Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production

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EXECUTIVE SUMMARY

The purpose of this report has been to examine oil and gas production on state leases to determine if any policy of royalty relief could be implemented that would help maintain the life of a given well, and the economic benefits derived from its ongoing production. Economic benefits include not only the royalty and tax (i.e., severance, sales, property, etc.) revenues, but the direct, indirect, and induced economic impacts (i.e., multiplier impacts) that are associated with ongoing operations on state leases.

This report is data-intensive and examines all state production on a well-level basis since 1977. The empirical methodology employed in this research included a profitability analysis that estimates which wells may be unprofitable under a number of historic and forecasted conditions. Cost information used in this analysis comes from a publicly available source. Costs are based upon typical (i.e., average) industry operating conditions within various broad geographic areas of the state, well depths, and production volumes.

Wells on state leases (and their respective costs) were segmented into three main geographic regions: North Louisiana, South Louisiana, and offshore (state waters). The empirical analysis in this report is based upon currently active wells and assumes no new drilling. The forecast period for the profitability analysis is limited to ten years (2002-2012).

Some of the conclusions and recommendations of this report include the following.

- Assuming 2002 commodity prices, the forecasted profitability analysis of production on state leases estimates that a large number of wells, accounting for a small amount of state lease production, could become unprofitable by 2012.
- Introducing royalty relief, in the form of a 25 percent discount to the existing rate, would result in a modest shift in wells (and production) on state leases, from unprofitable to profitable status. The additional economic benefits from this discount are equally modest.
- It is the recommendation of this report that the Mineral Board, and its Office of Mineral Resources, not institute a broadly-applied royalty relief program for existing production on state leases based upon the following conclusions from the research in this report:
    - It is extremely difficult to estimate the break-even point of profitable production across state leases without actual, well-specific cost information. This break-even point can shift with a host of factors that are difficult to control (i.e., well age, depth, location, operator, water cut, unique lease conditions, etc.)
    - A broadly-applied royalty relief program for state leases could be fraught with a significant "free rider" problem. That is, a large

number of operators could receive a benefit from the State that would not impact their overall decision to stay in operation.

  - Because of the potential free rider problem, a broadly-based royalty relief program is likely to result in considerable negative net benefits to the state. For instance, based upon the estimates in this report for 2002, the State could potentially lose close to $56 million in royalty revenues by instituting a broadly-based program. This estimated loss is net of all the positive economic benefits that could occur.

- It is the recommendation of this report that any type of royalty relief program on existing production be instituted on a "case-by-case" basis. A case-by-case program is more likely to eliminate any free rider problem, and should be easier to administer due to the limited number of requests that are estimated in this research.
- It is the recommendation of this report that a case-by-case royalty relief program be implemented with the following requirements:
  - Relief should be offered on a well-specific profitability basis. Only wells that are unprofitable, or nearing unprofitable status, should be considered.
  - Well-specific cost information and documentation should be provided in any application for royalty relief.
  - Requests for royalty relief should show that it would maintain well-profitability for at least one year.

- The preceding recommendations are based on existing production and not associated with any royalty relief proposals tied to new drilling.

Lastly, while not a direct charge of this research, the empirical examination of production on state leases, and Louisiana in general, shows some significant changes. In particular, there has been a noticeable increase in production declines as indicated by the sharp drop in post peak year production. Further, there has been an equally impressive increase in well productivity, as measured by production per well, over the same period of time. This would tend to indicate that overall state oil and gas production is being maintained by a relatively few number of newer, more productive wells. The future disposition of production, and state mineral revenues, could be significantly impacted should drilling activity stop, or slow considerably in Louisiana.

1 INTRODUCTION

Louisiana recently celebrated its centennial anniversary of oil and gas exploration and production ("E&P"). The centennial was a milestone in the state's history and its experience with the oil and gas industry. Over the past one hundred years, oil and gas development and production have been referred to as the engine that has moved Louisiana's economy. However, this Louisiana-specific development could also be more broadly characterized as fueling the engine of technical understanding and innovation in the energy business in the Gulf Coast region, if not beyond.

This milestone of oil and gas production in Louisiana certainly marks a degree of maturity for a resource basin that has seen considerable declines since its peak activity levels of the early 1970s. An inevitable consequence of aging oil and gas producing areas is that at some point, the economic viability of further development of these resources will weaken. Resource depletion, coupled with increasing costs, will force producing leases to reach their profitability limit. At that point, production stops, wells are plugged, and production infrastructure is removed.

A number of factors can lead to the shut-in of any given oil and gas well. In many instances, this can be the normal economic consequence of market or operational factors. In other instances, however, wells may be prematurely shut-in as a consequence of unfavorable regulatory or policy conditions which, if removed, could maintain the economic profitability of a particular lease for some further period of time.

As an energy-intensive economy, Louisiana experiences a number of costs from the premature shut-in of oil and gas production. The first, and the most obvious, is the loss of severance taxes levied on oil and gas production. Another is the reduced revenues collected from royalties on state-owned lands. Perhaps less well recognized are a host of direct, indirect, and induced economic benefits associated with oil and gas production.

Direct economic impacts are those that are directly associated with the annual employment and expenditures made by oil and gas operations. Indirect economic impacts are those additional economic activities stimulated by direct economic impacts, like the services supporting oil and gas E&P activities. Induced economic impacts are those activities generated from changes in income generated by the economic impacts.

A 2002 Center for Energy Studies ("CES") study, commissioned by the Office of Mineral Resources ("OMR") at the Louisiana Department of Natural Resources ("LDNR"), found that there were considerable economic impacts associated with oil and gas E&P activities on state leases. The CES *State Lease Economic Impact Study* found that for production activities on state leases alone:

- A “typical” production year has a direct annual economic impact of $359 million. Indirect and induced economic impacts generated by this activity were estimated at $76.8 million per year. Total annual economic impacts from typical year production are $436 million.

- Creates 1,117 direct employment opportunities and some additional 1,027 indirect and induced employment opportunities.

- In a typical year, state and local governments receive millions in revenues from state lease operations. Some $274 million of these annual public revenues come from royalties, $88 million come from severance taxes, and $27 million are associated with sales taxes on production.

- When both drilling and production activities are considered, it becomes apparent that Office of Mineral Resources, and its associated State Mineral Board, is a $1 billion economic enterprise for the state. While not its primary responsibility, policies pursued by the agency can have considerable impact on economic development and the state’s revenues.

At the conclusion of the 2002 CES *State Lease Economic Impact Study*, the OMR inquired about how its policies and actions could help maintain or further the overall economic development agenda of the state. One area they wanted to explore was the potential for developing an incentive program, such as targeted royalty relief for production on state leases that are marginal or nearing marginal status that could delay the losses in state economic benefits.

The key in evaluating an incentive policy would, in part, rest upon developing an understanding about:

- Which leases are at, or nearing, uneconomic (marginal) status.

- Estimating how royalty relief, under various scenarios, could extend the life of uneconomic leases.

- Comparing the costs (lost royalties) to the benefits (direct, indirect, and induced) of instituting a limited royalty relief program.

The purpose of this study is to provide the OMR with empirical estimates to answer each of these questions. In order to answer these questions, CES has developed a comprehensive empirical model for examining oil and gas production and profitability on state leases. As discussed later in this report, the CES Production Profitability Model incorporates over 50,000 observations and numerous variables and intermediate calculations and assumptions.

This report is divided into five additional sections, the first of which is this Introduction. Section 2 discusses the analytic approach used in this study to develop empirical estimates of future oil and gas production, and identifies those resources which may become challenged, from a profitability perspective, in the near future. This section of the report highlights the relatively comprehensive and data-intensive approach used to develop an empirical model to estimate well-specific profitability.

Section 3 is the first of two sections in this report that examine the nature of oil and gas production in Louisiana. The section examines historic oil and gas production throughout Louisiana, including offshore production in the Gulf of Mexico, to highlight both the changing trend of production in the state, and the growing importance that production in federal waters is having on overall state totals. This section also brings the analysis of trends in oil and gas production down a level to focus on production limited to the jurisdiction of the state of Louisiana. This analysis examines oil and gas production in the three various regions of the state including North Louisiana, South Louisiana, and offshore state waters.

Section 4 examines state production from a slightly different perspective. This section breaks historic Louisiana production out by completion year to examine the trends in production as wells in the state become older. One of the primary purposes of the analysis is to determine if there have been structural shifts in the nature of the production decline for both oil and natural gas. A comparable analysis is also conducted for state leases.

Section 5 provides an analysis of production trends on state leases and estimates of well profitability for state oil and gas leases. The section provides estimates of which wells may not be operating profitably based upon alternative assumptions and cost information derived from the profitability model posited in Section 2.

Section 6 of this report presents a forecast of oil and gas production on state leases for the period 2002-2012. The technical forecast possibilities are based upon a variation of an exponential decline curve methodology, as discussed in Section 2. Constant prices and costs are assumed for future “baseline” production. The number of unprofitable wells and volumes of production are also estimated. Forecast production is based upon wells existing in 2002 – no new wells are assumed to be added during the period (i.e., no new drilling).

Section 7 examines the effects that royalty relief would have on profitability of oil and gas production on state leases. The profitability model estimates the impact that various levels of royalty relief could have on the number of unprofitable wells and the potential level of production that could come from unprofitable wells that would become profitable as a result of royalty relief. Estimates are generated which determine which wells become profitable as a result of various ranges of royalty relief, the period in which the operating lives of these wells have been extended, and the amount of production associated with the extended production life.

Section 8 presents the overall conclusions associated with the report.

2 CONCEPTUAL APPROACH

2.1 Introduction

The key analytic tasks undertaken in this research are to:

- Develop a methodology to estimate when a given oil or gas well would reach its economic, or profitable, limit of production;
- Examine the impact that an incentive program, like royalty relief, would have on wells approaching their economic limits; and
- Compare the economic benefits of oil and gas production to the cost of implementing an incentive program to determine if there would be net benefits.

To address the first issue, a working definition of a "marginal," or "economically challenged," oil and gas well is needed. Currently, Louisiana identifies three different types of wells for severance tax purposes. These are shown below in Table 2.1.

Table 2.1: Definitions of Wells in Louisiana for Severance Tax Purpose

Well Definition	Oil Production Limits	Gas Production Limits
Capable Wells	Greater than 25 Bbls/d	Greater than 250 Mcf/d
Incapable Wells	Between 10 to 25 Bbls/d	Less than 250 Mcf/d
Stripper (Marginal) Wells	Less than 10 Bbls/d	NA

The Interstate Oil and Gas Compact Commission ("IOGCC") defines a marginal oil well as one the produces less than 10 barrels per day ("bbls/d") and a marginal gas well as one that produces less than 60 thousand cubic feet per day ("Mcf/d"). Many states, in addition to the IOGCC, commonly use definitions of "marginal" oil and gas operating status that focus almost entirely on the level of production and do not (directly) focus on well profitability. This study relies heavily on the definition of profitability as being the factor that limits oil and gas production, and not pre-defined levels.

2.2 Production Data Used in the Analysis

The data used in this analysis comes from the Louisiana Department of Natural Resources' ("LDNR") Strategic Online Natural Resources Information System ("SONRIS") as well as the LDNR Production Auditing Reporting System ("PARS") database.[1] The SONRIS system is a comprehensive interactive relational database that includes production information, owner-operator information, well characteristics and operating history information, among other variables. The database includes a "flag" or indicator that marks whether a particular lease has a state ownership interest (i.e., "state lease"). Records associated with actively producing state leases were selected for this analysis from 1986 to 2002. The final dataset used in this analysis is comprised of almost 50,000 observations on state leases only. The broader database, upon which

[1]SONRIS and PARS essentially include the same sets of information. The primary difference between the two systems is that SONRIS includes a user-friendly, web-enabled interface. PARS, on the other hand, is more of a traditional relational database that is more conducive for large empirical and statistical analyses like the one conducted in this report. For the remainder of this report, all LDNR production information will be referenced as SONRIS.

many of the descriptive statistics and historic trends were examined in Sections 3 and 4, are based includes over 100,000 observations.

2.3 Unit of Analysis

One of the first challenges in this study was to determine the appropriate unit of analysis for oil and gas operations profitability. The two options included examining information at the (1) well-specific level, or the (2) lease-specific level. The selection of one measure over the other was not a simple matter of choosing the one most readily available in the SONRIS database. As discussed later, the SONRIS database does not provide information consistently across either unit.

Ultimately, well-specific information was determined to be the more appropriate unit of analysis. This determination was based upon four factors:

(1) Well-specific information appeared to be the consistent and readily identifiable unit of analysis throughout SONRIS.

(2) Most of the per-unit cost information used in this analysis is reported at the well-level and not the lease-level.

(3) Most definitions of “marginal” production are at the well level and not the lease level.

(4) An argument could be made for using either unit. However, well-specific information is more flexible since it can be more easily aggregated to the lease-level to determine lease-specific profitability. The inverse is not true. The data reconciliation process discussed below will match wells to leases to ensure maximum data flexibility.

Thus, the first significant task in this analysis has been to develop two sets of estimated information for each reporting unit, (well and lease) even though the actual profitability estimates will later be conducted entirely at the well-level. The following discusses each of the steps taken to develop this consistent historic production dataset.

2.4 Development of a State Lease Production Dataset

The actual reporting unit for oil and natural gas production that is included in SONRIS is referred to as the “Lease-Unit-Well” or "LUW." Likewise, each of the reporting units has a unique identifying code, which is referred to as a LUW code. Existing state filing requirements allow operators to report production at a number of different levels that include: (1) the well level; (2) the unit level;[2] and (3) the lease level. The data reconciliation challenge was to take data from each of these reporting levels and convert them to a consistent set of both well-specific and lease-specific information. Figure 2.1 has been provided as a schematic that shows how each of the various reporting units was reconciled.

[2]Typically defined on a geological or engineering basis.

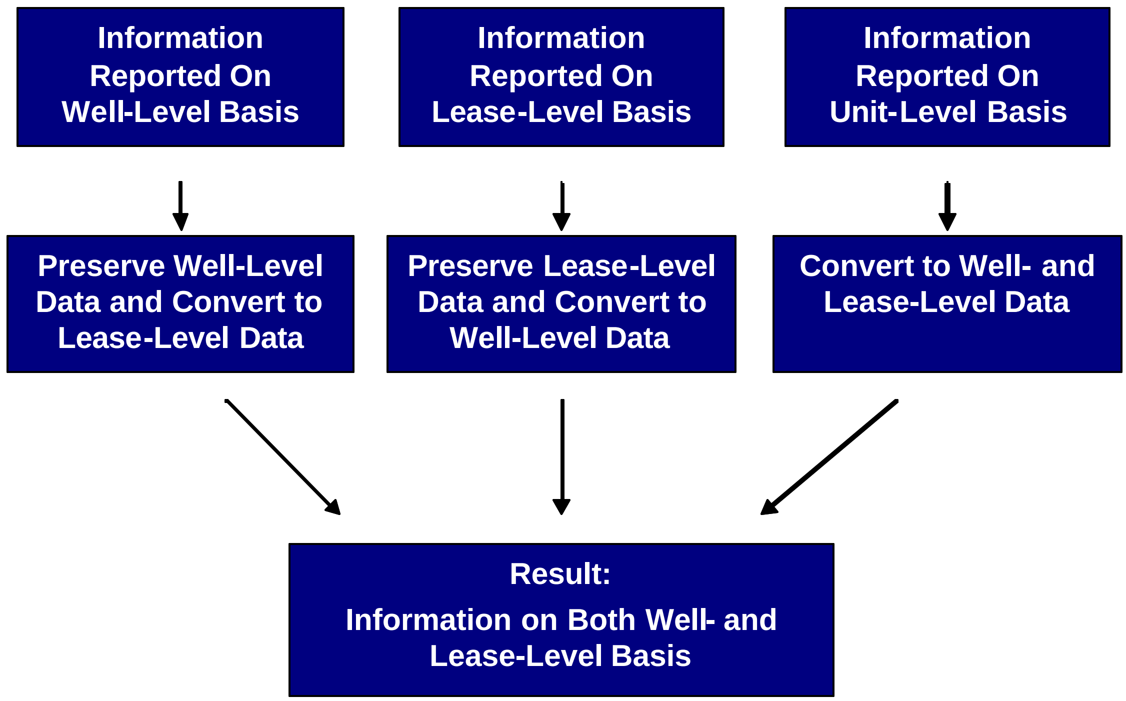

Figure 2.1: Schematic of SONRIS Data Reconciliation Process

Reconciling information reported at the well level was relatively straightforward and is highlighted by the left-hand set of boxes in Figure 2.1. Since the data are already reported on a per well basis, the only other step needed to be conducted was to assign wells to a lease. This was done with information provided in the SONRIS databases. Production history and other information was simply summed by the lease identification code to generate total lease-specific information.

Reconciling information reported at the "lease" and "unit" level however, was a little more difficult. The first reconciliation step conducted for each of these sets of information was to determine the unique number of wells associated with each of the reporting units (i.e., lease and unit). Using assignment information provided in the SONRIS database, wells were mapped to leases and units. In some instances, the data indicated changes in well assignment over time and had to be reconciled for consistency purposes.

In addition to well assignment, each well needed to be adjusted for its actual operating history. This was done by mapping each well to the historic well status data included in SONRIS to determine, down to the daily level, each well's actual operating history. Total production was then divided by total operating wells, adjusted for operating history, to get the effective average production per well. Estimating the actual operating status of each well allows annual production per well to be controlled for the actual amount of time each well was operating at a particular lease.

2.5 Forecasting Well-Specific Production

Future economic production is a function of technologically feasible production. Future technologically feasible production is forecasted using an exponential decline curve methodology. A generalized representation of this decline curve approach has been presented in Figure 2.2

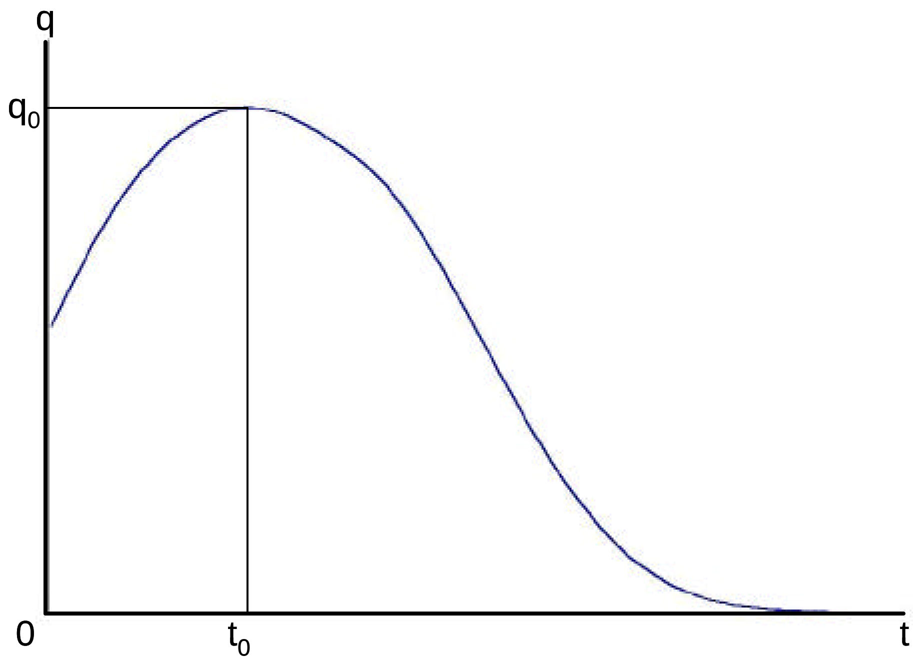

Figure 2.2 Exponential Production Decline Curve

Here, production is represented by q on the vertical axis, while time is represented by t on the horizontal axis. Annual production is a function of time and is represented by the formula

(1) $$Q = q_0 \exp(-at)$$

Where q_0 represents the peak level of production, a is defined as the annual average decline rate and t is time. As seen from the figure, production falls from its initial point of peak production at an increasing rate. Eventually, the production curve becomes asymptotic to the horizontal axis.

The decline shows four general regions of production that are directly related to the life of a given lease:

(1) Build-Up Period: when a new lease is brought on line and production is ramped up to its peak level.

(2) Plateau Period: when production begins to flatten out around its peak in preparation of future decline;

(3) Decline Period: declining production occurs as resources are exhausted; and

(4) Shutdown Point: profits are zero, or revenues equal costs, and future production will result in a loss.

The exponential decline curve is a well recognized method for forecasting future production and is popular for a number of different reasons that include:

- It represents the decline for the important solution drive mechanism well and, being slightly steeper than the hyperbolic decline curve, gives a conservative result of the exhaustion of a well or lease;
- It is mathematically more tractable than other methods such as the hyperbolic decline curve, reflective triangle method, discretized linear fit method, and the interative substitution method.[3]

2.6 Estimating Current and Future Profitability

The next step in this analysis is to determine well profitability so that marginal or economically challenged wells could be identified. A schematic outlining how per-well profitability was determined has been presented in Figure 2.3.

[3]Shell International Petroleum Maatschappij B.V. *Petroleum Economics: A Phase II Course at the Shell Training Centre*. Noordwijkerhout, Holland. January, 2, 1988: Chapter 1, Production Profiles.

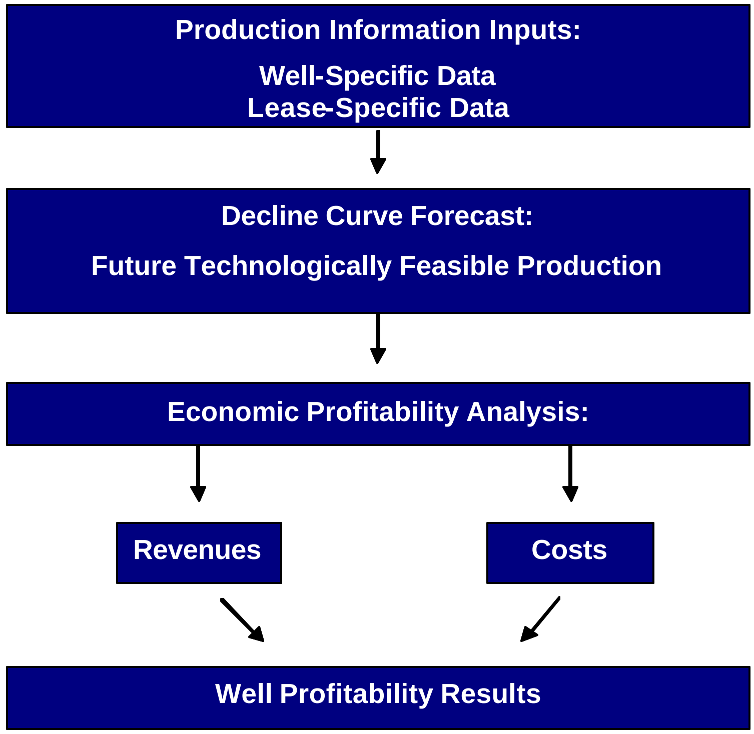

Figure 2.3: Schematic of Profitability Analysis

Generally, wells can be said to be marginal when it is unprofitable (or very close to unprofitable) to continue operations. Profits are simply defined as revenues less costs, or more formally:

(2) $$\Pi_{it} = R_{it} - C_{it}$$

Estimating total revenues (R_{it}) is relatively straightforward since it is the simple product of wellhead prices and the quantities produced for any given well (i) in any given year (t), or alternatively:

(3) $$R_{it} = p_{it} q_{it}$$

What may be more difficult is defining the appropriate costs for an analysis of this nature. Economic theory would suggest that production would be pursued up to the point where price is equal to minimum average variable costs. In the case of oil and gas operations, average variable costs are often represented by lease operating expense ("LOE"). Using well-specific LOE as a determinant of profitability has been employed in past empirical studies of marginal production and will be employed here.

Total average variable costs (per well), or LOE (per well), can be given more formally for each well (*i*) and each period (*t*), as:

(4) $$C_{it} = c_{it} q_{it}$$

were c_{it} is the unit average variable costs, q_{it} is the production amount, and C_{it} is the total well-specific cost. Therefore, total profits (p) can be defined as:

(5) $$\Pi_{it} = (p_{it} q_{it}) - (c_{it} q_{it})$$

If profits (p) are greater than zero, then the well is considered profitable, otherwise, it is considered unprofitable (uneconomic) and stops production.

This general formula can also be applied to the forecasted technical production volumes discussed in the earlier section to determine the economically profitable future production volumes that may be generated by a particular well. Future profitability is determined by taking forecast prices and costs and multiplying them by forecast production estimated through the exponential decline curve method. So for the first forecast year ($t + 1$) profits for a given lease (i), can be defined as:

(6)
$$\Pi_{i(t+1)} = (p_{i(t+1)} q_{i(t+1)}) - (c_{i(t+1)} q_{i(t+1)})$$

This formula can be generalized to all forecast years (n):

(7)
$$t = [(t+1),(t+2),...,(t+n)]$$

Overtime, profitability will track overall production, and at some future point, will become uneconomic. Figure 2.4 presents an illustration of when a particular lease becomes uneconomic.

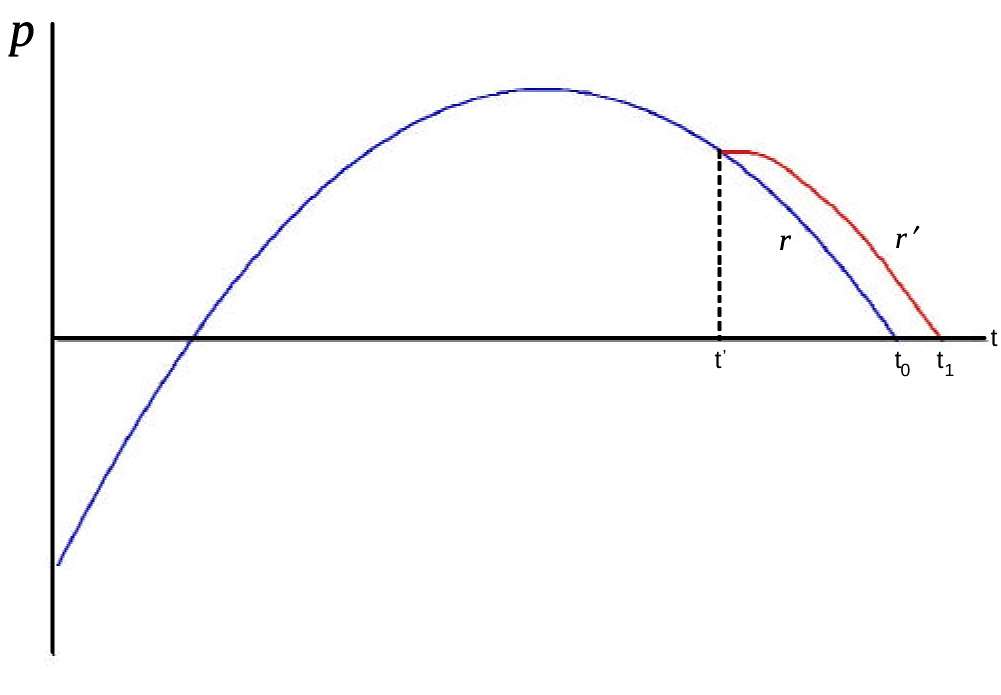

Figure 2.4: Example of a Change in Well Profitability

Profit is tracked by the function r and for illustration purposes assumes constant future prices wellhead prices.

One of the key issues in this study, however, is to determine whether state incentive policies, particularly royalty relief, can have a positive impact in extending the life of a given lease. An illustration of the potential impact that royalty relief can have on profitability is presented in Figure 2.4 and is given by the curve r'.

This curve (r') represents an increase in profitability resulting from royalty relief that is offered at time (t'). Here, royalty relief is offered to all wells that reach some relatively low level of production (q') late in the potential life of the lease. The shut-down level of production, under this incentive program, has been shifted from t_0 to t_1. In other words, the life of the program has been extended by the period representing the difference between the two shutdown points (ie., t_0 vs. t_1).

2.7 Price and Costs Used in the Estimating Process

The next step in the analysis was to apply actual data to the general profitability formulations presented in equations (1) through (6). Production information, (q_{it}) was available or otherwise estimated from the annual data reported by operators in SONRIS. Price (p_{it}) information and cost (c_{it}) data were not available in SONRIS and had to be gathered from other sources.

The wellhead price information utilized in the profitability models came from two different sources collected by the US Department of Energy, Energy Information Administration ("EIA"). Wellhead oil price information comes from Form EIA-182 *Domestic Crude Oil First Purchase Report*. A "first purchase" constitutes a transfer of ownership of crude oil during or immediately after the physical removal of the crude oil from a production property for the first time.[4] Transactions between affiliated companies are reported as if they were "arms-length" transactions. The primary objective of the form is to calculate an average first purchase price at various levels of aggregation. A company's monthly average first purchase prices are weighted by volume across geographical areas for selected crude streams and gravity bands.

Wellhead natural gas prices, on the other hand, came from information collected in Form EIA-895 *Monthly and Annual Quantity and Value of Natural Gas Report*. All gas-producing states and the Minerals Management Service ("MMS") are requested to submit this report. The form is three pages in length and collects a host of information on the number of producing wells, the production of natural gas, and the values of marketed production.

As noted earlier, a well-specific measure of LOE is the appropriate cost to use in determining lease profitability. While annual well-specific cost information for

[4]A discussion of the Form EIA-182 can be found in the Explanatory Notes Section of: US Department of Energy, *Petroleum Marketing Annual, 2002*. Washington, DC: Energy Information Administration, 382.

Louisiana leases are not publicly available, cost information that is similar in nature is collected by the US Department of Energy, Energy Information Administration ("EIA") and compiled in an annual report entitled *Oil and Gas Lease Equipment and Operating Costs, 1986-2002* (hereafter, "EIA Lease Cost Report"). This report includes LOE estimates for three Louisiana regions; North Louisiana; South Louisiana; and Offshore Louisiana.

The costs developed in the EIA Lease Cost Report are estimated to be representative of typical operations for each reported region. Costs are separated by primary oil producing leases and primary natural gas producing leases. The design criterion used for each type of lease (i.e., oil, gas) takes into account the primary methods of operation in each region.[5]

The cost estimates developed in the EIA analysis are generally developed via an annual survey or interview process that queries leading supply, service, and contracting companies for local June prices for each provider's component of the operating function. Costs do not include any depreciation expense, *ad valorem* taxes, royalties, or severance taxes.

[5]As the EIA *Lease Cost Report* title would suggest, equipment costs were also prepared by EIA. These costs were excluded from the analysis in this report since the assumed relevant costs were based upon average variable costs. These costs assume that in the relatively short run, all capital costs are fixed, thus, the estimates of lease-specific LOE will not include any fixed equipment costs. There is the potential for some variable capital costs to be included in the average variable cost estimate (or LOE estimate), but there was no non-arbitrary way of separating the percentage of the broad types of equipment costs between fixed and variable capital. Thus, cost estimates may be biased to the low side due to the exclusion of all equipment (capital) costs.

For primary oil producing leases, costs were determined for activities associated with the production of 200 barrels of liquid per day, per well. These costs assumed a typical lease of 10 wells. Tubing costs were included in the costs for primary oil producing leases. All wells were assumed to be moved with artificial lift with the two prime methods being electric motors and natural gas engines. The actual artificial lift mechanism used to develop cost estimates for any given region is based upon the type of lift that was locally predominant.

Operating costs for a number of different highly discrete well depths were provided in the EIA *Lease Cost Report*. Average per well cost was determined by dividing the total number of wells by total costs that were included in the EIA report. Regression analysis was then used to smooth, or average costs across the various discrete reporting depths. An illustration of how this smoothing technique was implemented has been provided in Figure 2.5. Estimated costs are given by straight line ($\hat{C}$) while actual costs (C) are represented by the various bars presented in the figure.

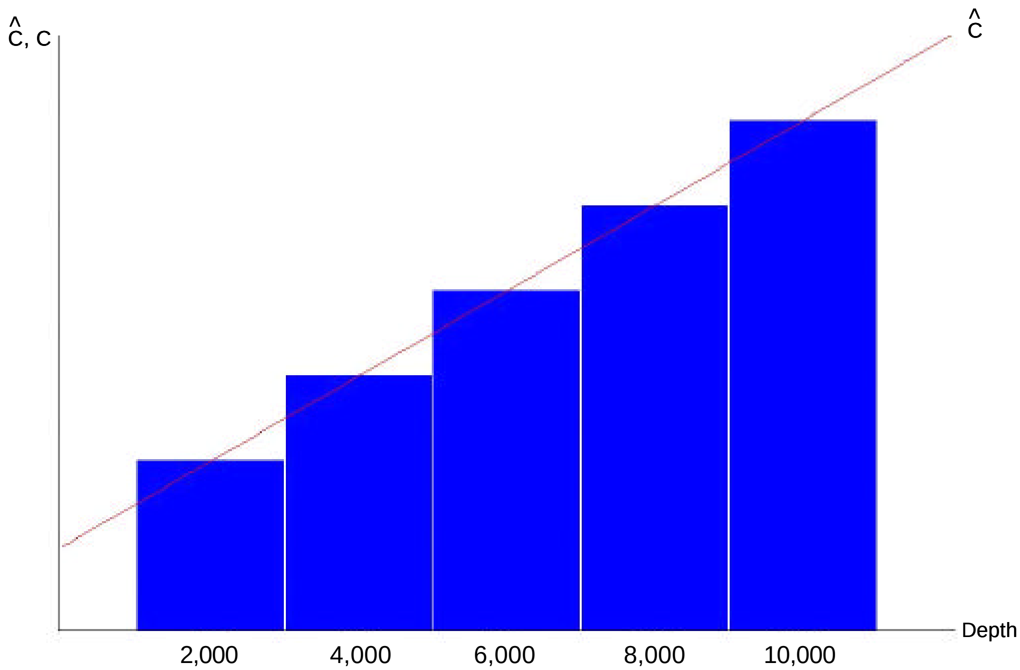

Figure 2.5: Illustration of Regression Smoothing Technique

2.8 Regression Smoothing Technique

Regressions were defined by the following set of equations, each representing a various Louisiana operating region (i.e., north, south, and offshore). For oil production, these equations are given by:

(8.a) $$\hat{C}_{it}^{ON} = a^{ON} + b^{ON} d_{it} + e^{ON}$$

(8.b) $$\hat{C}_{it}^{OS} = a^{OS} + b^{OS} d_{it} + e^{OS}$$

(8.c) $$\hat{C}_{it}^{OO} = a^{OO} + b^{OO} d_{it} + e^{OO}$$

Where:

$\hat{C}_{it}^{ON}$ = estimated oil costs, North Louisiana, for well (i) in year (t)
$\hat{C}_{it}^{OS}$ = estimated oil costs, South Louisiana, for well (i) in year (t)
$\hat{C}_{it}^{OO}$ = estimated oil costs, Offshore Louisiana, for well (i) in year (t)
d_{it} = depth for well (i) in year (t)
e = random error term for each equation

For primary gas producing wells, cost was collected by EIA on a single well basis. The gas producing well was assumed to be producing into an onsite separator with two storage tanks (condensate and water).[6] Tubing costs were not included in primary gas producing lease cost estimates (unlike primary oil producing lease cost estimates) nor were any waste disposal equipment costs included. Gas production rates of 50, 250, 500, 1,000, 5,000, and 10,000 Mcf/d were utilized as were well depths of 2,000, 4,000, 8,000, 12,000, and 16,000 feet. Regression analysis was also used to smooth the costs over various discrete well depth/volume categories.

The equation used to estimate these gas cost regressions were slightly different than those for oil production, and given by:

(9.a) $$\hat{C}_{it}^{GN} = a^{GN} + b^{GN} d_{it} + d^{GN} v_{it} + e^{GN}$$

(9.b) $$\hat{C}_{it}^{GS} = a^{GS} + b^{GS} d_{it} + d^{GS} v_{it} + e^{GS}$$

(9.c) $$\hat{C}_{it}^{GO} = a^{GO} + b^{GO} d_{it} + d^{GO} v_{it} + e^{GO}$$

Where:

$\hat{C}_{it}^{GN}$ = estimated gas costs, North Louisiana, for well (i) in year (t)
$\hat{C}_{it}^{GS}$ = estimated gas costs, South Louisiana, for well (i) in year (t)
$\hat{C}_{it}^{GO}$ = estimated gas costs, Offshore Louisiana, for well (i) in year (t)
d_{it} = depth for well (i) in year (t)
v_{it} = produced gas volume for well (i) in year (t)
e = random error term for each equation

[6] Like the analysis of oil well costs, equipment costs were excluded in the current analysis for lease-specific estimating purposes. The reason for excluding these gas producing equipment costs are the same as in the oil case. However, for reference, gas operating costs are based upon the presence of line heaters, dehydration units and methanol injectors where they were deemed needed by EIA.

Rarely, do wells produce only oil or only gas. In many instances, both hydrocarbons are produced. The cost methodology used in this research can be used to develop a generalized joint cost function. First, a primary cost function was developed based upon an initial well classification (i.e., oil, gas). Leases were classified by estimating a gas to oil ratio ("GOR") for each lease. If the GOR was greater than 5,000 cubic feet/barrel ("cf/bbl") the lease was classified as primarily gas producing. If the GOR was less than 5,000 cf/bbl, the lease was classified as oil producing.

As shown earlier, smoothed cost estimates were developed based upon the regression analysis in Equations (8) through (9). In order to estimate joint production cost (i.e., oil and gas, gas and oil) the "incremental" parameters estimated in each of these equations were added to the primary estimated cost function. Here, the incremental parameters are those associated with depth and volume (in the case of natural gas only). Intercepts, were assumed to be a relatively constant cost specific to the primary production function, and not used to develop the joint cost estimate.

So, if a lease were determined to be primarily oil producing, the parameters from Equation (8) would be used to estimate the oil-related costs, while the parameters on depth (d) and volume (v) would be taken from the estimated gas cost function in Equation (9). Therefore, for a lease defined as primarily oil producing, in North Louisiana, that had some associated gas production, its estimated unit costs would be formulated as:

$$\hat{C}_{it}^{ON} = (a^{ON} + b^{ON} d_{it} + d^{ON} v_{it} + b_{Iit}^{GN} d_{it} + d_{it}^{GN} v_{it}) + e^{GN} \qquad (10)$$

2.9 Assumptions Used in the Study

Some of the data used in this analysis, particularly data associated with production costs and prices, were gathered from a variety of sources and had to be reconciled with the original production information provided by LDNR. The major assumptions employed in this study include:

- The analysis is limited to state leases only.
- The unit of analysis is limited to the well-level.
- Only existing wells and production are used in the empirical analyses. No drilling activity was modeled or assumed.
- In general, simple averages were used to develop all per-unit estimates where information is not directly reported (i.e., per-well, per-lease). No attempt was made to distribute or pro-rate any information unless otherwise specified in the text.
- Average variable costs, as a proxy for LOE, were used. No capital or equipment costs were incorporated into the cost analyses. Given data limitations, costs were assumed to primarily be a function of depth and volume.
- Depreciation expense was not considered. Only severance taxes were considered, no other taxes were included in the cost estimates.
- General royalty rates were set at each lease-level based upon the average age of the lease. Older leases in Louisiana typically have much lower average royalty rates.
- Oil and gas prices were set at the wellhead level as reported by DOE. All leases were assumed to face the same per unit wellhead price. Baseline prices used in the forecast are constant and based upon 2002 levels.

- Abandonment costs and salvage were not considered.
- A GOR of 5,000 was used to determine if a well was primarily gas or oil producing.
- All production was assumed to be of commercial and uniform quality.
- Missing and incomplete information was omitted from the analysis as was any information considered to be an anomaly or outlier.

3 OVERVIEW OF OIL AND GAS ACTIVITIES IN LOUISIANA

3.1 Introduction

Oil and gas production has fallen significantly from the peaks of the early 1970s. Nevertheless, Louisiana oil and gas production is still considerable despite the fact that the nature and level of these trends have changed over the years. The following subsections highlight and discuss a number of descriptive statistics and empirical trends associated with overall Louisiana production.

3.2 Louisiana Jurisdictional Production

Figure 3.1 shows the number of active oil wells that have been operating in Louisiana jurisdictional areas since 1960. For purposes of this analysis, Louisiana jurisdictional areas are defined as the onshore and offshore areas that are directly regulated, for tax and royalty purposes, by the state of Louisiana. The activity associated with state oil wells follows four distinct trends over the past 30 years: the first period between 1960-1967; the second period between 1967-1979; the third period between 1979 to 1986; and the fourth period from 1986 to current.

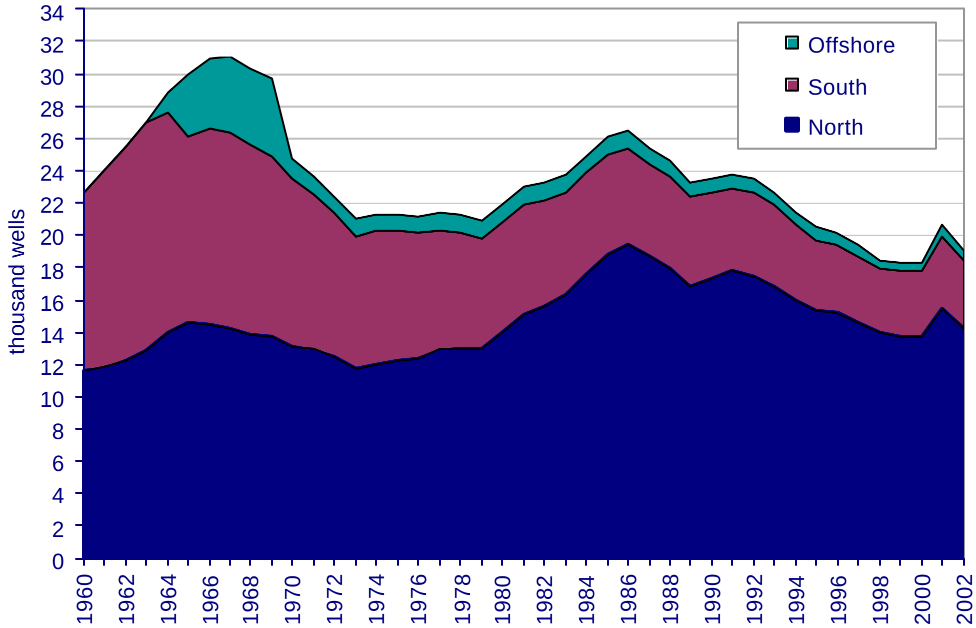

Figure 3.1: Louisiana State Producing Crude Oil Wells

Note: Offshore figures exclude federal OCS
Source: Louisiana Department of Natural Resources

During the first period, 1960 to 1967, the number of crude oil wells increased to an all time peak of 31,051 operating wells. From 1967 to 1979, operating oil wells began their first significant decline, to 20,898 operating wells – a level of which the industry had plateaued around for about five years. The industry got a second life during 1979-1986 when the number of operating oil wells increased by an annual average rate of about 3.4 percent. Since 1986, the number of operating oil wells has been in decline. Today, the total number of operating oil wells is about 61 percent of the state's 1967 peak.

In 1960 operating oil and gas wells were close to evenly split between North and South Louisiana. Beginning in 1964, offshore oil wells (in state waters), began to come on-line. By the peak year (1967), over 15 percent of the state's operating oil wells were offshore (in state waters), with 46 percent and 39 percent in North and South Louisiana, respectively.

The relative share of active oil wells has changed more for South Louisiana, over time, than any of the other in-state production areas. The percent of South Louisiana wells fell consistently from 1970 (42 percent) to approximately 1990 where it has leveled off at 22 percent of all actively producing wells in the state. The share of wells in North Louisiana have followed an opposite pattern however, increasing steadily since 1970 from 53 percent of total to just under 75 percent of total in 1990. North Louisiana oil wells have remained around 75 percent of total for the last decade.

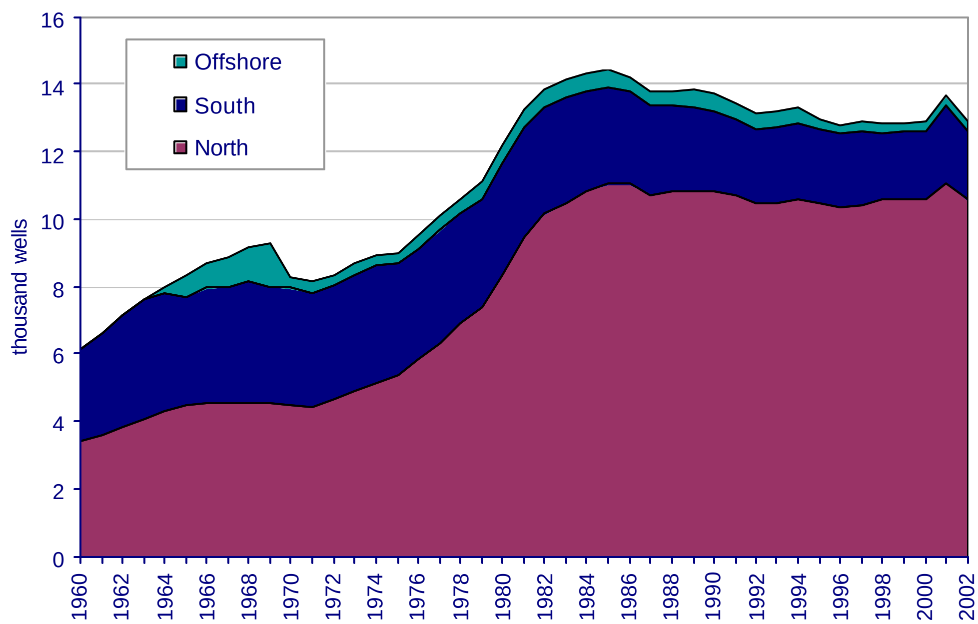

Figure 3.2: Louisiana State Producing Natural Gas Wells

Note: Offshore figures exclude federal OCS
Source: Louisiana Department of Natural Resources

Figure 3.2 provides a comparable historical analysis of trends for operating natural gas wells in Louisiana. Producing natural gas wells in the state have followed considerably different patterns than those of oil, owing in part to the considerable changes in regulation that have occurred over the past two decades in all aspects of the business (i.e., production, transmission, distribution, and sales). The number of natural gas wells increased gradually from 1960 until around 1978 at an average of 3.2 percent per year.

In 1978, the Natural Gas Policies Act was initiated to start the process of deregulating wellhead natural gas prices. Natural gas industry deregulation was considerably amplified in 1982 with the Natural Gas Wellhead Decontrol Act, and as a result, there was an exceptional increase in the number of active natural gas wells in Louisiana.

The number of active natural gas wells increased dramatically from 1980 until 1985: a period in which gas prices were reaching the relative high of $2.73 per Mcf. In the following year, the price of natural gas fell by about 16.9 percent. (change from 1985 to 1986). Overall, by 1986, natural gas prices had fallen by 19.0 percent from its 1984 high and stayed relatively flat throughout the decade. As a result, the number of active natural gas wells decreased by almost 10 percent from 1986 to 2000.

In 2000, natural gas prices had their first meteoric rise, which had a noticeable impact in the number of active natural gas wells throughout the state. Active gas wells in North Louisiana, in fact, actually set a new peak in 2001 at 11,060 wells. The previous high for active North Louisiana wells was 11,049 in 1986. In addition, North Louisiana, over time, has seen its share of active gas wells increase. In 1960, North Louisiana accounted for 56 percent of all state active gas wells: that share increased to 82 percent by 2002.

Figure 3.3 shows historic crude oil production in Louisiana that has been graphed on two separate vertical axes. North Louisiana and jurisdictional offshore Louisiana production are graphed on the left-hand axis while South Louisiana production, because of its greater magnitude, is graphed on the right-hand axis. Oil production in South Louisiana accounts for roughly 72 percent of total state production while offshore and North Louisiana account for the remaining 28 percent. Generally, these shares have been constant since the 1960s.

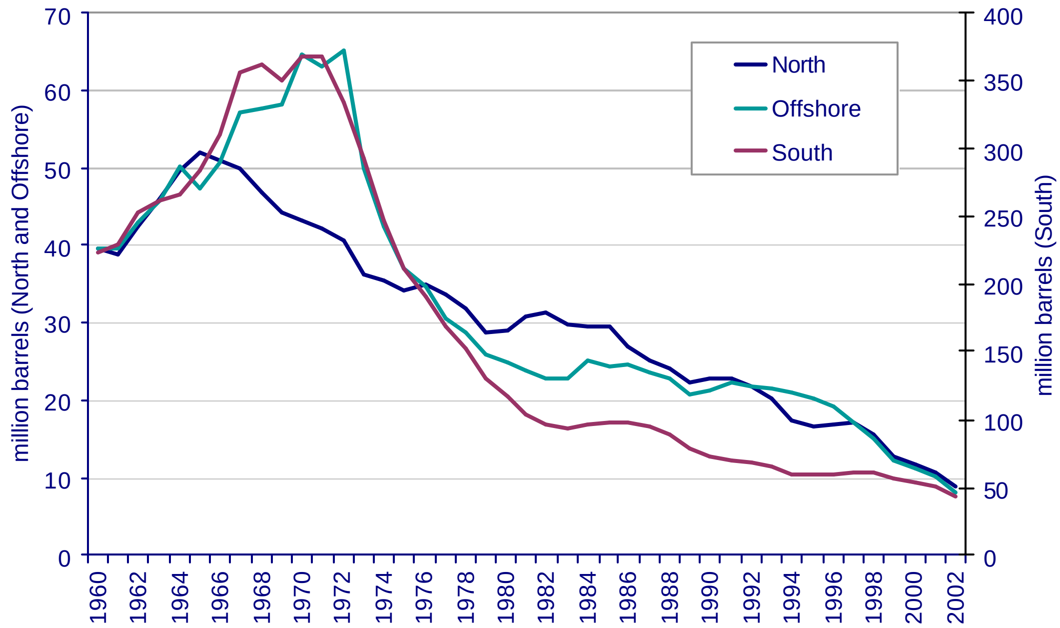

Figure 3.3: Louisiana State Historic Crude Oil Production

Note: Offshore figures exclude federal OCS
Source: Louisiana Department of Natural Resources

All three series show that historically, overall crude oil production in the state has fallen considerably from peak production levels attained in the mid 1960s (North Louisiana) to early 1970s (offshore and South Louisiana). Today, crude oil production is 17 percent of its 1965 peak in North Louisiana, 12 percent of its 1970 peak in South Louisiana, and 12 percent of its 1972 peak in offshore Louisiana. Relative to their respective peaks, crude oil production in North Louisiana has experienced an annual average decline of almost 5 percent, with South Louisiana and offshore Louisiana each seeing a 6 percent average decrease per year.

Figure 3.4 shows average oil well production since 1960 for each of the three Louisiana regions. South Louisiana production per well peaked in 1971 at 38.2 thousand barrels per well ("Mbbls/w") and has been declining at an annual average rate of almost 4 percent since that time. While clearly falling relative to its peak in 1971, South Louisiana oil well productivity was relatively constant between 1982 and 1999, hovering between 13 and 16 Mbbls/w. Oil well productivity in South Louisiana has also fallen considerably since 1999 (by over 26 percent).

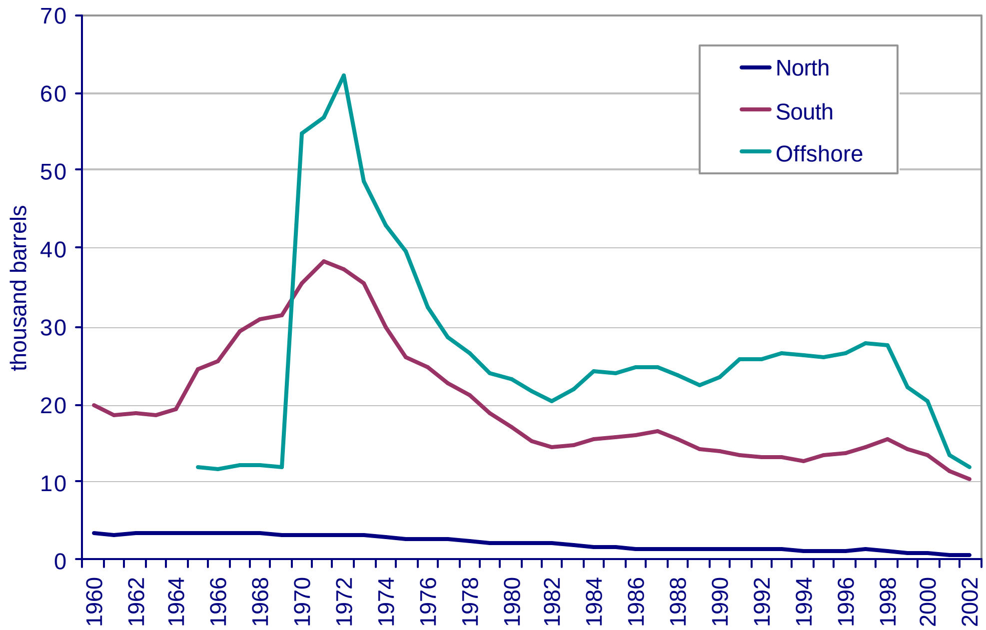

Figure 3.4: Louisiana State Average Crude Oil Production per Well

Note: Offshore figures exclude federal OCS
Source: Louisiana Department of Natural Resources

Offshore Louisiana average oil production peaked one year after South Louisiana (1972) with a considerably higher level of production per well (62.2 bbls/w). However, unlike other regions of the state, average offshore oil production since

1982 has increased by about 2 percent per year until 1998. Within the last several years average offshore oil well productivity increased. By 1997 offshore average oil production had reached a level not seen since 1977.

Figure 3.5 shows historic natural gas production in Louisiana on two different axes. North Louisiana and offshore production have been graphed on the left-hand axis, while South Louisiana natural gas production has been graphed on the right-hand axis. The three areas of the state have followed two different trends. South Louisiana and offshore production have been decreasing since reaching their peak around 1970. Natural gas production in North Louisiana, while relatively small compared to other regions of the state (averaging 18 percent of total), has been slowly increasing since reaching its lowest point in the late 1970s.

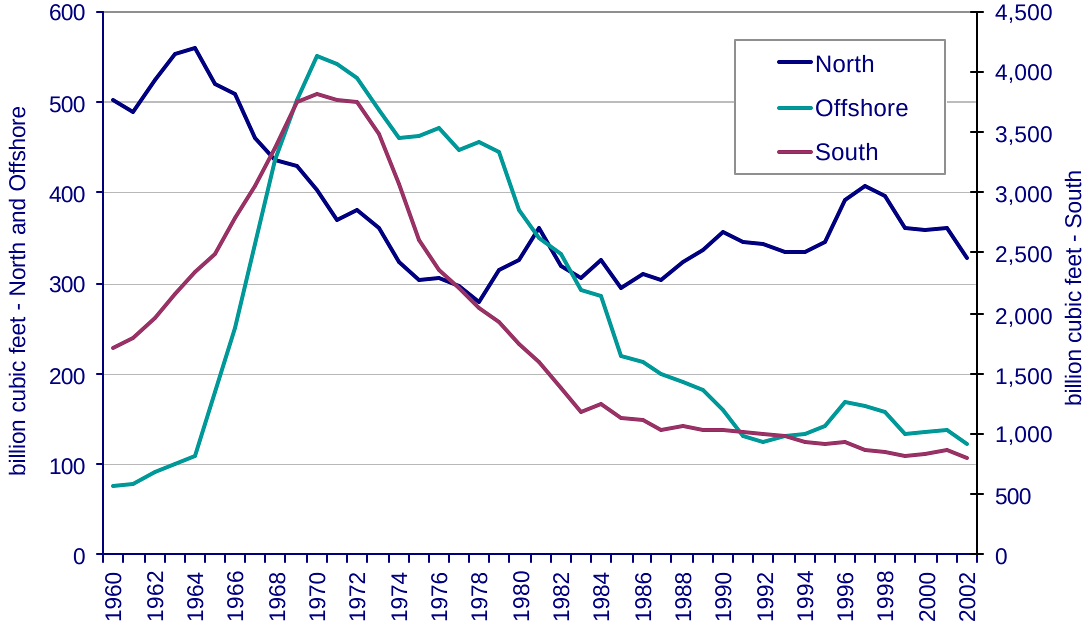

Figure 3.5: Louisiana State Historic Natural Gas Production

Note: Offshore figures exclude OCS and casinghead gas.
Source: Louisiana Department of Natural Resources

Currently, South Louisiana natural gas production is 21 percent of its 1970 peak and offshore Louisiana production is 22 percent of its peak of the same year. South Louisiana gas production has been declining at a slightly faster average annual rate than the offshore region (4.6 percent versus 4.3 percent). Overall, South Louisiana production, while falling, still accounts for over 64 percent of total Louisiana jurisdictional production.

North Louisiana gas production has followed a very different pattern than the other two regions of the state. North Louisiana gas production peaked almost 30 years ago, in 1964, and decreased at an annual average rate of about 4.8 percent until 1979 (when it increased by almost 13 percent). However, since

1979 total natural gas production in North Louisiana, while up and down over various years, generally followed an increasing annual trend of about 1.6 percent until 1997. Since that time, natural gas production has been decreasing. By 2002, natural gas production was nearly 60 percent of the region's all time peak.

Figure 3.6 shows historic natural gas well productivity for the three producing regions in Louisiana. All three regions have seen considerable decreases in average natural gas production (i.e., production per well) since its height of the early 1970s. Average production for offshore areas has fallen perhaps more dramatically than the other two regions. However, offshore gas production has seen a noticeable increase since 1993 when average gas production increased by 130 percent from 1993 to 1998. Average production for the offshore area has fallen by 26 percent since that period.

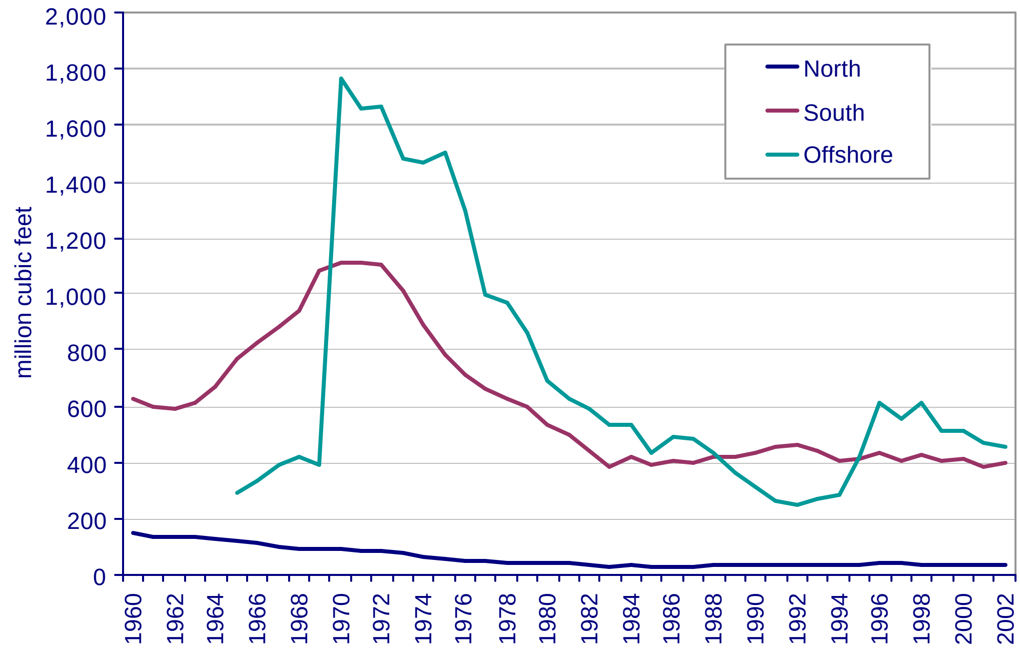

Figure 3.6: Louisiana State Average Natural Gas Production per Well

Note: Offshore figures exclude OCS and casinghead gas.
Source: Louisiana Department of Natural Resources

Natural gas production by well in South Louisiana has been relatively stable for the past twenty years. In 1983, natural gas production in South Louisiana averaged 385 MMcf per well. Average production today is slightly higher at 395 MMcf/well. Overall, average South Louisiana natural gas production is only about 35 percent of its peak in 1971, but has stayed close to this level for two decades.

4 EXAMINATION OF THE “TREADMILL” HYPOTHESIS FOR LOUISIANA PRODUCTION

4.1 Introduction

One explanation for the changing nature of gas markets has been that energy companies, both large and small, have been drilling and producing in the same areas for several decades. As such, these basins are becoming exhausted at a faster rate, and it takes virtually twice the effort to just stay in place. In other words, producers are on a virtual supply “treadmill” having to work harder and harder each year just to stay in place.

One detailed, state-level study that brought this hypothesis to the forefront was conducted by Simmons International, an energy industry investment banking firm headquartered in Houston, Texas. The original goal of the Simmons’ study was to test another widely reported “theory” about gas supply reactions following the natural gas price run-up of the winter of 2000-2001. This theory arose to explain what was perceived as an uncharacteristically and modest supply response following the 2000-2001 price run-up -—despite the fact that there was a significant increase in drilling activity during the same period.

Many industry analysts attempted to explain the anemic supply response anomaly as production from “marginal” wells. The “marginal well” theory posited that producers rushed to develop a host of quick, marginal wells to take advantage of the price run-up and were not developing meaningful resources during the period. If they had, the supply response would have been more considerable.

The Simmons study[7] tested this "marginal well hypothesis" by examining a number of different types of wells across a 53 county sample in Texas. Contrary to the marginal well theory, the Simmons study found that wells drilled in reaction to the 2000-2001 price run up:

- Added about 8 billion cubic feet ("Bcf") per day in supply;
- Had a profound impact on supply by accounting for about 30 percent of total Texas production;
- Instead of finding "marginal" wells, the study found quite the opposite:
  - Seven percent of 2001 wells accounted for 49 percent of 2001 production;
  - The remaining 93 percent of the active wells in Texas accounted for some 51 percent of total state production.
- The study found huge declines in post-peak year production of about 82 percent, a level considerably above historic trends;
- Had large new wells not been drilled in 2001, there would have been a serious supply crunch; and
- The remaining 93 percent of operational wells in the state, while not individually consequential, are collectively very important for holding up total state gas supply.

[7] There is no directly citable "report" to reference for the Simmons study. This analysis has been given in a number of presentations by Matthew R. Simmons, President of Simmons International. One such presentation was before the Louisiana Comprehensive Energy Policy Commission. A number of versions of this presentation are available on the Simmons International webpage at: http://www.simmonsco-intl.com/.

The most general and fundamental result of the Simmons study was that new drilling is important in maintaining gas supply, and that if drilling activities are not maintained, there could be considerable supply consequences.

This section of the report takes the methods applied in the Simmons study and applies them to Louisiana production data to determine if a treadmill-type phenomenon occurs in the state. This analysis is important for several reasons. First, if production is dropping off at ever increasing rates, it will have implications for any production forecast to determine future well profitability. Second, if production is falling off at a more rapid pace, it has implications for the development of marginal wells in the future. Third, for those wells that are individually producing at very small levels (the other “93 percent” referenced above), maintaining their economic viability will be important for state revenues.

The following subsections are a bit of a digression to examine this “treadmill hypothesis” using Louisiana, well-specific information. Production on all leases are examined first (oil and gas), followed by a comparable analysis for state leases.

4.2 Louisiana Production

Figure 4.1 provides an examination of overall historic Louisiana oil production. The area graph is color coded to highlight the contribution from various oil producing wells by year of completion. Production has been aggregated for the three producing areas of the state (North Louisiana, South Louisiana, offshore).

As seen from the figure, and highlighted in an earlier section of this report, oil production has been consistently decreasing since the late 1970s.[8]

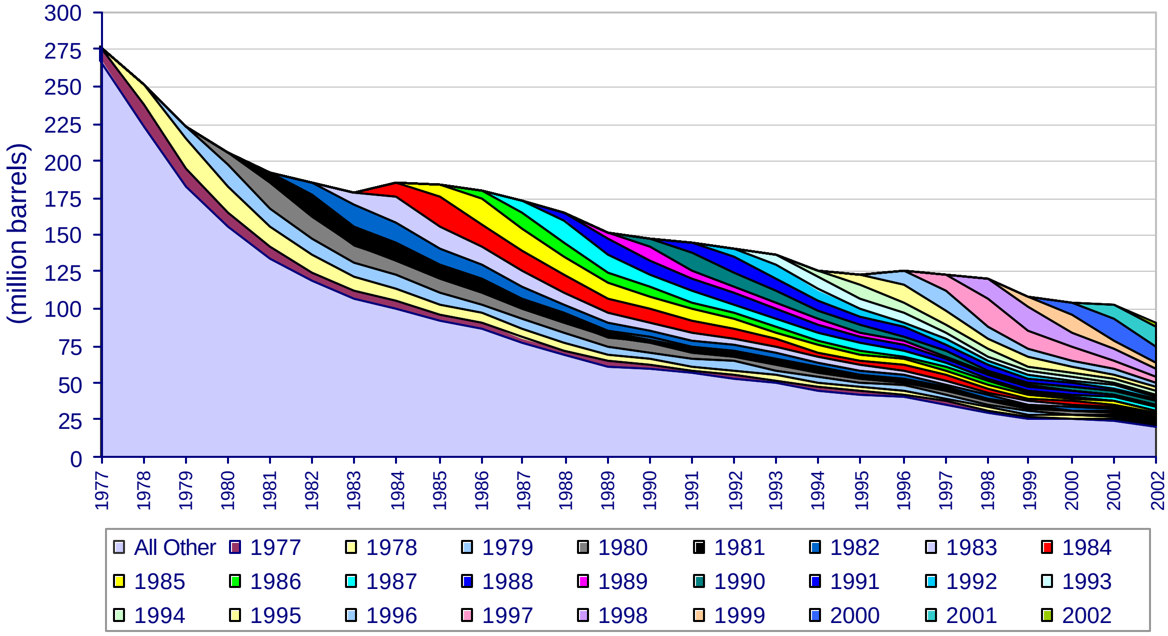

Figure 4.1: Oil Production by Completion Year (all LUWs)

[8]The data used in this analysis is based upon information reported to the Louisiana Department of Natural Resources. This information is collected electronically in the Production Area Reporting System ("PARS") and made available (in part) through the SONRIS system. Both of these sets of information are described in greater detail in Section 2, however, this electronic information is reported at the operating unit of detail, and as a result, the earliest production year available in the PARS database is 1977. Hence, the difference in starting years (1977 versus 1960) for figures presented here, and those provided in Section 3.

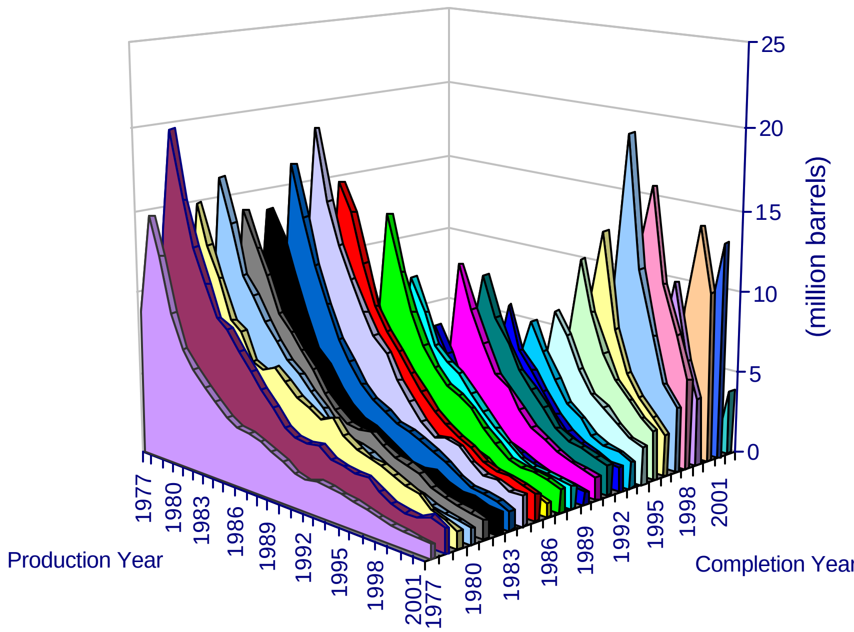

Figure 4.2: Oil Production by Completion Year (all LUWs)

Figure 4.2 turns the production presented in Figure 4.1 into three-dimensions to highlight the contribution of each completion year to total Louisiana production. So, the purple series in the immediate foreground of the figure shows total annual production from all wells which reported a completion date of 1977. Likewise, the maroon curve immediately following the 1977 completion date production shows the annual production from wells completed in 1978. This progresses for each completion year available.

Two discernable trends are recognizable from both Figure 4.1 and Figure 4.2. As completion years become more contemporaneous:

(1) The absolute peaks in average production appear to be higher in overall magnitude; and

(2) The overall decline rates for production are becoming steeper.

In Figure 4.2, each of these trends can be seen by examining: (a) the “thickness” of the area towards the more recent completion years in the graph; and (b) the steeper slopes for curves in the more recent completion years.

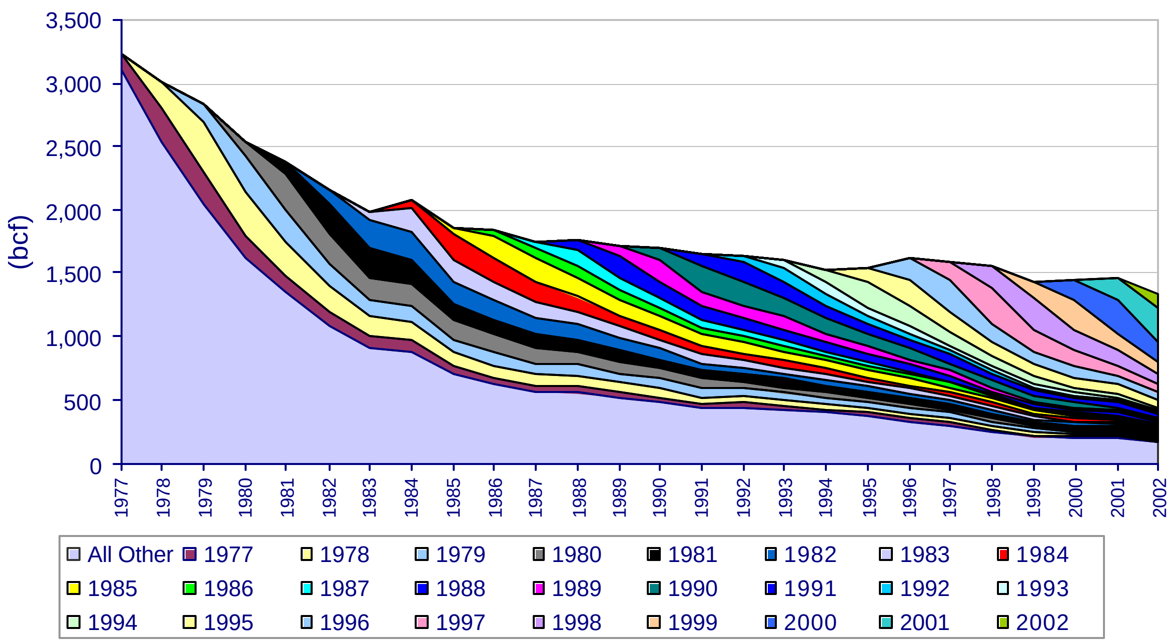

Figure 4.3: Gas Production by Completion Year (all LUWs)

Similar trends are discernable in examining annual natural gas production. Figure 4.3 presents an annual two dimensional representation of annual Louisiana natural gas production. The areas in the graph that present production in the more recent completion years is much thicker than earlier years, indicating an increase in the average production, and overall contribution, that these wells are having on total Louisiana natural gas production. In addition, the steepness of each of the curves are much greater than past completion years where declines took more traditional, exponentially decreasing trends.

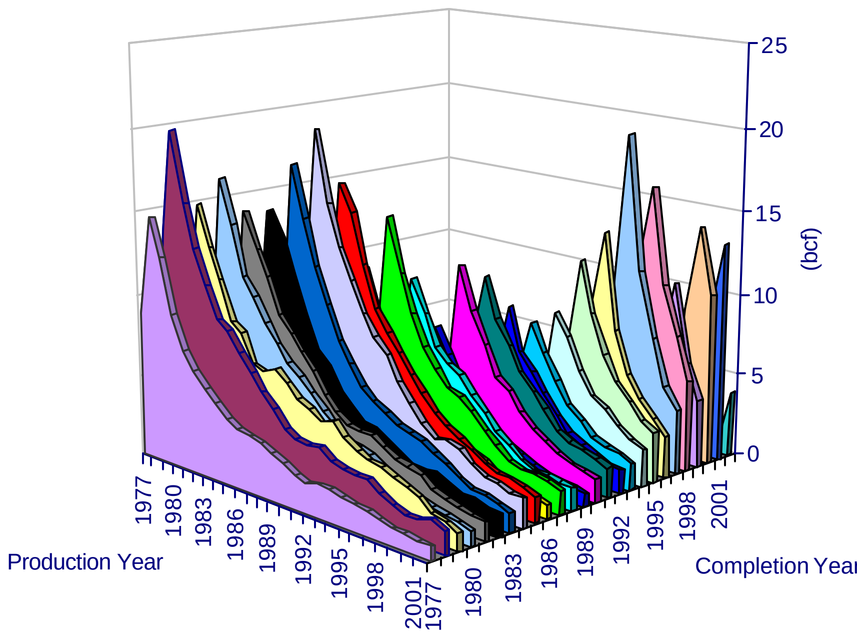

Figure 4.4: Gas Production by Completion Year (all LUWs)

Figure 4.4 decomposes production from wells by their completion year and shows relatively high peaks coming from more contemporaneous natural gas wells. These peaks, and steep drop offs, appear to be more prevalent for wells completed since 1995.

Figure 4.5 offers a three dimensional presentation of average oil well productivity by completion year. This analysis is based upon data reported for individual wells, and excludes production reported at the aggregate lease level.[9] Three trends are discernable from the figure:

(1) Average production peaks are much sharper as completion year becomes more contemporaneous.

(2) The decline rate for newer oil wells is considerably steeper for wells completed more recently.

(3) There has been a recent average production increase (or "blip") for wells completed during 1977 to 1995 time period. This production increase began in 2000, and is probably attributable to operators re-entering older wells to expand production in response to the oil price increases in that year.

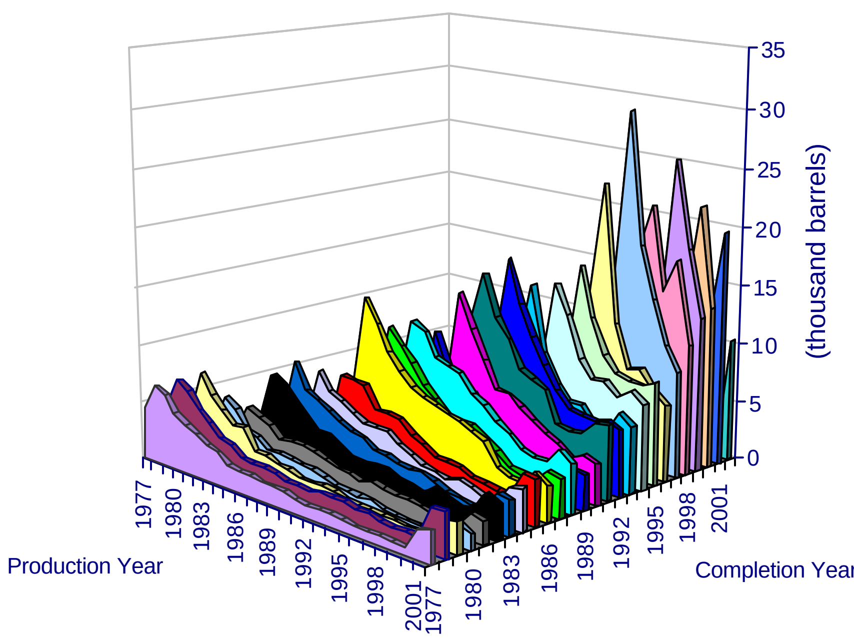

Figure 4.5: Average Well Oil Production by Completion Year (single well LUWs)

[9]The method by which data is compiled by LDNR in its electronic databases is discussed in detail in Section 2. Multiple well information can be difficult to examine since there is no definitive way of allocating overall lease or unit production to a given well. Thus, this analysis focuses upon single-well reporting units only.

Figure 4.6 provides a comparable historic average production analysis for natural gas wells by completion year. This figure highlights the same three trends found for oil production, although somewhat more dramatic.

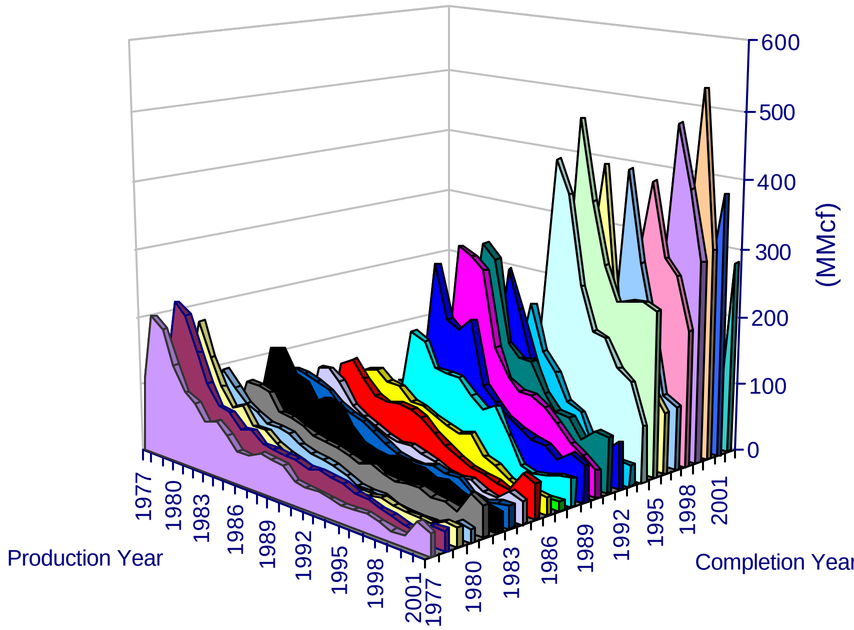

Figure 4.6: Average Well Gas Production by Completion Year (single well LUWs)

The last figure presented in the analysis appears to confirm the "treadmill" hypothesis. This figure examines average first year decline for all Louisiana producing wells by completion year. In other words, the decline in production one year after a well has peaked. Mathematically, peak year production decline is defined as:

$$PYDR = \frac{q_{t+1}}{q_t^0}$$

Where q_t^0 is peak production from a given well at any year (t) in its life, and q_{t+1} is the production one year after that peak level has been attained. In essence, the formula defines the average first year decline as measured by the ratio of production one year after a well has peaked relative to overall peak production.

This relationship is a good indicator of how production is declining, on average, for wells that are completed in any given year. So, if a well with a completion date of 1977 has a peak year decline ratio ("PYDR") of 0.90, then production is 90 percent of the prior year's peak. If the PYDR is 0.70, then production in the year proceeding a well's peak has fallen to 70 percent of the prior year's level. The lower the ratio, the faster production has fallen one year after the peak. As noted earlier, the Simmons study of Texas leases found that recently completed wells were experiencing dramatic post-peak drop-offs in production.

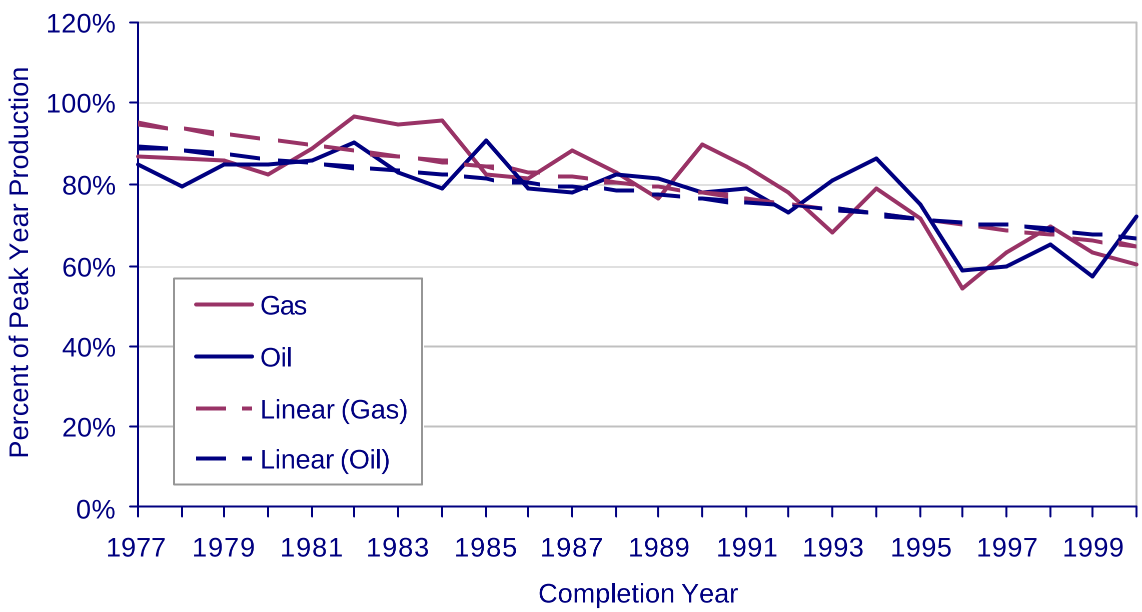

Figure 4.7: Production in the Year Following Peak Year (all LUWs)

Figure 4.7 clearly shows that the trend in post-peak production from both oil and natural gas wells in Louisiana has been falling at an increasing rate since 1977, for both types of wells (oil, gas). The linear trends, which have also been plotted on the figure, show that the post peak drop-offs for natural gas wells in Louisiana, which were at about the 95 percent level in 1977, have fallen to around 62 percent in 2001. Oil wells, on the other hand, have seen their post peak production decrease from 89 percent in 1977 to 68 percent by 2001. Overall the gas decline rate appears to be decreasing at a much faster rate than oil.

4.3 State Lease Production

State leases were also examined to determine if the trends noted above at the overall state production level existed at the state lease level as well (i.e., increased average production, increasing decline curves). Annual oil production from state leases, by well completion year, has been presented in Figure 4.8. Like the figures from overall state production, increasing volumes are discernable from wells completed since 2000. One noticeable difference in the state lease trends is that the peak oil production increases occur only recently (since about 2000). The overall state trends showed these increases occurring as early as 1995.

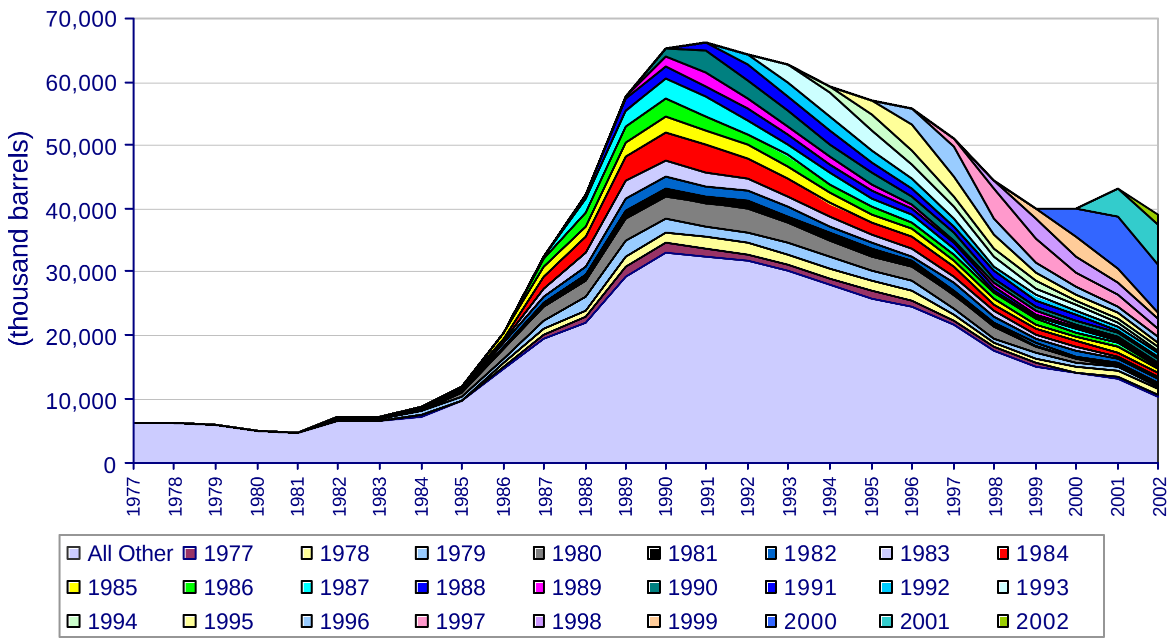

Figure 4.8: Oil Production by Completion Year (all LUWs)

The recent increase in peak oil production on state leases is shown more clearly on Figure 4.9 which is a three-dimensional representation of state lease production by completion year. Production in years 2000 and 2001 take a noticeable spike that is considerably different, and higher, than prior years' production trends.

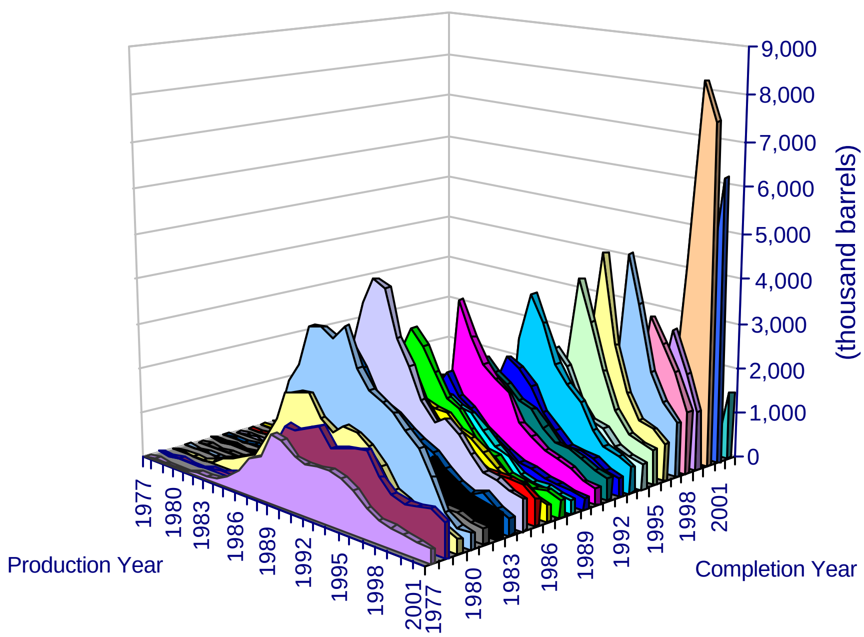

Figure 4.9: Oil Production by Completion Year (all LUWs)

Figure 4.10 presents the two-dimensional graph for natural gas production on state leases by completion year. Increases in peak gas production start initially around 1995, fall off, and pick up again in 2000. The trends in gas production peaks on state leases are much more consistent with overall state trends than oil production. The trend of increasing peak gas production is seen clearly from the three-dimensional representation provided in Figure 4.11.

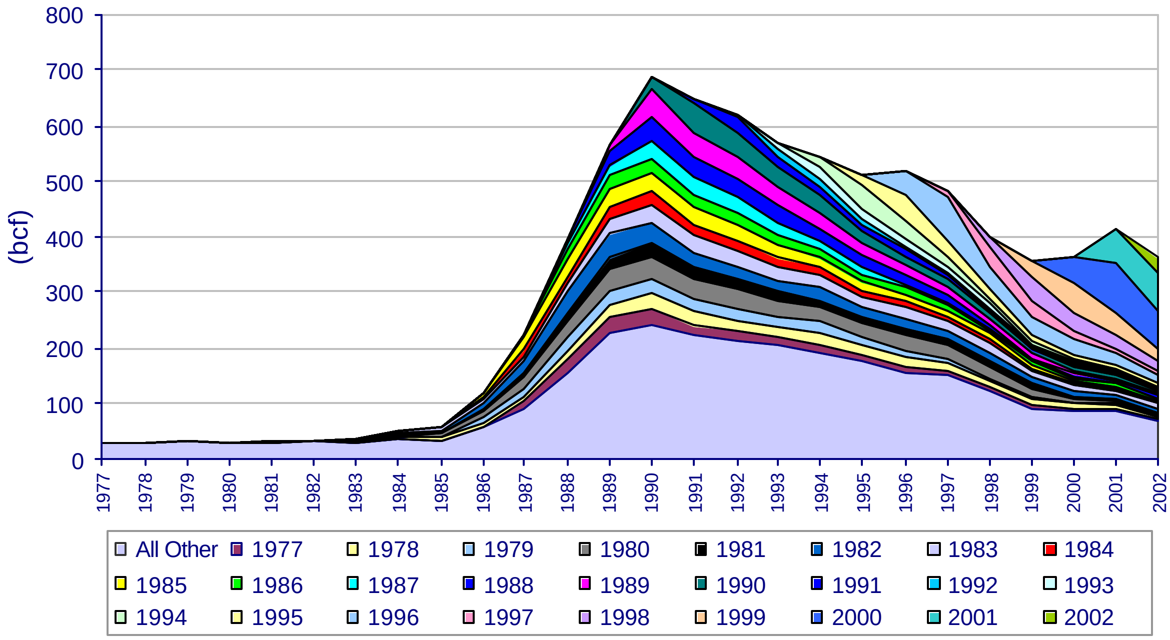

Figure 4.10: Gas Production by Completion Year (all LUWs)

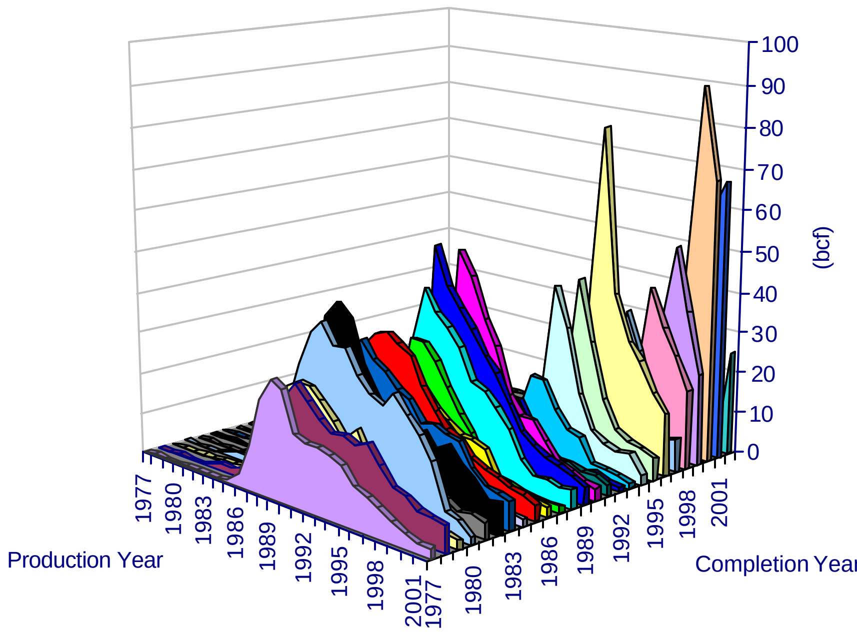

Figure 4.11: Gas Production by Completion Year (all LUWs)

Average oil and gas well production have been presented in Figure 4.12 and Figure 4.13. Both figures highlight a number of the same trends found in the examination of the statewide totals that include: (a) higher peak production; (b) faster decline rates; and (c) increases in production from recently completed wells.

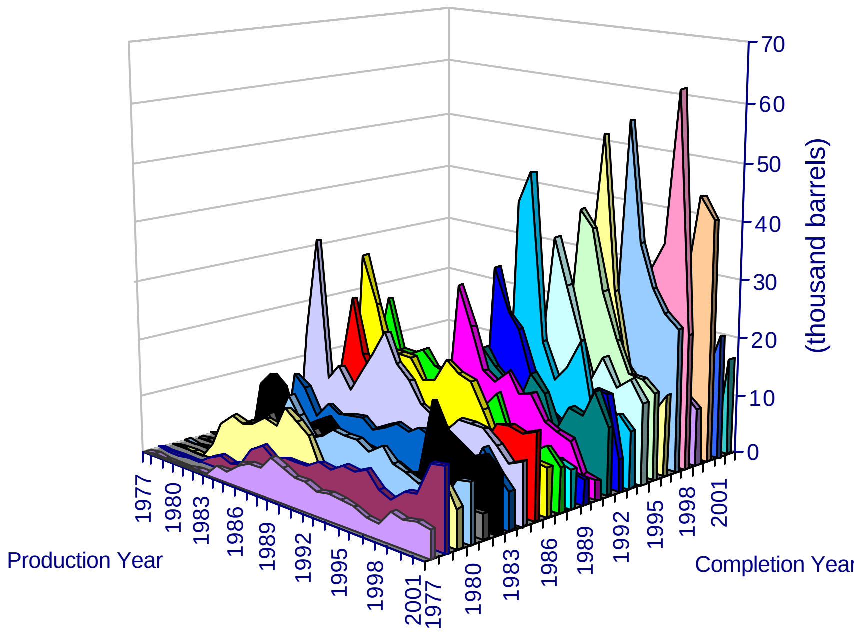

Figure 4.12: Average Well Oil Production by Completion Year (single well LUWs)

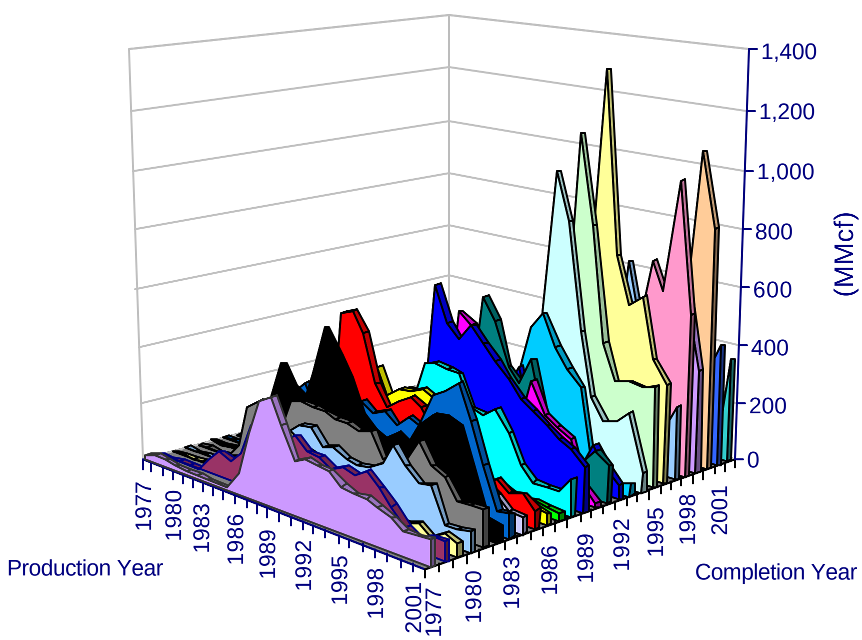

Figure 4.13: Average Well Gas Production by Completion Year (single well LUWs)

Figure 4.14 examines the linear trends in the declines of oil and gas production on state leases by well completion year. Trends are comparable to overall state production, with a few exceptions. Based on the overall trend analysis, post peak production ratios for oil production starts at around 91 percent in 1977, and declines to a level of around 79 percent for 2002. For natural gas, post peak production ratios start at around 98 percent in 1977, and fall to 71 percent by 2002. The average annual decrease is much steeper for natural gas than oil. The post peak production ratios for state leases are slightly more tempered than those for overall state production. This is particularly true for oil production. Nevertheless, there is a noticeable decrease in the post peak production trends for state leases, and it is noticeably steep for natural gas production in particular.

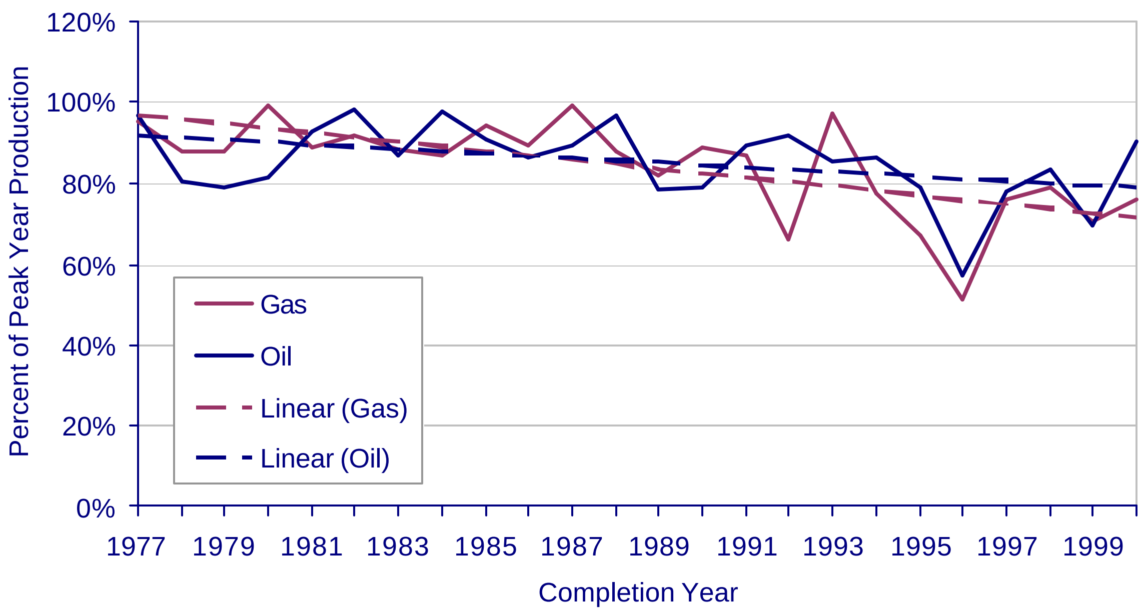

Figure 4.14: Production in the Year Following Peak Year (all LUWs)

5 ANALYSIS OF STATE LEASES AND BASELINE PROFITABILITY

5.1 Introduction

This section of the report examines the recent trends in production and profitability on state leases. Three areas have been examined here and in the remaining sections of this report: North Louisiana; South Louisiana; and offshore. The historic period under investigation dates to 1986 due to data limitations on production costs. The goals of this section of the report are to:

- Highlight existing status of production on state leases;
- Estimate the profitability of wells on state leases to determine which leases are marginal from a profitability perspective; and
- Compare the results from the profitability-driven analysis and the standard production-level definition to examine any differences between the two approaches at examining "challenged" or potentially vulnerable production.

Before starting this discussion, the production on state leases should be placed into perspective. Figure 5.1 shows total oil and gas production on state leases as a percent of overall Louisiana production. As seen from the figures, production on state leases is rather significant.

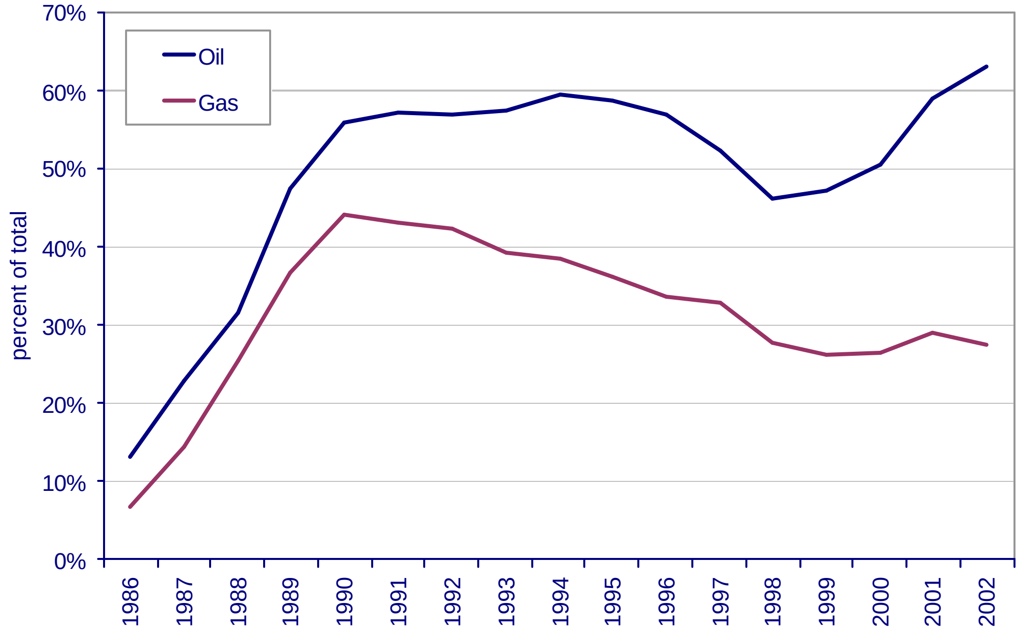

Figure 5.1: Production on State Leases as a Percent of Total Production

5.2 State Lease Production Trends

Figure 5.2 presents a map outlining each of the state leases in Louisiana. Each dot represents a well on a state lease, and is colored by its primary production (oil, gas). The map is for active wells on state leases in 2002.

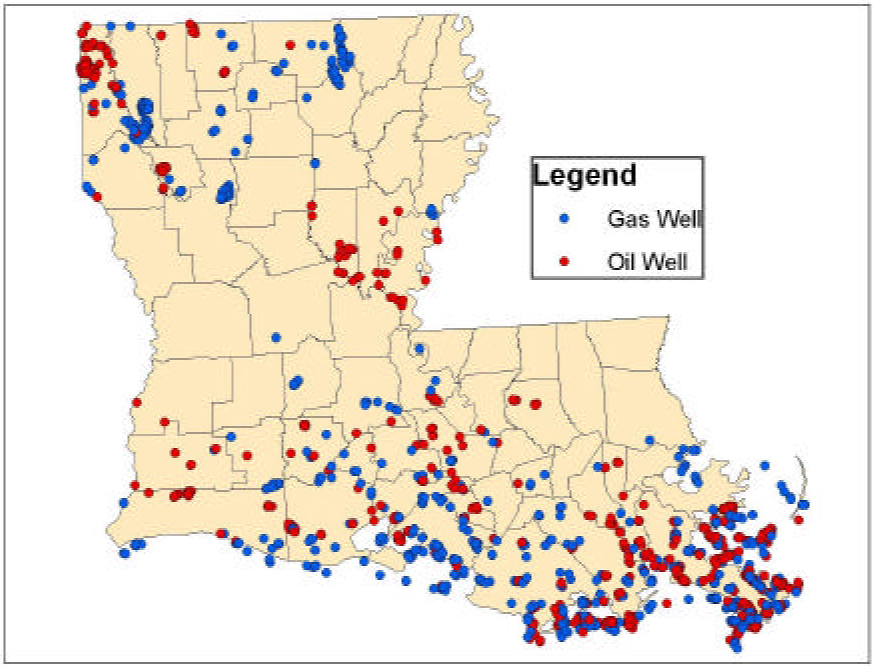

Figure 5.2: Active Wells on State Leases

Figure 5.3 and Figure 5.4 present historic graphs examining the trends on state leases. In most respects, the trends are similar to statewide production as discussed in Section 4. Generally, active wells have been in decline since their recent peak around 1990. In 2000, the number of producing natural gas wells increased, no doubt due to the substantial increases in commodity prices for that year. One other noticeable shift has been the change in the number of active offshore oil wells versus those in North Louisiana. Around 1997, the number of active oil wells in North Louisiana began to outpace those offshore. Likewise, by 2001 the number of natural gas wells in North Louisiana grew to a level comparable to those offshore.

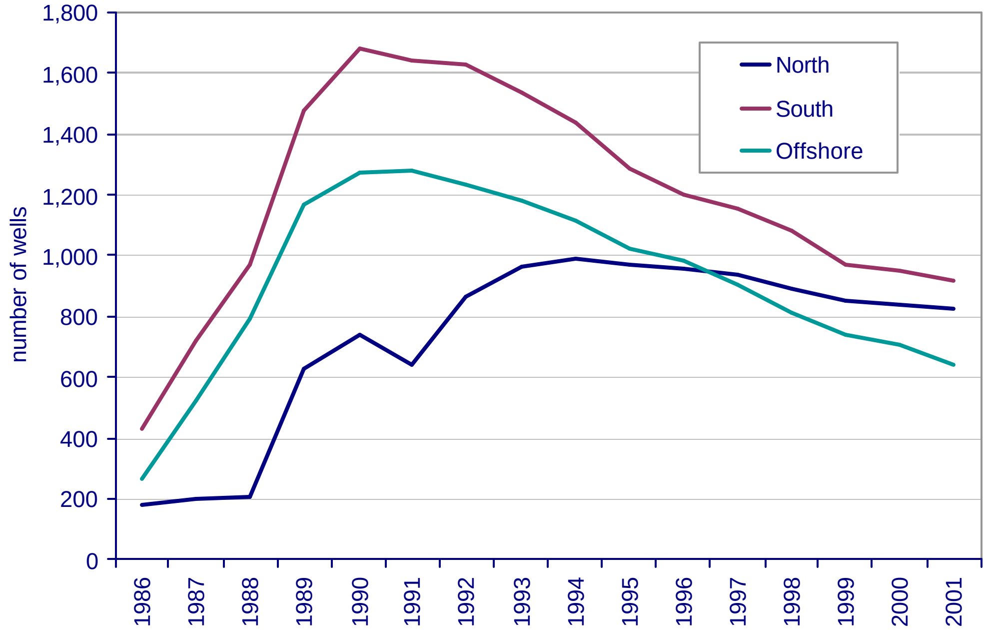

Figure 5.3: Annual Number of Operating Oil Wells on State Leases

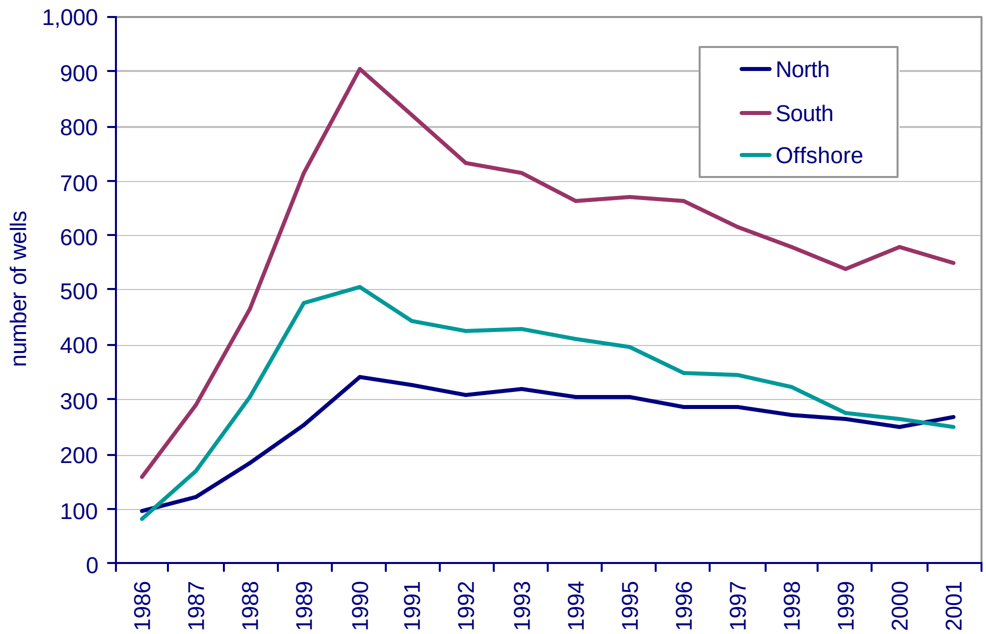

Figure 5.4: Annual Number of Operating Gas Wells on State Leases

Figure 5.5 and Figure 5.6 present the recent historical trends associated with oil and gas production on state leases. Like overall state trends, production volumes on state leases have followed trends, reflected in part, by the relative changes in energy prices. Production in South Louisiana appears to be more sensitive to changes in these relative energy prices. Offshore oil production rivaled that of South Louisiana in order of magnitude. The differences in oil production levels since 1986 tend to increase.

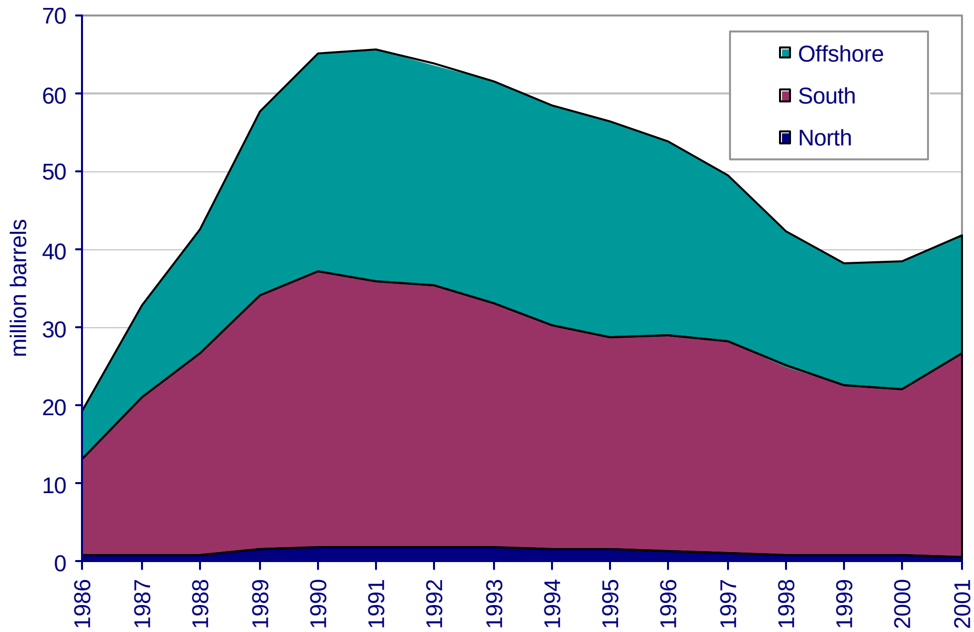

Figure 5.5: Total Annual Oil Production on State Leases

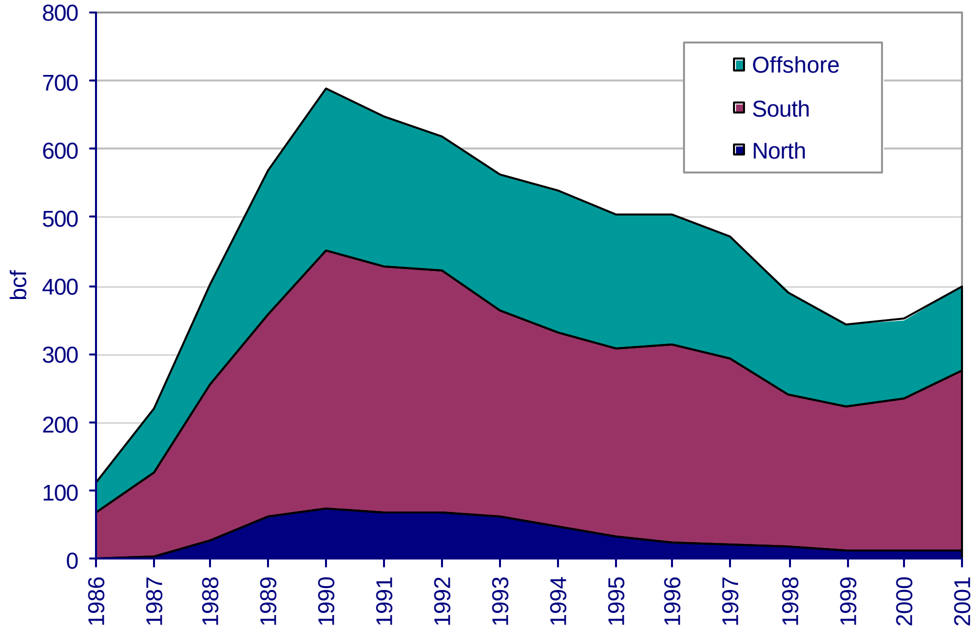

Figure 5.6: Total Annual Gas Production on State Leases

Figure 5.7 and Figure 5.8 present the relative differences in average production for oil and gas production for state leases by region. For oil, trends in average daily production have been relatively constant over the past several years with South Louisiana and offshore production shifting from time to time as the region with the highest average well productivity. However, overall average oil well productivity for state leases in South Louisiana and offshore are higher than the statewide averages seen earlier. Average daily gas production on state leases is relatively comparable to the overall state averages.

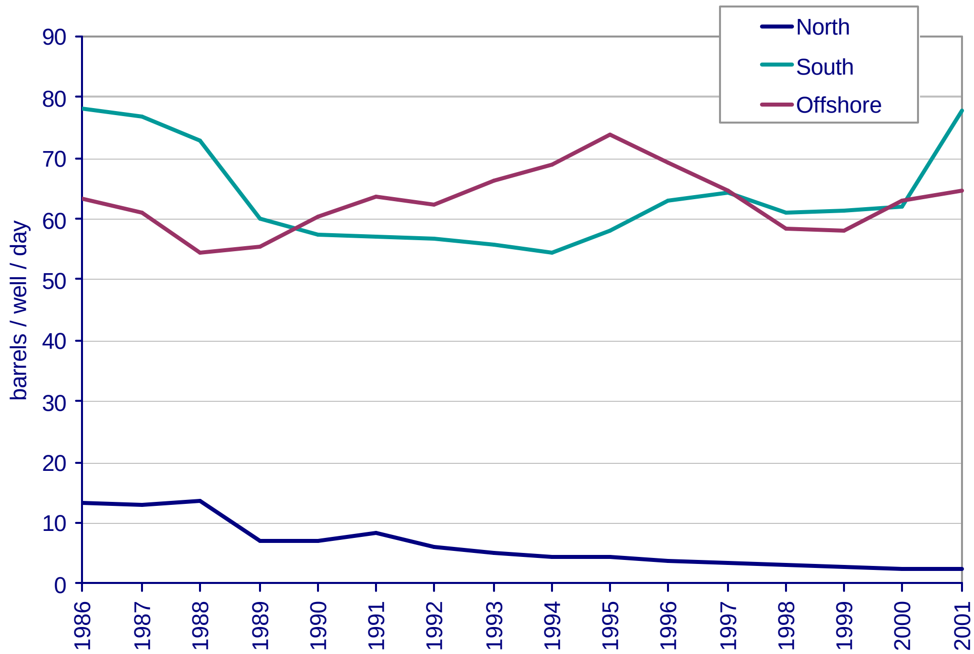

Figure 5.7: Average Annual Oil Production per Well on State Leases

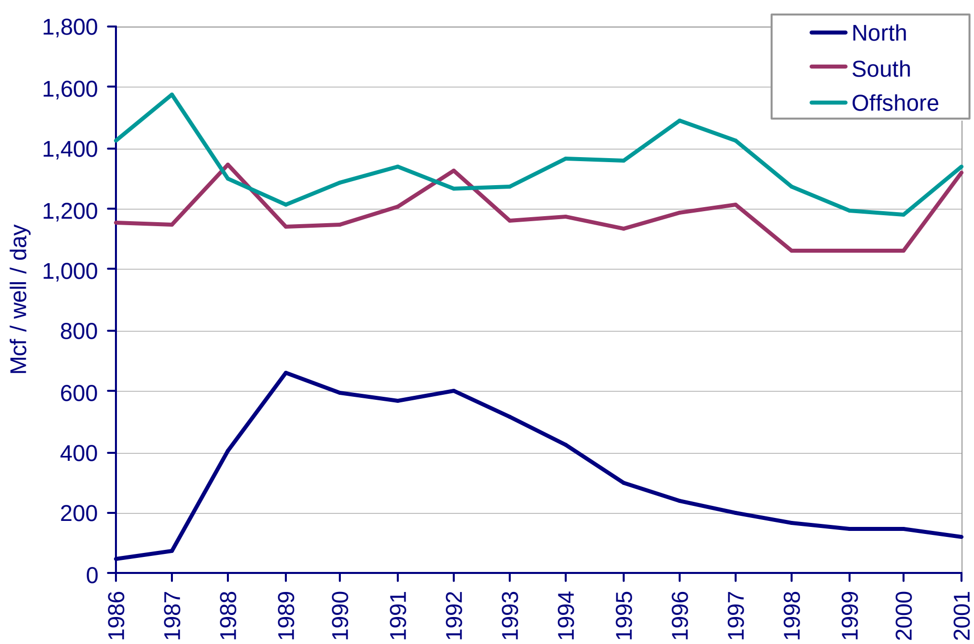

Figure 5.8: Average Annual Gas Production per Well on State Leases

5.3 Profitability Analysis – Estimated Number of Unprofitable Wells

Figure 5.9 identifies the estimated number of unprofitable oil wells that were in operation during the period 1986-2001 based upon the methodology discussion in Section 2. Table 5.1 provides estimates of the number of unprofitable wells on state leases for each producing area in the state.

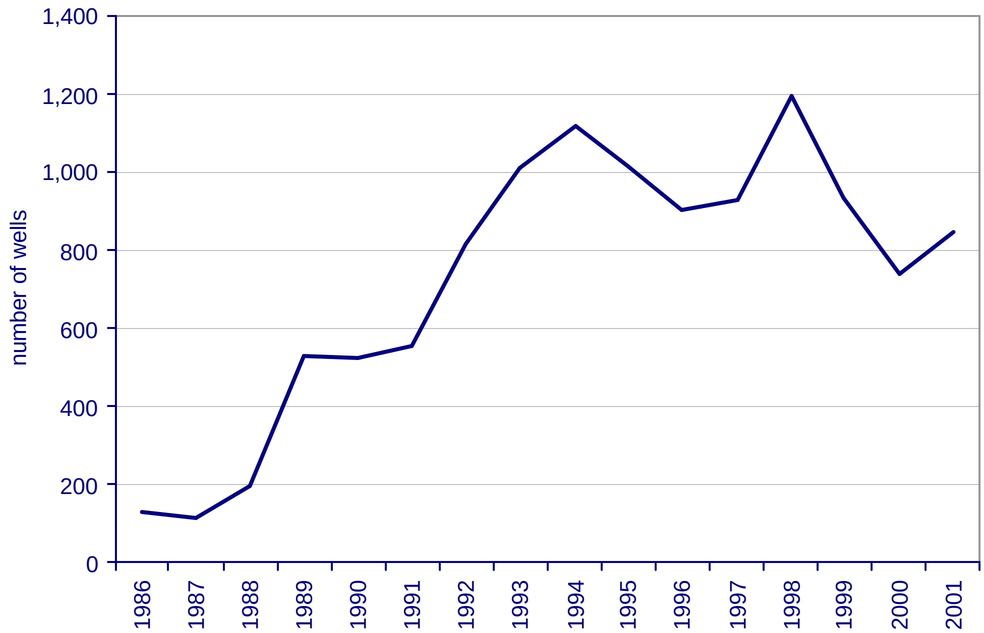

Figure 5.9: Estimated Number of Unprofitable Oil Wells on State Leases

Table 5.1: Estimated Number of Unprofitable Oil Wells on State Leases by Producing Region

Year	North		South		Offshore	
	Unprofitable Wells	% of Total	Unprofitable Wells	% of Total	Unprofitable Wells	% of Total
1986	96	53.0%	16	3.7%	19	7.0%
1987	61	30.5%	28	3.9%	26	5.0%
1988	101	48.8%	57	5.9%	41	5.2%
1989	326	51.9%	132	8.9%	73	6.3%
1990	323	43.4%	129	7.7%	73	5.7%
1991	317	49.2%	158	9.6%	77	6.0%
1992	590	68.2%	164	10.1%	61	4.9%
1993	741	76.7%	187	12.2%	83	7.0%
1994	814	82.6%	219	15.2%	87	7.8%
1995	792	81.7%	167	13.0%	55	5.4%
1996	757	79.3%	110	9.1%	39	4.0%
1997	777	83.3%	108	9.3%	46	5.1%
1998	821	92.1%	226	20.9%	146	18.0%
1999	744	87.8%	134	13.8%	57	7.7%
2000	643	77.2%	66	7.0%	27	3.8%
2001	722	87.5%	84	9.2%	42	6.5%

The estimated number of unprofitable oil wells in offshore Louisiana shows some volatility, but a generally decreasing trend over recent years. The number of unprofitable wells increased between 1986 and 1994, from 19 to 87 wells. It then decreased to 46 in 1997, spiked to 146 in 1998, and has decreased to 42 in 2001. This is approximately 6.5 percent of all the active offshore oil wells on state leases.

The estimated number of unprofitable oil wells in North and South Louisiana, however, has been much more volatile. South Louisiana peaked in 1998 with its highest estimated number of unprofitable wells, 226, accounting for almost 21 percent of all active wells in the region. North Louisiana also peaked that year, as well with 821 wells, or about 92 percent of all active North Louisiana wells. This number has decreased to 722 in 2001, or 88 percent.

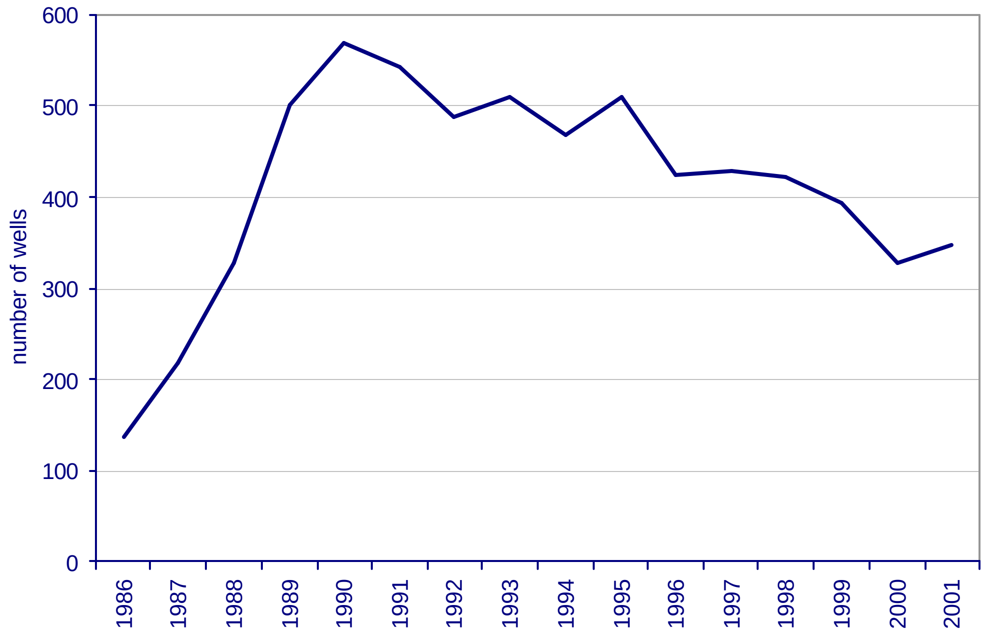

Figure 5.10: Estimated Number of Unprofitable Gas Wells on State Leases

Table 5.2: Estimated Number of Unprofitable Gas Wells on State Leases by Producing Region

Year	North		South		Offshore	
	Unprofitable Wells	% of Total	Unprofitable Wells	% of Total	Unprofitable Wells	% of Total
1986	69	69.7%	8	5.0%	60	72.3%
1987	82	66.1%	7	2.4%	129	76.8%
1988	98	53.3%	20	4.3%	210	68.4%
1989	104	41.1%	43	6.0%	353	74.0%
1990	129	37.7%	66	7.3%	373	74.0%
1991	135	41.4%	81	9.9%	326	73.4%
1992	122	39.5%	64	8.7%	302	71.1%
1993	122	38.0%	68	9.5%	319	74.5%
1994	125	40.7%	49	7.4%	294	71.4%
1995	139	45.7%	71	10.6%	300	75.9%
1996	116	40.4%	53	8.0%	254	72.6%
1997	125	43.9%	57	9.2%	246	71.7%
1998	124	45.4%	53	9.2%	245	76.1%
1999	124	46.6%	58	10.8%	211	76.4%
2000	90	36.0%	44	7.6%	194	72.9%
2001	123	45.9%	29	5.3%	194	77.6%

Figure 5.10 presents the results from a comparable historic profitability analysis for active natural gas producing wells on state leases while Table 5.2 provides estimated unprofitable gas wells for all three Louisiana producing regions. For the offshore region, the estimated number of unprofitable gas wells has ranged from a high of 373 in 1990 to a low of 60 in 1986. For North Louisiana, the estimated number of unprofitable gas wells has ranged from a low of 69 (also in 1986) to a high of 139 (1995). In 2001, North Louisiana had an estimated 123 unprofitable gas wells on state leases. This represents about 46 percent of the total number of active gas wells on state leases in that region.

Overall, the estimated number of unprofitable natural gas wells in South Louisiana has varied from a low of 7 wells in 1987 to a high of 81 in 1991. In 2001, there were an estimated 29 unprofitable gas wells in South Louisiana on state leases. This is only about 5 percent of all the active wells on state leases in the South Louisiana region.

Figure 5.11 provides a map of all the wells that have been estimated to be unprofitable in 2002. The map highlights each type of well on a state lease and its profitability status.

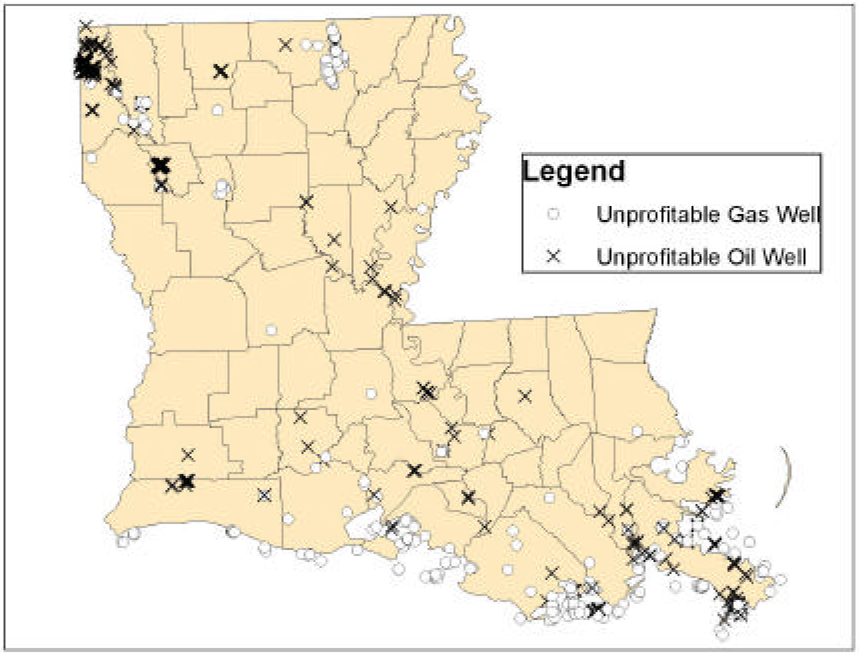

Figure 5.11: Estimated Unprofitable Wells on State Leases (2002)

5.4 Profitability Analysis – Estimated Unprofitable Production Volumes on State Leases

Figure 5.12 and Figure 5.13 provide the results from the profitability analysis on a production level basis for oil and gas wells for state leases. Figure 5.12 examines the amount of oil production associated with estimated unprofitable state lease wells. Here, the estimated results for unprofitable North and South Louisiana oil wells progress on a similar path. The total estimated production from unprofitable oil wells in North Louisiana ranges from a low of 22 thousand barrels ("Mbbls") in 1986 to a high of 283 Mbbls in 1998. In 2001, estimated unprofitable oil production in North Louisiana was around 192 Mbbls, or about 26 percent of total oil production on state leases in the region for that year

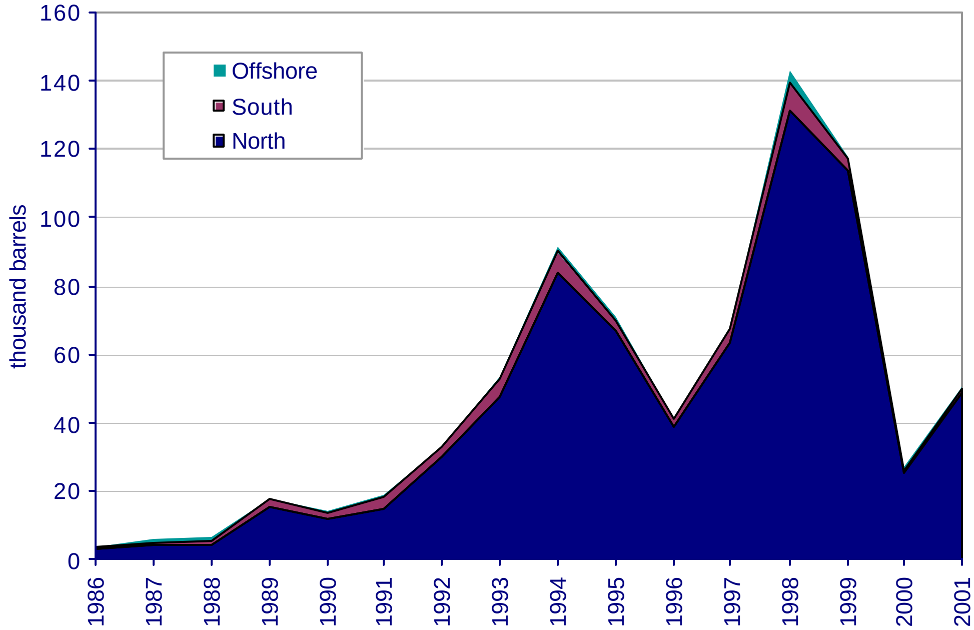

Figure 5.12: Estimated Oil Production from Unprofitable Wells on State Leases

Referencing earlier information from Table 5.1 for 2001, it is apparent that for North Louisiana state leases, unprofitable oil production accounts for a relatively small amount of overall regional production (26 percent), but a relatively large proportion of total regional wells (88 percent). For the other regions (offshore and South Louisiana) a relatively small number of unprofitable wells account for an equally small proportion of unprofitable oil production on state leases.

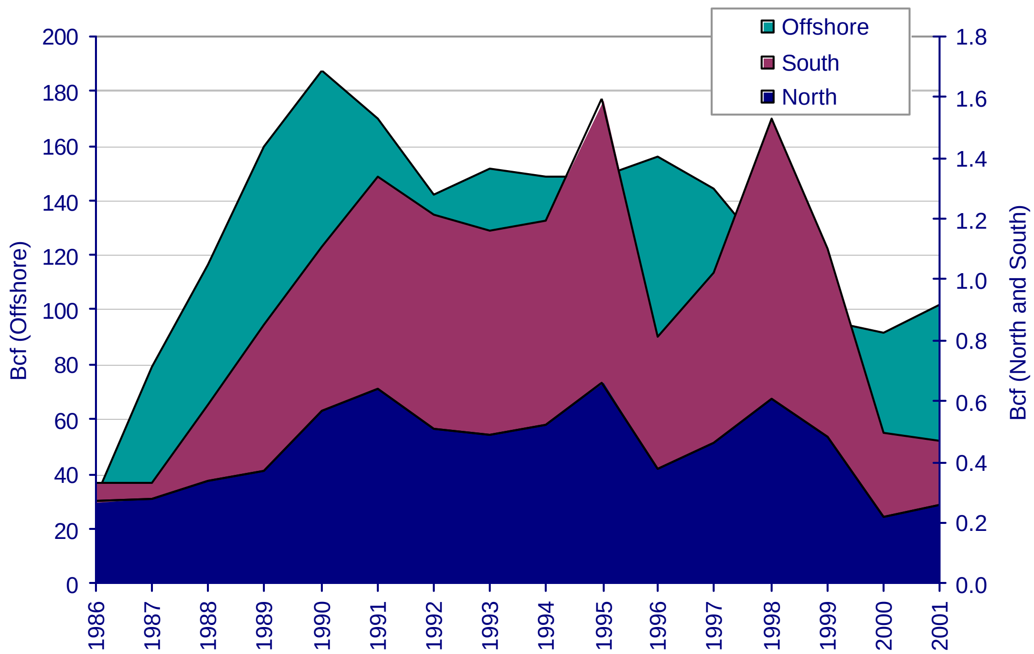

Figure 5.13 Estimated Gas Production from Unprofitable Wells on State Leases

Figure 5.13 highlights the estimated volumes of natural gas production from unprofitable wells. Like oil, unprofitable gas production from North Louisiana far exceeds the levels for the South and offshore. Unprofitable gas production in North Louisiana ranges from a low of around 223 million cubic feet ("MMcf") in 2000 to a high of close to 660 MMcf in 1995. In 2001 however, unprofitable gas production in North Louisiana had fallen to a level of about 256 MMcf, or less than 2 percent of the region's total production. Alternatively, unprofitable gas production in North Louisiana may account for only 2 percent of total regional gas production, but 46 percent of the total wells on state leases in the region.

6 BASELINE PROFITABILITY ANALYSIS OF FORECASTED PRODUCTION

6.1 Introduction

As noted earlier in the assumptions associated with this report (Section 3), no new wells or drilling activity was assumed to occur during the forecast period in which the forward looking profitability analysis was conducted. In addition, prices associated with forecast production in the baseline profitability analysis have been held constant. In later sections, sensitivities associated with fossil fuel prices will be considered. The analysis in this section concentrates on existing wells only and establishes a baseline from which various royalty relief scenarios can be considered. For purposes of the forecast period, there are 2,423 active oil wells, and 1,089 active gas wells on state leases.

6.2 Profitability Analysis – Forecast Production on State Leases

Figure 6.1 and Figure 6.2 show the annual forecast production of oil and gas on state leases, based upon the decline curve methodology discussed in Section 3; however, one adjustment to this methodology has been made and should be discussed.

As noted in Section 4, recently completed wells from about 1995 onwards have been experiencing considerably faster decline rates than their older counterparts. As noted in various places in Section 4, peak production declines for recently completed wells are somewhere in the 67 percent range, relative to earlier completed wells which hover around the 90 to 80 percent range.[10] This increase in post-peak production declines for recently completed wells has been factored into the forecasted production for wells completed after 1995.

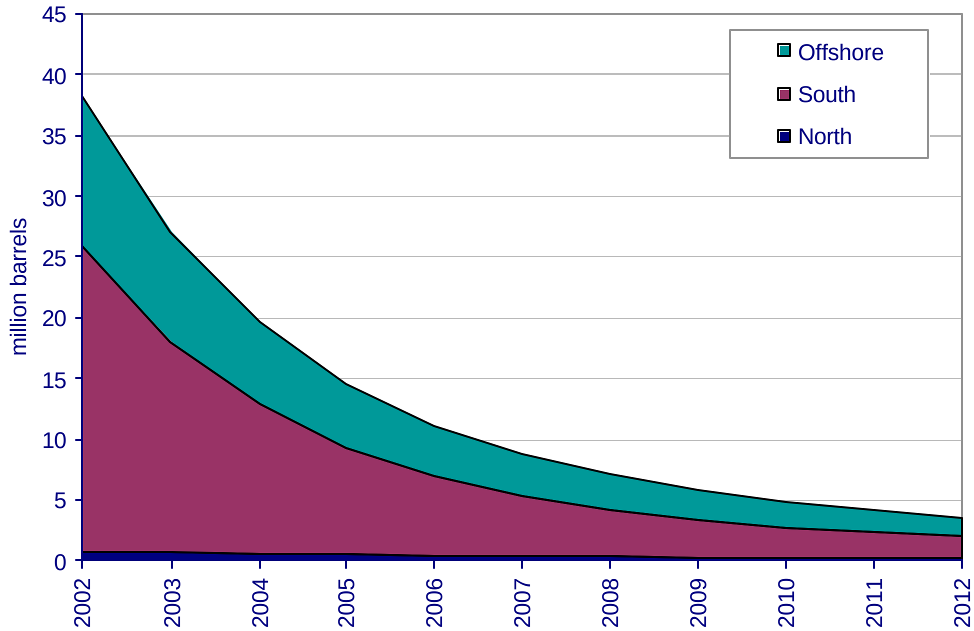

Figure 6.1: Forecasted Annual Oil Production on State Leases

As seen in both figures, forecasted production from existing wells on state leases is expected to progress along a typical decline curve. Total oil production on existing state leases is presented on Figure 6.1 and estimated to be around 38 million barrels ("MMbbls"). Forecasted oil production on state leases is estimated to fall from 38 MMbbls to a level of about 3 to 4 MMbbls between 2010 to 2012. It is important to remember that for purposes of this analysis, forecasted

[10]In other words, production in the year following a well's peak is 67 percent of the prior year's (peak) level. As was discussed and examined in Section 4, this level historically hovered around the 80 to 90 percent mark.

production is from existing wells only and does not include new production that could come on line from wells drilled during the forecast period.

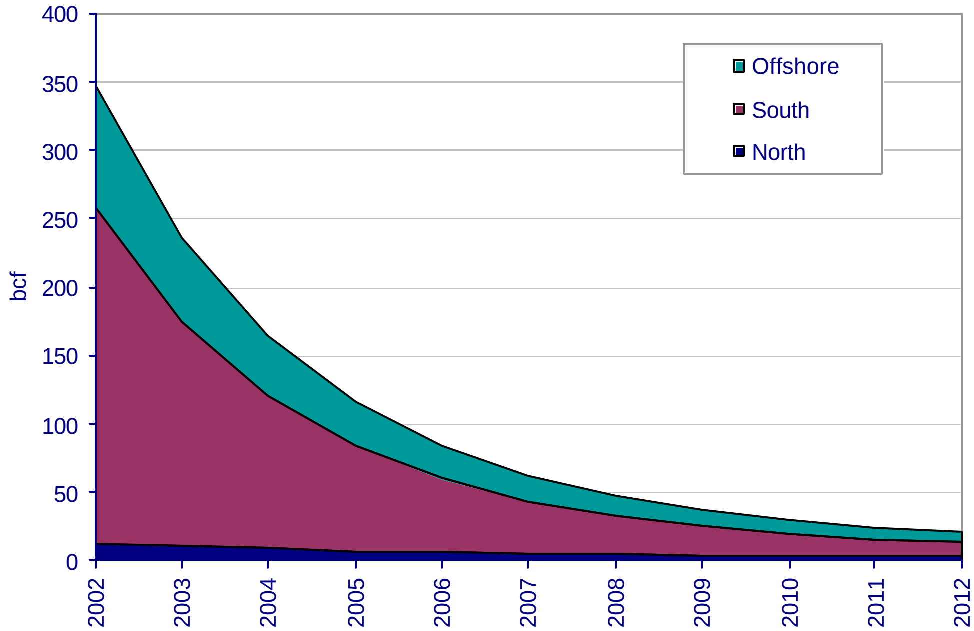

Figure 6.2: Forecasted Annual Gas Production on State Leases

Figure 6.2 shows forecasted natural gas production from existing gas wells on state leases. Gas production is forecasted to run from a high of about 346 billion cubic feet ("Bcf") in 2002 to a low of about 20 Bcf by 2012.

6.3 Profitability Analysis – Forecast Number of Wells on State Leases

Figure 6.3 and Figure 6.4 provide the estimated number of unprofitable wells on state leases for oil and gas, respectively, during the forecasted period. Figure 6.3 shows the significant growth in estimated unprofitable oil wells in North Louisiana. Percentage-wise, unprofitable oil wells in North Louisiana grow from a level of 87 percent of total wells in the region in 2002, to around 97 percent of all oil wells on state leases by 2012.

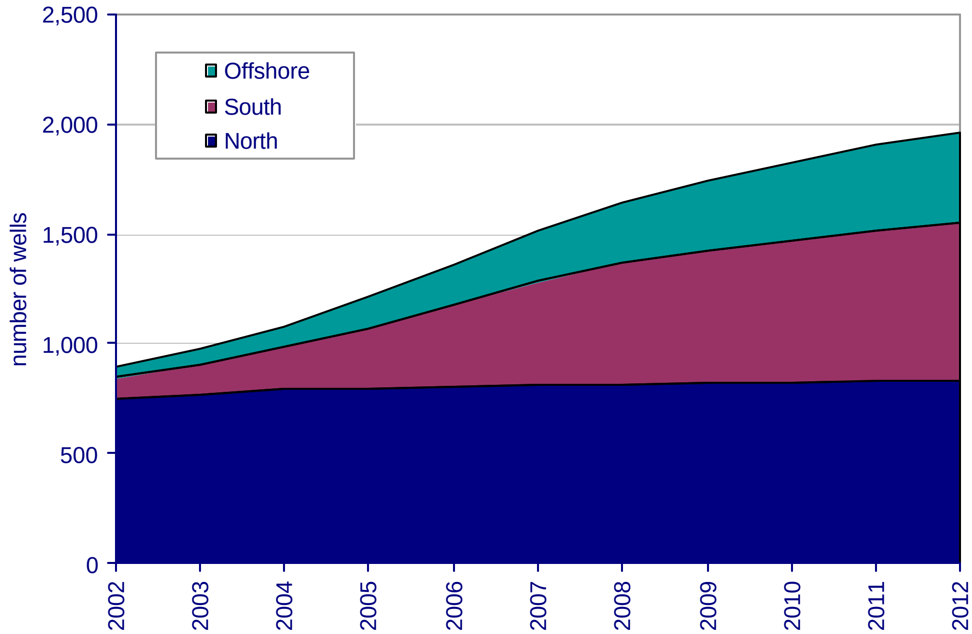

Figure 6.3: Forecasted Number of Unprofitable Oil Wells on State Leases

Unprofitable oil wells offshore and in South Louisiana follow relatively similar trends. The growth in unprofitable oil wells on state leases in both regions are relatively slow prior to 2006. After this period, the growth increases significantly to about 412 in the offshore region, and 712 for South Louisiana in 2001. Overall, the estimated number of unprofitable oil wells in South Louisiana and offshore each accounts for almost 10 percent of the active wells on state leases in each of these regions in 2002, and increases to around 77 percent (South Louisiana) and 64 percent (offshore) by 2012.

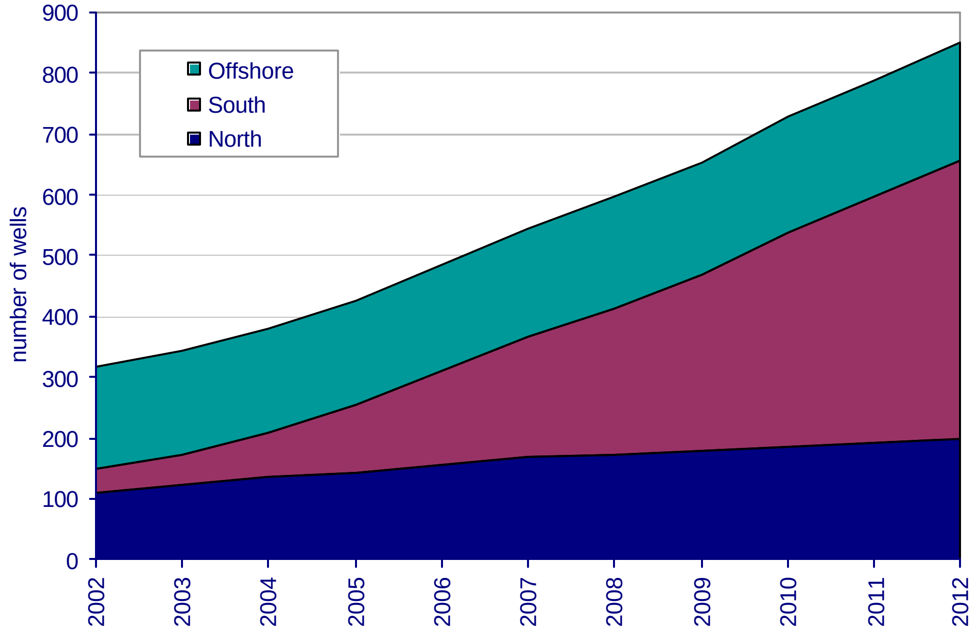

Figure 6.4: Forecasted Number of Unprofitable Gas Wells on State Leases

Figure 6.4 shows the estimated number of unprofitable gas wells on state leases during the forecast period. For North Louisiana, there is a steady increase in the estimated number of unprofitable gas wells on state leases: from about 112 to 198 from 2002 to 2012. The number of unprofitable gas wells offshore is also relatively steady throughout the forecast period and tops-out around 194 in 2012.

The number of unprofitable wells in South Louisiana increases at a more rapid rate, from 36 to 456 – over a one thousand percent increase from 2002 to 2012.

Figure 6.5 maps the estimated unprofitable wells by the year 2012.

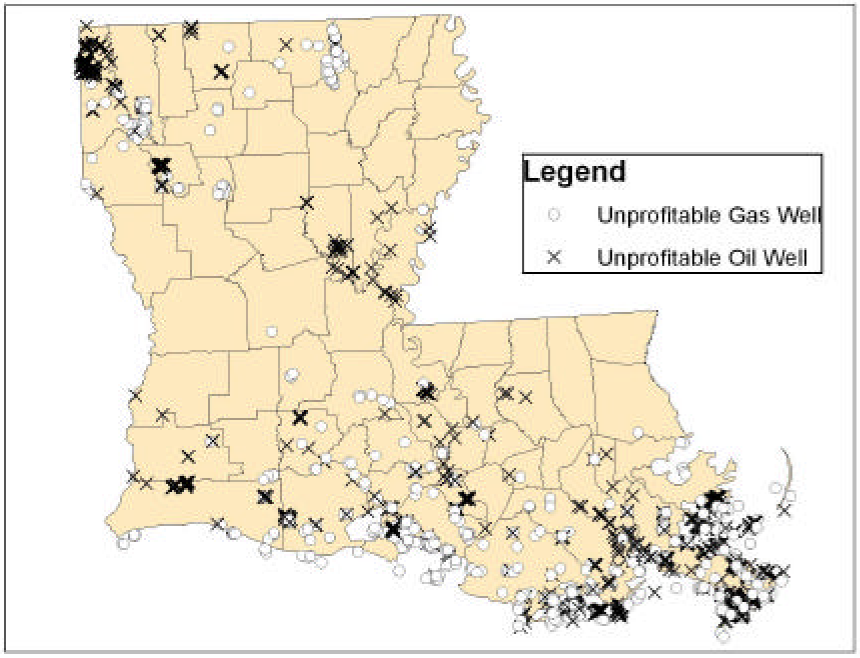

Figure 6.5: Location of Estimated Unprofitable Wells on State Leases (2012)

6.4 Profitability Analysis – Forecasted Unprofitable Production on State Leases

Figure 6.6 and Figure 6.7 present the forecasted production from unprofitable oil and gas wells. These figures can be thought of as the estimated production that could be attained if profitability were altered.

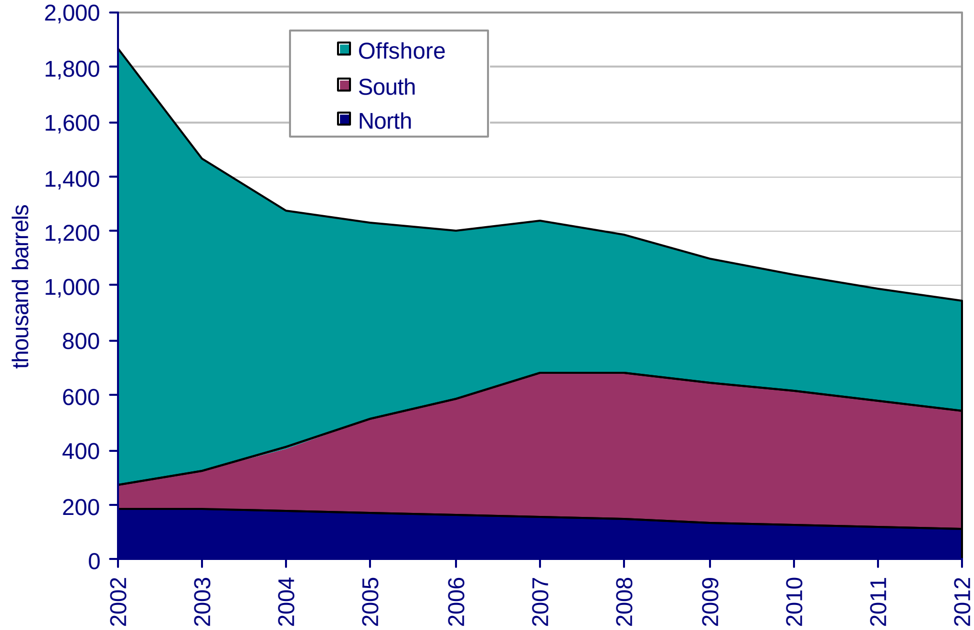

Figure 6.6: Forecasted Oil Production from Unprofitable Wells on State Leases

Unprofitable oil production in North Louisiana decreases from a level of 186 Mbbls to 113 Mbbls by 2012. From 2002 to 2007, the majority of the estimated unprofitable oil production on state leases comes from the offshore region of the state. During this period, South Louisiana's unprofitable oil production during this period also grows from almost 83 Mbbls to over 531 Mbbls in 2005. It then drops to 434 Mbbls by 2012. Percentage-wise, unprofitable oil production in the South grows from 0.3 percent of total oil production in 2002 to 24 percent in 2012.

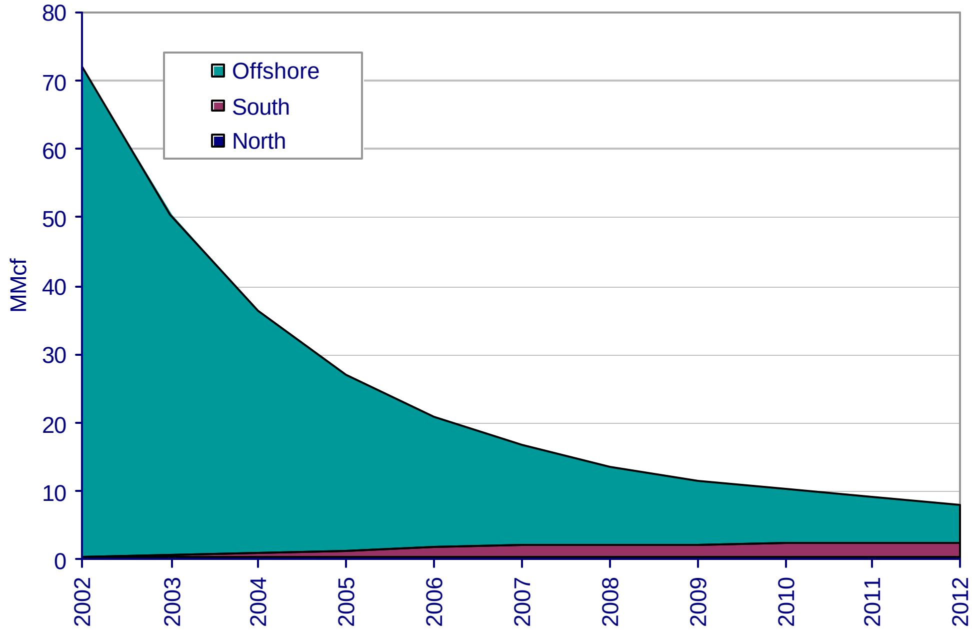

Figure 6.7: Forecasted Gas Production from Unprofitable Wells on State Leases

Unprofitable gas production on state leases has been provided in Figure 6.7. During this period, uneconomic gas production on state leases decreases from around 71 MMcf to about 8 MMcf by 2012. Most of the uneconomic state lease production during this period comes from offshore. Total estimated uneconomic production from offshore decreases from 80 percent to 78 percent of estimated total regional gas production on state leases. By 2012, the total uneconomic gas production in North Louisiana accounts for about 12 percent of total estimated gas production on state leases in the region.

7 THE IMPACT OF ROYALTY RELIEF ON BASELINE FORECASTED PRODUCTION

7.1 Introduction

This chapter examines the impacts that various ranges of royalty relief would have on oil and gas production on state leases. A 25 percent discount to the existing royalty rate was considered for sensitivity purposes. Larger discounts were not considered since they could result in lowering the royalty rate below its required 12.5 percent floor. Average royalty rates were applied to wells on state leases depending upon their age. Wells over 40 years old were given an average royalty rate of 12.5 percent. Those wells on state leases that are between 10 and 40 years of age received an average royalty rate of 18 percent. Wells completed in the last 10 years received an average rate of 20 percent.

Royalties, which enter unit costs outlined in Section 2, are reduced by 25 percent to determine: (1) whether the discount would shift any particular well from being unprofitable to profitable status; and (2) the increased production associated with wells that were made profitable as a result of the royalty discount. Lastly, this section will examine the economic impacts associated with the increased production resulting from the various levels of royalty relief outlined above.

7.2 The Impacts of A 25 Percent Royalty Discount

Figure 7.1 presents the estimated increase in profitable oil wells that could result from offering a 25 percent royalty discount on existing production. The estimated impact that royalty relief would have on each of the three regions of the state have also been presented by the various colored bars. As seen from the figure, the most immediate impact associated with royalty relief would be for wells currently operating in South Louisiana. By 2007, over 65 wells would shift from unprofitable, to profitable status as a result of a 25 percent discount on their current royalty rates.

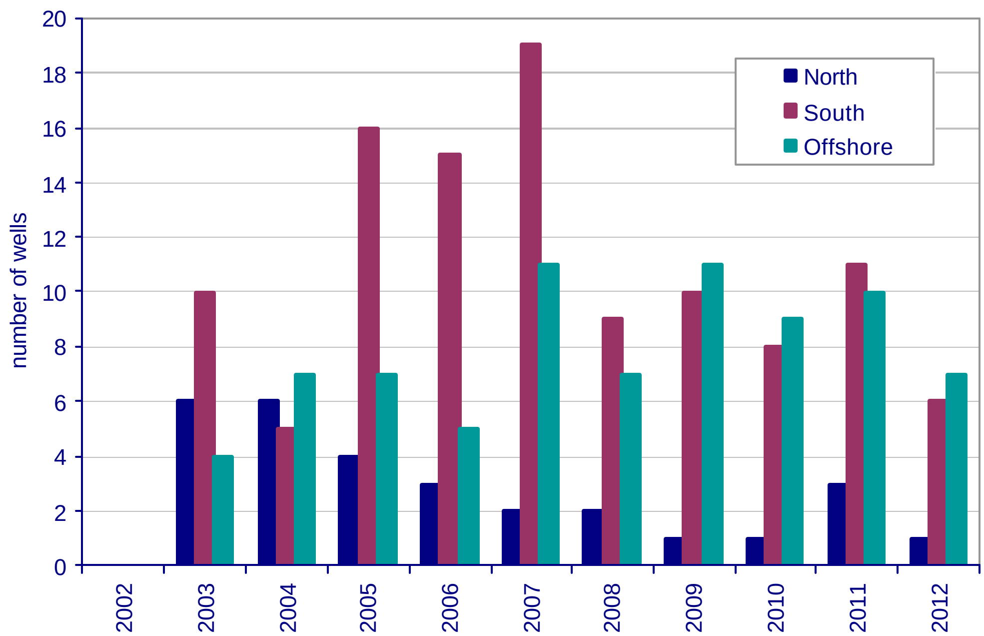

Figure 7.1: Number of Oil Wells on State Leases that Become Profitable by a 25 Percent Royalty Discount

Over the remaining years, there is a steady number of wells turning profitable because of a 25 percent royalty break from all three regions. Wells in North Louisiana tend to be the main beneficiaries. Over the entire forecast period, some 29 wells turn to profitable in North Louisiana, while 109 wells in South Louisiana, and 78 wells offshore, benefit from the royalty discount.

Figure 7.2 presents the estimated results associated with a 25 percent royalty discount on natural gas wells on state leases. The prime beneficiary of royalty relief on gas wells on state leases appears to be wells located in South Louisiana. During the forecast period, 52 South Louisiana gas wells are estimated as being able to shift to profitable status as a result of a 25 percent royalty discount. In addition, 2 Offshore and 17 North Louisiana gas wells benefit from this policy over the forecast period. Overall, however, there are very few opportunities for royalty relief to shift the relative economic status gas wells on state leases. The results would tend to indicate that under average operating conditions royalty relief would have minimal impact on gas production on state leases.

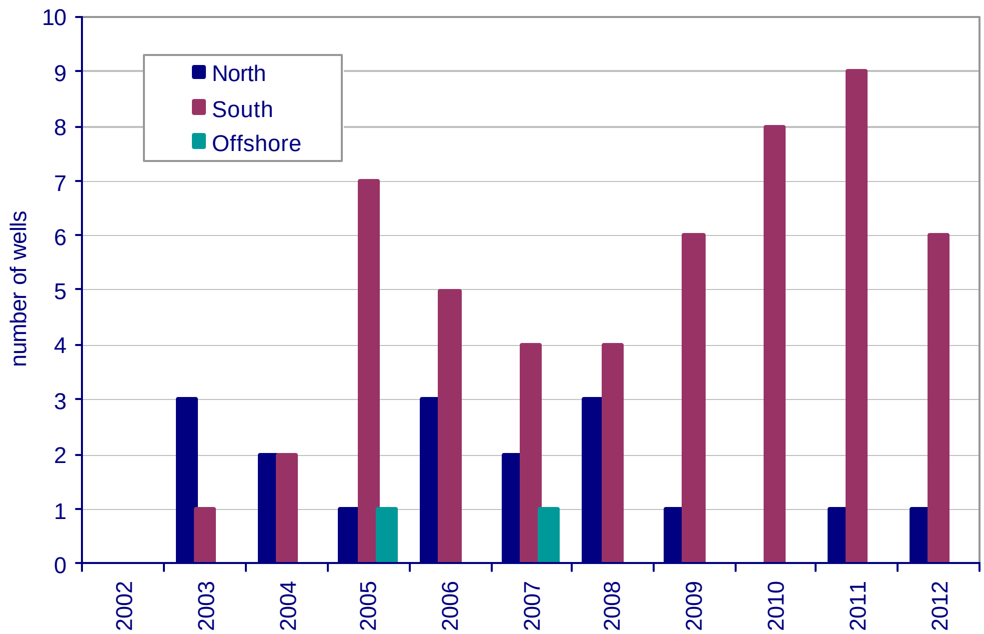

Figure 7.2: Number of Gas Wells on State Leases that Become Profitable by a 25 Percent Royalty Discount

Figure 7.3 plots the location of the wells, both oil and gas, that have been estimated to change profitability status as a result of a royalty discount. As seen from the map, there are not a large number of wells that have their profitability outlook changed as a result of royalty relief. In addition, the estimates indicate that most wells on state leases would have their economic lives extended by only one year at best.

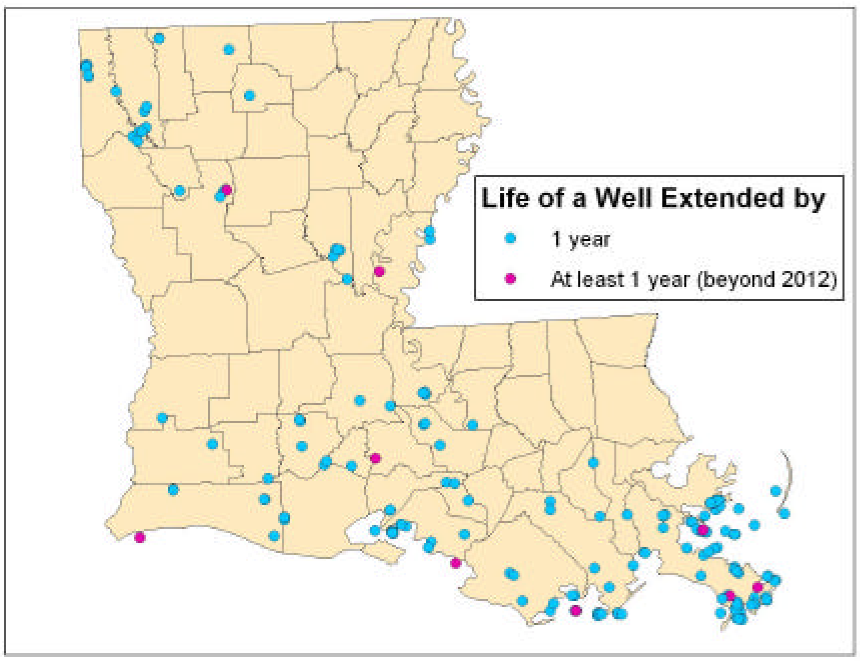

Figure 7.3: Location of Wells on State Leases that Change Profitability Status as a Result of a 25 Percent Royalty Discount

Figure 7.4 graphs the increase in production from oil wells on state leases that turn profitable as a result of a 25 percent royalty discount. As seen from the figure, the first year results in a significant increase in oil production in South Louisiana resulting from a mild degree of royalty relief. This additional production stimulated from royalty relief moderates during the period 2004 to 2007, but picks up considerably after this period. Starting in 2008, the relative benefits in production from royalty relief on state leases starts to decrease. Small additional amounts of oil production from state leases are also stimulated from a royalty discount on oil, but not in the same order of magnitude as the other two regions of the state.

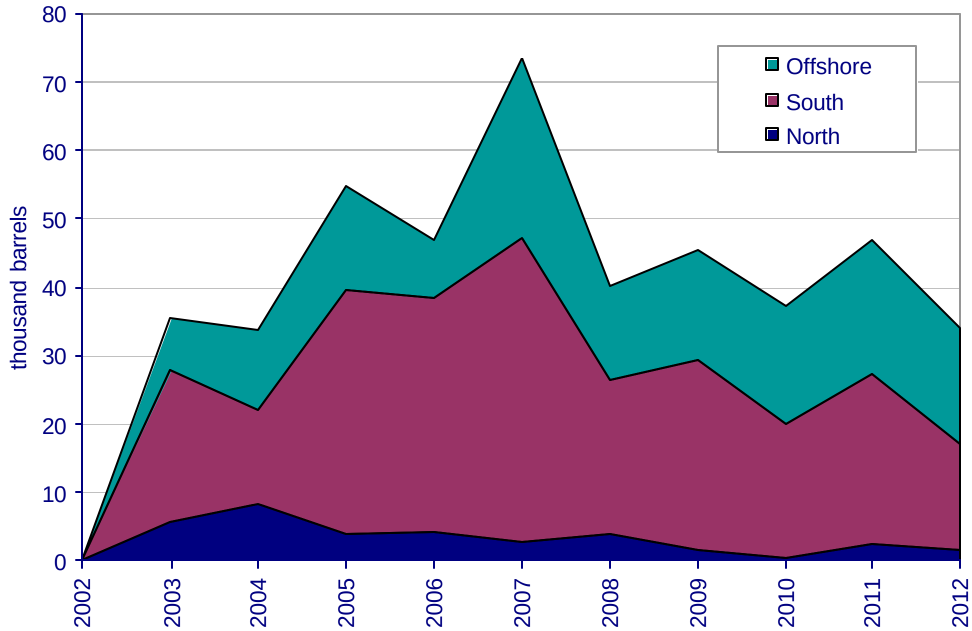

Figure 7.4: Estimated Increase in Oil Production on State Leases Resulting from 25 Percent Royalty Discount

Figure 7.5 presents the estimated increase in gas production on state leases resulting from a 25 percent discount in royalty rates. As seen from the figure, the gains in gas production, while significant in later forecast years, are slow in developing. The prime beneficiary of these discounts is clearly the gas well on state leases operating in the southern portion of the state. There are some benefits to wells producing in offshore regions as well, but these gains are restricted to a relatively tight time period between 2006 to 2009.

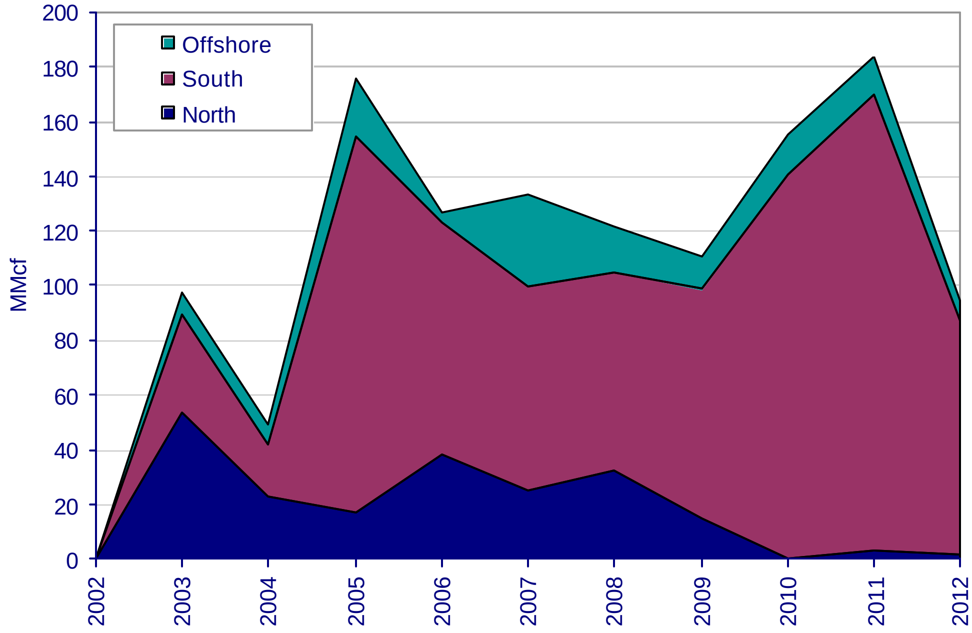

Figure 7.5: Estimated Increase in Gas Production Resulting from a 25 Percent Royalty Discount

7.3 The Economic Impacts Associated with Royalty Relief

The last analysis conducted in this report has been to examine the economic impacts associated with various forms of royalty relief discussed above. Table 7.1 presents the economic impact analysis in a number of different sub-tables. The three tables in the left hand column of the page present the economic impact estimates associated with oil production at the various royalty rate discounts. The middle column of tables presents the economic impact estimates associated with various levels of royalty relief on gas production. The column on the right hand side of the table sums the economic impacts to determine the total impact on oil and gas production from a 25 percent discount in royalty relief. The numbers presented in the table are in current dollars and have not be discounted to present value terms, nor have they been adjusted for inflation. As seen on the table, the total economic impact associated with a 25 percent royalty discount would be around $472,000. The state and local taxes resulting from this increased production would amount to about $29,440.

Table 7.1: Economic Impact from Royalty Relief

Year	Incremental Production (BOE)	Total Economic Impact ($)	State Tax ($)	Local Tax ($)	Indirect Impact on Jobs
25 Percent Discount on Royalties -- Oil					
2002	0	$ 0	$ 0	$ 0	0.00
2003	35,364	$ 198,597	$ 41,705	$ 4,951	0.98
2004	33,652	$ 188,986	$ 39,687	$ 4,711	0.93
2005	54,668	$ 307,004	$ 64,471	$ 7,653	1.51
2006	46,759	$ 262,591	$ 55,144	$ 6,546	1.29
2007	73,546	$ 413,023	$ 86,735	$ 10,296	2.03
2008	40,286	$ 226,237	$ 47,510	$ 5,640	1.11
2009	45,545	$ 255,772	$ 53,712	$ 6,376	1.26
2010	37,397	$ 210,017	$ 44,104	$ 5,236	1.03
2011	47,119	$ 264,611	$ 55,568	$ 6,597	1.30
2012	34,056	$ 191,254	$ 40,163	$ 4,768	0.94
Total	**448,392**	**$ 2,518,092**	**$ 528,799**	**$ 62,775**	**12.38**

Year	Incremental Production (BOE)	Total Economic Impact ($)	State Tax ($)	Local Tax ($)	Indirect Impact on Jobs
25 Percent Discount on Royalties -- Gas					
2002	0	$ 0	$ 0	$ 0	0.00
2003	16,889	$ 94,846	$ 19,918	$ 2,364	0.47
2004	8,456	$ 47,486	$ 9,972	$ 1,184	0.23
2005	30,278	$ 170,038	$ 35,708	$ 4,239	0.84
2006	21,921	$ 123,106	$ 25,852	$ 3,069	0.61
2007	23,010	$ 129,220	$ 27,136	$ 3,221	0.64
2008	20,936	$ 117,570	$ 24,690	$ 2,931	0.58
2009	19,116	$ 107,354	$ 22,544	$ 2,676	0.53
2010	26,852	$ 150,794	$ 31,667	$ 3,759	0.74
2011	31,635	$ 177,658	$ 37,308	$ 4,429	0.87
2012	16,294	$ 91,506	$ 19,216	$ 2,281	0.45
Total	**215,387**	**1,209,579**	**254,012**	**30,154**	**5.95**

Year	Incremental Production (BOE)	Total Economic Impact ($)	State Tax ($)	Local Tax ($)	Indirect Impact on Jobs
25 Percent Discount on Royalties -- Oil and Gas					
2002	0	$ 0	$ 0	$ 0	0.00
2003	52,253	$ 293,443	$ 10,973	$ 7,315	1.44
2004	42,108	$ 236,472	$ 8,843	$ 5,895	1.16
2005	84,946	$ 477,042	$ 17,839	$ 11,892	2.34
2006	68,680	$ 385,698	$ 14,423	$ 9,615	1.90
2007	96,556	$ 542,243	$ 20,277	$ 13,518	2.67
2008	61,221	$ 343,807	$ 12,856	$ 8,571	1.69
2009	64,661	$ 363,126	$ 13,579	$ 9,053	1.78
2010	64,249	$ 360,811	$ 13,492	$ 8,995	1.77
2011	78,754	$ 442,270	$ 16,538	$ 11,026	2.17
2012	50,351	$ 282,760	$ 10,574	$ 7,049	1.39
Total	**663,779**	**3,727,671**	**139,394**	**92,929**	**18.32**

8 CONCLUSIONS

The purpose of this report has been twofold: first, to examine the historic and recent trends in Louisiana oil and gas production with an eye for identifying what may appear to be structural changes that could have implications for resource development and energy policy in the state, and second, to examine and estimate the implications that a royalty relief program may have on state production and the ongoing economic benefits of oil and gas activities on state leases. The analysis in this report was limited to existing production. No new wells were assumed to be drilled during the forecasted analysis period (2002-2012).

Since cost information on specific operations is usually proprietary, this study relied upon publicly available cost data compiled by the U.S. Department of Energy. This cost information is based upon average conditions in the producing basins examined by the DOE. As such, the estimates provided in this report may be conservative since in many ways the cost information only represents average operating conditions and not the extremely challenging cost environment many marginal operators face. Nevertheless, a good faith attempt has been made to adjust the reported cost information to reflect the challenges marginal operators may have in recovering a number of relatively fixed costs over small production volumes.

The profitability forecasts for oil and gas production from existing state leases that are included in this analysis indicate that a large number of wells, accounting for a very small amount of production, could become unprofitable over the next decade. These results assume that there are no technological innovations that could change the relative economics over the next decade. In addition, prices were held constant at their 2002 level.

Introducing royalty relief on state leases, in the form of a 25 percent discount to the existing royalty rates, would shift a small number of wells and production to profitable status. The estimates provided in this report indicate that, at most, the Office of Mineral Resources ("OMR") would probably have 40 applications in any given year for royalty relief should the Mineral Board promulgate a rule of this nature. Results included in this analysis also indicate that there would be some additional economic benefits associated with a customized or case-specific royalty relief program. These benefits, however, are relatively small and would sum to less than a half million dollars in total economic output over the next ten years.

A limited program that was initiated on a "case-by-case" basis would be necessary in order for the net benefits of such a program to remain positive. Here, a "case-by-case" program would require an OMR review of each request for royalty relief individually, and offer relief only on a showing that it would result in benefits to the state.

A broad program of royalty relief would be considerably costly to the state. For example, if the Mineral Board were to offer a broad 25 percent discount to all active leases in 2002, the State would loose some $57 million in royalty revenues, while only gaining roughly $225,000 in increased royalty revenues from unprofitable production, as well as the direct, indirect, and induced economic benefits that results from that production. Hence the net benefits would be negative, and such a broadly applied program would result in an overall loss to the state.

The reason for the significant revenue losses to the state is an example of a classic “free rider” problem in economic theory. In this case, a broadly-defined royalty relief program would not discriminate between profitable and non-profitable operations. Profitable operators would receive substantial benefits without impacting overall output. Thus, the state would incur all the costs of a broadly applied program (i.e., decreased royalty revenues) with a small level of economic benefits (i.e., increased economic impacts).

Based on the information and research conducted in this report, a case-by-case program should be implemented with the following features:

- Relief should be offered on well-specific profitability. Only wells which are unprofitable, or near unprofitable status should be considered;

- Well-specific cost information and documentation should be provided in any application for royalty relief; and
- Any request should show that royalty relief applied to a particular well would maintain that well's profitability for at least one year.
- The preceding recommendations are based on existing production and are not associated with any royalty relief proposals tied to new drilling.

Perhaps one of the more dramatic conclusions found in this report is one that was, at least originally, found in investigating a peripheral issue associated with recent trends in decline rates on state leases and overall Louisiana oil and gas production trends. The analysis included in this report corroborates a number of concerns and theories regarding oil and gas production in maturing basins like Louisiana. Namely, that production in many maturing areas are on a virtual supply "treadmill."

This treadmill theory posits that current production is being maintained by a combination of aggressive drilling and increased average well productivity. These gains, however, come at a significant cost: dramatically increased decline rates that deviate considerably from historic norms. In such an environment, the existing supply disposition of a given region (or state) can only come from continued drilling. If drilling were to come to a halt, annual production volumes would face serious deterioration.

The implications of this treadmill hypothesis for Louisiana are clear. If the State cannot maintain its current level of drilling, future production, as well as state revenues from royalties and taxes, could falter. As seen in Figure 8.1, the recent decrease in the number of active drilling rigs in Louisiana, relative to other oil and gas producing states, adds even more reason to be concerned about this recent trend.

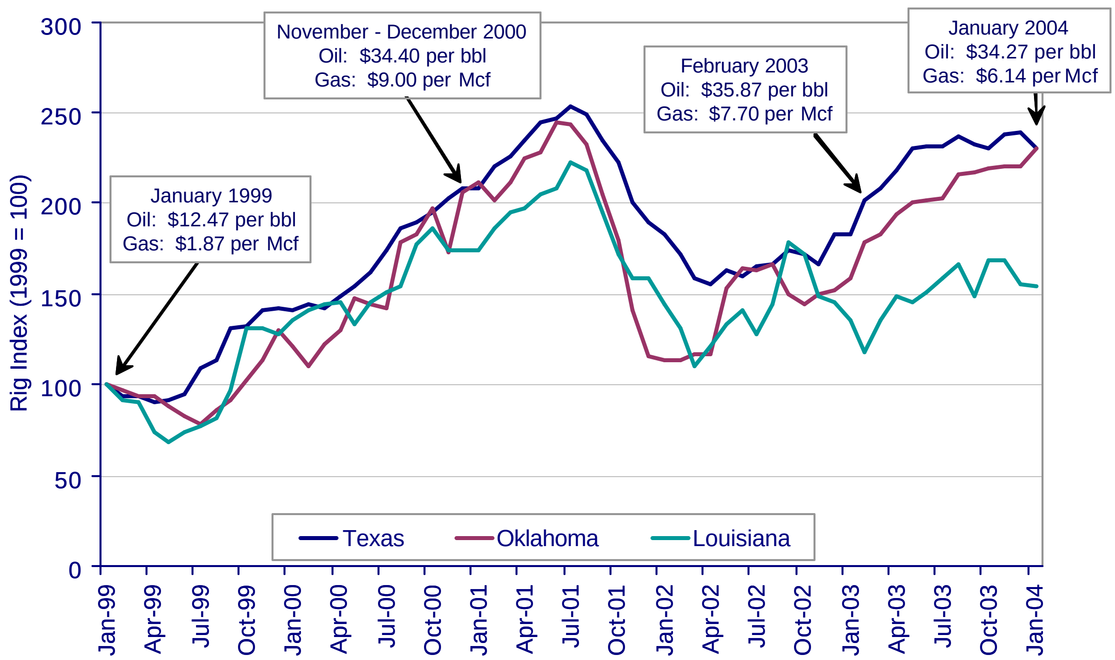

Figure 8.1: Monthly Rotary Rig Count in Louisiana Relative to Other States