<u>Bidding under Uncertainty for GOM Exploration Blocs (A)</u>
<u>A Case Study in Incorporating Embedded Option Value into Competitive Bidding</u>

By Stephen V. Arbogast and Dr. Praveen Kumar

The first half of 2001 had not been kind to Grant Holmes. Charged with the responsibility of recommending lease bonus bids to Flagler Petroleum Exploration Company's (FPEC) top management, Grant had seen his February recommendations used, only to see FPEC win no blocs when the winning bids had been announced. Subsequent analysis revealed that FPEC had been the 'cover' or top alternate bid on 6 blocs, including their three highest priority tracts. There had been much soul searching and some recriminations. FPEC was not used to being 'shut out' of Gulf of Mexico (GOM) leasing rounds. Several executives were overheard commenting that Grant's group, Southwest District Acreage Acquisition (SWDAA) had 'blown it' by calculating their project economics too finely. Others defended SWDAA's record and argued that competitors were not risking prospects properly and/or accepting prospective returns which FPEC would not deem attractive.

Now another lease round was shaping up. The US Department of the Interior had indicated the blocs which were being ready for bid. FPEC and other active GOM players already had seismic data and interpretation on all the blocs. Lease bids would be due at the end of June with the awards announced late in July.

Grant felt tremendous pressure to make sure he didn't pitch 'another shutout'. He was sure that if SWDAA simply took forward recommendations based on their traditional methodology, FPEC's senior management would adjust the bids higher. Their basis for doing so would be highly subjective and revolve around what management judged would be necessary to 'win' a target number of blocs. This subjective process could get messy and expensive. Some executives would no doubt want to make a 'statement to the industry' that FPEC was a committed GOM player. Others would want to hedge against another 'negative' surprise. Grant could see his recommended bids progressively losing their ties to valuation as layers of 'insurance' and 'competitive messages' were laid on to determine the final 'bonus' bid amounts. Such an outcome would be damaging to the disciplined approach which Grant had imposed upon what had been a somewhat 'seat of the pants' process.

Another factor bothering Grant was his dissatisfaction with the economic methodology SWDAA employed to arrive at lease bid recommendations. This methodology involved working with FPEC's Seismic Interpretation Group (SIG) and executing a four step process. The steps involved were as follows:

1. SIG would provide SWDAA with a 'most probable' estimate of producible reserves from the prospect. This estimate would represent the most likely proven reserve case assuming 'commercial' quantities of oil were found on the bloc. SIG would also include a most likely production profile to accompany this reserves estimate. Finally, SIG would provide a probability estimate of a commercial discovery on the bloc in question.
2. SWDAA would use SIG's inputs as key assumptions for base case project economics. Projected development and operating costs and crude oil prices would be used to develop a

pro forma cash flow for the field. SWDAA would examine results for prospects yielding greater than a 20% expected return including the risk that no commercial quantities would be discovered.

3. SWDAA would then ‘back calculate’ a bonus that could be bid to win the bloc and still achieve a minimum 15% Discounted Cash Flow return. This ‘raw’ bid number would become the basis for management consideration of final bids to submit.
4. Lastly, SWDAA would compute sensitivity cases. SIG would provide estimates of a ‘max’ likely reserves case as well as a ‘minimum’ commercial amount. Returns would be calculated for each case. SWDAA would also test some sensitivities surrounding development and operating costs, depending upon the complexity of the geology and difficulty of the operating location.

Grant’s group had the authority to alter its ‘calculated’ bonus number up or down depending upon its assessment of the sensitivities and also industry competitive conditions. These recommendations then went to FPEC’s management committee along with all economics and SWDAA’s explanatory analysis. The MC frequently adjusted the bids up or down depending upon its own assessment of the field prospects and the industry’s outlook.

Attachment 1 illustrates this process at work for bloc 241, the Ursus prospect. Using SIG’s inputs, Grant’s group computed a maximum allowable $400 M bonus bid for this bloc. Attachment 2 provides the economic assessment for another bloc, 113 – prospect Sentinel, which yielded a $110 M bonus bid.

Grant had several problems with FPEC’s established methodology. These issues were, he felt, well illustrated by the two blocs at issue here. In the first place, Grant’s experience with other commercial fields indicated that almost all of them ended up yielding more recoverable oil that was originally estimated. This track record of higher ultimate recovery had been realized from a variety of sources, including:

- Secondary recovery techniques, such as gas or CO_2 reinjection, enable fields to be ‘re-worked’ to maintain pressure and boost ultimate recovery
- Field infrastructure sometimes can be used to commercialize smaller ‘satellite’ fields that would otherwise be uneconomic
- New technologies are constantly being developed which, when applied to existing fields end up increasing the percentage of reserves ultimately recovered.

Repeated examples of these developments had, over time, altered Grant’s mental image of a prospective oil field. Initially he thought of exploration as a search for a finite pool of hydrocarbons that would either be found or missed. Increasingly he thought of petroleum exploration as a series of options – first to find a commercial field and then to exploit that field progressively by capturing the additional options embedded within that field.

Grant’s second problem concerned the process of upstream development. Grant’s group was forced to develop lease bid recommendations based only upon seismic data. If the firm was awarded the bloc, further seismic and an exploration drilling program were the likely next steps. If such program yielded adequate estimates of recoverable hydrocarbons, the project would be commercialized and developed. Drilling and operating the field would then provide new information about the field, including potential extensions and means to either improve flow or enhance the field pressure driving production output. Production drilling also might also provide further geological information suggesting trends that might point to adjacent prospects.

Two things about this process bothered Grant. The process itself was one of the firm's gaining increasing knowledge about a field's geology and production prospects. Yet, Grant was forced to develop lease bid recommendations by projecting a field's full-scale development economics using the least information available. Somehow, it seemed flawed to base the bid determining whether the firm got access to further field information on development economics whose minimal data basis suggested the maximum possibility for error. This led to a second problem – the 'tyranny of money-forward economics'. Once the firm did win rights to a bloc, all costs already expended were treated as 'sunk cost'. Each decision to proceed further down the development path – from seismic to drilling, drilling to commercial development, and development to extension/expansion – were treated as distinct projects justified on the basis of only the new money to be spent. In some cases, this proved consistent with fully developing a field's economic potential. In other cases however, disappointing fields would be fully developed despite yielding low overall returns when all costs from inception were counted.

Grant was not sure what to do about these problems. Instinctively however, he wondered if there might be a way to 'value' the amount being 'risked' at each stage of the process to gain more information about a field's ultimate potential. Grant reasoned that the information gained at each stage had intrinsic value which could somehow be evaluated against the cost involved in moving forward through each stage of the process. He also sensed that in many cases the firm was underestimating the economic potential of prospects when it bid for blocs. A major part of this underestimation was the firm's inability upfront to value extensions, expansions and satellite prospects. This lack of a fundamental methodology also implied that the firm would have difficulty 'discriminating' between prospects with strong potential for expanded ultimate recovery and those with less upside. This in turn left the company more vulnerable to 'money forward' decision-making, as the 'money forward' investments were not informed by good information on differential 'ultimate development' potential.

Concerned about pitching another 'shutout' but not wanting to be accused of 'cooking the numbers', Grant decided to seek help from Ned Heath. Ned, a former Treasurer and now Corporate Planning Manager, was something of an economics methodology guru within FPEC. Support from Ned for any new lease bid methodology would be an important source of credibility.

Meeting with Ned Heath

Grant took about twenty minutes to outline his concerns to Ned, who quickly engaged with the subject matter:

> *"This is a really interesting area. I'm glad you came to see me; I too have been mulling over these problems. I've been thinking about trying to approach the issues through the use of options theory. I think that conceptualizing your problems as questions of how to value*

various options does a good job of illuminating the real issues. Unfortunately, the existing valuation techniques don't provide quantifications that management is ready to trust as a reliable basis for betting the company's money. Perhaps we can lay out your issues conceptually and then consider whether there would be some better way to assign monetary values that management might respect.

Let me illustrate what I'm talking about. Your problems can be reconfigured into a series of options. The major options you're talking about would be four:

1. *a 'knowledge' option that revolves around knowing more about the two field potentials after having executed initial drilling, but before the final commerciality decision; this one is often labeled as a 'deferral' option, meaning that the ultimate decision is deferred until later as opposed to made implicitly at the beginning when the firm may submit conservative bonus bids and lose any right to develop.*
2. *an 'operating' option that involves optimizing drilling, production levels and field maintenance once development is fully underway*
3. *a 'technology' option that involves using secondary, more advanced, or new technologies to boost ultimate field recovery; and*
4. *an 'extension' option to use the geological knowledge gained from and the infrastructure installed upon the primary field to identify and develop field extensions and satellite fields*

All of these options involve 'knowledge gains' that occur over the course of field development. Presumably, if we knew all these things upfront, they could be put in the field economics for lease bidding – but we don't so we leave them out. However, our firm must win the bid to be able to enjoy these. Losing the bid thus costs more than just the field development modeled in your lease bid economics – it also means foregoing all of these options for further development.

Are these options worth something? By inspection, it's clear that they are valuable, perhaps very valuable. Should this value be attributed to the primary field and more specifically to the lease bid? To do so would not be following our normal procedure. Typically, we treat any of these items that turn into projects as stand-alone investments to be evaluated when and if they materialize. Yet, there is this inconvenient fact that as yet we don't control these options. To do so, we need to win the lease bid. The lease bid thus 'controls' whether FPEC gets to have all of these options or none of them. Surely this implies that the lease bid is entitled to some share of any Net Present Value we might attribute to these options.

This leads to the third question – can a realistic valuation be estimated for any of these options? This has been the real stumbling block. Effectively FPEC has treated these options as so nascent and vague as to defy valuation at the lease bidding stage. The question before us is this – can any realistic assessment of value be attributed to these options at the front end of the process – and by realistic, we're talking about: 1) a probabilistic assessment of underlying value for the optional development activity and 2) the attribution of an appropriate share of that value to the lease bidding process?

This is at first glance an information question. Prior to doing any drilling on a field, is there a reliable basis in data for valuing such things as optimized field practices, extensions or secondary recovery? I'm going to ask you in a moment whether such things as 'historic practice' or knowledge of other fields in the region provide some credible basis for such estimating. But before we wrestle with that issue, we need to recognize that this information question is different for the deferral option versus all the others.

The fact that FPEC will only make a commerciality decision after drilling the field implies that the company's downside exposure is capped. It would seem that FPEC can lose at most the sum of its lease bid and the costs of initial drilling. If it decides then to abandon the field, no further loses will be incurred. We need to check that this downside 'cap' has been effectively reflected in our NPV economics. Does SIG's 'most probable' reserves estimate reflect the midpoint of 'only commercial levels of discovery' or does it reflect a midpoint that also includes uncommercial levels of hydrocarbons (including complete dry holes). You would hope that it would be the former, and that they would then provide you with a probability assessment for making a commercial find. Your economics can then blend the 'average' commercial development with the probability of uncommercial discoveries and a write off of lease bids/initial drilling. This approach, at a minimum, would reflect the reality of commerciality decisions made only after drilling, and would avoid the mistake of computing lease bids on the basis of scenarios that include erroneously developing the field despite finding uncommercial reserves or nothing at all.

The final question then for the deferral option would be 'what would I pay at the lease bidding stage for the opportunity to make my development decision only after initial drilling?' If my range of probabilistic scenarios captures this 'cap' on my downside, then I've probably already gotten some of the value captured in my field NPV. What I've probably failed to capture is the fact that my risk of a mistake is lowered by making the commerciality decision later. In all likelihood, I'm probably using too high a discount rate, one that ignores the 'information gain' provided by drilling and a later commerciality decision.

Now let's come back to the other options and the question I asked earlier – is there a basis 'upfront' for attributing value to development options for a field which we don't know whether we will win let alone develop?

Grant considered the question in silence for some minutes. At last he commented that FPEC must have consolidated data reflecting all fields being operated worldwide. He could look to see how actual reserves recovery compared with initial estimates and the causes which led to greater than expected levels of ultimate recovery. Warming to the subject, Grant had two other thoughts. One was to gather similar data on all Gulf of Mexico fields currently in production. The second was to ask the Production geologists and engineers to construct a portfolio of 'comparable' fields, i.e. a collection of global fields whose physical characteristics most resembled those of the blocs to be bid upon. The data would probably take a week to gather, after which the two agreed to reconvene to discuss what if anything could be done with the information.

Second Meeting with Ned Heath

Three days after their first session Ned found himself reviewing the historic field data sent over by Grant (Attachments 3 & 4). The first data base conveyed the following summary information:

- Worldwide, FPEC had found that operating practices tended to optimize production levels by 8% versus original estimates and total reserves recovered by 10%. These estimates were the mean of results that varied between cases where recovered reserves were actually 10% lower than first estimates to a high of 25% above original forecasts, with 0 to + 15% falling within one standard deviation of the mean. These gains were realized at a cost of 2% p.a. nominal increase in operating costs, which represented the net of productivity gains and inflation.

- FPEC had found that 65% of all fields made use of secondary and tertiary recovery methods. On average, these projects boosted proved reserves by 10% and delivered average returns weighted by capital invested of 25%. The range of project returns varied from 10% to 35%, with a standard deviation of 7%.

- Finally, FPEC found that satellite fields were developed through the primary field infrastructure in 25% of its cases. In another 10 % of cases, satellite fields were identified near the primary field but required stand-alone development. Average returns were 21% in the former case and 14% in the later, with ranges of 12-30% and 4-22%. Standard deviations were 3% and 5% respectively. For new developments located on ‘frontier’ areas, the results were higher: 45% of commercial discoveries ended up having satellite fields that could be developed using primary infrastructure; another 20% required stand-alone development. Project returns, ranges and standard deviations were similar to those in the global data base.

Turning to the GOM specific data, Ned observed the following:

- Fields developed in less than 500 feet of water (shallow water fields) had operating optimization results better than the worldwide data. Fields in deeper water managed to achieve an average of 14% increase in recovered reserves, but at a cost of 5% p.a. higher operating expenses
- Again, shallow water fields resembled the worldwide numbers. Deep water fields had few examples of secondary/tertiary applications due to their being at an earlier stage in their productive history.
- Most GOM shallow water fields were older and had historically seen satellite fields developed separately. Returns on these extensions average 15%. Deep water fields were again too new to provide a diverse data sample. There were two cases of GOM deep water fields, both of which saw the development of satellite fields through the use of primary field infrastructure. The reappraisals on these satellite projects forecast 25% and 20% returns respectively.

When Grant arrived, Ned asked him for his impressions of the data's significance. Grant replied that he didn't really know what to think. He pointed to the divergence in results between GOM deep and shallow water fields.

> *"Bloc 241 is a deep water bloc. Bloc 113 is not 'shallow water' in the old field sense, but it's not deep either – sits in about 450 feet of water versus 2000 feet for 241. What troubles me here is that the worldwide data doesn't really replicate what to expect on a deep water bloc, and the GOM data on deep water is so sparse. There does seem to be some basis for estimating upsides for Bloc 113, but even there we could miss the satellite field potential – seeing that earlier GOM development used less sophisticated technology. This drove earlier satellite field development to be based upon separate, more expensive infrastructure and probably rendered some reserves non-commercial as a result. As you can see, 'there's a million stories in this Naked City.' I don't even know how reasonable it is to look at historical performance. The geology for these two blocs could turn out to be totally different."*

Ned appeared unsurprised by Grant's uncertainties. Slowly he began to lay out a path forward:

> *I think in this matter the 'perfect' is the enemy of the good. Perhaps it would be best to move away from expectations that we can generate a highly accurate prediction of what these options are worth. After all, by definition we are attempting to evaluate potential projects under conditions of acute uncertainty.*
>
> *Perhaps the better course would be to focus on a few more probable outcomes. We can agree that these 'portfolios of options' have some value – in the sense that reasonable people would pay something to possess them. We can also agree that available data provides a more reasonable basis for estimating their value for Bloc 113. Finally, we can agree that it makes sense to 'differentiate' among exploration prospects with more and/or more certain embedded optionality and those blocs with less or less certain potential.*
>
> *If we keep these basic principles in mind, we should be able to generate some option valuations which can be appropriately 'risked' for inclusion in lease bidding."*

Grant nodded in agreement but still didn't look happy.

> *"I hear you. That makes good sense. However, proceeding along this path will still leave us taking 'suspect' numbers to a suspicious management. Said differently, we still will have to sell this approach to a management that is a) quick to believe that planners are 'cooking' the numbers; b) believes that all this future potential is properly treated as stand-alone projects when/if they materialize; and c) is more comfortable making 'money-forward' decisions as information improves. Whatever valuations we come up with will have to be combined with a strategy to address these organizational dimensions as well"*

Attachment 3

To: Mr. Grant Holmes

From: O. M. Scott

SUBJECT: Global Performance of Operating Fields

You have asked that we survey our global data base of fields operated by Flagler Petroleum (FP) for the purpose of assessing the extent to which ultimate reserves recovery exceeded initial estimates. You have also asked that we provide information regarding the means by which any increase in ultimate recovery was accomplished. Our findings are provided below.

First let us provide some information on the data based analyzed. Only fields operated by FP which reached a peak production of 50 kbd or more were assessed. These boundaries were established so that a) we could vouch for the data and b) we would focus on fields whose profile generally resembled the production/reserves targeted in our GOM bidding.

The data sample falling within these boundaries consists of 75 fields worldwide. These include fields that have been fully exploited and or divested within the last 20 years and those currently in production. For fields either divested or currently in production, the latest estimate of ultimate recovery was contrasted with the initial estimate. Of these 75 fields, 40 were onshore and 35 were offshore; 15 of the offshore fields were in water depths greater than 500 feet.

All project return information has been weighted by capital invested.

Responding to your specific questions, our findings were as follows:

- ***Operating Field Practices***: Operating practices considered 'normal', i.e. non-extraordinary and not subject to capital appropriation, yielded an average 8% improvement in annual production levels and a 10% aggregate increase in reserves recovery versus the estimate used in lease bidding or government production sharing negotiations. The difference in production versus aggregate recovery was realized as 'life extension' beyond initial estimates. Normal operating practices included selecting an optimal production level after assessing reservoir pressure via production tests, the use of 'down-hole' stimulation techniques normally expensed as maintenance costs, and the optimized location and spacing of development wells based upon initial field performance
- Not all fields in the sample yielded higher ultimate recovery of reserves. The range of results varied from -10% to + 25%, with 0 to + 15% falling within one standard deviation of the mean.
- Economic returns from optimized operating practices were highly attractive, based upon an average increase in operating costs of 2% p.a. for the sample

- ***Enhanced Recovery Projects:*** Of the 75 fields in the sample, 49 ultimately were the object of enhanced recovery projects. Such projects included gas reinjection, water flooding, steam injection, use of advanced chemical or fracturing treatments and CO_2 injection. All projects were approved capital budge items.
- Of the 49 projects, project returns estimated in Project Reappraisals averaged 25%. The range of project returns varied from 10% to 35%, with returns from 18% to 32% falling within one standard deviation of the mean.
- Returns for offshore field projects were lower than that of the total sample. Offshore fields totaled 16 out of the 49 projects, of which 4 were in water deeper than 500 feet. The offshore field average return was 20 % with a range of 8-32%. Returns from 14-26% fell within one standard deviation of the mean.
- The four projects in ultra deep water were reappraised as having a 16%, 18%, 19% and 22% return respectively

- **Extensions and Satellite Fields**: Of the 75 fields in the sample, 26 were judged to have played a role in the subsequent development of either a) new hydrocarbon-bearing sands in the same field or b) adjacent 'satellite' fields. In both cases, enhanced geological interpretation from developing and operating the field led to identification of the additional prospects. None of these development projects were foreseen at the lease bidding stage. Of the 26 projects, 18 were developed using existing field infrastructure and the remaining 8 were stand-alone developments. Project returns ranged from 12-30% and averaged 21% for the former category (18-24% within 1 SD) and 14% for the latter (range 4-22%; 8-19% within 1 SD).

- Of the 18 projects developed with existing field infrastructure, 9 were in water deeper than 500 feet. Returns for these 9 projects averaged 23%.

Please don't hesitate to contact us if you need additional information.

Attachment 4

To: Mr. Grant Holmes

From: O. M. Scott

SUBJECT: Performance of GOM Operating Fields

You have asked that we survey our data base of Gulf of Mexico (GOM) fields operated by Flagler Petroleum (FP) for the purpose of assessing the extent to which ultimate reserves recovery exceeded initial estimates. You have also asked that we provide information regarding the means by which any increase in ultimate recovery was accomplished. Our findings are provided below.

First let us provide some information on the data based analyzed. By definition, all fields in the data base are offshore fields. Only fields operated by FP which reached a peak production of 50 kbd or more were assessed.

The data sample falling within these boundaries consists of 18 fields. These include fields that have been fully exploited and or divested within the last 20 years and those currently in production. For fields either divested or currently in production, the latest estimate of ultimate recovery was contrasted with the initial estimate. Of these 18 fields, 12 were 'shallow fields' in water less than 500 feet while 6 were in water depths greater than 500 feet.

All project return information has been weighted by capital invested.

Responding to your specific questions, our findings were as follows:

- ***Operating Field Practices***: Normal operating practices yielded an average 9 % improvement in annual production levels and a 12% aggregate increase in reserves recovery versus the estimate used in lease bidding or government production sharing negotiations.
- Not all fields in the sample yielded higher ultimate recovery of reserves. Shallow water fields had results similar to the worldwide sample. Deep water fields however yielded a 14% average increase in ultimate recovery. The deep water results ranged from -2% to + 20%, with +10% to + 18% falling within one standard deviation of the mean.
- Economic returns from optimized operating practices were highly attractive, based upon an average increase in operating costs of 2% p.a. for shallow water and 5 % p.a. for the deep water fields

- ***Enhanced Recovery Projects:*** Of the 18 fields in the sample, 15 ultimately were the object of enhanced recovery projects.
    - Project returns estimated in Project Reappraisals averaged 24%. The range of project returns varied from 14% to 35%, with returns from 19% to 29% falling within one standard deviation of the mean.

- The two projects in deep water were reappraised as having a 12 and 30% return respectively

- **Extensions and Satellite Fields**: Of the 18 fields in the sample, 9 were judged to have played a role in the subsequent development. Seven of these projects were in shallow water with the remaining two in deep water. None of these development projects were foreseen at the lease bidding stage. Of the 9 projects, the 7 shallow water fields were developed as stand alone projects. The 2 deep water projects were developed using existing field infrastructure. Project returns for stand alone developments averaged 15% with a range of 8-22% (10-20% with 1 SD) while the two deep water projects were reappraised at 25% and 20 % respectively.

Finally, you have asked that we consider which fields might be 'most comparable' to the two blocs, 113 and 241, now under consideration. There are really no good comparables. Bloc 113 is in medium depth water and therefore the shallow GOM is not really comparable. Most of the shallow water field data also reflects earlier practices and technology. Bloc 241 is a deep water bloc, but on a new trend from FP's current GOM deep water operations.

The best we might suggest would be to use the high side of GOM operating practices for Bloc 113 while evaluating enhanced recovery and extension prospects by looking at GOM deep water and checking against worldwide data. To the extent anything is relevant to Bloc 241, it would be the few other GOM deep water developments.

Please don't hesitate to contact us if you need additional information.

<u>Bidding under Uncertainty for GOM Exploration Blocs (B)</u>

Grant had wrestled with quantifying the embedded options in the prospective exploration blocs and had been back to see Nick two more times. As a result of these discussions, Grant had undertaken two analytical efforts:

- The development of several industry scenarios to validate the base case price outlook received earlier from Corporate Planning and delineate price sensitivity cases; these he used to develop rough probabilities to be assigned to the different crude price outlooks

- A schematic diagram of the sequential decisions to be made by Flagler, commencing from the Lease Bid decision through to possible Field commercial development and the embedded options which such development would secure

After talking again to the Exploration management, Grant used the schematic diagram to estimate the probabilities associated with each of the possible outcomes from the decision nodes. These probability estimates he documented in Attachment 1. Grant also obtained from Exploration comparative satellite field potential for the two blocs; he then visited with his contacts in Development and obtained estimated capital costs and returns for this satellite field potential. These are provided in Attachment 2.

Feeling better equipped in terms of data and decision framework, but still ‘at sea’ on valuation, Grant headed back for another conversation with Nick.

Attachment 1

Memo: To Files

From: Grant Holmes

SUBJECT: Sequential Decision Probabilities for Bidding on
Lease Blocs 241 and 113

This memo documents the sequential decisions which Flagler could potentially make assuming it was awarded one or both of the exploration blocs cited above:

Bloc 241

Action	Cost	Probability
Win Bid	Lease bid; value TBD	50%
Win, Run Seismic Then abandon	$15 M	25%
Win, Run Seismic Drill, Abandon	$15 M + $35 M	15%
As above, but Develop uncommercial Reserves	$15 M + $35 M + $1150 M Expected IRR is 8% vs. 15% WACC	10%
Win, Run Seismic Drill, Marginal Reserves, develop	$15 M + $35 M + $1150 M	12%
Win, Run Seismic Drill, Commercial Reserves, develop	$15 M + $35 M + $1150 M	25%
Win, Run Seismic Drill, Maximum Reserves, develop	$15 M + $35 M + $1150 M	13%

Embedded Options
#1 Operating Options }
#2 Secondary Recovery} Varies by Case – see other attachments
#3 Extensions/Satellites}

Bloc 113

Action	Cost	Probability
Win Bid	Lease bid; value TBD	50%
Win, Run Seismic Then abandon	$10 M	15%
Win, Run Seismic Drill, Abandon	$10 M + $20 M	15%
As above, but Develop uncommercial Reserves	$10 M + $20 M + $450 M Expected IRR is 10% vs. 15% WACC	10%
Win, Run Seismic Drill, Marginal Reserves, develop	$10 M + $20 M + $450 M	20%
Win, Run Seismic Drill, Commercial Reserves, develop	$150 M + $20 M + $450 M	30%
Win, Run Seismic Drill, Maximum Reserves, develop	$10 M + $20 M + $450 M	10%

Embedded Options
#1 Operating Options }

#2 Secondary Recovery} Varies by Case – see other attachments

#3 Extensions/Satellites}

Attachment 2

Memo: To Files

From: Grant Holmes

SUBJECT: Satellite Field Potential for Exploration Blocs 241 and 113

This memo documents the relative extension/satellite field potential of the exploration blocs cited above, along with the respective capital cost and most probable returns associated with such potential. Finally, it provides probability estimates indicative of the likelihood that such potential is ultimately realized. Analysts can generally assume that if such potential exists, investment would occur 5 years after first oil production, with extension/satellite production coming on-stream in the seventh year after first production.

	Reserves Potential	Capital Cost	Most Probable IRR
Bloc 241	400 MB; 40% probable	$400 M	25%
Bloc 113	50 MB; 70% probable	$110 M	20%