Report 13: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines

Technical Progress Report
DOE Award DE-FC26-02NT15464
Work completed: January 1, 2006 – March 31, 2006

Author
Greg Beshouri, President, AETC
Kirby S. Chapman, Ph.D., Kansas State University
Jim McCarthy, Principal, Innovative Environmental Solutions, Inc.
Sarah R. Nuss-Warren, Research Associate, Kansas State University
Mike Whelan, Principal, Collaborative Research Associates, Inc.

Submitted by
Kansas State University
National Gas Machinery Laboratory
245 Levee Drive
Manhattan, KS 66502

March, 2006

Disclaimer

Abstract

This quarterly report re-evaluates current market objectives in the exploration and production industry, discusses continuing progress in testing that evaluates emission control technologies applied to a two-stroke cycle natural gas-fueled engine, and presents a scheme for enacting remote monitoring and control of engines during upcoming field tests. The examination of current market objectives takes into account technological developments and changing expectations for environmental permitting which may have occurred over the last year. This demonstrates that the continuing work in controlled testing and toward field testing is on track

Market pressures currently affecting the gas exploration and production industry are shown to include a push for increased production, as well as an increasing cost for environmental compliance. This cost includes the direct cost of adding control technologies to field engines as well as the indirect cost of difficulty obtaining permits. Environmental regulations continue to require lower emissions targets, and some groups of engines which had not previously been regulated will be required to obtain permits in the future. While the focus remains on NOx and CO, some permits require reporting of additional emissions chemicals.

Continuing work in controlled testing uses a one cylinder Ajax DP-115 (a 13.25 in bore × 16 in stroke, 360 rpm engine) to assess a sequential analysis and evaluation of a series of engine upgrades. As with most of the engines used in the natural gas industry, the Ajax engine is a mature engine with widespread usage throughout the gas gathering industry. The end point is an assessment of these technologies that assigns a cost per unit reduction in NOx emissions.

Technologies including one pre-combustion chamber, in-cylinder sensors, the means to adjust the air-to-fuel ratio, and modification of the air filter housing have been evaluated in previous reports. Current work focuses on final preparations for testing pre-combustion chambers with different characteristics and using mid-to-high-pressure fuel valves. By using the Ajax DP-115 these tests are completed in a low-cost and efficient manner. The various technologies can be quickly exchanged with different hardware, and it is inexpensive to run the engine.

Progress in moving toward field testing is discussed, and a sketch of the first planned field test is presented. While early field tests will be completed using 4-stroke cycle rich-burn engines, later tests will be conducted on 2- and 4-stroke cycle lean-burn engines. The advantages of beginning with the rich-burn engine are summarized.

Table of Contents

Introduction

The objective of this project is to identify, develop, test, and commercialize emissions control and monitoring technologies that can be implemented by exploration and production (E&P) operators to significantly lower the cost of environmental compliance and expedite project permitting. The project team will take considerable advantage of the emissions control research and development efforts and practices that have been underway in the gas pipeline industry for the last 12 years. These efforts and practices are expected to closely interface with the E&P industry to develop cost-effective options that apply to widely-used field and gathering engines, and which can be readily commercialized.

The project is separated into two phases. Phase 1 work establishes an E&P industry liaison group, develops a frequency distribution of installed E&P field engines, and identifies and assesses commercially available and emerging engine emissions control and monitoring technologies. Current and expected E&P engine emissions and monitoring requirements will be reviewed, and priority technologies will be identified for further development. The identified promising technologies will be tested on a laboratory engine to confirm their generic viability. In addition, a full-scale field test of prototype emissions controls will be conducted on at least ten representative field engine models with challenging emissions profiles. Emissions monitoring systems that are integrated with existing controls packages will be developed. Technology transfer/commercialization is expected to be implemented through compressor fleet leasing operators, engine component suppliers, the industry liaison group, and the Petroleum Technology Transfer Council.

Forecasts of future U.S. natural gas demand of 30 trillion cubic feet (Tcf) /yr by 2015 require 36% production growth from 2001 levels. Demand growth will be addressed by both conventional gas and coal-bed methane. The majority of the increase in conventional gas production is expected from three primary areas: Offshore Gulf of Mexico, Rocky Mountains, and Canadian imports. Mature basins in the Southwest and Mid-Continent areas will also contribute to the total domestic supply, and maximizing their output will be necessary to meet the aggressive 30 Tcf gas demand target.

Oil and gas production operations in the United States face a wide variety of environmental regulations that are imposed by multiple, sometimes overlapping, jurisdictions. In particular, onshore production must grapple with existing and emerging regulations that address National Ambient Air Quality Standards for ozone, fine particulates, and NO_2, regulations regarding acid deposition and regional haze, and pending air toxics regulations, all of which will limit emissions from compressor engines. NOx and formaldehyde will be the likely focus. The scope of these regulations will include the assessment of the need for emissions controls on the wellhead and field gathering reciprocating engine-driven compressor and pumping equipment that is ubiquitous in E&P operations. Current estimates are that approximately 15 million horsepower are presently operating in upstream production applications (Hanover Compressor Company 2001 10-K Annual Report filing). At an average size of 250 HP, this implies a total E&P fleet of 60,000 engines.

Though in many oil and gas production areas the airshed emissions inventory is dominated by coal power plants, regulatory agencies continue to pursue incremental reductions in total pollutant loading. Reciprocating engines have been identified as a meaningful source category. This is evident in Federal and State actions, as well as Environmental Impact Statements associated with new development. These engines are used to produce electricity for a leasehold, compress and re-inject natural gas for increased oil production, compress natural gas so that it can be delivered to local gathering systems that ultimately feed into gas transmission pipelines, and drive smaller-load equipment such as pump jacks.

At present, the region with the greatest confluence of emissions concerns for small IC engines is the Rocky Mountain and Intermountain West area. In these regions, significant concerns about regional haze control accelerated the implementation of NOx and fine particulate regulations that are only pending in many other producing areas. However, the incremental adoption of regulations state-by-state, as well as the proximity of many remote production areas in the Southwest to National Parks and Class I Wilderness Area (which are protected air-sheds) may likely stimulate aggressive compressor engine controls in that and other production regions, as well. Finally, the East Texas and Louisiana regions are subject to conventional ambient ozone concerns, and have promulgated strict NOx controls for reciprocating engines. In addition, EPA will propose regulations in 2006 for final adoption in 2007 that will address smaller IC engines in all applications throughout the U.S. These rules include a New Source Performance Standard for IC engine, as well as air toxics standards for: (1) area sources (i.e., engines at smaller facilities), and (2) Engines 500 hp and smaller at major sources.

Oil and gas production from <u>all states</u> will be required for the U.S. to meet the expected 30 Tcf/year gas demand and to minimize the ongoing slide in domestic oil production, and impediments to production that are created by air quality permitting must be alleviated through focused R&D efforts.

Gas compressor operations are an essential element of oil and gas production. Increased emissions constraints on compressor operations affects oil and gas production in four distinct ways:

- The <u>length of time to obtain an emissions permit</u> is increased as multiple jurisdictions evaluate the effects of various pollutants and attempt to define a mutually acceptable permit level for a given engine. Furthermore, permitting may become impossible when performance targets for application of emission controls to small engines are inappropriately established at levels that are technically infeasible or only achievable based on expenditures well in excess of forecasts of the implementing agencies.
- The capital and operating costs of compressor engine operation are increased as this <u>equipment is physically modified and/or operated differently</u> to comply with the air permits.
- The capital and operating costs of compressor engine operation are increased when <u>expensive and maintenance-intensive continuous emissions monitors are required</u>, as is the case in parts of California. In many settings, the cost of this monitoring exceeds the cost of NOx control.
- Compressor operators may be forced to <u>limit the annual hours of operation</u> to avoid exceeding a fixed annual ceiling on allowed emissions.

Each of these situations impedes oil and gas production by:

- Deferring the start of wellhead production, thereby increasing the general business risk in current price-volatile markets and increasing the carrying costs of various lease and development fees,
- Directly increasing the cost of compression services used at the wellhead,
- Artificially limiting the annual take from a well due to constrained operations.

The net effect is reduced oil and gas production for a given cost within a fixed time period. Multiplying this through thousands of production sites will most certainly have a significant negative impact on the ability of U.S. operators to meet domestic energy demands, and on the general productivity of the U.S. hydrocarbon resource base.

In addition, application of controls may result in emissions tradeoffs that can result in other deleterious environmental effects if not properly considered. These issues may be exacerbated by presumptions of technology performance that have not been proven for the engine sizes or operating applications present in oil and gas operations.

These economic and operating burdens to oil and gas operations can be reduced through a focused effort to develop cost-effective retrofit components, engine combustion controls, and engine performance monitoring options. The proposed project will significantly improve the cost-effectiveness of implementing NOx and formaldehyde controls and monitoring on compressor engines, while characterizing emissions tradeoffs – thus ensuring that compliance with air regulations does not prevent oil and gas operations from achieving their maximum productivity at competitive production costs.

Basis of the Project

This project draws heavily on the experience gained from the interstate gas pipeline industry's experience with NOx emissions reductions, and their efforts to develop cost-effective options for extensive deployment throughout their systems. A number of gas pipelines faced EPA statutory deadlines in 1994/1995 to achieve and certify dramatic reductions in compressor engine NOx emissions across a very wide range of ageing and diverse, but critical, equipment. Even though typical pipeline reciprocating compressor engines range in size from 600 HP to 8,000 HP and are largely two- and four-stroke cycle integral compressors, there is some commonality in equipment types and operational concerns with the wellhead and gathering facilities under study in this project. Beginning in 1990, the pipeline industry embarked on a comprehensive R&D program that targeted significant (50%+) reductions in the cost of NOx controls without any significant engine performance compromises. All of the technologies developed had to be field-retrofitable and commercially-supported. That program was a significant success and created a number of technical options that allowed up to 80% NOx reductions in a cost-effective and operationally-acceptable manner. The individuals involved with this current project were key participants in that prior pipeline NOx and formaldehyde reduction program.

The gas pipeline emissions control technology development effort was instructive in that it employed the following six distinct phases of activity, each of which was necessary for success:

- Obtain an industry consensus for

- specific engine types and models on which to focus development efforts,
    - installed cost targets,
    - realistic emissions levels to be achieved under all operating conditions.

- Develop an inventory of installed horsepower to confirm initial industry guidance and to create a useful tool for impact analysis;
- Create a coordinated, core team of engine technologists, regulatory experts, and industry representatives to ensure that engine design issues, regulatory drivers, and practical operating considerations always were addressed simultaneously;
- Aggressively field test component and controls developments;
- Characterize the fundamental relationships between engine operating parameters and exhaust emissions so that accurate, non-instrumented emissions monitoring systems could be deployed; and
- Transfer technology results to organizations with an existing presence in the industry so that equipment could be provided on commercial terms, with emissions guarantees, and supported on an ongoing basis.

This project followed a similar broad outline with the expectation that the end product is a set of cost-effective emissions control and monitoring options that can be applied to a wide range of compressor engines in common use in oil and gas production. Operators will enjoy reduced costs of compliance, greater permitting certainty, reduced costs of emissions monitoring, and possible improved compressor performance due to improved combustion stability. All of this will sum to increased production as wells are brought online more rapidly, compression equipment is run harder and longer to facilitate increased production, and lifting cost savings are reallocated toward additional resource base development.

Current Market Objectives

As gas production increases, more horsepower is expected to be put into use, which increases operator cost in terms of fuel use as well as installation and maintenance of environmental compliance equipment. Thus, market factors, including gas price and demand for production, determine which types of engines and emissions solutions will be appealing to fleet owners, operators, and suppliers as they strive to meet increasingly challenging emissions regulations. Any successful testing program must consider these market drivers, along with impending environmental regulations. This will enable the packages for technology transfer that come out of field testing to more easily gain widespread acceptance as they meet harsh environmental regulations.

Market Drivers—Production and Pricing

The use of reciprocating engine compressors for oil & gas production is a function of overall production volumes and the particular characteristics of producing wells. By far the most common use of E&P field engines is to drive a gas compressor, with additional uses found driving generators for leasehold power and providing direct mechanical drive to pump jacks. The selection and operation of a gas engine-driven compressor system is based on well-specific considerations, notably the wellbore pressure and flow.

Compressors are used to boost the pressure of gas flowing from a wellhead so that it exceeds the operating pressure of the gas gathering or pipeline system (sales lines), and thus can flow into these grids. Often, wells in their initial production phase have very high flowing pressures (1500 psi to 4000 psi) and this gas will flow directly into the sales lines with no need for additional pressure boost. However, over time the pressure in the well naturally decreases as the wellbore area is drained of gas and eventually the well pressure will fall below that of the gathering or pipeline system. At this point, the gas must be compressed up to line pressure to allow admission into the sales lines. In time, the operating pressure of entire gas fields will fall below pipeline/gathering line pressures, and widespread field compression requirements emerge.

At present, the continental US is undergoing an oil & gas drilling boom. The most common metric of exploration activity, the Baker-Hughes rig count, has grown to 1590 rigs from only 600 rigs in January 2000[1]. Over 1300 of these rigs are searching for natural gas. The specific market targeted by this project is comprised of stationary natural gas-fueled engines that are service while wells are in production, and the equipment used to operate gas gathering systems. The equipment used to operate exploration rigs, primarily portable diesel engines, are not a subject of this project, nor is the equipment that is used to operate gas transmission lines.

The current high natural gas prices are largely a function of increased depletion of lower-48 & Gulf of Mexico supplies that has not yet been offset by increased production activity. This depletion has its origins in the long period of low gas prices in the late 80's through the 1990's that forced producers to exploit low cost supplies and to de-emphasize higher-risk (and potentially high reserve addition) exploratory plays. These low prices had their origin in the gas supply shock of 1976-1982, which stimulated its own drilling boom and a large addition of incremental gas supply in both the US and Canada. Subsequently, gas imports from Canada grew significantly through the 1990's as large export pipeline projects came into service. What was initially described as the "Gas Bubble" of the late 1980's became known as the "Gas Sausage" by the end of the 1990's, due to the persistent supply overhang. The low price regime did not provide any incentives for producers to aggressively drill for oil and gas (world oil prices themselves collapsed in 1998/99) and there was no reason to employ capital to build gas additional supply inventories (as proven reserves) in a glutted market.

However, unknown to most observers, the rate of depletion of existing fields (notably in the Gulf of Mexico) began to accelerate around 2000 and what had appeared to be a permanent supply

---

[1] "Baker Hughes North American Rig Counts." *Baker Hughes Investor Relations*. Baker Hughes Inc. 4/21/06. 4/21/06. <http://www.bakerhughes.com/investor/rig/rig_na.htm>

overhang disappeared within a few years. Ironically, this began to occur almost immediately after a set of widely accepted energy market forecasts emerged that projected US gas demand would grow from the then ~22 Tcf/yr to 30 Tcf/yr by 2010. This was primarily based on the assumption that natural gas would fuel most of the growth in US electricity consumption over that period. Indeed, a burst of gas turbine power plant capacity addition projects that began in the late-1990's seemed to confirm these forecasts.

Unfortunately, the rate of depletion has overwhelmed gas producers with deliverability from existing wells falling at a much sharper rate than previously experienced, and even though gas prices turned upwards in 2001, the increased exploration activity stimulated by these price signals has not yet compensated for production declines. Remarkably, despite the fact that annual average wellhead gas prices have increased roughly three-fold over the last 12-years, domestic natural gas production has been flat over that period[2]. This is a clear signal that gas markets are supply constrained at present. This price movement and expectations of permanently high gas price levels have stimulated the current exploration boom.

Of consequence to reciprocating engines is that the recent increase in exploration efforts (and price) is targeting many formations that were previously deemed too risky or uneconomic to develop. Many of these plays are termed "unconventional" gas resources: coalbed methane, shale and tight sands gas, and current forecasts show they are providing most of the incremental production that is offsetting broader production declines elsewhere A common characteristic of unconventional resources is that they produce at lower pressures than wells in conventional sedimentary basins, thus they have a greater need for compression over a longer period of their productive lives. Some unconventional wells never produce at gathering system pressures and must employ gas compression during the entire productive life of the well in order to have product delivered into the pipeline grid.

In many cases, a primary economic factor that determines whether a gas field should be developed is the size of the field and the number of wells required to drain the reservoir. Current pricing allows many smaller, lower-flow wells to be economic–particularly unconventional resource wells. This is demonstrated by the simple count of producing wells. In 2004, there were 405,000 active wells producing essentially the same amount of gas as in 1994, when only 291,000 wells were in service[3].

While each field is different and some fields employ central compression to minimize the overall cost of compression service, the general impact of smaller, lower-flow wells is wider use of gas compression equipment. In addition, the development of some of these new fields has been in areas not previously served by gas infrastructure. Thus, the footprint of gas gathering systems has been significantly expanded, and additional engine horsepower has been installed to meet these market demands.

---

[2] "Natural Gas Summary." *Natural Gas Navigator*. Energy Information Administration. 4/7/06. 4/21/06. <http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm >

[3] "Number of Producing Gas and Gas Condensate Wells." *Natural Gas Navigator*. Energy Information Administration. 4/7/06. 4/21/06. <http://tonto.eia.doe.gov/dnav/ng/ng_prod_wells_s1_a.htm>

Current status and trends in the natural gas market thus have the following implications for field compression requirements, and for the use of stationary gas engines:

- Additional field compressors will be required because of the larger number of wells. This effect would tend to reduce the average size of gas compressors employed due to the lower flows from smaller wells.

- Additional field compressors will be required because the operating pressure of unconventional resource wells is normally less than from conventional wells. This production must then be boosted in order to meet gathering system pressures. This may or may not have an effect on the unit size of the compressors, due to the variance in the size of the wells.

- Field compressors on existing wells will be operated longer, as wells will remain economic for a longer period even as production and flows diminish. As an example, there are numerous wells in the Hugoton Basin that operate under vacuum conditions in order to draw the gas out of the reservoir. This production must then be compressed in order to flow into the gas gathering and transmission systems.

- Gas gathering systems will be expanded to serve production that is occurring over a broader geographical area. As gathering system compression is much larger on a unit basis than field engines, it is likely that larger units (~1000 HP and greater) will be employed in that duty.

- Where gas compressors are used to force gas back into oil reservoirs for secondary or tertiary oil recovery, the high oil prices will encourage continuation of this practice beyond the point where it would have terminated historically. This implies both longer use of existing gas compression and/or increased use of compression in fields where secondary/tertiary recovery was not deemed economic.

The implications these market trends have for the specific types of reciprocating engine that will be employed for gas compression are not straightforward. Rich-burn engines (with non-selective catalytic reduction) will likely remain the preferred engine type, due to the certainty of their emissions permitting. Since NSCR-controlled rich burns can achieve sub-1 gram NOx levels readily, in emissions constrained regions these provide the greatest certainty of operation and the lowest transaction costs (ability to obtain air permits). However, their lower fuel efficiency will narrow their advantage over lean burn engines, particularly under the current price scenario. In addition, a very common complaint about rich-burn engines involves the engine control technology

Some large HP lean burn engine models can achieve a ~1 gram NOx performance level. For all lean-burns, their fuel economy is ~10% better than a comparably sized rich burn engine, and their maintenance profile is often more appealing. However, it may be difficult to site lean burns when a rich-burn "equivalent" is available. This determination will be based on local regulations, and on the particular details of the contract between the compressor rental fleet and the gas producer regarding fuel expense and maintenance.

Where the equipment is owned and operated by the gas producer, which is common for the larger operating companies, the incentive to reduce fuel expense is more direct, and for many applications lean burn units will be favored over rich burns. However, air permitting is not a discretionary item and many operators do not have any options other than rich burn engines with NSCR controls. This is an example of where improved lean burn retrofit engine equipment may expand the applicability of lean burn engines, and thus provide substantial fuel cost savings to the operator, while conserving gas for consumer applications. The total amount of gas used in field operations is not trivial–in recent years this has totaled almost 750 Bcf/yr (valued at $6 Billion at current prices).

In summary, current gas market dynamics indicate that the use of reciprocating engines to support gas production will continue to grow, and that while emissions regulations place a burden on operators, the regulations can be satisfied by the use of rich-burn engines with NSCR controls, though at a significant fuel penalty. As gas prices remain high, this fuel penalty becomes a greater determinant of the engine selection, and is creating a market pull for the development of lean-burn retrofit equipment. Sometimes troublesome NSCR controls operation likewise leads to significant interest in improving the key components that comprise the rich-burn NSCR control system.

Environmental Drivers – State Actions on Permits, Guidance, and IC Engine Rules

This section addresses emissions targets based on existing rules and available permits from states with oil and gas operations, as well as examples of guidance and rules for California and New York–two states that often set precedent for emission targets in other regulatory jurisdictions.

Small Engine Regulatory Summary for Select Oil and Gas States

A summary follows highlighting the prevailing size-based permitting threshold for several states with oil and gas operations. A brief discussion of emission limits/factors is also included – although most permits to date have been based on manufacturer specification. Currently, the reliance on manufacturer specifications is apparently being supplanted by State's perspective on presumptively achievable emission levels. These more recent tendencies are being driven by Draft EIS documents that present emission targets that continue to be reviewed and debated. However, the EIS targets are promoting NOx emissions on the order of 1 to 2 g/bhp-hr regardless of engine size or application. In some cases, these emission levels may not have been demonstrated in practice or have been reviewed for economic feasibility for that range of engine sizes and applications in oil and gas operations.

These data were taken from state regulations and available permit data. Several states had searchable permit files but lacked sufficient information to easily search by source category and size.

Size-based thresholds include:

- New Mexico: Engines 200 hp and larger require permits.

- Oklahoma: Units <50 hp or <150 hp and more than 20 years old are considered *de minimis* for permitting.

- Colorado permitting requirements are based on size and operating hours:

  - >175 hp, operates > 1,450 hr/yr;
  - >175 hp to ≤ 300 hp, operates < 850 hr/yr;
  - > 300 hp to < 750 hp, operates < 340 hr/yr; and
  - ≥ 1200 hp, at single location < 12 consecutive months or is a seasonal source that operates ≥ 3 month/yr (2,190 hr/yr).

- Texas has different requirements depending upon location (relative to ozone nonattainment status) with 50 hp de minimis threshold in the Houston/Galveston area, and 150 hp in other areas of concern.

- Wyoming: Permit requirements include rich burn units at 200 hp and lean burn units at 300 hp.

In general, the emissions permitted include NOx and CO. Formaldehyde is included in some permits, but often it is only reflected as an emission factor for reporting purposes. New units must comply with MACT requirements for engines greater than 500 hp at major sources. No pre-established emission targets are prevalent at this time in the regulations or permits for most oil and gas states. NOx limits on the order of 2 g/bhp-hr are most common in permits, with levels as low as 0.5 g/bhp-hr included in some permits. CO on the order of 1 to 3 g/bhp-hr is most prevalent. Wyoming permits include NOx limits at 1.0 g/bhp-hr and CO at 2.0 g/bhp-hr for rich burn engines and as low as 0.5 g/bhp-hr for lean burn engines. When required, compliance is typically based on a performance test for NOx and CO and any subsequent tests can be conducted using a portable analyzer.

States that Lead Regulatory Criteria–Examples of Guidance and Requirements from California and New York

To identify trends in regulatory criteria, this section discusses "leading edge" emission targets related to two states with a tendency toward more stringent requirements due to special concerns in their regions–California and New York. Although these are not primary oil and gas producing states, CA guidelines and a recent revision to the NY RACT regulation may serve as precedent for other areas. This section discusses air quality criteria related to:

- Review of guidance on distributed generation from California, based on a California Air Resources Board (CARB) document, "Guidance for the Permitting of Electrical Generation Technologies".
- Review of a recent New York RACT Rule that requires rigorous limits for existing IC engines throughout the state.

California Guidance for Permitting of Electrical Generation Technologies

In July 2002, CARB issued guidance for permitting electrical generating units. The document is intended to provide: (1) local districts in California guidance for making permit decisions for electrical generation technologies, especially generation close to the place of use (i.e., distributed generation); and (2) applicants with guidance for developing a project plan/application. The document addresses technologies and emissions performance for turbines smaller than 50 MW and internal combustion engines.

The CARB permitting guideline document includes:

- A review of control technologies considered BACT in California for pollutants including NOx, CO, VOCs and particulate matter.
- Emission performance for BACT expressed in terms of lbs/MW-hr, as follows:
  - NOx = 0.5 lb/MW/hr (equivalent to 0.15 g/bhp-hr or 9 ppmvd at 15% O_2).
  - VOC = 0.5 lb/MW/hr (equivalent to 0.15 g/bhp-hr or 25 ppmvd at 15% O_2).
  - CO = 1.9 lb/MW/hr (equivalent to 0.6 g/bhp-hr or 56 ppmvd at 15% O_2).
  - PM = 0.06 lb/MW/hr (equivalent to 0.02 g/bhp-hr).
- Note that the NOx limit for IC engines is the same as the turbine NOx limit for units < 3 MW.
- The emission levels in the guidance require post combustion controls. For NOx, NSCR is required for rich burn engines and SCR is required for lean burn units. CO and VOCs require an oxidation catalyst for lean burn engines, while NSCR addresses these pollutants for rich burns.
- CARB notes that rich burn engines from 86 to 750 bhp have achieved these emission levels.
- An initial performance test and subsequent periodic testing are identified as reasonable monitoring requirements. For units less than 100 hp, a quarterly portable analyzer test is recommended in lieu of reference method source tests.
- CARB recommends requirements for parameter monitoring (e.g., catalyst temperature) and operator requirements to log and report all maintenance activities for the engine and emissions control equipment.
- CARB notes that existing local district permitting thresholds for IC engines vary, but implies that a 50 bhp threshold, consistent with the lowest threshold from district regulations, is appropriate.

New York RACT Rule

In February 2004, New York revised its existing NOx RACT rule to extend the applicability and lower the NOx emission limit for IC engines (NY State DEC Rules, Subpart 227-2, Reasonably Achievable Control Technology for Oxides of Nitrogen). The rule addresses combustion sources, but the 2004 revisions focused almost solely on IC engine NOx emission requirements. The NY RACT Rule affects existing engines statewide and includes the following requirements:

- Applicability threshold of 200 hp in nonattainment areas and 400 hp in the rest of the state.
- For natural gas-fired IC engines, an emissions limit of 1.5 g/bhp-hr effective April 1, 2005.

- Alternatively, an IC engine may comply:
  - By reducing NOx emission 90% or more from the unit's 1990 baseline; or
  - By using a "system" averaging plan that demonstrates equivalent reductions for all affected equipment included in the plan. The averaging plan must be approved by the state and include provisions to validate emission reductions.
- An operator can pursue an alternative NOx emission limit based on a demonstration that the NOx limit is not economically or technically feasible.
- Compliance must be certified using an EPA Reference Method source test. Test frequency is not clearly defined in the rule.
- Emergency power units are exempt.

Controlled Tests

Controlled tests are being conducted on the Ajax DP-115 at Kansas State University to address a series of upgrades intended to improve emissions. The DP-115 is a mature two-stroke cycle lean burn (2SCLB) engine, typical of those found at gathering sites. While many technologies have already been tested, more remain. Progress in controlled testing during this quarter was focused on preparation for upcoming tests.

The next tests scheduled involve pre-combustion chambers (PCCs) with differing orifice sizes. The orifice size, combined with the pressure on the PCC fuel line, determines the richness of the mixture in the pre-combustion chamber. Preparations for testing the remaining pre-combustion chambers continued. The preparations included re-assembling the PCC fuel line, assembly of the PCC, and improvement of the cooling to the dynomometer. However, delays arising from engine maintenance prevented the tests from being conducted. Meanwhile, final preparations for testing higher-pressure fuel valves were underway. The upgraded fuel flowmeter was installed, and acquisition of the natural gas compressor for the fuel continued. Additionally, preliminary plans for future technology installation, such as scavenging port modification, ignition energy control, and exhaust gas recirculation (EGR) were examined. For EGR, extensive plumbing and improved air intake measurement are both necessary, and initial technical drawings were created.

Remote Monitoring and Control

Although the controlled tests for the two-stroke cycle lean burn (2SCLB) engine are still being conducted at NGML, progress toward field testing using remote monitoring and control is underway. The site for the first field tests, which will be conducted on four-stroke cycle rich burn engines, has been selected, and tests could begin as early as June. The remaining field tests will be conducted as sites are chosen and final control solutions are selected for each type of engine.

For four-stroke cycle rich-burn (4SCRB) engines the goals are to monitor the alarm status of the air-to-fuel ratio controllers and use full-authority fuel control. The A/F ratio will be measured with an exhaust gas oxygen sensor (EGO), or lambda sensor, in the exhaust stream. The signal will feed back into an Altronic controller, which will control the A/F ratio to a programmed setpoint by determining the opening of fuel valves. The keys to this strategy include assuring that the controller can achieve the setpoint for the engine's entire operating range and verifying that the lambda sensor stays in compliance. To ensure full-authority control, the controller and valve will be examined to ensure that the needed A/F ratios could be achieved under all likely conditions, and any specialized algorithms for the controller will be developed. To monitor combustion performance and complement the oxygen sensor, an ion sense signal will be used. The ion sense signal, which is a current of ions produced in the combustion chamber, is related to the A/F ratio in the combustion chamber, so it will provide a reliable check for the lambda sensor. It can also detect misfire, detonation, instability and relative balance. The DAQ used to run the controller will be connected to a network to provide remote monitoring.

The engine selected for this test is the CAT 342 (150-200hp) at the Eastern Municipal Water District. It is a representative engine, and has a challenging emissions profile at 0.15g NOx and 0.6 g CO/hp-hour. Although it is not located at a gathering site, it is running a centrifugal compressor at similar workloads to those at gathering sites, and many engines of this type are located at gathering sites. This site is particularly good for the first field test for several reasons. Firstly, this engine has already been released for testing, which means test can begin sooner than at other sites and that a loss in productivity on this engine will not harm its operator. This helps maintain and develop good relationships with operators, which is essential to technology transfer as well as field testing. Secondly, since AETC has done previous work on this engine, much of the instrumentation and infrastructure already exists on this engine, which lowers the cost of testing.

Plans for the remaining field tests are still underway. While the control strategy for the four-stroke cycle lean-burn is expected to be much the same as for the 4SCRB, the control strategy for the 2SCLB will not be finalized until the controlled tests at Kansas State University are completed. However, tentative ideas for sites are being developed. Discussions about sites with fleet owners and operators are beginning, and significant support is expected from engine manufacturers. A meeting has been planned for late spring which would include possible field testing hosts. They would give advice on superior field testing sites which will allow all the remote monitoring and control goals to be met.

Conclusions and Future Work

Although much remains to be done, considerable progress has been made in the last quarter. Controlled tests are continuing, and the next tests to be pursued will be conducted soon. Plans for beginning the first field tests to assess solutions for remote monitoring and control have been finalized, and that testing is expected to begin in June. Finally, given the current market and environmental drivers in the exploration and production industry, testing is heading in the right direction to find emissions solutions which will have the potential to gain widespread acceptance in the industry, allowing the project to meet its goal of technology transfer.

Acknowledgements

The authors sincerely appreciate the technical assistance from: Mr. Gene McClendon, and Mr. Bruce Chrisman. Advanced Engine Technologies Corporation, Altronic, Inc., Cooper-Ajax, Diesel Supply Company, Dynalco, Exline Inc., Progressive Equipment Company, TSI, and Emerson Process Management contributed equipment, sensors, and transportation services to this

project. Without these individuals and companies, this phase of the project would not have been possible.