Applying Optimization Technology in Reservoir Management

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Abstract

This paper presents the application of optimization techniques in reservoir management to determine the best development plan that maximizes the economic performance of an asset. A distinguishing characteristic of this approach is that it can evaluate all feasible scenarios for a specific financial objective within a set of well-defined constraints. The output of this integrated workflow is a complete set of decisions that drive capital investment, development scheduling, production, hydrocarbon recovery, and, ultimately, economic performance of the asset.

The conventional approach to reservoir management often considers a limited number of development options because of the complexity of the events within an investment plan and the time required for the evaluation. Input into the decision-making process traditionally comes in the form of sensitivity analyses from reservoir simulation, cost engineering, wellbore planning, pipeline networking, and project economic-analysis tools. These technologies are used to simulate performance by examining a specific development scenario, calculating future production, and performing a discounted cash-flow analysis to assess the return on the required investment.

The exact scheduling of new infrastructure and production facilities as well as the drilling and stimulation of additional wells is critical to maximizing economic performance, especially if remaining reserves are material in size. These discrete events sometimes receive little attention. While the industry's ability to predict asset performance and assimilate several diverse perspectives together has significantly advanced, many reservoir-management decisions still are based on heuristics, rules of thumb, analogs to other assets, and ease of execution.

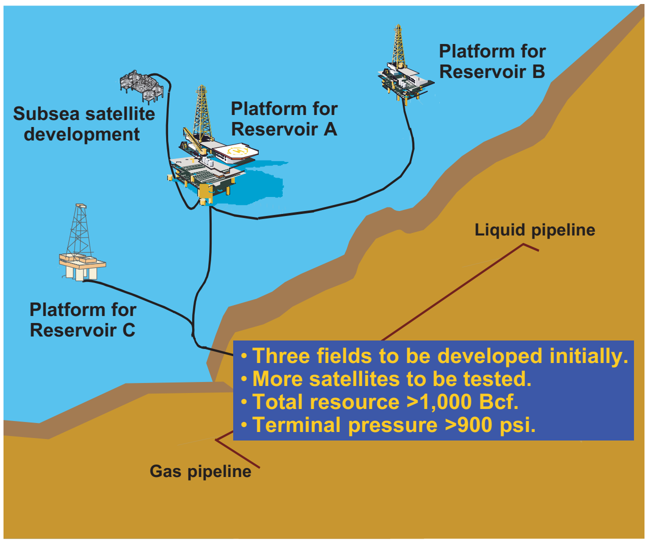

Fig. 1—Regional complex of gas reservoirs.

Use of optimization techniques is not new in the energy business. However, in reservoir management, the technology must cope with more nonlinear phenomena within the physical system, complex and realistic objective functions and constraints, and discrete decisions that occur at distinct points over the asset life. The use of mixed-integer nonlinear programming algorithms can be useful in these situations. These algorithms implicitly construct a tree of all possible development plans and then efficiently prune the branches to eliminate candidates that can be shown to be nonoptimal.

The effectiveness of optimization technology is illustrated by applying it to the ongoing expansion of a regional complex of gas reservoirs. The approach is used to determine the development schedule of the different reservoirs and the timing of their wells, the timing and staging of compression, and the development of satellites to meet a contract specification. The results demonstrate four cornerstones of reservoir management that are key to maximizing

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economic performance: ordering—the schedule of events in the development schedule; integration—coupled consideration of the total physical system; objective—the appropriate choice of a performance metric; and decision making—determining the development plan that maximizes value.

Introducing Reservoir Management and Optimization

Reservoir management is the organizing of all appropriate technical, operational, and business resources from discovery to abandonment to best exploit a reservoir in an efficient, safe, and responsible manner (Al-Hussainy and Humphreys 1996). Its objective is maximizing the value of a hydrocarbon asset or a portfolio of assets while improving estimates of the hydrocarbons in place, production forecasts, capital investment, and operating expenses. This objective requires a holistic view of the total asset, development projects, and investment under consideration.

Every development or redevelopment of an asset faces the formidable task of evaluating many feasible options and possible design permutations. The task is complicated further by numerous constraints that must be defined clearly in this process. These constraints could be technical, operational, strategic, or financial limitations; and, ultimately, they establish the region and boundary within which the optimum plan exists. The output of this complete evaluation for asset development is a set of discrete decisions that drive investment, production rates, development schedule, hydrocarbon recovery, and, in effect, the economic performance of the asset. Given that finding and development costs are on the rise, compounded by the difficulty of replacing reserves (Helman 2004), and that the return on investment has averaged less than 7% over the past 20 years (Brashear et al. 2001), improving reservoir-management decisions should continue to be a central focus for the industry.

Background

The magnitude of the investments associated with developing oil and gas assets motivates the consideration of methods and techniques that can minimize these outlays and improve the overall economic value. For several decades, industry practices have attempted to address this issue by considering a variety of approaches that can be referred to collectively as traditional methods. These methods include trial-and-error approaches that conduct a series of “what-if” analyses or case studies as well as heuristic and intuition-based efforts that impose rules and learning on the basis of experience or analogies. In contrast, mathematical-optimization techniques can provide an efficient methodology toward achieving these goals by combining all the traditional approaches into a comprehensive and systematic process.

Early applications of optimization to reservoir management (Aranofsky and Williams 1962; Sullivan 1982; Haugland et al. 1988) focused on the importance of strategic development and investment decisions along with the more-tactical production and operating strategies. More-recent efforts (Iyer et al. 1988; Aseeri et al. 2003; Udoh et al. 2003) have developed tailored solution strategies that exploit the structural characteristics of these systems, leading to the solution of larger applications. Sullivan (1982) discussed an optimization framework to select the development plan that maximized the economic worth of an offshore system of three gas reservoirs. Related efforts by Vasantharajan et al. (1999) and van den Heever et al. (2001) integrated the physical and economic systems, and by use of integer optimization, techniques were able to determine the optimal production forecast and development plan.

This paper attempts to synthesize the best features of these earlier efforts and extend their applicability and robustness. First, the nonlinear aspects of the physical models are handled directly, without explicitly developing an equivalent or approximate linear system of equations. This method allows the use of more-realistic models for the entire physical system and for complex interactions to be exploited. Second, the planning, infrastructure-design, and operational-optimization problems are solved simultaneously with the same integrated-asset framework. This step enables exploitation of the apparent synergies between the decisions made across the entire asset base. Third, the asset models are optimized in a global manner over their entire life cycle, which permits the time value of decisions to be understood implicitly. Finally, a mathematical-optimization framework is incorporated that can systematically construct and efficiently consider all possible development scenarios and operating strategies to determine the overall economic optimum. The framework must integrate discrete, nonlinear optimization algorithms that can effectively determine the entire set of decision variables to optimize the objective.

Development of a Regional Gas Complex

In this paper, the development of a regional complex of gas reservoirs similar to those found in the Gulf of Mexico, the southern gas basin of the North Sea, west Africa, and in basins in the Far East is examined. The example in this paper is an amalgamation of the fields typically developed around the world.

The complex to be developed consists of three main fields with at least one additional satellite. It is assumed that several development decisions have already been made when this work commences. For example, the gas in place for each reservoir; the size, configuration, and number of platforms; and the pipeline infrastructure have been determined or specified. The layout of the reservoirs and infrastructure is shown schematically in **Fig. 1.** Sample data needed to define the models for the subsurface and surface facets are shown in **Tables 1 and 2.**

The Reservoir A platform has eight well slots, with each well costing U.S. $15 million. Sand production and water coning place flow limitations on the different wells, ranging from 10 to 25 MMscf/D. Water influx occurs in Reservoir A, although the relatively high production rates limit the support to approximately 100 psi for the period of interest. Flow limitations for wells in Reservoirs B and C are comparable to wells in Reservoir A, although Reservoir B does contain one well that can produce up to 30 MMscf/D. The total gas-

TABLE 1—RESERVOIR, PLATFORM, AND WELL DATA

Reservoir	Gas in Place, Bcf	Initial Pressure, psi	Platform Cost, U.S. $Million	Well Cost U.S. $Million
A	500	2500	150	15
B	500	5000	100	20
C	250	2500	100	10

TABLE 2—SURFACE NETWORK CONFIGURATION DATA

Pipeline	Diameter, in.	Distance, miles
A Terminal	16	10
B–A Platform	7	8
C Terminal	10	8

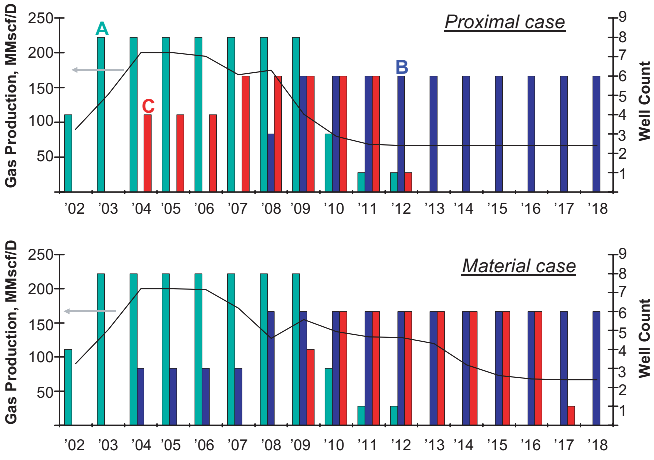

Fig. 2—Production and well scheduling for the proximal and material cases.

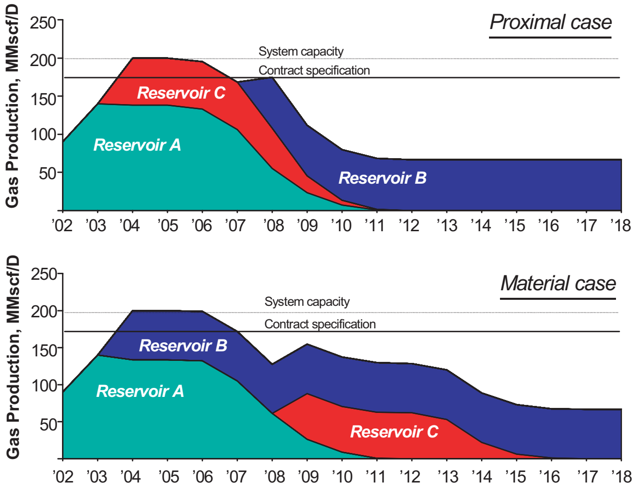

Fig. 3—Reservoir production for the proximal and material cases.

handling capacity at the terminal is 200 MMscf/D, and the gas must be delivered at a pressure of at least 900 psi.

Modeling the Physical and Economic Systems

State-of-the-art reservoir management requires a mathematical representation of the entire physical system. The model must have enough fidelity and robustness to predict the system behavior that influences the critical aspects of asset performance. For the purpose of this paper, reservoir performance was modeled with an overall material-balance equation with water influx (Agarwal et al. 1965). Every well in the gas complex can have different rock properties, completion design, and well geometry, and the radial inflow equation is used to predict well performance (Bradley 1987). The backpressure equation provides tubing hydraulics (Beggs 1989). At the surface, pipeline hydraulics from the Panhandle equation (Bradley 1987) and a polytropic compressor model (Beggs 1989) complete the mathematical representation of the physical system.

Another approach for modeling the complete system is use of a detailed simulator that fully couples the reservoirs, wells, and surface facilities to calculate the performance of multiple reservoirs in various configurations with the surface facilities (Bette and Heinemann 1989). For development planning of the gas-complex example in this paper, the mathematical model described above is often quite accurate for the task at hand.

Developing a complex of fields requires a long-term contract. The contract has an 18-year term with a production commitment of 50 MMscf/D in Year 1, 100 MMscf/D in Year 2, and 175 MMscf/D in Years 3 to 18. A 10% penalty is imposed when production falls below the contract commitment. The gas price begins at U.S. $4.50/Mscf and increases with a presumed inflation rate of 2.5%/yr. Liquid production does not contribute to asset revenues.

The economic value of the complex comes from the sale of gas and gas condensate. Capital costs include those from drilling, workovers, platforms, pipelines, compression, and other infrastructure. Maintenance and operating costs constitute a specified fixed component and a variable portion that is determined for the selected infrastructure. The annualized cost of abandoning the fields is estimated as a percentage of the sunk capital. Royalty payments, tax liabilities, and contract penalties are considered in determining the net cash flows. These cash flows are discounted at 10% over the life of the asset to determine the net present value (NPV).

Developing the Gas Complex Without Optimization

Traditional approaches to the development of this gas complex without the use of mathematical-optimization techniques usually simulate performance by examining a specific development scenario, calculating future production, and performing a discounted cash-flow analysis to assess the return on the required investment. By use of a combination of these traditional techniques, two different development cases are considered. These scenarios develop the gas reservoirs on the basis of costs, proximity to shore, and productivity. The fields will be developed sequentially, with one reservoir completed before the next one is started. All the decisions about investment and scheduling are made only once during any year, and only four wells can be drilled in a given year with the limited availability of drilling rigs. The objective in these two cases is to achieve a production plateau as rapidly as possible and to maintain the rate at this level for as long as possible while honoring the constraints described above. It is expected that such a strategy would maximize the overall economic performance of the asset.

The first of these two cases is termed the proximal case, in which the lower-cost reservoirs closest to the terminal are preferentially developed. Hence, the order of development is Reservoir A, then Reservoir C, and finally Reservoir B. The second case is the material case, wherein the reservoirs are developed according to their size. The schedule in this case is A, then B, and then C.

The drilling schedule and gas production for the proximal and material cases are compared in **Fig. 2.** In the proximal case, four wells are drilled in Reservoir A in 2002 and four more wells in 2003. These wells remain effective until 2009, when they start to go off production. Production increases and reaches the system capacity of 200 MMscf/D in 2004, when four wells in Reservoir C are brought on stream. As total production falls off the plateau, two additional wells are drilled in Reservoir C in 2007. In 2008, Reservoir B is brought on stream with three wells, and finally the remaining three Reservoir B wells are drilled in 2009. All these additional wells can only increase the production in 2008. By 2013, only the Reservoir B wells remain on stream.

Drilling and production from Reservoir A in the material case occurs with the same schedule as the proximal case. However, next come three wells from Reservoir B in 2004 and the remaining three Reservoir B wells in 2008. Drilling and streaming of the first four Reservoir C wells occurs in 2009, and the final two Reservoir

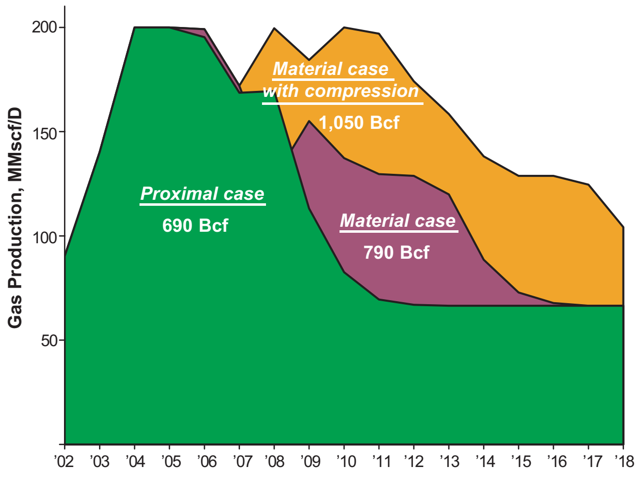

Fig. 4—Total daily production from the proximal, material, and material-with-compression cases.

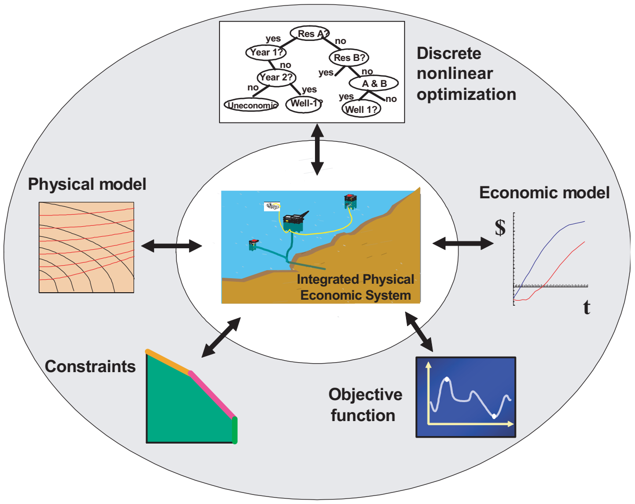

Fig. 5—The optimization framework.

C wells are brought on production in 2010. The initial decline off the 200-MMscf/D plateau is more pronounced in the material case, although the secondary decline from 2009 to 2015 is much less severe because of the drilling schedule.

The production from the three different reservoirs is illustrated in **Fig. 3.** The early production of the high-pressure gas in Reservoir B leads to higher recovery in the material case. Both plans require approximately U.S. $800 million of capital investment, but the cumulative production in the material case is 790 Bcf compared with 690 Bcf in the proximal case. This difference translates into higher penalties (U.S. $230 million) and development costs [U.S. $7.30/bbl oil equivalent (BOE)] for the proximal case when compared with the material case (U.S. $180 million and U.S. $6.07/BOE, respectively). A straightforward economic analysis indicates that the proximal case generates an NPV of U.S. $900 million compared with the U.S. $1.12 billion NPV of the material case. These comparisons demonstrate the first fundamental thesis of this work: The ordering and scheduling of investment and operations has a pronounced effect on the financial performance of the asset.

Requiring gas delivery at the terminal at a pressure of at least 900 psi constrains the wellhead pressures for all three platforms. These conditions limit production and recovery from the A, B, and C reservoirs. An improvement to both of the previous cases is to add a compressor station at the terminal. The compressor is modeled as a multistage unit with a variable compression ratio not to exceed 3.5:1, a maximum throughput of 200 MMscf/D, and a total capital cost of U.S. $180 million. The operating cost is related to the gas throughput, fuel usage, and nominal maintenance requirements. To be consistent with the objective for these cases, the compressor unit is activated in 2008 in the material case because a sharp drop in the production plateau below the specified contract rate is observed. Several alternative start dates for the compression and Platform C also were considered, but streaming the compressor in 2008 was found to create the most value.

The effect of compression is shown in **Fig. 4,** which compares the total production from the three reservoirs in the proximal case, the material case, and the material case with compression. The production in this last case is higher than in the previous two, and the use of compression helps delay the streaming of the C reservoir by 1 year. Average daily production approaches the system capacity through 2012, and the cumulative production increases to approximately 1,000 Bcf. Compression increases the total capital investment to U.S. $980 million. The additional gas production more than offsets this increase, because penalties fall to U.S. $60 million, and the unit cost decreases slightly to U.S. $5.88/BOE. The NPV of the material case with compression increases significantly to U.S. $1.43 billion.

The material case with compression, hereafter referred to as the base case, exemplifies the need to use models that integrate the surface and subsurface behavior of an asset to optimize its financial performance. Focusing on the performance of a subset or a component of the total asset usually will ensure suboptimal performance, because the synergies of these coupled entities cannot be exploited. Therefore, a second fundamental thesis demonstrated here is that integration of the total physical system and its financial performance is important when optimizing asset value.

Applying Optimization Technology

Optimization techniques use mathematical models constrained by practical limitations to examine all possible scenarios or alternatives and determine the set of decisions necessary to achieve the best objective value. The five components that make up the optimization framework are shown in **Fig. 5.** Efforts to define and characterize these components are collectively referred to as the optimization formulation. The integrated framework then is solved to determine the set of decision variables that simultaneously satisfy the constraints and maximize the objective value.

The activities and objectives involved in the application of optimization technology are the same as those in reservoir management. Both focus on the efficient use of limited resources to best exploit an asset over its life. While this natural alignment is encouraging, it must be stressed that the proper formulation of the optimization framework is critical because it enables the identification and consideration of all feasible alternatives for the asset.

Decisions made to optimize hydrocarbon assets can be classified mathematically into two major categories, as either design decisions or as operational decisions (van den Heever et al. 2001). Typical design decisions, such as selecting the type of platform, the staging of compression, and the number of wells to be drilled in a reservoir, are discrete in nature. These decisions are either Boolean (true/false) or integer valued. Alternatively, operational decisions, such as

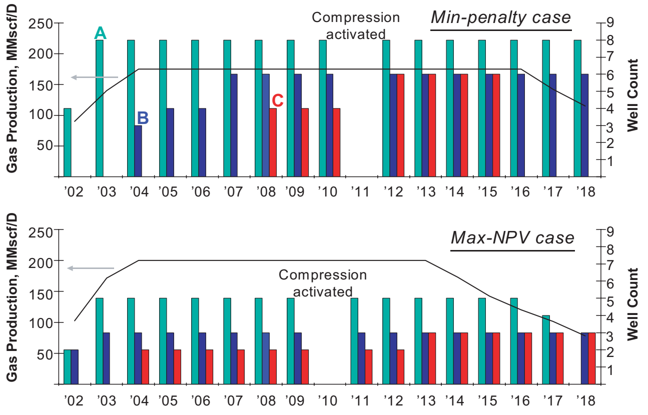

Fig. 6—Production and well scheduling for the minimum-penalty and maximum-NPV cases.

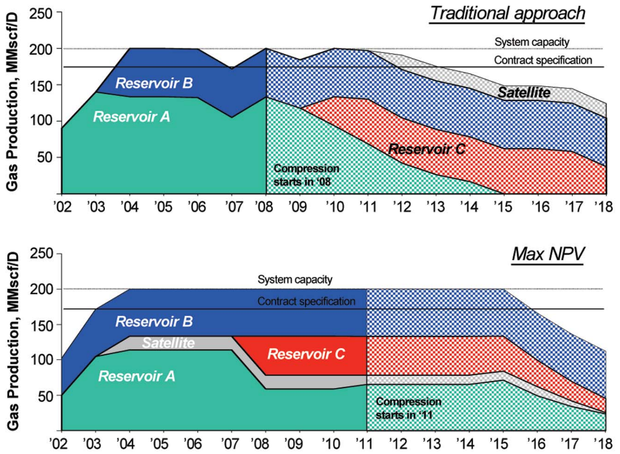

Fig. 7—Reservoir production comparisons for the traditional and optimized satellite cases.

production rates from gas wells and reservoir pressure profile, are continuous and can assume any real value.

Another key aspect of these problems is the highly nonlinear nature of the mathematical relationships needed to describe the physical system appropriately. Modeling reservoir performance to relate pressure changes to depletion or the equations that describe well productivity and flowing pressure creates a system of highly coupled, nonlinear expressions. The models used to describe the physical and economic components reflect a compromise between the appropriate level of detail needed to characterize the system accurately and the ability of the optimization algorithms to solve the resulting problem.

This combination of decisions, which are discrete or integer valued, and the nonlinear nature of the equations, which describe the asset response, complicates the solution of these planning models significantly. It is interesting to observe that integer linear models (Iyer et al. 1988) or continuous nonlinear models (Vasantharajan et al. 1999) have been used separately with great success. The combination of these attributes presents one of the most challenging problems in numerical optimization. The manner in which these entities are described can have a tremendous effect on the robustness and efficiency of the solution techniques.

Optimizing the Development of the Gas Complex

In this section, the optimization technology is applied to an integrated framework comprising the physical and economic models of the gas complex and their associated constraints. Now that the system to be optimized has been described and its boundaries or constraints identified, the remaining task in formulating the optimization problem is selection of an appropriate performance criterion against which the asset can be evaluated. The mathematical term for this criterion is objective function. While an economic metric often is the choice, it should be noted that technological quantities also could be considered. For example, maximizing ultimate recovery or maintaining production are criteria typically used in reservoir management.

Now examine asset-development plans that can result from using different but relevant objective functions. The first of these is termed the minimum-penalty case. Here, the reservoir ordering, drilling sequence, and timing for compression are selected such that the production-contract penalties are minimized. The expectation under this objective would be a development plan that ramps production to the contract level and maintains the rate at this plateau (175 MMscf/D) for as long as possible. This case will be compared with the second scenario, maximum NPV, which maximizes the NPV of the asset as the objective. In the maximum-NPV scenario, the investment and operation schedule are selected such that the NPV of the entire gas complex is maximized over the life of the asset. Production in both cases is constrained only by the asset capacity of 200 MMscf/D.

Fig. 6 shows the well sequence by reservoir and the total production rate generated in these two cases. In the minimum-penalty case, the production increases quickly to 175 MMscf/D in 2004 and is maintained at this level through 2016. The production penalties are reduced to U.S. $20 million over the entire life of the contract. The well sequence is similar to that in the material case, with Reservoir A being drilled in 2002–03, followed by the wells in Reservoir B drilled in 2004 and 2007, and finally the wells in Reservoir C in 2008 and 2011. Compression also is activated in 2011. In the minimum-penalty case, the optimizer drills the wells and turns on the compressor only as they are needed to keep the rate at or above the penalty threshold. This plan uses 20 wells and requires a capital investment of U.S. $980 million. The economics model shows an NPV of U.S. $1.39 billion for this case.

The profile in the maximum-NPV case is substantially different from any of the cases considered earlier. In this case, the production increases up to the system capacity of 200 MMscf/D in 2004, and this level is held through 2013. Production declines rapidly after 2013 and results in increased penalties of U.S. $60 million. The drilling sequence is the biggest difference. The optimizer in the maximum-NPV case develops the reservoirs in a parallel fashion rather than the sequential development in all the preceding cases. In effect, in this case the optimizer selects the highest-rate well available, regardless of its platform location. Two wells are drilled in Reservoir A in 2002, followed by three wells in 2003. Two wells are also drilled in Reservoir B in 2002, with one additional well in 2003. The wells in Reservoir C are drilled in 2004 and 2013. Because this plan uses only 11 wells in the development, capital costs are reduced to U.S. $750 million. NPV increases to U.S. $1.7 billion.

The maximum-NPV case recovered somewhat more gas (1,050 Bcf) than the minimum-penalty case (1,010 Bcf). This increase, coupled with the significantly reduced capital, provided a

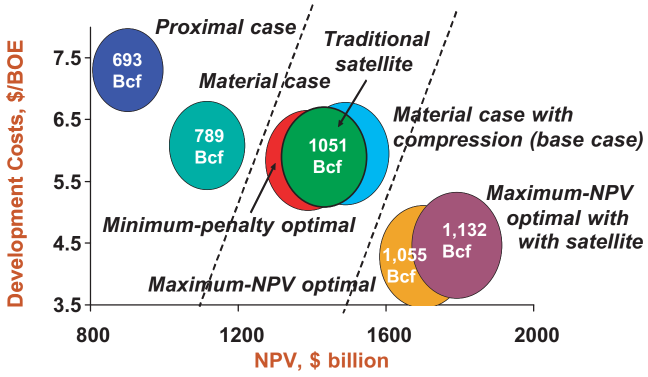

Fig. 8—Comparison of all results.

TABLE 3—BRIEF DESCRIPTIONS OF CASES CONSIDERED

Case Name	Case Description
Proximal Case	Traditional approach, which develops lower-cost reservoirs, closest to the shore first.
Material Case	Traditional approach, which develops reservoirs in the order of their size/reserves.
Material Case With Compresson	Base Case. Traditional approach, which develops reservoirs in the order of their size, with compression brought on to sustain the production plateau.
Minimum Penalty	Minimizes contract penalty as objective. Ramps production up to contract level and sustains production plateau as long as possible.
Maximum NPV	Uses mathematical optimization to maximize NPV of the complex by considering all feasible development scenarios.
Traditional Satellite	Conventional approach in which a satellite well is brought on to sustain production after main reservoirs are developed.
Maximum NPV With Satellite	Scenario that uses mathematical optimization to maximize NPV of the complex, integrating satellite well along with the main reservoirs.

considerable advantage when comparing the development costs of the two scenarios. These were U.S. $5.84/BOE for the minimum-penalty case, but only U.S. $4.28/BOE for the maximum-NPV case. While the minimum-penalty case clearly met its objective, it did so to the detriment of the economic value of the asset. The NPV of the minimum-penalty case was U.S. $1.39 billion, which was even lower than the base case (U.S. $1.43 billion). The accelerated production and lower capital requirement clearly enhanced the value of the maximum-NPV case. The result is the best thus far, with an NPV of U.S. $1.7 billion. These comparisons exemplify the third foundational element: Specification of the proper objective is critical in optimizing financial performance and asset value.

Satellite Expansion

In this section, the gas complex is expanded with a 90-Bcf satellite well 5 miles from Platform A. The satellite is to be developed by a single subsea well with a maximum flow rate of 20 MMscf/D and a cost of U.S. $40 million. Two cases are compared here. The first scenario examines a traditional method of development whereby the satellite is brought on stream to sustain production after the three main reservoirs are developed, compression is activated, and production is declining. The ordering of the reservoirs, scheduling of wells, and installation of compression are varied through a battery of case studies, with the results fed into the economic models to post calculate the NPV of each case. The cases then were ranked and the best one selected. In the second scenario, the satellite is included in the integrated system to be optimized, with maximizing the NPV of the complex, including the satellite, as the objective. The results of the two cases are shown in **Fig. 7.**

In the traditional case, the reservoirs are developed in a sequential ordering, with Reservoir A followed by Reservoir B and then Reservoir C. Compression is activated, as in the base case, in 2008 and helps to keep the production at a level near system capacity. The satellite well comes on stream in 2012 as the production begins to decline and adds approximately 20 MMscf/D to the complex for 6 years. As in the previous maximum-NPV case, the optimized satellite development uses a parallel ordering, with Reservoirs A and B being drilled concurrently. The satellite well is drilled next, in 2004. The production from these wells enables the drilling of Reservoir C to be delayed until 2007 and compression even further to 2011.

Traditional development, drilling 21 wells and adding compression, requires U.S. $1.04 billion of capital investment. Cumulative production totals 1,050 Bcf. The optimized development requires U.S. $840 million of capital for its 12 wells and compression. Total recovery is 1,130 Bcf. The NPVs of the two cases are much different, with the optimized case at U.S. $1.79 billion and the traditional case approximately U.S. $300 million lower at U.S. $1.49 billion.

The satellite cases demonstrate that the additional gas will add value to the complex only if it is integrated in the proper manner. Note that the NPV of the traditional satellite case is lower than that of even the base case. In this case, gas from the satellite has value, but not enough to overcome the increase in capital investment over the planning horizon considered. The maximum-NPV satellite case increases the asset value again by early investment to accelerate drilling and increase production over the entire life of the contract. While the optimized case counterintuitively expends considerably more capital up front, its ability to integrate all components of the workflow and simultaneously optimize over the entire asset life leads to superior overall economic performance. This result leads to a fourth fundamental thesis: While the quality of the asset directly influences performance, determining the "best" development decisions maximizes the economic value.

Conclusions

This paper highlights and demonstrates four fundamental theses of reservoir management to best exploit an asset from discovery to abandonment. They are: ordering—the development schedule of multiple reservoirs and wells; integration—the coupled consideration of subsurface, surface, economic, and other aspects; objective—the appropriate choice of a performance metric to discriminate between alternative development plans; and decision making—the quality of the assets influences performance, but development decisions maximize value.

A brief description of the cases considered is provided in **Table 3,** and the economic results of these cases are summarized in **Fig. 8.** This figure shows the cases without mathematical optimization in the upper left portion. Capital efficiency is improved by simultaneously lowering capital costs while increasing production, as demonstrated by the optimized cases in the lower right portion of the graph. The comparison demonstrates the advantage of an optimization-based approach to reservoir management that completely integrates the workflow to make decisions that drive capital investment, scheduling, production, recovery, and, ultimately, asset performance.

The highly nonlinear nature of the physical system and the combinatorial complexity of development decisions warrant the proper modeling of the assets, the appropriate formulation of the optimization systems, and the use of tailored state-of-the-art mathematical techniques to render these numerical systems tractable. However, the considerable economic benefits, as demonstrated in this paper, provide the motivation for use of these techniques. Because most of the capital-investment commitments are made in the early life of an asset, a narrow window of opportunity exists to influence the economic performance of the asset. Thus, there is a clear need to apply such technology at the earliest opportunity.

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