TORIS EXPLORATION MODEL

NIPER/BDM-0358

BDM OKLAHOMA
A BDM Federal Company

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TORIS ONSHORE EXPLORATION SYSTEM

for

Management and Operating Contract for the Department of Energy's National Oil and Related Programs

by

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Prepared for
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1.0 INTRODUCTION

1.1 Overview of the System

The purpose of this documentation is to provide a detailed description of the models and methods used to assess future exploration and development of the domestic onshore undiscovered oil resource. The methodology was designed to be consistent with methods used in the Total Oil Recovery Information System (TORIS). This documentation provides details on data acquisition, analytical assumptions, data evaluation techniques, engineering analysis, economic evaluation, and timing algorithms used in these models to assess future oil exploration activities. The goal is to provide an overview of the full analytical system as developed and currently implemented by TORIS.

The report outlines the general approach and data sources used in describing the resource remaining in undiscovered reservoirs nationwide. The analysis relies on the quantification of undiscovered resources developed by the U.S. Geologic Survey (USGS). The current description of the remaining undiscovered resource is defined by their assessment published in 1995 (1995 National Assessment of United States Oil and Gas Resources—Results, Methodology, and Supporting Data). Reservoir properties are based on data gathered from existing oil reservoirs within individual plays. A database of existing oil reservoirs was created by merging the existing TORIS database with databases created by NRG associates (NRG, 1993). Procedures have been established to allow easy updates to the system as new data become available. The incorporation of new or expanded assessments or new play characterization, can be readily handled in the existing structure.

The modeling procedures include a comprehensive assessment method for determining the relative economics of various prospects based on future financial conditions, the nature of the undiscovered resource, prevailing risk factors, and the available technologies. The model evaluates the economics of exploration and development from the perspective of an operator making an investment decision. The individual accumulation is the unit of analysis for these models. The evaluation of each accumulation considers the full cost of developmental drilling and production. An accumulation, by definition, is the collection of all pools within a field within a given geologic play. The exploration evaluation considers both the size and frequency of undiscovered accumulations in order to determine the order of discovery within a play. Investment efficiency is used as the criteria in determining the order in which plays are explored. A timing model determines the development timing of each newly discovered accumulation on a sunk exploration cost basis constrained by capital and regional rig availability.

Technology advances, including new exploratory evaluation, improved drilling and completion practices, and advanced production and processing operations can be explicitly modeled to determine direct impacts on production, reserves, and various economic parameters. All analyses are performed on individual accumulations.

The output reports from the model provide detailed, quantitative results needed for R&D and policy planning related to the full domestic oil resource. Consistent with the existing TORIS system for evaluating the known oil resource, results from the oil exploration system can be used to analyze, evaluate, and compare DOE's oil R&D program objectives, either by individual program area or in their entirety. Furthermore, the model design provides flexibility to quickly evaluate competing or new tax, environmental, or other policy alternatives in a consistent, comprehensive manner. These capabilities are critical to completing DOE's mission of developing and promoting a highly effective program to maximize future domestic oil production.

1.2 Background of USGS Reserve Description

The 1995 National Assessment of United States oil and gas resources was a three year study which covered both onshore and state waters. This study defined the proved reserves, reserve growth, and undiscovered reserves by play.

The area of study was divided into eight regions (see Figure 1-1), and the regions were subdivided into 71 separate geological provinces. Although the provinces are numbered from 001 to 072, some were not assessed due to lack of either data or hydrocarbon resource. The provinces are subdivided further into plays, the basic unit of assessment.

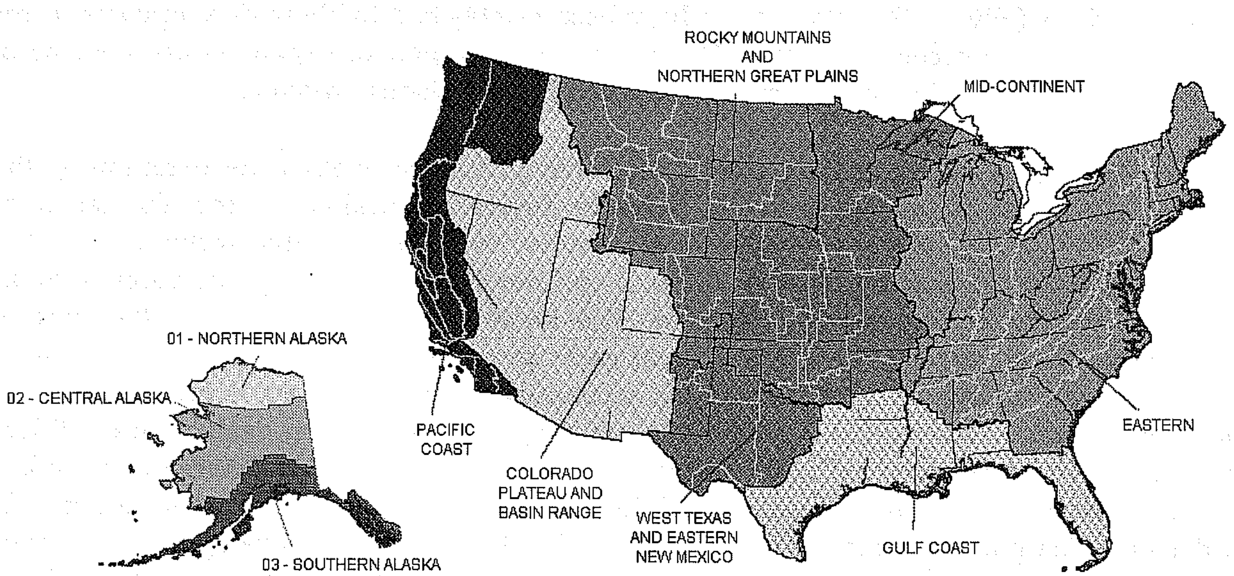


Figure 1–1 USGS Region Map

For the eight USGS regions, the USGS defined a total of 562 plays (see Figure 1-2). These plays consist of 242 "classified" plays and 320 "unclassified" plays. Plays are classified as oil, gas, or oil and gas based on prior production. Plays with no defined resource, due to lack of production history, are defined as unclassified.

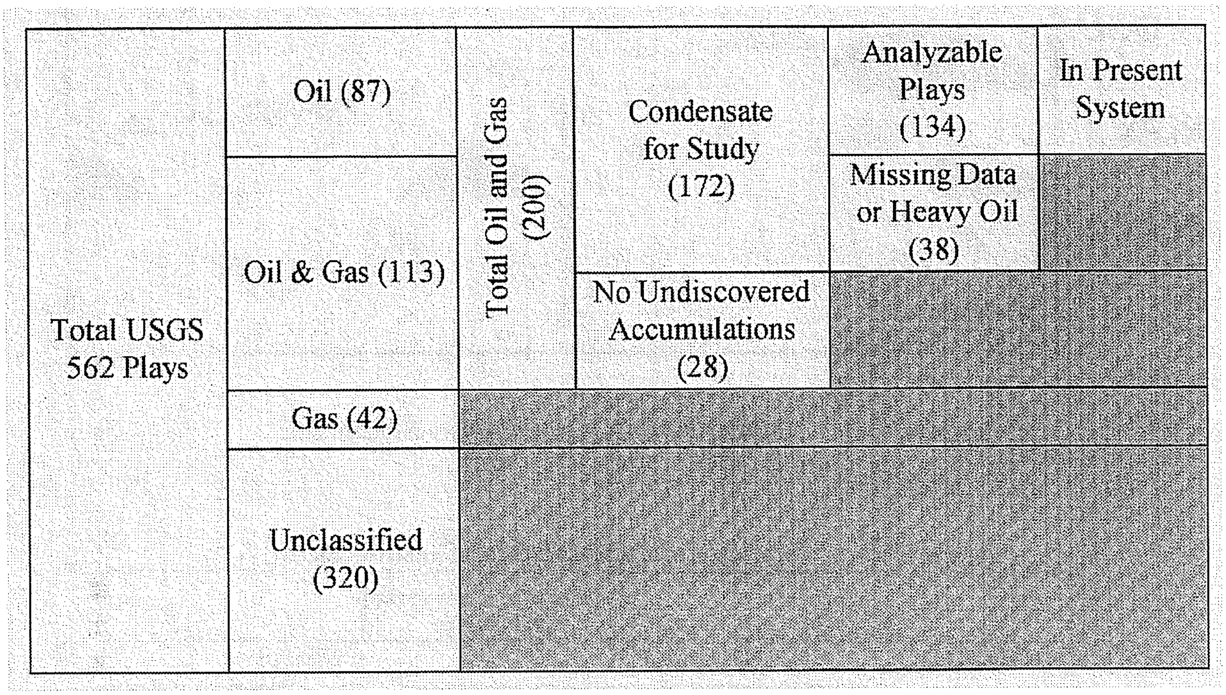


Figure 1–2 Inventory of USGS Plays

A play number is composed of four digits: the first two digits correspond to the province in which the play occurs; the last two digits identify the individual play. For example, play number, 0101 is play 1 in province 1, which further corresponds to the Topset play in Northern Alaska.

A play is defined by the USGS as a set of known or postulated accumulations or pools of oil and or gas that occur in a limited area and have similar ages and geologic settings (see Figure 1-3). The plays assessed by the USGS considered only those plays of which were thought to contain accumulations greater than 1 MMBO or 6 BCFG. Thus, a size class distribution was developed to define the technically recoverable reserves in each play (see Table 1-1).

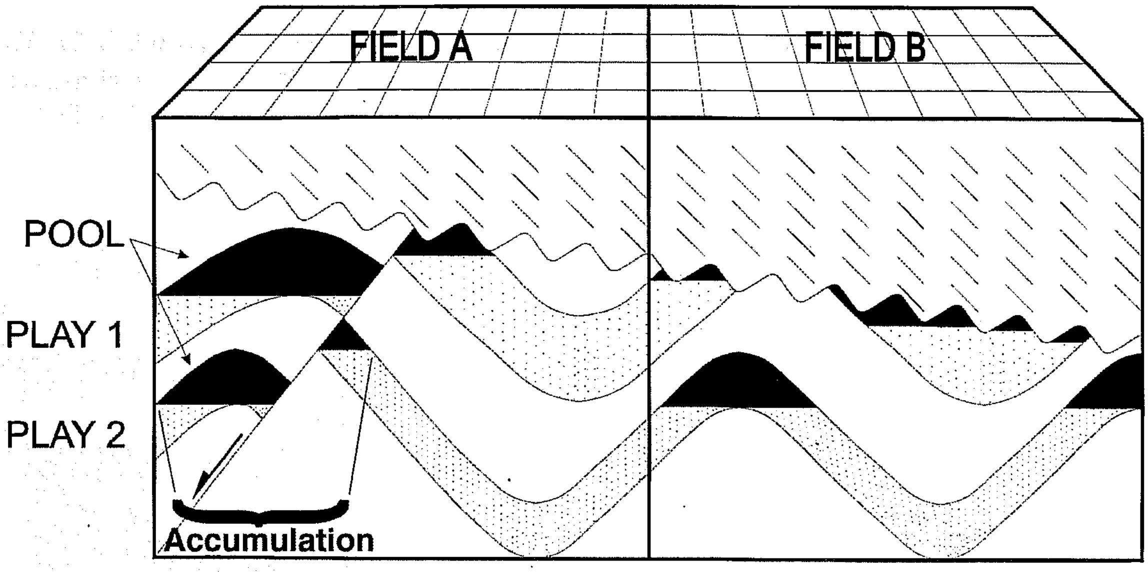


Figure 1–3 Field, Play, Accumulation Schematic

Table 1-1 Exploration Model Size Classification

	Technically Recoverable Oil Range	
Size Class	**≥ MMbbl**	**< MMbbl**
1	1	2
2	2	4
3	4	8
4	8	16
5	16	32
6	32	64
7	64	128
8	128	256
9	256	512
10	512	1,024
11	1,024	2,048
12	2,048	4,096
13	4,096	8,192
14	8,192	16,384
15	16,384	32,768

The following terms are as defined by the USGS:

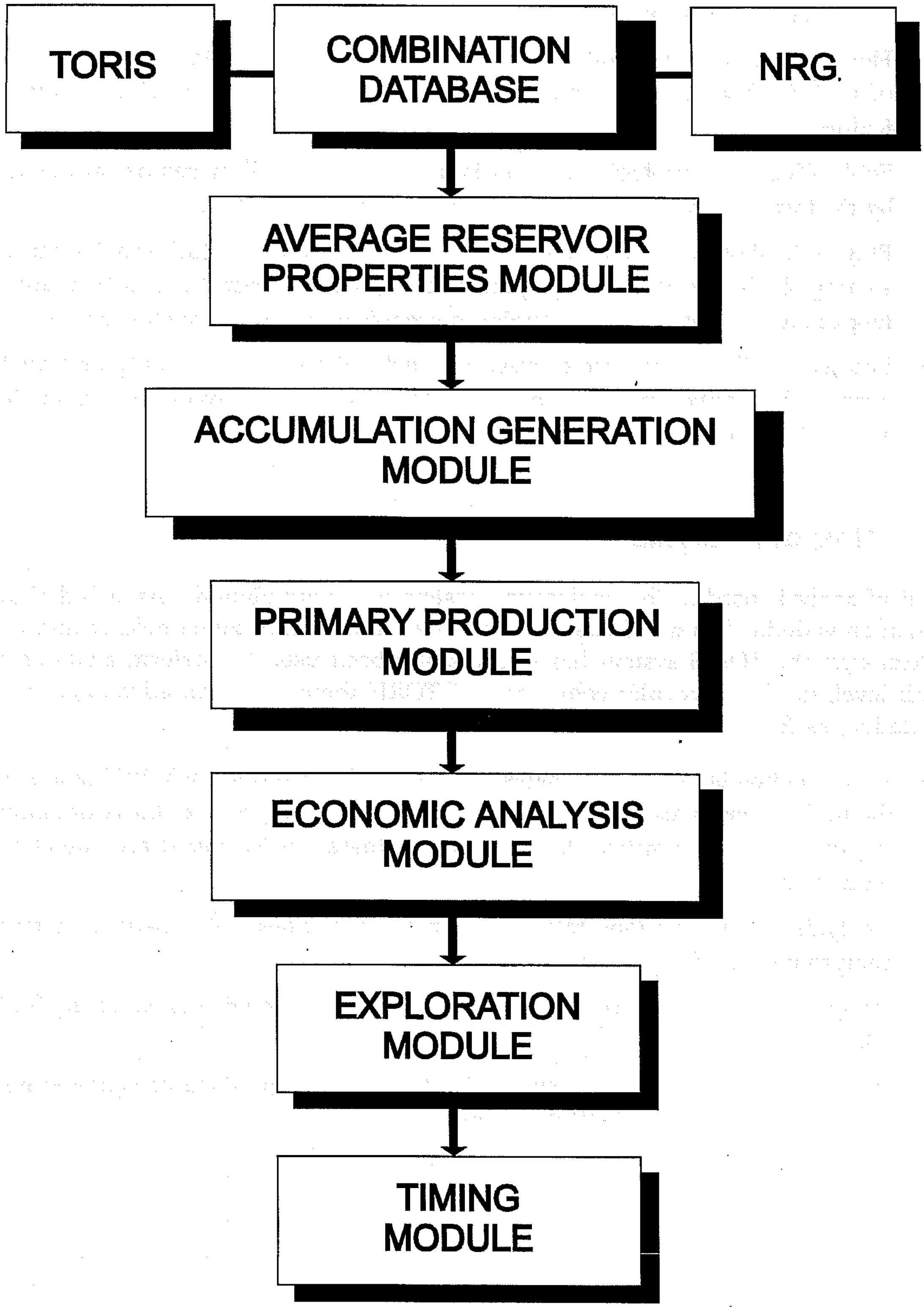
- Accumulation—All pools within a field within a given geologic play.
- Field—An individual producing unit consisting of a single pool or multiple pools of hydrocarbons grouped on, or related to, a single structural or stratigraphic feature.
- Pool —The basic geologic unit consisting of a single oil or gas deposit as defined by the trap, charge, and reservoir characteristics of the play.
- Play —A play is a set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.
- Reservoir —The occurrence of reservoir rocks of sufficient quantity and quality to permit the containment of oil and (or) gas in volumes sufficient for an accumulation of the minimum size.

1.3 Unit of Analysis

The unit of analysis used in the exploration system is "accumulation". As stated above, an accumulation is defined as a collection of pools (reservoirs) in a given field within a given play. Although the TORIS system has traditionally been used to perform analyses at the reservoir level, for this particular component of TORIS there are major advantages in using accumulation, as follows:

- Accumulation is the unit of analysis that the USGS used in their 1995 assessment of the undiscovered resource. It is not practical to disaggregrate these undiscovered resource. It is not practical to disaggregate these undiscovered accumulation into reservoirs.
- Analyzing accumulations rather than reservoirs does not constitute a technical compromise for the primary recovery model.
- Using accumulations is consistent with the industry practice of exploring for fields rather than reservoirs.
- Using accumulations is consistent with the industry practice of considering only primary production in E&P decisions.

1.4 System Flowchart



2.0 DATA SOURCES

2.1 Creation of the Discovered Reservoir Database

The key task in the ultimate goal of developing a database of representative reservoir properties for undiscovered reservoirs in USGS defined geologic plays was to develop a master database containing reservoir properties of discovered reservoirs. This database had to be classified by USGS geologic play in order that properties could be averaged by size class by play. The database was created by merging the Total Oil Recovery Information System (TORIS) oil reservoirs database, developed and maintained by the U.S. Department of Energy (DOE), and the "Significant Oil and Gas Fields of U.S. Database (10th Update)" developed and maintained by NRG Associates. The NRG Associates' database has relatively good coverage of the small to medium-sized reservoirs that are the likely sizes of prospects that remain to be discovered throughout most of the U.S., relative to the coverage of reservoirs in the TORIS database, where the coverage is best for the larger reservoirs. Larger reservoirs are those with greater than 50 million barrels (MMbbl) original oil in place (OOIP). The systematic and deliberate combination of the TORIS and NRG databases provides a database of crude oil reservoirs that effectively addresses the fullest possible spectrum of the characteristics of crude oil reservoirs that remain to be discovered in the U.S. The remainder of this section will explain the data sources and methodologies used in creating the master database of known reservoir properties.

2.1.1 Database Sources

This section describes the two databases that served as sources of data on properties of U.S. crude oil reservoirs: 1) the Total Oil Recovery Information System (TORIS) database of oil reservoirs, and 2) the NRG Associates' "Significant Oil and Gas Fields of U.S. Database (10th Update)".

2.1.1.1 TORIS System Overview

TORIS was originally developed by the National Petroleum Council (NPC) for its 1984 assessment of the nation's enhanced oil recovery (EOR) potential. This analysis was requested by the U.S. Secretary of Energy. In this effort, the EOR committee of the NPC utilized and built upon data bases of individual reservoirs and computer models that were then under development by DOE.

The TORIS database currently contains information on 3,717 crude oil reservoirs, and accounts for nearly two-thirds of the original oil-in-place estimated to exist in discovered oil reservoirs in the U.S. This database was initially screened to eliminate from consideration those reservoirs having unknown values for the following parameters.

- Original oil-in-place (OOIP)
- Depth
- Producing acreage
- Thickness (net pay)

The database was then also screened to eliminate duplicates. This procedure involved sorting the reservoirs by field name and reservoir name. If key properties, particularly OOIP, depth, well counts, etc., were found to be similar for any two reservoirs, they were considered duplicates. The reservoir data set containing a better coverage of all properties was retained and the other eliminated. The reservoir ID was also utilized in the elimination process. The higher the number, the later its inclusion in the database, and hence the better its validity.

This screening process resulted in a net 2,658 reservoirs remaining in the database. An additional 21 reservoirs that had no entries for the field name and reservoir name elements in the database were also eliminated. Data for the remaining 2,637 reservoirs in the TORIS database were used for merging with the NRG database.

2.1.1.2 NRG Associates Database

The "Significant Oil & Gas Fields of U.S. Database" was designed, developed, and is maintained by NRG Associates in Colorado Springs, Colorado. The database contains information on nearly 14,000 oil and gas fields and 20,000 major reservoirs organized into nearly 600 field/reservoir clusters.

The NRG reservoirs are classified according to "NRG Field/Reservoir Clusters", defined as a geologically similar group of reservoirs and prospects, and is essentially consistent with the definition of plays. NRG Associates have developed a correlation matching their clusters to USGS plays.

These reservoirs are grouped into eight regions: Gulf Cenozoic, Gulf Mesozoic, Gulf Offshore, Rocky Mountains, Mid-Continent, Illinois-Michigan, Pacific, and Permian. The NRG database has reasonable coverage on critical elements needed for reservoir description, such as location, reservoir properties and characteristics, and discovery and development history.

As the NRG database contains both oil and gas reservoirs, a GOR-based criterion was used to distinguish oil reservoirs from gas reservoirs. For the purposes of this exercise, all reservoirs in the NRG database with a GOR value less than 10,000 standard cubic feet per barrel (scf/bbl) were assumed to be oil reservoirs. This resulted in 7,632 "oil" reservoirs in the NRG database that were available for merging with the TORIS database.

2.1.2 Methodology

This chapter describes the approach used for creation of the master database of known reservoirs classified by USGS defined plays.

2.1.2.1 Database Elements

The elements that comprised the representative properties database were geologic and physical properties, volumetric data, and fluid properties. The different elements in each of these categories are listed below:

Geologic and Physical Properties

- Play Description (represented by USGS play code)
- Permeability
- Total Depth
- Initial Reservoir Temperature
- Initial Reservoir Pressure

Volumetric Data

- Producing Acreage
- Gross Pay
- Net Pay
- Porosity
- Formation Volume Factor
- Initial Fluid Saturations (Oil, Gas, and Water)

Fluid Properties

- Crude Oil API Gravity
- Crude Oil Viscosity
- Initial Gas-Oil-Ratio

2.1.2.2 USGS Defined Geologic Plays

The U.S. Geologic Survey (USGS) defines a play as a set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. The two-dimensional plan extent over which a play concept is considered to be valid and within which all known accumulations and potential exists for undiscovered accumulations or other additions to known accumulations and potential exists for undiscovered accumulations or other additions to reserves within the play defines the play area. The play attributes are those geologic characteristics that describe principal properties of and necessary conditions for the occurrence of oil and (or) gas accumulations of the minimum size (1 million barrels of oil equivalent) within the defined parameters of a play. A total of five hundred and sixty two plays were defined by USGS for its 1995 assessment. These include conventional and unconventional plays (coal-bed methane, continuous accumulations), and confirmed and hypothetical plays.

2.1.2.3 Crosswalk Tables

A cross walk relating the NRG clusters to USGS plays was obtained from NRG Associates directly. The crosswalk correlates 553 NRG clusters with 296 USGS plays. The crosswalk left out 266 USGS plays, and the reason for the exclusion is provided in the table below:

Hypothetical Plays	165
Unconventional Gas Plays	46
Highly Under explored/Low Potential Plays	18
Offshore Plays	3
Appalachian Plays	34
	266

There were 61 NRG clusters which could not be matched with USGS plays, and artificial USGS play codes were assigned to the reservoirs belonging to these NRG clusters. These were identified by four digit numbers beginning with the number nine. These belong to the following categories.

Pacific Offshore	4
Rockies	7
Permian	15
Texas	8
Gulf Offshore	19
Mafla	5
Michigan	2
Norphlet Offshore	1
	61

As part of earlier work performed in developing a preliminary or prototype database for the Oil Exploration Model, a one-to-one correspondence between reservoirs in the NRG database and TORIS database was attempted. This resulted in matching 2,648 reservoirs in TORIS database (including duplicates, and invalid reservoirs, i.e., those containing no information on OOIP, depth, acreage or net pay) with 2,341 reservoirs in NRG database. There were 1,069 remaining reservoirs in the TORIS database that had no match with reservoirs in the NRG database.

2.1.2.4 The Approach for Developing Representative Accumulation Properties for Undiscovered Reservoirs

The final approach evolved over a period of time and consists of two steps:

1. Creating the master database of known reservoirs by merging TORIS and NRG databases
2. Generating averages for reservoir properties by USGS defined plays and field size classes (Note - this step will be covered in section 3.0, "Data Generation Modules").

The logic for characterizing the reservoirs by USGS defined geologic plays is that "by definition", the reservoirs in a geologic play are expected to have similar characteristics. Hence, the parameters defining this characterization for the undiscovered reservoirs in these geologic plays can be assumed to be those for the existing reservoirs in these geologic plays.

The purpose of further differentiating accumulations belonging to a USGS defined play by field size classes is to distinguish the representative reservoir properties of undiscovered accumulations that could be a function of the field size class. Although major geologic characteristics are expected to remain similar across all field size classes, parameters such as producing acreage, reservoir pay zone thickness, and oil-in-place are also expected to be functions of field size. USGS defined field size classes are represented in ranges of technically recoverable oil as indicated in Table 1–1.

2.1.2.5 Creating the Master Database

The steps involved in the merger of the NRG and TORIS databases to create the master database of known reservoirs in the different USGS plays are given below. Microsoft Excel 5.0 was used to create the master database. Visual Basic program macros were utilized to carry out the different steps. These steps were as follows:

1. Created a database subset for each of the USGS defined geologic plays containing fields for the required elements.
2. Based on the crosswalk of USGS geologic play definitions with NRG field cluster definitions, assigned all the NRG "oil" reservoirs to the corresponding USGS defined geologic play database subset.

3. Based on the one-to-one crosswalk of reservoirs in the TORIS database and the NRG database, assigned reservoirs in the TORIS database to their matching NRG reservoir(s), and hence to a USGS defined geologic play database subset.

4. An attempt was made to match the remaining 610 reservoirs in the TORIS database to a USGS defined geologic play by the following means:

   - A crosswalk between USGS plays and TORIS plays was attempted. Only 55 one-to-one matches were obtained. This resulted in the assignment of an additional 81 TORIS reservoirs to USGS play database subsets.

   - Based on a match of field name and TORIS geologic play code with another reservoir from the TORIS database already in the master database, an additional 112 TORIS reservoirs were assigned to the master database.

   - Using EXCEL search features, a very rigorous search for matching strings was initiated between the remaining reservoirs in the TORIS database and the reservoirs in the NRG database. This enabled the assignment of an additional 191 TORIS reservoirs to the master database. Thus, a total of approximately 90% of the TORIS reservoirs were assigned to the master database.

5. Each USGS defined geologic play database subset in the master database was subjected to visual inspection to determine the selection of one set between the TORIS-NRG pairings that were assigned to the database based primarily on coverage and quality of data. All else being equal, preference was given to the reservoir data set from the TORIS database. This was done due to the extensive quality control and peer reviewed methodologies employed in developing and maintaining the TORIS database.

6. For some of the reservoirs in the TORIS database, BDM-Oklahoma provided a tabulation of factors. These factors are used in correlating field production reported by EIA with those in TORIS. Some of the reservoirs in the TORIS database are aggregated, i.e. represent more than one field in the EIA database, while some of the reservoirs in the TORIS database are desegregated, i.e., represent a portion of one field in the EIA database. The factors are used by BDM-Oklahoma to correct the production figures while correlating the field production data between the TORIS and EIA databases. The following criteria were used to aid this process:

   - If a TORIS reservoir(s) has a factor greater or equal in value to 0.5, select the TORIS reservoir in the pair over the NRG reservoir(s).

   - If a TORIS reservoir(s) has a factor less than 0.5, select NRG reservoir(s) in the pair over TORIS reservoir(s).

7. Next, the database subsets were converted to ASCII text files, one file for each of the USGS play database subsets. The nomenclature for the files was kept simple: XXXX.dat, where XXXX represents the USGS play code.

2.2 Calculation of USGS Undiscovered Accumulations

For the purposes of assessing the undiscovered oil resource, the USGS assumed a model of the size-frequency distribution of the population of oil accumulations. The Truncated Shifted Pareto, or TSP model describes a "J-shaped" distribution in which ever-increasing numbers of accumulations occur in successively smaller size classes. The distribution is called shifted because it has been statistically moved to have its origin at the minimum accumulation size, in this case 1 MMBO. The TSP distribution is referred to as "truncated", because, for the purpose of analyses, the distribution is cut off at the size of the largest accumulation in the distribution. This function and its use in describing the distribution of oil and gas accumulations was proposed and described by Houghton.

The TSP distribution was used to provide a guide to the province geologists in their development of estimates of undiscovered accumulations. A TSP distribution was fit to the population of accumulations known from each play and, in chronological order of discovery, to the first third of the accumulations discovered, the second third discovered, and the last third. The results of these fitted populations were provided to the province geologists and review panels as source information regarding the changing size distribution of accumulations within the play as a function of time.

Province geologists were requested to synthesize all available information and concepts in order to develop a set of hypotheses concerning undiscovered conventional accumulations within the play. These hypotheses were captured as a list of specific information requested from each province geologist. The requested information included:

1. Largest undiscovered accumulation in the play at a 5 percent (1 in 20) probability.
2. Absolute largest conceivable accumulation remaining to be discovered.
3. Median size of undiscovered accumulations greater than the minimum size.
4. Minimum, maximum, and most likely (median) number of undiscovered accumulations.
5. Depth distribution of undiscovered accumulations
6. Hydrocarbon type (oil or gas)
7. Content of sulfur in oil or hydrogen sulfide in gas.
8. Types and amounts of non-hydrocarbon gases.
9. API gravity of undiscovered oil.
10. GOR
11. NGL to associated gas and nonassociated gas in the play

Unless the province geologist had another specific model in mind, a TSP was fit to the median size and to the largest accumulation expected at a 5 percent probability in the postulated population of undiscovered accumulations, considering also the estimated maximum limiting value. The resulting TSP distribution was used to fill in the remaining fractiles of the size distribution of the undiscovered population.

In order to make use of this work provided by the USGS geologists, the TSP distribution provided for each play had to be converted to a finite number of undiscovered accumulations for each of the 15 size classes. The method used to convert the statistical distribution of undiscovered accumulations into finite numbers of accumulations is described as follows:

The proposed complementary cumulative distribution is given by:

$$G(x) = \frac{\{[(x - x_c) / a]\}^{-1/b} - T^u}{1 - T^u}$$

By definition, $G(x)$ gives the probability that a randomly selected accumulation is greater than x. This distribution is defined by three parameters, $a, b,$ and T^u, which have been determined on a play basis as previously explained using discovery histories. These parameters are included in a set of files provided with the 1995 assessment CD-ROM..

Suppose the scope of possible accumulation sizes is divided into class sizes {1, 2, 3, ... M} and s_i, s_{i+1} represent, respectively, the lower and upper limits for the *i-th* class. Then the probability that a randomly selected accumulation falls within the i-th class is given by:

$$p(s_i \leq x < s_{i+1}) = G(s_i) - G(s_{i+1})$$

Then, if the total number of accumulations N is fixed, the expected number of accumulations within the i-th class n_i is given by:

$$n_i = N[G(s_i) - G(s_{i+1})]$$

Using this procedure resulted in a table containing the number of undiscovered accumulations for each size class of each geologic play. These data were then used as input to the accumulation generation module.

3.0 DATA GENERATION MODULES

3.1 Average Properties Module

3.1.1 Purpose

The average properties module's primary purpose is to create a file containing average reservoir properties, weighted on original oil in place (OOIP), for each combination of USGS geologic play and size class for which reservoir data are available. For those size class and play combinations which cross state borders, it also writes data to a second file. The purpose of this second file is to carry, on a play and size class basis, information specifying the percentage of OOIP occurring in each state.

3.1.2 Required Input

There are four files which are input to the average properties module:

- File "recov-f.dat" containing geologic play numbers. This file identifies which plays are to be included in the analysis. Each record in this file contains a USGS play code which is used to construct the name of the file containing the reservoirs associated with that specific geologic play
- File "playnumber.grp" where "playnumber" is a numeric USGS play code. There are several of these files, and each contains reservoir data for a given play. Each record in the files contains the property data (permeability, porosity, etc.) for one reservoir. Each record also contains a code which identifies which accumulation the reservoir belongs to. The file is sorted in ascending order using this accumulation code as the sort key. In addition, each record contains a code identifying the source (NRG or TORIS) for the ultimate recovery expected from the reservoir. Also present in each record is a reservoir ID key which enables the table lookup of the ultimate recovery in one of the two files described below.
- File "recfact.nrg" containing cumulative recovery, remaining reserves, and ultimate recovery for reservoirs whose source of data was the NRG data base.
- File "recfact.tor" containing ultimate recovery factors for reservoirs whose source of data was the TORIS data base.

3.1.3 Description of Processing

The program begins by reading and storing the ultimate recovery data from the NRG and TORIS ultimate recovery files. Then it enters a primary DO loop in which it reads through the file containing the geologic play numbers. After each play number is read, it is used to construct the name of the file containing the reservoirs associated with the play. Next the program initializes several arrays used to store the reservoir data. Then it enters a secondary loop which serves for reading and processing the reservoir properties data.

Immediately after a record is read for a given reservoir, the program checks for a change in the accumulation code associated with the reservoir, since several reservoirs may be associated with a given accumulation. When a change in the accumulation code is detected, subroutine "STORACUM" is called. This subroutine determines which geologic size class the <u>prior</u> reservoir or group of reservoirs belongs to and stores the data associated with these reservoirs according to size class and state. When processing resumes in the main program, the arrays used to store individual reservoirs are reinitialized to zero via a call to subroutine "ZEROACUM".

Next the program checks the original oil in place for the reservoir that has just been read. If the OOIP is not positive, the reservoir's properties cannot be included in the averages for its associated accumulation and a branch is taken to the end of the DO loop to read the next reservoir. If the OOIP is positive, processing continues for the reservoir, beginning with the following set of reservoir data validations. When a given parameter is found to be invalid, its value is set to zero.

- Gross pay less than net pay

- Porosity greater than 50 percent

- Initial oil saturation greater than 100 percent

- Initial formation volume factor greater than 2.0

The program then checks the code that identifies the source (NRG or TORIS) for the ultimate recovery factor and attempts to obtain the ultimate recovery from the array associated with the applicable file. If the ultimate recovery for the reservoir cannot be found, the reservoir is discarded. If found, the ultimate recovery is converted to a recovery factor by dividing it by the OOIP. If this recovery factor does not lie in the range 0 < recovery factor < 1.0, the reservoir is discarded by branching to the end of the DO loop and reading the next reservoir.

If the ultimate recovery is valid, then the reservoir is qualified for inclusion in the analysis for the accumulation it belongs to. Its ultimate recovery is added to the total ultimate recovery for the accumulation and an index is set based on what state the reservoir is located in. The properties associated with the reservoir are then stored using this state index in an a three-dimensional array ("ACUM"). However, the value for a given property (porosity, permeability, etc.) must be positive to qualify it for storage in the array.

When the end of the reservoir file is encountered, all the properties for the associated geologic play, with the exception of the last accumulation, have been read and stored in a four-dimensional array ("PROP") and the secondary DO loop is exited. Subroutine "STORACUM" is then called to store the properties for the last accumulation read in the secondary loop. Then a check is made to determine if at least one of the accumulations in the reservoir file was qualified for analysis. If not, control transfers to the end of the primary DO loop to process the next geologic play.

If at least one geologic play is qualified for analysis then processing, then the OOIP-weighted averages are calculated for each of the reservoir properties using all the data in the entire play and OOIP-weighted averages for the properties are determined by size class. Next the distribution of OOIP by state is determined. Then, for each of the size classes, the program replaces missing average property values in each accumulation using the corresponding average for the entire play. Then the program enters a DO loop which serves to (1) write the properties, by play and size class, to the reservoir properties file.; (2) optionally output data to a second file which details the distribution of OOIP by state, play, and size class; and (3) optionally output statistics describing the range of values (minimum, average, and maximum), by play and size class, for each of the reservoir properties. The end of this DO loop coincides with the end of the primary loop described above, and processing terminates when an end-of-file condition is reached in the file containing geologic play numbers.

3.1.4 Assumptions and Limitations

A key goal of the Exploration System is consistency with the USGS projection of the undiscovered resource. As a direct result of this approach, the unit of analysis used in this program is geologic accumulation. As defined by the USGS, an accumulation is a group of pools that exists in a given field within a given geologic play. Since this program determines average properties based on accumulations, in many cases the averages are determined using values from two or more reservoirs within a given field. Such an approach ignores the fact that properties may vary widely between individual reservoirs.

When data are not available for a given size class, this program assigns properties to that size class which represent the OOIP-weighted averages for <u>all</u> the size classes within the geologic play. While this may be a reasonable approach for use for macroeconomic forecasting, it may not be applicable to studies having a relatively limited scope.

3.1.5 Output

Five files which are output by the average properties module:

- File "avg.dat" containing reservoir counts and average reservoir properties for every size class in a given play
- File "multiple.dat" containing data to those plays which exist in more than one state
- File "avgprop.msg" containing diagnostics for missing OOIP, recovery factors and inconsistent data
- File "stats.fil" containing the minimum, average, and maximum values by size class by play for each reservoir parameter
- File "volcalcs.msg" containing messages pertaining to invalid reservoir data

3.2 Accumulation Generation Module

3.2.1 Purpose

The purpose of the accumulation generation module is to create an accumulation database for use by the primary production module. The accumulations are generated based on the play size class reservoir property data contained in the output file generated by the average properties module.

3.2.2 Required Input

- File "undisc.dat" containing the distribution of undiscovered accumulations by play and size class.

- File "avg.dat" containing average properties by size class and the average number of accumulations per size class for discovered accumulations.

- File "usgsres.dat" containing the USGS play codes and the corresponding USGS region codes.

- File "multiple.dat" containing USGS play code, size class number, number of states spanned by a given size class in a specific play, and up to four sets of state postal codes accompanied by the percentage of OOIP that exists in the state. For those cases where an existing play/size class combination spans state borders, this file describes the distribution of OOIP in those states.

3.2.3 Description of Processing

The program begins by reading the distribution of undiscovered accumulations by play and size class and storing this information in a two-dimensional array which is indexed by the play code and size class. Next the program reads in the region code associated with each play. Then it reads and stores data in the file that describes the OOIP distribution for play/size class combinations which span state borders. Next the program initializes the array used in the creation of the output accumulation file.

The program then enters a primary loop in which it reads through the average properties file. The loop begins with the reading of the average properties for a given combination of play and size class. Then the array of undiscovered accumulations is checked to determine if there are any undiscovered accumulations in this play/size class. If the number of undiscovered accumulations is not positive, the program skips to the end of the loop to read the next record. If there is at least one undiscovered accumulation in the play for the size class under consideration, the program examines the recovery factor read from the average properties file. If the recovery factor is not positive, the program skips to the end of the loop to read the next record. If the recovery factor is positive, the program calculates the OOIP for the accumulation to be generated by dividing the recoverable reserves corresponding to the midpoint of the USGS definition of the size class by the recovery factor. Then the program checks the following data items to determine if they have positive values:

- Recovery factor
- Net pay
- Porosity
- Initial oil saturation
- Initial formation volume factor
- Depth
- API gravity
- Permeability

If any one of these data items does not have a positive value, the program skips to the end of the loop to read the next record. Next the program performs the data checks:

- The API gravity is compared to 20° (check for heavy oil). If the API gravity is less than 20°, the program skips to the end of the loop to read the next record.

- The permeability is tested for a positive value. If the permeability is not positive, the program skips to the end of the loop to read the next record.

- The region code corresponding to the play code is tested for a positive value. If the region code is not positive, the program skips to the end of the loop to read the next record.

At this point, the program has determined that is appropriate to output accumulations for the combination of play and size class under consideration. The region code, state postal abbreviation, play code, and size class are combined to create an 11-character exploration system ID and the array used for the output file is loaded with average property data from discovered accumulations in this play and size class. A test is then made to determine if the play/size class combination being processed spans state borders.

If the play/size class under consideration is located in two or more states, multiple accumulations and their exploration system IDs are generated and output, along with the reservoir properties, for the states based on the percentage of OOIP that exists in each state. Then the exploration system ID and the number of accumulations associated with the ID are output to a separate file. Next the exploration system ID, initial gas-oil ratio, and API gravity are output to a third file.

If the play and size class under consideration is located entirely in one state, the exploration system ID for the accumulation is output, along with the reservoir properties. Then the exploration system ID and the number of accumulations associated with the ID are output to a separate file. Finally, the exploration system ID, initial gas-oil ratio, and API gravity are output to a third file.

3.2.4 Output

- File "error.out" which contains diagnostics describing missing recovery factors, net pay, initial oil saturation, formation volume factor, depth, API gravity, and permeability

- File "input.gsm" which contains accumulation properties. This is the key file output by the program and is subsequently input to the Primary Recovery Prediction Model (PRPM). It is in the format of a TORIS database and contains, for a given combination of play and size class, the following data items: exploration system ID, net pay, gross pay, porosity, initial oil saturation, initial gas saturation, initial formation volume factor, depth, temperature, permeability, API gravity, viscosity, original oil in place, initial gas-oil ratio, area, initial pressure, and the recovery factor.

- File "und.gsm" which contains the accumulation ID and the number of such accumulations that occur in a given size class with a given play. This file is also subsequently input to the PRPM.

- File "gordata.out" containing the accumulation ID, gas-oil ratio, and the API gravity. These data are used solely for informational purposes and the file is not used as input for any subsequent program.

4.0 PRIMARY PRODUCTION MODULE

4.1 Purpose

The Primary recovery Predictive Model (PRPM) was developed to project future oil production from yet to be discovered prospects. The exploration system assesses the impact of alternative technology advances on oil exploration success, and is able to generate estimates of the newly discovered resource that is a future target for ASR/EOR technologies. The PRPM functions as a predictor of primary production over time, for accumulations "discovered" by the exploration model.

Just as the existing TORIS process models evaluate performance for a portion of an injection pattern and aggregate the results to a field level based upon reservoir area and well spacing, so also this model evaluates individual well drainage areas and aggregates the results to obtain a forecast of total reservoir performance. However, unlike the existing TORIS models which estimate the incremental recovery from an already producing waterflood, the PRPM must be able to estimate the timing and impact on production rate, of future installation of artificial lift equipment.

The PRPM utilizes two components for estimating production: a material balance component which predicts the volume of fluid produced for a given pressure drop, and a well performance component which predicts the flow rate (and therefore time) corresponding to the production volume. The model assumes aΔ)p, calculates a corresponding production volume using the material balance equation, estimates the well flow rate using the inflow performance and tubing performance relationships, and then iterates this process until a complete forecast of production rate and reservoir pressure versus time has been developed (see Figure 4–1). The model predicts performance for either a solution gas drive or a strong water drive reservoir, and utilizes a series of correlations for existing fluid properties as a function of pressure. However, in the current configuration, the model assumes all reservoirs to be solution gas drive. The following sections of this report detail specific elements of the models indicated in Figure 4–1.

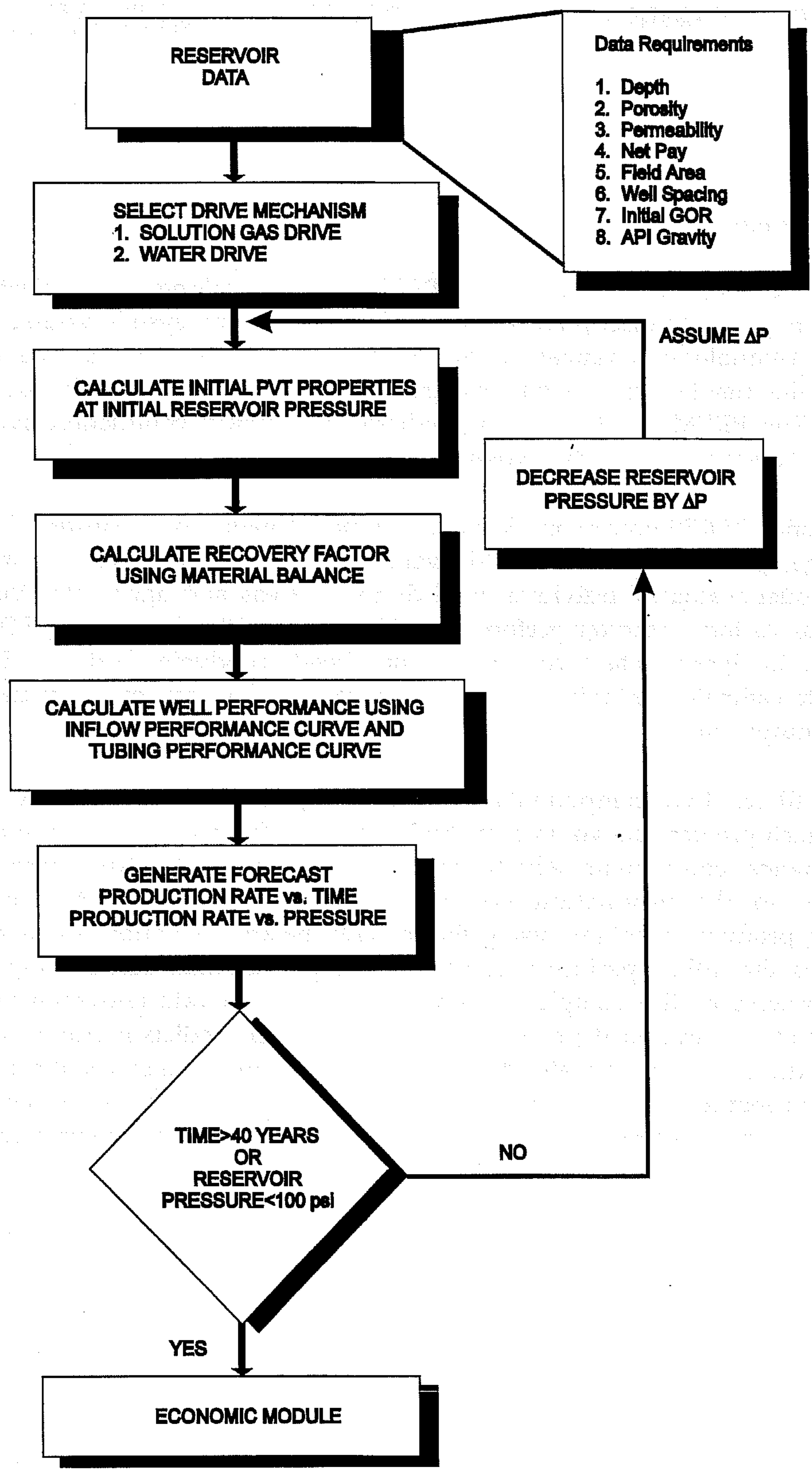


Figure 4–1 Primary Production Model Flowchart

4.2 Primary Production Mechanism

4.2.1 Solution Gas Drive

Several methods appear in the literature for predicting the performance of solution gas drive reservoirs from their rock and fluid properties. Three of these methods are widely used and relate the reservoir pressure decline to oil recover and gas-oil ratio. These are:

- Muskat Method
- Shilthius Method
- Tarner Method

All the above methods are based on the following assumptions which reduce the accuracy of the predictions, although in most cases not appreciably:

The reservoir is assumed to be homogeneous at all times in regard to porosity, fluid saturations, and relative permeability. However, heterogeneity can be modeled by adjusting the net pay based on the continuity, in the same way as DOE's Infill Drilling Predictive Model (IDPM).

- There is uniform pressure in both oil and gas zones throughout the reservoir.
- There is negligible gravity segregation.
- There is equilibrium at all times between the gas and oil phases.
- There is no water encroachment and negligible water production.

In the Muskat method, the values of the many variables that affect the production of gas and oil and the values of the rates of changes of these variables with pressure are evaluated at any stage of depletion (pressure). Assuming these values hold for a small drop in pressure, the incremental gas and oil production can be calculated for a small pressure drop. These values are recalculated at the lower pressure, and the process is continued to any desired abandonment pressure. Muskat's method calculates the producing gas oil ratio at any given pressure based on the following equation:

$$R = \frac{\dfrac{R_{so}}{B_o}\dfrac{dS_o}{dp} + \dfrac{S_o}{B_o}\dfrac{dR_{so}}{dp} - \dfrac{R_{so}S_o}{B_o^{2}}\dfrac{dB_o}{dp} - \dfrac{(1-S_o-S_w)}{B_g^{2}} - \dfrac{1}{B_g}\dfrac{dS_o}{dp}}{\dfrac{1}{B_g}\dfrac{dS_o}{dp} - \dfrac{S_o}{B_o^{2}}\dfrac{dB_o}{dp}} \tag{4-1}$$

Equation 4–1 is simply an expression of the material balance for volumetric under-saturated reservoirs in differential form. The producing gas-oil ratio may be written as:

$$R = R_{so} + \frac{k_g \mu_o B_o}{k_o \mu_g B_g} \tag{4–2}$$

Equation 4–2 is the cumulative surface producing gas oil ratio, R in SCF/STB, which is the sum of the flowing free gas and the solution gas which flows to the wellbore in the oil. Equation 4–1 and 4–2 are equated and solved for dSo/dp to give:

$$\frac{dS_o}{dp} = \frac{\frac{S_o B_g}{B_o}\frac{dR_{so}}{dp} + \frac{S_o}{B_o}\frac{dR_{so}}{dp} + \frac{S_o k_g \mu_o}{B_o k_o \mu_g}\frac{dB_o}{dp} - \frac{(1 - S_o - S_w)}{B_g}\frac{dB_g}{dp}}{1 + \frac{k_g \mu_o}{k_o \mu_g}} \tag{4–3}$$

The above equation an incremental form can be written as:

$$\Delta S_o = \Delta p \left(\frac{S_o X(p) + S_o Y(p) - (1 - S_o - S_w) Z(p)}{1 + \frac{k_g \mu_o}{k_o \mu_g}} \right) \tag{4–4}$$

The functions X(p), Y(p), and Z(p) are obtained from the reservoir fluid properties. The total oil saturation at any given pressure can thus be calculated by the following equation:

$$S_{o_j} = S_{o_{(j-1)}} - \Delta p \left(\frac{\Delta S_o}{\Delta p} \right) \tag{4–5}$$

Where, j corresponds to the pressure at the end of the pressure increment, and j-1 corresponds to the pressure at the beginning of the pressure increment. The following procedure is used to solve for the ΔS_o for a given pressure drop Δp, and thus estimate the recovery factor using the material balance equation:

1. Calculate fluid properties at start and end of the pressure drop interval. Determine the relationship with pressure for each property over the pressure drop.
2. Solve Equation 4–4 for the $\Delta S_O / \Delta p$ using the oil saturation corresponding to the initial pressure of the given Δp.
3. Estimate ΔS_{oj} using Equation 4–5 and solve Equation 4–6 using the estimated oil saturation.

4. Determine an average value for $\Delta S_o/\Delta p$ from the two values estimated in steps 2 and 3.
5. Using $(\Delta S_o/\Delta p)_{avg}$ solve for S_{oj} using Equation 4–5. This value of S_{oj} becomes $S_{o(j-1)}$ for the next pressure drop interval.
6. Calculate the recovery factor at the new pressure using the above estimated oil saturation.
7. Repeat steps 1 through 6 for all pressure drops until the desired abandonment pressure is reached.

This algorithm is used to estimate the recovery factor and oil saturation as a function of pressure for a given well drainage area in a given reservoir. To determine the well performance, an inflow performance curve and a tubing intake curve were derived at the desired conditions (see Section 1.3)

4.2.2 Bottom Water Drive

The bottom water drive model is based on the principals of fractional flow theory. Strong bottom water drive is the basic assumption in this model. During the process a constant pressure system is also assumed. The rate of water influx is equal to the total fluid (oil + water) produced at any given time from the reservoir. The tubing curve calculates the maximum fluid that can be lifted at a given set of pressure and water cut conditions. The water cut is calculated using the fractional flow curve. The production rate simulation for the model is similar to the simulation for the solution gas drive model.

A determination must be made as to whether a reservoir is to be modeled as having a solution gas drive or water drive mechanism. In the current configuration we defer this determination by assuming all reservoirs to be solution gas drive.

4.3 Production Simulation

4.3.1 Inflow Performance Curve

The expression, Inflow Performance Curve (IPR), customarily is used to define the relationship between surface oil rate and wellbore flowing pressure. The simplest and most widely used IPR equation is the straight line IPR, which states that rate is directly proportional to the pressure drawdown in the reservoir. The constant of proportionality is called the productivity index, J, defined as the ratio of rate to pressure drop in the reservoir. The straight line IPR is only used for the under-saturated oils, and we can write the equation as:

$$q_0 = J(p_R - p_{wf}) \tag{4–6}$$

Where, p_R is the average pressure in the volume of the reservoir being drained by the well (see Figure 4–2). It is not uncommon to use initial reservoir pressure or pressure at the external boundary of the drainage area instead of p_R , the difference is inevitably small and can be neglected.

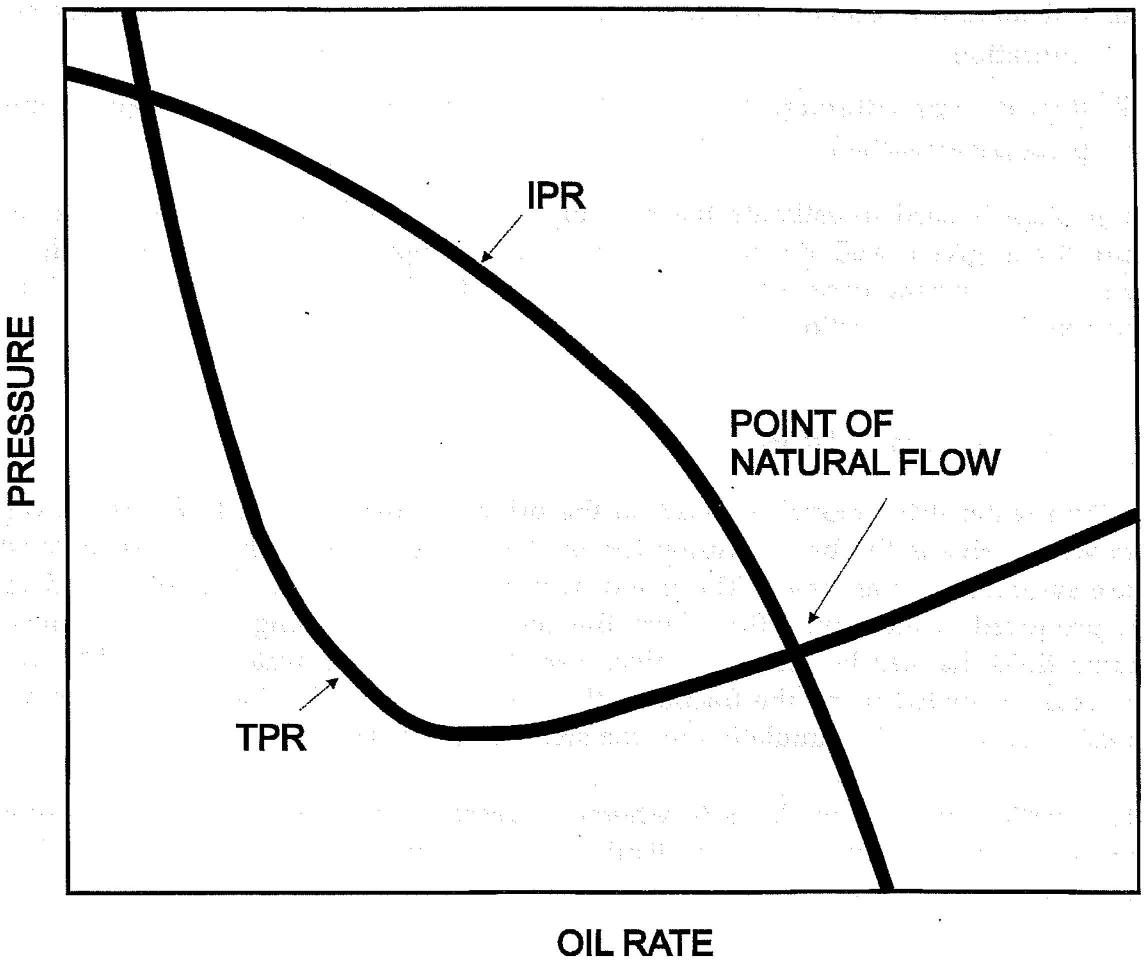


Figure 4–2 Inflow Performance Curve

A straight line IPR was used for the purpose of this model as the newly discovered reservoirs are initially assumed to be undersaturated. To derive the IPR curve the maximum rate of flow, q_{max}, or absolute open flow, AOF, was calculated assuming the wellbore flowing pressure, p_{wf}, equal to zero.

Although, in practice this condition will never arise, it is useful for defining the potential for different wells in the same field. The IPR curve is the straight line joining the two points, i.e. when there is not pressure drawdown and when there is maximum drawdown. The slope of the line is equal to the ratio of the maximum pressure drawdown to the maximum rate and is the reciprocal of the productivity index (see Figure 4–3).

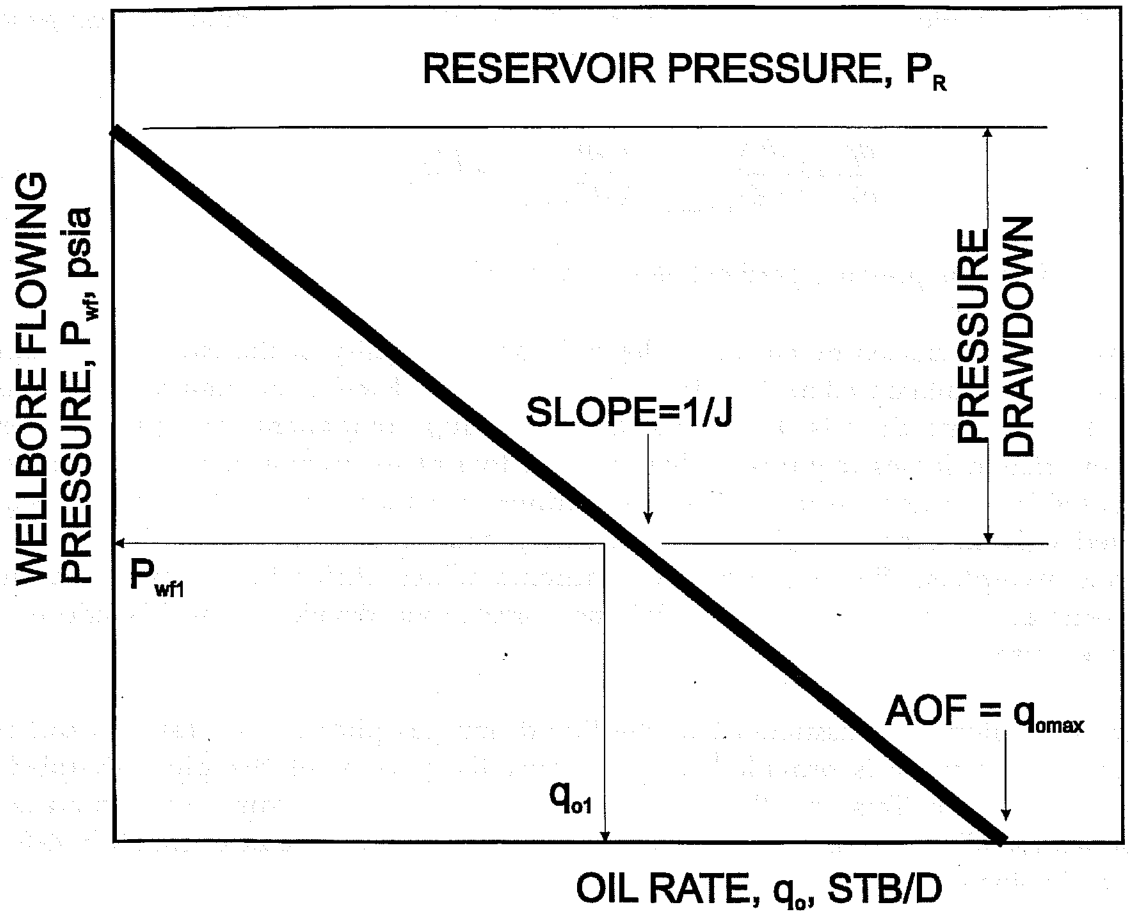


Figure 4–3 Tubing Performance Curve and Point of Natural Flow

The determination of q_{max} is made by using the radial flow equation for single phase flow:

$$q = \frac{kh(P_R - P_{wf})}{\mu_0 \ln(\frac{r_e}{r_w})} \tag{4–7}$$

Where, $P_{wf} = O_j$, the drainage radius, r_e, calculated from the well spacing, r_w = 0.5 ft, and μ_0 is calculated for the reservoir temperature and pressure.

4.3.2 Tubing Performance and Gradient Curves (TPR)

One of the major factors in determining the flow rate of a well is the pressure drop which occurs through the production tubing. This pressure drop along the production tubing at a given flow rate and inlet pressure, can be determined by correlations, thereby calculating the pressure at the other end of the tubing. The pressure drop in vertical tubing is dependent on elevation, friction in the pipe and the acceleration of the fluid. In their general form the pressure gradient equations can be written as,

$$\frac{dp}{dZ} = \left(\frac{dp}{dZ}\right)_{elevation} + \left(\frac{dp}{dZ}\right)_{friction} + \left(\frac{dp}{dZ}\right)_{acceleration} \tag{4–8}$$

Where, dp/dZ is the pressure gradient along a vertical plane.

The pressure drop caused by elevation depends on the density of the two phase mixture and usually is calculated using the liquid holdup value. Except for high velocity fluids, most of the pressure drop is due to the liquid holdup component. The pressure drop caused by friction losses requires evaluation of a two phase friction factor. The pressure drop caused by acceleration the fluids is sometimes considered negligible and is usually calculated only in case of high velocities. Many correlations have been developed for predicting two-phase flowing pressure gradients which differ in the way the three components are calculated. In this model the correlations developed by Hagedorn and Brown were used.

In these correlations it is assumed that the liquid and gas phases may travel at different velocities, so a method is provided for predicting the portion of the pipe occupied by liquid at any location. This uses the same correlations for liquid holdup and friction factor calculations for all flow regimes. The three components of the gradient equation 4–8 are determined using equations (4–9 through 4–11):

- Elevation Factor

The pressure gradient component due to elevation is dependent on the fluid density and is given by:

$$\left(\frac{dp}{dZ}\right)_{elevation} = \frac{g}{g_c}\left[\rho_L H_L + \rho_g (1 - H_L)\right] \tag{4–9}$$

Where g = acceleration of gravity

g_c = gravitational constant

H = gas or liquid holdup, and

p = gas or liquid density

- Friction Factor

The pressure gradient component due to friction is given by:

$$\left(\frac{dp}{dZ}\right)_f = \frac{fw^2}{2.9652 \times 10^{11} \rho_s d^5} \tag{4-10}$$

Where w = mass flow rate, lbm/day,

p = density based on liquid holdup, lbm/ft^3,

d = inside pipe diameter, ft, and

f = two-phase friction factor.

The two-phase friction factor is correlated with a two-phase Reynold's number using the Moody diagram.

- Acceleration Factor

The pressure gradient due to acceleration gradient is given by:

$$\left(\frac{dp}{dZ}\right)_{acc} = \frac{\rho_s \Delta(v_m 2)}{2g_c dZ} \tag{4-11}$$

Where) $(v^2) = v_m^2(P_1,T_1) - v_m^2(P_2,T_2)$

If we define E_k as:

$$E_k = \frac{dZ}{dp}\left(\frac{dp}{dZ}\right)_{acc} = \frac{\rho_s \Delta(v_m 2)}{2g_c dp} \tag{4-12}$$

then the total pressure gradient can be calculated as:

$$\frac{dp}{dZ} = \frac{\left(\frac{dp}{dZ}\right)_{el} + \left(\frac{dp}{dZ}\right)_f}{1 - E_k} \tag{4-13}$$

To calculate the tubing intake curve:

1. Calculate the AOF rate for the well using the radial flow equation, determine the IPR slope, and divide the well production range into 500 equal increments.

2. Assume a wellhead flowing pressure of 190 psi. Take the first lowest increment of oil rate and water cut to determine the total flow rate in the first rate.
3. Divide the depth of the well into "n" equal depth increments of 200 ft.
4. Using the Hagedorn and Brown equations and the initial rate, determine the pressure gradient for the first 200 ft below the surface.
5. Calculate the drop in pressure for a depth of 200 ft from the point of interest.
6. Add the pressure drop to the initial pressure. This is the final pressure of the flowing fluid at a depth of 200 ft from the origin.
7. Repeat steps 4 to 6 "n" times till the bottom of the well is reached. The final pressure calculated is the bottom hole flowing pressure for the flow rate chosen in step 2.
8. Increment the oil rate and repeat steps 2 to 7 for all 500 oil rates until the oil rate is equal to AOF.
9. Repeat steps 1 to 8 for every incremental drop in reservoir pressure.

The resulting set of flowing pressure and rates define the tubing curve for the GOR and cut established at the reservoir pressure. In this model, based on the data available, it is possible to calculate both inflow and tubing performance curves. The intersection of the IPR and TPR curves determines the rate of stable flow, which is the point at which the wellbore flowing pressure is equal to the tubing intake pressure. This point is determined analytically based upon the curves determined as above, and the corresponding flow rate is generally called the "natural" flow rate.

Natural flow rate and pressure usually change with reservoir depletion depending on the variation of IPR and TPR resulting from changes in the reservoir pressure and flow characteristics. As shown in Figure 4–2, there may be two points of intersection of the two curves. The point to the right represents the natural flow and a stable rate whereas the point to the left represents an unstable rate condition. In this condition, liquid holdup takes place and artificial lift is required. Mathematically, the stable point of natural flow exists when the curves intersect each other with slopes of opposite signs. If the curves have slopes with the same sign at the point of intersection, then a small change in rate will cause the system to change it's state of equilibrium. In most cases, artificial lift is introduced at this point to maintain a constant rate for a longer period. To incorporate artificial lift, a pump model was introduced to the performance prediction which calculates the lifting rate based on the decision of installing a fixed bottom hole pressure. The following assumptions were used for artificial lift:

- The bottom hole flowing pressure is assumed to be 75 psia.
- The pump is assumed to work at a constant 65% efficiency.

4.4 Assumptions and Limitations

The method used to describe the performance of a well from in a specified drainage area has the following assumptions:

- The reservoir is homogeneous at all times regarding it's physical properties. However, heterogeneity can be modeled by adjusting the net pay based on the continuity, as in DOE's Infill Drilling Predictive Model (IDPM).
- The reservoir is assumed to be undersaturated and has no gas cap. There is negligible gravity segregation.
- There is uniform pressure in the oil and gas zones throughout the reservoir.
- There is negligible water encroachment except in the case when the drive mechanism is a strong water drive.
- A straight line IPR curve is assumed at all times.
- The well head flowing pressure is assumed to be 190 psi.
- The reservoir is assumed to be in equilibrium at all times during the production simulation.

The limitations of the model are as follows:

- The PRPM material balance is a "tank" model and does not account for reservoir geometry, drainage area, position and orientation of the well. It assumes that each well is isolated from the other wells in the same field and has no impact on the drainage areas of the other wells.
- PRPM does not account for any workover/stimulation effects which may be introduced in the course of the life of the well.
- PVT properties and other related properties are calculated using various correlations. These correlations are less applicable to more volatile or heavy oils.
- In the case of a strong water drive reservoir, the system behaves as if a piston-like displacement is taking place from the bottom of the drainage area. There is no ability to model partial water drives.

4.5 Required Input

The following key parameters are required by the model to predict the performance of a well in a given reservoir:

- depth
- porosity
- net pay

- permeability
- well spacing
- reservoir total area
- drainage area
- initial gas/oil ratio
- API gravity
- initial oil saturation
- lithology (sandstone or carbonate)
- drive mechanism (solution gas drive or water drive)
- temperature
- initial reservoir pressure
- specific oil gravity
- oil viscosity

The development schedule of a field is presently assumed to be 20% each year, but can be changed to any fixed development schedule. If any variable development schedule is to be implemented because of exploration and development constraints, then it must be modeled by creating a data file containing the reservoir listing and the development schedule for the particular reservoir.

4.6 Description of Algorithms

This model was designed under the assumption that very little information about the reservoir and fluid properties are available for the analysis. In order to evaluate parameters required by the model to predict performance for a given well in a reservoir it is absolutely necessary to make use of correlations which have been derived from various field and experimental data. The correlations used for most of the critical parameters are outlined in this section.

4.6.1 Initial Formation Pressure, psia

$$P_{form} = 14.7 + 0.433 \cdot D(ft)$$

4.6.2 Initial Formation Temperature, °F

$$T_{form} = 60.0 + 1.70 \cdot D(ft)/100)$$

4.6.3 Specific Gravity

$$SGG = 1.0 - 1.76 \times 10^{-03} \cdot API$$

where,

SGG=Oil Specific Gravity

API=American Petroleum Institute Oil Gravity, °API

4.6.4 Bubble Point Pressure, psia (Vazquez and Beggs)

API ≤ 30.0	API > 30.0
A = 1.0937	A = 1.187
B = 27.64	B = 56.06
C = 11.172	C = 10.393

$$PB = \left(\frac{B \cdot GOR_i}{SGG \cdot P^{A/B} \cdot 10^{C\,API/(T+460)}} \right)^{1/A}$$

where,

PB=bubble point pressure, psia

B=oil formation volu me factor, bbl/STB

GOR_i=inital gas-oil ratio, scf/STB

P=pressure, psia

T=temperature, °F

4.6.5 Oil Viscosity, cp

Dead Oil Viscosity (Beggs and Robinson)

$$Z = 3.0324 - 0.02023 \cdot API$$

$$X = \frac{10^Z}{T^{1.163}}$$

$$\mu_D = 10^X - 1$$

where,

μ_D=dead oil viscosity, cp

Live Oil Viscosity (Vazquez and Beggs)

$$A = \frac{10.715}{(RS + 100)^{0.515}}$$

$$B = \frac{5.44}{(RS + 150)^{0.338}}$$

$$\mu = A \cdot \mu_D{}^B$$

where,

RS=solution gas-oil ratio, scf/STB

μ=live oil viscosity, cp

Live Oil Viscosity above bubble point (Beggs and Robinson)

$$VM = 2.6 \cdot P \cdot 1.187 \cdot 10^{\left(-0.039P \cdot 1 \times 10^{-3.5}\right)}$$

$$\mu_l = \mu \cdot \left(\frac{P}{PB}\right)^{VM}$$

where,

μ_l=live oil viscosity above bubble point pressure, cp

4.6.6 Water Viscosity, cp

$$\mu_w = e^{(1.003 - 1.479E-02 \cdot T + 1.982E-05 T^2)}$$

where,

μ_w=water viscosity, cp

4.6.7 Gas Viscosity, cp (Lee et al)

$$W = \gamma_g \cdot 29$$

$$T_{abs} = T + 460$$

$$K = \frac{(9.4 + 0.02 \cdot W) T_{abs}^{1.5}}{209 + 19 \cdot W + T_{abs}}$$

$$X = 3.5 + \frac{986}{T_{abs}} + 0.01 \cdot W$$

$$Y = 2.4 - 0.2 \cdot X$$

$$\rho_g = \frac{P \cdot W}{10.72 \cdot z \cdot T_{abs} \cdot 62.4}$$

$$\mu_g = \frac{K \cdot \exp(X \rho_g^{\,y})}{10{,}000}$$

where,

W=gas molecular weight, lb/lb-mole

γ_g=gas gravity

T_{abs}=absolute temperature, R

z=gas deviation factor

ρ_g=gas density, lb/ft^3

4.6.8 Solution Gas Oil Ratio, scf/STB (Vazquez and Beggs)

API ≤ 30.0	API > 30.0
A = 1.0937	A = 1.187
B = 27.64	B = 56.06
C = 11.172	C = 10.393

$$R_{so} = \gamma_g \cdot P^{A/B} \cdot 10^{C \cdot API/(T+460)}$$

4.6.9 Formation Volume Factor, (Vazquez and Beggs)

$$D = (T - 60) \cdot \frac{API}{\gamma_g}$$

API ≤ 30.0	API > 30.0
A = 0.1751	A = 0.11
B = 1.8106	B = 0.1337

$$B_{opb} = 1 + 4.67E - 04 \cdot GOR + A \cdot D \cdot 1E - 04 + B \cdot GOR \cdot D \cdot 1E - 08$$

$$B_o = 1 + 4.67E - 04 \cdot R_{so} + A \cdot D \cdot 1E - 04 + B \cdot R_{so} \cdot D \cdot 1E - 08$$

$$B_o = B_{opd} \cdot \exp\left[C_o \cdot (PB - P)\right]$$

where,

B_{opb}=oil formation volume factor at bubble point pressure, bbl/STB

B_{opd}=oil formation volume factor below bubble point pressure, bbl/STB

B_o=oil formation volume factor above bubble point pressure, bbl/STB

C_o=oil isothermal compressibility, psi^{-1}

5.0 ECONOMIC ANALYSIS MODULE

5.1 Purpose

The purpose of the economic analysis module is to evaluate the profitability of developing an accumulation. This model evaluates the accumulation using a standard annual cash flow approach. The results of this economic evaluation are used in the exploration module as a means of ranking the order of discovery and development of accumulations. The economic criterion used in this ranking is the calculated investment efficiency. Investment efficiency is defined as the ratio of the project's total discounted cash flow to the maximum cumulative negative discounted cash flow. In addition to investment efficiency, the economic module also calculates capital expenditures. The expenditure numbers are used by the timing model in evaluating the consumption of the annual capital spending allotments set by an algorithm within the model.

5.2 Required Input

The economic analysis module requires a series of input files in order to run.:

- A file whose name is specified in the "option.dat" file is the primary input file. It contains pattern production data. The file is output by the Primary Recovery Prediction Model. It consists of 40 years of annual oil, gas, and water production for a single well (pattern). A separate production schedule is input for each accumulation analyzed. Along with the production data, information is passed concerning the areal extent of a pattern, the areal extent of the accumulation, and the number of patterns necessary to completely develop the accumulation. Depth and API gravity are also passed as input to the economic module as depth is used in the drilling and operating cost algorithms and API gravity is used as a means of adjusting the oil price according to quality of the oil.
- File "option.dat" which contains switches allowing the user to specify whether or not detailed output files will be generated. This file also specifies the name and location of the primary input file.
- File "cost.dat" in which the user specifies the following input parameters to the economic module.
  - Royalty rate
  - Discount rate
  - Percent of facilities costs which are tangible

- General and Administrative (G&A) multipliers for both expenses and capital
- Lease bonus cost factor
- Geologic and Geophysical (G&G) Factor
- Percent of G&G which is depleted
- Percent of lease bonus which is capitalized
- Water, gas, and oil variable operating costs
- Parameters for regional development well cost equations
- Parameters for regional new producer equipment cost equations
- Parameters for regional pump equipment cost equations
- Parameters for regional fixed operating cost equations
- Parameters for incremental operating costs due to inclusion of pumping equipment
- Regional dry hole rates

- File "regions.dat" which gives the numerical state code as well as the USGS region code for all 50 states.
- A file called taxes.dat which contains about 56 parameters which define the federal tax laws which will apply in the analysis. A complete listing of these parameters will appear in the appendix of this report. These parameters define the tax credits, tax rates, tax deductions, Alternative Minimum Tax (AMT) criteria, etc. which apply to the operator being considered in the analysis.
- File "depramor.dat" which contains the annual fractional rates which determine the ACRS depreciation schedule as well as the annual fractional rates which determine the amortization schedule used in the analysis.
- File "price.dat" which contains a switch allowing the user to specify either fixed price or price track for calculating revenue. This file contains the fixed oil and gas price to be used throughout the analysis as well as the annual inflation rate. If the price track switch is selected, this file will contain oil and gas prices as well as an inflation rate for every year of the analysis.
- File "cases.dat" allows the user to specify several cases to be run by the model in a single run of the economic module. For each case the user specifies a reduction factor for both drilling as well as "other" investments. There is also a reduction factor for Operating and Maintenance (O&M) costs as well as oil price. A common usage of this file would be to run several different oil prices at the same time. The oil price for each case is determined by the base oil price which was specified in price.dat multiplied by the price reduction factor specified for each case.

5.3 Description of Processing

Processing begins by opening and then calling specific subroutines to read all seven of the input files specified above. A subroutine is called to calculate all prices and costs on a unit basis. For example, the oil price is calculated by multiplying the base price by the price reduction factor for the case which is being run. The cost to drill and equip a single well, as well as fixed operating costs and incremental pump costs are determined based on the equations which apply to the region in which the accumulation under analysis is located.

The next subroutine calculates annual production and costs for the entire project. A pattern initiation schedule is created by allowing development of 80% of the accumulation subject to a maximum of 30 new patterns per year. Each pattern initiated requires the drilling of one well plus the regional developmental dry hole rate.

Following the costing routine there is a rigorous cash flow algorithm. This algorithm does a detailed analysis from the operator point of view on the annual project revenues, costs, and taxes. First the oil price is modified by a gravity adjustment factor. Then lease bonus and G&G costs are estimated along with all tangible and intangible capital costs. Gross revenue is calculated by multiplying production by oil price. Royalty is calculated and subtracted from gross revenue to give net revenue. State severance taxes are calculated using state-specific algorithms. Operating costs are estimated using region-specific algorithms. Severance and operating costs are subtracted from net revenue to give net operating income. The net operating income is reduced by the allowable depreciation, amortization, and cost depletion in order to give taxable income.

A detailed tax analysis is then performed on the taxable income in order to estimate both state and federal corporate income taxes. This analysis contains all of the switches necessary to evaluate AMT as well as a series of tax credits. This allows the economic evaluation module to be run from the perspective of a major oil company or varying categories of independent operators. The subtraction of state and federal income taxes from the pre-tax income results in net income after taxes. The subtraction of all amortization and depreciation from net income after taxes and accounting for all money actually spent results in an estimate of cash flow after taxes. Discounting this value by the prevailing discount rate gives an estimate of cash flow after taxes. At this point the investment efficiency, which is required for the Exploration model, is calculated.

After completion of the cash flow routine the results are written to the output files and the same process is applied to all cases being run. Once all cases have been completed for a given accumulation, the data for the next accumulation are read from the primary input file. The same sequence of steps is then followed for the next accumulation.

5.4 Output

A total of eight files are produced for every run of the economic evaluation. A ninth file is created if detailed pro-forma output is desired for the run. The switch to turn the detailed output on or off is located in a file named "option.dat" file. The output files are described as follows:

- A file having an extension of ".tim" is the primary output of this model and serves as input to the exploration module. In addition to 40 years of oil, gas, and water production, the file also reports depth, API gravity, number of patterns to develop, and the year in which a pump is needed. Also for each case which is run there is an investment efficiency, a total tangible capital, and a total intangible capital.
- A file having an extension of ".lb" contains a single record for each accumulation showing the accumulation ID and the lease acquisition cost paid for that property.
- A file having an extension of ".sum" contains a single record for each accumulation showing the accumulation ID, the cumulative production, the cumulative after tax cash flow, and the rate of return for Case #1 only.
- A file having an extension of ".ref" contains an ID number for each accumulation analyzed.
- A file having an extension of ".out" reports the following variables for each case run for each accumulation.
  - Reserves
  - Net Present Value (NPV) of oil production less royalty and severance tax
  - Total severance taxes
  - Total corporate federal taxes
  - Total corporate state taxes
  - Total personal federal income taxes
  - Total personal state income taxes
  - Total sales taxes
  - NPV of project
- A file having an extension of ".npv" reports all of the elements listed above for the ".out" file except for personal and sales taxes. In addition to these it also reports the following.
  - NPV of expenses
  - NPV of Tangible investments (excluding drilling)
  - NPV of Intangible investments (excluding drilling)
  - NPV of developmental well costs

- NPV of federal tax credits

- A file having an extension of ".tcp" reports for each accumulation, 40 years of oil, gas, and water production, depth, API gravity, total area, pattern area, total number of patterns, net pay, well spacing, porosity, initial oil saturation, boi, as well as the starting year for the pump.
- A file having an extension of ".ver" reports a single line of data for each accumulation. The data consist of state, process code, play code, exploration system ID number, depth, and original oil in place.
- If a detailed financial report is requested through the options.dat file a file having an extension of ".pro" is generated. This is an extremely detailed financial report which reports the following elements for each year the project is active and for each case which is run.
  - Number of patterns
  - Oil production
  - Gas production
  - Oil price
  - Remaining reserves
  - Gross revenue
  - Adjusted oil Price
  - Gravity/transportation cost adjustment
  - Adjusted revenues
  - Royalties
  - Net sales
  - Total operating cost
  - G&A on expensed items
  - G&A on capitalized items
  - Pressure maintenance/cycling
  - General O&M
  - Total investments
  - Tangible investments
  - Intangible investments
  - Tangible drilling costs
  - Intangible drilling costs
  - Other tangible capital

- Depreciable/capitalized investments
- Portion of intangibles to capitalize
- Adjustment for federal tax credits
- Depreciation base
- Depreciation on tangibles
- Depreciation on capitalized intangibles
- Depletable G&G/Lease costs
- Depletable lease Acquisition cost
- Additions to depletion base
- Depletion base
- Expensed G&G/lease costs
- Expensed lease purchase costs
- Expensed G&G costs
- Net revenues
- Operator severance taxes
- Operating costs
- Expensed Intangible, G&G, and lease acquisition
- Depreciation total
- Depletion allowance
- Taxable income
- Tax credit addback
- G&G/lease addback
- Net income before taxes
- State income tax
- Federal income tax
- Federal tax credits
- Net income after-taxes
- Annual after-tax cash flow
- Discounted after-tax cash flow
- Cumulative discounted after tax cash flow

6.0 EXPLORATION MODULE

6.1 Purpose

The purpose of the exploration model is to sequence the discovery and development of the undiscovered accumulations contained in a file output by the economics module. The figures at the end of the Exploration Module Section provide a thorough explanation of this sequence (See Figures 6–1 through 6–4).

6.2 Required Input

Two files are input to the exploration module:

- File "und.gsm" containing, for each combination of state, play and size class, an exploration system ID and the number of accumulations associated with that ID. This file is sorted by size class within play.
- Random-access file generated by the economics module containing an exploration system ID, 40 years of annual production for oil, water, and gas, depth, API gravity, number of patterns to develop, and the year in which a pump is needed. The file also contains economic data for eight oil prices (one record per oil price). This economic data includes investment efficiency, total tangible capital, and total intangible capital.

6.3 Description of Processing

The program begins by zeroing two arrays used for the scheduling of the exploration of accumulations. Next it reads and stores the exploration system IDs for undiscovered accumulations and the number of accumulations associated with each ID. Then the program reads through the economics file and stores the record pointer and investment efficiencies (for eight prices) associated with each ID in the economics file. Then the program enters a primary DO loop.

The purpose of this loop is to order the discovery of accumulations, on a play basis. The program processes the array containing the exploration system Ids, extracting the play number from each ID. If the play number has not changed, the program copies the number of accumulations, the record pointer to the economics file, and the eight investment efficiency associated with each ID into working arrays. It also populates, by size class, a 15-element array containing the product of the size class number contained in the ID times the number of accumulations associated with the ID. This process of generating the working arrays continues until the play number changes.

When the play number changes, subroutine "ORDACCUM" is called. Using the contents of the working arrays, this routine develops the discovery order for each accumulation in the play using the following algorithm:

- The array containing the product of the size class number times the number of accumulations is examined to determine which element has the maximum value for the product.

- The discovery of an accumulation is selected from the size class based on the maximum product.

- If the maximum product value is not unique, the accumulation to be discovered is selected from the <u>highest</u> size class.

- After an accumulation is discovered, the array element from which the accumulation was selected is decremented by a value equal to the size class.

- The process is repeated until all accumulations in the play have been scheduled for discovery.

In the section of code that performs the discovery ordering, subroutine "ORDACCUM" creates a four-dimensional array that will be subsequently used in the assignment of the development order of the accumulations. Only two data elements are stored in this array for each exploration system ID - the random record number of the record containing the ID and the investment efficiency (for each of the eight prices). These data are stored in discovery sequence. The subroutine also tracks the maximum number of accumulations that occurs in any play as well as the number of accumulations that occur at each level of the discovery ordering.

When processing returns from "ORDACCUM" to the mainline, a second routine ("INITWORK") is immediately called to re-zero the working arrays used in the development ordering process.

After the discovery order has been determined for all accumulations in all plays (the end of the first primary loop), the program enters a second primary loop in the main program. This loop serves to set the order in which the accumulations are developed, using the scalars and arrays populated in subroutine "ORDACCUM". The processing performed in this loop creates eight identically formatted output files, one for each of the eight prices under consideration. Each of the eight files contains the production and economics information, for one oil price, contained in the input file received from the economics module. Each record in these files represents a single accumulation, and the order of the records in the file represents the order in which the accumulation is developed.

6.4 Output

Eight files are output by the exploration module, one for each of the oil prices under consideration. The formats of the eight files are identical. The information carried in the files includes the exploration system ID, 40 years of annual production for oil, water, and gas, depth, API gravity, number of patterns to develop, and the year in which a pump is needed. The file also contains economic data consisting of investment efficiency, total tangible capital, and total intangible capital.

- The Exploration Model decides on the order by which new accumulations of different size classes are found in different plays

- Two Step Process:
  - **Discovery Order** In each play, select the order of new accumulations(to be found) based on Ray/Keltch probability method
  - **Development Order** Across all plays, decide the development order of all accumulations based on "Investment Efficiency" for timing purpose

Figure 6-1 Exploration Model

Size Class	1	5	7	Selection Process	
No of Accumulations	2	2	1	Selection Order	Size class Selected
1st Probability	2	10	7	1	5
2nd Probability	2	5	7	2	7
3rd Probability	2	5	0	3	5
4th Probability	2	0	0	4	1
5th Probability	1	0	0	5	1

Probability = [Size Class Number] x [No of Accumulations]

Figure 6-2 Discovery Order Accumulation Selection Within Each Play

Rank Order	Play A	Play B	Play C
1	5	6	9
2	7	4	5
3	5	7	5
4	1	3	7
5	1	5	2
n			

Accumulation Size class to be found

Figure 6–3 Accumulation Size Class to be Found

Exploration Ranking

Rank Order	Play A	Play B	Play C
1	5	6	9
2	7	4	5
3	5	7	5
4	1	3	7
5	1	5	2
n			

- Across all plays
- For each exploration rank
- Sort by investment efficiency
- Investment efficiency is calculated:
  - Conduct full cashflow analysis
  - At a given Oil Price and ROR
  - Assuming drilling schedule of 30 wells/year
- Timing priority will be given to those projects with higher "investment efficiency"
- Repeat for other exploration ranks

Figure 6–4 Development Order

7.0 TIMING MODULE

7.1 Purpose

The purpose of the timing module is to schedule the development of the individual undiscovered accumulations based on annual constraints of drilling capacity and available investment capital. The accumulations are developed in the order determined by the exploration model. The figures at the end of the Timing Module Section provide an example to this purpose (See Figures 7–1 through 7–5).

7.2 Required Input

The timing module requires the following input files:

- The primary input files consist of pattern production data. These files are created by the exploration module and there is one file for each oil price in the analysis. For each accumulation, these files contain the accumulation ID number, API gravity, depth, number of patterns, as well as 40 years of oil, gas, and water production and injection for a single pattern. The accumulations are written by the exploration module in the order in which the accumulations will be developed by the timing model.
- File "drillcap.dat" which contains all information needed to calculate the annual drilling footage constraint for each USGS region. Some of the elements in this file include onshore percentage of total drilling footage, percentage of onshore footage available for oil exploration, exploration dry hole rate, slope and intercept for total U.S. drilling capacity formula, and regional developmental dry hole rates. This file also contains the annual investment capacity.
- File "techpen.dat" is read by the timing model, but no longer used in the current configuration of the model. This file could be used after slight program modifications to regulate the fraction of available drilling capacity and capital capacity constraints which are applied in a given year.
- File "options.dat" which contains information needed to configure the timing process. It contains information such as the starting year of timing, number of years to time, switches which turn capital and resource availability constraints on and off, a maximum number of wells per year constraint, the oil prices which will be analyzed, and the names of the primary input files.

7.3 Description of Processing

The algorithm used by the timing model is straightforward. Processing begins by reading the input files described above. After reading the "drillcap.dat" file, the "techpen.dat" files and the "options.dat" file, a loop is set up and the production data are read for the first accumulation in the primary input file. After reading the production data, the drilling capacity and capital constraints are applied and a pattern initiation schedule is created for development of the accumulation. The constraints are adjusted to account for the development of the accumulation and processing continues to the next accumulation. If the capacity to drill or invest for a given year is more than the constraint available for that year, the number of wells for the year is reduced and the remaining wells are developed in a future year. This loop continues until all accumulations have been processed and a pattern initiation schedule has been created for every accumulation in the analysis.

The next step is to perform post processing. The accumulations are developed using the pattern initiation schedule just created. The same detailed cash flow analysis used in the economic module to calculate an investment efficiency is used by the post processor. The individual accumulation production and economic results are then totaled by an aggregation routine and output files are generated.

7.4 Output

Several output files are generated by each run of the timing module. The following are the more important files:

- File "summary.out" contains 25 years of annual values for the following elements. These data are provided for each oil price run by the model
  - Number of patterns initiated
  - Oil production (MMbbl)
  - Gas production (BCF)
  - Royalties ($MM)
  - Severance taxes ($MM)
  - State taxes ($MM)
  - Sales taxes ($MM)
  - State revenues ($MM)
  - Federal taxes ($MM)
  - Federal tax credit ($MM)
  - Federal royalties ($MM)
  - Federal revenues ($MM)

- Intangible drilling costs ($MM)
- Tangible drilling costs ($MM)
- Total operating costs ($MM)

- File "sumall.out" contains the same data elements as "summary.out" in this version of the timing model. If there were other processes being modeled besides primary production from undiscovered reservoirs, this file would display the aggregate results.
- File "resgro.out" contains 40 years of annual reserves added for each USGS region
- File "tresgro.out" contains 40 years of annual reserves added for all of the USGS regions combined.
- File "reswell.out" contains the pattern initiation schedule as well as cumulative pattern production for each undiscovered accumulation.
- File "drill.out" contains 25 years of drilling footage and capital available as well as drilling footage and capital spending actually used by the model. These data are provided on a USGS region basis.
- File "gro.out" contains region code, total resource, number of patterns, net present value, and a 20 year pattern initiation schedule for each accumulation in the study.
- File "stax.out" contains 25 years of state income tax for each state involved in the analysis. These data are provided for oil price analyzed.
- File "sroy.out" contains 25 years of royalty paid for each state involved in the analysis. These data are provided for each oil price analyzed.

Four Very Important Constraints

- Exploration ranking
- Economic preference
- Drilling capacity (regional)
- Capital availability

Figure 7–1 Timing Model

- The Exploration Model decides on the order by which accumulations of different size classes are found in each play:

Rank Order	Play A	Play B	Play C
1	5	6	9
2	7	4	5
3	5	7	5
4	1	3	7
5	1	5	2
n			

Accumulation Size class to be found

Figure 7–2 Exploration Ranking

Exploration Ranking

Rank Order	Play A	Play B	Play C
1	5	6	9
2	7	4	5
3	5	7	5
4	1	3	7
5	1	5	2
n			

- Across all plays
- For each exploration rank
- Sort by investment efficiency
- Investment efficiency is calculated:
  - Conduct full cashflow analysis
  - At a given Oil Price and ROR
  - Assuming drilling schedule of 30 wells/year
- Timing priority will be given to those projects with higher "investment efficiency"
- Repeat for other exploration ranks

Figure 7–3 Economic Preference

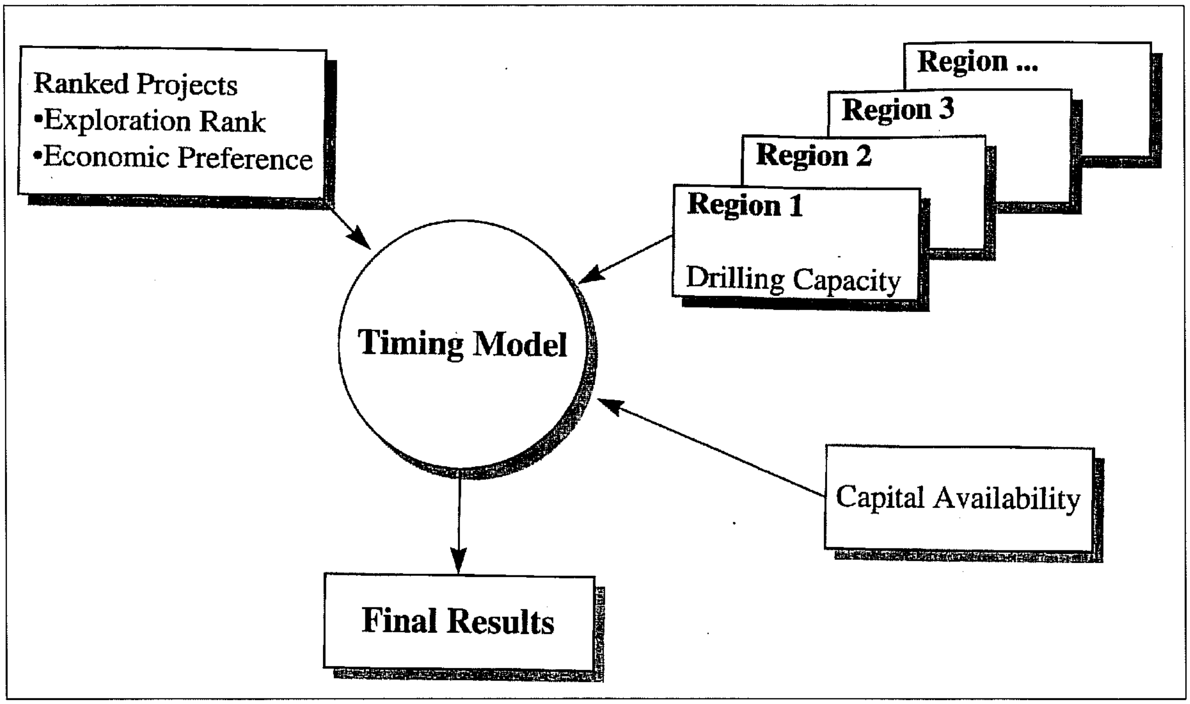
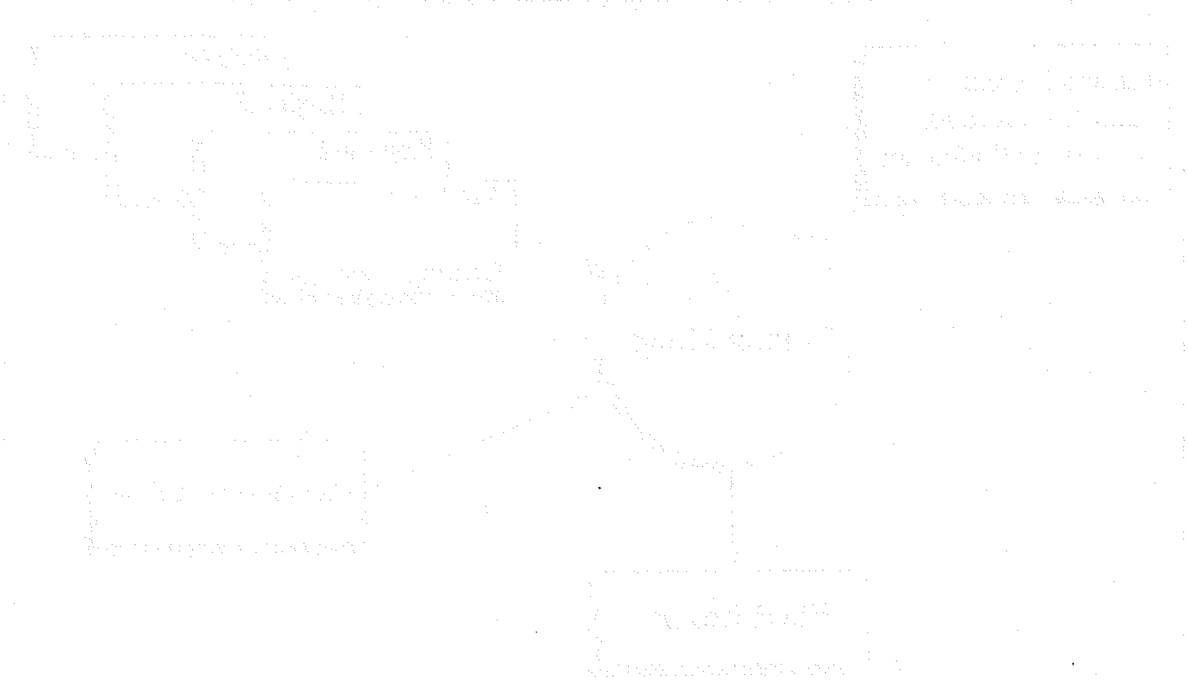


Figure 7–4 Overal Timing Algorithm

- How many wells can we drill in new fields/reservoirs in each region?
- Competition
  - Gas wells (Development/Exploration)
  - Oil wells (Development in Existing Fields)
  - Storage wells
  - EOR wells
  - Others
- Factors Controlling Drilling Capacity
  - Oil Price
  - Gas Price
  - Rig Utilization
  - Regional Demand

Figure 7–5 Drilling Capacity



8.0 APPENDICES

8.1 Calibration Run

A calibration run was made in order to determine if the exploration module generated plausible results. The following assumptions were made:

- All operators fell into the "Major Operator" category
- The price of oil was constant for the entire period of the analysis. The analysis considered seven oil prices ranging from $16/bbl to $28/bbl
- The minimum acceptable rate of return (ROR) on investment was 25%
- Operators were not subject to the alternative minimum tax (AMT)
- The results of the model run were to be presented without extrapolation.

The results of this calibration run are presented in the following pages.

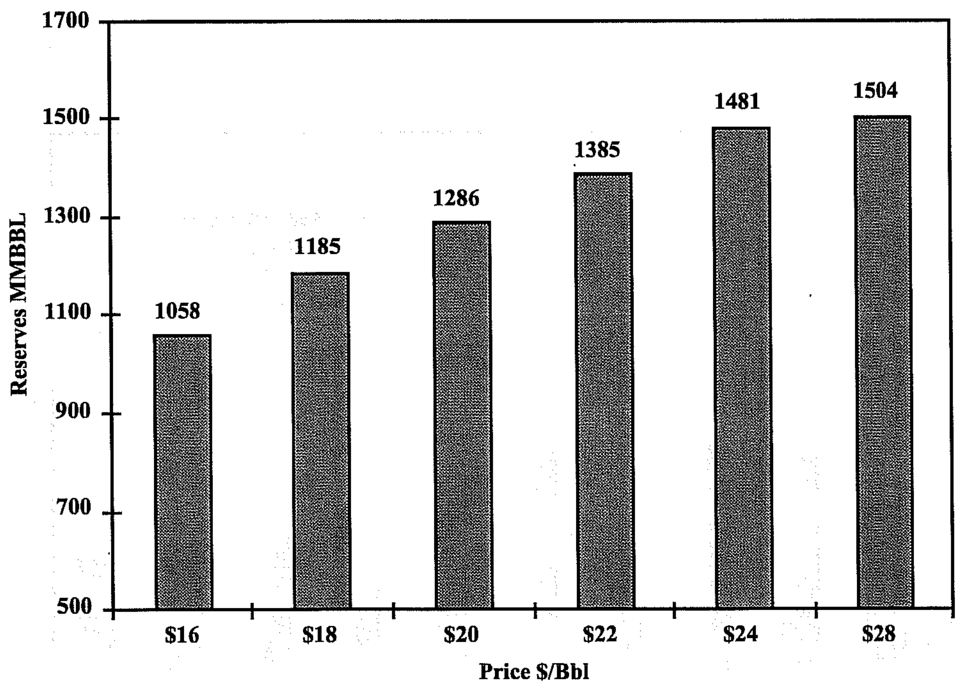


Figure 8–1 Potential Reserves From Undiscovered Resources (Lower 48 Onshore)

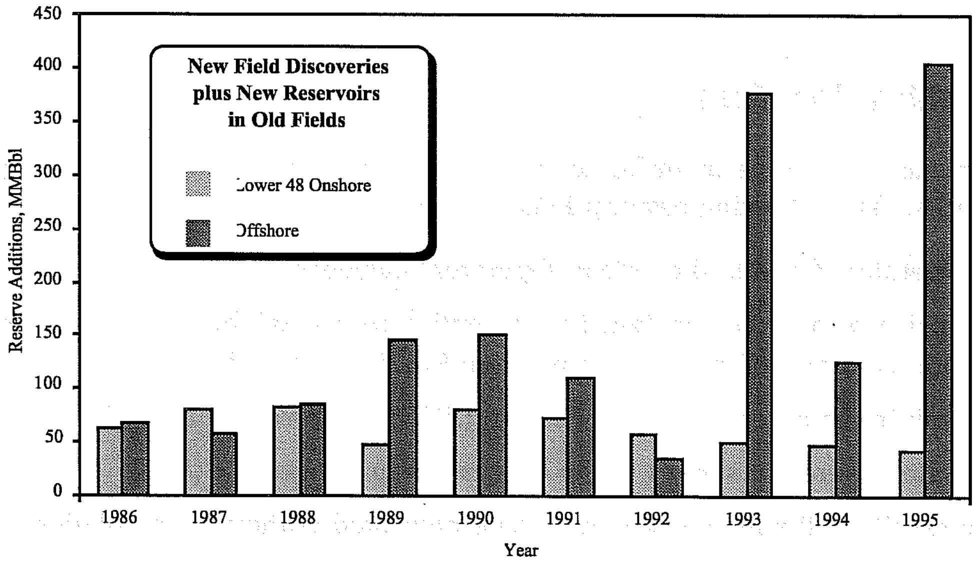


Figure 8–2 Historical Reserve Additions (EIA, Lower 48 States and Offshore)

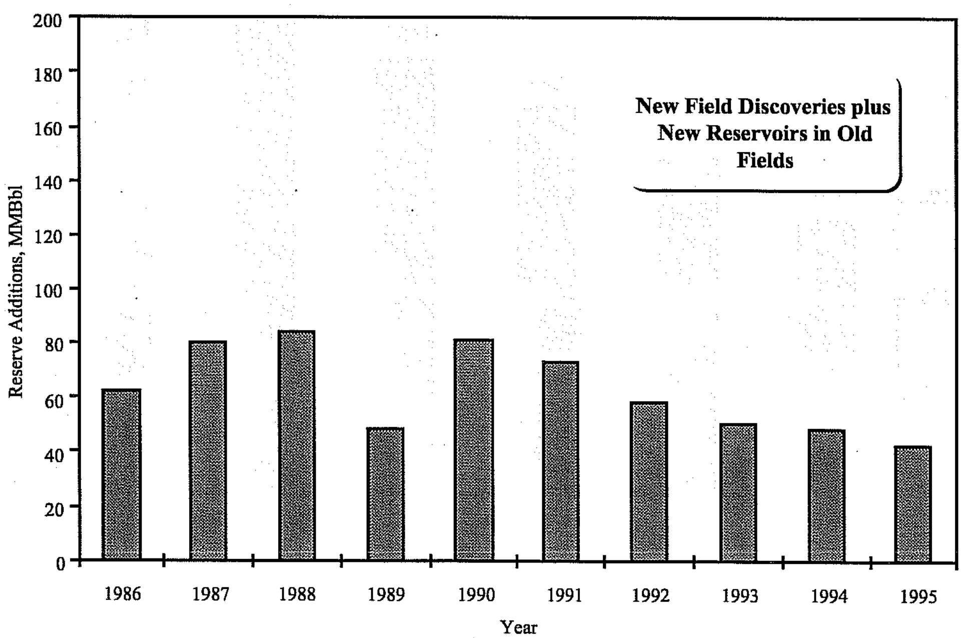


Figure 8–3 Historical Reserve Additions (EIA, Lower 48 States and Onshore)

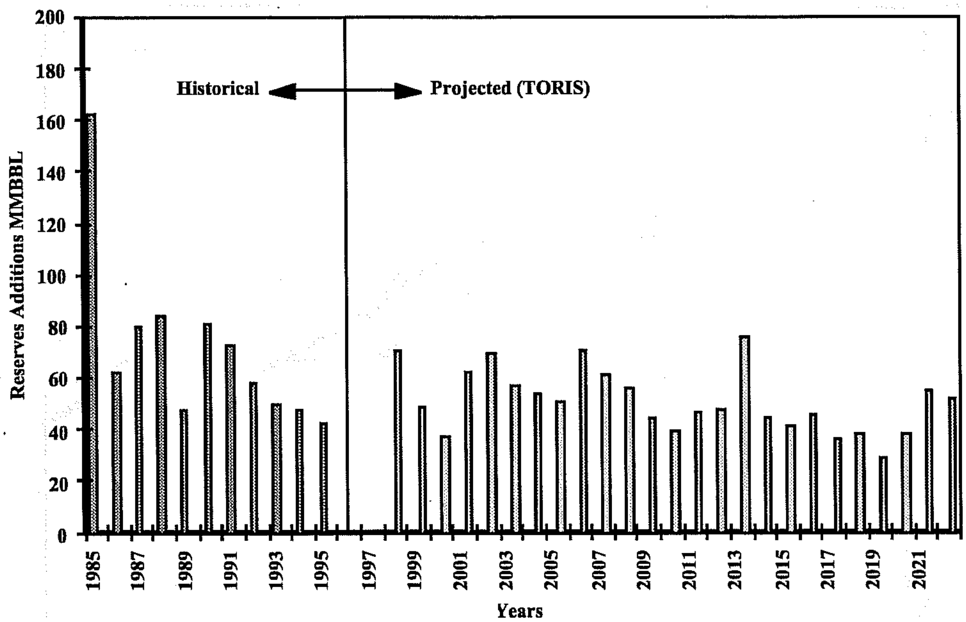


Figure 8–4 Reserves Additions—Historical vs Projected ($20/Bbl)

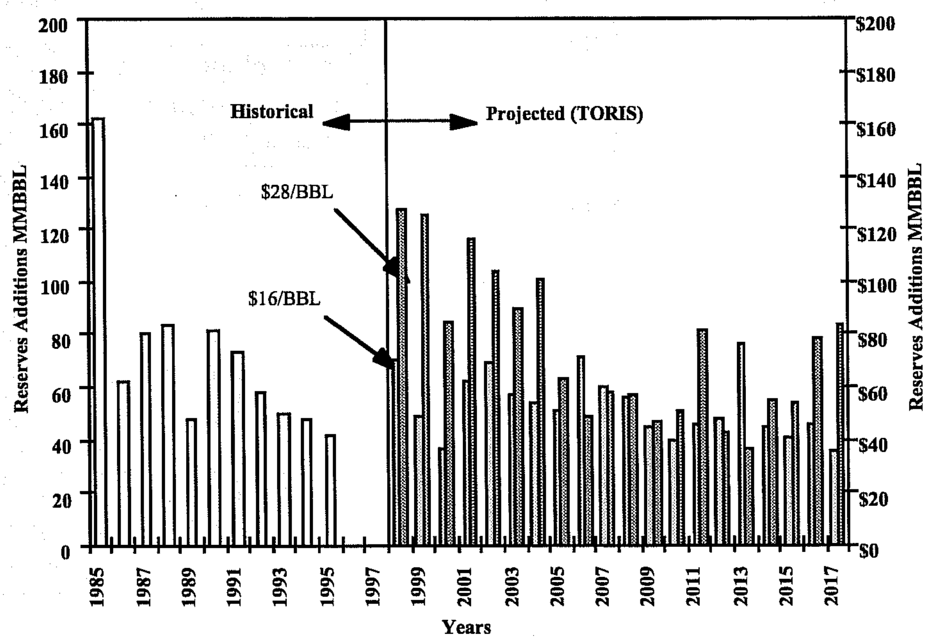


Figure 8–5 Reserves Additions—Historical vs Projected ($16 and 28/Bbl)

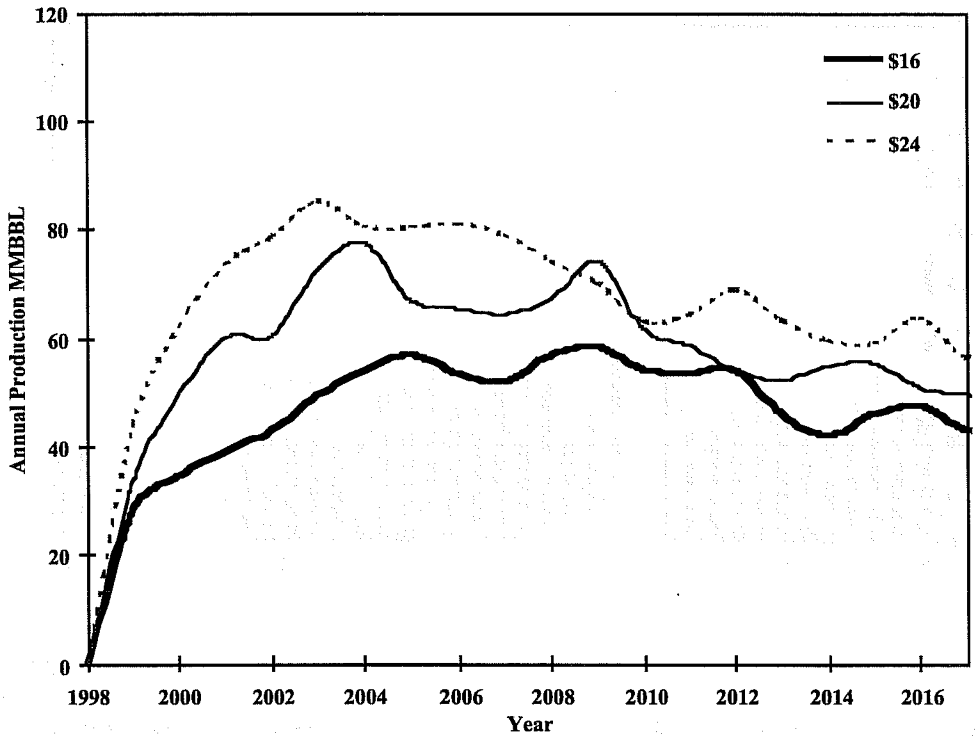
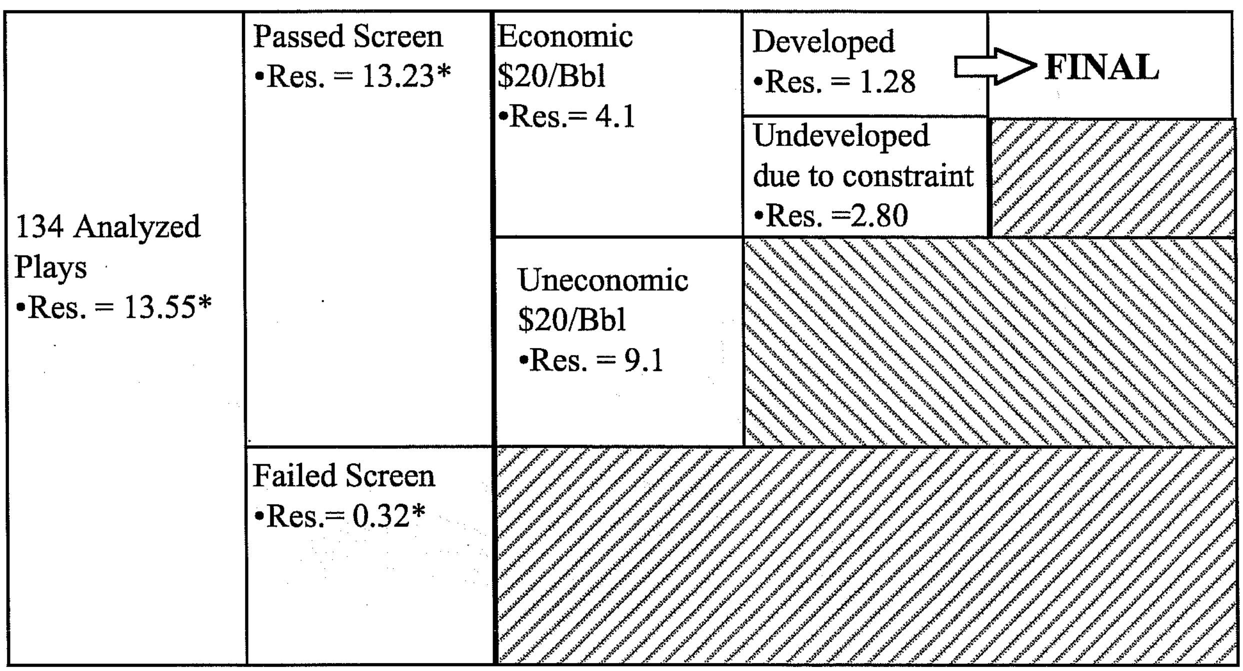


Figure 8–6 Projected Annual Production from New Discoveries



* Technically Recoverable Reserves estimated by USGS

Figure 8–7 Inventory of Resource (Reserves in Billion Barrels)

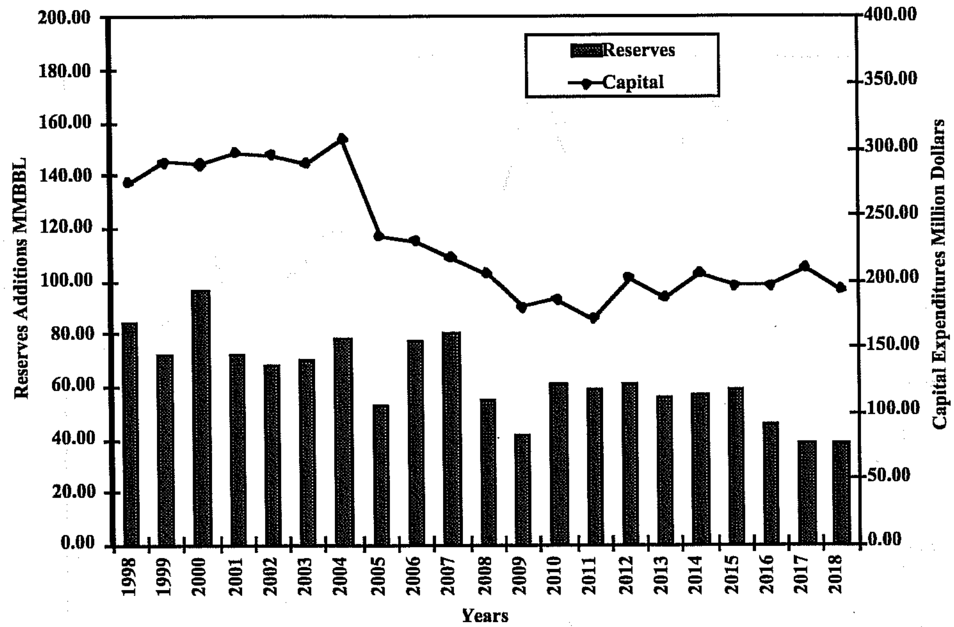


Figure 8–8 Projected Reserves Additions vs Capital Expenditures ($20/Bbl)

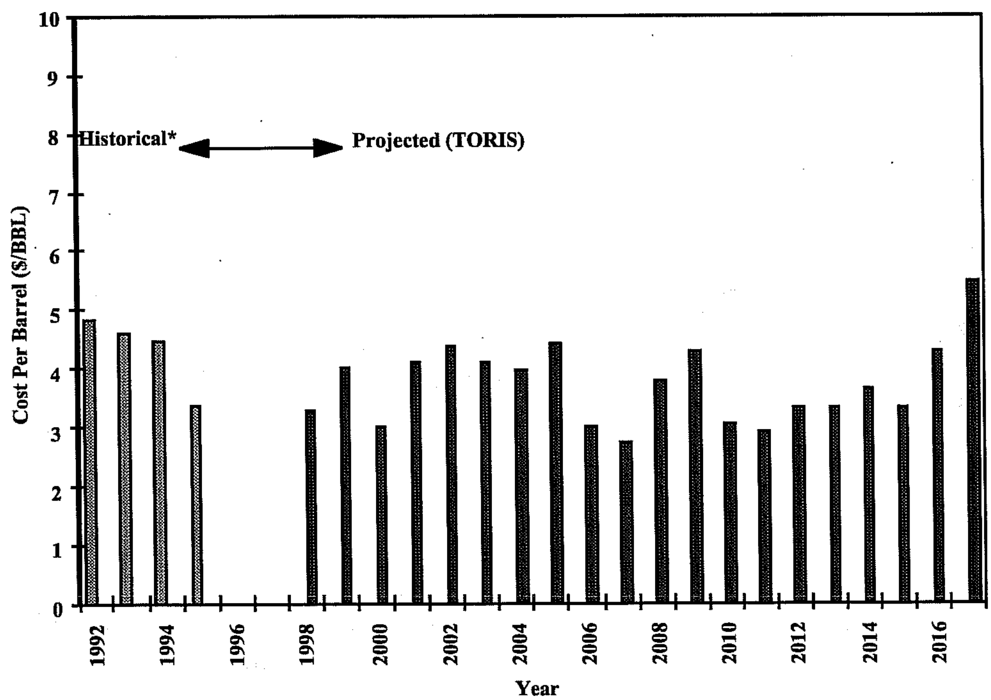


Figure 8–9 Cost per Barrel of Reserve Added Historical* vs Projected ($20/Bbl)

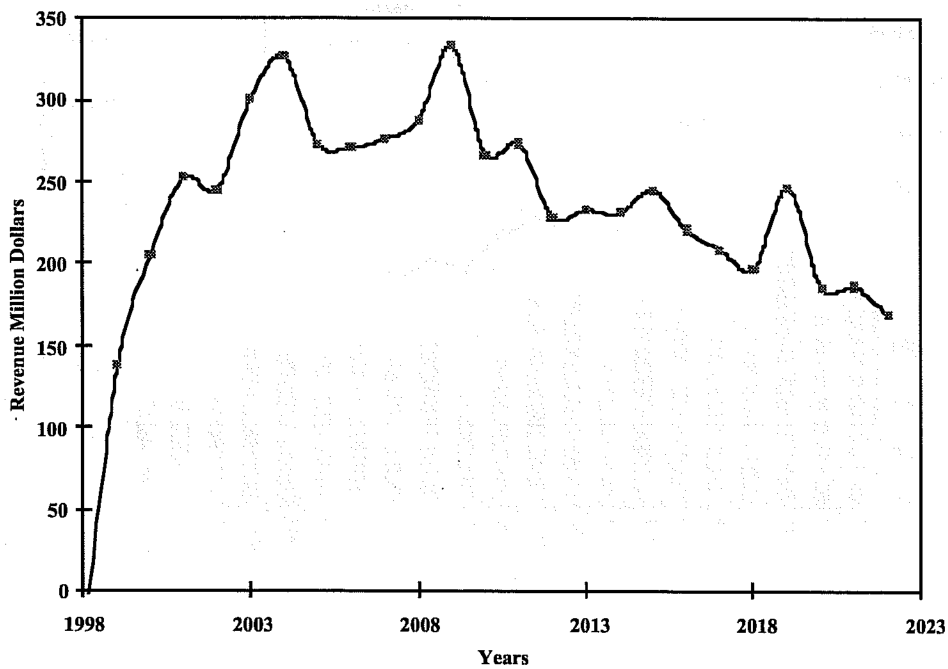


Figure 8–10 Net Federal Revenues ($20/BBL)

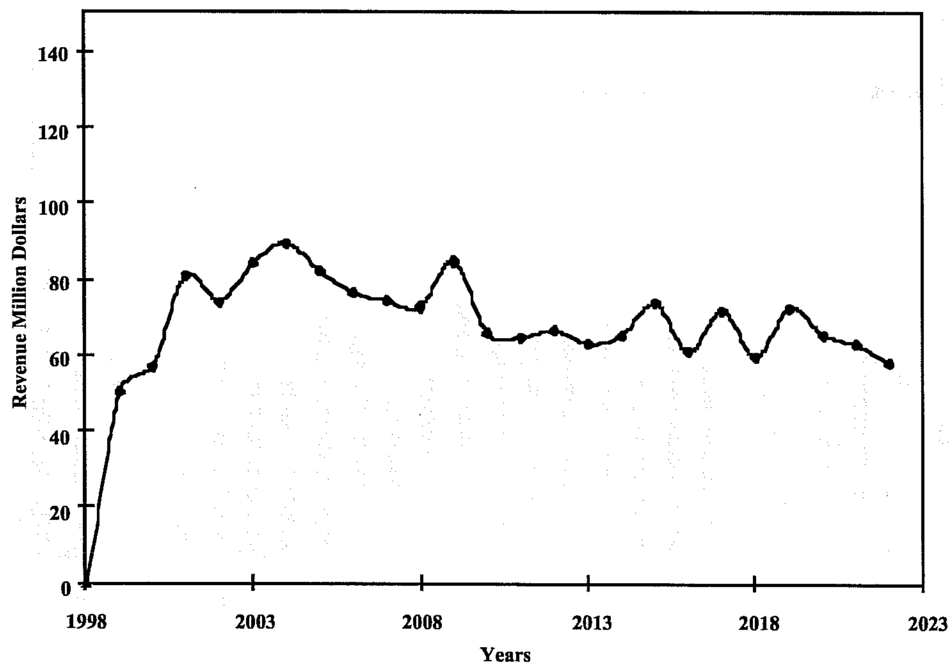


Figure 8–11 Net Revenues to State ($20/BBL)

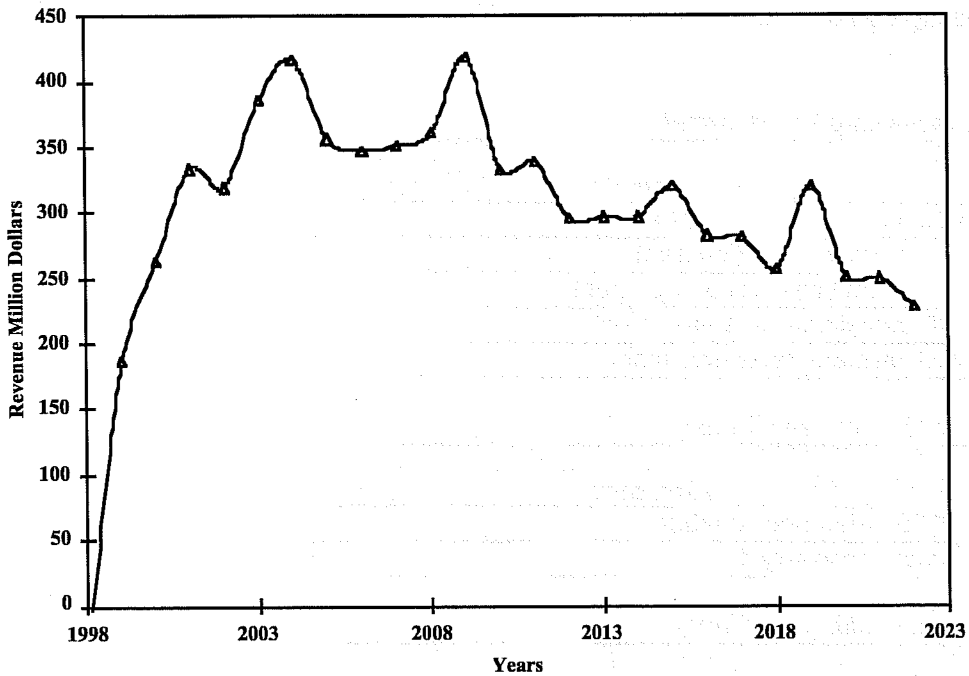


Figure 8–12 Net Public Sector Revenues ($20/BBL)

8.2 Description of Input Files

8.2.1 Average properties module input files

avgprop.f

Logical Unit #1; recfact.nrg (fixed format)

Character Position	Contents
1 - 11	NRG identification number
12 - 13	NRG source code (ignored)
14 - 22	NRG cumulative recovery, mbbl
23 - 31	NRG remaining reserves, mbbl
32 - 40	NRG ultimate recovery, mbbl

Logical Unit #2; recfact.tor (free format)

Data Element	Contents
1	TORIS reference number
2	ultimate recovery factor

Logical Unit #3; recov-f.dat (free format)

Data Element	Contents
1	USGS Play reference number

Logical Unit #4; 'USGS play code'.grp (fixed format)

Character Position	Contents
1 - 3	accumulation code
4 - 43	blank
44 - 46	source, NRG/TORIS
47 - 52	TORIS identification number
53 - 53	blank
54 - 64	NRG identification number
65 - 152	blank
153 - 154	state abbreviation
155 - 159	blank
160 - 168	depth, ft
169 - 169	blank
170 - 177	reservoir temperature, deg. F
178 - 178	blank
179 - 186	initial reservoir pressure, psi
187 - 187	blank
188 - 196	field area, acres
197 - 207	blank
208 - 213	gross pay, ft
214 - 214	blank
215 - 220	net pay, ft
221 - 221	blank

Logical Unit #4; 'USGS play code'.grp (fixed format) (cont.)

Character Position	Contents
222 - 227	porosity, fraction
228 - 228	blank
229 - 135	formation volume factor
136 - 136	blank
137 - 147	original oil in place, mmbbl
148 - 152	blank
153 - 158	initial oil saturation, fraction
159 - 159	blank
160 - 165	initial gas saturation, fraction
166 - 173	blank
174 - 182	API gravity, degrees API
183 - 183	blank
184 - 192	viscosity, cp
193 - 193	blank
194 - 202	gas oil ratio, Scf/bbl
203 - 213	blank
214 - 222	permeability, md

8.2.2 Accumulation generation module input files

make_res.f

Logical Unit #1; UNDISC.DAT (free format)

Column	Contents
1	USGS Play reference number
2	distribution of undiscovered reservoirs in size class 1
3	distribution of undiscovered reservoirs in size class 2
4	distribution of undiscovered reservoirs in size class 3
5	distribution of undiscovered reservoirs in size class 4
6	distribution of undiscovered reservoirs in size class 5
7	distribution of undiscovered reservoirs in size class 6
8	distribution of undiscovered reservoirs in size class 7
9	distribution of undiscovered reservoirs in size class 8
10	distribution of undiscovered reservoirs in size class 9
11	distribution of undiscovered reservoirs in size class 10
12	distribution of undiscovered reservoirs in size class 11
13	distribution of undiscovered reservoirs in size class 12
14	distribution of undiscovered reservoirs in size class 13

make_res.f

Logical Unit #1; UNDISC.DAT (free format) (cont.)

Column	Contents
15	distribution of undiscovered reservoirs in size class 14
16	distribution of undiscovered reservoirs in size class 15

Logical Unit #2; AVG.DAT (fixed format)

Character Position	Contents
1 - 5	USGS Play reference number
6 - 10	USGS size class
11 - 15	reservoir count for respective size class
16 - 16	blank
17 - 18	state abbreviation
19 - 19	blank
20 - 29	depth, ft
30 - 30	blank
31 - 40	reservoir temperature, deg F
41 - 41	blank
42 - 51	initial reservoir pressure, psi
52 - 52	blank
53 - 62	producing area, acres
63 - 63	blank
64 - 73	gross pay, ft
74 - 74	blank
75 - 84	net pay, ft
85 - 85	blank
86 - 91	porosity, fraction
92 - 92	blank
93 - 98	formation volume factor, bbl/Scf
99 - 99	blank
100 - 109	original oil in place, mmbbl
110 - 110	blank
111 - 116	initial oil saturation, fraction
117 - 117	blank
118 - 123	initial gas saturation, fraction
124 - 124	blank
125 - 134	API gravity, degrees API
135 - 135	blank
136 - 145	viscosity, cp
146 - 146	blank
147 - 156	initial GOR, Scf/bbl
157 - 157	blank
158 - 167	permeability, md
168 - 168	blank
169 - 174	ultimate recovery factor, fraction

Logical Unit #4; USGSRES.DAT (free format)

Column	Contents
1	USGS Play reference number
2	USGS region reference number; (1-8)

Logical Unit #7 multiple.dat (fixed format)

Character Position	Contents
1 - 5	USGS Play reference number
6 - 10	USGS size class
11 - 15	state count for respective size class
16 - 18	blank
19 - 20	state abbreviation (I)
21 - 30	technical recoverable oil percentage per state (I)
31 - 33	blank
34 - 35	state abbreviation (II)
36 - 45	technical recoverable oil percentage per state (II)
46 - 48	blank
49 - 50	state abbreviation (III)
51 - 60	technical recoverable oil percentage per state (III)
61 - 63	blank
64 - 65	state abbreviation (IV)
66 - 75	technical recoverable oil percentage per state (IV)

8.2.3 Primary production module input files

main000.f

Logical Unit #10; INPUT.GSM; random access file

RECORD NO 1; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 7	source code
8 - 8	blank
9 - 10	state abbreviation
11 - 11	blank
12 - 12	source code
13 - 13	blank
14 - 16	source code
17 - 17	blank
18 - 53	source code
54 - 54	blank
55 - 102	source code
103 - 104	blank
105 - 115	alphanumeric reservoir identification
116 - 116	blank
117 - 120	source code

Logical Unit #10; INPUT.GSM; random access file
RECORD NO 2; (free format)

Reference No.	Contents
5	field acres, acres
6	gross pay, ft
7	porosity, %
8	initial oil saturation, %
12	initial gas saturation, %
14	initial oil formation volume factor, bbl/stb
16	true vertical depth, ft; mid-perforation

Logical Unit #10; INPUT.GSM; random access file
RECORD NO 3; (free format)

Reference No.	Contents
19	permeability, md
21	API gravity, degrees API
22	oil viscosity, cp (reservoir conditions)
24	OOIP, bbl
34	initial producing GOR, Scf/bbl

Logical Unit #10; INPUT.GSM; random access file
RECORD NO 4; (free format)

Reference No.	Contents
35	reservoir acreage, acres
36	initial formation pressure, psi
51	ultimate recovery factor, fraction OOIP

8.2.4 Economic module input files

horeco.f
Logical Unit #85; OPTION.DAT (free format)

Data Element	Contents
1	detail summary output code; (1=yes, 0=no)
2	cumulative summary of all processes; (1=yes, 0=no)
3	years of analysis
4	number of processes
5	process file name and location

Logical Unit #85; COST.DAT (free format)

Data Element	Contents
1	royalty rate, fraction
2	discount rate, %
3	percent development well cost tangible, %

Logical Unit #85; COST.DAT (free format) (cont.)

Data Element	Contents
4	percent facilities cost tangible, %
5	environmental capital cost multiplier
6	G&A expense multiplier
7	G&A capital multiplier
8	lease bonus cost factor
9	G&G factor
10	percent of G&G depleted, %
11	percent lease acquisition cost capitalized, %
12	water O&M, $/bbl
13	gas O&M, $/mcf
14	oil O&M, $/bbl
15	number of regions
16	development well cost function
17	new producer equipment cost function
18	cost to convert primary to secondary cost function
19	cost to convert a producer to an injector cost function
20	cost for secondary facilities upgrade cost function
21	pump equipment cost function
22	operating cost for secondary operations function
23	operating cost excluding pumping cost function
24	incremental operating cost due to pumps function
25	percent dry hole per region, %

Logical Unit #85; REGIONS.DAT (free format)

Column	Contents
1	state reference number, 1-51
2	region code
3	region code
4	state name

Logical Unit #85; TAXES.DAT (free format)

Data Element	Contents
1	federal income tax rate, %
2	independent producer depletion rate, %
3	intangible drilling costs capitalized, yes/no
4	other intangibles capitalized, yes/no
5	include environmental costs, yes/no
6	environmentals capitalized, yes/no
7	implement alternative minimum taxes, yes/no
8	allow AMT taxes paid to be used as credits in future years, yes/no
9	six month amortization rate, %
10	intangible drilling cost preference deduction, %
11	ACE rate, %
12	maximum alternative minimum tax reduction for independents
13	alternative minimum tax rate, %

Logical Unit #85; TAXES.DAT (free format) (cont.)

Data Element	Contents
14	expense environmental costs, yes/no
15	allow property net income limitations, yes/no
16	net income limitation limit, %
17	percent depletion rate, %
18	percent of intangible investment to capitalize, %
19	EOR tax credit, yes/no
20	EOR tax credit rate, %
21	EOR tax credit addback, %
22	EOR tax credit use by year, %
23	allow tax credit for expensed G&G, yes/no
24	G&G expensed tax credit addback, %
25	allow lease acquisition depletable tax credit, yes/no
26	lease acquisition depletable tax credit rate, %
27	lease acquisition depletable tax credit addback rate, %
28	allow tax credit for expensed lease acquisition costs, yes/no
29	tax credit rate for expensed lease acquisition costs
30	tax credit for expensed lease acquisition cost addback, %
31	allow tangible development tax credit, yes/no
32	tangible development tax credit rate, %
33	tangible development tax credit addback, %
34	allow intangible drilling cost tax credit, yes/no
35	intangible drilling cost tax credit rate, %
36	intangible drilling cost tax credit addback, %
37	allow environmental tangible tax credit, yes/no
38	environmental tangible tax credit rate, %
39	environmental tangible tax credit addback, %
40	allow environmental intangible tax credit, yes/no
41	environmental intangible tax credit rate, %
42	environmental intangible tax credit addback, %
43	allow environmental operating cost tax credit, yes/no
44	environmental operating cost tax credit rate, %
45	environmental operating cost tax credit addback, %
46	allow tax credit on tangible investments, yes/no
47	number of years for tax credit on tangible investments
48	allow tax credit on intangible investments, yes/no
49	number of years for tax credit on intangible investments

Logical Unit #85; DEPRAMOR.DAT (free format)

Data Element	Contents
1	years in schedule #1
2	years in schedule #2
3	schedule #1 values for each year
4	schedule #2 values for each year

Logical Unit #85; PRICE.DAT (free format)

Data Element	Contents
1	fixed price (1), or AEO price track (2)
2	fixed oil price, $/bbl
3	fixed gas price, $/mcf
4	fixed inflation, %/yr
5	AEO price track; number of years
6	year, mm/dd/yy
7	oil price, $/bbl
8	gas price, $/mcf
9	inflation, %/yr

Logical Unit #85; CASES.DAT (free format)

Data Element	Contents
1	number of cases
2	case number
3	drilling reduction factor
4	other investment reduction factors
5	O&M reduction factors
6	price reduction factor

Logical Unit #29; SINTAX.DAT (fixed format)

Character Position	Contents
1 - 1	blank
2 - 6	number of states
7 - 7	blank
8 - 9	numeric state code
10 - 14	blank
15 - 20	state personal income tax as percentage of gross income

Logical Unit #15; PRPMDATA.LB (fixed format)

Character Position	Contents
1 - 1	blank
2 - 12	alphanumeric reservoir identification
13 - 14	blank
15 - 24	lease acquisition cost, dollars

Logical Unit #10; PRPMDATA.DAT; (fixed format)

Character Position	Contents
1 - 11	alphanumeric reservoir identification

Logical Unit #10; PRPMDATA.DAT; (free format)

Data Element	Contents
1	depth, ft
2	number of laterals (set to zero for this model)
3	length of lateral (set to zero for this model)
4	API gravity, degrees API
5	total area of accumulation, acres
6	area of single pattern, acres
7	total number of patterns to develop accumulation
8	years of production data, years
9	year pump activated
10 - 49	annual oil production, mmbbl/yr
50 - 89	annual gas production, mmscf/yr
90 - 129	annual water production, mmbbl/yr

8.2.5 Exploration module input files

rankacum.f

Logical Unit #1; UND.GSM (fixed format)

Character Position	Contents
1 - 11	alphanumeric reservoir identification
12 - 22	number of accumulations per play per size class

Logical Unit #2; $1.TIM; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 12	alphanumeric reservoir identification
13 - 13	blank
14 - 18	API gravity, degrees API
19 - 19	blank
20 - 26	depth, ft
27 - 27	blank
28 - 34	length of lateral, ft
35 - 35	blank
36 - 42	number of wells drilled
43 - 43	blank
44 - 50	number of patterns to develop accumulation
51 - 51	blank
52 - 56	years
57 - 57	blank
58 - 61	USGS region code

Logical Unit #2; $1.TIM; (fixed format) (cont.)

Character Position	Contents
62 - 62	blank
63 - 66	process code (expl=6)
67 - 67	blank
68 - 71	years of production data, years

Data Element	Contents
72 - 112	annual oil production, mmbbl/yr
113 - 152	annual gas production, mmscf/yr
153 -192	annual water production, mmbbl/yr
193 - 232	annual water injection, mmbbl/yr

8.2.6 Timing module input files

timing.f

Logical Unit #85; GORDATA.PRN (fixed format)

Character Position	Contents
1 - 1	blank
2 - 12	alphanumeric reservoir identification
13 - 14	blank
15 - 20	recovery factor

Logical Unit #85; DRILLCAP.DAT; (free format)

Data Element	Contents
1	number of regions
2	total onshore percentage
3	total oil percentage of total onshore
4	growth percentage
5	years of growth
6	exploration dry hole rate

Logical Unit #85; DRILLCAP.DAT; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 21	region name
22 - 22	blank
23 - 25	region code, (1-8)
26 - 31	blank
32 - 43	slope of total footage drilled vs. oil price, ft/$
44 - 49	blank
50 - 61	linear coefficient, ft
26 - 64	blank
65 - 76	total capital, mm$

Logical Unit #85; DRILLCAP.DAT; (fixed format) (cont.)

Character Position	Contents
77 - 82	blank
83 - 94	fraction of region which produces
95 - 100	blank
101 - 112	fraction of region which is dry

Logical Units #85 TECHPEN.DAT; (free format)

Data Element	Contents
1	number of years

Logical Units #85 TECHPEN.DAT; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 3	year
4 - 12	blank
13 - 18	fraction of total capacity
19 - 31	blank
32 - 38	increase factor
39 - 49	blank
50 - 56	cost factor

Logical Units #85 OPTIONS.DAT; (free format)

Data Element	Contents
1	number of years
2	start year (1997 or 1998)
3	check for capital constraints; (0=no, 1=yes)
4	check for resource availability; (0=no, 1=yes)
5	max number of wells drilled in each year
6	number of price analyzed
7	oil prices analyzed
8	number of files for timing
9	name of the files; (*.tim)

Logical Units #85 EPARES22.PRN; (fixed format)

Character Position	Contents
1 - 2	blank
3 - 7	reference number
8 - 9	blank
10 - 14	year

Logical Unit #20 EPARES.P1 through EPARES.P8; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 12	alphanumeric reservoir identification
13 - 13	blank
14 - 18	API gravity, degrees API
19 - 19	blank
20 - 26	depth, ft
27 - 27	blank
28 - 34	length of lateral, ft
35 - 35	blank
36 - 42	number of wells drilled
43 - 43	blank
44 - 50	number of patterns to develop accumulation
51 - 51	blank
52 - 56	years
57 - 57	blank
58 - 61	USGS region code
62 - 62	blank

Logical Unit #20 EPARES.P1 through EPARES.P8; (fixed format) (cont.)

Character Position	Contents
63 - 66	process code (expl=6)
67 - 67	blank
68 - 71	years of production data, years

Data Element	Contents
72 - 112	annual oil production, mmbbl/yr
113 - 152	annual gas production, mmscf/yr
153 -192	annual water production, mmbbl/yr
193 - 132	annual water injection, mmbbl/yr

8.3 Description of Output Files

8.3.1 Average properties module output file

avgprop.f

Logical Unit #11; avg.dat (fixed format)

Character Position	Contents
1 - 5	USGS Play reference number
6 - 10	USGS size class
11 - 15	reservoir count for respective size class
16 - 16	blank
17 - 18	state abbreviation
19 - 19	blank
20 - 29	depth, ft
30 - 30	blank
31 - 40	reservoir temperature, deg F
41 - 41	blank
42 - 51	initial reservoir pressure, psi
52 - 52	blank
53 - 62	producing area, acres
63 - 63	blank
64 - 73	gross pay, ft
74 - 74	blank
75 - 84	net pay, ft
85 - 85	blank
86 - 91	porosity, fraction
92 - 92	blank
93 - 98	formation volume factor, bbl/Scf
99 - 99	blank
100 - 109	original oil in place, mmbbl
110 - 110	blank
111 - 116	initial oil saturation, fraction
117 - 117	blank
118 - 123	initial gas saturation, fraction
124 - 124	blank
125 - 134	API gravity, degrees API
135 - 135	blank
136 - 145	viscosity, cp
146 - 146	blank
147 - 156	initial GOR, Scf/bbl
157 - 157	blank
158 - 167	permeability, md
168 - 168	blank
169 - 174	ultimate recovery factor, fraction

Logical Unit #12; multiple.dat (fixed format)

Character Position	Contents
1 - 5	USGS Play reference number
6 - 10	USGS size class
11 - 15	state count for respective size class
16 - 18	blank
19 - 20	state abbreviation (I)
21 - 30	technical recoverable oil percentage per state (I)
31 - 33	blank
34 - 35	state abbreviation (II)
36 - 45	technical recoverable oil percentage per state (II)
46 - 48	blank
49 - 50	state abbreviation (III)
51 - 60	technical recoverable oil percentage per state (III)
61 - 63	blank
64 - 65	state abbreviation (IV)
66 - 75	technical recoverable oil percentage per state (IV)

8.3.2 Accumulation generation module output files

make_res.f

Logical Unit #12; INPUT.GSM; random access file

RECORD NO 1; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 7	source code
8 - 8	blank
9 - 10	state abbreviation
11 - 11	blank
12 - 12	source code
13 - 13	blank

Logical Unit #12; INPUT.GSM; random access file (cont.)

RECORD NO 1; (fixed format)

Character Position	Contents
14 - 16	source code
17 - 17	blank
18 - 53	source code
54 - 54	blank
55 - 102	source code
103 - 104	blank
105 - 115	alphanumeric reservoir identification
116 - 116	blank
117 - 120	source code

Logical Unit #12; INPUT.GSM; random access file
RECORD NO 2; (free format)

Data Element	Contents
5	field acres, acres
6	gross pay, ft
7	porosity, %
8	initial oil saturation, %
12	initial gas saturation, %
14	initial oil formation volume factor, bbl/stb
16	true vertical depth, ft; mid-perforation

Logical Unit #12; INPUT.GSM; random access file
RECORD NO 3; (free format)

Data Element	Contents
19	permeability, md
21	API gravity, degrees API
22	oil viscosity, cp (reservoir conditions)
24	OOIP, bbl
34	initial producing GOR, Scf/bbl

Logical Unit #12; INPUT.GSM; random access file
RECORD NO 4; (free format)

Data Element	Contents
35	reservoir acreage, acres
36	initial formation pressure, psi
51	ultimate recovery factor, fraction OOIP

Logical Unit #13; UND.GSM (fixed format)

Character Position	Contents
1 - 11	alphanumeric reservoir identification
12 - 22	number of accumulations per play per size class

8.3.3 Primary production module output files

main000.f
Logical Unit #22; ecoinpt.dat; (fixed format)

Character Position	Contents
1 - 11	alphanumeric reservoir identification

Logical Unit #22; ecoinpt.dat; (free format)

Data Element	Contents
1	depth, ft
2	number of laterals (set to zero for this model)
3	length of lateral (set to zero for this model)
4	API gravity, degrees API
5	total area of accumulation, acres
6	area of single pattern, acres
7	total number of patterns to develop accumulation
8	years of production data, years
9	year pump activated
10 - 49	annual oil production, mmbbl/yr
50 - 89	annual gas production, mmscf/yr
90 - 129	annual water production, mmbbl/yr

8.3.4 Economic module output files

horeco.f

Logical Unit #12; DV30RR25.SUM; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 12	alphanumeric reservoir identification
13 - 24	cumulative production, mmbbl
25 - 36	cumulative after tax cash flow, dollars
37 - 48	rate of return, %

Logical Unit #38; DV30RR25.OUT; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 3	state abbreviation
4 - 4	blank
5 - 8	process code, (6=exploration module)
9 - 9	blank
10 - 13	USGS Play reference number
14 - 19	reference number
20 - 20	blank
21 - 20	depth
21 - 28	process code
29 - 36	total area
37 - 44	pattern area
45 - 52	process code

Logical Unit #38; DV30RR25.OUT; (fixed format) (cont.)

Character Position	Contents
53 - 60	years
61 - 67	process code
68 - 68	years
69 - 69	blank
70 - 72	"P" indicator

Logical Unit #38; DV30RR25.OUT; (free format)

Data Element	Contents
1	reserves undiscounted, mbbl
2	npv oil production less royalty and severance tax, mbbl
3	npv gas production less royalty and severance tax, mmcf
4	total severance taxes, m$
5	total state taxes, $m
6	total federal taxes, $m
7	total federal tax credit, $m
8	total federal income taxes, $m
9	total state income taxes, $m
10	total sales taxes, $m
11	npv of project, $m

Logical Unit #68; DV30RR25.TIM; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 12	alphanumeric reservoir identification
13 - 13	blank
14 - 18	API gravity, degrees API
19 - 19	blank
20 - 26	depth, ft
27 - 27	blank
28 - 34	length of lateral, ft
35 - 35	blank
36 - 42	number of wells drilled
43 - 43	blank
44 - 50	number of patterns to develop accumulation
51 - 51	blank
52 - 56	years
57 - 57	blank
58 - 61	USGS region code

Logical Unit #68; DV30RR25.TIM; (fixed format) (cont.)

Character Position	Contents
62 - 62	blank
63 - 66	process code (expl=6)
67 - 67	blank
68 - 71	years of production data, years
72 - 112	annual oil production, mmbbl/yr
113 - 152	annual gas production, mmscf/yr
153 - 192	annual water production, mmbbl/yr
193 - 132	annual water injection, mmbbl/yr

Logical Unit #19; DV30RR25.NPV; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 3	state abbreviation
4 - 4	blank
5 - 8	process code, (6=exploration module)
9 - 9	blank
10 - 13	USGS Play reference number
14 - 19	reference number
20 - 20	blank
21 - 20	depth
21 - 28	process code
29 - 36	total area
37 - 44	pattern area
45 - 52	process code
53 - 60	years
61 - 67	process code
68 - 68	years
69 - 69	blank
70 - 72	"P" indicator

Logical Unit #19; DV30RR25.NPV; (free format)

Data Element	Contents
1	npv oil production less royalty and severance tax, mbbl
2	npv gas production less royalty and severance tax, mmcf
3	npv of expenses, m$
4	npv of tangible investments (excluding drilling, $m
5	npv of intangible investments (excluding drilling), $m
6	npv of development well costs, $m
7	npv of state taxes, $m
8	npv of federal taxes, $m
9	npv of federal tax credits, $m
10	npv of project, $m

Logical Unit #22; DV30RR25.TCP; (fixed format)

Character Position	Contents
1 - 11	alphanumeric reservoir identification

Logical Unit #22; DV30RR25.TCP; (free format)

Data Element	Contents
1	depth, ft
2	number of laterals (set to zero for this model)
3	length of lateral (set to zero for this model)
4	API gravity, degrees API
5	total area of accumulation, acres
6	area of single pattern, acres
7	total number of patterns to develop accumulation
8	years of production data, years
9	gross pay, ft
10	well spacing, acres
11	porosity, fraction
12	initial oil saturation, %
13	initial oil formation volume factor, bbl/STB
14	year pump activated
14 - 44	annual oil production, mmbbl/yr
45 - 84	annual gas production, mmscf/yr
84 - 124	annual water production, mmbbl/yr

Logical Unit #24; DV30RR25.VER; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 3	state abbreviation
4 - 4	blank
5 - 8	process code, (6=exploration module)
9 - 9	blank
10 - 13	USGS Play reference number
14 - 19	reference number
20 - 20	blank
21 - 20	depth
21 - 28	process code
29 - 36	total area
37 - 44	pattern area
45 - 52	process code
53 - 60	years
61 - 67	process code
68 - 68	years
69 - 69	blank
70 - 72	"P" indicator

Logical Unit #14; DV30RR25.PRO; (free format)

Data Element	Contents
1	year
2	number of patterns
3	oil production, mbbl
4	gas production, mmscf
5	oil price, $/bbl
6	gas price, $/Scf
7	remaining reserves, mboe
8	gross revenues, m$
9	adjusted oil price, $/bbl
10	gravity/trans. cost adjustment, m$
11	adjusted revenues, m$
12	royalties, m$
13	net sales, m$
14	total operating cost, m$
15	G&A on expensed items, m$
16	G&A on capitalized items, m$
17	pressure maintenance cycling, m$
18	general O&M, m$
19	total investments, m$
20	intangible investment, m$
21	intangible drilling costs, m$
22	other intangible costs, m$
23	portion of intangibles to capitalize, m$
24	tangible investments, m$
25	tangible drilling cost, m$
26	other tangible capital, m$
27	depreciable capitalized investments, m$
28	portion of intangibles to capitalize, m$
29	adjustments for federal tax credits, m$
30	depreciable capitalize base, m$
31	deprecation on tangibles, m$
32	depreciation on capitalized intangibles, m$
33	depletable G&G lease costs, m$
34	depletable lease acquisition cost, m$
35	depletable G&G costs, m$
36	adjustments for federal tax credits, m$
37	additions to depletion base, m$
38	depletion base, m$
39	expensed G&G lease costs, m$
40	expensed lease purchase cost, m$
41	expensed G&G costs, m$
42	net revenues, m$
43	operator severance taxes, m$
44	operating costs, m$
45	expensed int., G&G, and lease acquisition, m$
46	depreciation total, m$

Logical Unit #14; DV30RR25.PRO; (fixed format) (cont.)

Data Element	Contents
47	depletion allowance, m$
48	taxable income, m$
49	tax credit addback, m$
50	intangible addback, m$
51	G&G lease addback, m$
52	net income before taxes, m$
53	state income taxes, m$
54	alternative minimum tax, m$
55	federal income tax, m$
56	federal tax credits, m$
57	net income after taxes, m$
58	plus total depreciation, m$
59	plus depletion, m$
60	less additional depletable items, m$
61	less depreciable capitalized items, m$
62	less tax credit addbacks, m$
63	annual after tax cash flow, m$
64	discounted after tax cash flow, m$
65	cumulative discounted after tax cash flow, m$

8.3.5 Exploration module output files

rankacum.f

Logical Units #11 through #18; econ1.$2 through econ8.$2; (fixed format)

Character Position	Contents
1 - 1	blank
2 - 12	alphanumeric reservoir identification
13 - 13	blank
14 - 18	API gravity, degrees API
19 - 19	blank
20 - 26	depth, ft
27 - 27	blank
28 - 34	length of lateral, ft
35 - 35	blank
36 - 42	number of wells drilled
43 - 43	blank
44 - 50	number of patterns to develop accumulation
51 - 51	blank
52 - 56	years
57 - 57	blank
58 - 61	USGS region code
62 - 62	blank
63 - 66	process code (expl=6)
67 - 67	blank
68 - 71	years of production data, years

Logical Units #11 through #18; econ1.$2 through econ8.$2; (fixed format) (cont.)

Character Position	Contents
72 - 112	annual oil production, mmbbl/yr
113 - 152	annual gas production, mmscf/yr
153 - 192	annual water production, mmbbl/yr
193 - 232	annual water injection, mmbbl/yr

Logical Units #21 through #28; debug.1 through debug.8 ; (fixed format)

Character Position	Contents
1 - 11	alphanumeric reservoir identification
12 - 21	investment efficiency

Logical Units #31; cumprod.$2; (fixed format)

Character Position	Contents
1 - 20	cumulative production, bbl

8.3.6 Timing module output files

timing.f

Logical Unit #81 SUMMARY.OUT; (free format)

Data Element	Contents
1	case no.
2	iproc, (6 for timing module)
3	number of patterns initiated
4	oil production, mmbbl
5	gas production, bcf
6	royalties, mm$
7	severance taxes, mm$
8	state taxes, mm$
9	sales taxes, mm$
10	state revenues, mm$
11	federal taxes, mm$
12	federal tax credit, mm$
13	federal royalties, mm$
14	federal revenues, mm$
15	intangible drilling costs, mm$
16	tangible drilling costs, mm$
17	total operating costs, mm$

Note: Data Elements 1-17 are repeated for each case no. (oil price)

Logical Unit #82 SUMALL.OUT; (free format)

Data Element	Contents
1	case no.
2	iproc, (6 for timing module)
3	number of patterns initiated

Logical Unit #82 SUMALL.OUT; (free format) (cont.)

Data Element	Contents
4	oil production, mmbbl
5	gas production, bcf
6	royalties, mm$
7	severance taxes, mm$
8	state taxes, mm$
9	sales taxes, mm$
10	state revenues, mm$
11	federal taxes, mm$
12	federal tax credit, mm$
13	federal royalties, mm$
14	federal revenues, mm$
15	intangible drilling costs, mm$
16	tangible drilling costs, mm$
17	total operating costs, mm$

Note: Data Elements 1-17 are repeated for each case no. (oil price)

Logical Unit #83 SROY.OUT; (free format)

Data Element	Contents
1	case no.
2	royalty in state at oil price defined by case no., mm$

Note: Data Elements 1-2 are repeated for each case no. (oil price) and each state

Logical Unit #84 STAX.OUT; (free format)

Data Element	Contents
1	case no.
2	state taxes at oil price defined by case no., mm$

Note: Data Elements 1-2 are repeated for each case no. (oil price) and each state

Logical Unit #24 DRILL.OUT; (fixed format)

Data Element	Contents
1 - 1	blank
2 - 3	region number, (1-8)
4 - 4	blank
5 - 16	total US drilling constraint available, mft
17 - 17	blank
18 - 29	total US drilling constraint used, mft
30 - 30	blank
31 - 42	total US investment capital available, m$
43 - 43	blank
44 - 55	total US investment capital used, m$

Note: Data Elements 1-4 are repeated for each region

Logical Unit #77 RESGRO.OUT; (free format)

Data Element	Contents
1 - 9	case no.
10 - 11	blank
12 - 13	region number (1–8)
14 - 15	blank
16 - 375	annual reserve additions at oil price defined by case no. and region, mmbbl

Note: Data Elements 1-3 are repeated for each region then each case no. (oil price)

Logical Unit #79 RRESG.OUT; (fixed format)

Character Position	Contents
1 - 2	blank
3 - 13	alphanumeric reservoir identification
14 - 15	blank
16 - 19	economic life, year
20 - 21	blank
22 - 33	pattern cumulative production, mbbl
34 - 35	blank
36 - 40	patterns initiated

Logical Unit #78 TRESGRO.OUT; (free format)

Data Element	Contents
1	total reserves added at oil price defined by case no. and region, mbbl

Logical Unit #78 TRESGRO.OUT; (fixed format)

Character Position	Contents
1 - 9	case no.
10 - 11	blank
12 - 13	region number, (1–8)
14 - 15	blank
16 - 375	annual reserve additions at oil price defined by case no. and region, mmbbl

Note: Data Elements 1-4 are repeated for each region then each case no. (oil price)

Logical Unit #96 GRO.OUT; (fixed format)

Data Element	Contents
1 - 1	blank
2 - 7	number of accumulation
8 - 8	blank
9 - 10	region number, (1–8)
11 - 11	blank
12 - 23	net present value
24 - 24	blank

Logical Unit #96 GRO.OUT; (fixed format) (cont.)

Data Element	Contents
25 - 36	number of patterns in accumulation
37 - 37	blank
38 - 49	total oil resource of accumulation, mbbl
50 - 51	blank
52 - 54	patterns initiated

Note: Data Elements 1-4 are repeated for each accumulation in the study

9.0 REFERENCES

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