

Assessing the Impact of High Resource Prices and Alternative Royalty Regimes on Offshore Gulf of Mexico Production

Lee O. Upton, III

Principal

Innovation & Information Consultants, Inc.

696 Brechin Drive

Winter Park, FL 32792

Ph: (407) 875-3870

loupton@iic-inc.com

Corporate Headquarters:

72 Junction Square

Concord, MA 01742

Ph: (978) 369-0550

Fax: (978) 369-8815

I. Introduction

Resource (oil and gas) prices and fiscal policy initiatives are two important drivers of offshore petroleum activity in the Gulf of Mexico. The ability to effectively quantify the impacts of changes in price and fiscal policy on future exploration, development and production provides valuable information for exploration companies, field operators, policy makers, academics and other interested parties. Pursuing a potential hydrocarbon resource in the federal offshore waters of the Gulf of Mexico is a capital-intensive endeavor and requires individuals and companies to make numerous assumptions and decisions throughout the exploration, development and production process. Decisions on whether to drill new exploratory wells, invest capital in recent discoveries, focus on additional infrastructure in currently producing fields, or abandon fields that are no longer profitable, depend on an economic assessment of the project, including the short-term profitability and long-term viability of each specific project.

In addition to the significant rise in hydrocarbon prices, the Federal government continues to pursue alternative royalty regimes designed to simultaneously stimulate offshore oil and gas exploration and ensure royalty revenue collection from offshore oil and gas production. Litigation concerning the applicability of price thresholds on offshore is likely to result in the significant loss of royalty revenue for leases issued under the Deepwater Royalty Relief Act (“DWRRA”) implemented in 1996. As a result of the rapidly changing political, economic and legal changes within the petroleum industry, industry personnel and policy makers need to recognize the impact of potential changes in the operating environment.

To assess potential impacts, a differential analysis is effective in quantifying variations in projected offshore exploration, development and production activity when employing varying assumptions concerning projected resource prices and alternative royalty regimes. Typically, an increase in resource price and/or implementation of royalty relief programs will stimulate leasing activity and subsequent exploratory well drilling in the Gulf of Mexico. As a result, improved field economics resulting from high resource prices and a favorable regulatory environment will lead to the development and production of new resources more rapidly than in situations with low resource prices and/or the absence of federal policy initiatives designed to stimulate offshore exploration, development and production activity. Empirical evidence shows that benefits of federal policy initiatives tend to apply mainly to marginal fields, which might not ordinarily be developed under prevailing economic conditions. Furthermore, confusion surrounding the applicability of price thresholds and the evolution of potential alternative royalty regimes raises questions about what the future might hold for offshore oil and gas exploration, development and production activity in the Gulf of Mexico.

The remainder of this paper focuses on assessing forecasts of offshore oil and gas activity under varying price and policy scenarios. The analyses rely on a long-term Gulf of Mexico offshore forecasting model (EDP Model) developed by Innovation & Information Consultants, Inc. (IIC, Inc.) for the Minerals Management Service (MMS).¹ The model is an expected value simulation requiring user specification of key economic and policy inputs. Section II of this paper contains a brief overview of the EDP model, including a discussion of the underlying theoretical forecasting approach and a review of several key assumptions which influence the long-term forecasts. Section III covers recent trends in resource price and federal royalty policy, and highlights potential forecasting scenarios to measure differences in key EDP output variables. Section IV provides detailed quantitative results of different forecasting scenarios

¹ For a complete technical discussion of the EDP methodology, see P.K. Ashton, R.A. Speir, and L.O. Upton III. Modeling exploration, development and production in the Gulf of Mexico (Herndon VA: U.S. Department of the Interior, Minerals Management Service, Environmental Studies Program, 2004). OCS Study MMS 2004-018. Volume III of the study is the technical appendix. Although the EDP model has undergone several updates, the underlying theory remains similar to the original model design.

and indicates the potential differential impact between forecasts using different future price and policy assumptions. Section V assesses potential policy and industry implications. Section VI and VII provide references and additional resources.

II. EDP Model Overview and Research Methodology

The development of the EDP model is largely attributable to a desire to incorporate economics with a traditional discovery approach in order to forecast future oil and gas exploration, development and production activities over a forty-year time horizon. Primary considerations included implementing significant flexibility to allow adaptation of the EDP model to dynamic changes occurring in the Gulf of Mexico operating environment. Within the Gulf of Mexico, the model user can define boundaries of different geographic areas and regions relevant to how they wish to define the existing geologic division of resources and the investment and policy decisions that are applicable to these regions.

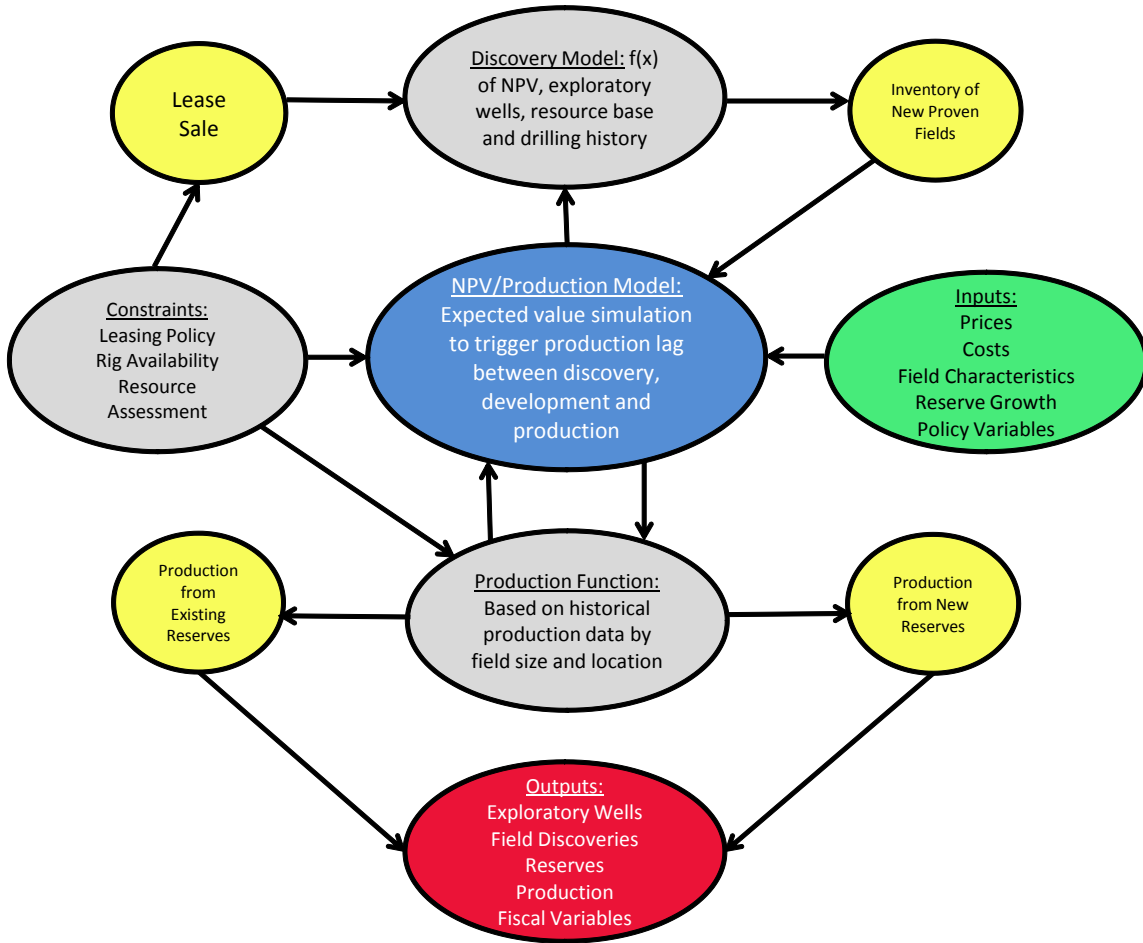
The EDP model employs a field-level approach, which provides a far greater level of detail than that used in many existing forecast models. Employing a field-level approach relies upon designing and implementing economic, discovery, development and production algorithms specifically tailored to oil and gas fields of different sizes. The current model orientation divides the Gulf of Mexico into twenty-one different geographic areas, based on three planning areas (Eastern, Central and Western) and seven water depth categories (0-60, 60-200, 200-400, 400-800, 800-1,600, 1,600-2,400, and greater than 2,400 meters).² Each discovered and undiscovered field is allocated to the specific area where the majority of the field resources are located.

An inherent advantage of allocating fields (both discovered and undiscovered) to specific geographic areas is the ability to incorporate different assumptions specific to the operating conditions prevalent in each area. For example, the cost to drill an exploratory well in the Central Gulf of Mexico in a water depth of 130 meters is often significantly different than the cost to drill an exploratory well in a water depth of 2,000 meters. The specific location of the exploratory well involves consideration of a number of decisions, including the type of drill rig, estimated drill depth, etc., each of which requires different economic assumptions concerning cost, timing and rig availability, among others. Similar differences exist in economic and regulatory assumptions (e.g., royalty relief) based on the geographic allocation of resources in the Gulf of Mexico. The EDP model incorporates these differences by applying a field-level approach distinguished by user-defined geographic areas.

The EDP model creates forecasts by modeling the different phases of offshore hydrocarbon extraction. The first phase involves drilling wildcat exploratory wells in hopes of discovering new fields. The second phase involves developing the newly discovered fields, including subsequent in-field drilling and the addition of necessary infrastructure. Finally, the third phase involves production of oil and gas reserves, as well as monitoring additional drilling and infrastructure needs. Intertwined among these three phases is the model's field-level economic estimation process, which ties each phase to the underlying economic assumptions. Finally, each phase is affected by the different regulatory and capital constraints faced in offshore Gulf of Mexico resource extraction. A general schematic (Figure 1) illustrates the various model components as well as some of the constraints encountered in the forecasting process.

² Recent revisions to royalty relief policies warrant an update to the EDP model, breaking out the 1,600 through 2,400 meters region into two distinct groups, 1,600-2,000 meters and 2,000-2,400 meters. However, for the purposes of this paper, the forecasts are oriented along the current EDP model configuration.

Figure 1 – Overview of EDP Model Structure



The central feature of the EDP model is the economic component (the blue circle in Figure 1), which is a net present value (NPV) discounted cash flow (DCF) model that calculates the economic value of developing and producing newly discovered fields of varying field size. The use of field-level economics in the EDP model is not unique in oil and gas modeling per se, but involves a level of detail that far surpasses many existing models. The field-level NPVs are the primary component of the model's simulation of the producer/explorer's decision making process regarding when and where to explore (drill) for resources. There are several assumptions which feed into the NPV calculation, including estimating petroleum prices, the relevant field size, annual production volumes, drilling, development, infrastructure and operating costs, as well as the appropriate discount rate. This paper focuses primarily on analyzing changes in forecast results (outputs) based on changes made to the input assumptions contained in the green circle in Figure 1. These include assumptions about resource prices, costs (e.g., capital and operating expenditures), and policy variables related to federal royalty regimes.

During a model simulation, the economic component of the EDP model performs an annual cycle through all field sizes, specific to water depth category and planning area, and computes revenue and costs before discounting the cash flow streams back to present value. In its simplest form, revenue represents the price of the commodities produced (oil, gas, NGLs) multiplied by the volume of each commodity. The revenue computation depends on a number of financial inputs including current and future oil and gas prices, and the royalty regimes and tax rates in place. The decision maker (namely the one computing the net present value) makes an assumption regarding the future expectation of price over the discounted cash flow

period. This is different than what the actual oil price is, determined annually by the user in the model. Thus, the calculation of net present value in each model year does not know what the user has entered for the next model year's actual price.

The revenue computation deducts computed royalty and tax payments to determine the net revenue stream over the life of the field. Royalties may be set at a fixed rate and the model captures the effect of suspension volumes on existing production based on deepwater relief. Effective handling of different royalty relief scenarios is considered by allowing the user to modify the model to account for continuing relief (suspension) volumes as well as other modifications to royalties such as variations in the rate by water depth. In addition, the EDP model allows price threshold specification to determine whether potential royalty relief is "lost" in a case where resource prices exceed specified price thresholds.

The cost component of the EDP model reflects a time series behavioral simulation model of exploration, development, and production activity. The objective of the cost component is to model these activities, recognizing that the costs of each activity will vary depending on several key factors including: water depth, drilling depth, field size, drilling rig type (function of water depth), number and type of platforms and number of slots per platform/structure (function of water depth, field class), drilling success rate, and number of development and producing wells. The costs relating to exploration, development and production activity in the Gulf of Mexico are driven by choices, technology, and the expected size of the prospect. The EDP model attempts to simulate those choices that are most consistent with current practice and projections of future technological options.³

The two key inputs in the current research involve resource price and federal policy initiatives. Changes in these inputs directly influence the field-level economic through revisions to the NPV calculated in the DCF model. For example, as resource prices increase, we expect that field-level net present value will also increase. Figure 2 illustrates the influence of price⁴ on the net present value calculation for fields of different sizes⁵ in two distinct geographic areas. The dark blue line represents a size 11 field located in the Central Gulf of Mexico between water depths of 800 and 1,600 meters. The red line represents a size 8 field located in the Central Gulf of Mexico in a water depth in excess of 2,400 meters. The difference in the size of field influences both the revenue and cost components of the NPV calculation as the additional drilling and infrastructure needs for the larger field lead to a lower NPV than the smaller field at lower prices. However, the larger resource base will lead to higher NPVs at higher prices as the increase in volumes will subsequently lead to higher revenues after the initial drilling and infrastructure is in place.⁶

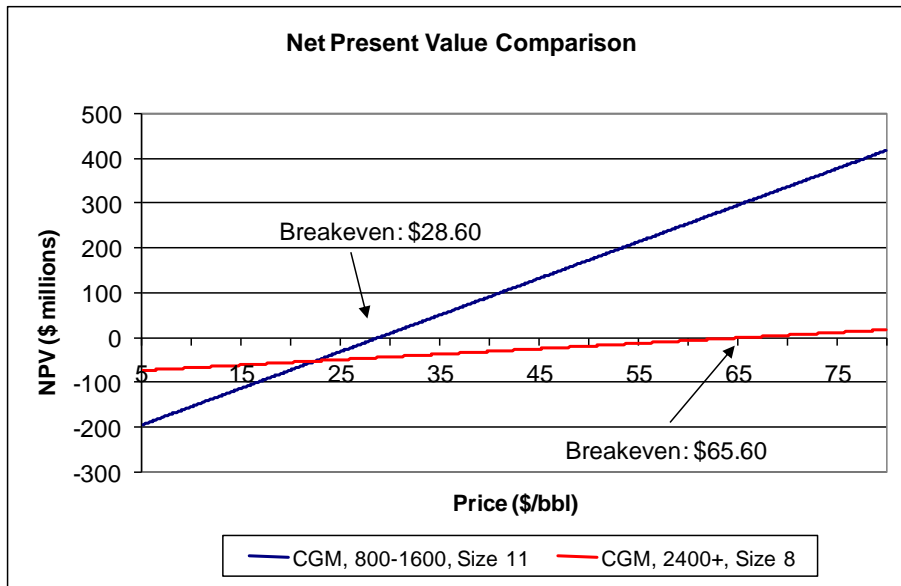
³ A key factor in updating the EDP model is the periodic reassessment of cost equations based on the aforementioned variables. In a recent model update, IIC, Inc. revised several key cost equations based on changes in observed capital and operating costs for Gulf of Mexico oil and gas exploration, development and production activity.

⁴ Price refers to the price of a barrel of oil. Figures 2 and 3 employ a static gas to oil price relationship and the model will compute the gas price (and subsequent revenues) based on this relationship. However, the model allows the user to override this static relationship by selecting different oil and gas prices in every model year.

⁵ The USGS classifies fields based on the size of the total reserves located within the field. Boundaries (in mmBOE) for each field class (1-25) are given by the range $0.03125 * 2^{(n-1)}$ through $0.03125 * 2^n$.

⁶ The different slopes of the two lines represent the fact each field has a different production profile and different timing associated with placement of infrastructure and ongoing operating expenses, driven by field size and location factors.

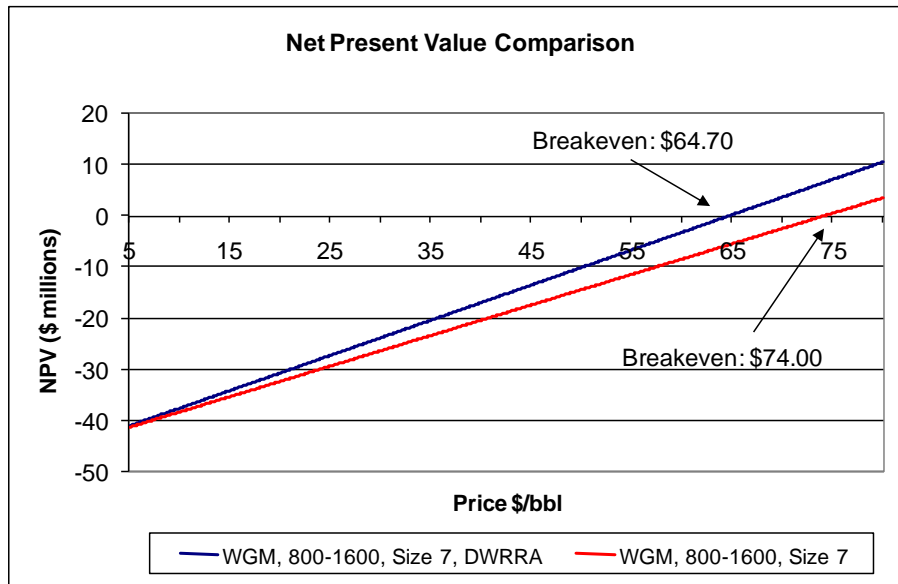
Figure 2 – Field Level Economics by Field Type at Different Resource Price



Field level economics (i.e., field profitability) are a direct input into the exploration process and are the primary means by which the model selects an area to explore and discover new fields. The difference in breakeven prices represents the decision point for operators and producers. A discovery of a size 8 field in the Central Gulf of Mexico, in a water depth in excess of 2,400 meters, will not be profitable under current economic conditions and assumptions unless the price exceeds \$65.60. However, if the model discovers a field of this size due to exploratory drilling, then the field will be placed in a holding queue. Then, at the beginning of each model year, the model will reassess the NPV under current, model year economic conditions to determine whether the field becomes profitable given the new information or changes in operating landscape.

A second input assumption that directly affects the NPV calculation is the use of federal policy initiatives to influence the revenue component of NPV calculation. For example, the implementation of royalty relief will lead to higher NPVs at equivalent prices since the producer will generate higher revenues by avoiding royalty payments. Figure 3 illustrates the difference in the NPV computations for a size 7 field located between 800 and 1600 meters in the Western Gulf of Mexico under two distinct royalty regime assumptions.

Figure 3 – Field Level Economics Including Royalty Relief



The solid blue line represents the NPVs when varying initial resource price with 87.5 million BOE in royalty relief consistent with the DWRRA. The red line is a similar calculation but under a royalty regime that prohibits any royalty relief for this field size, water depth and planning area. There are two notable observations in Figure 3. First, royalty relief leads to a higher NPV at similar prices. Second, the effect of royalty relief leads to a lower break-even price which indicates that field development and production can occur under less favorable economic conditions (e.g., lower resource prices.)

The use of field-level economics influences each stage of the exploration, development and production process. Exploratory well drilling,⁷ spurred by both historic and expected field profitability, is the first step in the process of finding undiscovered resources. The exploration process begins with a determination of the exploratory well demand for each geographically-defined area in the Gulf of Mexico.

Since the mid-1970s, Gulf of Mexico exploratory well drilling has shown a pattern of responsiveness to oil and gas price changes, however the relationship has not been stable. The number of wells drilled each year tends to increase with rising prices and decrease with falling prices after some delay. Standard statistical procedures produce relationships that explain little of the year-to-year variation in drilling due to variations in the length of the lag period. The EDP model expands beyond a typical oil/gas price lagged control system, electing to determine exploratory well demand in response to yearly field production economics over a multi-year historic period. Establishing the exploratory well equations depends on a series of assumptions:

- Oil and gas companies react at the model area level to both the possibility of future profitable discoveries and to the values of past discoveries by increasing or decreasing exploratory drilling in an area.
- The drilling reaction in any given year is the result of the cumulative effects of fields discovered and the possible future discoveries in multiple past years, not solely the prior year.

⁷ The wells that discover fields in the EDP model are “wildcats” in the purest sense, as they discover only new fields, not reservoirs in existing fields.

- Historic data and anecdotes from industry trade press suggest that the industry awareness of the value of discoveries tended to occur a few years before the MMS published initial field size estimates.
- The full size of the field discovery is usually not known immediately; rather the field tends to “grow” in accordance with the MMS reserve appreciation methodology.⁸

IIC, Inc. developed exploratory well equations where the expected exploratory well demand is a function of the net present value of discovered fields and the net present value of expected discoveries. Exploratory well equations were fitted using an optimization procedure that minimizes the sums of the squares of the yearly differences between exploratory wells produced by the drilling equations and actual historic drilling.⁹

The EDP model handles field discovery based on the traditional discovery model originally developed in the late 1950s by J.J. Arps and T.G. Roberts.¹⁰ Arps and Roberts found that the number of field discoveries could be reliably expressed as an exponential function of cumulative “wildcat” wells. Applying this general methodology, a search coefficient can be established that will dictate the annual field discoveries based on exploratory well drilling. The search coefficients for each USGS class size were determined on a geographic area basis by analyzing historical field discovery and exploratory well drilling, and relying on MMS estimates of the total number of fields. Expected discoveries are then forecasted based on the search coefficient, the annual well demand, cumulative field discoveries and the total number of fields that exist in a particular area.

In addition to stimulating exploratory well drilling and subsequent new field discovery, the economic component of the model handles the decision whether to develop newly discovered fields based on field economics (net present value) specific to each new discovery. Once the field is “discovered,” the development and production process only commences if the owner/operator expects a positive return on investment.

To simulate the development, delineation, and subsequent in-field exploration process, fields’ proved reserves grow each year. This reserve growth will continue at an exponentially declining rate for 50 years, as defined by the MMS in its National Assessment reserve appreciation methodology,¹¹ unless constrained by rig availability. The final “phase” of field maturity is the production phase, which begins once there is sufficient infrastructure in place. The EDP model relies upon a standard production function to forecast annual, field-level oil and gas production. Annual production is defined as a percentage of the annual estimate of remaining reserves. As fields age, the remaining reserves estimate is both reduced by the cumulative production and increased by reserves added due to in-field reserve growth.

The EDP model incorporates reserve growth by requiring consistent in-field drilling of both production and non-production wells as the field ages. If all in-field well requirements are met for a given field, then the reserves added will equal the difference between this year’s unconstrained reserve estimate and last year’s reserve estimate. Rig constraints represent one situation where in-field well requirements are not met. In the event insufficient rigs are available to drill needed wells, we observe a reduction in the amount of in-field reserves discovered, leading to a reduction in the amount of production.

⁸ G.L.Lore et al. 2000 assessment of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic OCS as of January 1, 1999 (Washington, DC: U.S. Department of the Interior, Minerals Management Service, 2001). MMS 2001-087

⁹ For a complete discussion of the exploratory well fitting process, see Ashton, Speir and Upton, op. cit.

¹⁰ “Economics of drilling for cretaceous oil on the east flank of the Denver-Julesburg Basin.” Bulletin of the American Association of Petroleum Geologists. (November 1958).

¹¹ See Lore, op. cit.

Any discussion of an offshore oil and gas forecasting model must consider the different capital and regulatory constraints faced by operators in the Gulf of Mexico. Foremost among these constraints are the availability of drilling rigs and leasing constraints due to federal regulation. The EDP model handles possible rig constraints using an internal algorithm that allocates rigs to different geographic areas based on a preference matrix according to the annual rig count by rig type. For example, it is unlikely that a jack-up rig would be employed in the deepwater region of the Gulf of Mexico, and the model would not allow such an occurrence. An insufficient number of rigs needed to satisfy the exploratory and in-field well demand will result in a drilling constraint for the particular model year. The constraint restricts the number of wells drilled, leading to reduced exploration and/or production activity.

Currently, federal leasing programs limit the leasing activity in the Gulf of Mexico. The MMS holds annual lease sales for the Central and Western Gulf of Mexico. Until recently, Eastern Gulf of Mexico sales were limited in scope and frequency. The model employs a lease drilling constraint designed to limit the drilling activity in Gulf of Mexico areas where leasing is prohibited. Therefore, annual exploration activity in these regions may be significantly less than what might otherwise be expected with unconstrained area-wide leasing. Long-term impacts include a reduction in the number of exploratory wells, fields discovered and oil and gas production.

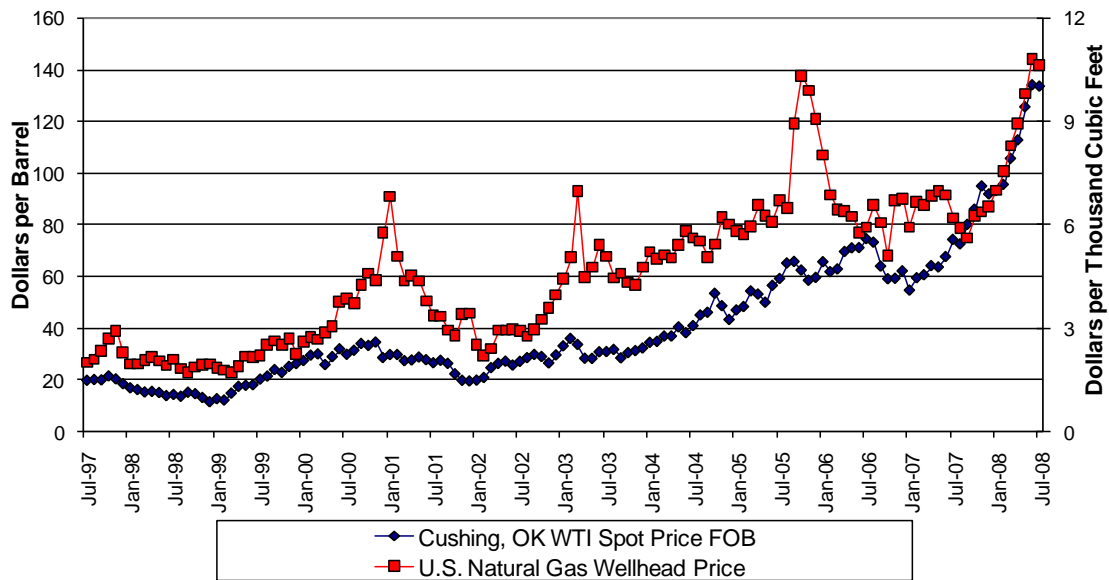
One external model constraint is the availability of quality information on field discoveries and resource estimates. For example, the most comprehensive updated MMS assessment of undiscovered resources (e.g. specific field sizes by geographic area) dates to 2004. As a result, the first “model year” in the current EDP model is 2005 and the forty-year forecast cycle runs from 2005 through 2044. Having a few years of overlap between the forecast period and actual history provides an opportunity to ensure proper calibration between initial model year output estimates and actual data (pending availability). One example involves examination of forecast production from 2005 through 2007 versus actual production data reported by the MMS.

The flexibility of the EDP model allows us to investigate differences in forecasts based on changes in economic and regulatory assumptions. The research results presented in this paper result from a differential analysis of an expected value simulation of offshore Gulf of Mexico exploration, development and production activity over a forty-year time period under different economic and regulatory assumptions. In essence, the analysis measures the incremental differences we might expect from changes in resource prices and royalty regimes versus base forecasts. The objective is to quantify the potential forecast differences in relation to economic and policy decisions. Given the significant number of levers in the EDP model, I elect to focus solely on resource price, cost escalation and royalty regimes for the current research.

III. Recent Trends

One of the key assumptions regarding forecasting oil and gas exploration activity involves expectations of future resource prices. In the five year period between July 1997 and July 2002, the average spot price of WTI was \$22.45 per barrel, with a low of \$11.35 and a high of \$34.42. However, in the ensuing five year period, the average WTI spot price increased to \$62.60 per barrel, with a low of \$28.31 and a high of \$133.88. We observe similar escalation in the price of natural gas, including recent dramatic increases in both oil and gas prices over the past 16 months. Figure 4 illustrates the dynamic nature of resource prices over the past ten years.

Figure 4 – Resource Price Trends
WTI Spot Price Versus Natural Gas Wellhead Price



Forecasting offshore exploration, development and production activity requires an estimate of future resource prices. Resource prices influence the field-level economics and lead to several important questions related to our future expectations when forecasting Gulf of Mexico oil and gas activity:

- Is it reasonable to expect a continued period of high oil and gas prices indefinitely into the future, or are these periods of high prices transitory in nature?
- If the recent run-up in prices over the last 16 months is transitory in nature, what are the long-term implications of periodic price spikes?
- How do we best incorporate our price expectations over the short-, mid- and long-term future?

We can use the EDP model to measure differences in forecast results based on our assessment of future oil and gas prices in light of these questions.

Assessing future oil and gas price increases (or decreases) influences only the revenue component of the field-level NPV calculation. One might be tempted to view an increase in resource price as a financial boon for companies operating in the offshore Gulf of Mexico. However, we must also consider the cost component. Recent empirical evidence indicates a rapid escalation in drilling, capital investment, and operating costs. The EDP model allows the user to exogenously incorporate expectations about increases in drilling, capital and operating costs. The EDP model relies on historical and prospective indices designed to model changes in the cost components of the field-level NPV calculation. For example, Table 1 provides a summary of IIC, Inc. generated drilling and operating cost indices for historical purposes (through 2004).

Table 1 – Historical Cost Indices

Year	Operating Expense	Drilling Cost
1997	0.879	0.924
1998	0.898	0.944
1999	0.859	0.952
2000	0.882	0.955
2001	0.950	0.993
2002	1.000	1.000
2003	1.092	1.012
2004	1.171	1.046

Source: IIC, Inc. calculations

In computing historical field-level NPVs, the EDP model relies on these historical cost indices to appropriately scale the cost components of the NPV calculation. However, for forecasting purposes, we need to incorporate an indication of how drilling and operating costs might change in the future. For example, recent history has shown that operating costs have risen significantly. Table 2 illustrates the dramatic rise in operating costs in the shallow region of the Gulf of Mexico. If the rate of increase in drilling and operating costs exceeds any corresponding rate of increase in resource price, the NPV could actually decline for a particular field despite the increase in resource price.

Table 2 – Annual Operating Cost Increases

	2002	2003	2004	2005	2006
12-slot 100 ft WD	4.6%	8.7%	6.6%	26.1%	39.1%
12-slot 300 ft WD	4.7%	8.8%	6.6%	25.6%	38.0%
18-slot 100 ft WD	5.2%	9.2%	7.3%	23.9%	36.8%
18-slot 300 ft WD	5.1%	9.2%	7.3%	23.7%	35.9%
18-slot 600 ft WD	6.5%	9.9%	7.8%	21.6%	34.6%
Average	5.2%	9.2%	7.1%	24.2%	36.9%

Source: Energy Information Administration, Office of Oil and Gas, Table 5 and IIC, Inc. calculations.

Turning to the policy side, royalty revenues constitute a significant source of revenue for federal and state disbursement and have ranged between 4 and 6 billion dollars over the last few years.¹² Over the past ten years, the federal government has instituted several different royalty relief regimes designed to stimulate interest in offshore leasing and subsequent exploration activity. In 1995, Congress passed the DWRRA, which provided economic incentives on leases sold beginning with OCS sale 157 (CGM, April 24, 1996) and ending with OCS sale 177 (WGM, August 8, 2000). These initiatives provided suspension of royalty payments on initial field production up to certain levels depending on water depth:

- 200-400 meters: 17.5 million BOE per field
- 400-800 meters: 52.5 million BOE per field
- 800 meters and greater: 87.5 million BOE per field

¹² The Minerals Revenue Management website, <http://www.mrm.mms.gov/>, contains detailed statistics on annual royalty payments for offshore Gulf of Mexico leases.

Upon completion of the DWRRA, the federal government instituted a new set of provisions, concerning economic incentives in the Gulf of Mexico deepwater environment. Royalty relief volumes shifted from a field basis to a lease basis and the standard deepwater royalty relief provisions included:

- 400-800 meters: 5 million BOE per lease
- 800-1,600 meters: 9 million BOE per lease
- 1,600 meters and greater: 12 million BOE per lease.

However, a focus on deep gas production and expansion into deeper regions of the Gulf of Mexico has led to revised royalty provisions in OCS sales. The most recent sale (WGM, August 20, 2008) contains royalty provisions for both deep gas and deepwater production. While certain royalty rules were still subject to implementation under the Energy Policy Act of 2005, the general royalty relief provisions included:

- Deep gas royalty relief (varies by water depth, drill depth and type of well)¹³
- 400-800 meters: 5 million BOE per lease
- 800-1,600 meters: 9 million BOE per lease
- 1,600-2,000 meters: 12 million BOE per lease
- Greater than 2,000 meters: 16 million BOE per lease

An important note is that under no circumstances can a single lease receive a royalty suspension both for deep gas production and deepwater production.

Currently, the EDP model can handle both field- and lease-specific deepwater royalty relief regimes. The deep gas provisions are more problematic and provide an opportunity for updating the EDP model. The structure of the model currently does not segregate leases on a vertical drill depth basis. The EDP model is an expected value simulation based on estimating average drill depths for given water depth categories. One potential solution is to employ a more fluid drilling depth distribution within selected fields. However, for the purposes of this research, we focus on deepwater royalty relief regimes.

IV. Results

The use of an expected value simulation model provides an opportunity to examine some of the differential impacts caused by manipulating specific input levers. Given the infinite possibility of potential combinations of input assumptions, we limit the analysis of differential forecasts to three distinct, mutually exclusive situations:

- Investigation of varying future resource prices;
- Changing assumptions concerning capital and operating expenses; and
- Implementing varying deepwater royalty relief policy regimes.

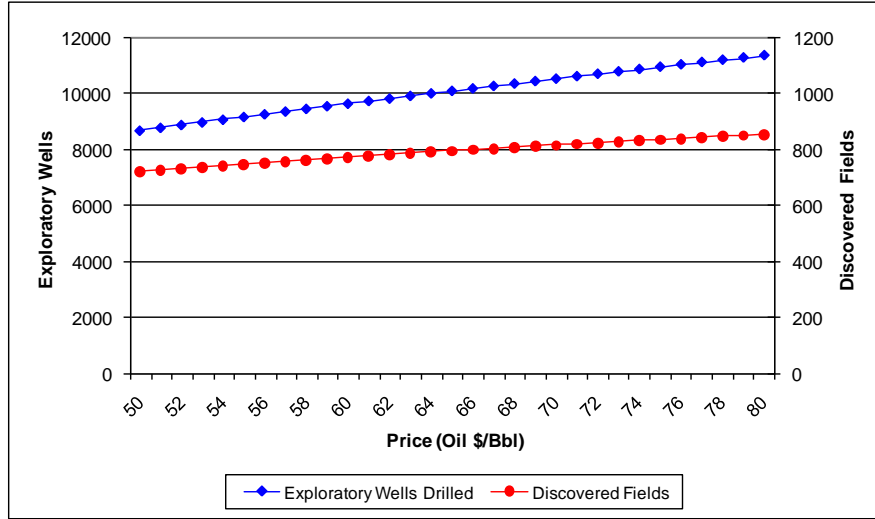
While different combinations of changes in the aforementioned scenarios (e.g., inclusion of both price changes and alternative royalty relief regimes) would also be a useful exercise, the current research involves changing only one input variable while holding others constant. As a result, the difference between forecast results measures a de facto elasticity in output variables (fields discovered, exploratory wells drilled, oil and gas production, royalty revenues, etc.) We begin by analyzing differences in forecast results as a result of incremental changes in price assumptions.

¹³ Section 30 CFR 203.41 lists the different royalty relief schemes for deep gas wells.

Resource Price

Intuitively, we expect an increase in exploratory wells drilled and fields discovered when we increase prices and hold all other input assumptions constant. We ran the EDP model using incremental resource price assumptions to confirm this relationship. Figure 5 depicts the cumulative number of exploratory wells drilled and fields discovered in the Gulf of Mexico under incremental resource price scenarios. We began by running the model at an initial oil resource price of \$50 per barrel, escalated at 3 percent in each model year.¹⁴ Subsequent runs increased the model price by \$1 per barrel each time, up to \$80 per barrel.

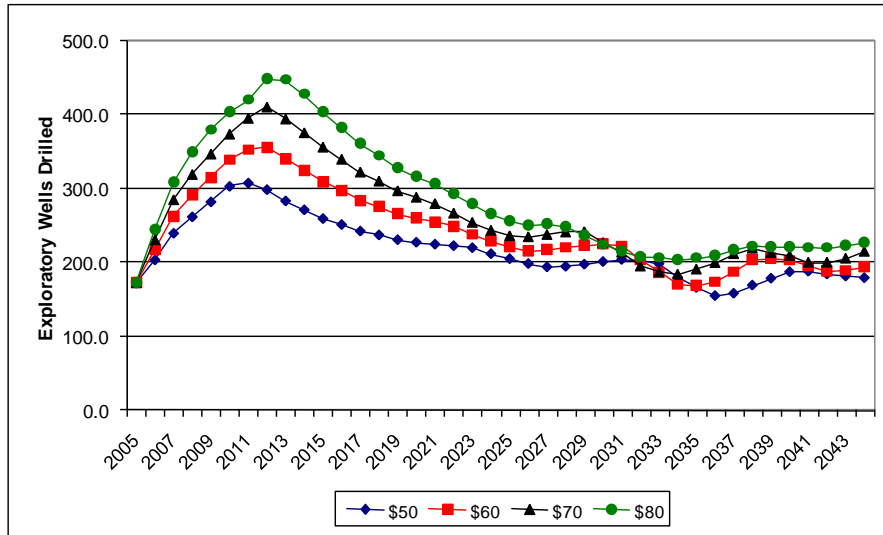
Figure 5 – Price Sensitivity Forecast Results



The results indicate that an increase in our forecast price expectations yields an increase in the amount of exploratory well drilling and also the number of fields discovered. This is due to the fact the field-level economics are improving with an increase in price. However, Figure 5 only tells half of the story. An increase in our price expectations also serves to hasten the exploration process. As field-level economics improve, there is an incentive for exploration companies to drill earlier in the forty-year forecast period. Figure 6 illustrates this trend by examining the number of expected exploration wells drilled under \$50, \$60, \$70 and \$80 price scenarios.

¹⁴ For simplicity, we employ a static gas to oil price ratio in these simulations, although past historical data indicate that the correlation between oil and gas prices is not equal to 1.0.

Figure 6 – Time Series of Exploratory Well Drilling at Various Resource Prices



Interestingly, the model forecasts an acceleration of exploration activity at higher prices, although the “peak” of exploration activity occurs slightly later in the forecast period. The EDP model reliance on both “discovered” and “expected” NPV in the exploratory well fitting equations leads to this observed shift. Higher prices lead to improved NPVs across a larger number of fields. Thus, as exploration companies increase drilling because of higher expected NPVs of ultimate field discoveries, there is a corresponding bump when these fields are actually discovered.

We can also examine the differential impacts of changes in resource price expectations by examining recent price data and de-coupling the static gas to oil price relationship. We performed four separate analyses, including:

- A base \$50/bbl oil price scenario, escalated at 3 percent, static gas to oil price relationship
- A \$70/bbl oil price scenario, escalated at 3 percent, static gas to oil price relationship
- Use of actual oil and gas prices for 2005-2008, then decline to static \$80/bbl and \$7/mcf
- Use of actual oil and gas prices for 2005-2008, then increase of 3 percent

Table 3 presents the differential results under these four resource price forecast scenarios. As we might expect, the higher price scenarios yield increased exploration, development and production activity. The use of actual prices tends to accelerate the offshore activity, given the recent rapid rise in both oil and gas prices. Interestingly, the real price decline scenario yields significantly less exploration activity, yet because of the high resource prices in the initial forecast years, the oil and gas production exhibit less significant variances from the base forecast. The initial period of high resource prices stimulate exploration activity earlier in the forecast period resulting in earlier production from newly discovered fields. However, as the forecast period progresses, the decline in field-level economics using a static price (implicit price decline vis-à-vis other cases) results in lower future exploratory activity.

Table 3 – Forecast Differences based on Resource Price Assumptions

	<u>\$50/bbl (Base Case)</u>	<u>\$70/bbl</u>	<u>4 Yr Actual - Decline</u>	<u>4 yr Actual - Increase</u>
Exploratory Wells Drilled	8,696.4	10,549.4	7,087.8	10,308.5
% Change from Base Case		21.3%	-18.5%	18.5%
Fields Discovered	722.7	816.9	624.9	811.6
% Change from Base Case		13.0%	-13.5%	12.3%
Reserves Discovered (mmBOE)	51,884.0	57,840.5	46,644.9	59,083.3
% Change from Base Case		11.5%	-10.1%	13.9%
Oil Production from Forecasted Discoveries (mmBbl)	17,691.0	20,763.4	17,637.6	21,416.0
% Change from Base Case		17.4%	-0.3%	21.1%
Gas Production from Forecasted Discoveries (Bcf)	102,749.0	118,843.4	98,110.2	119,180.3
% Change from Base Case		15.7%	-4.5%	16.0%

Notes: Cumulative Impacts through 2044, No royalty relief regimes

Capital and Operating Costs

The next series of model forecasts involve changing cost component input assumptions pertaining to the field-level NPV calculations. Recent trends indicate that drilling and operating costs escalated significantly concurrent with increases in resource price. In a situation where the capital and operating expenses increase at a greater rate than the increase in price, the field-level economics will suffer over time. This is due to the fact that future field-level NPV calculations will be lower when increases in cost components are not offset by corresponding increases in revenue. As a result, short-term exploration activity might be similar, but in the long-run, exploration activity will decline as new field discoveries will no longer be profitable to develop. Table 4 provides a summary of the cumulative effects of three different forecast scenarios. First, we include a base case with an initial resource price of \$70 per barrel and cost escalation matching price escalation at 3 percent. Second, we increase the long-term cost escalation to 6 percent. Finally, we examine a cost spike case, where we include a rapid increase in the short-term before stabilizing over the long-term.

Table 4 – Forecast Differences based on Drilling Cost Assumptions

	<u>Base Case</u>	<u>6% Constant</u>	<u>Spike Case</u>
Exploratory Wells Drilled	10,549.4	10,001.4	10,176.0
% Change from Base Case		-5.2%	-3.5%
Fields Discovered	816.9	789.4	798.7
% Change from Base Case		-3.4%	-2.2%
Reserves Discovered (mmBOE)	57,840.5	55,895.4	56,557.8
% Change from Base Case		-3.4%	-2.2%
Oil Production from Forecasted Discoveries (mmBbl)	20,763.4	20,070.9	20,035.2
% Change from Base Case		-3.3%	-3.5%
Gas Production from Forecasted Discoveries (Bcf)	118,843.4	115,587.0	115,487.1
% Change from Base Case		-2.7%	-2.8%

Notes: Cumulative Impacts through 2044, No royalty relief regimes, \$70/bbl initial resource price

The results are intuitively correct, because an increase in underlying costs over time reduces the amount of exploration activity in the Gulf of Mexico, driven by lower field profitability. Interestingly, the spike

case highlights a short-term reduction in exploration, development and production activity as we observe less oil and gas production from new fields over the forty-year term. However, in the long-run, the number of exploratory wells, fields discovered and reserves discovered is actually higher than the six percent constant cost escalation case. The initial high spike in drilling costs initially suppresses exploration activity, only to stimulate activity when the drilling costs stabilize at a lower level. The key is that the discoveries of new fields are occurring later in the forty-year projection period.

Alternative Royalty Relief

The final comparison analysis involves implementing different deepwater royalty relief regimes while holding price and cost input assumptions constant. We focus specifically on examining the presumed implementation of the following royalty relief regimes:

- No relief
- Implementing DWRRA into the future (on a per-field basis)
- Implementing DWRRA into the future (on a per-lease basis)
- Continuation of the existing per lease royalty relief policy

Table 5 presents the results of the expected value model simulation for key variables under each royalty regime scenario.

Table 5 – Forecast Differences based on Royalty Regimes

	No Relief	DWRRA - Field	DWRRA - Lease	Current Program
Grown Reserves Discovered	51,884.0	52,690.8	53,333.5	52,479.0
% Change from No Relief		1.6%	2.8%	1.1%
Total Production (new discoveries)	35,973.7	36,595.6	37,193.0	36,534.1
% Change from No Relief		1.7%	3.4%	1.6%
Present Value of Total Royalty Revenue (new discoveries)	37,327.6	30,689.0	25,969.7	33,250.5
% Change from No Relief		-17.8%	-30.4%	-10.9%

Notes: Cumulative Impacts through 2044, Initial resource price of \$50/bbl, royalty revenue amounts in \$millions

The results indicate that over a forty-year projection period, royalty relief provides only a slight increase in the number of grown reserves discovered and even the total production. This is largely driven by two factors: first, the high price is sufficient to attract interest, regardless of the royalty regime and second, over an extended period of time, we also expect discoveries of a significant portion of the resource base, as long as exploratory well drilling continues. Perhaps the most interesting element of Table 5 is the present value of future royalties collected from new discoveries as the results indicate a substantial divergence between cases involving royalty relief and the no relief case. However, it is important to remember that we are not including additional bonuses due to increased leasing from offering royalty relief or the additional tax revenues paid by oil companies on the sale and marketing of hydrocarbon resources produced in the Gulf of Mexico.

As a final analysis we consider the role of price thresholds. The model currently does not handle price thresholds in the most efficient manner. In reality, the field-level economics should consider the probability that future resource prices will exceed price thresholds. Yet the model treats price thresholds on a yearly basis, without consideration of future probabilities in the decision making (and NPV calculation) process. As a general point, the inclusion of price thresholds would yield results that fall

somewhere between the no relief case (which is a situation where the decision-maker assumes resource price exceeds price thresholds in every year) and the royalty regime cases in Table 5 (which is a situation where resource prices never exceed price thresholds).

V. Conclusion

The results presented above provide only a small snapshot of potential forecast differences based on changing specific economic and regulatory inputs. We provide a limited view of how changes in resource prices, cost assumptions, and royalty regimes influence potential offshore Gulf of Mexico exploration, development and production activity. While the scenarios are often an overly simplistic representation of future expectations, the results shed some light on key considerations:

- Higher resource prices lead to improved field economics and stimulate offshore exploration, development and production activity;
- Changes in resource price are the predominant driver in offshore exploration, development and production activity;
- Increases in drilling and operating costs tend to dampen offshore exploration activity through reduced field economics;
- Implementing royalty relief leads to improved field economics and increases in offshore exploration, development and production activity;
- Royalty relief tends to stimulate the development and production of marginal fields; and
- Over an extended time horizon, royalty relief leads to an escalation of short-term exploration activity, but leads to a significant decline in royalty revenue.

There are several avenues of potential future research. First, the inability of the EDP model to handle deep gas royalty regimes presents a serious limitation when investigating the impacts of federal policy initiatives. Future EDP model development and updates need to address the potential impact of deep gas royalty relief. Given a situation of constrained resources (e.g., rigs and capital investment), the decision of where to drill relies specifically on incorporating all potential royalty regimes. Second, the relatively static manner in which the model treats price thresholds also prevents a detailed analysis of the impact of price thresholds on forecasting outputs. Price thresholds present a difficult modeling scenario when considering field level economics. The key is how to incorporate the possibility that price thresholds will become applicable from the decision-makers perspective in each model year. Third, the model relies on history to help predict future activity. The rapid rise in resource prices presents potential calibration issues. Namely, can we expect a divergence in field economics and drilling response based on recent price volatility? Only time will tell if the increase in price and field-economics will lead to an increase in exploration activity. If we do not observe a commensurate increase in exploration activity associated with increases in resource price, the exploratory well fitting equations in the EDP model will need to be revised with updated data.

The different scenarios presented in this paper indicate that resource prices are the predominant driver in offshore exploration, development and production activity. However, royalty relief also serves to accelerate the exploration, development and production of offshore fields, with a specific emphasis on allowing marginal fields to become profitable under particular royalty relief regimes. The key question for policy makers is whether the increase in offshore activity is sufficient to offset the decline in royalty revenues. As a final reminder, we note that the analyses discussed in this paper do not consider additional fiscal variables. While royalty relief might stimulate a limited amount of additional discovery and production of offshore fields, there is likely to be an increase in leasing activity which will lead to higher bonus and rental amounts. Policy makers, industry personnel and researchers need to remember that

these are integral components of the overall picture of offshore, Gulf of Mexico field exploration, development and production.

VI. References

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VII. Additional Resources

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