30 CFR Part 203, Subpart B Regulation
Relief or Reduction of Royalty Rates – Deep Gas Provisions

Benefit-Cost/Small Business and Regulatory Flexibility Analyses

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I. Introduction

The intent of this analysis is to satisfy the requirements of E.O. 12866 and the Small Business and Regulatory Flexibility Act (SBRFA). Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions and, for significant regulatory actions, submit a detailed report of their assessment to the Office of Management and Budget (OMB) for review. A rule may be significant under E.O. 12866 if it meets any of four criteria. The two that could apply to this rule are that it has an effect on the economy of $100 million or more in a year and that it raises novel legal or policy issues. For a major rule, SBRFA requires agencies to prepare an initial regulatory flexibility analysis when proposing a major rule. A rule may be major if it meets any of three criteria. The one that could apply to this rule is again that it has an effect on the economy of $100 million or more in a year. SBRFA requires an agency to prepare a final analysis when issuing a final rule that will have a significant impact on a substantial number of small entities.

The material presented in parts II through V describes the proposal, the compelling need for this regulatory action, considers a range of possible alternatives to serve that need, and analyzes the benefits and costs of the regulatory action. Gas producers gain additional profit and the public benefits from additional domestic gas production and reduced gas prices due to this regulatory action. The adverse effects of this regulatory action are the forgone Federal royalties on production that would have been generated without this program. Parts VI and VII review the novel policy issue and small business effect of this proposal. Appendix 1 discusses assumptions about drilling and undiscovered resources used to quantify the effects of the proposal and several alternatives. Appendix 2 displays printouts of the spreadsheets used to calculate the effects reported here.

II. Proposed Action

The rule proposes a two-tiered royalty suspension program for leases issued before 2001 in the Gulf of Mexico (GOM) in less than 200 meters of water depth (hereafter referred to either as *shallow water* or *on the shelf*).

The proposed incentive program provides:

- A royalty suspension volume (RSV) for a lease on the first 15 billion cubic feet (BCF) of deep gas production for a new well drilled and completed from 15,000 feet to 18,000 feet subsurface (i.e., below sea level) and on the first 25 BCF for a new well drilled 18,000 feet or deeper subsurface. In both instances, the suspension volumes approximate the smallest reservoir size that can be developed economically. Larger suspension volumes might be effective but could also provide more relief than necessary to drilling targets that could be undertaken in the status quo.
- A deep well drilled after the date of the proposed rule may qualify for the incentive, if the lease has not had any deep gas production from a well drilled before the proposed rule. The deep drilling must result in production that starts before 5 years following the effective date of the final rule.
- A royalty suspension supplement (RSS) of 5 BCF, applied to future oil and gas production anywhere on the lease, is allowed in certain instances for an unsuccessful well drilled to a target reservoir 18,000 feet or deeper. The small sized credit provides a relatively powerful incentive to expedite exploratory drilling, because of the high risk in very deep depths. Larger suspension amounts per credit could cause

drilling inefficiencies in some circumstances. The RSS is limited to the same lease for legal reasons. Two royalty suspension supplements are available per lease prior to production from a deep well, but only for drilling before a successful deep well on the lease.

- Notwithstanding any remaining RSV or RSS, a lease must pay full royalty on all production when the annual average closing gas price on NYMEX exceeds $5 per million British thermal units (MMBtu). This price threshold value is escalated for inflation from the year 2000 at the GDP price deflator. Any production during a year when prices exceed the threshold counts against any remaining RSV and RSS.

This royalty relief incentive will have two distinct effects on production: recovery of some otherwise uneconomic gas resources (incremental production) and recovery of some marginally economic gas resources that would not have been produced until several years in the future without the incentive (accelerated production).

III. Need for the Proposed Action

A. Supply Gap and Price Volatility

Demand for natural gas is expected to rise strongly while domestic supplies are dwindling. Natural gas provides about one-fourth of the annual United States energy consumption. The National Petroleum Council *[Natural Gas, Meeting the Challenges of the Nation's Growing Natural Gas Demand*, NPC, December, 1999] forecasts that demand for natural gas will increase by about 30% in the United States by 2010 (from 22 to 29 trillion cubic feet (TCF)) annually. Because gas transportation is largely limited to pipelines, domestic production of natural gas provides the large majority (almost 85%) of U.S. consumption (versus 42% for crude oil) [*Annual Energy Outlook 2002*, EIA].

Approximately one-fourth of domestic natural gas is produced in Federal waters of the GOM, four-fifths of which is currently derived from leases located in shallow water.

Data available on the MMS website show shallow water production has been declining since the mid-1990s, down from 4.76 TCF in 1997 to 3.96 TCF in 2000. Since the mid-1980's annual gas production from the OCS has exceeded additions to proven reserves each year. As a result, total proven natural gas reserves on the GOM OCS have declined from nearly 46 TCF in 1986 to approximately 24 TCF in 1999 [*Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1999*, OCS Report MMS 2002-007]. Without a reversal of these trends, OCS production of natural gas could experience a significant decline over the next 5 to 10 years, resulting in less domestic supplies and higher more volatile natural gas prices to consumers and commercial users.

B. <u>Market Failure</u>

We do not believe published accounts of domestic natural gas markets fully account for obstacles to the reversal of these decline trends. The proposed action is designed to respond to several broader market failures that will make it progressively more difficult for shelf production to provide its expected share of total supply. These failures include: 1) excessive royalty rates for deep gas prospects imposed by existing lease documents, 2) the transitory nature of OCS infrastructure, a key factor of OCS production, and 3) an externality associated with the inability of the operator or entrepreneur to capture the full benefits of a) information generated about a frontier area and b) the necessary technology developed for use in such an area.

The existing royalty rate is too high to permit expeditious exploration and development of most deep OCS oil and gas fields, as required by the OCS Lands Act.

The royalty rate imposed on OCS leases has traditionally been made uniform for the whole lease to eliminate one source of uncertainty for those who would bid on a new lease's uncertain potential, and to allow ease of unitization between adjacent leases. The original royalty rates on active leases were set with shallow depth drilling in mind, since this has been the most easily assessed and the predominant source of production on these leases. Because deep drilling is significantly more costly and risky than shallow drilling on the same lease, this uniform rate is too high to make exploring and producing most deep prospects economic. Over the 50 plus year history of OCS production in the Gulf of Mexico, the MMS proprietary data base (TIMS) shows that only about 5% of wells have been drilled below 15,000 feet true vertical depth. Since the gas from shallow and deep wells sells at the same price, the royalty share on the latter source needs to be less if it is to become a competitive source of shelf production.

Further, the time has come to encourage production of the deep potential. Typically, when the resources that are economic to produce are exhausted, a lease is abandoned by returning it to the government and removing production infrastructure (platforms, pipelines). Once abandonment occurs, production of any remaining potential on the lease generally becomes more costly since new facilities must be installed. As production from traditional shallow wells winds down on many leases, the benefits to the operator from abandonment grow. MMS is seeking to adjust original lease terms to encourage the exploration and production of the deep zones now while extensive infrastructure is still in place on the shelf.

MMS is proposing to adjust the original royalty rates through the use of a royalty suspension volume, in part to address another form of market failure. The deep zones on the shelf are still considered a frontier area. For example, outside the Norphlet trend area off Mobile, no commercially successful wells have yet been drilled deeper than 20,000 feet. That means little is known about where the best prospects are likely to be found, what flow characteristics and problems are associated with such reservoirs, and which technology and processes work best with the unusually high pressures and temperatures extant at deep depths. Yet MMS estimates there is 5 to 20 TCF of undiscovered gas in deep depths, largely those deeper than 18,000 feet [*The Promise of Deep Gas in the Gulf of Mexico*, OCS Report MMS 2001-037]. Thus, operators achieving early deep successes will resolve basin risk issues and identify best technologies thereby generating information valuable to later operators. Yet, these pioneers are unlikely to capture all the benefits of their breakthrough since they don't control all the deep prospects, so less than the optimal level of effort will be devoted to this activity. Royalty reductions help compensate for this market shortcoming. Moreover, setting a zero royalty for a fixed production volume (i.e., royalty suspension) concentrates this compensation so it maximizes the private value of the incentive and ensures that the timing of the incentive coincides with the timing of the initial public benefits from the activity. Further, royalty reduction available only for activity undertaken during a limited period, as proposed, will expedite the activity while the transitory infrastructure is still available.

C. <u>Goal of Policy Response</u>

For the nation as-a-whole, increased drilling and production of deep prospects in the GOM will add information on this under-explored area. Such information will improve the results from subsequent deep drilling and foster better techniques for assessing deep potential. Also, that new information will improve MMS's ability to appraise the value of the deep resource potential on tracts offered in subsequent lease sales, thereby further helping to assure receipt of fair market value, an important responsibility of MMS. Increased production of deep gas and oil resources will extend the useful life of substantial infrastructure already installed in the shallow water GOM, promote domestic energy security and use of cleaner natural gas, generate added operator profits, and moderate domestic gas prices. Only the last two of these effects can be readily quantified. For the most part, we use estimates of added resources to be discovered as a proxy for all the benefits from options to the status quo.

Cost-benefit analysis in parts V and VI estimate readily quantifiable measures of the net social benefits from incremental production and the loss of royalty associated with production that would have occurred anyway. These estimates include a measure of the benefits from the accelerated portion of production using a present value process to measure the gain from earlier production of reservoirs than would otherwise occur.

IV. Alternatives

Responses to this need to jump-start deep gas exploration and production vary from doing nothing in hopes that rising prices, together with other Federal incentives, will open this horizon and reverse the decline in OCS gas production, to providing one of several royalty relief incentives targeted to deep gas potential. Incentive options range from reducing royalty rates on deep production, suspending royalties until deep gas producers recover a fixed value, or suspending royalties for one of several volumes. We analyze quantitatively 6 volume suspension alternatives and qualitatively explain why the rate reduction and value suspension approaches are inferior. We also review two procedural issues for any of the incentive options: 1) whether to qualify sidetracks as well as new wellbores for deep gas royalty relief and 2) whether to use an auction process to distribute the royalty suspensions.

A. Inadequacy of Existing Incentives

Existing Federal incentives are not likely to increase OCS gas production much in the near-term. Over the past 7 years, the Minerals Management Service (MMS) has implemented several royalty suspension programs. Royalty suspensions foster greater recovery of oil and gas by increasing industry's expected financial return relative to other (e.g., foreign) investment opportunities. Deepwater royalty suspensions have been offered since 1996. Most of the interest in deep water is directed to oil rather than gas fields. Also, because of long lead-times associated with deepwater projects (10 to 20 years), it will still be years until deepwater production becomes a major contributor to our nation's domestic supplies. For the same reason, deepwater sources have only limited ability to respond to near term shortages and price increases. Since the deepwater royalty incentives were introduced in the 1996 lease sales, only 22 of over 3,400 deepwater leases have posted production, with five of those leases on fields that produced before 1996.

Deep gas drilling incentives have been offered for new shallow water leases issued after 2000. These incentives cover only a fraction of the shallow water deep gas potential, as we estimate that most of the undiscovered deep gas resources are on old leases issued before 2001. These older leases are in areas that industry generally feels has the best potential since they were acquired first. Even new shallow water leases face 5 to 10 year lead times from lease issuance to production, in part because exploration drilling is generally postponed until the end of the primary lease term for all but the best prospects. Accordingly, production from deep wells on existing leases in shallow water, where significant infrastructure already exists and some deep exploration has already occurred, is the most promising source on the OCS for additional natural gas in the near-term.

Before the lease sales held in 2001, MMS had not exercised its royalty relief authority in lease terms for new shallow water leases in over 20 years. Except for deep wells, few financial and technical obstacles inhibited drilling and initiating production in shallow water. However, little of the deep reservoir potential on existing leases has been explored because deep wells pose a high risk of geologic or mechanical failure and entail higher cost than drilling other wells on the lease. TIMS data show that only about 30% of all exploration and development wells drilled deeper than 15,000 feet TVD SS have produced versus 70% for such wells drilled to shallower depths. Cost estimates for wells drilled deeper than 15,000 feet TVD SS run $9 to $23 million [*The Promise of Deep Gas in the Gulf of Mexico*, OCS Report MMS 2001-037] versus $4 to $6 million for wells drilled to say 12,000 feet TVD SS [estimates used in MMS proprietary tract evaluation model, MONTCAR]. TIMS data show that only 260 of some 2,800 pre-2001 leases in shallow water have ever produced from reservoirs deeper than 15,000 feet TVD SS. Yet, significant undiscovered resources could be produced from these deep reservoirs.

B. Alternative Volume Suspensions

Five different volume suspension alternatives to the proposal have been evaluated in the development of this rule. Table 1 summarizes the RSV and RSS levels of the proposal and these 5 alternatives.

Alternative #6 is the same royalty relief terms as were offered to new shallow water leases issued in sales held in 2001 -- 2003. The four other alternatives provide more relief to wells drilled deeper than 18,000 feet TVD (very deep) than to wells drilled to 15,000 to 18,000 feet TVD (deep wells). The other features of the incentive structure remain as in the proposal for each alternative. In this section we qualitatively describe

Table 1: Alternative Volume Suspension Levels Considered

Alternative	RSV for lease with new successful deep well to 15,000 - 18,000 feet TVD (BCF)	RSV for lease with new successful very deep well to 18,000 feet TVD or deeper (BCF)	RSS per very deep well for lease with up to 2 unsuccessful wells to 18,000 feet TVD or deeper (BCF)
1. Proposal	15	25	5
2. Reduce one tier	10	25	5
3. Reduce both tiers	10	20	5
4. No failure credit	15	25	0
5. Higher RSV with no credit	15	45	0
6. Sale terms	20	20	0

the rationale for and attributes of each of the 5 alternatives to the proposal. The next section quantitatively compares them to the proposal in the cost-benefit evaluation.

1. <u>Recent Lease Sale Incentive Terms</u>

Volume alternative #6 would extend terms offered on new leases issued in 2001, 2002, and 2003 sales to active leases issued before 2001. MMS has issued between 700 and 800 new leases in the shallow water GOM in the last two years with royalty suspended for the first 20 BCF of gas produced from successful deep wells and with no royalty credit for unsuccessful wells. The advantage of this alternative is that it continues the deep gas incentive level that industry and royalty collection officials have become accustomed to in the GOM. It also would avoid the need for the transition option feature in the proposal whereby leases can switch from the deep gas incentive terms in their lease agreement to those in the proposed. However, this alternative has some disadvantages when applied to existing leases.

A single incentive across all deep drilling categories works best with new leases where bidders can adjust the bonus bid they offer based on the value they attribute to the royalty relief on the specific tract. That adjustment serves to bid away (i.e., give back to the government) any excess incentive. In other words, the bid process serves to moderate unwarranted windfalls if the royalty suspension levels are inadvertently set more generously for selected tracts than needed to induce the desired activity.

Such an approach, however, is less effective on existing leases where no bonus adjustment is employed. More importantly, a single suspension level does not balance incentives to the needs of different drilling targets. Wells in the 15,000-18,000 feet TVD SS interval historically (as documented in TIMS) face significantly less risk of failure (2/3s versus 5/6s) and one-third less cost than wells deeper than 18,000 feet TVD SS. Given the same incentive, many lessees who have multiple deep targets will typically go for the less risky and less costly one, other things equal. However, the large majority (80%) of the undiscovered gas potential appears to be below 18,000 feet TVD SS. Historically (as documented in TIMS), only about 13% (294 of 2,263) of wells deeper than 15,000 feet TVD SS reach drilling depths below 18,000 feet TVD SS. Thus, there is relatively little geologic data on this very deep but promising play.

2. <u>Other Non RSS Alternatives</u>

Alternatives #4 and #5 address the basic problem with the sale term alternative by offering greater incentive to successful wells drilled to very deep depths, those deeper than 18,000 feet TVD. Further, they achieve this two-tier approach without invoking the novel policy feature in the proposal of a royalty suspension supplement (RSS) even when the very deep well does not produce.

Eschewing an RSS has several attractions. The proposed RSS establishes a precedent of the government investing in and thus sharing some of the risk of exploration with the lessee. That raises at least two concerns. One concern is the moral hazard possibility that lessees will engage in inefficient drilling activities just to earn a royalty suspension. The proposed rule contains a variety of features to guard against this hazard. See section VI. The other concern is that the industry will be emboldened to press for similar government participation in future royalty relief opportunities. However, the uniqueness of the circumstances associated with this rule -- long shunned, high risk, frontier area-like prospects on already leased tracts -- limit its precedent setting implication for other areas.

Volume alternative #4 adopts the more conservative approach, in the sense of limiting forgone royalty, to accentuating very deep drilling without an RSS. Evaluation of this alternative provides a base against which to compare the effect of the RSS on a variety of measures. Because alternative #4 offers less expected royalty relief value to lessees, it creates less incentive than the proposal. To see this, assume a prospective very deep well has a 25% chance of success. Under the proposal a lessee drilling a very deep well can expect royalty relief benefit of 10 BCF (25% * 25 BCF + 75% * 5 BCF) versus only 6.25 BCF under alternative #4. Alternative #4 represents the notion that perhaps omitting the RSS would reduce forgone royalty relative to the proposal more than it will reduce drilling effort.

Volume alternative #5 increases the RSV for successful wells deeper than 18,000 feet TVD SS to 45 BCF, again without any provision for an RSS. This alternative generates the same expected value as the proposal without resort to the RSS. But it would be more costly than the proposal in terms of forgone royalties to the government. A numerical example demonstrates this point.

Suppose prospect A represents the set of already profitable drilling targets, while prospect B represents those that are marginally uneconomic but which can be made profitable by either the proposal or this higher RSV option. Prospect A has a 40% probability of success and prospect B has a 20% probability of success. Prospect B is the marginal project because of the lower probability of success. The proposed program would provide a royalty suspension volume of 25 BCF with a royalty credit of 5 BCFE while the alternative program would provide a royalty suspension volume of 45 BCF with no royalty credit. Under the proposed program, Prospect A would receive an expected benefit of 13 BCFE in royalty relief, that is (25 * 0.4 + 5 * 0.6), and Prospect B would be expected to benefit by 9 BCFE, that is (25 * 0.2 + 5 * 0.8), for a total of forgone royalties to the Treasury on 22 BCFE. However, under the alternative program, Prospect A receives an expected benefit of 18 BCF (45 * 0.4 + 0 * 0.6) while Prospect B receives an expected benefit of 9 BCF (45 * 0.2 + 0 * 0.8), for a sum of lost royalties to the Treasury on 27 BCF. In each case, the marginal prospect receives the same level of incentive (9 BCF) – but the cost of achieving it in terms of forgone federal revenues is higher under the alternative program (27 BCF) than the proposed program (22 BCF). This is the case because the higher RSV alternative provides added relief to projects that are already profitable without any relief. Accordingly, since a higher volume suspension without the credit provision does not increase the benefits of the incentive to the target class of prospects, but does cost more in terms of aggregate forgone royalties, it accepts a potentially significant cost to avoid resort to the RSS feature.

3. <u>Reduced Incentives that Include an RSS</u>

Alternatives #2 and #3 adopt the novel features associated with the RSS because of the benefits this royalty relief element promises. Though the proposal and alternative #5 have the same expected royalty relief value, the proposal provides a more powerful very deep drilling incentive. This benefit of the RSS feature is due, as we argue in more detail in Appendix 1 section 1.D.2. on page 67., to considerations related to risk aversion by some lessees, present values of royalty suspensions spread over time, and likelihood of finding reservoir sizes adequate to use a very large RSV.

While retaining the benefits of an RSS, alternatives #2 and #3 seek to reduce forgone royalty costs by reducing the RSV for successful deep and or very deep wells. Alternative #2 reduces the RSV only for deep wells while alternative #3 reduces the RSV for both deep and very deep wells from the levels in the proposal. Alternative #2 directs less of the categorical incentive to the 15,000 – 18,000 foot TVD SS zone since most of the potential deep resources are deeper than 18,000 feet TVD SS. Alternative #3 trims the RSV in both drilling depth zones. These alternatives represent the idea that reducing the incentive for success may provide a more cost-effective incentive level than the proposal, albeit at the loss of some absolute level of drilling benefits.

C. <u>Non-Volume Suspension Relief Options</u>

1. <u>Royalty Rate Reduction</u>

The option of simply reducing royalty rates on production from completions deeper than 15,000 feet has some attractive features. Royalty, even at a reduced rate provides some revenue to government from the beginning of any new production, moderates the forgone royalty associated with production that would have occurred in the absence of royalty relief, and reduces the royalty loss if MMS makes errors in forecasting the royalty suspension level necessary to achieve the desired incentive. Also, royalty rate reductions can be useful when the incentive is to be applied to production that can occur in a variety of ways that individually deserve different suspension amounts. In such situations, a uniform royalty rate reduction applicable to all types of production approaches would avoid the complication of supplemental conditions and constraints on lessee choice needed to prevent the incentive from distorting the lessee's selection of the most efficient mode of production.

But royalty rate reduction is an inferior incentive tool on many counts. The profit boost from a royalty rate reduction would be stretched over the life of the deep well rather than concentrated at the beginning of the production period as with a royalty suspension. That means lessees with larger reservoirs would reap proportionally larger benefit with a royalty rate reduction because they produce more at lowered royalty rates than do smaller, marginally economic reservoirs more in need of the incentive. Stretched out receipt of the relief would also increase the risk to the lessee that the reservoir discovered would be too small or the relief would be rescinded too soon to yield the intended or expected boost to profits. Further, since discount rates are higher for private entities than the government, a royalty rate reduction provides a lessee with less incentive than a volume suspension that is of equivalent cost to the government.

In summary, because the proposed deep gas incentive is aimed at a narrowly defined target, i.e., new deep wells, whose costs and risk can be reasonably estimated, there is no need to default to and accept the limitations of the more general incentive structure of a royalty rate change. Carefully chosen royalty suspensions will be a more efficient and familiar set of incentives. Since the Deep Water Royalty Relief Act (DWRRA) of 1995, royalty suspension has become the customary incentive tool both for lessees and MMS. That familiarity reduces uncertainty and possible conflict that would be associated with a new relief structure.

2. Royalty Value Suspension

The DWRRA granted the Secretary the authority to suspend royalties for a "period, volume, or value of production… which suspensions may vary based on the price of production from the lease;" Royalty suspension can be viewed as a way to help operators recover development capital by increasing early cash flow retained by operators from their projects. Suspension for a given dollar value is a precise way to grant just the intended amount of relief for the selected class of projects. Also, this approach has the theoretical advantage of increasing the number of barrels or cubic feet of relief provided as prices decline, and reducing the number as prices increase.

But, there are a number of practical disadvantages too. Inflation will reduce the value of a fixed dollar amount of relief, necessitating the creation of an escalation procedure. Such a procedure requires careful selection of the appropriate escalator, subsequent monitoring and perhaps controversy, and adds uncertainty to long term planning by lessees. Also, establishing production value across many different lessees can be complicated. Different participants on the same lease may sell their product shares at different prices which they may not disclose to their partners. So granting a value suspension to a lease can lead to complex accounting to determine when it has been exhausted, and may compromise proprietary information among companies participating in a lease or well. Further, audits periodically result in adjustment of the value assigned to a lease's product and to the allowed transportation cost deductions, thereby requiring periodic correction in the amount of relief previously taken. The recent royalty-in-kind initiative is driven in part as a way to avoid recurrent conflict between oil and gas producers and MMS as to the appropriate production value against which to assess royalty. Perhaps for reasons like these, Congress mandated that the deep water program during 1996 – 2000 use the simpler volume of production measure for royalty suspensions.

In summary, because the volume suspension approach is simpler to structure than a value suspension approach, it is less prone to weaken the intended incentive by confusing or adding uncertainty to a lessee's deep drilling activity. The industry understands and has responded well in the past to the volume approach and MMS has continued its use after the period mandated in the DWRRA to avoid inconsistency with established program formulations and in accounting for royalty on unitized tracts. A similar situation exists in shallow water, where leases issued during the past few years have financial terms expressed as royalty suspension volumes for deep depth drilling.

D. Procedural Issues

1. Incentives for Sidetrack Wells

The issue of whether sidetrack wells should be eligible for the deep gas incentive is complex. Sidetrack wells tend to be less costly to drill than new vertical or directional wells from the surface, largely because they cover less distance. That fact implies two things. A rational policy to encourage deep gas production should not discourage use of the cheaper option when it is available. Also, the level of the incentive appropriate to encourage production without giving too much relief is less for sidetracks than for new wells. Further, the decision on whether to make sidetrack wells eligible at all for an incentive then must weigh the extra production the royalty relief is likely to yield against the added regulatory complexity and forgone royalty cost of a new category of royalty suspension.

In the case of deep wells completed in the 15,000-18,000 foot interval, little extra production is likely for two reasons. First, historical data suggest that sidetracks are primarily used to either assist in production from regular wells on the reservoir, or to extract resources from smaller reservoirs. TIMS data shows only 7% of gas production in this depth interval is associated with reservoirs having only sidetrack wells. The rest comes from reservoirs having only new wells or both new wells and sidetracks. Either circumstance would normally qualify the lease for relief under the terms of the proposed rules. That situation indicates adding a sidetrack qualification provision cannot be expected to add much production in this interval.

Second, the conditional nominal value of the royalty suspension of 15 BCF is likely to be a bit over $8 million ($3.25 per thousand cubic feet (mcf) * 15,000,000 mcf * 1/6). As the chance of success is only about one in three in this interval, the expected value of the royalty suspension is only about $2.7 million. If the relief is actually taken on production over 6 years on average per well, then the present value benefit becomes about $1.9 million. API survey data [combined *Joint Association Survey on 2000 Drilling Costs* and *Joint Association Survey on 1999 Drilling Costs*, American Petroleum Institute, Independent Petroleum Association of America, and Mid-Continent Oil & Gas

Association] indicates the average cost of drilling a new well is about $11.4 million, so its average cost net of expected royalty suspension value is $9.5 million. In contrast, the same surveys show the average sidetrack cost has been about $7.6 million in this interval, equal to 80% of the cost of a new well with expected royalty relief.

This finding does not change significantly when we look at the historical distribution of sidetrack well costs rather than the average. We explored the possibility that the new well-only incentive might affect appreciable sidetrack drilling by applying the API cost data per foot drilled to the range of drilling length observations in our data on deep wells. The expected net cost of a new deep well under the proposed royalty relief is still higher than the expected net cost of a deep sidetrack with no royalty relief in over 90% percent of the reservoir targets drilled thus far to deep depths. For the remaining cases, the differences between the full costs of sidetracks and costs net of royalty relief for new wells is small. So royalty relief only for a new well is generally not large enough to distort investment decisions by reversing the relative economics of a new deep well versus a new deep sidetrack.

Since the cost of the sidetrack at full royalty is still lower than the cost of a new well with expected royalty relief, the proposed incentive is not likely to distort the choice of well types in situations where the lessee has an option of drilling either one. This means that extending royalty relief to sidetracks will, at best, add production only from reservoirs uneconomic to produce with new wells with royalty relief or with sidetracks without relief, while providing relief to all sidetracks that would have been drilled anyway. The added reservoirs will be small relative to other reservoirs. TIMS data indicate that reservoirs drilled with only sidetrack wells already average less than half the size of those drilled into by other wells.

In the case of deep wells in the sub-18,000 foot category, the case against a sidetrack incentive is less clear cut. With the exception of the prolific Norphlet trend, so little drilling has taken place to very deep depths that historical evidence cannot offer a reliable guide about the potential importance of deep sidetrack wells. The sparse data that are available show four of the 10 reservoirs producing gas in this depth interval have only sidetrack wells, and those reservoirs tend to be the larger ones. But, 10 observations are far too few to reflect the range of situations likely given the potential scope of all the undiscovered very deep reservoirs. (We have over 500 such reservoirs in the 15,000-18,000 foot drilling depth.) At the same time, the conditional nominal value of a royalty suspension volume of 25 BCF is about $13.5 million ($3.25/mcf * 25,000,000 mcf * 1/6), or about $9.2 million on a present value basis. The conditional nominal value of a royalty suspension supplement of 5 BCF is about $2.7 million ($3.25/mcf * 5,000,000 mcf * 1/6), or about $2.3 million on a present value basis, assuming it is used over a 2 year period. At a chance of success of about one in five in this interval, the expected value of the royalty relief is about $3.7 million. The API survey data indicates the average cost of drilling a very deep, new well in this very deep category is about $15 million, so the average cost net of expected royalty relief is about $11.3 million. In comparison, the average cost of a sidetrack to this drilling depth has been about $8.2 million, or 73% of the cost of a new well with expected royalty relief. Again, the proposed incentive is not large enough to result in a switch to the less efficient new well in some situations where the lessee has an option of which to drill. So, while we have decided it is most prudent not to include royalty suspensions for sidetracks in the proposed rule, we seek comments on the need for, size, and form of royalty relief on sidetrack wells, and we will consider those comments in preparation of the final rule.

2. Auctioning RSVs

We briefly considered alternative mechanisms of distributing a royalty suspension volume to lessees. One, a case-by-case approach was quickly dropped. While case-by-case review could conceivably eliminate forgone royalty, it would add delay and much uncertainty about approval and thus interference in the delicate deep drilling decision. As such we believe it would do little to increase new deep drilling in the near future.

Another approach would seek to allocate approximately the same total royalty relief with an auction process rather than with a uniform allocation to all lessees as proposed. Under the auction process not all lessees would receive the same relief and allocation would work as follows. Authorized leaseholders, those with leases awarded prior to 2001, would submit to MMS an offer of the volume of royalty relief they would require to undertake deep well drilling. MMS would rank the offers from the least amount of royalty relief to the greatest, taking into consideration the depth of the wells (15,000-18,000 ft or sub-18,000 ft). MMS would select the best ranked (lowest) offers until their cumulative amount reached a predetermined cutoff level of royalty relief. MMS would then renegotiate the terms of existing leases of the selected leaseholders to provide the royalty relief per their individual offers. The remaining offers—those requiring the largest royalty relief—would not be accepted. For any royalty relief awarded, the leaseholder must begin drilling a deep well within a designated time period.

The eligibility requirements that MMS would apply under the proposal would also apply under this approach. For example, leaseholders that have already drilled successful deep wells before the proposed rule is published would not be eligible for this program. However, leaseholders who first drill a successful deep well after the proposed rule is published would be eligible to receive royalty relief if their bid for royalty relief was accepted. MMS would ask leaseholders to specify in their offers the depth of wells they would drill, and the volume of royalty relief suspension volume they seek on a successful well. Leaseholders would specify separate royalty relief suspension volumes in their submission, one for 15,000-18,000 ft depth and the other for the sub-18,000 ft depth. Leaseholders can also specify a royalty relief supplement for up to two unsuccessful wells in the sub-18,000 ft depth. The magnitude of the royalty relief supplement per well should not exceed 5 BCF.

This alternative approach may result in added drilling activity and production for lower or the same Federal forgone royalties compared to the preferred alternative, because it encourages lessees who would drill without relief to accept lower relief amounts than they would receive under a fixed allocation system. However, due to a number of unresolved implementation issues, we decided to seek comments also on this concept rather than include this feature in this proposed rule. Unlike sidetrack comments, we expect to use any auction comments to guide the design of future royalty relief opportunities.

One issue is the cutoff for accepting the ranked offers in this approach. It should be related to the incremental production MMS estimates the relief can generate and the total Federal cost expended. Factors relevant to this determination include, for example, the total number of wells MMS expects to produce, the volume of royalty relief provided to each well, the expected number of wells that would not be drilled without royalty relief, the number of bids judged to have been offered by authorized lessees who can claim relief from new drilling activities and who actually intend to drill to deep depths, and the likelihood of drilling success. In using those estimates to determine the pool of accepted offers, MMS would seek to allocate approximately the same total royalty relief as the preferred alternative. All of these magnitudes are based on forecasts which are always subject to error. Whereas the proposed categorical approach fixes the size of the relief and lets government revenues bear the risk of erroneous forecast, the auction approach would fix the maximum size of the government revenue exposure and let the drilling response bear the risk of an erroneous forecast. How much is MMS likely to save and at what cost in terms of drilling delayed or forgone as a result of employing this alternative allocation mechanism?

Other issues are associated with this approach, and resolving them satisfactorily would involve a delay until this additional analysis could be performed. That delay alone would compromise the effectiveness of this incentive since it is justified by the expectation of a near-term result. The following are some of these unresolved issues:

(1) The risk to the integrity of the auction approach if successful bidders choose not to drill within the specified period and thus inadvertently penalize unsuccessful bidders. A fee for participating in the auction might avoid this risk if it could be structured properly. Identification and evaluation of a fee structure or other ways to minimize this risk will take time and could add another form of distortion to lessee drilling decisions.

(2) The choice of a reasonable period of time in which to expect operators to commence drilling after their offer is accepted. Setting the period too long would complicate repeat auctions should the early drilling response to the first auction prove inadequate.

(3) Should MMS accept offers in a single sale at the outset of the program, or allocate the relief in a series of sales held over several years? Multiple sales would allow MMS to correct problems identified but may result in the cumulative grant of more relief than intended. Also, it may complicate planning by lessees and constrain the competition needed for a successful auction.

(4) If the total royalty relief allocated using the auction process turns out to be substantially lower than the total proposed under this rule, the auction approach could result in less drilling activity than would have resulted under this proposed rule. Should the total royalty relief granted under the auction proposal be the same as would be offered under the proposal, greater or smaller?

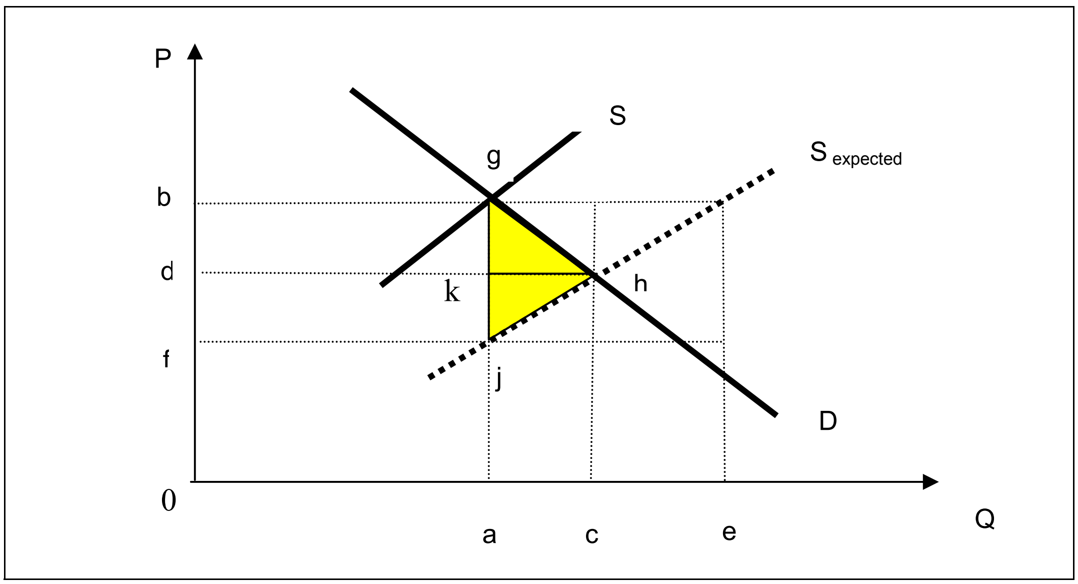
V. Measuring Benefits and Costs

The proposed royalty relief program for deep gas drilling will generate real benefits to the nation from increased exploration and production. It will also result in substantial transfers, from producers to consumers in the form of slightly reduced prices spread over all domestic gas sales and from government to owners of those leases in the GOM that respond to the deep drilling incentive in the form of reduced royalty collections. In this section we explain how we calculated these benefits and transfers and put the change in royalty collections in the context of all royalty receipts from the all the OCS and from the deep gas component.

A. Net Social Benefits

Figure 1 illustrates conceptual amounts that need to be estimated to value the benefits and costs of this incentive. A supply shift from S to S_{expected} due to the increased deep gas production (e – a) is expected to result from the drilling incentive. Associated with that supply shift is a royalty cost saving (b – f) for certain gas producers, those taking

Figure 1: Net Social Benefits



advantage of the deep drilling royalty suspension incentive. In response to this shift the market clearing quantity adjusts from a to c and the price from b to d. Consumers gain from the market price reduction spread over all gas. Much of this gain is a transfer from producers who earn less on the production they would sell in the absence of the incentive. Certain producers gain extra profits on the increased production made possible by the royalty suspension (some of which displaces other gas supply) and on the transfer of royalty from the government associated with deep gas production that would have been profitable even without the relief. Social benefits can be calculated with estimates of net increase in market equilibrium quantity (c – a = h – k) and in royalty cost savings by certain producers (b – f = g – j).   Net social benefits (represented by the triangle ghj) are the sum of the net gains after deduction of the transfers to producers and consumers associated with the additional production attributable to this rule.

B. Change in Equilibrium

An estimate of the price moderation and supply increase effects can be developed using estimates of gas demand and supply elasticity, of future gas consumption, and of the additional production from the royalty relief. A review of estimates in economic literature and models designed for MMS recommends use of a domestic demand elasticity value of -0.72 and a supply elasticity value of about 1.0 [William G. Foster, "Petroleum Supply and Demand Elasticity Estimates", January 28, 2000]. Assuming a flat gas price of $3.50/mcf (see reasons for this choice in Appendix 1 on pages 72) and an annual consumption of 25 TCF (the middle of the NPC demand forecast and a level EIA expects by the middle of this decade [*Annual Energy Outlook 2002*, EIA]), we find incremental production from the proposed action to be 0.147 TCF (0.533 %) in a typical year.

Increased supply of 0.147 TCF (e – a in Figure 1) from deep depth drilling could reduce prices by about two and a half cents (0.74%) per mcf compared to what they would otherwise be. If we then factor in the response of this price decline on current gas supplies, we determine the net effect to be a decline in the equilibrium market price (b – d in Figure 1) of 1.1 cents (0.31%) per mcf. Associated with this reduction in equilibrium price is an increase in equilibrium quantity (h – k) of 0.058 TCF or 39.5% of the initial supply increase of 0.147 TCF.

Before turning to an estimate of the royalty cost saving, we note that a price reduction of 1.1 cents saves consumers about $280 million ($0.011 per mcf * 25 TCF) annually in expenditures on natural gas. However, from a social benefit perspective a large part of it would be offset by reduced income to gas producers.

The royalty cost savings are available only to those producers able to take advantage of the deep gas incentive, not all gas suppliers. With a landed gas price of $3.50 per mcf (less transportation costs of $0.25 for mcf), a one-sixth royalty would generate $0.54 per mcf, so that is the value of the royalty cost savings (g – j). The net social benefit (ghj) averages about $15.7 million annually [(58 BCF * $0.54/mcf)/2]. Estimates explained in Appendix 1 on pages 63-64 indicate that about 75% of this net social benefit is in the form of added income to GOM producers, leaving 25% as added consumer surplus.

C. <u>Production, Fiscal, and Social Welfare Effects of Alternative Royalty Suspensions</u>

This section explains how we computed this average effect, determined the present value of the benefits and cost of the proposed incentive, and compared the proposal to 5 alternatives. Appendix 1 details the source of the drilling intensity, reservoir size, and price assumptions. Table 2 summarizes the common assumptions used to estimate the values for each alternative.

We measured the likely effect of the deep gas incentive with a 6 step process. Please see a description of that process as well as the resultant spreadsheets in Appendix 2. The title at the top of each spreadsheet indicates the alternative it covers. We then compared alternatives by adjusting the drilling intensity based on the strength of each alternative royalty suspension option relative to the proposal and repeated steps 3 through 6.

Table 2: Assumptions

Assumption	Value
Elasticity of U.S. Gas Demand	-0.72
Elasticity of U.S. Gas Supply	1.09
Average landed price of gas	$3.50/mcf
Average transportation cost of OCS gas	$0.25/mcf
Royalty Rate for OCS gas	16.7%
Average tax rate for OCS lessees	0%
Discount rate	7%
Gas to Oil production ratio in deep reservoirs	26 mcf/bbl
Thermal Gas to Oil ratio	5.62 mcf/bbl
Likelihood of Deep Drilling Success	33% at 15K'- 18K', 20% at 18K' or deeper
Cost of Drilling a Deep Well	$9 to $23 million
Average size discovered deep reservoirs	21 BCFE at 15K'-18K', 30.5 BCFE at 18K' or deeper
Average size undiscovered deep fields	45.5 BCFE at 15K'-18K', 97.3 BCFE at 18K' or deeper
Average size deep fields whose discovery is accelerated	60 BCFE at 15K'-18K', 97.3 BCFE at 18K' or deeper
Average period accelerated production moved forward	6 years
Share of extra reserves drilled under the incentive that are accelerated rather than added	50% at 15K' – 18K', 25% at 18K' or deeper
Average # production wells per undiscovered field	2
Average deep well flow rate	2.5 BCF/year at 15K'-18K', 4.6 BCF/year at 18K' or deeper
Average duration of RSS production	2 years
Share of leases with RSS able to use it	67%

Appendix 1 reviews these determinations for each alternative. Tables 3 and 4 display the results of this comparison.

Table 3 describes the average annual increase in drilling and reserves each year the incentive is in effect. The row headings show the incentives associated with each alternative while the second and third columns summarize the associated drilling intensity and discovery sizes. The data in the 'no incentive' row shows the baseline levels and the other rows the addition to this baseline associated with each alternative.

The far right column shows the volumes used in row J of the spreadsheets for each year the incentive is effective.

Table 3: Annual Accrued Effect of Incentive

Option	# of Deep, Very Deep Wells Drilled Annually (successful)	Expected Size of incremental (accelerated) reservoirs, BCFE	Incremental hydro-carbons discovered, BCFE	Acceleration premium for hydro-carbons discovered earlier, BCFE	Total hydro-carbon + Acceleration premium Discovered, BCFE
No incentive	37 (12), 11 (3)	21, 30.5			344
	Added Wells	Discovery Sizes	New Production	Production Moved Forward	Added hydro-carbons
Proposal Alternative 1: 15 BCF 15,000-18,000 ft, 25 BCF >18,000ft + 5 BCF for up to 2 unsucessful wells>18,000 ft	17 (6), 24 (4)	45.5 (60), 97.3 (97.3)	385	92	477
Alternative 2: 10 BCF 15,000-18,000 ft, 25 BCF >18,000 + 5 BCF for up to 2 unsuccessful wells >18,000 ft	11 (4), 24 (4)	45.5 (60), 97.3 (97.3)	354	72	426
Alternative 3: 10 BCF 15,000-18,000 ft, 20 BCF >18,000 + 5 BCF for up to 2 unsuccessful wells >18,000 ft	11 (4), 21.5 (3.5)	45.5 (60), 97.3 (97.3)	317	68	386
Alternative 4: 15 BCF 15,000-18,000, 25 BCF >18,000 ft	17 (6), 11.5 (1.5)	45.5 (60), 97.3 (97.3)	202	72	275
Alternative 5: 15 BCF 15,000-18,000, 45 BCF >18,000 ft	17 (6), 19 (3)	45.5 (60), 97.3 (97.3)	312	84	396
Alternative 6: 20 BFC >15,000 ft	23 (8), 9 (1)	45.5 (60), 97.3 (97.3)	197	88	285

Table 4 continues the same rows as in table 3, with column 2 showing the cumulative deep production associated with the baseline and the additions associated with each alternative. The third column shows the ratio of added deep production (incremental plus

Table 4: Cumulative Effect of Incentive

Option	Deep Gas Production from Undiscovered Fields, TCF	Added Production, TCFE relative to Forgone Royalty, TCF	Present Value of Transfer from Producers to Consumers, million $	Present Value of Transfer from Government to Producers, million $	Present Value Royalty Receipts from New Deep Gas Production, million $	Present Value Net Social Benefits from Incentive, million $
No incentive	3.81	na			$1,359	na
	Added Deep Production	Added over Baseline Production	Consumer Gain	Producer Gain	Government Loss	Social Gain
Proposal Alternative 1: 15 BCF 15,000-18,000 ft, 25 BCF >18,000ft + 5 BCF for up to 2 unsucessful wells>18,000 ft	2.35	1.36	$2,740	$834	-$267.4	$152.7
Alternative 2: 10 BCF 15,000-18,000 ft, 25 BCF >18,000 + 5 BCF for up to 2 unsuccessful wells >18,000 ft	2.10	1.47	$2,456	$709	-$140.9	$136.8
Alternative 3: 10 BCF 15,000-18,000 ft, 20 BCF >18,000 + 5 BCF for up to 2 unsuccessful wells >18,000 ft	1.90	1.46	$2,128	$647	-$128.3	$119.3
Alternative 4: 15 BCF 15,000-18,000, 25 BCF >18,000 ft	1.35	1.08	$1,598	$597	-$305.3	$89.0
Alternative 5: 15 BCF 15,000-18,000, 45 BCF >18,000 ft	1.95	1.26	$2,263	$691	-$350.3	$126.6
Alternative 6: 20 BFC >15,000 ft	1.41	0.80	$1,747	$817	-$580.2	$97.4

the acceleration premium) relative to the production on which royalties are forgone because this production would have occurred anyway without the incentive. All but one alternative has a ratio larger than one indicating they add more new production than the amount of production on which royalty is forgone. The next 2 columns in table 4 show the size of transfers, to consumers and to producers, in present value terms. The last 2 columns show the size of royalty losses and social benefits associated with each alternative in present value terms. The last column demonstrates that the largest net social gain is associated with the proposed alternative, indicating it is the best policy alternative from a social welfare standpoint.

Comparison of the second and the next to last columns offers another point of view on the relative merits of the alternatives. Some of the forgone royalty would be offset by royalty collections on the condensate associated with the added gas reserves and on added gas production after the royalty suspensions have been used. Taking those into account and distributing the production over the next 15 years, we estimate a net reduction in present value of royalty receipts of $267 million under the proposal versus $141 million for alternative 2 and $128 million for alternative 3. These comparisons suggest that alternative 2 promises almost 90% of the production effects (2.10 TCF versus 2.35 TCF) for just over half the forgone royalty, while alternative 3 promises 80% of the production effects (1.90 TCF versus 2.35 TCF) for just under half the forgone royalty cost to the government. That is, while the proposal is the optimal policy, alternatives 2 or 3 may be more cost-effective, though they give up some of the total drilling benefits available with the proposed incentive.

D. <u>Price Sensitivity</u>

We've also conducted a price sensitivity analysis on the status quo and our proposal. This sensitivity analysis addresses the issue of variability in drilling intensity as gas prices change for all of the measures shown in Tables 3 and 4. We compared two alternate price assumptions, \$4.50/mcf and the most recent EIA projection (which averages \$2.90/mcf at the wellhead over the next 15 years) to our base assumption of \$3.50/mcf (\$3.25 at the wellhead).

The assumptions we used to adjust the expected drilling intensity are as follows. Elsewhere we have noted that we based the price threshold on a price level at which market conditions achieve the same results as the proposed incentive. That is, a price of \$5/mcf achieves the same effect as royalty relief at \$3.50/mcf. Thus, a price of \$4.50/mcf should achieve about two-thirds the effect as the proposal. That translates into 16 successes out of 50 deep wells annually and 5.67 successes out of 28 very deep wells annually. The EIA price averages about 10% below our base price assumption. Assuming a linear response, that implies 11 instead of 12 deep successes and 2.5 instead of 3 very deep successes annually.

As for the effect of the proposed incentive at these alternative price levels, we believe it is reasonable to assume the reduction in the minimum economic field size (MEFS) is proportional to the increase in the price level. Applying those MEFS to our undiscovered field size distribution estimate allows us to estimate the change in drilling intensity in the same way we did originally, by comparing the counts of economic fields with and without royalty. In the \$4.50/mcf base case, we project 30% more deep wells (as opposed to 50% more in the \$3.50/mcf base case) under the proposal and 80% more very deep wells (as opposed to 200% more in the \$3.50/mcf base case). As for the EIA price assumption, we capped the additional successes associated with the incentive at the same increment as the base (6 more deep successes and 4 more very deep successes). Setting them any higher would result in the illogical result of more deep drilling intensity under the proposal at the lower price than at the higher price.

Tables 5 and 6 shows the key inputs and results. Since most of the measures of interest relate to the policy instrument used, not to variations in market conditions, we were able to limit the extensive analysis of options to the price sensitivity effects on our

Table 5 Sensitivity of Proposal to Price Assumption
Annual Accrued Effect of Incentive

Option	# of Wells Drilled Annually (successful)	Expected Size of reservoirs, Bcfe	Total hydrocarbon + Acceleration premium Discovered, Bcfe
No incentive	37 (12), 11 (3)	21, 30.5	344
Proposed Alternative I: 15 BCF 15,000-18,000 ft, 25 BCF >18,000ft + 5 BCF for up to 2 unsuccessful wells>18,000 ft	17 (6), 24 (4)	45.5 (60), 97.3 (97.3)	477
Price Sensitivity			
No incentive at $4.50/MCF	50 (16), 28 (5.67)	21, 30.5	509
Alternative I: $4.50/mcf rather than $3.50/mcf	13 (5), 22 (4.33)	45.5 (60), 97.3 (97.3)	403
No incentive AT $2.90/MCF	34 (11), 9 (2.5)	21, 30.5	307
Alternative I: EIA price trend rather than flat $3.50/mcf	17 (6), 23 (6.5)	45.5 (60), 97.3 (97.3)	446

proposal. However, to be meaningful for comparison purposes, we needed to re-compute the market clearing conditions under the revised gas prices in the status quo. The results suggest that the change in net social benefits is roughly proportional to changes in the assumed price over a significant range.

Table 6 Sensitivity of Proposal to Price Assumption
Cumulative Effect of Incentive

Option	Deep Production from Undis-covered Fields, TCF	Added Production, TCFE relative to Forgone Royalty, TCF	Royalty Receipts from New Deep Gas Production, $millions	Present Value of Transfer from Government to Producers, million $	Present Value Royalty Receipts from New Deep Gas Production, million $	Net Social Benefits from Incentive, million $	Percent Change in Price	Percent Change in Net Social Benefit
No incentive	3.81	na	na	na	na	na	na	na
Proposed Alternative I: 15 BCF 15,000-18,000 ft, 25 BCF >18,000ft + 5 BCF for up to 2 unsucessful wells>18,000 ft	2.35	1.36	-$267.4	$2,740	$834	$152.7	na	na
Price Sensitivity								
No incentive at $4.50/MCF	5.65	na	Na	Na	Na	na	na	na
Alternative I: $4.50/mcf rather than $3.50/mcf	2.33	0.93	-$878.3	$3,441	$1,609	$195.0	28.6%	27.7%
No incentive AT $2.90/MCF	3.41	na	Na	Na	Na	na	na	na
Alternative I: EIA price trend rather than flat $3.50/mcf	2.35	1.53	-$118.6	$2,238	$630	$134.3	-10.8%	-12.0%

E. Total Royalty Collections With and Without the Proposed Incentive

MMS regularly forecasts royalty receipts as part of the annual budget process. To do that we apply a price forecast prescribed by OMB to our own estimate of OCS production, accounting for expected depletion and discoveries. We forecast that 97.6% of oil and 99.6% of gas production that will be royalty-bearing comes for the Gulf of Mexico (GOM). Because the GOM accounts for virtually all the royalty-bearing production, we did not adjust the budget forecast for purposes of using it as a base for the royalty effects of the deep gas incentive. We, however, did make one adjustment to our royalty effects forecast to make it more consistent with the budget forecast. The simple average of the 11 year OMB wellhead price forecast is \$3.55/mcf compared to a flat wellhead price of \$3.25/mcf used in our economic analysis. We inflated our royalty effects estimate by 9% (\$3.55/\$3.25) to remove a price assumption difference effect from the estimate of royalty with and without the incentive. That price assumption adjustment changes the cumulative loss of royalty from \$87 million to \$95 million over the next 16 years. See columns I and J on the last spreadsheet in Appendix 2.

Our latest budget forecast is for cumulative OCS royalty receipts of \$52.1 billion from 2003 though 2013 (i.e., the next 11 years) with no deep gas incentive. Over the same period we estimate royalty receipts under our proposed deep gas incentive would be \$51.5 billion or 1.1% lower. See columns H and K on the last spreadsheet in Appendix 2. Because the royalty suspension supplement can be applied to oil as well as gas, this broad measure of royalty offers the most complete estimate of the proposed royalty effect. The 11 year period, however, is not long enough to reflect the additional royalty receipts from incremental deep gas production after the royalty suspension volumes have been used up. The net gas royalty loss diminishes over a longer period as production from new, larger reservoirs discovered under the incentive produce beyond the royalty suspension volumes and pay royalty on production that would not have occurred without the incentive. If we assume royalty receipts continue at the level we forecast for 2013, then by 2020 the deep gas incentive will result in a negligible 0.04% reduction (\$323 million) in cumulative royalty receipts of some \$86 billion.

Royalty receipts only from deep gas sources provide another perspective on the royalty effect of the incentive. Future production will emerge from 3 kinds of deep gas wells:

(1) Those already in production. None of the leases that account for this deep gas production are eligible for the incentive and so will continue to pay royalty. The 162 producing deep gas wells on the shelf have recently provided about 7.7% of total gas production. If no new deep production emerges on these leases, their share of total production will decline over time as their deep wells deplete. We assumed these wells maintain their same 7.7% share of gas production from currently existing wells.

(2) Those that would be drilled in the absence of the incentive. We estimate that even without the incentive 90 additional successful deep wells would be drilled anyway over the six years the incentive is in effect on leases that have no prior deep gas production. Appendix 1 explains why these discoveries are likely to be smaller on average than discoveries with the more extensive drilling induced by the incentive.

(3) Those extra wells that will be drilled because of the incentive. New production will come from wells that would not be drilled in the absence of the incentive, which we estimate at 2.85 TCFE (trillion cubic feet on gas equivalent), 2.35 TCF of which is gas. The condensate and the gas production after the RSV from these added wells will pay royalty and so will offset some of the forgone royalty.

Table 7 shows the amounts of gas and gas equivalents that would result from each of these 3 kinds of deep wells. It summarizes calculations shown on the last spreadsheet in Appendix 2. Common assumptions in these calculations include a gas to oil ratio of 26 mcf/bbl meaning gas makes up 82.2% of the thermal content of production from deep wells and deep well production rates of 2.5 BCF/year in the 15,000-18,000 feet TVD SS interval and 4.6 BCF/year in the 18,000 feet TVD SS and deeper category. The first 2 rows show a status quo situation in the absence of the incentive. Row 3 adds the effect of the incentive. The last column of rows 4 and 5 show the incentive adds about 38% to the

Table 7: Gas Production and Royalty Receipts in the Next 15 Years
With and Without the Incentive

	Royalty-bearing Production Without incentive (Status Quo)	Royalty-free Production With Incentive	Royalty-bearing Production With Incentive	Total Production With Incentive
From Ineligible Leases (Status Quo)	3.49 TCFE of which 2.87 TCF is gas	0	3.49 TCFE of which 2.87 TCF is gas	3.49 TCFE of which 2.87 TCF is gas
From New Deep Wells that Would be Drilled Anyway (Status Quo)	3.95 TCFE of which 3.25 TCF is gas	2.10 TCF	1.85 TCFE of which 0.87 TCF is gas [(3.95 TCFE * 0.822) – 2.1 TCF]	3.95 TCFE of which 3.25 TCF is gas
From Added Deep Wells	0	1.14 TCF	1.72 TCFE (1.215 + 0.509) of which 1.21 TCF is gas [(2.86 TCFE * 0.822) – 1.14 TCF]	2.86 TCFE of which 2.35 TCF is gas
Total Deep Well Production	7.44 TCFE		7.06 TCFE	10.3 TCFE (38% increase from Status Quo)
Total Deep Gas Production	6.12 TCF	3.24 TCF	5.22 TCF	8.46 TCF (38% increase from Status Quo)
Total Royalty Receipts from Deep Gas	$3.54 billion	0	$3.29 billion	$3.29 billion (7% decrease from Status Quo)

status quo deep gas production. Row 6 uses an implicit royalty value of $0.52/mcf (derived from the results of the budget analysis) to calculate that the incentive reduces royalty receipts by about 7%.

VI. Novel Policy Issues

This rule raises a novel policy issue in two categories. One, the rule may have an effect on grants to States under Section 8(g) of the OCSLA. Two, it expands the scope of royalty relief incentive to include exploration, not just development efforts, in a categorical way on existing leases.

The section 8(g) effect is likely to be small. Under its provisions, States receive 27% of royalty collected on leases within 3 miles (or 3 leagues offshore Texas) of their seaward boundary. In 2000, the MMS webpage shows these distributions totaled $40 million for the four States bordering the producing areas of the GOM. The main effect of the proposal will be to postpone some new royalty distributions. Based on the proportion of shelf leases that are in the 8(g) zone, royalty suspensions from the deep gas program could affect up to 5% of the total production from the GOM in any one year. If deep gas production occurs in the 8(g) zone at the same proportion as elsewhere in the GOM, these State grants could be reduced by $1 to $2 million a year for 5 to 10 years. However, extra production that occurs because of the incentive will also provide extra royalties, mostly after the royalty suspension volumes have been produced. Also, the added economic activity in those States associated with more deep and very deep drilling will generate new tax revenues.

The novel policy issue raised by the framework of the rule is due to the royalty suspension supplement and the application of a categorical royalty relief program to existing leases. The RSS for an unsuccessful deep gas well expands the scope of royalty relief to reward efforts for exploration in frontier well depths whether or not they eventually lead to deep depth production. In effect, the RSS has the government share some of the exploration risk with the lessee. Nevertheless, the size of this share is relatively small. The expected present value of an RSS is about $2.3 million compared to drilling costs of about $15 million (see page 22).

It is important to note that several features of the proposal essentially eliminate any moral hazard potential of the RSS.

- The cost of a well deeper than 18,000 feet TVD SS is almost 6.5 times the value of the RSS, so drilling just to gain the credit is not worthwhile.
- The RSS is only available to wells in new boreholes, so tactical sidetracking (extension) of an already drilled well will not qualify.
- The RSS is only available on leases that have not yet had a productive well deeper than 15,000 feet TVD SS, so operators facing lower risk as a result of previous success also will not qualify.
- To earn the RSS requires that the lessee demonstrate to MMS that seismic or other information was available before drilling and identified a prospective target reservoir.
- The RSS from a non-productive well can be used only if it fails to meet the producibility requirements specified in 30 CFR Part 250, subpart A (generally 15 feet of net pay) or MMS agrees that the well is not commercial.
- In the event that market conditions improve substantially after a well qualifies for an RSS, the lessee must deduct any RSS used from an RSV that the now productive well receives.

- Finally, the program of accruing RSV's and RSS's expires 5 years after issuance of the final rule, so any unforeseen effects of the RSS will not continue indefinitely.

The proposal creates an administratively efficient royalty relief program in this very risky environment. Categorical RSV's have been used for several years as an incentive to accelerate exploration and production in deep water and for deep gas on new leases. Application to deep gas on existing leases is a logical extension of that policy. A well-defined categorical program for deep-gas drilling is more effective than the elaborate case-by-case requirements of the application process for deepwater royalty relief on older leases, in large part because the focus for deep gas is mostly on inducing exploration drilling, rather than encouraging development following a discovery which would allow for a careful case-specific review. Moreover, minimizing the government's approval process serves to reduce uncertainty to lessees about the availability of royalty relief for deep gas production, so they can make drilling decisions by focusing solely on exploration and development risks and not on the potential availability of royalty relief.

VII. <u>Regulatory Flexibility (RF) Act</u>

Several factors make promulgation of this rule at this time important. U.S. demand for natural gas is expected to rise strongly over the next decade while domestic supplies are dwindling. Imported gas provides only a small share of domestic supplies because of the inherent difficulty and danger of transporting gas. A large and promising source of domestic gas, deep reservoirs on existing OCS leases in the shallow water part of the GOM, has been little explored. This is because the costs and risks of drilling deep reservoirs are high relative to drilling shallow reservoirs on these same leases. Further, these higher costs would rise if much of the extensive infrastructure (platforms and pipelines) developed to support the production of shallow reservoirs gets removed as the shallow reservoirs deplete. That means there is a significant chance these deep resources would never be produced if not encouraged now.

A. Objectives of, and legal basis for, the proposed rule

To accelerate and increase drilling into deep reservoirs, this rule proposes to:

(1) Suspend royalty payments for specified volumes of deep production that begins in the 5 years after the rule becomes effective; and

(2) Allow producers to apply designated amounts of royalty suspension supplements to other lease production for deep drilling that fails to encounter producible reserves.

Together, these measures will reduce the royalty costs associated with deep drilling and production below the royalty costs of other production on the same lease.

Title 30 CFR Part 203 regulates the reduction of oil and gas royalty under 42 U.S.C. section 1337(a)(3). Under section 1337 (a)(3)(B), we may reduce, modify, or eliminate royalties on certain producing or non-producing leases or categories of leases to promote development or increased production or to encourage production of marginal resources, in the GOM west of 87 degrees, 30 minutes west longitude.

B. Nnumber of small entities to which the proposed rule will apply

Companies that extract oil, gas, or natural gas liquids, or are otherwise in oil and gas exploration and development activities and operate leases on the OCS, will be most affected by this rule. The Small Business Administration (SBA) defines a small business as having:

- Annual revenues of $6 million or less for exploration service and field service companies.
- Fewer than 500 employees for drilling companies and for companies that extract oil, gas, or natural gas liquids.

Under the North American Industry Classification System Code 211111, Crude Petroleum and Natural Gas Extraction, MMS estimates that a total of 1,380 firms drill oil and gas wells onshore and offshore. Of these, approximately 130 companies are active offshore in the GOM. Merger and acquisition activity is constantly adjusting the exact number of operators. Publicly available data (from Compustat, Standard and Poor's, McGraw-Hill, and from Dunn & Bradstreet via Hoovers' sites on the internet) indicate that 39 (30 percent) of these companies active in offshore activities qualify as large firms according to SBA criteria, leaving about 91 (70 percent) companies that qualify as small firms with fewer than 500 employees. Further breakdown of the small entity operators indicate that 28 percent have between 100 and 500 employees, 53 percent have between 1 and 100 employees, and the rest have no employees as they are fully staffed by contractors. As explained in the next section, compliance costs are minimal for small as well as large entities.

C. Reporting, recordkeeping and other compliance requirements

The proposed rule requires reporting within the meaning of the Paperwork Reduction Act in four situations. These situations are:

(1) Notify the Production and Development Division of MMS in the GOM region (MMS-PD) of intent to commence drilling a deep well;

(2) Notify MMS-PD that production has commenced from the deep well and request confirmation of the size of royalty suspension volume;

(3) Provide MMS-PD with data from the deep well to confirm that the well drilled was an unsuccessful certified well and request supplement; and

(4) Notify MMS-PD of a decision to exercise an option to replace the deep gas royalty suspension terms in the lease document with the terms in the proposed rule.

The frequency of reporting is on occasion. Responses are voluntary but are required to obtain or retain a benefit. We will protect information considered proprietary according to 30 CFR 203.63(b) and 30 CFR 250.196.

Because this program is administered on a categorical rather than a lease-by-lease basis, minimal administrative time and cost is needed to qualify for royalty relief. The notifications in items (1) and (2) above only entail sending a letter affirming that an action which is a normal part of business operations has occurred. Item (3) involves sharing data from well logs and seismic surveys that the company would develop even in the absence of this rule as a normal part of its exploration business. The notification in item (4) involves making a business decision about which of two alternative incentives best fit the prospects faced by the individual lease. The professional skills involved include those normally used in the operation of all OCS leases -- geologists, geophysicists, engineers, and economists. Since no special analysis or independent review would be necessary to accomplish these compliance activities, we see very little burden on normal operations of either small or large companies. Beyond the paperwork notifications, there are no other compliance costs associated with this proposed rule.

The following passages and table are derived from our Paperwork Reduction Analysis. The proposed rule would increase the total paperwork hour burden of the 30 CFR part 203 regulations by 361 hours annually, spread across the entire industry. Based on a cost factor of $50 per hour, the burden of the new paperwork requirements would be $18,050 for the entire industry. This cost pales in comparison to the $10 to $20 million that it costs to drill a single well on the OCS to the deep depths covered by this proposed rule. As explained on pages 65-66 in Appendix 1, we estimate transfers to OCS producers both large and small entities from reduced royalty obligations will average about $38 million per year [($102 million * 6 years)/16 years]. The small business proportional share would be $27 million. So, even if small businesses were to bear 100 percent of this compliance costs, it would represent less than 1/10th of one percent of the average annual gross benefits obtained by small business in the form of their proportional share of added industry profits. The last sub-section of this Regulatory Flexibility section mentions two reasons, i.e., risk sharing and location advantages, to think that small OCS entities could get a disproportionate share of the large benefits of this rule, so small entities could get significant positive net benefits from this rule as well. Furthermore, choosing to engage in this program, and hence incurring the nominal compliance cost, is voluntary. Non-participation is not detrimental, since companies that choose not to participate are no worse off than they would be in the absence of the rule.

Except for the row associated with §48(b), these annual measures of burden costs cover the 5 to 6 years in which the incentive would be effective. The switch option of §48(b) is only available for 6 months after the rule becomes effective. We assume the small business share of compliance costs is proportional to the small business presence in offshore activities, i.e., 70 percent. This means that small business would incur up to 253 burden hours in year 1 and 204 burden hours in years 2 through 6.

INDUSTRY BURDEN BREAKDOWN

30 CFR 203 Section	Reporting Requirement	Hour Burden	Annual Number	Annual Burden Hours
43(a) 46(a)	Notify MMS of intent to commence drilling.	1 hour	89 Notices	89
43(b) (1)(2)	Notify MMS that production has commenced and request confirmation of the size of royalty suspension volume.	2 hours	25 Notices	50
46(b)(1) (2)	Provide data from well to confirm and attest well drilled was an unsuccessful certified well and request supplement.	8 hours	19 Sub-missions	152
48(b)	Notify MMS of decision to exercise option to replace one set of deep gas royalty suspension terms for another set of such terms.	2 hours	35 Notices	70
TOTAL REPORTING BURDEN – 1 year			168 Responses	361 Hours
TOTAL REPORTING BURDEN - 2-6 years			133 Responses	291 Hours

D. <u>Federal rules that may duplicate, overlap or conflict with the proposed rule</u>

We are not aware of any Federal rules that conflict with the proposed rule. Two other kinds of royalty relief apply to OCS leases, but do not overlap this proposed rule. Deep water royalty relief has been granted to leases in water at least 200 meters deep in the GOM since 1996, but no leases covered by this proposed rule are eligible for deep water royalty relief. Also, any OCS lease may apply for royalty reduction when it nears the end of its economic life, but this form of relief is only relevant to mature production on a lease, not to development of new reservoirs covered by this proposed rule.

A different royalty relief incentive for deep gas drilling has been included for newly issued leases in the five OCS lease sales held since the beginning of 2001. This incentive is not available to older leases issued before 2001, so they do not overlap the main set of leases targeted by this rule. However, a provision of this proposed rule allows newly issued leases a one-time option to switch to the incentives in this proposed rule. This switching provision is included to be fair and is voluntary. Lessees paid a premium in their bid for the new leases because their lease terms included deep gas royalty relief. Lessees of older leases had no expectation of royalty relief so their lease bids included no such premium. Allowing new lessees to switch lets those who paid for deep gas royalty relief in their bonus bid choose the more favorable of the two incentives. This switching provision also optimizes the incentive effects of the proposed rule because it will promote more deep gas development by those lessees that choose to switch. Finally, switching enables administrative simplifications when lessees on the same unit choose the same incentive terms. We estimate the aggregate small entity share of the one-time paperwork cost for the switch to be proportional to their presence in offshore activity, i.e., 70 percent of $3500, or about $2500.

The proposed rule slightly overlaps two regulations applicable to OCS leases. OCS lessees must submit an application for permit to drill (30 CFR 250.414) to the local MMS district office for review, processing, and eventual entry into an agency-wide data base. This application is a more involved submission than the letter required in the proposed rule notifying MMS-PD of intent to commence drilling. We propose to require the simplified but duplicate version of this application because it is a minimal action that provides important lead time for coordinating other MMS actions that may concern the lease. For example, a potential royalty suspension requires adjustment if the subject lease participates in our royalty-in-kind program. OCS lessees must also notify the local MMS district office when production begins on the lease (30 CFR 250.180). If the deep well is not the first production on the lease, the notice required under this rule would not be duplicative. It, also, would be vital to help avoid confusion when a lease has both royalty-bearing and now royalty-free production. Most of the older leases in shallow water have to be in production already as a condition of holding their lease. The proposed notification would be redundant only when the deep well is the first production on the lease. We believe it is simply easier to set this minimal notice burden on the start of all deep production than to create separate notice rules depending on whether a lease has prior production or not. Even when redundant, the notice serves as a useful check on a long-standing routine report.

E. Significant alternatives to the proposed rule

The Regulatory Flexibility Act requires the agency to consider alternatives to the proposed rule. The paperwork costs are less than 1/10th of 1 percent of these benefits and are the minimal necessary to allow the monitoring essential to a consistent administration of a categorical relief program across all participants. The alternative of a case-by-case relief program, where each operator would apply to participate would enormously increase the paperwork burden and associated costs for all participating lessees, both small and large entities. While case-by-case review might reduce forgone royalty, it would add uncertainty about approval and thus discourage new drilling relative to the categorical program. Also, an application process would discourage participation especially by small operators who are unlikely to have the staff needed to assemble and defend an appropriate application.

Alternative forms of the categorical deep gas incentive we considered included: (1) reduction of royalty rates for production emerging from new deep wells, (2) suspending royalty for a fixed value rather than a volume of new deep production, (3) a royalty suspension volume only for successful deep wells, (4) different royalty suspension volumes, and (5) no incentives. These alternatives are fully discussed in section IV of this economic analysis. The administrative costs are the same for all the categorical incentive alternatives. Only the benefits are different. The alternative we chose results in the largest benefit to producers and to the small entity share of producers. Additionally, this proposed incentive structure also may especially benefit small operators more than the alternative categorical incentive structures mentioned above.

The RSS feature improves the ability of small companies with limited drilling programs to spread their risk. Success on one or two of many deep wells that a large operator drills in a given period can pay the costs incurred for the unsuccessful wells. Small operators may be able to drill only one or two deep wells in a given period. The royalty suspension supplement can reduce the net cost of unsuccessful deep wells immediately, so the small operator does not necessarily have to wait for a deep well success in a later period to offset at least some unsuccessful exploration costs. This is a feature not found in any of the alternative categorical incentive structures which confer royalty relief only on successful wells.

Because of the risk, high cost, and technical complexity, we expect most lessees/operators involved in exploration and development in deep drilling depths of the GOM to be large companies. However, the location eligible for deep gas royalty relief is in shallow water, where we find relatively more small operators compared to those found in deep water. Thus, relatively more of those OCS operators who will benefit from the deep gas incentive in this rule may be in the small business category than those who benefit from deep water royalty relief.

Appendix 1. Estimating Deep Drilling Activity and Discoveries

An estimate of the rate and magnitude at which drilling and production would occur with and without the proposed incentive hinges on two factors – 1) the number of deep wells drilled and produced and 2) the size of the reservoirs discovered and produced.

1.A. Status Quo

Reviewing trends (TIMS) in drilling deep depths during the past 10 years in shallow water, we would expect 12 new productive wells in a typical year in the 15,000-18,000 feet TVD SS interval (deep drilling depths) and 3 productive wells annually at deeper than 18,000 feet TVD SS (very deep drilling depths) without the incentive. Given the historic success rates, that number of productive wells imply 37 total wells (productive and unproductive) would have been drilled annually in deep drilling depths and 11 wells to very deep drilling depths below 18,000 feet TVD SS. We assume all these new productive deep wells are on different leases so each earns an RSV. That yields an estimate of the maximum number of RSV's that would be used. Also, at some distant point in the future, the royalty incentive on new leases, begun in 2001 lease sales, alone should begin to increase the pace of this status quo deep drilling activity. We don't need to account for this effect on status quo production because this analysis focuses on deep drilling activity on existing leases whose prospects will not be subject to the new lease incentive.

To estimate the resource magnitudes associated with discoveries made from drilling under the status quo scenario, we assumed a continuation of previously discovered reservoir sizes in the GOM. Outside the Norphlet trend area, the TIMS data base shows 592 depleted, producing, producible, or undeveloped proved reservoirs in the 15,000-

18,000 feet TVD SS interval with an average size of 21 billion cubic feet of gas equivalent (BCFE) and 17 such reservoirs in the sub-18,000 feet TVD SS category with an average size of 30.5 BCFE. We exclude the Norphlet discoveries from our data on reservoir sizes as they are not typical of the remaining prospective sizes within deep and very deep drilling zones in the GOM on leases eligible for our proposal. The Norphlet trend off Mobile underlies less than 2% of the shallow water tracts in the GOM but contains 25% of all the reserves so far discovered deeper than 15,000 feet TVD SS and 3 times as many discovered reservoirs deeper than 18,000 feet TVD SS as the rest of the GOM combined. Due to its circumstance as the only intensively explored very deep play, Norphlet size data skews the image depicted by the limited historical data on the deep zones. Also, the proposed rule excludes leases from the incentives if they have past or current deep production, so most Norphlet area leases will not be affected by the proposal anyway.

This incentive proposal should change recent trends and induce additional drilling and production from prospective but risky zones. For reasons enumerated in section III, we don't expect projected natural gas prices alone to stimulate all economically appropriate exploration and production on the OCS.

1.B. Additional Drilling

To determine the additional deep drilling outputs induced by the incentive, we conducted an analysis of the minimum reservoir size that would be worth developing given a discovery, with and without the incentives, in conjunction with in-house geologic estimates of the size distribution of undiscovered deep depth reservoirs.

Within both drilling depth categories, we also computed the smallest expected reservoir size at which we anticipate that, under current lease terms, prompt exploration activity should be undertaken. Given the risks and costs expected, we found these promptly explorable (fully risked) reservoir sizes to be 50 BCFE in the 15,000-18,000 feet TVD SS interval and 90 BCFE in the sub-18,000 feet TVD SS category. These sizes are not representative of those found, but rather what lessees need to expect to find before they take on the high cost to drill a high risk prospect immediately in those deep zones. Indeed, reservoirs targeted at sizes as small as 35 BCFE and 55 BCFE in the two drilling depths respectively, could still be drilled with the expectation of some profit, but it would not be economically optimal to do so. Moreover, after the exploration costs have been expended, it is profitable on a go-forward basis to develop even smaller reservoirs.

MMS has developed estimates of reservoir size distributions for undiscovered gas and oil resources in the two deep drilling depth categories to support the published estimates of 5 to 20 TCFE recoverable but undiscovered resources deeper than 15,000 feet TVD SS in the shallow waters of the GOM. These estimates were developed from a combination of proprietary data obtained from lessees and geologic estimates of originally in-place resources. We computed the number of reservoirs in this distribution at and above the promptly explorable sizes. The resulting sets of reservoirs represent those whose activity milestones would be little if any affected by new economic incentives. As such, they are taken to represent the base case view of the future potential; call them the baseline number of undiscovered reservoirs.

Next, we calculated in both drilling depth categories the smallest reservoir size at which development (rather than exploration) could be expected to occur following a confirmed discovery within the next 6 years in the presence of the proposed royalty relief terms, but outside that time frame, if at all, otherwise. We estimated these minimum developable (a discovery having eliminated the exploration risk) reservoir sizes assuming no royalty to be about 15 BCFE in deep depths and 25 BCFE in very deep depths. The RSV alone reduced the minimum developable reservoir sizes by 15% to 20% from the full royalty size and by 20% to 30% when combined with the RSS in deep depths. Again we computed the number of fields in each drilling depth category whose size is expected to lie above these levels but below the minimum prompt exploration level sizes mentioned above. We assume reservoirs falling within this size range for each drilling depth category to have their activity milestones affected by the proposed royalty relief terms, resulting in additional drilling and production over the near term; call them the affected number of reservoirs. So, under the proposed set of incentives more reservoirs will be explored and at earlier times, and more of those discovered will be developed rather than abandoned for economic reasons. Ample protections in the structure of the proposal guard against abandoning marginal discoveries (see pages 42-43).

Finally, for both drilling depth intervals, we computed the ratio of affected reservoirs to baseline reservoirs. The results are taken to represent the proportional annual increase in drilling over the next six years associated with the proposed royalty relief program. For example, in the 15,000-18,000 feet TVD SS interval, we found this ratio to be about 0.5; for the sub-18,000 feet TVD SS category, the ratio was about 2.0. So, in evaluating the royalty effects from the proposed program, we judged that drilling intensity would increase by 50% over the status quo in deep drilling depths, and by 200% in the very deep drilling depths. We use rough proportional increases rather than exact counts because undiscovered resource estimates change repeatedly as new information emerges. Accordingly, with our proposal we expect additional annual drilling of 17 wells with 6 discoveries in the 15,000-18,000 feet TVD SS interval, and 24 additional wells with 4 discoveries in the sub-18,000 feet TVD SS category. Table 1.1 summarizes these drilling activity parameters for the no incentive (baseline) case and for the proposed incentive (affected number of wells) case.

Table 1.1– Number of Deep Wells Drilled Annually With and Without Proposed Incentive

Drilling depth interval	No Incentive		Proposed Incentive	
	Drilled	Produced	Drilled	Produced
15,000-18,000 feet TVD SS	37	12	54	18
Sub-18,000 feet TVD SS	11	3	35	7

To determine the resource magnitudes associated with these added discoveries, we again used estimates of the size distribution of undiscovered reservoirs. The average size of 61 undiscovered fields in the 15,000-18,000 feet TVD SS interval is 45.5 BCFE. This size exceeds (by a factor of 2) the average for previously discovered reservoirs in this interval. But the geologic estimates of undiscovered reserves are done, not in terms of individual reservoirs, but, in terms of fields which may contain several reservoirs. For purposes of estimating production flows from undiscovered fields, we assume an average of 2 development wells (reservoirs) per field. The first development (i.e., successful) well resolves the exploration risk associated with the field, so only one well per field incurs the failure rate we assume.

In the sub-18,000 feet TVD SS category, 86 undiscovered reservoirs are expected to average 97.3 BCFE. Again this size exceeds (by a factor of 3) the average for previously discovered reservoirs in this zone. While that seems counter-intuitive to the general expectation that the biggest and best reservoirs tend to be discovered first, remember these leases were acquired and are still held based largely on their less costly and less risky shallow drilling depth potential. As such, we infer that the deep potential in shallow water has not been systematically explored. Increasing the profitability of deep reservoirs relative to shallow reservoirs should redirect lessee attention to the deeper zones on their leases. The high average size in the sub-18,000 feet TVD SS category reflects an expectation that some large reservoirs remain to be found in this sparsely explored zone. The sub-18,000 TVD SS category is even less explored than the 15,000-18,000 feet TVD SS interval and is judged to contain most (80%) of the undiscovered deep gas resources. Further, the open-ended depth for the sub-18,000 feet TVD SS category hides the fact that it really encompasses multiple zones. In fact, excluding the Norphlet trend off Mobile, only 8% of the 208 wells drilled deeper than 18,000 feet TVD SS in the GOM are deeper than 21,000 feet TVD SS with no economic discoveries. So, the deepest part of this zone is essentially unexplored yet could contain large reservoirs like those found early in the development period of the shallower zones or the Norphlet trend. Table 1.2 summarizes these reservoir size parameters.

Table 1.2 -- Average Reservoir Size (BCFE) for Discoveries With and Without the Incentive

Drilling depth interval	No Incentive (Status Quo) Like Previous Discoveries	Proposed Incentive Undiscovered Reservoirs
15,000-18,000 feet TVD SS	21	45.5
Sub-18,000 feet TVD SS	30.5	97.3

1.C. Royalty Losses and Gains

The cost of this royalty relief program is taken as the net forgone Federal royalty on deep gas production that would have been generated without this program. Note that any such net costs are in the form of transfer payments, so whatever the government loses is also an operator gain. In fact, there are no net real resource costs associated with the proposal. Operators will voluntarily select drilling projects, and our proposal simply expands the feasible set from which they can choose, with essentially no new or increased environmental risks from having to build new platforms and pipelines.

Direct royalty losses stem from deep wells that would be drilled and produced without this incentive and from credits against otherwise royalty-bearing production to which the RSS will be applied (status quo deep drilling). Offsetting these losses are royalty gains stemming from the added discoveries that are induced by the incentive (incremental and a portion of accelerated deep drilling) and which subsequently generate gas production above the royalty suspension volumes and liquids (condensate) production, all of which are royalty-bearing under the proposal. Because only a portion of the resources affected by the incentive program will be produced in any one year, we account for the time profile of these opposing effects, as well as for the time-adjusted dollar values.

Based on past trends in deep drilling, we estimate that for each of the 6 years (one year from the proposed to the final rule and then 5 years after the final rule) when the drilling incentives will be in effect, about 255 BCF of reserves that would have been discovered that year in the absence of the incentive will in fact qualify for royalty suspension [(15 BCF * 12 deep wells) + (25 BCF * 3 very deep wells)]. Further, we forecast that under the proposal, there would be 35 wells drilled annually to depths deeper than 18,000 feet TVD SS, of which 28 would be unproductive. (See Table 1.1) The reduced success rate from historical experience (7 of 35 or 20% instead of about 3 of 11 or 27%) reflects our expectation that a disproportionate share of the easiest to find prospects (i.e., largely those in the prolific Norphlet trend) have already been drilled, leaving a riskier set of prospects yet to be found. However, only a portion of those leases with an unsuccessful well would be able to actually use the royalty credit. Historically, TIMS data show that about two-thirds of the leases that drill very deep wells have other production against which they could apply the royalty suspension supplement. This implies that only 19 of the 28 leases with unsuccessful wells would earn the royalty supplement of 5 BCF, thereby qualifying 95 BCF of production that would occur anyway for royalty suspension. When added to the RSV losses on baseline production of 255 BCF, we obtain an overall estimate of accrued royalty losses of 350 BCF annually from our proposal compared to the baseline.

Offsetting these royalty losses from productive and unproductive deep depth drilling would be gains from extra royalty-bearing resources discovered because of the incentive and produced after the RSV has been exhausted. Attributing the average reservoir sizes from Table 1.2 to the 6 added discoveries in 15,000 to 18,000 feet TVD SS drilling depths and 4 added discoveries deeper than 18,000 feet TVD SS, we forecast that projects totaling 662.2 BCFE [6 * 45.5 BCFE + 4 * 97.3 BCFE] in added reserves would be discovered in an average year of the incentive program. Of that amount, 190 BCFE will receive the RSV; the remainder, 472 BCFE, will be the extra royalty bearing production.

It's important to point out that a portion of the added discoveries results from acceleration in activities that might reasonably be expected to occur anyway but later in time without the incentive. Discoveries and production simply moved forward in time creates relatively lower valued benefits compared to discoveries or developments which otherwise would not have occurred at all. For purposes of this analysis, we include in the added production estimates the difference between the full accelerated reservoir size and the present value of the same reservoir size produced in a future period.

A representative example of this would occur when, say producing a 60 BCFE reservoir is accelerated by 6 years as a result of royalty relief. In fact, this reservoir size is typical of what we would expect in the subset of accelerated reservoirs (i. e., better prospects than those that would not be discovered and produced at all absent the incentive). The present value on 60 BCFE is 40 BCFE [60/(1.07)^6], so 20 BCFE (60 – 40) of the accelerated production is treated as equivalent to incremental production and included in the added production attributed to royalty relief. With the parameters, 7% annual discount rate over 6 years, this acceleration premium conveniently works out to be 1/3 of the accelerated reservoir size.

To properly account for the incremental or non-accelerated part of the added reserves, i.e., incremental discoveries, we take into account both the chance of making discoveries without the incentive program and the likely difference in the size of an accelerated discovery versus a new discovery. In the sub-18,000 feet TVD SS zone, TIMS data show very few discoveries (only 18 out of 73) have occurred outside the Norphlet trend; and none produced below 21,000 feet TVD SS. Those that have been discovered tend to be much smaller (averaging 30 BCFE instead of 100 BCFE). These observations suggest that most, perhaps 3 of the 4 very deep added discoveries, will not happen at all absent the proposed drilling incentive. Thus, for the sub-18,000 feet TVD SS category, we estimate 292 BCFE (3 * 97.3) of extra reserves discovered annually are incremental, that is in reservoirs that would not be discovered without the incentive. Also, 32.4 BCFE (1/3 * 1 * 97.3) of accelerated production is counted as added production, meaning a total of 324.3 BCFE from very deep discoveries are added on average each year the incentive is in effect. These discoveries are in reservoirs to which drilling is not simply accelerated, but would not have occurred otherwise. Further, 224.3 BCFE [324.3 – 4 * 25] of this increment occurs on royalty bearing production.

In the more active 15,000-18,000 feet TVD SS interval, there is no compelling reason to expect either the new or accelerated share of added reserves to exceed the other, so we assume that 3 of the 6 discoveries are incremental or would not happen absent the incentive and 3 are accelerated discoveries. However, on average, the accelerated discoveries here are probably larger (i.e., more profitable) than the new discoveries that would not happen absent the incentive.

So, we used 60 BCFE as a representative size for accelerated discoveries on these deep depth reservoirs. Thus, for the 15,000-18,000 feet TVD SS interval, this leaves 153 BCFE [(6 * 45.5 BCFE) – (1 – 1/3) * (3 * 60 BCFE)] of the added reserves. Further, 63 BCFE [153 – (6 * 15)] of this increment occurs on royalty bearing production. Thus, the sum of new incremental royalty-bearing production for both drilling depth categories is 287 BCFE. Table 1.3 summarizes the amount of gas that will be affected in a typical year by the proposed deep gas drilling incentives.

Rows one and three of Table 1.3 compute the direct royalty losses from deep drilling that would occur anyway, either immediately or eventually. The first 3 rows show the forgone royalty associated with well that would be drilled anyway. The fourth row shows our estimate of reserves affected by the incentive; the fifth row shows the accelerated portion of affected reserves; the sixth row shows the portion of accelerated reserves we treat as added production. The seventh row shows the incremental reserves; the eight row shows the total added production; and the ninth and tenth rows shows the royalty-free production from added reserves. All of the RSV on the accelerated production is included because that production is unavailable later when it would have paid full royalty. A portion of the lost royalty is offset by the gain from the earlier production of the accelerated reserves portrayed by the premium shown in row 6.

Table 1.3 -- Average Annual Incremental Effect on Royalty-Bearing Production for Proposed Incentive

Row		Proposed Incentive	
		Drilled	Produced
1	Unneeded RSV accrued by unaffected wells (BCF)		12*15 + 3*25 = 255
2	Leases with a failed very deep well and shallow production	(35 – 7) * 2/3 = 19	
3	Unneeded RSS accrued (BCFE)	5*19 = 95	
4	Reserves affected annually (BCFE)		[(18 – 12) * 45.5] + [(7 – 3) * 97.3] = 662
5	Accelerated production (BCFE)		3 * 60 + 1 *97.3 = 277
6	Acceleration premium considered part of added production (BCFE)		1/3 * 277 = 92.4
7	Incremental production (BCFE)		(6 * 45.5 – 3 * 60) + 3 * 97.3 = 385
8	Added production (BCFE)		385 + 92.4 = 477.4
9	RSV accrued by incremental production (BCF)		[(18 – 12) * (1/2) * 15] + [(7 – 3) * (3/4) * 25] = 120
10	RSV accrued by accelerated production (BCF)		[(18 – 12) * (1/2) * 15] + [(7 – 3) * (1/4) * 25] = 70

This extra production will generate net social benefits in the form of net income for operators that would not have occurred without the incentive. For the added discoveries, the RSV's and, indirectly, the RSS's are the economic factors that make drilling some uneconomic reservoirs profitable. Though all the RSV (120 BCF + 70 BCF) and RSS (95 BCFE) results in new net income to the operator, only the RSV associated with incremental production contributes to net social benefits. The RSV associated with accelerated production and the RSS are simply transfers from the Government. Since the incremental production would not have occurred at full royalty, the government does not forgo this royalty. With a landed gas price of $3.50 per mcf (less transportation costs of $0.25 for mcf), a one-sixth royalty generates $0.54 per mcf. We take the midpoint, $0.27 per mcf, as being representative of the profitability of each new mcf produced, i.e., $32.5 million (120 BCF * $0.27 per mcf) from incremental production and $19 million (70 BCF * $0.27 per mcf) from accelerated production. The incremental production over the 6 years we expect the incentive program to be active results in $195 million in accrued new profits, which makes up just over 3/4s of the total (undiscounted) net social benefit of the proposal computed in Appendix 2. The RSS of 95 BCFE can be taken against otherwise profitable production, so the added income to the operator is equal to the full value of the relief, $0.54 per mcf, or $51.5 million. Thus, we estimate the total annual new income accrued to operators under the proposal to be $103 million.

1.D. <u>Additional Drilling and Royalty under Alternative Volume Approaches</u>

We set the drilling intensity effect of each of the five RSV alternatives by choosing drilling success numbers that match the strength of its incentive relative to the proposal. Two of the five volume alternatives to the proposal ultimately considered were evaluated first and can be used to illustrate the process. These were: 1) the same royalty relief terms offered to new shallow water leases issued in sales held in 2001 and 2002, and 2) offer a larger RSV for successful gas wells deeper than 18,000 subsurface, but no RSS.

1.D.1. <u>Recent Lease Sale Incentive Terms</u>

In comparison to our proposal, extension of the recent lease sale royalty suspension terms to older leases would increase the size of the volume incentive in the 15,000-18,000 feet TVD SS interval by one-third (from 15 BCF to 20 BCF). The extension would reduce the incentive in the sub-18,000 feet TVD SS category in 2 respects; the RSV for successful drilling would fall from 25 BCF to 20 BCF while the RSS for certain types of unsuccessful drilling would be eliminated. Assuming drilling success rates in the sub-18,000 feet TVD SS category are 20%, then the expected royalty relief from drilling a very deep well falls from 9 BCF (20% of 25 BCF plus 80% of 5 BCF) to 4 BCF (20% of 20 BCF plus 0). That represents a 55% reduction in the overall incentive in comparison to our proposal.

We estimated drilling affected by the proposed policy to be 17 (54 – 37) extra wells in the 15,000-18,000 feet TVD SS interval and 24 (35 – 11) extra wells per year in the sub-18,000 feet TVD SS category. We assume a change in extra drilling activity in this alternative to be proportional to the change in the value of the incentive in each drilling depth category in comparison to the proposal. So, we estimate the recent lease sale incentive terms would result in 6 more wells (from 17 in the proposal to 23 in the recent-lease-sale-terms alternative) and 2 more added successes (from 6 in the proposal to 8 in the recent-lease-sale-terms alternative) in the 15,000-18,000 feet TVD SS interval, and (with rounding) 13 fewer wells (from 24 in the proposal to 11 in the recent-lease-sale-terms alternative) and 3 fewer added successes (from 4 in the proposal to one in the recent-lease-sale-terms alternative) in the sub-18,000 feet TVD SS category. As in all cases we treat 50% of the added deep well successes and 25% of the added very deep well successes as accelerated production. The computed drilling and production results for the recent-lease-sale-terms alternative are shown in the row with that label in Table 3, page 33..

1.D.2. Higher RSV with No RSS

The relative incentive effects of increasing the RSV from 25 to 45 BCF for a successful well in the sub-18,000 feet TVD SS in lieu of a royalty credit are more difficult to quantify. On an expected value basis, each option generates 9 BCF of relief (20% of 25 + 80% of 5 = 20% of 45 + 0). However, there are several reasons to believe the higher RSV alternative provides less incentive than the combined RSV and RSS proposed policy. One, there are likely to be fewer deep wells attempted under the higher RSV-only alternative because some lessees may be risk averse, or risk neutral with a less optimistic view of drilling success than we perceive to be the case. The credit shifts some of the private losses from bad drilling outcomes to the government, which is a feature not available with the higher RSV-only alternative. Two, the present value of the alternative relief is lower because the extra royalty-free volume is realized later in the production flow of the successful deep well than is the case with the credit. The credit can be used simultaneously with the RSV against other production, not necessarily at deep depths and not limited to natural gas. Three, there is less chance the deep reservoir actually discovered will be large enough to use all of the 45 BCF of relief than to use all of the 25 BCF of relief. On the other hand, the 45 BCF RSV option in the sub-18,000 feet TVD SS category is greater than the current 20 BCF RSV sale configuration, and neither alternative includes an RSS. Thus, the higher RSV-only alternative provides an incentive less than the proposal but more than the recent-lease-sale-terms alternative.

Since the expected royalty relief is equivalent to the proposal, the 45 BCF option probably has incentive effects that are closer to those of the proposed policy than to those of the recent-lease-sale-terms alternative for very deep drilling depths. Further, an analysis of the effects of the different relief policies on the minimum reservoir that could be explored profitably shows that size to be about 35 BCF under our proposal, 37 BCF with the 45 BCF RSV option, and 41 BCF for the 20 RSV option. Therefore, it seems reasonable to represent the effect of the higher RSV-only option as 1 less added success annually (down from 4 in the proposal to 3 rather than 1 as in the recent-lease-sale-terms alternative). The total of 6 successes at a 20% success rate implies 30 new wells annually (versus 35 with the proposal and 20 with the recent-lease-sale-terms alternative). Extra drilling in the 15,000-18,000 feet TVD SS interval is not changed from the proposed policy, since the RSV is kept the same at 15 BCF. So, overall we estimate the higher RSV (no credit) alternative in very deep depths would result in 5 fewer wells and 1 less success in comparison to our proposal. As the incentive effects are somewhat similar, we employ the same average discovery sizes as used for the proposed incentive. That should make this a liberal estimate of the relative significance of the drilling intensity of this alternative.

3. <u>Proposal Without the RSS</u>

The drilling intensity for this alternative, 15 BCF in the15,000-18,000 feet TVD SS interval and 25 BCF with no RSS in the sub-18,000 feet TVD SS category, is likely to be intermediate in relation to the previous two alternatives. In the 15,000-18,000 feet TVD SS interval it should have the same effect as the proposal and High RSV alternative, namely 17 additional wells and 6 additional successes for each year of the incentive.

In the sub-18,000 feet TVD SS category, this alternative ought to fall between the Sale Terms and High RSV alternatives, but closer to the former. On an expected value basis, it generates 5 BCF of royalty relief compared to 4 BCF for the Sale Terms alternative and 9 BCF for the High RSV alternative. We set the annual drilling success for this alternative at 4.5 wells out of 22.5 tries, or 1.5 more success per year on average than the Sale Terms alternative and 2.5 fewer successes than the High RSV alternative. In practical terms, the half well means an extra success every other year.

1.D.4. Reduced One or Two Tier Alternatives

The alternative that reduces the RSV only in the 15,000-18,000 feet TVD SS interval (from 15 BCF to 10 BCF for a successful well) will have the same drilling intensity effect in the sub-18,000 feet TVD SS category as the proposal. In the other interval, the expected value of the incentive is two-thirds the size of the incentive with the proposal. That implies additional successes of 4 out of 11 tries instead of the 6 out of 17 tries.

The alternative that also reduces the RSV in the sub-18,000 feet TVD SS category, only does so slightly, from 25 BCF to 20 BCF for a success. The expected value of the relief falls from 9 BCF to 8 BCF (20% of 20 + 80% of 5), so it would have somewhat less effect in the deepest interval. While this expected value is also below that of the High RSV alternative, we expect this alterative to exert somewhat more incentive for the risk aversion, present values, and reduced chance of finding adequate reservoir sizes arguments made above. Rather than duplicate the inputs used in the High RSV evaluation, we set the success rate between it and the proposal. Specifically, we set the annual drilling success for this alternative at 6.5 wells out of 32.5 tries, or 0.5 more success per year on average than the High RSV alternative and 0.5 fewer successes than the proposal. As the results indicate, this alternative and the High RSV alternative are quite similar on all the effects measures except for forgone royalty receipts.

1. E. Monetizing the Net Royalty Effect

Previous discussion in this appendix dealt with volumes of royalty-bearing and royalty-free production resulting from drilling activity induced by the incentive on average each year it is in effect. To compare the royalty losses with the E.O. 12866 and SBRFA criteria, volumes of royalty-bearing production should be converted into monetary terms. Doing so means taking account of the difference in the time profile of when the royalty costs and benefits will be realized. Production affected by this temporary policy will emerge over a number of years after the policy expires. Three assumptions are critical to the monetary estimate –the rate at which the royalty suspension volume and additional reserves are produced, the ratio of the gas to the liquids in the deep gas well production, and the prices used for gas and condensate.

TIMS data indicate that average gas production rates for wells in 3 drilling depth categories are as follows:

- 0-15,000 feet TVD SS – 1 BCF per year
- 15,000-18,000 feet TVD SS – 2.5 BCF per year
- greater than 18,000 feet TVD SS – 4.6 BCF per year

Applying those to the proposed RSV and RSS amounts indicates that it would typically take 5 to 6 years (15/2.5 or 25/4.6) for a single deep well to use the proposed RSV's in each drilling depth. Multiple wells on a lease could shorten that period, but would add cost for the lessee. In practice, decline rates could affect the duration of both RSV and the post-RSV (royalty-bearing) production. As with price variation through time, we omit these complications as beyond the needs of this analysis. Determination of the RSS duration is also complex as it can be used by gas and oil in shallow wells and by the liquids portion of deep wells on leases that subsequently drill a productive deep well. We assume that it takes a fixed period of 2 years to use up the RSS to reflect a likely combination of several shallow wells and perhaps some deep condensate production. Deep gas production eligible for relief would first use its RSV before applying the RSS.

Wells having a discovery virtually always produce both liquids (oil or condensate associated with gas) and gas (natural gas or gas associated with oil). In our proposal (and all options) the RSV only applies to the gas part of a new deep well's production. The liquids part of the production pays royalty (see proposed section 203.42(e)). According to the TIMS data base, the ratio of gas to oil can vary greatly, from 2 to 53,000 mcf gas per barrel of oil (bbl). The weighted average and the median for the 171 deep and very deep producing deep wells listed in the TIMS data base is 26 mcf gas/bbl oil. In combination with the gas to oil ratio, this means that while a well is producing 26 mcf of gas worth $91 at a price of $3.50/mcf it is also producing 1 barrel of oil (condensate) worth $28. Or, of every $119 of value produced from the deep well during the royalty suspension period, $28 or 23.5% will pay royalties.

For purposes of the calculation, we assumed a constant landed gas price of $3.50/mcf (and a wellhead price of $3.25). That is below the levels experienced in 2000 and 2001 but above the annual averages before and since, and above the levels EIA currently projects (which falls from $3.60 in 2000 to $2.66 in 2005 and then gradually rises to $3.26 by 2020). We use the high flat price so as to be conservative and not understate potential royalty losses. Notice that this price assumption does not approach the price threshold value, so we do not deal with the effects of a price spike discontinuing the RSV and RSS. For condensate value, we used a crude oil price of 8 times our gas price assumption (like the Deep Water Royalty Relief Act), or $28/bbl relative to our gas market price assumption of $3.50/mcf.

One other issue, the tax applied to the extra profit lessees collect, affects the quantification of the net royalty effect. Since lower royalty payments mean more company taxable income, our annual estimates of royalty receipts forgone is in part offset by higher tax payments. We have not included this factor in the estimates reported here, so we are being conservative in the estimate of actual forgone receipts associated with this proposal.

Appendix 2 Calculation of Effects for Volume Alternatives

We measured the likely effect of the deep gas incentive with a 6 step process. The following description of this process identifies the labeled columns on the spreadsheet calculations used for each alternative. The title at the top of each spreadsheet indicates the alternative it covers.

1. We estimated the size of production anticipated from deep wells in the absence of any royalty suspension incentive. This baseline simply multiplies the average number of successful wells drilled by the average reservoir sizes found in the recent past. The column labeled C on each spreadsheet displays the expected deep reserves discovered annually without royalty relief. We applied average well flow rates from the recent past to distribute reserves over a production period in column D. Columns E and F separate the flow into gas and condensate with a gas to oil ratio typical of deep reservoirs. For reference, column B reports deep gas production likely from leases that already have deep wells and are therefore ineligible for the incentive.
2. We estimated the change in drilling intensity (number of new deep wells) likely to result from the proposed royalty suspension. Using an in-house geologic estimate of the size distribution of undiscovered deep depth fields, we counted the number of undiscovered fields at or above breakeven sizes determined with and without royalty suspension. Breakeven field sizes were determined with cash flow analysis and assumptions about chances of drilling success, drilling costs, gas prices, and lessee discount rates. Because resource estimates change frequently, we used relative rather than absolute numbers of fields to establish the change in drilling intensity. The box in the upper right hand corner of the spreadsheet labeled Drilling Intensity Effects

displays the resulting well counts and related production characteristic assumptions. Appendix 1 explains this analysis in more detail.

3. We then estimated additional resources resulting from the increased drilling intensity associated with the proposed incentive. We derived this estimate by multiplying the average size of all estimated undiscovered deep reservoirs by the increased number of successful wells associated with the incentive. We used historical success rates to set the expected number of successful wells. The additional resources included only a portion of those reservoirs that would have been discovered later (accelerated). We used qualitative judgments, also explained in Appendix 1, to divide reservoirs that would not have been discovered in the foreseeable future (incremental) from the accelerated discoveries. The portion of accelerated discoveries included in the additional resource estimate is the difference between the full reservoir size and the present value of the same reservoir size discovered X years from now. Column J reports this added reserve estimate for each of the 6 years we assume the incentive will be in effect. Columns G, H, and I assign RSV and RSS to the drilling and discoveries associated with baseline reservoirs and distributes this forgone royalty over time with typical well flow rates. The box at the top middle of the spreadsheet labeled Incentive Size and Duration displays the RSV and RSS amounts and associated production periods.
4. We next estimated the annual increase in deep production from these additional resources. Columns L and O distribute the added reserves shown in column J over time with typical well flow rates. Column K assigns the RSV to the added reserves. Since reservoir sizes are reported in barrels of oil equivalent or cubic feet of gas

equivalent, we split reservoirs in to gas and condensate portions. This is important because the royalty suspension volumes only apply to the gas portions. Columns M and N separate the added production flow into gas and condensate with a gas to oil ratio typical of deep reservoirs.

5. We applied assumptions about wellhead gas prices, corporate tax rates, and ratios of gas to oil (condensate) in deep reservoirs to the increase in deep production each year to estimate the annual changes in royalty that flow from the proposed incentive. Column P computes the net change in royalty from flows shown in columns I, M, and N using assumptions shown in the box in the upper left hand corner of the spreadsheet labeled Market and Product Characteristics. The Column labeled Transfers from Gov't to Producers shows the value of the royalty-free production shown in column I. Column K reports RSV on production that would not have occurred without the incentive and so is not a transfer. Since this gas would otherwise not be produced at all under foreseeable conditions and without royalty relief, and certainly not if the existing infrastructure were not available, these effects will not be offset by less production and higher prices to consumers later.
6. We applied assumptions about gas supply and demand elasticity and future domestic demand for gas to the increase in deep production each year to estimate the annual net social benefits and changes in transfers to consumers that flow from the proposed incentive. The shift in the gas supply curve resulting from the incentive is shown in Column S (column R minus Q or columns L plus M). Column T adjusts the amount in column S to the increase in market equilibrium quantity (39.5%) associated with the elasticity assumptions shown in the Market and Product Characteristics box.

Column U computes the change in equilibrium price associated with that change in equilibrium quantity. Column V reports EIA's forecast of domestic demand over the period relevant to the deep gas incentive. Column W computes the transfer from producers to consumers from the price reduction in column U applied to the quantity in column V. Finally, column X computes the net social benefit or surplus (triangle ghj in Figure 1) as the change in equilibrium quantity occasioned by the incentive times ½ the royalty cost savings associated with the incentive.