3810 microns) were simulated and added to the mud to make 5 % solids by volume ratio. This particle size distribution represents the larger spectrum of particles in most muds. All tests were run for four hours, the tubular ceramic module was run using a flow of 61 liters per minute corresponding to a crossflow velocity of 3.6 m/s, transmembrane pressure of between 52-72 kPA and 25-30 C was maintained. The hollow fibre pressure was maintained at 55 kPA. A 20% dilution of the sample had to be made because each test required a minimum of 90 gallons per run. Permeate volume for both modules was measured manually using a graduated cylinder and a stop watch, the average of three readings was used as the final measurement. The turbidity of the sample was read using a Hach-2100P turbidity meter and particle size distribution was read using the Microtrac S3000® particle size analyzer. Parameters of importance that were measured include flux over time, the pressure, the solids concentration and temperature during filtration. Variations to the system were carried out in order to optimize filtration such as changing pore size of membranes, varying system parameters and varying the rheological characteristics of samples. This represent part of our on-going investigation and results of these variations are not extensively reported here as results reported in this paper are confined to showing the possibility of membranes filtration of drilling wastes.

Results

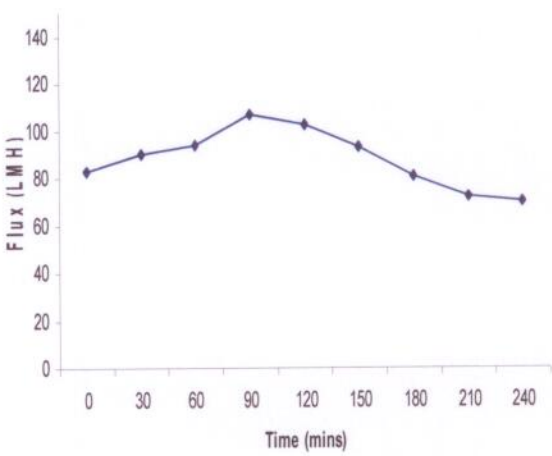

Figure 4: Flux over time of ceramic membrane filtration of field supplied lignosulphite WBM (Density 10 ppg, solids content: 10.2 % by volume)

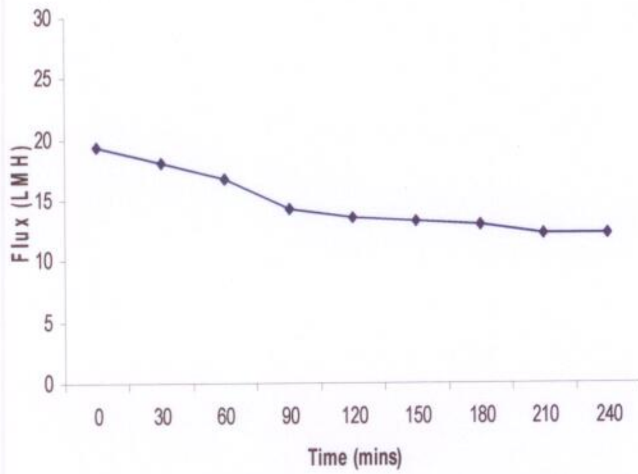

Figure 5: Flux over time of hollow fibre membrane filtration of field supplied lignosulphite WBM (Density 10 ppg, solids content: 10.2 % by volume)

After running the field supplied lignosulphite water based mud in both the tubular ceramic membrane and the hollow fibre membrane the flux over time is reported in figure 4 and figure 5 respectively. Tubular membranes have the lowest surface area to volume ratio when compared to other module configurations and this would explain the difference in the flux of the ceramic tubular membrane to the hollow fibre membrane. The conditions at which both tests were run was the least optimized conditions as the aim of the tests was to see the waste handling capacity of both modules when handling such solids laden waste, thus this is our baseline filtration. Filtration of the mud by the tubular ceramic membrane reached peak filtration after about 90 minutes, this unique gradual build up of flux is suspected to be caused by the interference of the mud solids plugging pores spaces and the inherent ability of muds to form a filter cake on the surface of the membrane. After reaching its peak, flux did not decline beyond 22% over the next two hour period. The Zenon unit has a high surface area to volume ratio, but primarily the test unit (figure 3) was not intended for our purpose but designed for wastewater filtration. Some design issues hindered its performance, for example a system with more fibre bundles than was in the test unit system would have improved filtration considerably. Still this design did not hinder the objective of assessing how hollow fibre membranes would handle solid laden wastes. The solids in the mud settled at the bottom of the unit as water was removed from the system and the waste concentrated, flux decline by 37% was observed before steady state filtration which seemed to occur between 90-120 minutes and after steady state there was a less than 5% decline in flux.

The solids content of the lignosulphite water based mud and the filtrates after filtration were measured using a mud retort. The solid content of the feed was 10.20 % by volume and the permeate samples from both modules were determined not to have any solids in them using the mud retort. A particle size analyzer, the Microtrac S300, was used to analyze the particle size distribution of the samples (feed, permeate and retentate), figure 6 and 7 show the particle size analysis of the feed and permeate of the lignosulphite mud (Permeate particle size distribution was similar in both modules; figure 7 represents permeate from both modules). The particle size distribution of the feed show a diverse range of particle sizes with the majority of particles falling within the 1-10 micron range and the about 30% within the 11-100 micron range. After the feed was run through the membranes the particle size distribution indicates most particles in the ultrafiltration range to be non-existence giving basically solids laden free permeate.

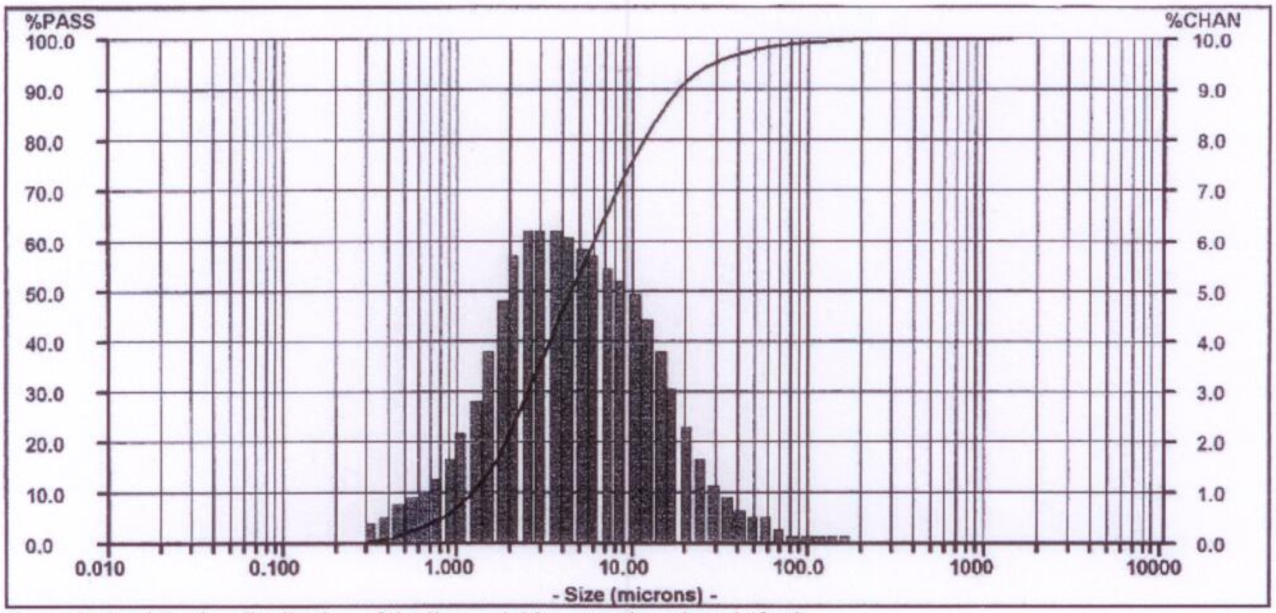

Figure 6. Particle size distribution of the lignosulphite water based mud (feed)

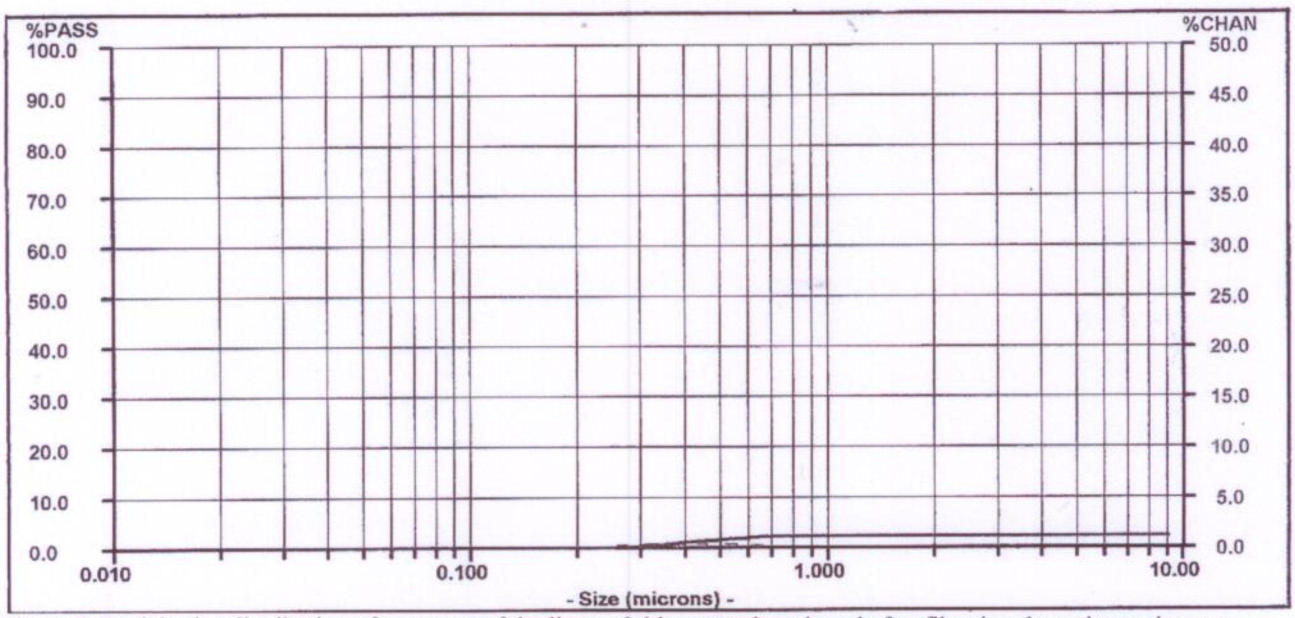

Figure 7. Particle size distribution of permeate of the lignosulphite water based mud after filtration through membranes.

Turbidity measurements were made of the samples also. The lignosulphite mud feed sample had 55200 NTU, the permeate from the ceramic tubular membrane had a measured turbidity of 6.86 NTU and permeate from the hollow fibre membrane had 7.44 NTU after membrane filtration. Surprisingly the turbidity of both permeate samples were close despite a 10 fold difference in their pore sizes. The dissolved character of the mud largely remained the same as ultrafiltration of the samples does not seem to affect the dissolved properties of the sample. Pictures of the feed and permeate from both modules are shown in figure 8 (appendix).

The laboratory prepared mud was also filtered using the ceramic membrane and the hollow fibre membrane. Larger micron size particles were simulated and added to the mud. The particle size range was significantly greater than the pore sizes of both membranes. The role of attrition causing smaller particles did not seem to affect filtration at least directly as flux rates were higher (figures 9 and 10) when compared to the lignosulphite mud filtration. With the tubular ceramic membrane a prescreen was needed as it was not practical to have the solids go through the membrane. A 10 micron prefilter was used but with the hollow fibre design the large particles easily settled to the bottom of the tank. Flux reduction in the hollow fibre membrane for the four hour period was less than 4% and for the ceramic tubular membrane it was about 7.5% after the initial hump, there was no recorded pressure rise in the hollow fibre membrane while the pressure rise in the ceramic tubular membrane was minimal. Turbidity measurement of the feed sample and permeate were made, the feed sample had a turbidity of 1670 NTU and permeate samples had a turbidity of 1.67 NTU, figure 11 (appendix) shows the picture of the feed sample and the permeate sample. It can be adduced that due to the absence of solids in the lower micron range (10-100 microns) filtration was easier and could be responsible for the higher fluxes. The particle size distribution of the permeate sample (not shown) was similar to figure 7 and the particle size distribution of the feed was more to the right of the particle size scale.

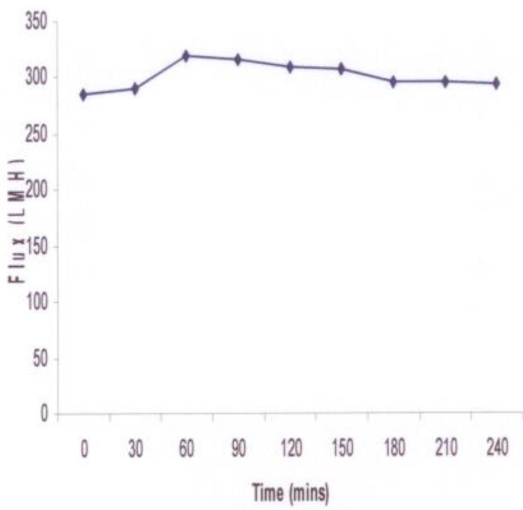

Figure 9: Flux over time of ceramic membrane filtration of lab made WBM
(Density 9.4 ppg, solids content: 5 % by volume)

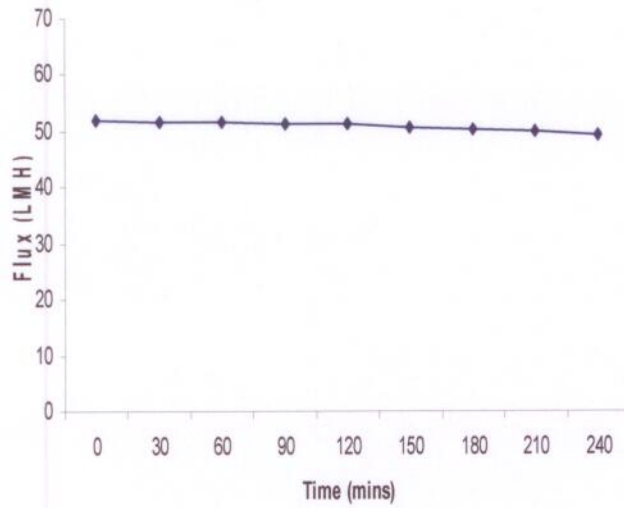

Figure 10: Flux over time of hollow fibre membrane filtration of lab made WBM
(Density 9.4 ppg, solids content: 5 % by volume)

Using the volume of the retentate, volume of permeate and volume of mud after filtration we calculated the percent volume of reduction. In the filtration of the lignosulphite mud using the tubular ceramic membrane we achieved a 61% volume reduction i.e. we reduced the volume of the mud by 61% leaving a concentrated retentate that was 39% of the initial mud volume and the rest was extracted water while in the hollow fibre module we achieved about 52% volume reduction of the lignosulphite mud. Higher volume reduction was achieved in the filtration of the lab based mud when compared to the lignosulphite based mud; the ceramic module achieved about 78% volume reduction while the hollow fibre unit achieved about 63% volume reduction.

As stated earlier we are investigating modifications that would help maintain filtration flux by lowering the propensity of fouling. One of such early investigation was to look at the effect of backflushing on the membrane flux. Backflushing usually entails forcing a fluid either permeate or air in the reverse direction of flow at pressure higher than the normal filtration pressure for a short period, this helps to unclog blocked pore spaces thereby reducing resistance to flux. For backflushing to be effective the fouling has to be physical in nature, fouling due to chemical interaction between the membrane and the feed sample would require chemical cleaning of the membrane. For these investigation we expect that flux decline would be mostly due to fouling of a physical nature (solids plugging the pores) than chemical interaction between the mud and the membrane at lest in the initial stages of filtration.

Backflushing in the traditional sense is mostly confined to ceramic membrane use but as explained in the operation of the Zenon Zeeweed unit above backflushing is incorporated in its system. We investigated the effect of backflushing on flux using the ceramic tubular membrane in the filtration of the lignosulphite mud, all conditions were maintained as previous experiments and all we did to backflush was to reverse flow at 90 kPA for 15 seconds. We chose the 120th minute and 180th minute time interval because in the previous runs flux decline was noticed at about those time intervals, figure 13 shows the result of backflushing. As we can see from the graph the decline was slowed down after backflushing and after the 180th minute backflush the flux rose similar to the previous flux, this shows that possible modifications in a design system can slow down flux decrease if such system is properly designed. Figure 4 and figure 13 compare the filtration with backflushing (right) and without (left).

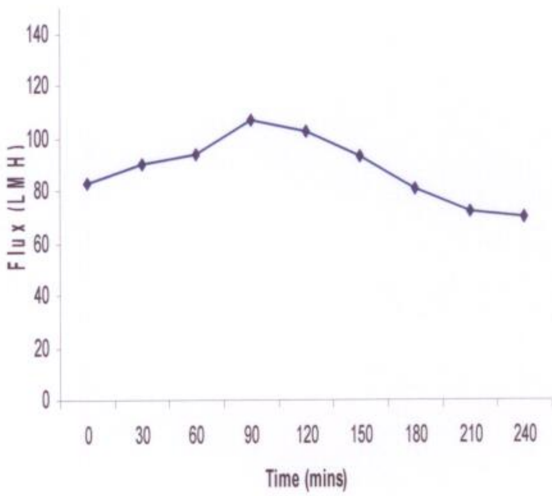

Figure 4: Flux over time of ceramic membrane filtration of field supplied lignosulphite WBM (no backflush) (Density 10 ppg, solids content: 10.2 % by volume)

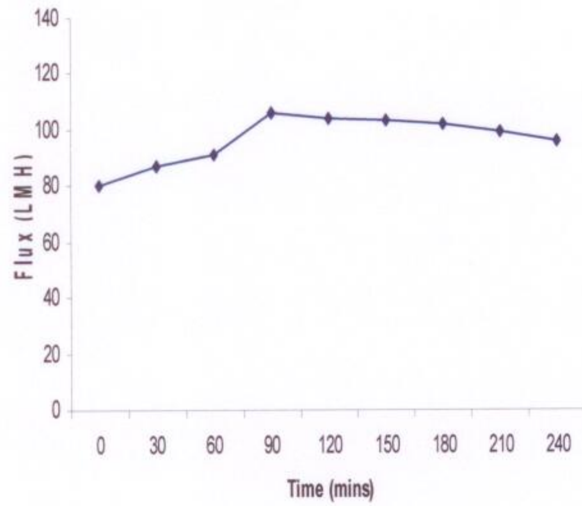

Figure 13: Flux over time of hollow fibre membrane filtration of field supplied lignosulphite WBM (with backflush) (Density 10 ppg, solids content: 10.2 % by volume)

Conclusion

We have demonstrated on a laboratory scale the filtration capability of membranes in processing drilling wastes. We have shown that there are possibilities in the engineering design of membrane systems to alleviate traditional challenges that face membranes in the filtration of solids laden wastes. Of importance is the realization that re-use and recycle of these water based wastes is dependent to a large extent on the concentration of suspended solids in these wastes, large concentrations of suspended solids (in the limit range of most traditional solids removal equipment) reduce the propensity of re-use. A qualitative comparison could be made of water based drilling wastes treated with traditional solids removal equipment versus membranes as shown in our study and it becomes clear that the limits of solids removal go a long way in determining the suitability of waste to re-use.

As shown from our results we had about 60% reduction in waste volume, this confers numerous advantages apart from the re-use of the extracted water from these wastes, an example of such an advantage would be the possible reduction in the footprint of drilling operations this portends. Excavations such as the reserve pits contribute largely to the footprint of drilling operations, with membrane filtration of wastes as a possibility during drilling operations, pits sizes could be designed to be remarkably smaller during planning stages due to the expected concentration of the waste, this would go along way in the reduction of the overall footprint of drilling operations complementing the reduction made over years in rig size. Also if wastes are to be hauled away, a reduction in the concentration reduces the volume to be hauled away. This reduced traffic reduces footprint as well as cost. Savings from concentrating wastes add up in reduced costs of hauling, reduced cost of purchasing fresh water and most importantly when the waste size is smaller it increases the viability of treatment options available to treat the wastes. With an estimated 30% of one's waste size previous treatment options, even environmentally friendly options deemed unrealistic due to the initial waste volume becomes realistic in the face of waste volume reduction.

A rational first step towards building sustainable re-use of water resources would be encouraging "in-house" reuse during drilling operations. Membrane filtration extracted water can be used in drilling operations such as in the mixing of muds (some dissolved constituents still in the extracted water might be a plus), rig wash and various operations where water quality in not necessary of or important. Huge pre-treatment costs hinder present desalination of produced water and other brines, Reverse Osmosis (RO) membranes used in desalination are very effective at desalination but extremely sensitive to solids, membrane systems such as the types described here would offer relatively inexpensive pre-treatment options for desalination aside from the other purpose of concentrating waste. The need for water resource recycle and re-use can not be overstated in the light of water concerns by stakeholders as stakeholders are requesting more water tracking from operators during their operations.

In conclusion, membranes have been around for a long period and are very effective at removal of solids. They find wide use in various industries and have reliably performed their operation in a cost effective manner when managed properly. Membrane systems are cost effective and the initial investments in them are moderate in relation to costs associated with drilling operations. The challenge is in the design and development of a system that can be seamlessly incorporated into drilling operations without much disruption of operation. Our investigations will continue by investigating the effects of operational parameters and how compositional and rheological parameters affect filtration. In the same vein we are looking into practical design issues aimed at ensuring durability of the system, easy operation and cost effectiveness amongst other practical issues.

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Products	Concentration (Ib/bbl)
Xanthum Gum	0.46
Salt Gel	11.1
Caustic Soda	0.46
Carboxymethylcellulose salt	0.96
Salt	52.5
Bentonite	4.62
Water	298

Table 1: Laboratory prepared mud recipe.

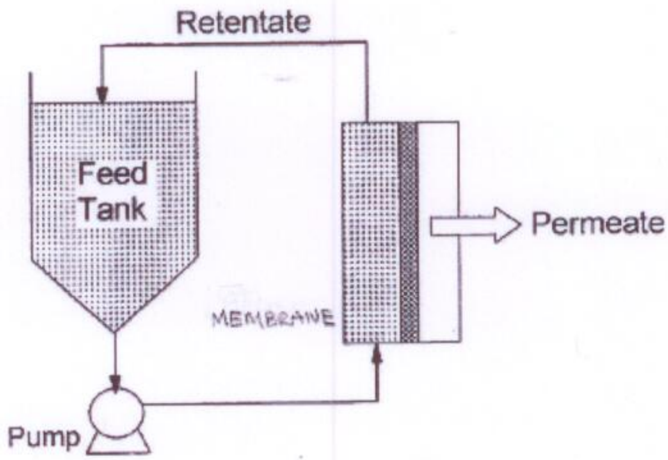

Figure 2. Schematic of Ceramic membrane filtration

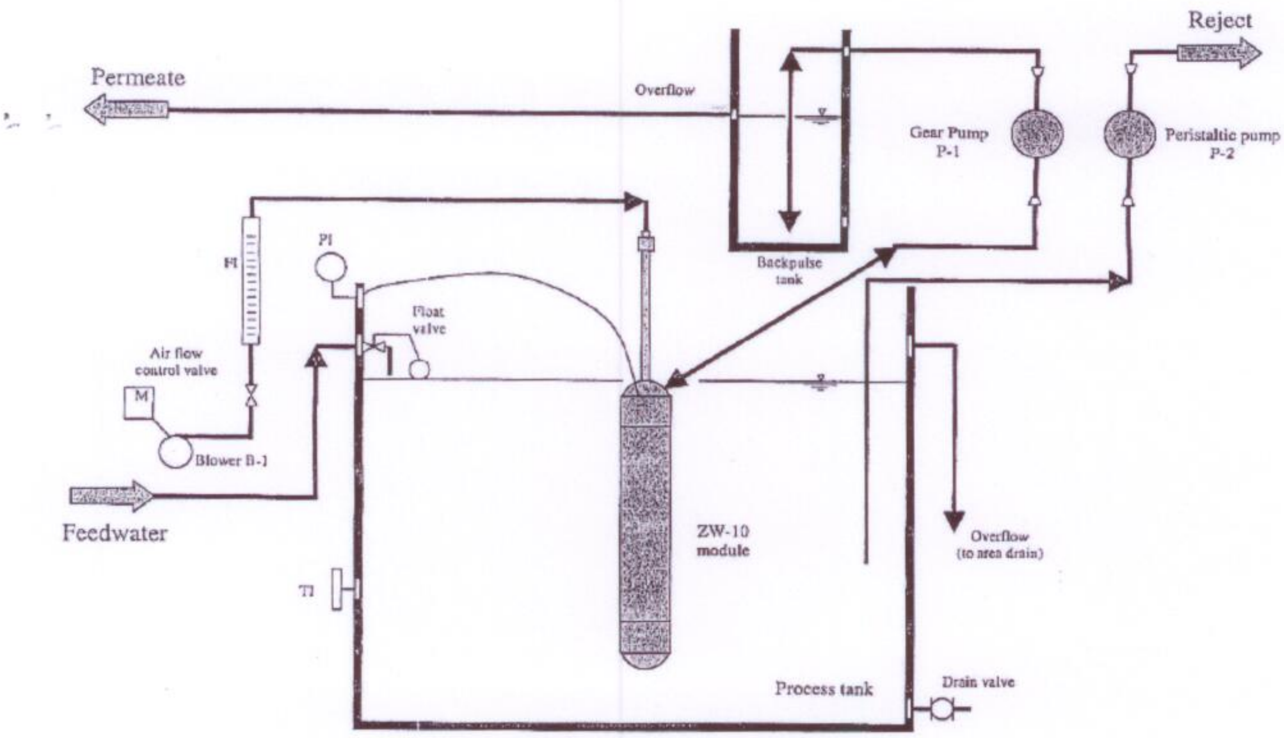

Figure 3. Schematic of hollow fibre membrane filtration courtesy of Zenon

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Figure 8. Feed sample (left) and permeate samples, ceramic tubular membrane, 0.005 micron (middle), hollow fibre membrane 0.04 micron (right) of field supplied lignosulphite WBM.

Figure 11. Feed sample (left) and permeate samples (right) of ceramic tubular membrane, 0.005 micron and hollow fibre membrane 0.04 micron of lab prepared mud.

SPE/IADC 119297

Well Design for Environmentally Friendly Drilling Systems: Using a Graduate Student Drilling Class Team Challenge to Identify Options for Reducing Impacts

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Abstract

The Oil and Gas industry is becoming more adept in reducing its impact on the environment and in showing optimal use of resources. This approach to environmentally friendly drilling offers the two-fold advantage of the reduction of the footprint of drilling operations while realizing savings by reducing waste treatment, hauling and remediation costs.

The Harold Vance Department of Petroleum Engineering at Texas A&M University has incorporated an Environmentally Friendly Drilling System (EFD) design into its PE 661 graduate drilling class. The "661 Team Challenge" semester project was assigned to the students to "design a well on paper" using low impact drilling technology. A systems engineering optimization protocol approach was utilized to incorporate a number of current and emerging EFD technologies into a single clean drilling system with no or very limited environmental impact. A web-based decision optimization tool was developed to follow the systems approach technology evaluation procedure and select an optimal system. The resulting well designs were judged as to their suitability for implementation in a protected wetland on the Texas Gulf Coast.

Introduction

The Harold Vance Department of Petroleum Engineering at Texas A&M University offers a series of five graduate courses designed to introduce Petroleum Engineering to new graduate students with a limited Petroleum Engineering Background. One of these courses is PETE 661 Drilling Engineering where we teach "drilling for non-drillers". Although this course is designed for non-drillers, there are a number of students with considerable experience in drilling who take the course as a refresher or for exposure to an alternate view of Drilling Engineering.

The Department also has an ongoing project in designing Environmentally Friendly Drilling Systems. Since researchers working on this project were in need of populating a data base of environmentally friendly technologies which could be utilized to limit the environmental impact of drilling operations a semester project was assigned to the students to populate this database and "design a well on paper" using low impact drilling technology.

Enrollment in the PETE 661 is open both to on campus students as well as those enrolled in our Distance Learning (DL) program. A major portion of a student's grade is for semester long projects such as the EFD planning. Most, but not all, of the local students fall into the non-driller or limited drilling experience category while many of the DL students are experienced Petroleum Engineers with at least some drilling experience. The novice drillers soon begin to network with the experienced drillers when they need help completing assignment. This behavior is encouraged by the professors that teach the class.

Most years the students are assigned a "standard" project where we provide them with data from sonic or resistivity logs from good clean shales. Whenever the opportunity arises where a non-typical project to be assigned however, we will assign the non-typical project. In the spring of 2008, the opportunity arose to assign another non-typical project that helped advance a research program, give the students an opportunity to team together on a real project topic and provide lessons in the importance of the environment when designing well operations.

Environmentally Friendly Drilling Systems

The A&M Environmentally Friendly Drilling (EFD) project was created to reduce the footprint of drilling and exploration operations through integration of advanced technologies. In the last four years it has become an industry leader in identifying, developing and promoting sound practices in development of our petroleum resources in onshore USA[1]. Its objectives are:

- To incorporate current and emerging technologies into a clean drilling system with no or very limited environmental impact.
- To define a viable drilling system (including transportation, testing, completion and production options) that could be used for exploration and exploitation of natural gas primarily in the lower 48 states in environmentally sensitive area and to test key enabling technology in the field.
- To represent a partnership of industry, academic and government partners developing methods to minimize well design costs while maintaining responsible drilling practices.

Statement of Goals and Significance of EFD

The 2007 National Petroleum Council (NPC) study[2] offered five "Core U.S. Strategies";
• Moderate Demand by Increasing Energy Efficiency
• Expand and Diversify U.S. Energy Supply
• Strengthen Global and U.S. Energy Security
• Reinforce Capabilities to Meet New Challenges
• Address Carbon Constraints

The study strongly recommended that the U.S. strengthen its technology base by rebuilding U.S. science and engineering capabilities. The study emphasized again and again the need for research and development opportunities.

New technological innovations are essential. Technology development has led to the development of unconventional petroleum resources. The Bakken oil shale resource is defined by the USGS[3] as a technology play i.e. because of technology developments. This oil shale can now be produced economically. This USGS estimate added 3.6 billion bbls of oil resource to the U.S. base (at $50 per bbl this equates to $180 billion dollars or roughly 6X the state's GDP (2007.)

However, new technological innovation is not enough. Development must be accomplished in an environmentally responsible manner. The NPC study did not specifically address environmental issues. Yet it is the environmental impact of following each of these strategies that is one of the major obstacles to achieving energy security. That is nowhere more evident than strategy to "Expand and diversify energy supply". The study calls for reducing the decline in U.S. conventional oil and natural gas production by increasing access for new energy development. Yet to do this one must consider the environmental factors – the chief reason why access has been limited in the past. [4]

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Low Impact Drilling Technologies can be Cost Effective

The Independent Petroleum Association of America (IPAA) and the Baker Institute recently reported to Congress that access to more Federal Lands is the primary way to increase domestic oil and gas production[4]. There is a tremendous volume of known, recoverable natural gas and oil located in environmentally sensitive areas in the United States. Many of these areas are on Federal Lands which are currently off-limits to drilling primarily because regulators. With more than 80% of public lands off limits (both on shore and offshore) to O&G explorations[5], the industry is developing new technology to address environmental issues. More than 40% of new drilling technologies reported in the past 8 years in the Society of Petroleum Engineers database also address environmental issues[6].

Congress and the environmental community are not convinced that technology is sufficient to develop these resources without adversely impacting the environment. While there are a number of technologies available to accomplish environmentally acceptable drilling, these practices are not widely adopted. The EFSD program has developed a way to organize these practices and to provide a way to adopt them in a cost effective manner.

Coordinating Technology: Systems Approach to EFD Design

A systems approach technology evaluation protocol was utilized.to incorporate a number of current and emerging EFD technologies into a single clean drilling system with no or very limited environmental impact, A web-based decision optimization tool was developed to follow the systems approach technology evaluation procedure and then select an optimal system for a given site[7]. This application provides quantitative basis for suggesting appropriate drilling systems, explicitly evaluates alternatives against selected criteria, uses best available information – both expert knowledge and data – in a coherent and logical way, and can help decision-makers with their choices of EFD technology for a given situation and best meet the goals of those involved.

Four main subsystems and thirteen subsets have been identified for the EFD operations after having interviews with more than five EFD experts. Table 1 shows an example of the EFD technology selection. Each path through the subset tables represents one example of a possible EFD system.

This quantitative decision tool is designed to help decision-makers select an optimal drilling system for a given site in order to minimize environmental impact and maximize profit. The evaluation protocol is refined based on EFD experts' inputs and feedbacks when necessary. The overall procedure is briefly illustrated as follows:

Step 1: Identify main subsystems and subsets for the EFD operation.
Step 2: List all technologies within each subset.
Step 3: Define attributes and develop attribute scales to evaluate technologies.
Step 4: Assign scores to all technologies using the attribute scales.
Step 5: For each attribute, calculate the overall attribute score of a system by adding the technology scores or selecting the minimum technology score.
Step 6: For each attribute and in order to homogenize the scores, develop a "utility function (u_i)" to convert the overall dimensional score of a system (e.g., $, acres, and grades) into a non-dimensional utility value (between 0 and 1) of the system.
Step 7: Decide on a weight factor (k_i) for each attribute (i^{th}).
Step 8: Calculate the overall score of the system as "$\sum k_i u_i$" (multi-attribute utility function).
Step 9: Use optimization technique to evaluate all systems and to find the best available system for a specific site. The best system means a system containing the highest overall score among all possible systems.

The Project Assignment

An independent operator is to drill five (5) wells on their lease in South Texas in an environmentally sensitive wetland area. The lease extends to the center of a lake on the McFaddin Ranch. **Fig. 1** The formation target is the upper Frio sand[8] at approximately 8500 ft. Well files for offset wells were made available on the class web site to be used as templates for the project. The operator has asked for well plans using low impact drilling technology so that the environment on the ranch is affected to the least extent possible since the Ranch is one of the preeminent sites in South Central Texas for wildlife conservation efforts and Ranch Stewardship programs[9].

The Goals

The goals of the project teams were to determine the optimum well designs that minimize impact on the environment and optimum return on investment. The well costs were determined by what processes the teams selected, the drilling costs and capital costs. The operator will utilize capital from investors to develop the field. Only well plans that employ technology used in other applications were to be considered.

The Well Design Basis

Teams had access to well design templates and well logs, AFE template, technical reports on low impact technologies, a database of technical experts available for assistance and a Systems Engineering Model that could be used for optimization of the project's selected technology.

Reporting Requirements and Grading

Team reports and presentations were to meet professional engineering standards. Well AFEs were to be accompanied by justification of the technologies chosen and included in the well plan. The AFE reports included the following sections.

- Cover letter (summarizing project AFE)
- Introductory Section (description of the project)
- Technology Chosen with justification
- Environmental and Safety
- References and Appendices (source of information used for technology selection, costs etc.)

Technologies Investigated

The class was split into teams with the students choosing their own members. Local students teamed with other local students and DL students teamed with other DL students. Four technologies were investigated as to environmental impact (e.g. solid, liquid, and gas waste, footprint, etc.) and cost. These five technologies were (1) Low Impact Footprint, (2) Light Weight Rig/Casing Drilling, (3) Zero Waste from Rig Site, and (4) Alternate Rig Power. Each team evaluated two technologies. The number of teams allowed for each technology to be evaluated by two local teams and two DL teams.

Results of Optimizing Technology for Low Impact Well Design

Rather than descibing all of the teams and their well designs, we elected to use a compilation of the various reports in order to show the efficacy of an optimization routine and to showcase certain new technologies.

Options for Low Impact Footprint

While the dirt and gravel roads typical of oil and gas operations do not have the same extensive impact that large, high-volume roads and highways create, there are still certain environmental problems associated with them.[10] Wooden mats and roads have been used for many years particularly in the oil and gas industry to provide temporary roads and pads for construction equipment and heavy trucks in areas that are environmentally sensitive or inaccessible due to poor soil conditions during the rainy part of the year Rolligon vehicles are used to transport heavy loads, personnel, products or equipment in sensitive areas. HexaDeck[11] and DURA-BASE[12] are portable roadway and heavy-duty flooring systems. These products can be used to create permanent or temporary pathways for vehicles, equipment, and pedestrians. Interlocking hexagonal tiles form a durable portable flooring surface for access and ground protection for oil and gas drilling operations, military deployments, and utility use.

Another attractive EFD technology considered for the low impact well design was the use of recycled drill site waste for road base material. Three companies offer these products for the industry; each has the necessary permits to deploy materials for O&G operations. An important advantage of these material is that they provide a way to re-use solid waste from drilling operations and lend themselves to remediation, that is they can be plowed into the soil after use and thus promote vegetative growth media where conventional gravel can difficult to remove efficiently.

Teams researched three techniques: conventional (Wood Chip Playset), composite mats (DURA-BASE) and conventional gravel site preparation. The road would be approximately 0.5 miles long and 24 ft wide. It must be designed to handle 36,000 lb loads with more than 50 truck loads of equipment and material. The assumption was that it would be remediated after the well has been drilled and completed. The assumption used for the well pad was sufficient mats to build a 2,000 ft^2 area to accommodate a light weight modular rig . **Table 2** shows the attributes of the three selections.

Options for Light Weight Rig/Casing Drilling

Teams considered two basic rig types, a conventional rig, and the new generation light weight top drive rigs. A variant of the light weight rig was also evaluated, one that enabled casing drilling operations and directional drilling. Teams preferred casing-while-drilling (CWD) technology[13] that offers a way to reduce the costs and environmental impact of drilling a well by reducing the footprint of operations .

The contest's assumptions were rental of a drilling rig and drilling period as 60 days, drilling to the Frio formation to a depth of approximately 10,000 feet[2]. The attributes of the various systems are shown in **Table 3**.

Top drive drilling has improved environmental attributes because of the elimination of drill strings, a reduction in drilling time, and a corresponding reduction in wastes from the well site operations. It is expected that industry will adopt the new technology when it becomes more readily available.

Options for Zero Waste From Rig Site, (A: Air Emission Control)

One of the biggest problems to address when planning drilling operations in sensitive areas is the emission from the diesel generator power packages. The team's approaches to a emission control system were to evaluate retrofit packages for conventional power. Four systems were compared for this project.

- Diesel Oxidation Catalyst (DOC)[14]
- Diesel Particulate Filters (DPF)[15]
- NOx Absorber Catalysts[16]
- Selective Catalytic Reduction (SCR)[17]

The description and costs for the systems were compared for the hypothetical light weight drilling rig option. **Table 4** shows the attributes for each system. The Table shows the relative "value" of each of the technologies as measured by their ability to reduce emissions and by their acceptance by the government, industry and the public. The higher cost subsets offer better emission control and would be preferred by the public, while the lower cost catalytic reduction processes are preferred by industry. For the McFaddin project, the less expensive option was selected because engine emissions at the location on the coastal plain were deemed not as critical as other areas.

Options for Zero Waste from Rig Site, (B. Brine & Drill Solids)

A typical well being drilled into the Barnett Shale generates as much waste in 90 days as a community of 4,000 people[18]. Handling this waste impacts the environment in a significant way, regardless of the area being developed. There are a number of new technologies being developed to recycle and reuse both liquid and solid waste from well operations but they have not been widely adopted because of the novel nature of the practices, or their expense. For the McFaddin Ranch, it was felt that controlling water discharge from the site, re-use of drilling solids, and minimization of truck transport to/from the well site was paramount. The teams researched options for the management of wastes and compared the options shown in **Table 5**.

In this instance, the need from minimal disruption of the coastal wetland was paramount. The preferred choice as selected by the well design team were (1) to treat waste water at the rig site and (2) to re-use well drill solids in a new road base material for access roads.

Options for Alternate Rig Power

Teams that were required to investigate alternate power systems found that the most cost effective and technology ready option was to use engines designed (or modified) to run on natural gas. Second most effective was to use diesel power re-equipped to reduce particulate and exhaust gas emissions. **Table 6** compares two power systems, the option employing natural gas engines having superior attributes but at an increased cost.

By utilizing a less costly fuel, rig operations employing the more expensive natural gas power recoup a significant portion of the added expense of the natural gas fired engine. The Table shows average fuel use for the two options.

For the scenario studied, a natural gas fired engine would save more than $130,000 in fuel costs over a 60 day drilling period. Concomittantly emissions were cut by a factor of 7 over traditional diesel power. Finally truck transport of fuel to the rig site was eliminated.

Options for Drilling Fluids & Cuttings Management

For cuttings management **Table 7** tabulates the cost of each option. The options show that cuttings injection is the most likely selection since bioremediation is slow and other options are either more expensive or impractical for the McFaddin Ranch site. Cuttings injection down the annulus of the well assumes that more than one well is being drilled in the development. In this instance, the leaseholder was planning to drill five wells so the team was allowed to include this option in their systems optimization.

Options for Produced and Flowback Water Management

In light of the evolving stringent regulatory standards and in demonstrating good stewardship of the environment, the O&G industry is expected to be active in reducing the footprint of its various activities on the environment by developing solutions that will reduce the size of reserve pits needed in drilling operations and achieve significant waste volume reduction through the extraction of water from drilling wastes. This approach to dealing with drilling wastes confers the two-fold advantage of optimal use of water resources through re-cycle and the reduction of the footprint of drilling operations well within reasonable economic costs by saving significant waste treatment, hauling and freshwater costs[19]. **Table 8** summarizes the options for water management at the rig site. The teams noted but did not allow for beneficial reuse of membrane treatment and recovery of water for reuse.

Optimization of Technologies; Results of Competition

Rather than compare all of the Team Challenge results, we chose to select the optimal system that contained all of the tecnologies which had been identified and characterized by the students. In order to provide a minimal footprint impact during drilling operation, the preferred system utilized a light weight rig that incorporated casing drilling as an option. The rig site and the access roads were constructed of biodegradable wood byproducts and reusable composite mats. The smaller and lighter weight rig allowed the creation of a smaller rig site and a less expensive access road. The rig was powered with natural gas engines that also reduced load weight and frequency of transport trips for fuel.

The drilling operation took advantage of lower emissions from the natural gas powered rig and used on-site treatment of waste brine to provide fresh water for drilling operations. Solids from drilling were concentrated as described by Oluwaseun[19]. The combination of all of these technologies described will meet the criteria for an environmentally friendly design, leaving little to no footprint. **Table 9** lists the EFD technologies best representing low impact choices. These choices were specifically chosen for the coastal margin in Texas. Cost figures have been omitted because of the specificity of locations and services available. Relative costs of EFD options are discussed by OK-Youn Yu[7].

Conclusions

The Team Challenge provided a number of positive results to its participants. First, the class members learned first hand of some of the newer technologies available to drilling contractors and operators available for lessening the impact of drilling operations. Next the landowner (McFaddin Ranch personnel) learned of the cost benefit of certain technology some of which could not be justified based on its expense. The exercise provided an excellent “field test” in itself of a EFD optimization system with almost 60 students using the optimization model to select the most appropriate practices to include in their well designs. Lastly, by having such a large group searching for data, the developers of the software populated the database of technologies with actual cost numbers and contact information. At the conclusion of the study more than 100 different techniques had been identified, characterized and catalogued.

Did the students find the optimization model useful? The answer was an unqualified yes as shown by a summary of the responses to a questionnaire distributed at the conclusion of the semester (**Figure 1).** Almost 75 % of the class felt that the program helped select optimal systems for their well designs. (A compilation of individual responses is contained in the Appendix).

Appendix

QUESTIONNAIRES ABOUT THE WEB-BASED DECISION OPTIMIZATION APPLICATION [Version 1.1]

1. What do you think the biggest advantage of using the Web-based decision optimization application is?

- Well guided for selecting the options
- It optimized the data for us
- It allows you to consider impacts based on factors other than cost-like environmental effects
- It allows you to weigh the options
- You can weigh the options
- Generate optimized values based on weight factor we want to assign
- Convenience
- Brings out the best combination scenario for any particulate area
- We managed to use the system efficiently and the system was able to optimize our data
- It relates the perception value to a dollar amount
- Each section is very systematic
- Easy to input ➔ location, ➔ multiple users
- We can keep the video as note and choose the part that we need to review
- Easy, handy, and comprehensive
- Eases the calculation
- Making the decision simple
- This will be helping to organize the input and output process of the information
- Pulling data from multiple sources, and consolidation of sources
- Time saving
- Optimizing function. Easy, quick and efficient
- Give a good idea about technologies and methods for different areas
- Ready made cost and perception
- Being impacts based on factor and not only upon cost/ environment
- It lets you grade different attractive using weighting factors appropriate for each criterion. It makes it easy to evaluate alternatives since it outputs the best combination
- There is a consistent rubric that forces every group to consider the same factors
- Makes the optimization easier
- Does weighting technique extremely well. Very easy to use
- Ready made cost and perception
- Yes, the options were elaborate and therefore selecting was not cumbersome
- Yes, it's fairly easy to use and understand with basic knowledge of software and optimization principles
- No, setting up the system was complicated in the beginning. Making our own modifications was difficult
- I did not think it was super easy to use. It was difficult to set up
- Basic design of each action item might be not independent
- Fairly easy. Requires basic knowledge
- It's easy to use but some more explanation about how the perceptions should be chosen (i.e., 1 is what, 0 is what, what your answer represents?)
- Yes, but how to input the weighting factors was a bit confusing
- It was hard to start, but the example posted by Dr. Burnett was very helpful
- Application is easy enough to use but not flexible
- Result sheet
- Yes, but it is not practical
- Yes, but it does not have "Save as" option
- Some data were hard to obtain (e.g., perception from industry and public)
- No, it was very complex. It took us a lot of time to understand how to determine the

points. It is also wage

- Most difficult part was to access the values to the emissions and what the public and government would think
- Modification not easy after set up
- The application is decently easy to use. The log in and user interface need to be improved
- Was easy but only if you explored it a little
- Yes, but if possible, develop a calculation for specific scenarios

2. Which part should be modified soon for the application?

- Maybe give a "Set-up" section with instructions
- Good instructions on what to do
- Better instructions on what to do and how to use it
- Some errors found in the results
- Put more description about scoring
- Not very familiar with system
- A little more instructions
- More instructions
- It would be good to simplify the process of inputting weighting factors.
- Perceptions are hard to estimate
- A percentage of power input, or power supplied needs to be added
- Can we show every step for the calculation?
- Minimum number of technologies analyzed should be less than 4
- The weighting point section
- The optimization matrix assumes that
- The factors and weight that are inserted are difficult and cumbersome to determine. Some fixed costs (standards) should be fixed
- Units should be made consistent
- The result summary page
- The optimization matrix assumes that power will be constant
- The outputs generated. I am not aware if there is a tutorial and manual on how to use it. Because not many teams used the application for
- Diesel costs and includes as many different types of rigs as possible.
- If you do not want to select a technology from a certain Subset, just skip it. (Do not need to fill out "0" for that).
- Should be more specific details about perception factors
- Make it more secure. Want some permission thing
- Can be a powerful and very useful tool
- More examples would be helpful
- If you can add an option of populating the results in a pdf file
- Give options to input and remove parameters
- Neatly charted and user friendly
- Include columns for fixed cost and daily costs and give direction on how to prorate capitalized costs. Needs to be more finance based in order to find the present net values for the wells
- Matrix versatile
- Lab view type design
- I think the outputs which the application generated. For team "International" some of the options generated by the application were conflicting. As one of student pointed out the application gave lot of options for power all together at once even for team "Green Aggies" the program generated Biodiesel and Fuel cells together.
- Unique and informative source
- Not really, it's perfect (^^)

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Figure 1. River Wetlands Terrain on McFaddin Ranch

Table 1. The structure of EFD Operations: A Systems Approach

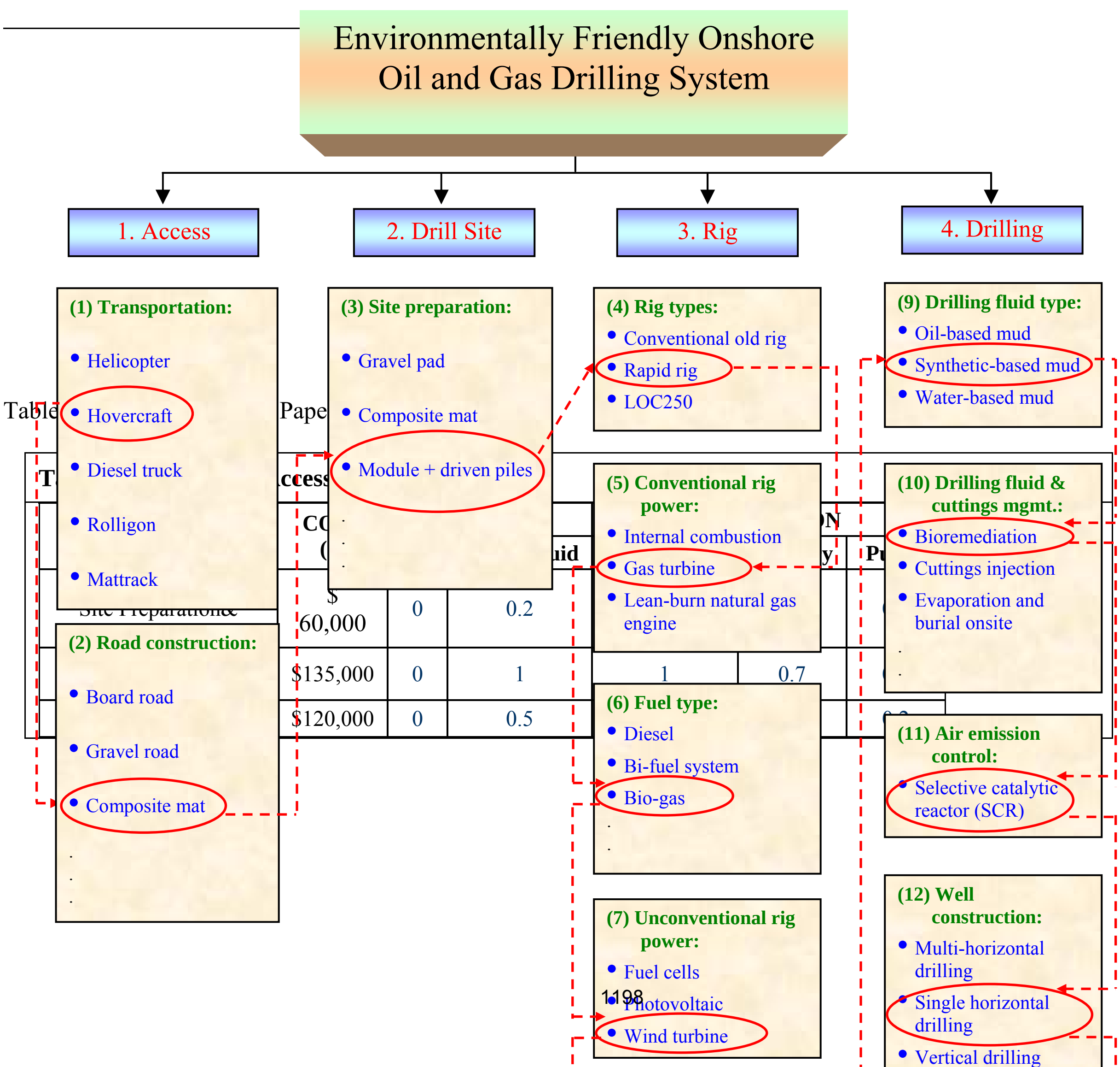


Table 3. Low Impact Technologies: Drilling Rigs

TECHNOLOGIES	COST ($)	FOOTPRINT (Acres)	EMISSION		PERCEPTION		
			Air	Solid/Liquid	Govt.	Industry	Public
conventional rig	1,200,000	1.581 (6400 m^2)	0.2	0.2	0.2	0.2	0.2
IDM Quicksilver	1,500,000	0.574 (25000 ft^2)	0.5	0.5	0.5	0.5	0.5
H&P Flex3	1,500,000	0.826 (36000 ft^2)	0.3	0.5	0.5	0.5	0.5
Nov IDEAL	1,800,000	0.906 (39474 ft^2)	0.75	0.75	0.75	0.75	0.75
Huisman Top Drive Casing Drilling	2,000,000	0.906 (39474 ft^2)	0.9	0.9	0.9	0.75	0.9

Table 4. Air Emissions Control for Diesel Gen packages

Subsets	Total Costs ($)	Ecological Footprint (Ac.)	Emissions		Perceptions		
			Air	S/L	Govt.	Industry	Public
Diesel Oxidization Catalyst (DOC[5]	*$23,000*	*0*	*0.4*				*0.4*
Diesel Particulate Filters (DPF)	$50,000	0	1.0				1.0
NOx Adsorption Catalysts	$51,000	0	0.8				0.8
Selective Catalytic Reduction (SCR)	$121,000	0	0.8				0.8

Table 5. EFD Choices for Zero Waste Discharge from Well Operations

Subsets	Total Costs ($)	Ecological Footprint (Ac.)	Emissions		Perceptions		
			Air	S/L	Govt.	Industry	Public
On site Brine Cleanup and Desalination	*$20,000*	*.25*	*0.9*	*0.9*	*0.5*	*0.4*	*0.4*
Annular injection of waste	$50,000	.1	0.6	0.6	0.6	0.6	1.0
Transport to offsite disposal	$51,000	5	0.1	0.1	0.3	0.6	0.8
Solid waste conversion to roadbed material	*$60,000*	*.4*	*0.8*	*0.8*	*0.6*	*0.4*	*0.8*

Table 6 Fuel Types source: http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm

Fuel Type	Power avg	Fuel consumption rate	For 60 days of operation	Cost
Diesel	700 hp	224.7 lb/700hp	46228 gal	$191,521
Natural Gas	700 hp	4732700 Btu/700hp	6815088000 BTU	$61,825

Table 7. EFD Techniques for Handling Drill Cuttings

Bioremediation	500 $/m^3	0.02 $/ft^3
Incineration	90 $/MT	90 $/MT
Land-spreading & Land-farming	4-5/ft^3	5 $/ft^3
Thermal treatment technologies (DWMIS)	75-150/ton	100$/ton
land fills	9-10/bbl	2.5$/ft^3
Underground cavern injection	2-6/bbl	1.5 $/ft^3
composting	40-70/bbl	15 $/ft^3
cuttings injection	7-8/bbl	2 $/ft^3

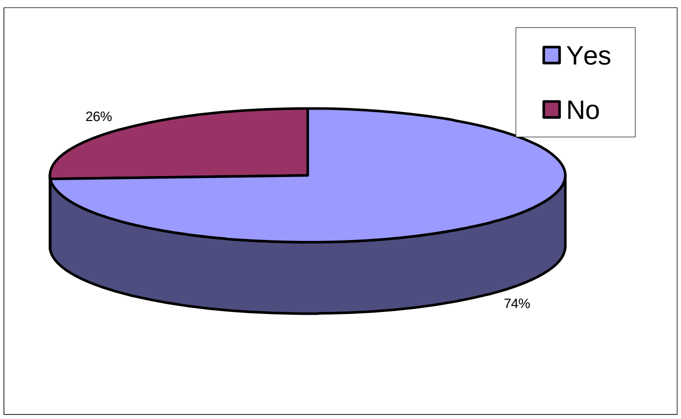
Table 8. EFD Techniques: Produced Water and Flow Back Brine

Membrane Treatment and Re-use	$1.00 to $3.00/ bbl	Beneficial reuse credit
Thermal treatment technologies	$2.00 to $5.00/ bbl	
Transport offsite and SWD injection	2-6/bbl	+ diesel surcharge

Table 9. EFD System for Drilling Low Impact Well vs. Conventional

Subsets	Conventional	EFD System
(1) Transportation	Conv. Diesel truck	Low sulphur diesel truck with noise suppressor
(2) Road construction	Gravel road	Wood Mat (rent)
(3) Site preparation	Gravel pad	Wood Mat (rent)
(4) Rig type	Conv. vintage rig	Rig-FlexRig 4
(5) Rig power (conv.)	Internal combustion	Lean-burn natural gas engine with noise suppressor
(6) Fuel type	Conv. diesel	Natural gas
(7) Rig power (unconv.)	N/A	Electric power from grid (10%)
(8) Energy storage	N/A	Flywheel
(9) Drilling technology	Conv. overbalanced	Managed pressure drilling with noise suppressor
(10) Fluid type	Water-based mud	Water-based mud
(11) Waste management	Lined reserve pit	Closed loop + container
(12) Cuttings treatment	Cuttings injection	Bioremediation
(13) Noise reduction	N/A	N/A (used suppressor for engine itself)

Table 10 Results of Survey of Users of Optimization Software



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Systems Approach and Quantitative Decision Tools for Technology Selection in Environmentally Friendly Drilling

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Abstract

One of the petroleum industry's goals is to reduce the environmental impact of oil and gas operations in environmentally sensitive areas. To achieve this, a number of Environmentally Friendly Drilling (EFD) technologies have been developed to varying degrees but few have been integrated into a field demonstrable drilling system (i.e., combination of technologies) compatible with ecologically sensitive or off-limits areas.

The main purpose of this paper is to present a decision-analytic technology selection process. The proposed method is based on a systems analysis that can be used for integrating current and new EFD technologies into an optimal EFD system. The system draws upon a large number of technologies (more than 100) identified by a government-industry joint venture studying low impact operations in sensitive ecological areas. In order to provide flexibility to the user, a small number of systems (1~5) are proposed for a given site, instead of a single best system. An optimization scheme is suggested based on a combination of multi-attribute utility theory and exhaustively enumerating all possible technology combinations to provide a quantitative rationale and suggest the best set of systems according to a set of criteria, with the relative importance of the different criteria defined by the decision-maker. This methodology is designed to help decision-makers select an optimal drilling system for a given site in order to minimize environmental impact and maximize profit at that specific site.

An application of the proposed approach is described by conducting a case study in Green Lake at McFaddin, TX; some of the difficulties in using this approach in practice are also discussed. This paper describes the results of the case study which provided a more logical and comprehensive approach that maximized the economic and environmental goals of both the landowner and the oil company leaseholder.

Introduction

Petroleum industries endeavor to develop technologies to minimize the environmental impact during drilling operations in environmentally sensitive areas because they realize effectively managing environment will lead greater access to large potential reserves in environmentally sensitive areas that are currently off-limit (Rogers et al. 2006). For example, directional drilling technology has allowed the industry to contact almost 60 times the volume of subsurface rock material that could be accessed in 1970 while occupying only one-third the surface area (Harrison 2005). Recent studies conducted by the Department of the Interior estimate that federal lands contain more than 20 billion barrels of untapped oil – most of which is currently off limits to drilling primarily due to state and federal regulations. Since EFD technologies can greatly reduce the above-ground footprint as well as the risk of spills, those off-limits areas might become accessible with greater adoption of EFD systems in the near future.

Even though a number of EFD technologies and concepts have already been developed to varying degrees, they have not been integrated into a field demonstrable drilling system compatible with ecologically sensitive or off-limits areas. Such sensitive areas include wetlands of the Gulf Coast and federal lands in the Western U.S. In general, it is difficult to select the best combination of EFD technologies for a given site because there are many possible combinations and many different and perhaps competing evaluation criteria.

A quantitative decision tool has been developed based on a system analysis to synergistically incorporate a number of current and emerging EFD technologies into a single and clean drilling system with limited environmental impact. This tool will help decision makers select an optimal drilling system for a specific site to minimize impact and maximize profit at that specific site. Since an exhaustive search optimization technique is a simple, practical and very robust method for this problem given the speed of modern computers (Cover et al. 2007), it is combined with multi-attribute utility theory to evaluate all possible systems in a quantitative basis and to suggest the best set of systems according to a set of attributes, with the relative importance of the different attributes defined by the decision-maker.

In this paper, we describe how systems analysis with decision-analytic methods could be used as part of the technology selection process, we introduce an application of our quantitative decision tool in Green Lake at McFaddin, TX, and we discuss the opportunities and limitations of our tool in future practice.

Systems Approach for Technology Selection in EFD

A systems approach to technology evaluation is designed to help decision-makers select an optimal drilling system for a given site. This evaluation protocol is an established solution to optimize decisions and ensures that the system selected satisfies chosen criteria called attributes. It can be refined based on EFD experts' inputs and feedbacks if necessary. Future interaction with appropriate experts would be valuable in revising this evaluation protocol. The steps to arrive at the best drilling system for a specific site are briefly illustrated as follows:

- Step 1: Identify the main subsystems and subsets for the EFD operation.
- Step 2: List the available technologies within each subset.
- Step 3: Define attributes and develop attribute scales to evaluate technologies.
- Step 4: Assign scores to all technologies using the attribute scales.
- Step 5: For each attribute, calculate the overall attribute score of a system by adding the technology scores or selecting the minimum technology score.
- Step 6: For each attribute and in order to homogenize the scores, develop a "utility function (u_i)" to convert the overall dimensional score of a system (e.g., $, acres, and grades) into a non-dimensional utility value (between 0 and 1) of the system that reflects the decision-maker(s) value.
- Step 7: Decide on a weight factor (k_i) for each attribute (i^{th}).
- Step 8: Calculate the overall score of the system as "$\sum k_i u_i$" (multi-attribute utility function).
- Step 9: Use optimization technique to evaluate all possible systems and to find the best available system for a specific site. Once all possible systems have been evaluated, the system with the highest overall score is the best system.
- Step 10: Conduct a sensitivity analysis to examine the impacts of possible changes in the attribute scores, weight factors, and utility functions on the optimal system.
- Step 11: Suggest a small number of systems that should be attractive for a given site.

By performing the procedure illustrated above, this decision tool provides a quantitative basis for suggesting appropriate drilling systems, explicitly evaluates alternatives against selected criteria, uses the best available information – both expert knowledge and data – in a coherent and logical way, and can help decision-makers with their choices of EFD technology for a given situation and best meet the goals of those involved.

An application of the proposed technology evaluation approach is described by conducting a case study in Green Lake at McFaddin, TX. How to evaluate all possible systems with given information is fully described in the following sections.

Application of the Proposed Technology Evaluation Protocol

In order to test the proposed evaluation protocol in a real site and then to refine the protocol, a case study is conducted in Green Lake at McFaddin, TX. It is assumed that an independent operator is to drill a well on their lease in South Texas in an environmentally sensitive wetland area. The lease extends to the center of Green Lake on the McFaddin Ranch (Figure 1). The formation target is the upper Frio sand (Hovorka et al. 2001) at approximately 8500 ft in vertical depth. In order to protect the ranch as much as possible, low impact drilling and utilizing the very best drilling system is extremely important. The step by step procedures to arrive at the optimal drilling system for this site are fully described in this section.

Step 1: Identify Main Subsystem and Subsets for the EFD Operation.
Four main subsystems and thirteen subsets have been identified for the EFD operations as shown in Figure 2.

Step 2: List Available Technologies within Each Subset.
Three different systems are pre-specified by an EFD expert in order to identify possible drilling technologies for Green Lake drilling site as shown in Table 1. A list of EFD experts contacted is available from the author. Although the technology

list shown in Table 1 is not an exhaustive search, what it shows is the current and state of the art technologies for onshore oil and gas drilling operations. The Figure 3 shows an example of the EFD technology selection. Each path through the subset tables represents one example of a possible EFD system.

Step 3: Define Attributes and Attribute Scales.

An attribute is one of the parameters considered in the evaluation of the system (e.g., cost, land area, emission, perception, and safety). Each attribute has an attribute scale used to score the technology on how well it meets the objective for this attribute (e.g., minimizes cost, footprint, emission, and maximizes positive perception and safety value). In order to evaluate available technologies for onshore oil and gas drilling projects against each attribute, attribute scales that explicitly described their possible impacts on a project need to be specified (Keeney and Raiffa 1976). Nine attributes and their draft scales as defined by EFD subject matter experts are given in this section. These attributes should be both comprehensive and measurable (Keeney and Raiffa 1976) but it should be noted that the attributes do not need to be directly measurable entity (i.e., $ and acres). Constructed attributes (i.e., perception) can be, and often are, used instead (Keeney 1992). The attribute scales developed in this section are draft scales and thus further interaction with appropriate experts would be valuable in revising these scales.

1. Total cost (x_1) = if purchasing a technology, then it is suggested to assume the resale value of the technology so as to estimate the total expenditure for the technology during the drilling operation. In this research, the resale value is assumed as 80 % of the original technology cost. On the other hand, if renting a technology, then a daily rate of the technology is required to estimate the total expenditure during the drilling operation; minimizing cost is preferred.

2. Ecological footprint (x_2) = the total used land area in acres; minimizing ecological footprint is preferred.

3. Emissions of Environmental Protection Agency (EPA) and state regulated air pollutants (x_3) = it is suggested by an environmental expert to consider three air contaminants (i.e., CO, Nox, and PM) for this attribute. The relative importance of those contaminants is CO (20%), Nox (40%), and PM (40%) as shown in Table 2. Table 2 shows an example of how to calculate air emission score for each technology. First, estimate three contaminants' real value for each technology in pounds per operating hour. Second, in order to get an overall air emission score for each technology, transform each contaminant's score into a non-dimensional score (U-value) between 0 and 1 using the proportional scoring approach, (x – worst score)/(best score – worst score). In this calculation, the best and worst scores should be obtained among all possible technologies being used. Finally, calculate the overall air emission score of a technology as $\sum k_i u_i$ (where k_i is a weight factor for each air contaminant, u_i is a non-dimensional score for each contaminant). This approach allows the decision-maker to make all air emission scores uniform and comparable; minimizing air emissions is preferred.

4. Emissions of EPA and state regulated solid and liquid pollutants (x_4) = the ordinal draft scale was constructed by an EFD subject matter expert as shown in Table 3; minimizing solid and liquid emissions is preferred.

5. Emissions of EPA and state regulated noise pollutants (x_5) = according to Occupational Safety & health Administration (OSHA), the eight-hour time-weight average sound level (TWA), in decibels, is recommended as the noise emission's scale. TWA may be computed from the dose, in percent, by means of the formula: TWA = 16.61 log(D/100) + 90. D is the noise dose, in percent: D=100 C/T (where C is the total length of the work day, in hours, and T is the reference duration corresponding to the measured sound level, L in decibel). $T = 8/2^{(L-90)/5}$; minimizing noise emission is preferred.

6. Government, as regulators, perception (x_6) = the ordinal draft scale was constructed as shown in Table 4; maximizing government perception is preferred.

7. Industry, as decision makers, perception (x_7) = the ordinal draft scale was constructed as shown in Table 5; maximizing industry perception is preferred.

8. General public perception (x_8) = the ordinal draft scale was constructed as shown in Table 6; maximizing public perception is preferred.

9. Safety value (x_9) = the ordinal draft scale was constructed as shown in Table 7; maximizing safety value is preferred.

It is required that these attributes and their scales discussed above be revised and restructured, if necessary, through a series of meetings with EFD subject matter experts until the attributes are clearly and meaningfully defined and meet the independence assumptions implied by our use of an additive utility function. These nine attributes are assigned to each available technology. In this paper, it is explicitly assumed that the attributes are independent for each possible technology in conducting the technology evaluation over one attribute at a time. In discussions with subject matter experts to date, this assumption seems reasonable.

Step 4: Assign Scores to All Technologies Using the Attribute Scales.

In order to evaluate available technologies with respect to the nine attributes (i.e., x_1 through x_9), EFD subject matter experts' inputs, basic assumptions, and other references are used as shown in Figure 4. Figure 5 briefly shows an influence diagram of each subset in a typical drilling site. As can be seen in Figure 5, attribute scores of a technology can be correlated with attribute scores of another technology in a different subset. For example, different rig type causes the variation of total drilling time and total drilling time varies total cost of technologies within many subsets.

Moreover, selected technologies within subset (5) through subset (8) shown in Figure 2 are mutually related each other as shown in Figure 6. For example, the number of possible fuel types for a conventional power generation engine varies by what kind of engine is selected, and whether using an energy storage device or not should be dependent on whether an unconventional power generation method is used or not. If it is decided not to use an unconventional power generation method, an energy storage device is not necessarily considered as a subset in the "Rig" subsystem. In this technology evaluation, the range of unconventional power usage is varied from 0% to 30% of total power usage.

The construction strategy and constraints for the "Rig" subsystem are specified as shown in Figure 6. Figure 7 shows an example of input spreadsheet used to score technologies in several subsets. The cost, footprint, and emission scores of a technology in subset (1), "Transportation", are not included in the input spreadsheet because those scores are already included as a mobilization part of technologies within other subsets. For example, the cost of gravel road shown in Figure 7 includes material, mobilization, and installation costs.

Step 5: Calculate the Overall Attribute Score for Each Attribute.

After each technology is evaluated with respect to the nine attributes (i.e., x_1 through x_9), for each attribute, the overall attribute score of a system is calculated by adding the technology scores of the system or selecting the minimum technology score of the system. The addition of individual scores is used for attributes such as cost, footprint, and emission as shown in Eq. 1 while the minimum score is used for attributes such as perception and safety as shown in Eq. 2. The overall score on the i^{th} attribute (X_i) is:

$$X_i = \sum_{n=1}^{N} x_{in}\, y_n \quad \text{for attribute } x_1 \text{ and } x_5 \text{ (i.e., i = 1 to 5)} \tag{1}$$

$$X_i = \mathrm{Min}\left[x_{in}\, y_n\right] \quad \text{for attribute } x_6 \text{ through } x_9 \text{ (i.e., i = 3 to 9)} \tag{2}$$

where n is the index for possible technologies, N is the number of possible technologies, i is the index for the attributes, x_{in} is the score of the n^{th} technology on the i^{th} attribute, and y_n is a binary decision variable that is one if n^{th} technology is selected and zero if it is not.

The constraint required to consider is:

$$\sum_{n=1}^{M} y_n = 1 \quad \text{for each subset except subset (7), (8), and (13)} \tag{3}$$

where n is the index for possible technologies, M is the number of possible technologies within each subset, and y_n is a binary decision variable.

One technology should be selected within each subset except subset (7), (8), and (13) shown in Figure 2. Subset (7), (8), and (13) are optional. Figure 8 shows the overall attribute score for each attribute of a system. As can be seen in Figure 8, the overall scores of cost (x_1), footprint (x_2), and emissions (x_3 through x_5) are calculated by summing the scores of technologies selected within each subset. The overall scores of perceptions (x_6 through x_8), and safety (x_9), however, are calculated by choosing the worst score among technologies selected within each subset for a system because it is suggested that perception and safety values should be considered on the systems level not on the individual technology level.

Step 6: Develop Utility Functions for Each Attribute.

A utility function is a relationship between the dimensional attribute score (e.g., $, acres, and grades) and a non-dimensional number (between 0 and 1) that captures decision-maker preferences. The utility function is used to transform all scores into non-dimensional values between 0 and 1. This allows the decision-maker to make overall attribute scores for each attribute uniform and comparable. Once the overall attribute score for each attribute of a system is calculated with respect to the nine attributes (i.e., x_1 through x_9), for each attribute (i) and in order to homogenize the scores, a utility function (u_i) needs to be developed to convert the overall dimensional score of a system into a non-dimensional utility value (between 0 and 1) of the system.

The proportional scoring approach is mainly used in this paper to develop a single-attribute utility function. This can be revisited as needed based on interactions with EFD subject matter experts. A general formula for the proportional scoring approach is given by:

$$u_i(X_i) = \frac{X_i - \text{Worst Score}}{\text{Best Score} - \text{Worst Score}} \tag{4}$$

where X_i is the overall score on the i^{th} attribute of a system.

Figure 9 shows the utility function curve used for the cost attribute. As can be seen in this example, first maximum and minimum values for total cost are obtained. It is found that the range should go from \$0.78 million dollars to \$1.9 million dollars, where obviously less total costs are preferred to greater ones. Thus, to remain consistent with the scaling rule where the utility functions ranged from 0 to 1, it is defined u_1 (\$0.78 M) = 1 and u_1 (\$1.9 M) = 0. Procedures similar to those described above are also used to assess utility functions for attribute x_2 through x_9 except attribute x_5.

According to OSHA, the employer shall administer a continuing, effective hearing conservation program if employee noise exposures equal or exceed an 8-hour time-weighted average sound level (TWA) of 85 decibels. In this research, therefore, it is assumed that if TWA of a technology does not exceed 85 decibels, the noise utility score of the technology would be closed to 1 while the noise utility score of the technology would be rapidly down to 0 if TWA of the technology exceeds 85 decibels. There are five noise making subsets (2, 3, 4, 5, 9) in a system and thus it is considered that a utility value of the noise attribute (x_5) would be similar until a combined TWA exceeds 425 (5 × 85) for a system. Figure 10 shows the utility function curve used for the noise attribute developed by the author.

In this research, the general shapes of the utility function for each attribute are linear. This implies risk neutrality, but it is very important, before proceeding, to do consistency checks on the reasonableness of the shape of the utility functions (i.e., exponential, linear, and so on) (Keeney and Raiffa 1976). This can be fulfilled by asking additional questions about the decision-maker's preferences, and comparing his/ her responses to the implications of the "fit" utility functions. When they are consistent with each other, the utility functions can be more confidence. When they are inconsistent, on the other hand, the inconsistencies are discussed, and part of all the assessment should be repeated (Keeney and Raiffa 1976). Figure 8 shows single-attribute utility values of a system.

Step 7: Decide on a Weight Factor for Each Attribute.

Since it is assumed that there is no interaction between each attribute, all of the weights are positive and they must sum to one (Hardaker 2004). In general, weight factors are decided by a decision-maker. For this case study, the weight factors are defined by an EFD expert who participated in this study. Table 8 shows the assigned weight factor for each attribute.

Step 8: Calculate the Overall Score of the System.

Once each single-attribute utility function $u_i(X_i)$ is derived for its attribute measure, these individual utility values are combined in some way into a final utility value. If mutual preferential and utility independence are satisfied, it is possible to define the multi-attribute utility function to the additive form (Clemen and Reilly 1999):

$$\begin{aligned} U\left(X_1, X_2, \ldots, X_I\right) &= U\left\{u_1\left(X_1\right), u_2\left(X_2\right), \ldots, u_I\left(X_I\right)\right. \\ &= k_1 u_1\left(X_1\right) + \ldots + k_I u_I\left(X_I\right) = \sum_{i=1}^{I} k_i u_i\left(X_i\right) \end{aligned} \tag{5}$$

where $u_i(X_i)$ is a single-attribute utility function scaled from 0 to 1, k_i is a weight factor for $u_i(X_i)$.

A multi-attribute utility function of the additive form can be derived in two steps. First, single-attribute utility functions $u_i(X_i)$ of a system are derived for each attribute measure in turn, then these individual utility values are combined into an overall utility value of the system to simplify comparisons with other possible systems. Figure 8 shows a multi-attribute utility value of a system with the weighting factors given in Table 8.

Step 9: Find the Best System.

In this section, an optimization scheme is suggested based on a combination of multi-attribute utility theory and exhaustively enumerating all possible systems to provide a quantitative rationale and suggest the best set of systems according to a set of attributes, with the relative importance of the different attributes defined by the decision-maker. Since exhaustive search optimization is a simple, practical and very robust method given the speed of modern computers (Cover et al. 2007), it is used to evaluate all possible systems and to find the 'best' available system that should be particularly attractive for a specific site. Larger problems would likely require more advanced optimization methods. Figure 11 briefly illustrates the total possible number of systems used in this case study. Once all possible systems have been evaluated, the system with the highest overall utility score is the best system with given weighting factors.

Step 10: Conduct a Sensitivity Analysis.

After the optimization scheme has given the 'best' system, a sensitivity analysis can be conducted to examine the impact of possible changes in the attribute scores, weight factors, and utility functions on the best system. For example, the weights assigned to cost attribute could be changed from the initially assigned value of 0.40. Since the weighting factors must sum to one in this study, the weights assigned to other attributes are known once a weight assigned to cost attribute is decided. Conducting a sensitivity analysis for the technology selection process is an importance step because it can give an idea the range of weights over which certain systems should be selected for a specific site (Guikema and Milke 1999).

Step 11: Suggest a Small Number of Systems.

Table 9 gives an example of the best systems of varying the weight on the cost attribute from zero to one. Selected technologies in subset (2), (4), (10), (12), and (13) are always same for all possible weights on cost attribute while selected technologies in other subsets are changed. For example, as the weight assigned to cost attribute increases, conventional diesel truck is selected for subset (1) instead of low sulphur diesel truck with tier III engine and with noise suppressor. More extensive sensitivity analyses need to be conducted for other input variables such as attribute scores, the utility function for each attribute in addition to weighting constants for other attributes to suggest more robust optimal systems for this case study.

Conclusion

Throughout this paper, a system optimization approach is suggested based on a combination of multi-attribute utility theory and exhaustive search optimization. This methodology is designed to help decision-makers with their choices of EFD technology in onshore drilling operations. However, the approach used in this study does have some limitations. The crucial limitation is that the computational burden of the procedure may become prohibitive for problems with a large number of decision variables. One possible way to resolve this problem in this research is if the analyst can identify subsets that will always select the same technology for any weight combinations, the elimination of those subsets from the original thirteen subsets can significantly reduce computational burdens in future steps.

Moreover, since the suggested systems would be based on subjectively assessed data, there can be considerable uncertainty about the input parameters used. Therefore, the sensitivity of the optimal solution to the input parameters and the effects of the uncertainty of those parameters are required to be examined and an approach that can be used to conduct a sensitivity analysis for multi-attribute technology selection problem is suggested. The sensitivity analysis is an important area for further research. Another issue is that estimating input values for available technologies are a very difficult step to proceed the quantitative approach suggested in this paper. Even though many EFD subject matter experts have already participated in this study, more people's inputs and feedbacks are necessary to make the proposed technology selection process easier and quicker.

In conclusion, the technology selection process for a drilling project is mainly based on managerial experience, but a more logical approach based on systems analysis is possible, and additional research could reduce the amount of effort required to use systems analysis for technology selection in a drilling project. Even though the technology selection process can be computationally burdensome, it can be very helpful to decision-makers in refining their decisions on a more scientific basis.

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Figure 1. Satellite map of Green Lake in Calhoun County, Texas on the McFaddin Ranch.

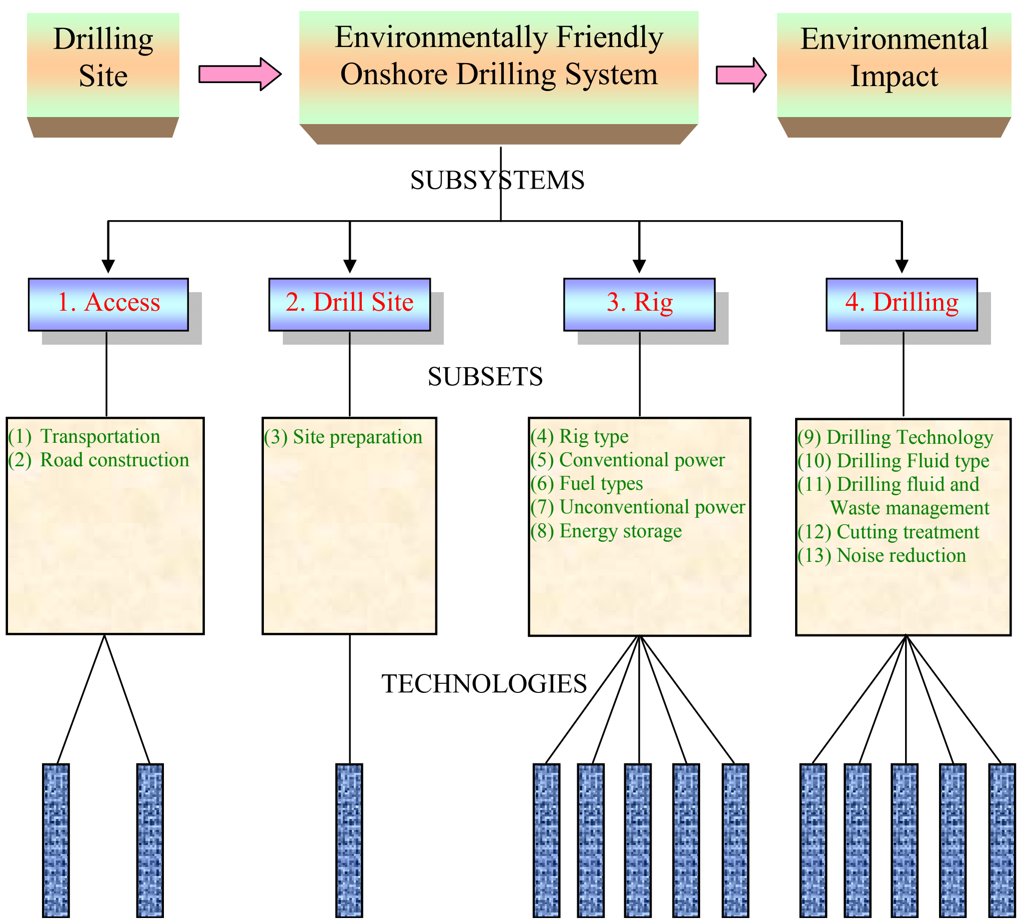

Figure 2. The structure of the EFD operations.

Figure 3. An example of the EFD technology selection.

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Basic Assumptions

- Power consumption (peak): 1 MW
- Access road width: 25 ft (2 lanes)
- Access road length: 1 miles
- Width of drilling site: 350 ft (conventional rig + pad)
  300 ft (compact rig + pad)
  200 ft (conventional rig + modules + piles)
  150 ft (compact rig + modules + piles)
- Length of drilling site: 350 ft (conventional rig + pad)
  300 ft (compact rig + pad)
  125 ft (conventional rig + modules + piles)
  100 ft (compact rig + modules + piles)

Access Road ⇒ **Composite Mat**

- Width = 25 ft (2 lanes)
- Length = 5280 ft (1 miles)
- Purchase rate = \$20.50 / ft^2
- Rent (30 days) = \$1.00 / ft^2

∴ Total cost when purchasing = 25 × 5280 × \$20.50 = \$2,706,000.00

Total cost when leasing = 25 × 5280 × \$1.00 = \$132,000.00

Figure 4. Basic assumptions and cost estimation of Dura-Base Composite Mat for access road.

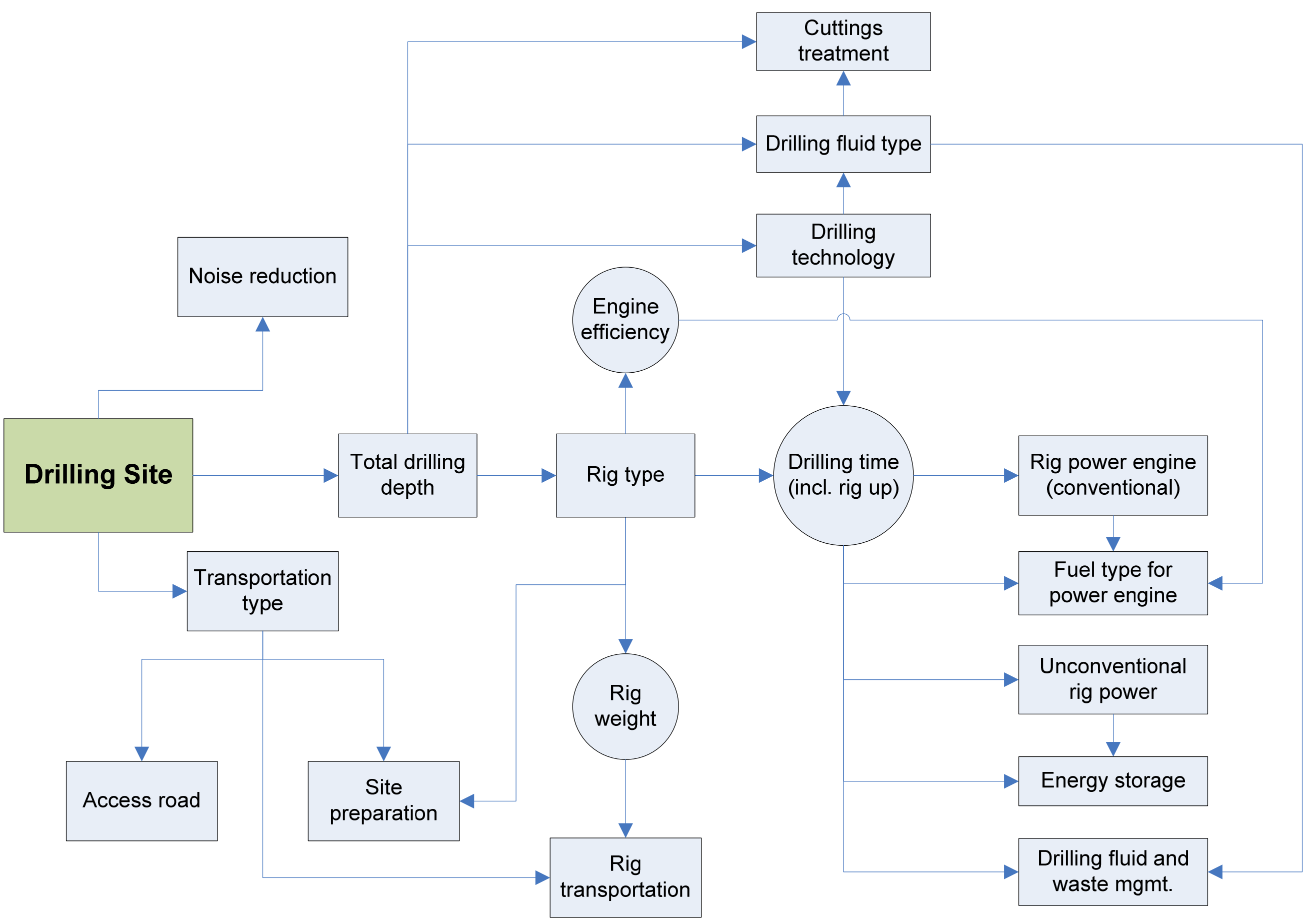

Figure 5. Brief influence diagram of a drilling project.

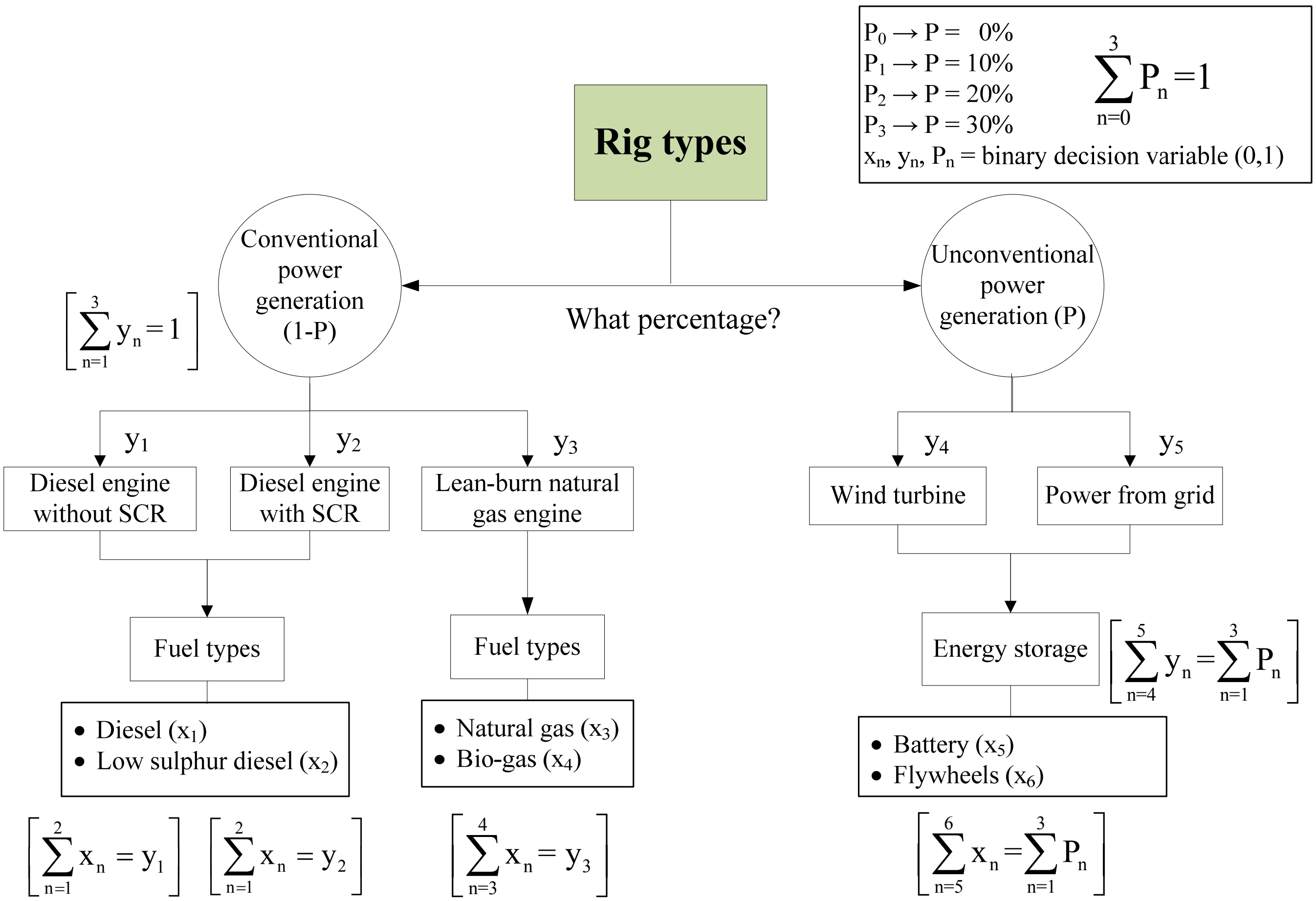

Figure 6. Construction strategy and constraints for the "Rig" subsystem.

Sub-sets	Technologies	Total cost ($)	Ecological Footprint (Acres)	Emissions			Perceptions			Safety Value
				Air	*Solid& Liquid*	*Noise (TWA)*	*Gov.*	*Ind.*	*Public*	
1	Coventional diesel truck						0.250	1.000	0.250	0.750
	MAX						0.250	1.000	0.250	0.750
	MIN						0.250	1.000	0.250	0.750
2	Gravel roads	$148,500	3.030	0.566		98.562	0.250	1.000	0.250	0.500
	DURA-BASE from Composite Mat (buy)	$541,200	1.515	0.964		82.870	1.000	0.500	1.000	1.000
	DURA-BASE from Composite Mat (rent)	$132,000	1.515	0.964		82.870	1.000	0.500	1.000	1.000
	MAX	$541,200	3.030	0.964		98.562	1.000	1.000	1.000	1.000
	MIN	$132,000	1.515	0.566		82.870	0.250	0.500	0.250	0.500
3	Gravel pad	$137,813	2.812	0.598		98.019	0.250	1.000	0.250	0.500
	DURA-BASE from Composite Mat (buy)	$502,250	1.406	0.967		82.242	0.750	0.750	0.750	1.000
	DURA-BASE from Composite Mat (rent)	$122,500	1.406	0.967		82.242	0.750	0.750	0.750	1.000
	Aluminum modules + driven piles	$372,408	0.007	0.973		97.614	1.000	0.500	1.000	0.500
	MAX	$502,250	2.812	0.973		98.019	1.000	1.000	1.000	1.000
	MIN	$122,500	0.007	0.598		82.242	0.250	0.500	0.250	0.500
4	Traditional older vintage rig	$220,000		0.973		78.630	0.500	1.000	0.500	0.500
	MAX	$220,000		0.973		78.630	0.500	1.000	0.500	0.500
	MIN	$220,000		0.973		78.630	0.500	1.000	0.500	0.500

Figure 7. An example of input spreadsheets.

Selected Technologies in Each Subset	Total Cost ($)	Ecological Footprint (Acres)	Emissions			Perceptions			Safety Value
Weights (Σ = 100% ∴ O.K!)	40%	20%	6.667%	6.667%	6.667%	5%	5%	5%	5%
			Air	*Solid& Liquid*	*Noise (TWA)*	*Gov.*	*Ind.*	*Public*	
(1) Transportation: Coventional diesel truck	$0	0.000	0.000	0.000	0.000	0.250	1.000	0.250	0.750
(2) Road construction: DURA-BASE from Composite Mat (rent)	$132,000	1.515	0.964	0.000	82.870	1.000	0.500	1.000	1.000
(3) Site preparation: Aluminum modules + driven piles	$372,408	0.007	0.973	0.000	97.614	1.000	0.500	1.000	0.500
(4) Rig type: Traditional older vintage rig	$220,000	0.000	0.973	0.000	78.630	0.500	1.000	0.500	0.500
(5) Rig power (Conventional): Internal combustion engine w/SCR,	$106,712	0.000	0.488	0.000	87.263	0.750	0.750	0.750	0.750
(6) Fuel type: Low sulphur diesel	$88,906	0.000	0.000	0.000	0.000	0.750	0.750	1.000	0.750
(7) Rig power (Unconventional): Electric power from grid (10 %)	$8,602	0.000	1.000	0.000	0.000	0.500	1.000	1.000	1.000
(8) Energy storage: Flywheels	$30,000	0.000	0.000	0.000	0.000	0.500	1.000	1.000	0.750
(9) Drilling tech.: Conventional overbalanced drilling	$204,000	0.000	0.000	0.000	116.700	1.000	0.500	0.500	0.500
(10) Fluid type: Water-based muds	$47,940	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000
(11) Waste mgmt.: Lined reserve pit + solid control equip.*	$24,000	0.037	0.000	0.500	0.000	0.750	0.750	0.750	0.500
(12) Cuttings mgmt.: Cuttings injection	$60,000	0.000	0.000	1.000	0.000	1.000	0.500	1.000	0.750
(13) Noise reduction: N/A									
Overall Attribute Scores (Σ or minimum value)	$1,294,568	1.559	4.398	1.500	463.077	0.250	0.500	0.250	0.500
Single Attribute Utility Values	0.539	0.991	0.815	0.600	0.677	0.250	0.500	0.250	0.500

∴ Multi-Attribute Utility Value = **0.628**

Figure 8. An example score matrix for a system.

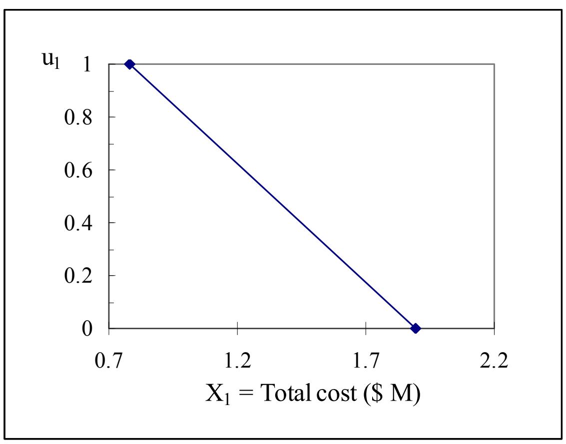

Figure 9. The single-attribute utility function curve for cost.

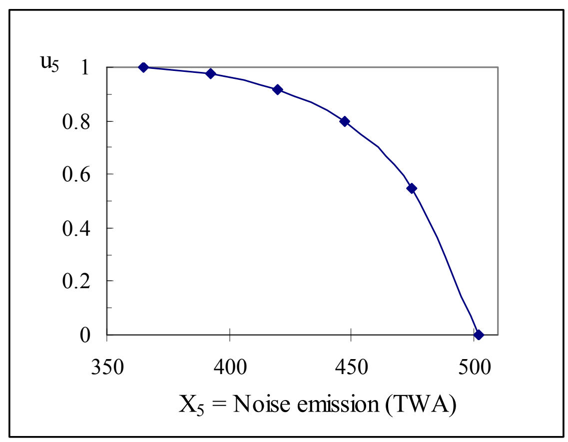

Figure 10. The single-attribute utility function curve for noise.

1. When "Diesel engine" is selected as a conventional power generation,

Subsets	Subsystems				∏
	1. Access	2. Drill Site	3. Rig	4. Drilling	
(1)	2	4	3	3	72
(2)	3		2*	1	6
(3)			2	2	4
(4)			1	2	2
(5)			1	1	1
				∏	3,456

2. When "Natural gas engine" is selected as a conventional power generation,

Subsets	Subsystems				∏
	1. Access	2. Drill Site	3. Rig	4. Drilling	
(1)	2	4	3	3	72
(2)	3		1	1	3
(3)			1	2	2
(4)			1	2	2
(5)			1	1	1
				∏	864

∴ Total number of possible systems = 3,456
within 1 conventional power generation scenario 864
Σ 4,320

4 different portions of unconventional power usage (0, 10, 20, 30%) were considere
∴ Total number of iterations = 4 × 4320 = 17280

*: 2 types of diesel engine

Figure 11. Total number of possible systems.

Subsets	1. Conventional Drilling	2. Moderately Improved Drilling	3. EFD in 5 years
(1) Transportation	Conventional diesel truck	Low sulphur diesel truck w/tier III engine, w/noise suppressor	Low sulphur diesel truck w/tier III engine, w/noise suppressor
(2) Road construction	Gravel road	DURA-BASE from Composite Mat (rent)	DURA-BASE from Composite Mat (rent)
(3) Site preparation	Gravel pad	DURA-BASE from Composite Mat (rent)	Aluminum modules + driven piles (elevated platform)
(4) Rig type	Traditional older vintage rig	Rapid Rig	LOC250 (CWD)
(5) Conventional rig power engine	Internal combustion engine	Internal combustion engine w/SCR, w/noise suppressor	Lean-burn natural gas engines w/noise suppressor
(6) Fuel type	Conventional diesel	Low sulphur diesel	Natural gas
(7) Unconventional rig power generation	None	Electric power from grid (10%)	Electric power from grid (30%)
(8) Energy storage	None	Flywheel	Flywheel
(9) Drilling technology	Conventional overbalanced drilling	Underbalanced drilling w/noise suppressor	Managed pressure drilling w/noise suppressor
(10) Fluid type	Water-based muds	Water-based muds	Water-based muds
(11) Drilling fluid and waste management	Lined reserve pit + solid control equipment	Closed loop + containers + solid control equipment	Closed loop + containers + solid control equipment
(12) Cuttings treatment	Cuttings injection	Cuttings injection	Chemical fixation and solidification (CFS)
(13) Noise reduction	None	None	None

Table 1. Pre-specified drilling systems.

Technologies	Unit	0.2	0.4	0.4	Overall score
		CO	NO_x	PM	
Gravel road: Diesel truck + dust	(gram/hp-hr)	15.5	4	0.1	0.566
	(lb/hp-hr)	0.03418	0.00882	0.00022	
	(lb/hr)/unit	10.253	2.646	0.216	
	(lb/operating)	3250.280	838.782	68.520	
	U-value	0.000	0.822	0.593	
Composite mat: Low sulphur diesel truck w/tier III engine	(gram/hp-hr)	15.5	0.2	0.01	0.976
	(lb/hp-hr)	0.03418	0.00044	0.00002	
	(lb/hr)/unit	10.253	0.132	0.007	
	(lb/operating)	369.117	4.763	0.238	
	U-value	0.886	0.999	0.999	
Internal Combustion Engine	(lb/MWh)	6.2	21.8	0.78	0.118
	(lb/hr)/unit	6.200	21.800	0.780	
	(lb/hr)*portion	6.200	21.800	0.780	
	(lb/operating)	1339.200	4708.800	168.480	
	U-value	0.588	0.000	0.000	
Internal Combustion Engine with SCR	(lb/MWh)	6.2	4.7	0.78	0.431
	(lb/hr)/unit	6.200	4.700	0.780	
	(lb/hr)*portion	6.200	4.700	0.780	
	(lb/operating)	1339.200	1015.200	168.480	
	U-value	0.588	0.784	0.000	
Lean-burn natural gas engine	(lb/MWh)	5	2.2	0.03	0.878
	(lb/hr)/unit	5.000	2.200	0.030	
	(lb/hr)*portion	5.000	2.200	0.030	
	(lb/operating)	1080.000	475.200	6.480	
	U-value	0.668	0.899	0.962	
Power from grid	(lb/MWh)	0	0	0	1.000
	(lb/hr)/unit	0.000	0.000	0.000	
	(lb/hr)*portion	0.000	0.000	0.000	
	(lb/operating)	0.000	0.000	0.000	
	U-value	1.000	1.000	1.000	

Table 2. An example of air emission score calculation.

Waste Management Technologies	Cuttings treatment	Solid/liquid emission score
Closed loop	Cutting injection	1.00
-	Bioremediation, Composting, In-situ vitrification, Land spreading, Plasma arc, Microwave technology	0.75
Lined reserve pit	Thermal desorption.	0.50
-	Chemical fixation and solidification	0.25
Open reserve pit	Evaporation and burial onsite	0.00

Table 3. Draft attribute scale for solid and liquid emission.

Description	Perception score
Strongly Support. All parties will encourage its use and are willing to appropriate funds for the cause.	1.00
Somewhat Support. There is interest from a majority. Its use will be encouraged, but funds will not be appropriated.	0.75
Neutrality. All parties are indifferent. There is no resistance, but there is also no help.	0.50
Somewhat opposition. Some resistance from the majority. Its use may be discouraged, but fines or restrictions won't be imposed.	0.25
Strong opposition. Strong resistance to its use from all parties. Restrictions or fines will be set up to eliminate this option.	0.00

Table 4. Draft attribute scale for government perception.

Description	Perception score
Strongly Support. All parties are very interested and willing to invest for the facility.	1.00
Somewhat Support. All parties are interested but somewhat hesitate to invest for the facility.	0.75
Neutrality. All parties are indifferent or uninterested.	0.50
Somewhat opposition. Some parties have opposition. The other parties are indifferent or uninterested.	0.25
Strong opposition. No parties are willing to invest for the facility.	0.00

Table 5. Draft attribute scale for industry perception.

Description	Perception score
Support. No groups are opposed to the facility, and at least one group has organized support for the facility.	1.00
Neutrality. All groups are indifferent or uninterested.	0.75
Controversy. One or more groups have organized opposition, although no groups have action-oriented opposition (for example, letterwriting, protests, lawsuits). Other groups may either be neutral or support the facility.	0.50
Action-oriented opposition. Exactly one group has action-oriented opposition. The other groups have organized support, indifference, or organized opposition.	0.25
Strong action-oriented opposition. Two or more groups have action-oriented opposition.	0.00

Table 6. Draft attribute scale for public perception. Source: adapted from Keeney (1992, P. 102)

Description	Safety score
Very safe. No hazard associated with a technology.	1.00
Safe. It is recommended for workers constructing a technology be instructed on the hazards of the technology but it is not the mandatory. No hazard associated with the technology for other workers.	0.75
Neutrality. It is recommended for workers in a site be instructed on the hazards of a technology but it is not the mandatory.	0.50
Somewhat dangerous. Workers constructing a technology have to be instructed on the hazards associated with the technology, and it is recommended for other workers be instructed on the hazards of the technology, but it is not the mandatory.	0.25
Very dangerous. Every worker in a site has to be instructed on the hazards associated with a technology.	0.00

Table 7. Draft attribute scale for safety value.

Attributes	Weights
Total cost (x_1)	0.40
Footprint (x_2)	0.20
Air emission (x_3)	0.20/3
Solid/ liquid emission (x_4)	0.20/3
Noise emission (x_5)	0.20/3
Government perception (x_6)	0.05
Industry perception (x_7)	0.05
Public perception (x_8)	0.05
Safety (x_9)	0.05

Table 8. Assigned weight factor for each attribute.

Subsets	Best system ($w_1 < 4\%$)	Best system ($4\% \leq w_1 < 40\%$)	Best system ($40\% \leq w_1 < 70\%$)
(1) Transportation	Low sulphur diesel truck w/tier III engine, w/noise suppressor	Low sulphur diesel truck w/tier III engine, w/noise suppressor	Low sulphur diesel truck w/tier III engine, w/noise suppressor
(2) Road construction	DURA-BASE from Composite Mat (rent)	DURA-BASE from Composite Mat (rent)	DURA-BASE from Composite Mat (rent)
(3) Site preparation	Aluminum modules + driven piles (elevated platform)	Aluminum modules + driven piles (elevated platform)	DURA-BASE from Composite Mat (rent)
(4) Rig type	LOC250 (CWD)	LOC250 (CWD)	LOC250 (CWD)
(5) Conventional rig power engine	Lean-burn natural gas engines w/noise suppressor	Lean-burn natural gas engines w/noise suppressor	Lean-burn natural gas engines w/noise suppressor
(6) Fuel type	Natural gas	Natural gas	Natural gas
(7) Unconventional rig power generation	Electric power from grid (30%)	Electric power from grid (10%)	Electric power from grid (10%)
(8) Energy storage	Flywheel	Flywheel	Flywheel
(9) Drilling technology	Managed pressure drilling w/noise suppressor	Managed pressure drilling w/noise suppressor	Underbalanced drilling w/noise suppressor
(10) Fluid type	Water-based muds	Water-based muds	Water-based muds
(11) Drilling fluid and waste management	Closed loop + containers + solid control equipment	Closed loop + containers + solid control equipment	Closed loop + containers + solid control equipment
(12) Cuttings treatment	Cuttings injection	Cuttings injection	Cuttings injection
(13) Noise reduction	None	None	None
Subsets	**Best system ($70\% \leq w_1 < 85\%$)**	**Best system ($85\% \leq w_1$)**	
(1) Transportation	Conventional diesel truck	Conventional diesel truck	
(2) Road construction	DURA-BASE from Composite Mat (rent)	DURA-BASE from Composite Mat (rent)	
(3) Site preparation	DURA-BASE from Composite Mat (rent)	DURA-BASE from Composite Mat (rent)	
(4) Rig type	LOC250 (CWD)	LOC250 (CWD)	
(5) Conventional rig power engine	Lean-burn natural gas engines w/noise suppressor	Internal combustion engine	
(6) Fuel type	Natural gas	Conventional diesel	
(7) Unconventional rig power generation	None	None	
(8) Energy storage	None	None	
(9) Drilling technology	Underbalanced drilling w/noise suppressor	Underbalanced drilling w/noise suppressor	
(10) Fluid type	Water-based muds	Water-based muds	
(11) Drilling fluid and waste management	Closed loop + containers + solid control equipment	Lined reserve pit + solid control equipment	
(12) Cuttings treatment	Cuttings injection	Cuttings injection	
(13) Noise reduction	None	None	

Table 9. Suggested best systems as varying the weight on the cost attribute (w_1).

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Alternate Power and Energy Storage/Reuse for Drilling Rigs: Reduced Cost and Lower Emissions Provide Lower Footprint for Drilling Operations

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Abstract
One of the major ways to reduce the footprint of drilling operations is to provide more efficient power sources for drilling operations. Rigs powered by the electrical grid can provide lower cost operations, emit fewer emissions, are quieter, and have a smaller surface footprint than conventional diesel powered drilling.

This paper describes a study to evaluate the feasibility of adopting technology to reduce the size of the power generating equipment on drilling rigs and to provide "peak shaving" energy through the new energy generating and energy storage devices such as flywheels.

An energy audit was conducted on a new generation light weight Huisman-US Inc. LOC 250 rig drilling in South Texas to gather comprehensive time stamped drilling data. A study of emissions while drilling operation was also conducted during the audit. The data was analyzed using MATLAB and compared to a theoretical energy audit. The study showed that it is possible to remove peaks of rig power requirement by a flywheel kinetic energy recovery and storage (KERS) system and that linking to the electrical grid would supply sufficient power to operate the rig normally. Both the link to the grid and the KERS system would fit within a standard ISO container.

A cost benefit analysis of the containerized system to transfer grid power to a rig, coupled with the KERS indicated that such a design had the potential to save more than $10,000 per week of drilling operations with significantly lower emissions, quieter operation, and smaller size well pad.

Introduction
Diesel engines present in the rig pose the problems of low efficiency and large amount of emissions. In addition the rig power requirements vary significantly with time and ongoing operation. Therefore it is in the best interest of operators to consider on alternate drilling energy sources which can make entire drilling process economic and environmentally friendly. A system of electrical power grid in combination with an energy storage device such as a flywheel unit is one source which can provide substantially cheaper energy as compared to diesel. This energy storage unit can supply/reuse the power above and below the base load and will allow the rigs to draw the base load either from diesel engines or power grid and hence improve the drilling efficiency.

Outline
Energy audit. The LOC rig is a casing while drilling rig (Huisman-Itrec 2005). The study was conducted on this rig because it has a sophisticated supervisory control and data acquisition (SCADA) system monitoring various drilling parameters. Also this rig is containerised which further serves the purpose of developing a mobile energy storage unit (Huisman-Itrec 2006). Initially a theoretical energy audit for the rig was conducted based on the specifications of the rig. Considering the data in Table A-1 the rig does not operate on its full load all the time.Table A-2 exhibits the theoretical values and rig specifications for various actuators. Hence design of this KERS system based on theoretical energy audit will simply result in an overly designed system which will be uneconomic and underutilized. Therefore, an actual energy audit of LOC-250 is done based on time stamped drilling data. As much as 23 parameters 1.3 million lines each were difficult to process and hence a comprehensive tool like MATLAB was chosen. Specifications of the flywheel unit were determined based on data processing results.

Table A-3 shows the parameters obtained with the respective sampling frequency. The data processing revolved around major power consumers of the rig namely mud pumps and top drive. Being a casing while drilling rig there is little or no tripping and hence the power consumption by drawworks is not emphasised in this audit. The main idea is to provide the base load requirement of the rig determined from the data processing by either diesel engines or service utility and remove the transient peaks of power by KERS system.

Data Processing

Steps in data processing and MATLAB code. All 23 parameters measured by the SCADA system were converted into Excel files by the use of 'Trend Reader' software. These files were too big to process fully by Excel as some of them consisted of as many as 1330000 lines, whereas the maximum size of excel file could not exceed 65000 lines. Hence a comprehensive tool MATLB was chosen. These files were then imported in MATLAB after converting them to '.txt' format. The color coded data signals shown in Table A-3 were combined and converted into power and energy units by the conversion equations shown in Appendix 2.The actual code is beyond the scoope for this paper and could be sumbmitted along with the supplemental data.

Simplified Description of MATLAB code. Appendix 3 contains all the remaining processed results based on which the alternate power system is designed. An easier description for MATLAB code explaining the results follows:

- Import the text file data in MATLAB by using either import wizard or textread command. Say data for Mud Pump is imported.
- Three vectors namely date, time and data are formed. As MATLAB plots the data VS index by default and index can be scaled to sample time we can delete the date and time vectors for simplicity. Plot the Mud Pump Flow VS Time **(Figure 1).**

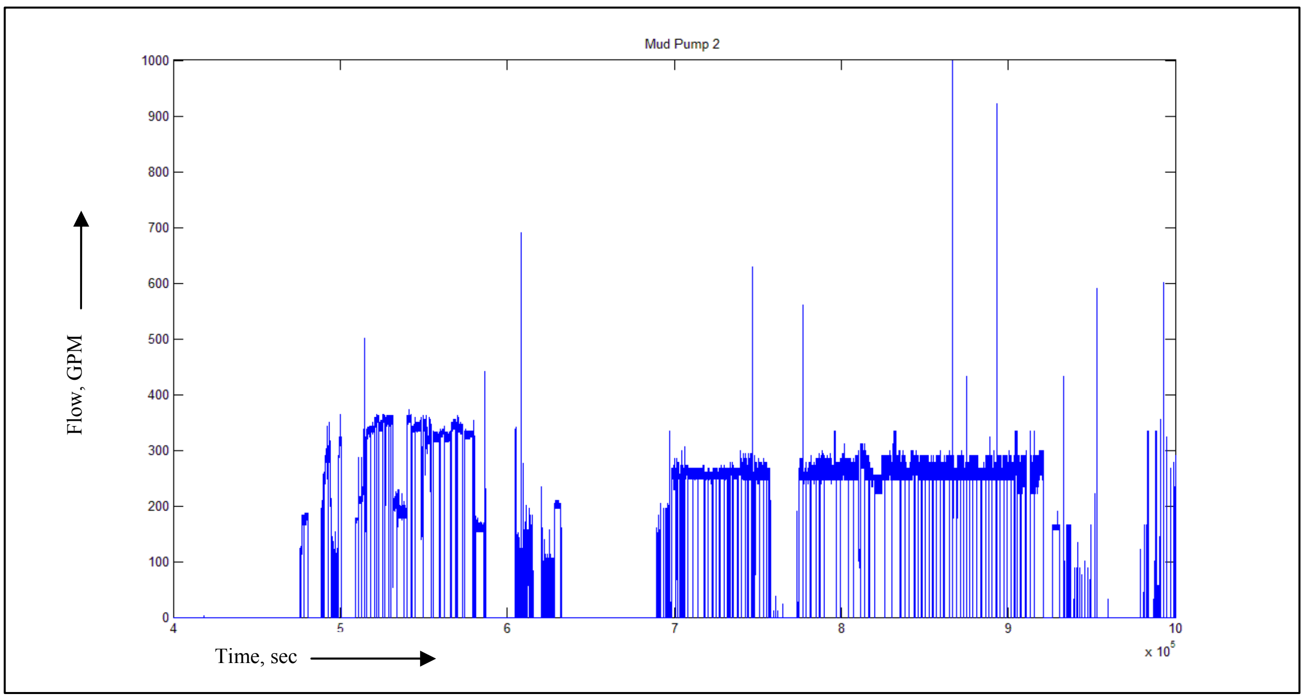

Figure 1 – Flow rate of one of the mud pumps its variations with time.

- Vector for mud pump data is ready to use. A similar procedure is followed for Pump Pressure data **(Figure 2)**.

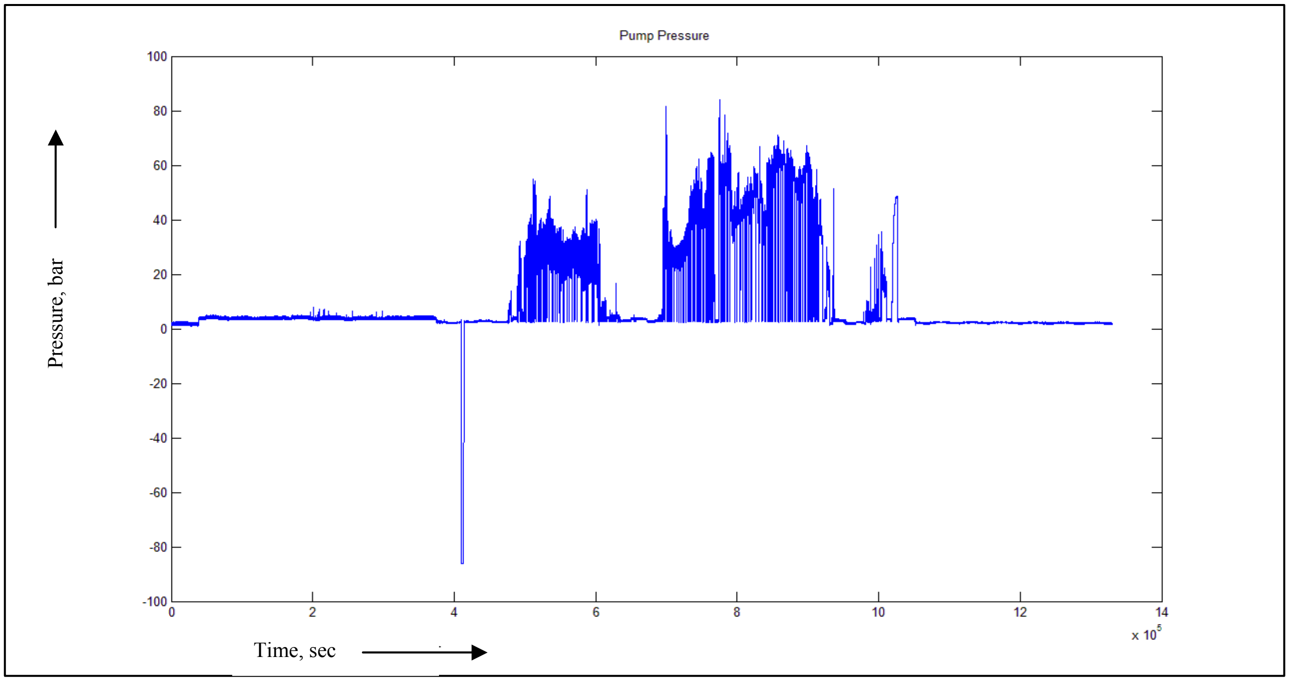

Figure 2 – Pump pressure vs. time is and its variations. Negative peak is considered to be a false triggered signal.

- Point-wise multiplication of Pump Pressure and Mud Pump flow will give the instantaneous power for the mud

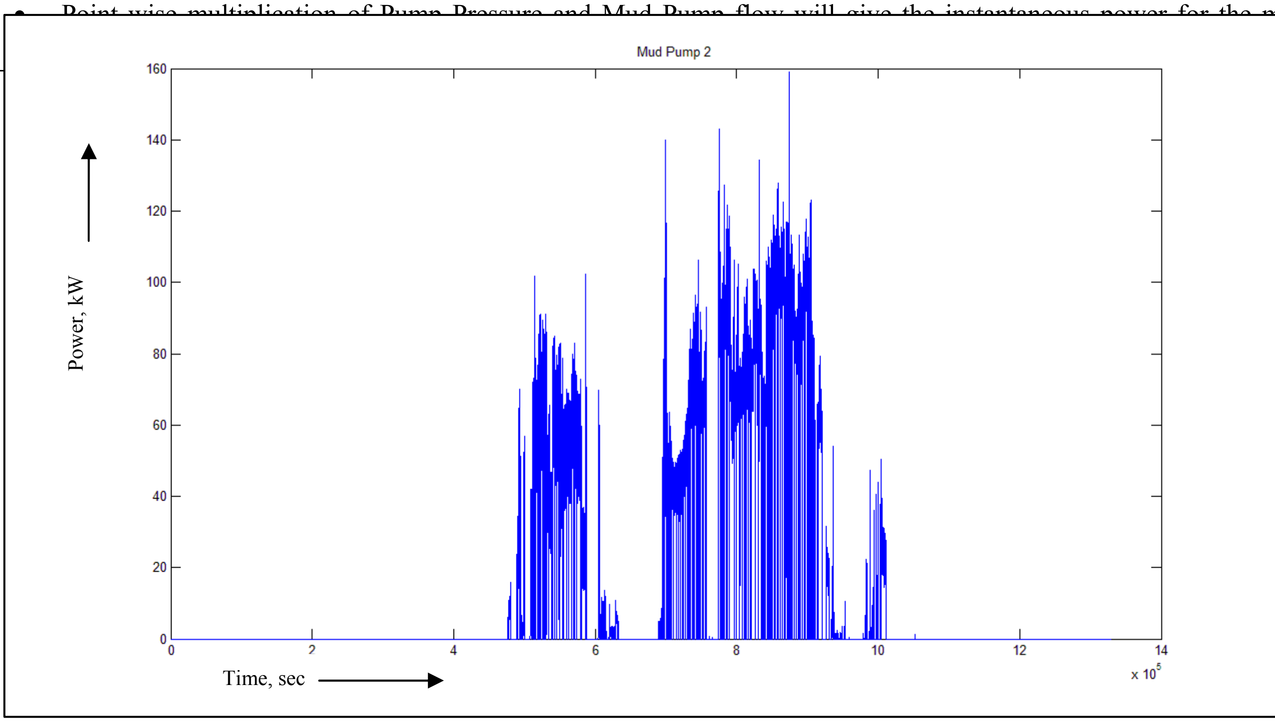

Figure 3 – Instantaneous power of mud pumps vs. time and its variations. Some of the exceptionally high values are considered to be false triggered.

- A moving average for a window length of 2 seconds is taken and plotted against this Mud Pump power curve. This is done because moving average is assumed to converge to the average value of a certain dataset and by increasing the window length the curve will move closer to base load value. **(Figure 4)**.

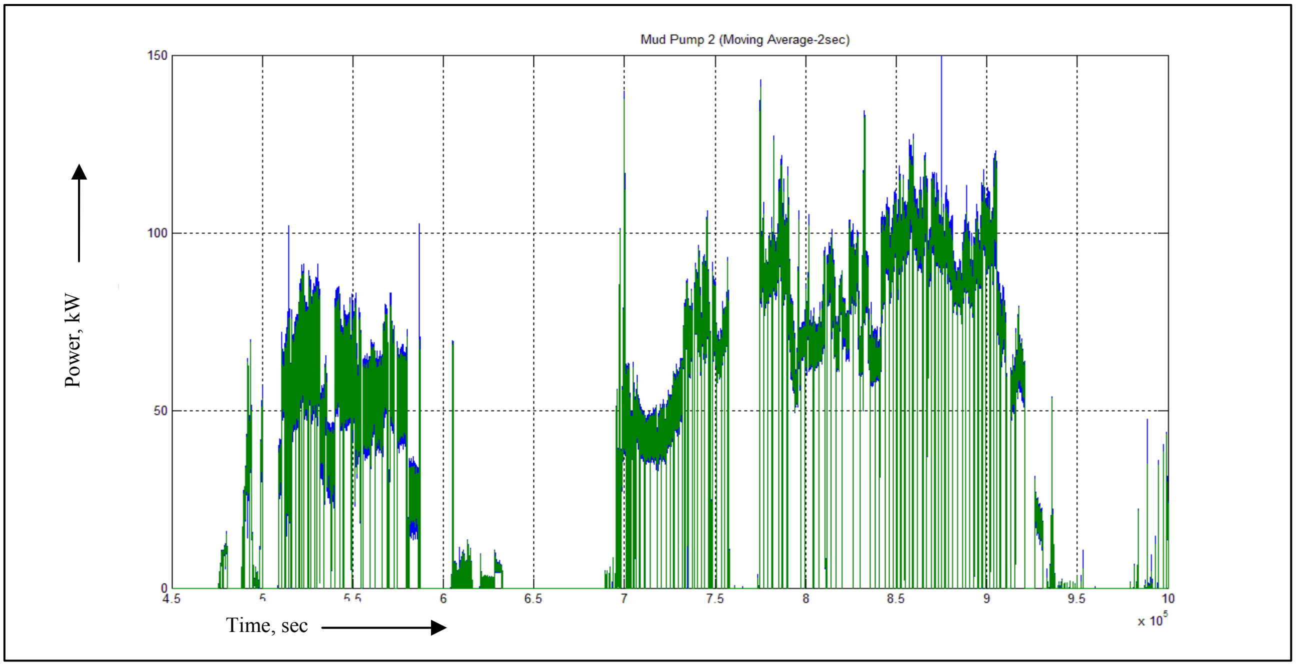

Figure 4 – A moving average of window length 2 seconds and actual power curve of the mud pump are plotted vs. time in order to determine transient peaks for this window length.

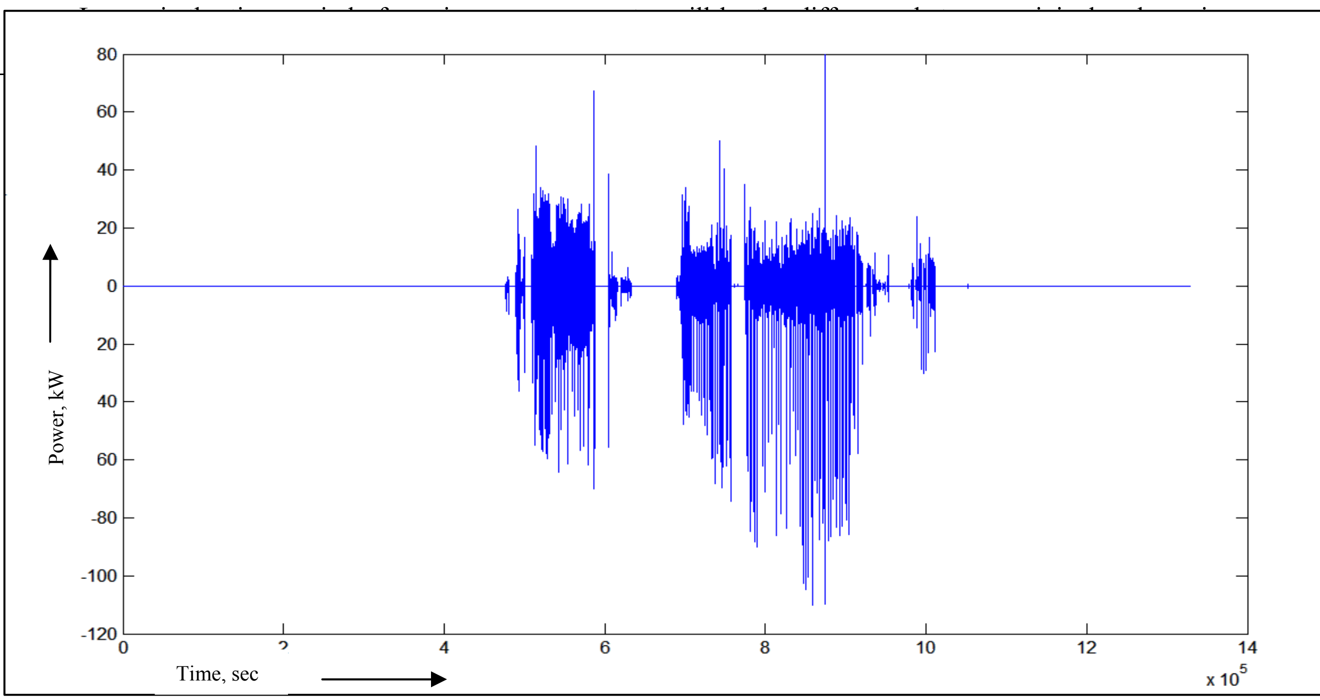

Figure 5 – Difference between the actual curve and moving average curve for the mud pump vs. time for the window length of 2 seconds.

- Rest of the peaks (difference between moving average and power) are plotted. The flywheel design is based on this difference between actual and moving average curve **(Figure5)**.
- A cumulative difference curve for Mud Pumps and Top Drive is plotted. This is the summary of all the peaks that flywheel unit will supply **(Figure 6)**.

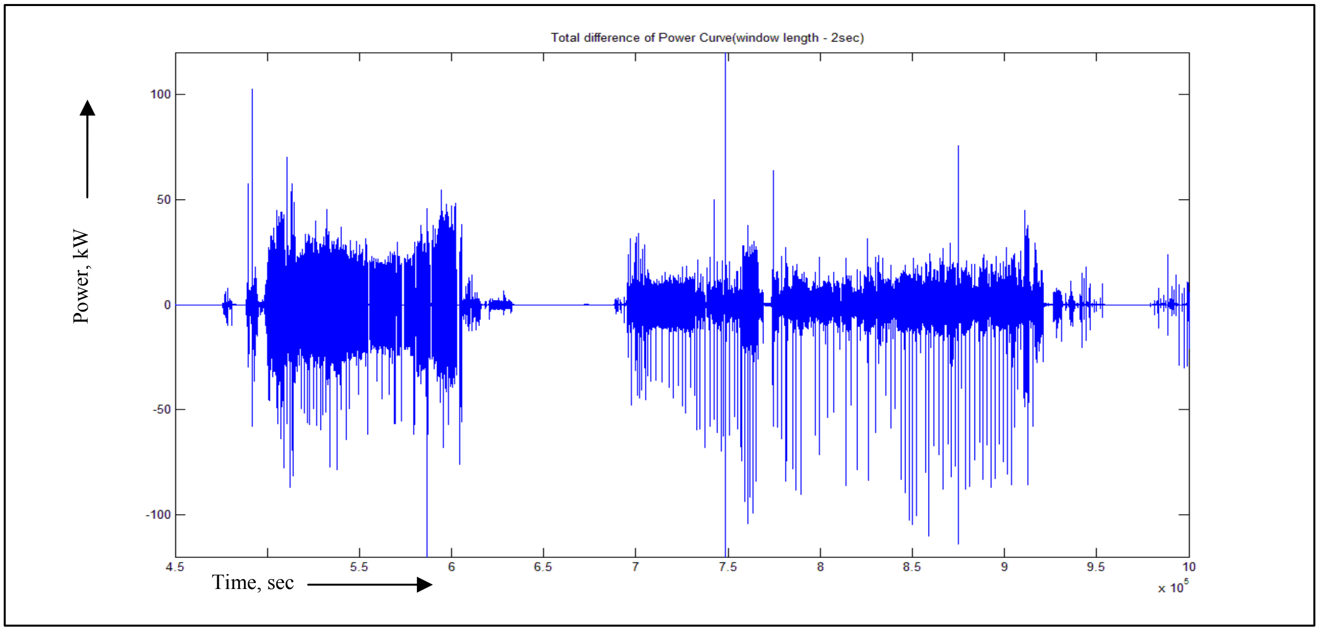

Figure 6 – Difference of the actual power curves and moving average curve is combined for mud pumps and top drive vs. time.

- An energy curve is obtained by adding all the previously consumed power peaks for both the mud pumps and top drive. This is done by adding all the n-1 values to the n^{th} value of peak and multiplying it by the time to give energy in KJ. All energy curves for the given window length are added. Below is the energy curve for mud pumps and top drive for window period of 2 seconds **(Figure 7)**.

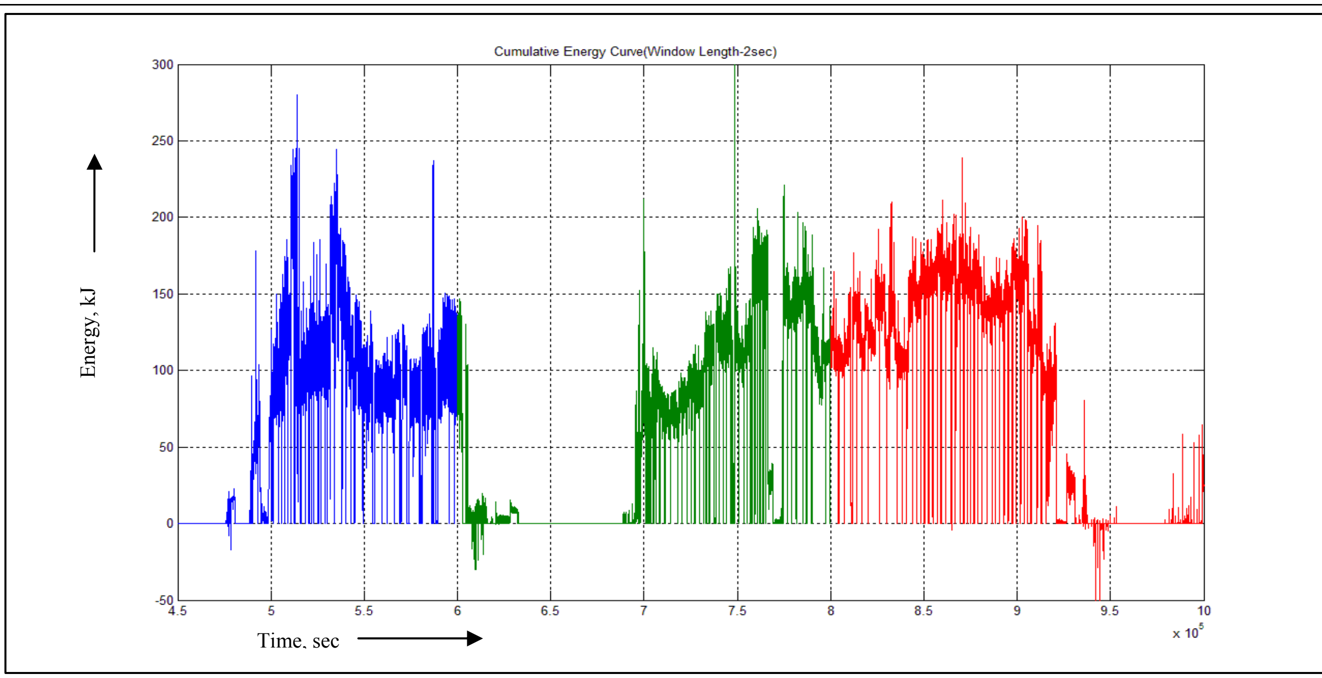

Figure 7- Energy curve for mud pumps and top drive for window length of 2 seconds.

- The peaks in this curve represents the minimum amount of energy flywheel unit should have for effective peak shaving. These energy curves are drawn for all window periods and are attached in the appendix. Hence after these eight steps we have the values for E_{max} and P_{max} for the flywheel unit.

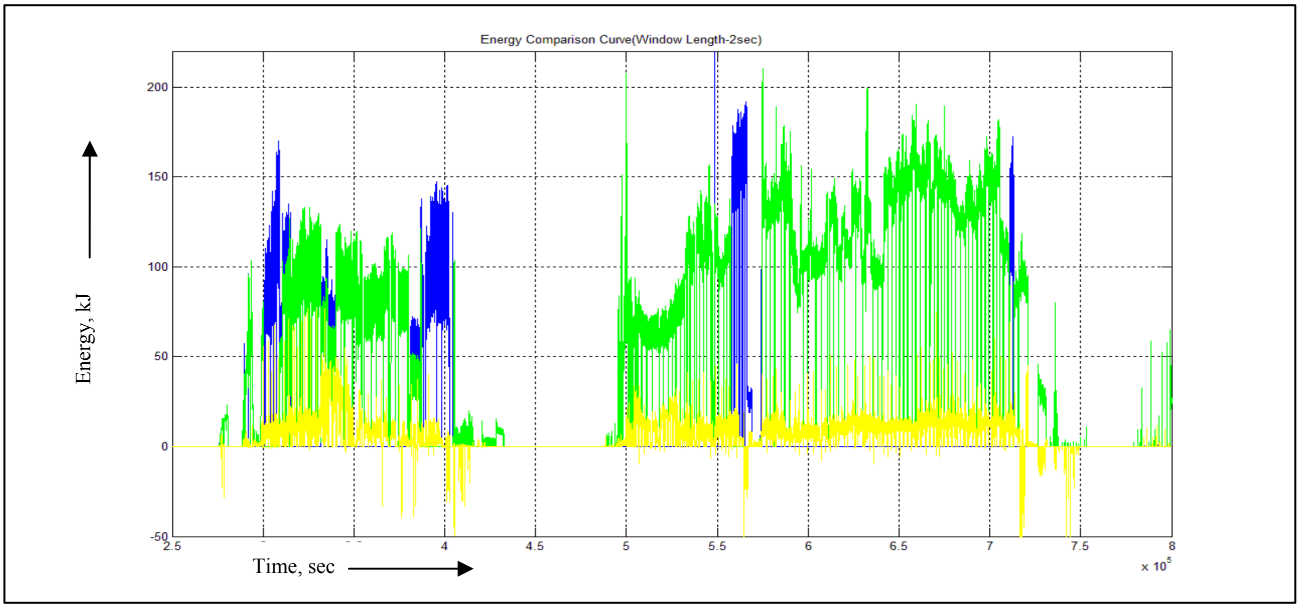

Figure 8 – Comparison of actual energy requirement of top drive and mud pumps vs. time and consumption of energy by mud pumps and top drive during drilling operation.

- The energy consumption for both mud pumps and top drive is compared and shown in cumulative energy comparison graph. This graph proves that mud pumps are the largest energy consumers **(Figure 8)**. This energy comparison is also done for all window lengths.

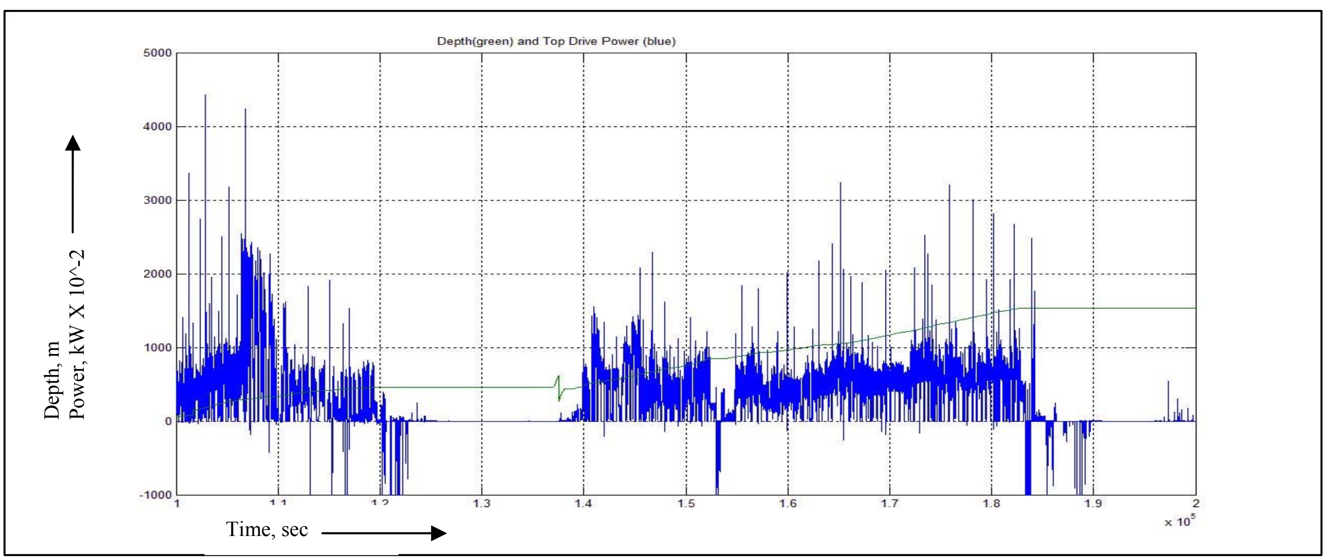

Figure 9 – Curve for drilling depth and simultaneous top drive power consumption vs. time.

- Another curve of interest would be top drive power and depth on the same time scale which shows stages of drilling where top drive consumed power **(Figure 9)**.
- Lastly power comparison with depth for mud pumps and top drive is made. These curves summarize the drilling operation. Drilling process started near to 9600000 second and halted at 12400000 second where there is no power

consumption by any component. Again power consumption begins at 1400000 second and goes up to 1800000 second. The amount of power consumed individually by these pumps and top drive is also shown **(Figure 10)**.

Figure 10 - Actual power consumption of mud pumps and top drive vs. time and variation is shown with drilling depth.

System Design

Design components. The switchbox contains many inbuilt blocks. One such block is dedicated transformer switchgear containing feeder cables. Such a transformer station can be connected to a service voltage of 11 KV by feeder cable which is another unit. Feeder cable 2 miles long will be on a storage winch. This winch will have a close circuit coolant circulation in order to avoid overheating of the mounted cable while in operation. Another block would be flywheel unit. Size, ratings and other specification of the flywheel unit are determined on the basis of rig data processing. There is one more data acquisition block which will monitor all the parameters while the unit is functional. Such a SCADA system is already in place in these rigs. Finally all of these blocks after appropriate size determination will be placed in a 20 ft or 40 ft closed ISO container which has the inherent advantage of easy transportation with no special freight regulations. The unit also contain emergency back up diesel generator unit in case the electrical design fails or power trips. A detailed design with dimensions is shown too **(Figure 12)**. This design shows feeder cables, transformer units and their cooling fans, switchgear, storage winch, winch cooling mechanism, AC unit, lighting unit. Intricate design of busbars, circuit breaker and isolators, motor control

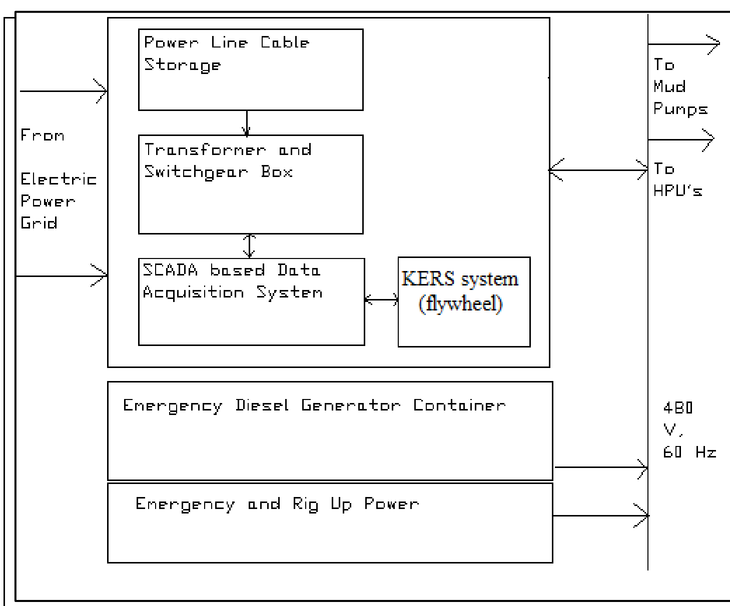

Figure 11 – Black box design for alternate power system.

centre cubicles and fuses are beyond the scope of investigation and are left up to the electrical design company. A brief description of all the components follows.

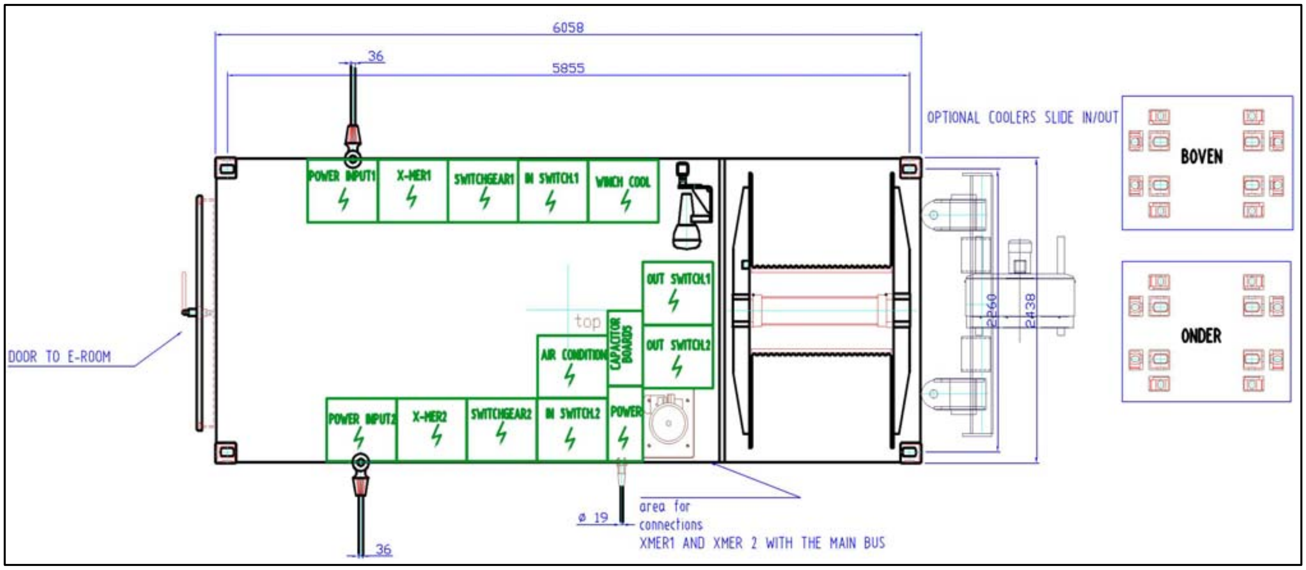

Figure 12 – Detailed design of 20 ft ISO container with design components in place.

Power line cable. Assuming an overall derating factor of 0.6 for ground (including air and ground temperatures, grouping of cables, depth of burial, overall derating factors for ground and air) (McAllister 1987) and calculating the transformer primary winding current for 3.3 MVA loading, $I_p = 3300000/(\sqrt{3} \times 11000) = 173.4$ Amps, where I_p is the primary winding current. Cable equivalent current for 25 'C = 173.4/0.6= 289.01 Amps. This value corresponds to a 3 core cable with cross sectional area of 95 mm^2 and outer core diameter of 12 mm in standard tables in the cable handbook (Fink and Beaty 1987).Thus the overall diameter of the cable would be 36 mm (Figure 13). Other details-cable coding BS6622 95/100 mm^2, 37 wires for 600 V, PVC insulation, current rating of 3 core cable 11 KV XLPE insulation (McAllister 1987).

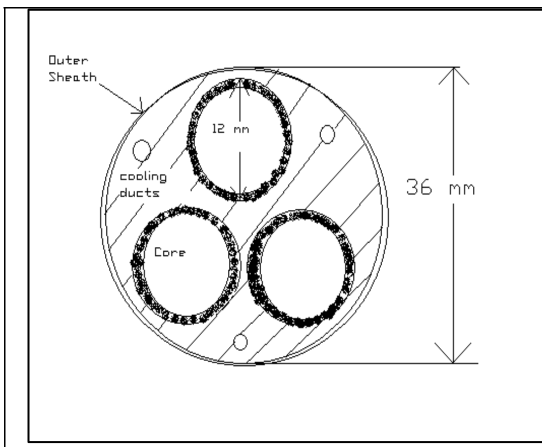

Figure 13 – Cross section of power cable with 3 inner cores and insulation.

Storage winch. Storage winch in this system is used for holding as much as 3000 meters long power cable which can be used as an alternative to connect the rig to the power grid instead of constructing power lines to drill site. This winch has to be accommodated design in 2.2 meter height and width dimension. The winch's main design parameters are wire diameter 36 mm, drum wire storage 3042 m, number of safety windings 3, number of layers 16, drum diameter in groove 640 mm, length of the drum 2200 mm, ratio of wire/ drum diameter 17.78, pitch of the drum 37.44 mm.

Transformer and switchgear. 3 Phase, distribution type,11 KV/480 V,60 Hz, Class F,DZ. 2 transformers will be needed to replace either of the diesel engines. Incoming and busbar section circuit breakers should be 3/4 pole for low voltage based on air break. For high voltage they should be either SF_6 or vacuum based. Earthing bars should be high grade copper located at front or rear enclosure, screen clamping type. Standard lightning arrestor and cabinet cooling system is also recommended (Alstom T&D Protection and Control 1995). Main busbar is 400 amps, high grade copper (Westinghouse Electric Cooperation 1964). Control and indicators include power factor meter, voltmeter, ammeter, frequency meter, synchronising devices and varmeter. Fuses are in series with contactor with rating of 1.5~2 times normal load current. Standards for safety vary from designer to designer and the manufacturer. Detailed design is left up to the electrical design and installation company and superior quality equipment or equipment with industry wide standard usage can be incorporated.

SCADA system. Same as currently installed to measure all the drilling parameters. In addition a feature of measuring power and current usage and transient could be included for obtaining additional data sets.

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KERS system. Flywheels are proven technology for power regulation of telecommunication equipment and high power industrial equipment support. They offer advantages of reliable operation, instant response, high efficiency, cost effectiveness and are environmentally friendly with minimal maintenance requirements (Rojas 2003). A high speed generator is coupled to the flywheel so as to attain maximum energy storage density. Magnetic bearing provides frictionless motion of the shaft. The entire unit is mounted in a vacuum enclosure to provide enhanced service life. Further a fully controlled inverter and a variable speed motor is connected which controls the charging and discharging of the unit. A monitoring system is mounted on this for controlled operation (Kirby 2004). Flywheel in the current system is designed for recycling energy. It discharges energy when the load exceeds the prescribed limit. A commercially available flywheel system is considered to fit in the described system. Its ratings are rated power 140 kW, duration 15 seconds, useable energy storage 2244 kW-sec max., flywheel rotational speed 36 to 24 KRPM, input voltage 420 - 600 VDC, recharge rate factory adjustable (per application) 12 minutes, typical stand by losses 2000 Watts, voltage discharge 400–500 VDC (adjustable per application), voltage regulation +/- 1%, DC ripple less than 2%, operating temperature -20 °C to 40 °C, humidity 95% non-condensing, altitude 1500 m max (without derating), audible noise 66 dBA at 1m, height 1981 mm, width 1219 mm, depth 610 mm, weight 872 kg (www.chloridepower.com). **Table 1** summarize the results from data processing and explore the possibility of this flywheel unit for being successfully implemented in the overall system. Other modern high speed flywheel units can also be incorporated considering size constraint of 20 ft ISO container and safety regulations. This investigation is primarily concerned with proving that flywheel unit can be successfully implemented for peak shaving in drilling rigs.

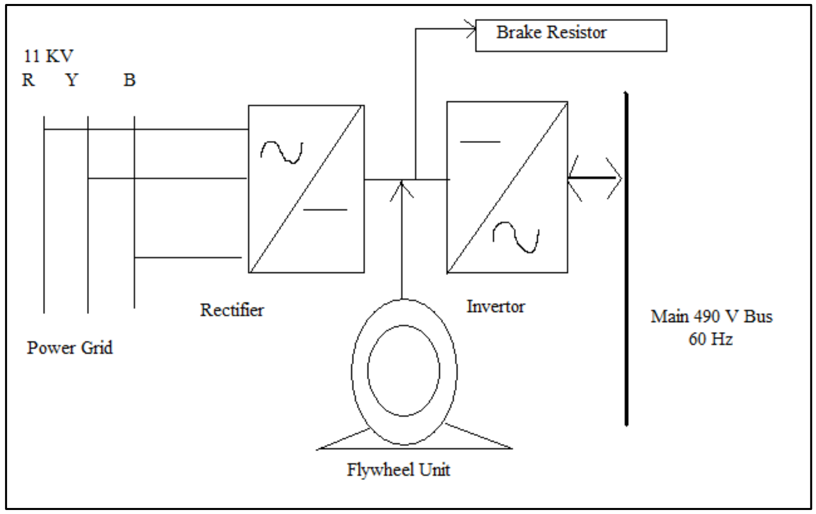

Figure 14 – KERS system positioning and operation.

Table 1 – Matching various parameters of a commercially available flywheel unit with rig data processing results.

Sr. No	*Window Length (seconds)*	*Maximum Energy (KJ)*	*KWh*	*Maximum Power (KW)*	*Flywheel height (cm)*	*Flywheel weight (Kg)*	*Cost ($/KW)*	*No. of Flywheels*	*Speed (Krpm)*
1.	2	785	.2	143	198	872	300	1	24-36
2.	10	28570	8	200	198	8720	300	10	24-36
3.	20	122857	34	217	198	Not Feasible	300	Not feasible	24-36

Results

Table 2 exhibits a cost benefit analysis of grid drilling with peak shaving with conventional diesel drilling. **Table 3** exhibits an abstract of emissions during construction, transportation and usage of drilling equipment (Hendriks and Janzic, 2005). It also indicates that such emissions are much higher in case of conventional rigs as compared to the rig under consideration here.

Table 2 – Cost benefit analysis of KERS system compared to conventional diesel drilling.

Sr. No.	**Parameter**	**Diesel Operation**	**Electric Operation**
1	Consumption	3400 L/day or 870 Gal/day and 11920 Gal overall (Huisman 2006)	366769 KWh@ 7□/KWh(Huisman 20006) and @ 80% of diesel fuel equivalent
2	Cost	**$28600**@ $2.4/Gal for 20 Days	**$26674** for 20 Days
3	Emissions	Noisy operation	Noise free operation (no moving parts of generators)
4	Pollution and Environment	Emissions and pollutants (CO2,CO,NOx,SOx) due to transport and drilling	Environmentally friendly

Table 3 – Emissions data from transport, operation and construction of drilling equipment. Courtesy Ecofys.

		LOC-250	Share (%)	Standard(low)	Share (%)	Standard(High)	Share (%)
Drilling							
CO_2	t/well	42	88	67	90	106	90
No_x	Kg/well	551	93	868	94	1374	94
CO	Kg/well	140	79	220	83	349	82
PM	Kg/well	12	89	19	91	29	91
SO_2	Kg/well	0	0	0	0	0	0

Conclusion

It is the operator who pays for diesel and its transportation. Hence electricity as an alternate energy source with peak shaving technology is lucrative in terms of return of investment and operational cost. In addition it is emission free and environmentally friendly technology. A cost benefit analysis of the containerized system to transfer grid power to a rig, coupled with the KERS indicated that such a design had the potential to save more than $10,000 per week of drilling operations with significantly lower emissions, quieter operation, and smaller size well pad.

This system can eliminate the emissions during drilling and hence can play a crucial role in environmental protection.

Nomenclature

AC	Alternating Current
Amps	Amperes
◦C	Degree Centigrade
Cm	Centi Meters
CO_2	Carbon dioxide
DC	Direct Current
dBA	Decibels
ft	Feet
gpm	Gallons Per Minute
Hz	Hertz
ISO	International Organization of Standards
KERS	Kinetic Energy Recovery and Storage
kG	Kilo Grams
kJ	Kilo Joules
kRPM	Kilo Rotations Per Minute
kV	Kilo Volts
kW	Kilo Watts
kWh	Kilo Watt Hour
l	Litres
LOC 250	Land Offshore Containerized (with hook load of 250 Tonnes)
MATLAB	Mathematics Laboratory
mm	Milli Meter
MVA	Mega Electron Volt
NOx	Family of Nitrogen Oxides
SCADA	Supervisory Control And Data Acquisition System
SF_6	Sulphur Hexa Fluoride
SOx	Family of Sulphur Oxides
V	Volts
XLPE	Cross Linked Polyethylene

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Appendix 1- Theoretical energy audit

The simultaneous power consumption of the rig is never equal to the total power as indicated in **Table A-2.** The actual power consumption is actually governed by the **Table A-1**. Hence an actual audit becomes necessary in order to design a KERS system.

Table A-1 – Shared load of engines and corresponding operating time. Courtesy Huisman.

Sr. No.	Share Load of Engines	Operating Time
1	75%	60%
2	50%	30%
3	10%	10%

Since an actual audit is required real time drilling data should be useful for calculating actual power consumption by the rig. **Table A-3** shows a list of 23 signals with start and end date, header information and sampling frequency. These were taken out of SCADA system already installed on the rig. The colour coding represents signals which were combined in MATLAB for obtaining relevant results.

Table A-2 - Actuator list and the corresponding power consumption.

Table A-3 – List of SCADA signals measured and processed

Main Power Consumers	Power in KW	No.
Drawworks	2X400	2
Mudpump	3X400	3
Topdrive	1X440	1
Wire line traction	2X55	2
Wire line storage	2X25	2
Total installed Power	2578	
Maximum simultaneous Power Consumption	1600	
Secondary Power Consumers		
Shaker	2X3	2
Degasser	18.5	1
Agitator	12X5.5	12
Centrifugal Pumps	3X55	3
Mud Pump liner wash pump	tbd	
BOP control Unit	15	1
Hydraulic Power Unit	2X110	2
Compressors	15	
Miscellaneous	tbd	
Total Installed Power	500	
Max Simultaneous Power Consumption	400	
Hydraulic Drives	2X110	2
Rig Up and Emergency Diesel Pump	40	1

Title	Total Headers	Start	End	Continuous	Sample Time(sec)
Gas Units	51	06-25-07,00:00:00	06-22-2008,23:59:59	Yes	0.5
Auxiliary Pressure	51	06-25-07,00:00:00	06-22-2008,23:59:59	Yes	1
Bit Location	51	06-25-2007 00:00:00	06-22-2008,23:59:50	Yes	10
Block Position	51	06-25-2007 00:00:00	06-22-2008,23:59:59	Yes	1
Depth	51	06-25-2007 00:00:00	06-22-2008,23:59:50	Yes	10
Dexponent	51	05-28-2007 00:00:00	05-25-2008 23:59:50	Yes	10
Flow Bell Nipple	51	05-28-2007 00:00:00	06-22-2008 23:59:58	Yes	2
GainLoss	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
HookLoad	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
MudPump1GPM	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
MudPump1SPM	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
MudPump1Total strokes	51	04-06-2007 00:00:00	01-06-2008 23:59:58	Yes	2
MudPump2GPM	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
MudPump2SPM	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
MudPump2Total strokes	51	04-6-2007 00:00:00	01-06-2008 23:59:58	Yes	2
PillTank1Volume	51	06-18-2007 00:00:00	06-15-2008 23:59:50	Yes	10
PillTank2Volume	51	06-18-2007 00:00:00	06-15-2008 23:59:50	Yes	10
Pipe Velocity	51	06-25-2007 00:00:00	06-22-2008 23:59:50	Yes	10
Pit Volume Total	51	06-18-2007 00:00:00	06-15-2008 23:59:58	Yes	2
Pump Pressure	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
Rate of Penetration	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
ReserveTankVolume	51	06-18-2007 00:00:00	06-15-2008 23:59:50	Yes	10
RotaryTableRPM	51	06-25-2007 00:00:00	06-22-2008 23:59:50	Yes	10
RotaryTableTorque	51	06-25-2007 00:00:00	06-22-2008 23:59:50	Yes	10
ShakerTankVolume	51	06-18-2007 00:00:00	06-15-2008 23:59:50	Yes	10
SICP	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
SuctionTankVolume	51	06-18-2007 00:00:00	06-15-2008 23:59:50	Yes	10
TopDriveRPM	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
TopDriveTorque	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
TotalGPM	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2
TotalStrokes	51	01-6-2008 23:59:00	05-21-2007 00:00:00	Yes	10
TripTankVolume	51	06-18-2007 00:00:00	06-15-2008 23:59:58	Yes	2
WeightOnBit	51	06-25-2007 00:00:00	06-22-2008 23:59:59	Yes	0.5
WireLineDepth	51	11-6-2007 00:00:00	06-15-2008 23:59:58	Yes	2
WireLineLoad	51	06-25-2007 00:00:00	06-15-2008 23:59:58	Yes	2
WireLineSpeed	51	06-25-2007 00:00:00	06-22-2008 23:59:58	Yes	2

Appendix 2 – Conversion Factors

Unit conversion so that Y axis is in terms of power in kW.
For mud pumps:

1gallon (US) = .00378 m^3
1 bar = 10^5 N/m^2
GPM x Pump Pressure (bar) = **.0063** kW………………………………….Equation A1

For top drive and rotary table:

Power = Torque (N-m) x RPM/60 = 2 x 3.14/60W = **1.0046 x 10^{-4}**kW…………Equation A2

An efficiency factor of 0.7 is also multiplied by the amount of maximum power and maximum energy estimated to be supplied from KERS system on the basis of data processing.Unit Conversion is done so that X axis is in terms of time in seconds.

For mud pumps each division on X axis represents 2 seconds which is the sampling frequency from **Table A-3**.

For top drive each division on X axis represents 2 seconds which is the sampling frequency from **Table A-3**.

Appendix 3 – Other Processed Results

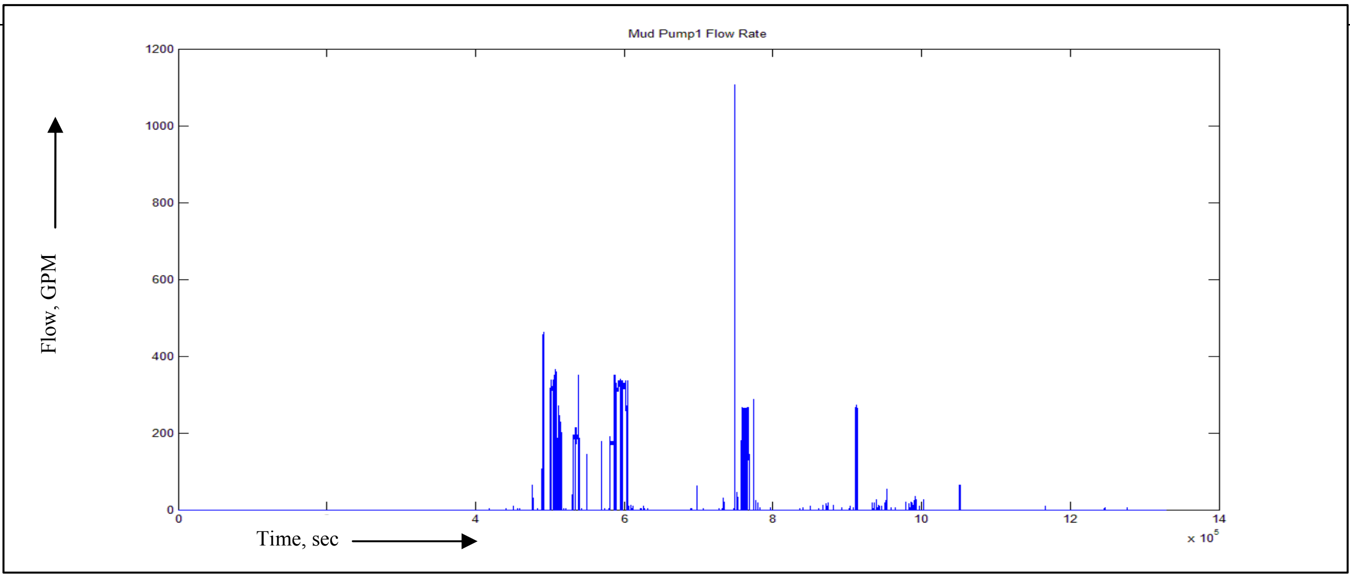

Figure A1 - Mud Pump 1 flow rate.

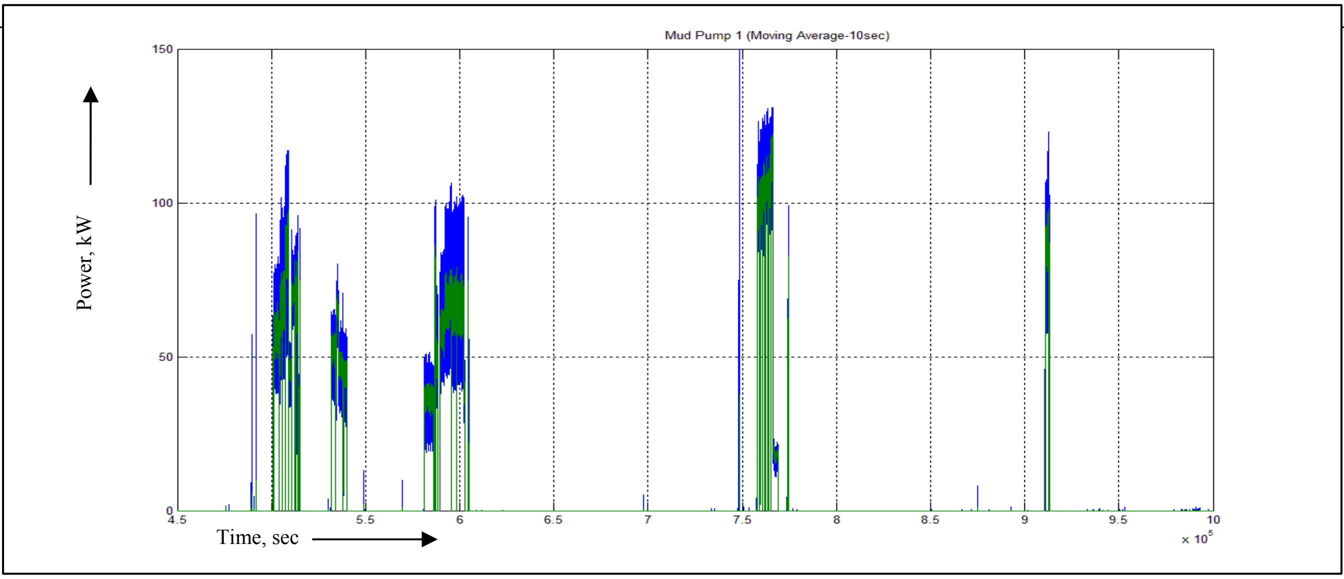

Figure A2 - Mud Pump 1 instantaneous power (blue) and moving average (green) of window length of 10 seconds.

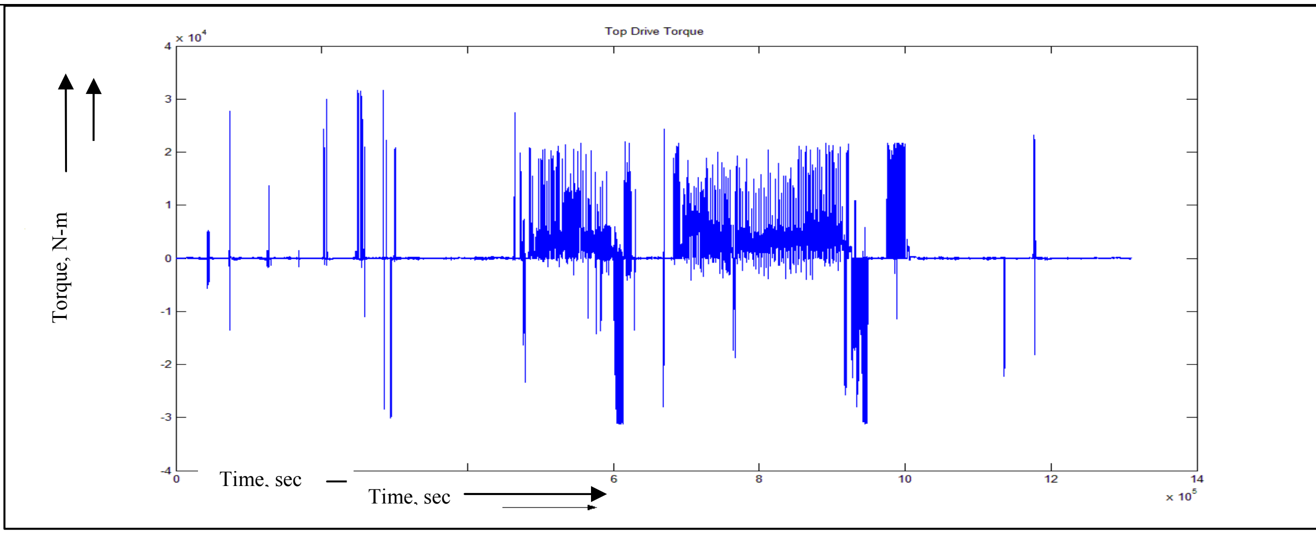

Figure A6 - Top Drive torque variations in N-m with time.

Figure A3 - Mud Pump 1 instantaneous power (blue) and moving average (green) of window length 20 seconds.

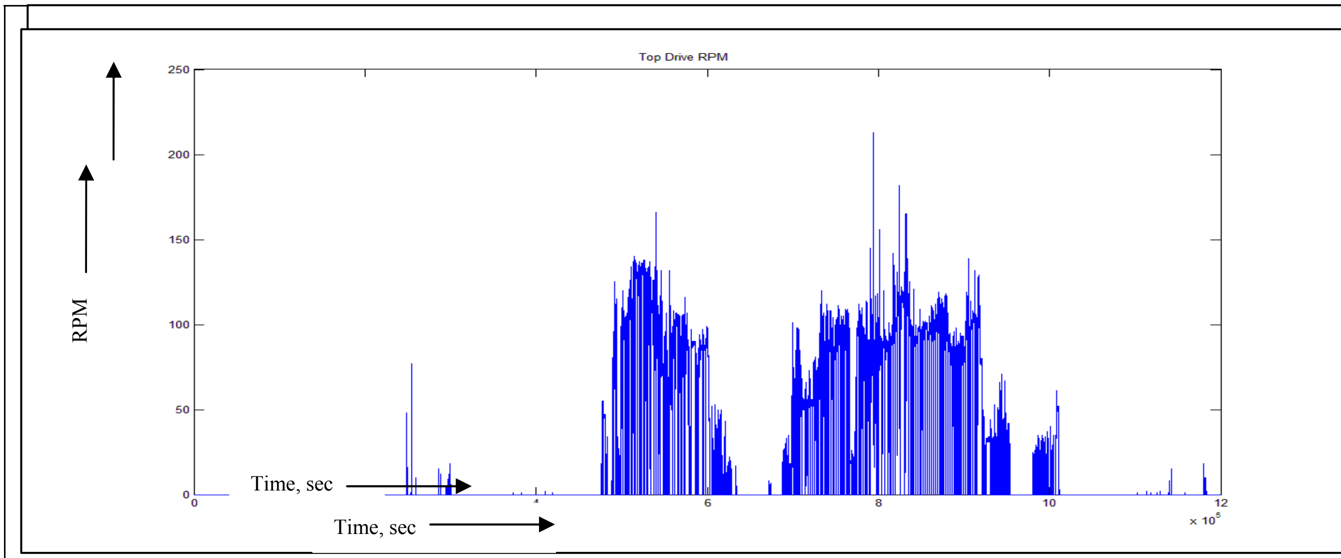

Figure A4 - Mud Pump 2 instantaneous power (blue) and moving average (green) of window length 10 seconds.

Figure A7 - Top drive RPM with time.

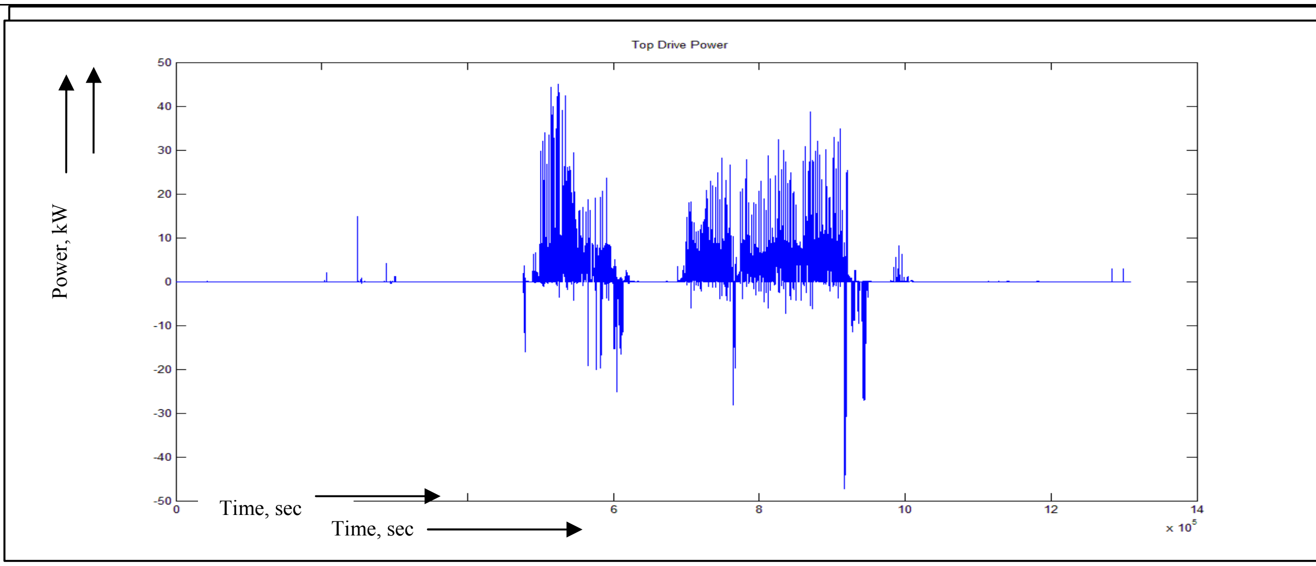

Figure A8 - Top Drive instantaneous power (blue).

Figure A5 - Mud Pump 2 instantaneous power (blue) and moving average (green) of window length of 20 seconds.

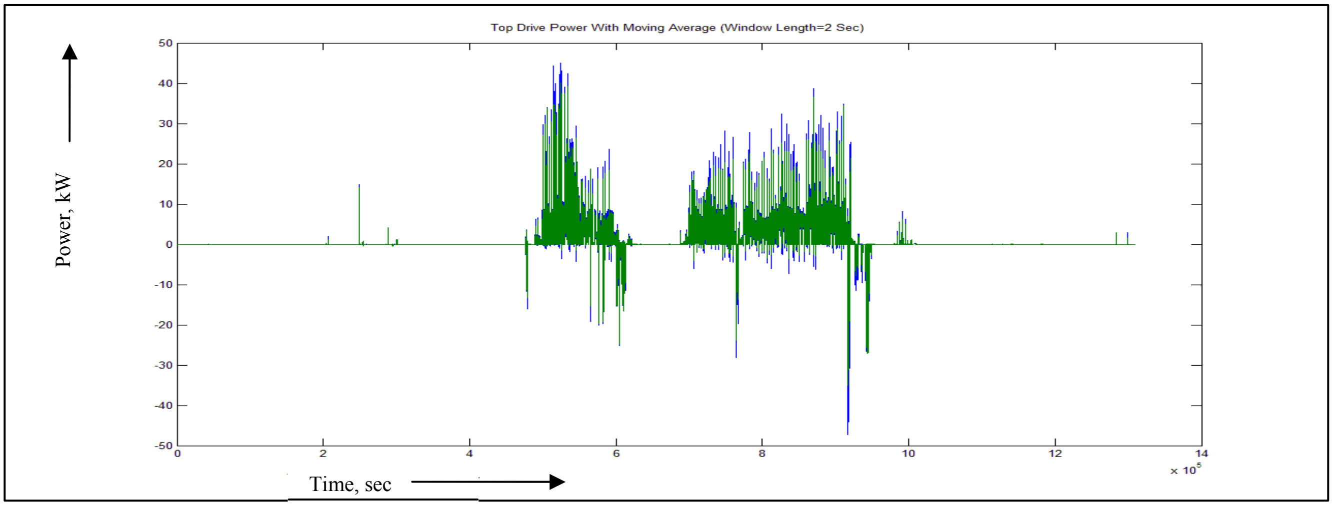

Figure A9 - Top Drive instantaneous power (blue) and moving average (green) of window length 2 seconds.

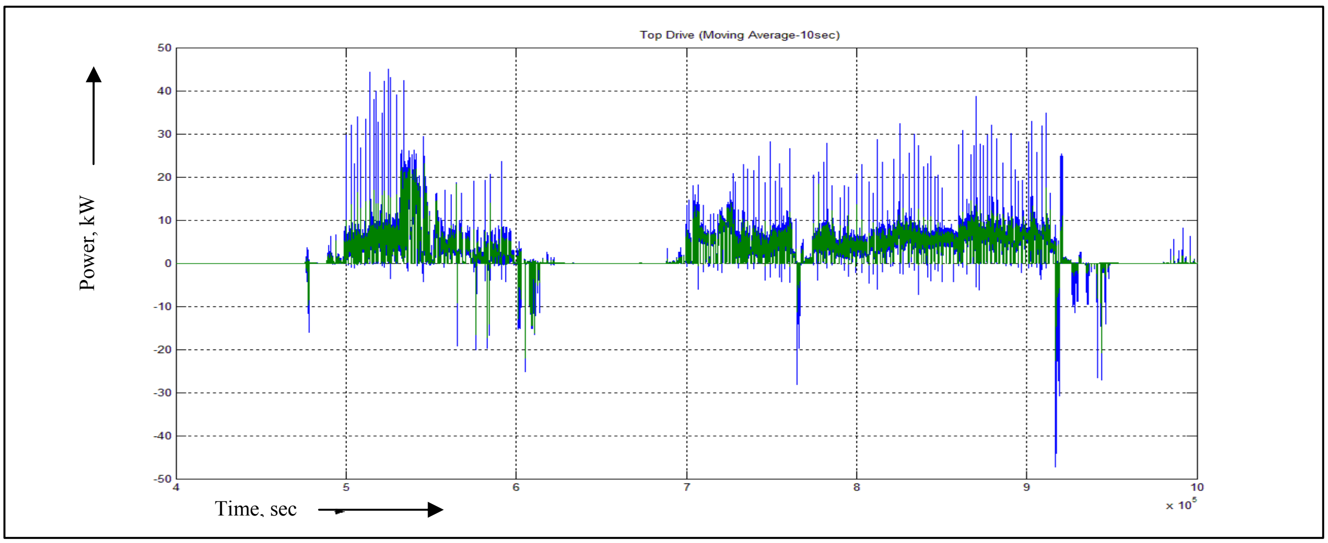

Figure A10 - Top drive instantaneous power (blue) and moving average (green) of window length 10 seconds.

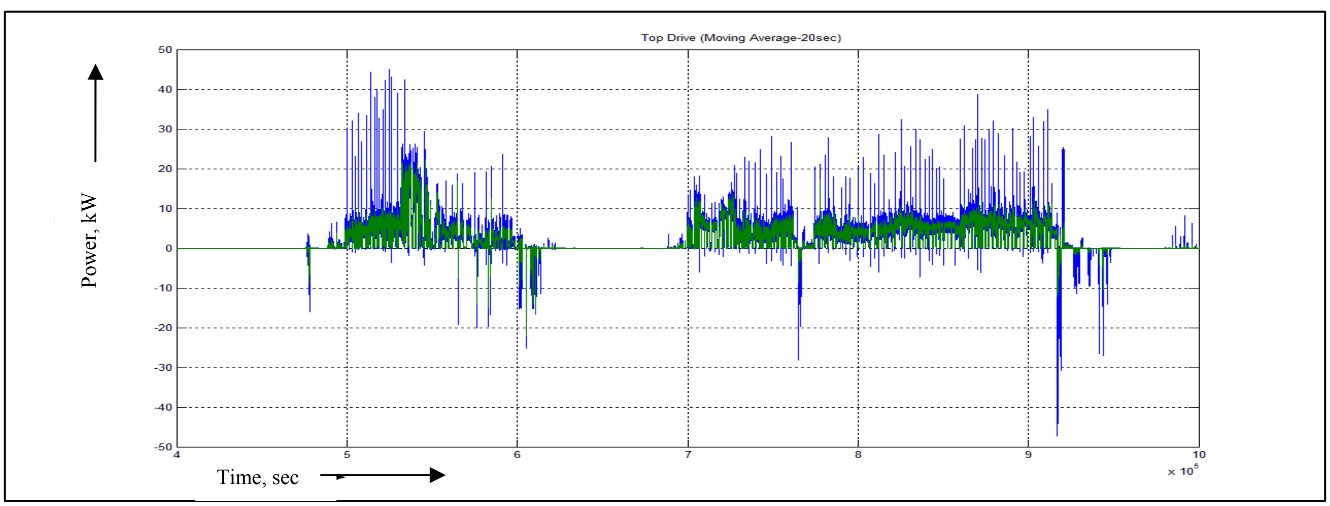

Figure A11 – Top Drive instantaneous power (blue) and moving average (green) of window length 20 seconds.

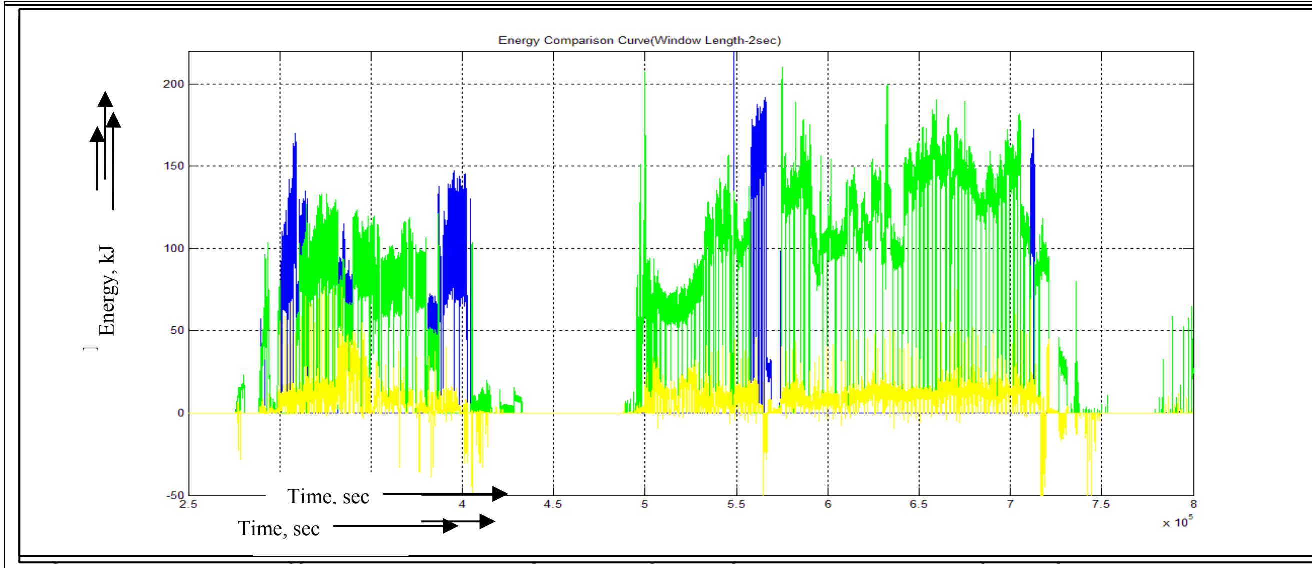

Figure A18 - Energy comparison curve for mud pumps and top drive for a window length of 2 seconds.
Figure A12 - Difference between instantaneous power and moving average curve for mud pumps and top drive , 2sec.

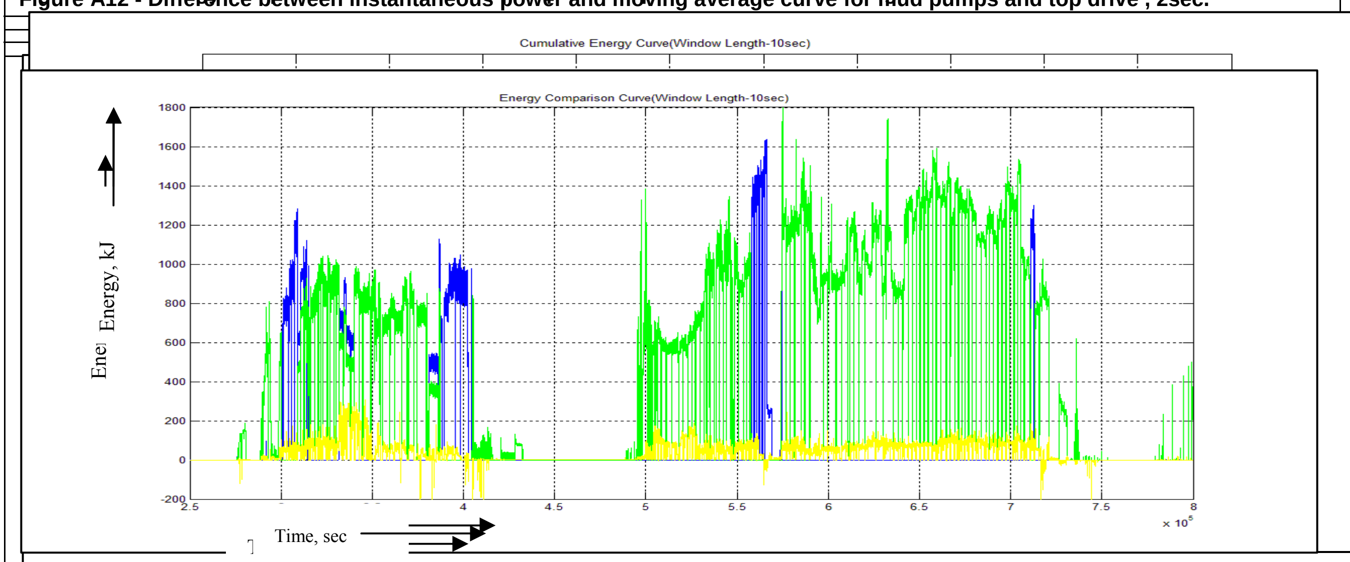

Figure A16 - Overall Energy curve for window length of 10sec (KERS system should be able to provide).
Figure A19 - Energy comparison curve for mud pumps and top drive for a window length of 10 seconds.
Figure A13 - Difference between instantaneous power and moving average curve for mud pumps and top drive, 10 sec.

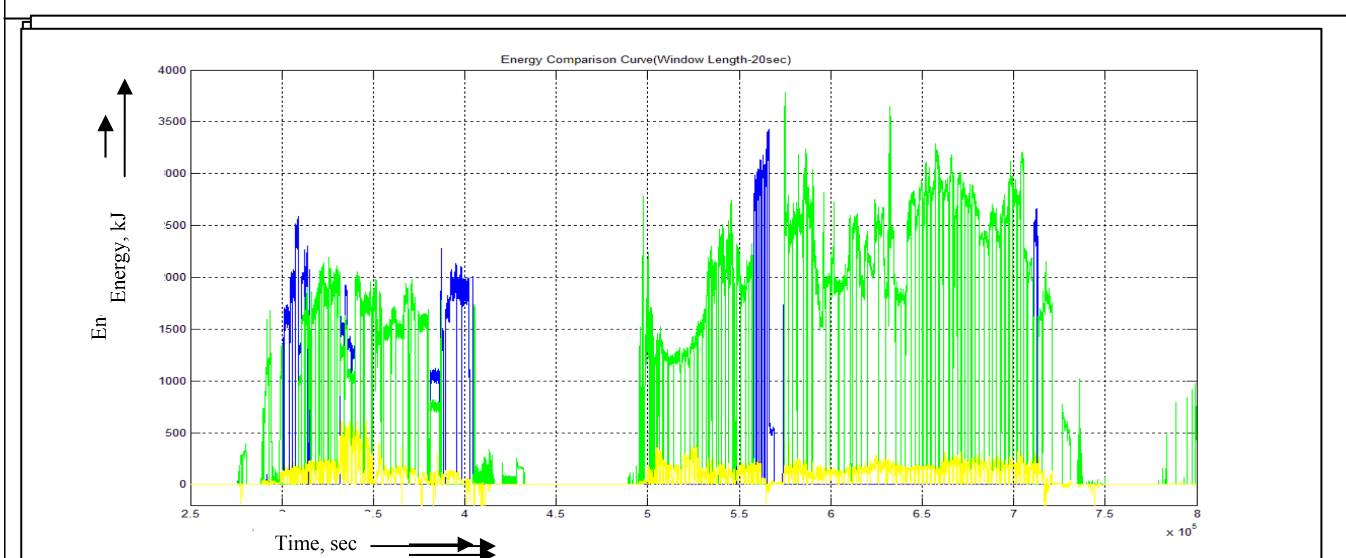

Figure A20 - Energy comparison curve for mud pumps and top drive for a window length of 20 seconds.
Figure A17 - Overall Energy curve for window length of 20sec (KERS system should be able to provide).
Figure A14 - Difference between instantaneous power and moving average curve for mud pumps and top drive , 20sec.

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