United States General Accounting Office

GAO

Report to the Chairman, Committee on Natural Resources, House of Representatives

April 1993

TRANS-ALASKA PIPELINE

Projections of Long-Term Viability Are Uncertain

149155

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United States
General Accounting Office
Washington, D.C. 20548

Resources, Community, and
Economic Development Division

B-251215

April 8, 1993

The Honorable George Miller
Chairman, Committee on
Natural Resources
House of Representatives

Dear Mr. Chairman:

On the basis of its January 1991 report Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?, the Department of Energy (DOE) stated that the Congress will have to authorize the leasing of the coastal plain of Alaska's Arctic National Wildlife Refuge (ANWR)—an area of high oil and gas potential—by 1997 to keep the Trans-Alaska Pipeline System (TAPS) operating.[1] DOE's report concluded that because of the projected rate of decline in oil production from Alaska's North Slope, TAPS will likely be forced to shut down by the year 2009. The 1997 leasing date was based on DOE's conclusion that it would take about 10 to 12 years after congressional authorization to develop new oil fields in ANWR.

The possible shutdown of TAPS could be a consideration in reaching a policy decision on whether to open ANWR's coastal plain to oil and gas development or whether to designate the coastal plain as wilderness, thereby precluding any future development. Consequently, you asked us to assess the accuracy of and the support for the conclusions reached in DOE's report. To assess DOE's conclusion that 2009 is the most likely year that TAPS will be forced to shut down, we evaluated the reasonableness of (1) the minimum operating level that DOE assumed for TAPS and (2) the model and the key economic, geologic, engineering, and cost assumptions that DOE used to estimate oil production at the North Slope. We also evaluated the reasonableness of DOE's conclusion that it will take 10 to 12 years to develop new oil fields in ANWR.

Results in Brief

No one really knows how much oil will be produced on the North Slope in the future or the exact operating level at which TAPS will be forced to shut down. Therefore, DOE's conclusion that TAPS will shut down between 2006 and 2011, with 2009 as the "most likely" year, implies a level of precision that does not exist. DOE's report provided a comprehensive study of oil production potential on the North Slope of Alaska and of the relationship

[1]Under the Alaska National Interest Lands Conservation Act of 1980, 1.5 million acres of ANWR's coastal plain was set aside in order to evaluate its oil and gas potential. However, congressional approval is required before drilling exploration or development can be undertaken.

between production and the continued operation of TAPS. However, the economic model used by DOE—although it is an acceptable tool for determining a single outcome on the basis of single-point estimates—does not estimate the probability that the resultant outcome is the most likely outcome that will occur. Neither DOE's assumption regarding TAPS' minimum operating level nor DOE's economic model and the model's underlying assumptions fully considered the uncertainties present in projecting future oil production and its relationship to TAPS.

Accordingly, we believe that it would have been more helpful in making future public policy decisions—such as whether or not to allow oil production in ANWR—if DOE had used a model, such as a Monte Carlo technique, that shows the uncertainty associated with projecting future oil production and its impact on TAPS' shutdown by developing probability distributions, or ranges. Although we believed that DOE's model was not the most appropriate one for projecting future North Slope oil development and for estimating the most likely TAPS shutdown date, we reran the model by varying certain key assumptions to demonstrate how changes in the assumptions could affect DOE's conclusion regarding the shutdown of TAPS. For example, if key assumptions such as TAPS' minimum operating levels, oil prices, and production rates are varied, the time frame for TAPS' shutdown could range from 2001 to 2021.

The companies that own TAPS may consider many factors when they decide whether to continue or discontinue part of their operations—including the operation of TAPS. Since the major owners of the pipeline are part of large, vertically integrated oil companies, there are many factors that must be considered when deciding whether or not to shut down TAPS. For example, the companies may be willing to incur the expensive changes required to continue operating TAPS at reduced levels if warranted by the overall profitability of the companies' Alaska operations.

Finally, we agree with DOE's conclusion that developing new oil fields in ANWR after a lease sale would take 10 to 12 years. We identified over 100 different actions, such as obtaining government permits and generating oil company development and construction plans, that would have to be completed before the production of new oil fields in ANWR could begin. However, permit denials, litigation, and/or engineering or construction challenges could add to the amount of time required to develop ANWR.

Background

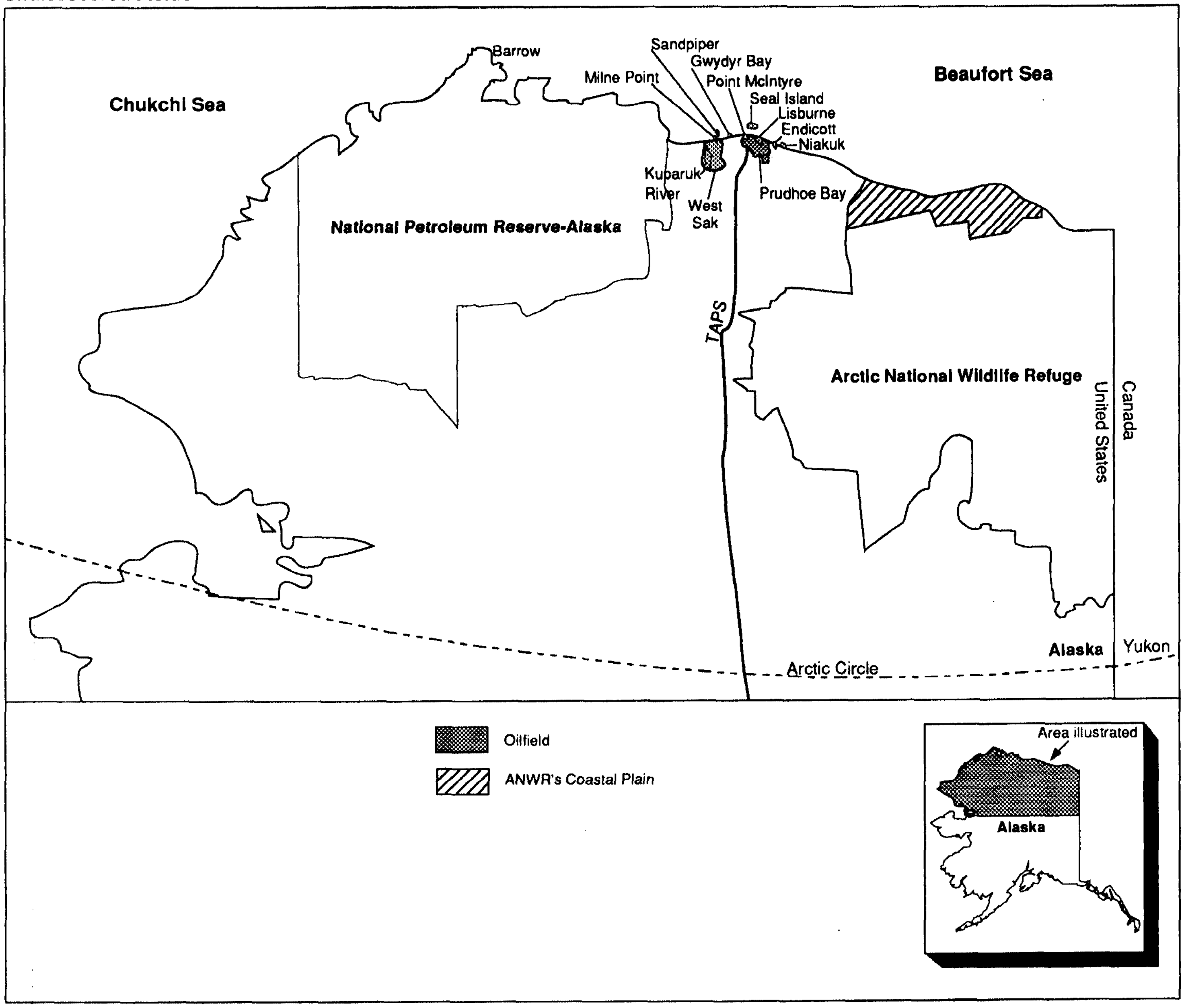
Alaska's North Slope is the nation's single largest source of domestic crude oil, providing about 25 percent of all domestically produced oil in 1991. Between 1977 and 1991, the five producing oil fields at the North Slope pumped almost 9 billion barrels of oil through TAPS, reaching a peak average of over 2 million barrels per day (BPD) in 1988. Since then, production has declined to about 1.8 million BPD; and, according to Alaska's Department of Natural Resources, overall production at the North Slope is expected to continue to decline. As of 1990, the North Slope fields that were producing oil were Prudhoe Bay, Kuparuk River, Lisburne, Endicott, and Milne Point. In 1990, Prudhoe Bay and Kuparuk River accounted for 74 percent and 17 percent, respectively, of the North Slope's production.

DOE's report comprehensively studied the potential for oil production on the North Slope and the relationship between that production and the continued operation of TAPS. The report estimates that the shutdown date for TAPS will occur when the North Slope's production falls below TAPS' minimum operating level. At that point, costly changes would be required to keep TAPS operating. The report also looks at the time necessary to develop new oil fields in ANWR. Using a discounted cash flow model and assumptions for various economic, geologic, engineering, and cost factors, DOE forecasted annual oil production rates and the amount of oil that may be economically produced at the five fields currently producing oil and at two fields—Niakuk and Point McIntyre—that DOE assumed would be producing oil within 3 to 4 years (potentially producing fields). To a lesser extent, DOE also estimated oil production at four discovered but nonproducing fields, and three areas with undiscovered fields.

Discovered but nonproducing fields are areas where oil has been discovered but not developed and which DOE believes have the potential for development. Because the fields are not currently producing oil, much remains unknown about them, including how much oil exists there. As of 1990, these fields were West Sak, Gwydyr Bay, Sandpiper, and Seal Island.

Areas with undiscovered fields are prospective areas that DOE believes have valuable deposits of oil. In 1990, DOE evaluated three areas with undiscovered fields—ANWR, Chukchi Sea, and the National Petroleum Reserve-Alaska (NPRA). (See fig. 1 for a map of these locations.)

Figure 1: North Slope Producing and Potentially Producing Fields, Discovered but Nonproducing Fields, and Areas With Undiscovered Fields

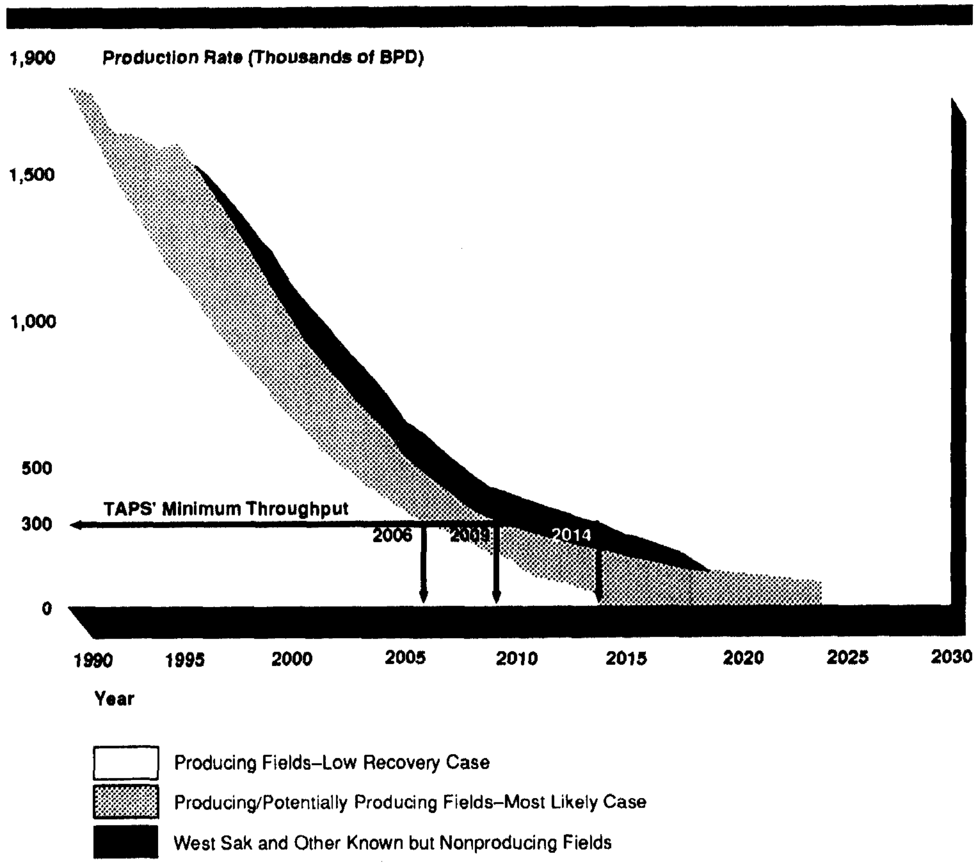


To estimate how much oil may be produced from the producing and potentially producing fields, DOE made numerous geologic assumptions and made low,[2] most likely, and high projections. For example, for Prudhoe Bay, DOE's low case assumed that 50 percent of the field's remaining oil would be produced; the most likely case assumed that 56 percent of the oil would be produced; and its high case assumed 59 percent. DOE used single values for most economic, engineering, and cost assumptions. Using these types of assumptions, DOE's report estimated that production from producing and potentially producing fields at the North Slope would continue to decline and that between 2006 to 2011, with 2009 as the most likely estimate, production would decline to 300,000 BPD—the assumed level at which costly changes would have to be made to keep TAPS operating.

Although uncertainty increases for discovered but nonproducing fields and for areas with undiscovered fields, DOE's model accounted for less uncertainty for these fields than it did for the producing and potentially producing fields. For the four discovered but nonproducing fields, DOE developed only a most likely projection of the amount of oil that might be recovered. DOE also used a single value for most economic, geologic, engineering, and cost assumptions. Under these assumptions, DOE's model indicated that if the discovered but nonproducing fields were developed (with the most significant contribution coming from West Sak) and if TAPS' minimum operating level was assumed to be 300,000 BPD, the most likely shutdown date for TAPS would be delayed 5 years, from 2009 to 2014. (See fig. 2.)

[2]Under the low recovery case, DOE assumed that the potentially producing fields—Point McIntyre and Niakuk—would not be developed.

Figure 2: Impact of TAPS' Minimum Operating Levels on DOE's Production Estimates for Producing and Potentially Producing Fields, West Sak, and Other Known but Nonproducing Fields



Legend

2006—At low recovery rates and mid-level National Energy Strategy (NES) oil prices, TAPS' throughput of 300,000 BPD is reached for producing fields.

2009—At "most likely" recovery rates and mid-level NES oil prices, TAPS' throughput of 300,000 BPD is reached for producing and potentially producing fields.

2014—At "most likely" recovery rates and mid-level NES oil prices, TAPS' throughput of 300,000 BPD is reached for producing and potentially producing fields, West Sak, and other known but nonproducing fields.

For the three areas with undiscovered fields, DOE created several potential development scenarios in which it speculated on the impact that small or large oil discoveries in these areas would have on the operating life of TAPS. Using these scenarios, DOE estimated that developing these fields could extend TAPS' operating life by as much as 13 years. However, because it is uncertain whether oil is present in these areas, how much oil exists, or whether the oil can be economically produced, the production potential of the areas is not clear.

DOE's Methodology DOEs Not Fully Consider the Uncertainties Associated With Projecting TAPS' Shutdown or Future Oil Production

Neither DOE's assumption about the minimum operating level of TAPS nor DOE's economic model and the model's underlying assumptions fully considered the uncertainties in complex issues such as estimating the level at which TAPS may shut down or projecting future North Slope oil production levels. As a result, DOE's most likely estimate of when TAPS will be shut down, and its estimate of how long the operating life of TAPS may be extended if discovered but nonproducing fields are developed, both imply a level of precision that does not exist.

TAPS' minimum operating level is unknown. In addition, we believe that DOE's model is not the most appropriate means of estimating when TAPS may no longer be viable. The economic, geologic, engineering, and cost data required for the discounted cash flow model that DOE used—particularly for the discovered but nonproducing fields—were limited and, therefore, subject to great uncertainty. DOE should have used a modeling technique that would have addressed this uncertainty by considering the full range of possibilities for certain key economic, geologic, engineering, and cost assumptions.

Although we believed that DOE's model was not the most appropriate means for projecting future oil development or for estimating TAPS' shutdown date, we reran the model after varying certain key assumptions in order to demonstrate how changes to the assumptions could affect DOE's conclusions. Our analysis, which accounts for more of the uncertainties in projecting future oil production than DOE's does, indicates that DOE's estimate of 2009 as the most likely shutdown date (or 2014 if discovered but nonproducing fields are developed) is only one possible outcome within a range of probable outcomes that goes from 2001 to 2021.

TAPS' Minimum Operating Level Is Unknown

TAPS minimum operating level is unknown and is subject to a great many uncertainties, including its mechanical and economic limitations. A key assumption in any estimate of when TAPS will be shut down is the minimum level at which it can be expected to operate without requiring costly changes to accommodate a lower daily flow rate of oil. According to the DOE report, at the time of the study Alyeska Pipeline Service Company

(Alyeska)[3] officials, which operate TAPS, told DOE's contractors, EG&G Idaho Inc., that TAPS' minimum operating level was 300,000 BPD. Subsequently, however, Alyeska officials told us it was 600,000 BPD. We attempted to reconcile these levels, but Alyeska officials did not provide us with any support for a minimum operating level.

When TAPS began operating in 1977, its maximum operating level was 600,000 BPD. Since then, Alyeska has increased TAPS' operating level to about 2.2 million BPD by adding additional pump stations and equipment as well as making other enhancements. Alyeska officials told us that they could probably operate again at a level as low as 600,000 BPD by closing some pump stations. We found that TAPS operated at an even lower level—with average flow rates ranging from 341,000 BPD to 487,000 BPD—for 2 months in 1977. According to Alyeska, these low rates required certain pieces of equipment to operate considerably out of their normal design operating ranges. While Alyeska believes that this is an acceptable condition for a short period of time, they believe that over a long period it would result in unacceptably high maintenance costs and high fuel and power rates. Because TAPS has not operated at low levels for long periods of time since the year it began operating, little is known about "how low it can go" before the pipeline is forced to cease operating.

The companies that own TAPS consider many factors when they decide whether to continue or discontinue part of their operations—such as shutting down the pipeline. However, these factors cannot be easily estimated. The major owners of the pipeline are part of large, vertically integrated oil companies; as such, they may be willing to incur the expensive changes required to continue operating TAPS at reduced levels if warranted by the overall profitability of their Alaska operations. In addition, the owner companies could choose to keep TAPS operating even if they recover only part of their costs if the potential profitability of North Slope oil warrants it. For example, the owner companies could renegotiate the transportation cost (TAPS' tariff) that Alyeska charges them for transporting their oil through the pipeline from the North Slope to the Valdez terminal. However, DOE's model assumes that decisions regarding the production of North Slope oil and the potential shutdown of TAPS are made independently by the owner companies. That is, DOE assumes that TAPS' tariffs are based on a fixed formula that was agreed upon by the owners, the state, and the courts in 1985 and will not change. Incorporating the decision-making process of the owner companies and

[3]Alyeska was created by an agreement among eight companies. The current owners are Amerada Hess Pipeline Corp.; ARCO Transportation Alaska, Inc.; BP Pipelines (Alaska) Inc.; Exxon Pipeline Co.; Mobil Alaska Pipeline Co.; Phillips Alaska Pipeline Corp.; and Unocal Pipeline Co.

Alyeska into the model is difficult without specific knowledge of the internal workings of the companies involved.

DOE's Model Is Not the Most Appropriate Means of Estimating TAPS' Most Likely Shutdown Date

DOE's model is not the most appropriate means for estimating the likelihood of when oil production will decline to the point where TAPS would be forced to shut down. We believe that a model which incorporated a Monte Carlo technique would have been more appropriate because it would have more fully considered the uncertainties associated with estimating complex issues such as future oil production on the North Slope.

DOE used commercially available computer software to create a model to evaluate the projected economics of individual oil fields. Using this model, DOE assigned "best estimates" or mid-point values to hundreds of variables, and the model calculated a single outcome on the basis of these estimates. This model is an acceptable tool for determining a single outcome on the basis of single-point estimates for multiple variables. However, this type of model does not estimate the probability that the resultant outcome is the one most likely to occur. One consequence of using this model is that if the variables' actual values deviate from the single-point estimates used in the model—which is almost certain, given that they are being projected nearly 30 years into the future—a projected "most likely" outcome is no longer valid.

Alternative models, such as those that use a Monte Carlo technique, could deal with the uncertainties in projecting the future production of oil on the North Slope. A Monte Carlo technique uses probability distributions (or ranges) for key variables, selects random values from each of the variables simultaneously, and repeats the random selection over and over again. The advantage of this type of analysis is that the interaction of a wide range of possible resource, oil price, and cost estimates can be modeled to develop a probability distribution of outcomes, including the estimated likelihood of when North Slope oil production would decline to the point where TAPS would be forced to shut down. (See app. II for a discussion of DOE's methodology.)

Uncertainties Associated With Key Economic, Geologic, Engineering, and Cost Assumptions Not Fully Considered

While we agree with DOE that overall oil production on the North Slope is declining and will continue to decline, we believe that DOE did not fully consider the uncertainties associated with key economic, geologic, engineering, and cost assumptions. Assumptions underlying DOE's projections of North Slope development are crucial to estimating the viability of TAPS. In our analysis, we had concerns about several of DOE's key assumptions; some of the experts we contacted expressed similar concerns.

Uncertainties Associated With Key Economic Assumptions

The future price of oil is one of the most significant economic assumptions used in DOE's model, because changes to oil prices affect future production and development decisions. The higher the projected price of oil, the greater the amount of oil that can be economically produced. The future price of oil is also very uncertain. Instead of using a range of oil prices, DOE used a single-point estimate for future oil prices in its economic model—the mid-level prices from its National Energy Strategy (NES).[4] DOE's mid-level oil prices were within the range of forecasts made in 1990 by others, including the Wharton Economic Forecasting Association; Data Resources, Inc.; DOE's Energy Information Administration; Ashland Oil Inc.; and Conoco Inc. However, compared with oil price forecasts available in early 1992, the oil price estimate used in DOE's report was above the range, resulting in higher projections of economically recoverable oil. Had DOE accounted for the uncertainty of future oil prices by using a range of oil prices—such as those contained in the NES—its estimate may have shown other likely dates in which North Slope oil production could decline to the point where TAPS would no longer be economically viable.

Another problem with DOE's oil prices—although one that has less potential impact on DOE's final estimate than does the use of a single-point estimate—is that DOE assumes that the North Slope crude oil price will be the same as imported crude oil in the lower 48 states. Historically, however, the price of North Slope crude has been lower than the average price of imported oil because they are marketed differently and because North Slope crude oil is of lower quality. We found that from 1987 to 1991, on average, the price of North Slope crude oil was almost $1 a barrel less than the world market price for oil in the lower 48 states. We, DOE

[4] Among the objectives of the NES are achieving balance among the increasing need for energy at reasonable prices and reducing the dependence on potentially unreliable energy suppliers. The strategy was published by DOE in February 1991. As a part of this effort, DOE developed three possible oil price levels—low, mid, and high. For DOE's January 1991 report, officials chose to use one set of prices—NES' mid-level prices. NES mid-level prices (in 1989 dollars) range from $16.80 in 1990 to $45.55 in 2030.

contractors, and experts we contacted all agree that DOE should have accounted for the lower price paid for North Slope crude oil in order to more accurately represent the true delivered price that oil companies would use in making their production and development decisions. If DOE had accounted for this price differential in its analysis of producing, potentially producing, and discovered but nonproducing fields, its estimate of TAPS' shutdown date might have been earlier than 2014.

The second major concern about DOE's economic assumptions involves the discounted cash flow rate, or discount rate, that DOE used. Discount rates are used to determine the present value of future revenues and costs from oil production and development. For producing and potentially producing fields, DOE used a 10-percent nominal discount rate and applied it to revenues and expenses. To account for the increased risk and uncertainties in discovered but nonproducing fields and areas with undiscovered fields, DOE assumed a 15-percent nominal discount rate. According to various studies available on oil and gas development and to the experts we contacted, there is no consensus on a single discount rate that can be used for these types of estimates. Furthermore, the use of different discount rates is not the recommended way to account for differences in risk. We believe that DOE should have accounted for the greater risk and for the uncertainty associated with discount rates by using a range of rates and applying a Monte Carlo technique to assign probabilities to their occurrence.

Uncertainties Associated With Key Geologic, Engineering, and Cost Assumptions

Our analysis and the experts we contacted both indicated that DOE's geologic, engineering, and cost assumptions related to the likely future production of oil from currently producing and potentially producing fields are generally reasonable. However, the uncertainty of DOE's assumptions increases for the four discovered but nonproducing fields, and it increases even more so for the three areas with undiscovered fields. Instead of accounting for uncertainty by providing a range of estimates, DOE used only single values for the geologic assumptions that are used to project the future development of the discovered but nonproducing fields. For areas with undiscovered fields, DOE developed potential development scenarios that consisted of its expectation—based on limited geologic data—of what would happen if small or large oil discoveries were made. Since they were based on limited data, these expectations could be misleading in looking at the range of possibilities for these areas and their potential impact on TAPS' operation.

For example, the West Sak field, a discovered but nonproducing field, could potentially be the biggest discovery of oil since oil was found at Prudhoe Bay, but West Sak's oil is expected to be difficult and costly to produce because of several unique characteristics. It is a heavy oil located in shallow unconsolidated sands, and thousands of wells are needed to produce it. According to DOE headquarters officials, in order for oil to be produced from West Sak, several environmental and technical issues would have to be addressed. The officials stated that because several thousand wells would be needed to produce oil from this field, there would be environmental implications, such as how to meet existing wetlands requirements. In addition, because the oil located in the West Sak field is very heavy, it will be difficult to produce and move through TAPS. Additionally, ARCO Alaska Inc., West Sak's primary owner, may have to develop new procedures to produce the field. (See app. III for a detailed discussion of our findings for each field included in DOE's report.)

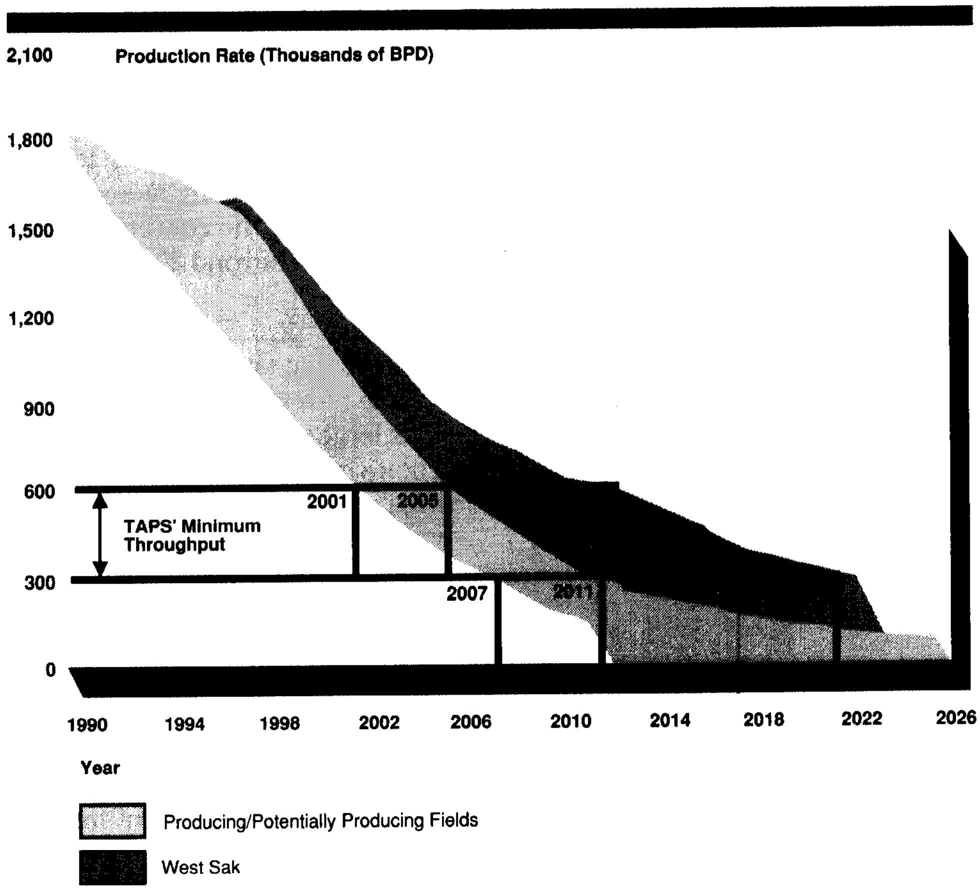
DOE estimated that West Sak contains about 8.5 billion barrels of oil and that about 5 percent could reasonably be expected to be recovered. However, some experts believe and other data suggests that DOE's assumptions are conservative. By picking a single resource and recovery estimate, DOE's report implies a level of precision in its analysis that does not exist—much remains unknown about the size of the West Sak field and its ultimate recovery potential. According to our own analysis and to experts we contacted, West Sak's resource estimates could range from at least 8.5 billion to 40 billion barrels of oil, and its estimated rate of oil recovery could range from 5 to 25 percent.

GAO's Analysis Demonstrates Some of the Uncertainties Associated With TAPS' Shutdown and Future Oil Production

Although we believed that DOE's model was not the most appropriate means for projecting future oil development or estimating TAPS' shutdown date, we reran DOE's model after varying certain key assumptions to demonstrate how changes in the assumptions could effect DOE's conclusions regarding the shutdown of TAPS and the estimated future oil production at the North Slope. In essence, our analysis included the use of both the low and high NES oil prices to provide a range of possible outcomes. In addition, for West Sak, we used a range of resource and recovery estimates to account for the uncertainty associated with producing this field.[5] did not assign probabilities to outcomes because DOE's model does not provide for it (see fig. 3).

[5]See appendix III for a detailed discussion of other changes we made to West Sak assumptions.

Figure 3: Impact of TAPS' Minimum Operating Levels on GAO's Range of Production Estimates for Producing and Potentially Producing Fields and West Sak



Legend

2001 — At low NES (National Energy Strategy) oil prices, TAPS' throughput of 600,000 BPD (barrels per day) is reached for producing fields.

2005 — At high NES oil prices, TAPS' throughput of 600,000 BPD is reached for producing and potentially producing fields.

2007 — At low NES oil prices, TAPS' throughput of 300,000 BPD is reached for producing fields.

2011 — At high NES oil prices, TAPS' throughput of 300,000 BPD is reached for producing and potentially producing fields.

2012 — At high NES oil prices, TAPS' throughput of 600,000 BPD is reached for producing and potentially producing fields and West Sak.

2021 — At high NES oil prices, TAPS' throughput of 300,000 BPD is reached for producing and potentially producing fields and West Sak

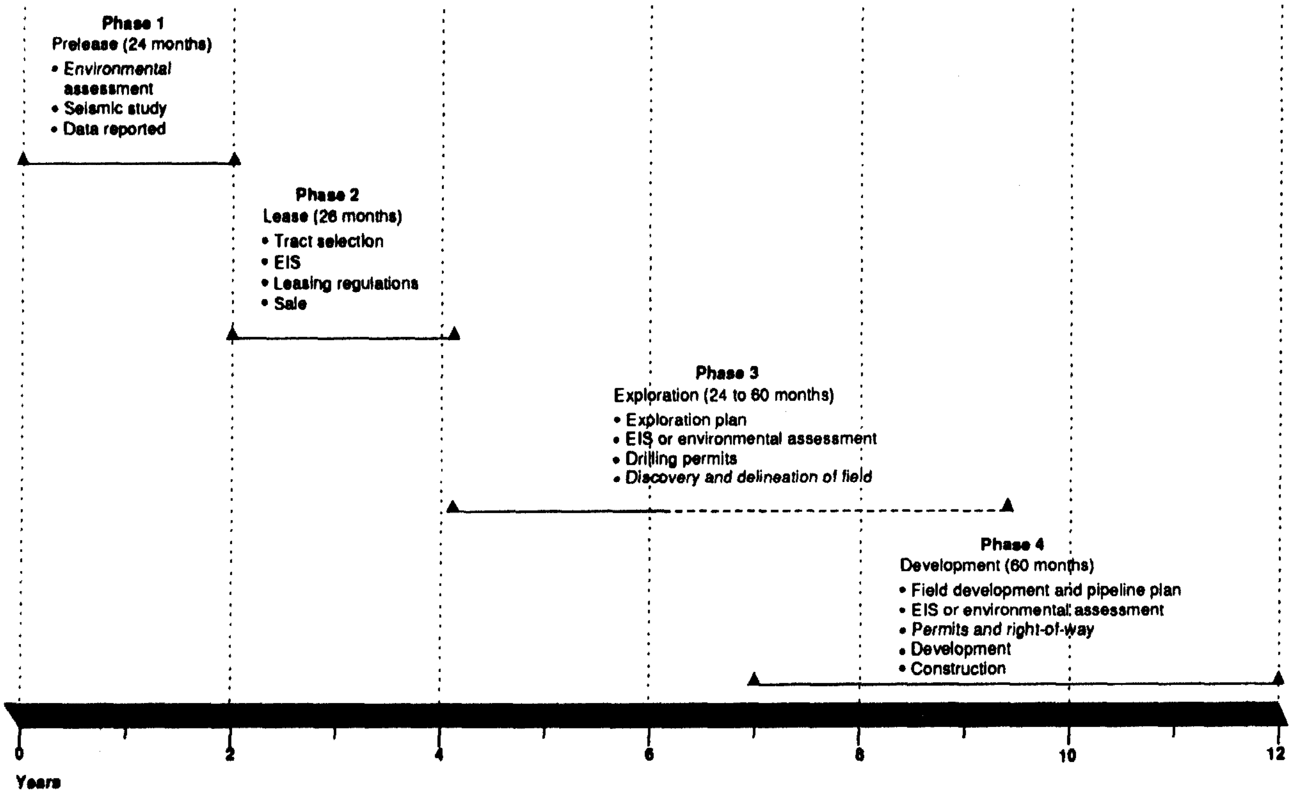
Because the data for areas with undiscovered fields are so uncertain, we did not include them in our analysis. However, if one or all three of the areas are found to have substantial quantities of economically producible oil, they could have a significant impact on the continued operation of TAPS. For example, according to DOE's study, if ANWR contained 6.25 billion barrels of economically recoverable oil, and TAPS' minimum operating level was 300,000 BPD, the continued operation of TAPS would be extended by about 10 years beyond 2009.

DOE's Projection About Developing New Fields in ANWR Is Reasonable

We believe that DOE's projection that it would take 10 to 12 years to develop a new oil field on the North Slope is reasonable, particularly for a field as large and controversial as ANWR. On the basis of this conclusion and DOE's other conclusion that 2009 is the most likely date for TAPS to shut down, DOE has stated that the Congress would have to authorize leasing ANWR by 1997 to keep TAPS operating.

We identified four phases of development and over 100 different federal, state, and local approval or permit requirements that would have to be completed before production of a new field in ANWR could begin. However, litigation, weather conditions, engineering or construction challenges, and/or oil company responsiveness to permit requirements could add months or years to the amount of time required to develop these fields. (See fig. 4 for a development time line and an illustration of the four phases and actions necessary to develop a new oil field in ANWR.)

Figure 4: Time Line and Actions Necessary to Develop a New Oil Field in ANWR



(See app. IV for a summary and detailed time line of these activities.)

Conclusions

On the basis of our assessment of the accuracy of and support for the conclusions reached in DOE's report, we agree with DOE that at least 10 to 12 years would be required to develop new oil fields in ANWR. However, DOE's conclusion that 2009 is the most likely year that TAPS will shut down implies a level of precision that does not exist. For one thing, Alyeska's statement that TAPS cannot operate below 600,000 BPD contradicts DOE's conclusion, which is based on a 300,000-BPD operating level. Also, such a projected shutdown date does not adequately consider the uncertainties of various economic, geologic, engineering, and cost assumptions used in projecting future development and production.

DOE has stated that the Congress would have to authorize leasing in ANWR by 1997 to keep TAPS operating after 2009 because developing a new oil field in ANWR that could offset the decline in North Slope production will probably take about 10 to 12 years. Whether and when ANWR should be leased is a public policy decision and part of a larger debate surrounding a national energy strategy. While we agree with DOE's conclusion regarding the length of time to develop ANWR, we believe that the shutdown of TAPS could occur sooner or later than DOE's projection, depending on a number of unknown factors—including the price of oil, TAPS' minimum operating level, and whether West Sak is developed and/or areas with undiscovered fields are found to contain substantial amounts of oil that are ultimately produced. Accordingly, it would have been more helpful in making public policy decisions if a Monte Carlo technique had been used to estimate the likelihood of when North Slope oil production would decline to the point at which TAPS would be forced to shut down.

Agency Comments

DOE provided written comments on a draft of this report. DOE stated that while GAO and DOE may express differences of opinion over the methodology and assumptions used in DOE's report, it believes that both reports can be used constructively. DOE had no other specific comments (see app. V).

We also discussed the facts of this report with the Washington, D.C., representative for the Alyeska Pipeline Service Company and with officials from the Department of Defense's Assistant Secretary of the Army (Civil Works). Alyeska generally agreed with the information presented on TAPS. Alyeska also stated that the price of oil and Alyeska's cost per barrel to transport the oil from the North Slope are the key factors in determining how long TAPS will operate. Although we requested written comments from Alyeska regarding the information on TAPS presented in our report, Alyeska declined to provide them.

The Department of Defense stated that it generally agreed with the findings in our report pertaining to the permits needed to develop ANWR that are issued by the Army Corps of Engineers.

To evaluate DOE's economic model and economic, geologic, engineering, and cost assumptions, we conducted our own analysis and obtained the views of a number of experts—including oil companies on the North Slope, state and federal officials, and public interest groups—through survey instruments and discussions.

Although we believe that the methodology for DOE's report could have been improved by considering ranges and probabilities for various economic, geologic, engineering, and cost assumptions, it would have been outside the scope of this evaluation to develop a new model for such an analysis. Instead, to illustrate the impact that various key assumptions had on DOE's conclusions regarding TAPS' shutdown and to demonstrate the uncertainties associated with projecting oil development on the North Slope, we reran DOE's model and used ranges for some assumptions.

The accuracy of our calculations for some oil fields may have been affected by limitations in our knowledge of key geologic, engineering, and cost assumptions. Oil companies and some government agencies that regulate these companies are in the best position to provide this information. In many cases, we received considerable information about the assumptions made for producing fields from the oil companies, government agencies, and public interest groups. But some oil companies did not respond to our requests for information, and our information is thus more limited—particularly with regard to some of the discovered but nonproducing fields and areas with undiscovered fields. Similarly, Alyeska officials met with us but did not provide key documentation regarding operating levels.

To assess the time required to develop a new oil field in ANWR, we met with federal, state, industry, and public interest officials. (See app. I for a more detailed discussion of our objectives, scope, and methodology.)

Our work was conducted from November 1991 through February 1993 in accordance with generally accepted government auditing standards.

Unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days after the date of this letter. At that time, we will send copies to the Secretaries of Defense, Energy, and Interior; the Administrator, Environmental Protection Agency; the Director, Office of Management and Budget; the state of Alaska; the Alyeska Pipeline Service Company; and the interested congressional committees. We will make copies available to others on request.

Please contact me at (202) 512-7756 if you or your staff have any questions. Major contributors to this report are listed in appendix VI.

Sincerely yours,

James Duffus III

James Duffus III
Director, Natural Resources
Management Issues

Contents

Figures

Abbreviations

ANWR	Arctic National Wildlife Refuge
BLM	Bureau of Land Management
BPD	barrels per day
COE	Corps of Engineers
DGC	Division of Governmental Coordination
DOE	Department of Energy
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
FWS	Fish and Wildlife Service
GAO	General Accounting Office
NEPA	National Environmental Policy Act
NES	National Energy Strategy
NPRA	National Petroleum Reserve-Alaska
TAPS	Trans-Alaska Pipeline System

Objectives, Scope, and Methodology

On January 9, 1992, the Chairman, House Committee on Interior and Insular Affairs (now called the Committee on Natural Resources), asked us to assess the accuracy of and support for the conclusions reached in the Department of Energy's (DOE) January 1991 report Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?. To accomplish this, we assessed DOE's conclusion that 2009 is the most likely year that the Trans-Alaska Pipeline System (TAPS) will be forced to shut down. To accomplish this, we evaluated the reasonableness of (1) the minimum operating level that DOE assumed for TAPS and (2) the model and the key economic, geologic, engineering, and cost assumptions that DOE used to estimate oil production at the North Slope. We also evaluated the reasonableness of DOE's conclusion that it will take 10 to 12 years to develop a new oil field in Arctic National Wildlife Refuge (ANWR).

To assess the reasonableness of the minimum operating, or throughput[1] levels used for TAPS, we interviewed DOE officials in Washington, D.C., and Idaho Falls, Idaho, and their contractor, EG&G Idaho, Inc. (EG&G Idaho, Inc., was the contractor DOE hired to develop the economic model and to write its January 1991 report.) We reviewed the available documentation they had to support their conclusions. We also met with Alyeska Pipeline Service Company officials to discuss TAPS' minimum operating level and requested documentation from them regarding future operating plans and the costs of operating the pipeline. Although company officials discussed with us in general terms the estimates of TAPS' future minimum operating levels, they chose not to provide us with any specific documentation regarding minimum operating level projections. We reviewed a number of other documents, such as the 1985 Settlement Agreement and Alyeska's monthly operating reports, to determine past operating levels and minimum throughput estimations.

We also evaluated the economic model used by EG&G Idaho, Inc., and assessed the reasonableness of the economic, geologic, engineering, and cost assumptions used in that model. We obtained a copy of the commercially available financial software package used by EG&G and evaluated various aspects of the model by running it for each of the producing, potentially producing, and known but nonproducing fields.

To assist in our assessment of the reasonableness of the economic, geologic, engineering, and cost assumptions in DOE's report, we developed a survey instrument that presented the assumptions and/or calculated values for producing or potentially producing fields, discovered but

[1]Throughput is the daily rate of oil flow through the pipeline expressed in barrels per day.

nonproducing fields, and areas with undiscovered fields. For each oil field, we identified five parameters: (1) resource estimates, (2) exploration and/or development costs, (3) operating costs, (4) taxation costs, and (5) transportation costs. We asked experts around the country to respond to our survey instrument and assess the reasonableness of DOE's assumptions/calculated values and, in cases where they found an assumption to be unreasonable, to provide us with documentation supporting their position. In most cases, we discussed the assumptions identified as unreasonable with applicable experts to determine the basis for their conclusions. This group of experts included oil companies with operations on the North Slope, federal and state agencies, consultants, professional organizations, and public interest groups. The survey instrument was quite detailed and lengthy, and we did not expect any single respondent to have information or knowledge about all, or even most, of the sections of the survey instrument. Respondents were instructed to reply to only the parts or sections in which they had sufficient knowledge to assess the reasonableness of the assumptions and/or the calculated values.

The following is a list of 29 organizations and individuals that we sent the survey instrument to:

Federal Agencies

- Bureau of Land Management
- U.S. Geological Survey
- Minerals Management Service

State of Alaska

- Department of Natural Resources
- Department of Revenue
- Oil and Gas Conservation Commission

Oil Companies

- Amerada Hess Corp.
- ARCO Alaska, Inc.
- BP Exploration (Alaska) Inc.
- Chevron Producing Company
- Conoco Inc.
- Exxon Corporation

Marathon Oil Company
Mobil Corporation
Phillips Petroleum Company
Shell Oil Company
Texaco Inc.
Unocal Corporation

Industry Organizations/Consultants

American Association of Petroleum Geologists
Society of Petroleum Engineers
Three industry consultants

Public Interest Groups

Alaska Coalition
National Audubon Society
National Wildlife Federation
Natural Resources Defense Council
Trustees for Alaska
Wilderness Society

Amerada Hess, ARCO, Exxon, Shell, Marathon, and the American Association of Petroleum Geologists chose not to respond, and five of the six public interest groups hired a consultant and submitted a consolidated response.

We also conducted our own detailed economic and geologic analysis of North Slope oil fields and their operating conditions. To evaluate DOE's assumptions on oil prices, we obtained oil price projections (forecasts) from recognized experts (economic forecasters) for 1990 and 1992 and adjusted them to the same dollar value. To assess the price differential between North Slope oil and imported oil, we interviewed officials from DOE, the state of Alaska, and private consultants. On the basis of their suggestions, we estimated the historic price differential between North Slope oil and the world market price of oil delivered to the lower 48 states. To evaluate the reasonableness of the interest rates and discount rates used by DOE, we used the results of our survey instrument, published data, and discussions with various experts.

To assess the reasonableness of DOE's geologic, engineering, and cost assumptions, our geologist conducted detailed literature searches (in addition to using the responses to our survey instrument); analyzed field production records, well logs, and geological and geophysical maps; and prepared field decline curve analyses. He also interviewed numerous industry, government, and university geologists and engineers. (For a detailed discussion of our findings regarding the geologic assumptions used by DOE, see app. III.)

For the West Sak oil field, which has the potential to make the greatest contribution to future North Slope oil production, we reran the model a number of times using different variables to determine how changes to variables such as oil price, oil in place, and recovery rate affected the economic viability of the field. For the Milne Point field, several of the experts we contacted noted that production from the Schraeder Bluff formation had not been included in DOE's analysis. Because Schraeder Bluff's production is small for a North Slope field—about 2,100 barrels per day (BPD) in 1991—we felt that not including its production in the model would not have a major impact on DOE's projections or on the estimates of overall North Slope oil production and the life of TAPS. (For a detailed discussion of DOE's methodology, see app. II.)

To assess the time required to develop a new oil field in ANWR, we met with federal officials from the Environmental Protection Agency (EPA), Interior's Bureau of Land Management (BLM) and Fish and Wildlife Service (FWS), the U.S. Army Corps of Engineers, and state officials from Alaska's Departments of Environmental Conservation, Governmental Coordination, and Natural Resources. As a result of these meetings and the documentation we obtained, we developed a time line and detailed flowchart showing the four phases of development which must take place prior to production and the length of time for each event. (See app. IV.) The federal and state officials reviewed the flowchart for completeness and accuracy.

To discuss various aspects of DOE's report, we met with numerous officials from government, industry, and public interest groups. They included Interior officials in Washington, D.C., Anchorage, Alaska, and Menlo Park, California; DOE officials in Washington, D.C.; DOE officials and DOE's contractor, EG&G Idaho, Inc., in Idaho Falls, Idaho; state of Alaska officials from the Departments of Natural Resources and Revenue and from the Alaska Oil and Gas Conservation Commission; officials from the American Association of Petroleum Geologists in Tulsa, Oklahoma; officials from ARCO Alaska, Inc., BP Exploration (Alaska) Inc., Conoco Inc., Alyeska Pipeline Service Company, and the Trustees for Alaska, in

Alaska; and the Natural Resources Defense Council and the Alaska Coalition in Washington, D.C. We also observed operations at the following North Slope fields: Prudhoe Bay, Kuparuk River, Milne Point, and Endicott.

Description of DOE's Methodology

The Department of Energy (DOE) used a discounted cash flow model to evaluate the economics of oil development and production at the North Slope. Using this model and available information, DOE estimated the amount of oil that can be economically produced from (1) currently producing and potentially producing fields, (2) discovered but nonproducing fields, and (3) areas with undiscovered fields.

In general, the economic limit for production is defined as the point in time after payback when the operating cash flow becomes negative. DOE estimated the annual cash flow for each oil field based on such things as projections of recoverable oil, a recovery factor, projections of costs, and revenues for each field. DOE's methodology is briefly described below.

Estimates for Currently Producing and Potentially Producing Fields

Reserves and economic projections for seven fields are included in DOE's estimates of recoverable reserves from producing and potentially producing fields. Producing fields are Prudhoe Bay, Lisburne, Kuparuk River, Milne Point, and Endicott. The other two fields that are close to development—potentially producing fields—are Point McIntyre and Niakuk. DOE developed three production scenarios for these fields. The low-recovery case includes only the five currently producing fields; the most-likely recovery case and the high-recovery case also include the Point McIntyre and Niakuk fields. In addition, the low-recovery case projections were based on the assumption that there would not be any new investment for expansions and recovery programs, whereas the most-likely case assumes there would be increases in projected recovery that can be reasonably expected as a result of future investments. For the high-recovery case, DOE assumed a significant improvement in recovery enhancement technologies.

DOE estimated the amount of oil that could be economically produced from these fields on the basis of projections of costs and revenues for each of the above fields. Relying primarily on published data, DOE developed estimates for development costs, operating costs, state and federal taxes, and royalties. Revenue estimates were derived by using a production profile for each field and wellhead oil prices. Wellhead oil prices for the North Slope were calculated by using oil price projections from DOE's National Energy Strategy (NES) for the lower 48 states adjusted for transportation costs from the North Slope to the lower 48 states. Transportation costs include (1) tariffs from the field pipelines to the Trans-Alaska Pipeline System (TAPS), (2) tariffs from the beginning of TAPS on the North Slope to the port of Valdez, and (3) marine transportation cost from Valdez, Alaska, to delivery points at the West Coast of the United States and the Gulf of Mexico. TAPS tariffs were developed on the basis of the methodology specified in a 1985 settlement agreement between TAPS' owners and the state of Alaska and input into the economic model. Finally, DOE used a constant 3.5-percent inflation rate throughout the life of development, and future costs and revenues were discounted by using a 10-percent nominal discount rate.

Estimates for Discovered but Nonproducing Fields

According to DOE, this category contains a large number of fields that are either too small to be developed economically or for which data are insufficient to make a reliable estimate of their recoverable reserves. DOE included four fields in this portion of its analysis: West Sak, Seal Island, Sandpiper, and Gwydyr Bay.

Unlike the producing fields, DOE developed only one estimate of the amount of oil that could be economically produced for each of these four fields. DOE input historical and projected production rates, information on operating costs, and investment costs for such things as wells and facilities into the discounted cash flow model to determine if each field would meet a minimum rate of return on investment for new development projects. DOE set a nominal rate of 15 percent as the minimum required rate of return to develop the new fields.

Estimates for Areas With Undiscovered Fields

DOE evaluated potential fields in ANWR, the Chukchi Sea, and the National Petroleum Reserve-Alaska (NPRA). DOE conducted an economic analysis using the discounted cash flow model for five development scenarios for ANWR, three scenarios for the Chukchi Sea, and one for NPRA. DOE projected production by using recoverable oil volumes and a recovery factor and estimated how much oil could be economically produced using future development and operation costs and revenues (developed by using the NES oil price forecasts adjusted for transportation costs from the North Slope). DOE assumed a nominal discount rate of 15 percent and an inflation rate of 3.5 percent.

Impact of TAPS' Minimum Operating Level

DOE plotted the production of oil that could be economically produced as production declines over time for each of the above fields to determine when it would reach TAPS' assumed minimum operating level of 300,000 BPD. Using only the producing fields, DOE projected that the minimum operating level for TAPS would be reached in 2006 for the low-recovery case. In addition to the producing fields, DOE assumed that two potentially producing fields—Point McIntyre and Niakuk—would be developed in the most-likely and high-recovery cases. For the most-likely case, TAPS' minimum operating level will be reached in 2009, and in 2011 for the high-recovery case. When the estimates of oil that could be economically produced for the known but nonproducing fields were added to the most-likely case, the TAPS shutdown date—due to throughput falling below the minimum operating level of 300,000 BPD—was extended by 5 years to 2014.

DOE's estimated TAPS' shutdown dates of 2006 to 2011 (or 2014) are based on the results of DOE's analysis for three production scenarios involving producing and potentially producing fields and its production analysis for West Sak and the other known nonproducing fields. The range does not include areas with undiscovered fields in ANWR, the Chukchi Sea, and NPRA.

Sensitivity Analysis Results

DOE's report discusses its analysis of the sensitivity of the discounted cash flow for some producing and potentially producing fields and West Sak with respect to changes in a number of variables. DOE, however, did not present any sensitivity analysis to show the impact that changes to various assumptions had on its estimated dates for TAPS' shutdown. To show the impact that varying some of the key assumptions had on the estimated dates for TAPS' shutdown, we reran the same model and varied some key assumptions such as oil prices for these fields.

Description of Geologic, Engineering, and Cost Assumptions Affecting Future North Slope Oil Production

We believe that the Department of Energy's (DOE) assumptions related to future oil production from producing fields (Prudhoe Bay, Kuparuk River, Endicott, Lisburne, and Milne Point) and potentially producing fields (Point McIntyre and Niakuk) at the North Slope are generally reasonable. However, we believe that a number of DOE's geologic, engineering, and cost assumptions for discovered but nonproducing fields (West Sak, Gwydyr Bay, Seal Island/North Star, and Sandpiper)[1] did not adequately consider the uncertainty associated with developing projections of future oil production. Instead of providing a range of production estimates, DOE provided one production estimate for each of these discovered but nonproducing fields. This shortcoming is particularly important for West Sak—a field that is potentially the largest discovery of oil since Prudhoe Bay. DOE did not include areas with undiscovered fields (ANWR, Chukchi Sea, and NPRA) in its "most likely" projections of future development because there was insufficient data to make estimates with any degree of accuracy. We also did not attempt to project what impact the development of these undiscovered fields may have on the viability of the Trans-Alaska Pipeline System (TAPS).

Assumptions That May Affect Development

Projections of future production rates[2] must be tempered by uncertainties in future technological breakthroughs and fluctuations in oil prices. To estimate future development, DOE made several assumptions for each field. Geologic assumptions included the estimated amount of oil contained in each field and the amount of oil that might be produced. DOE then estimated how much of the oil might be economically produced by making assumptions about, among other things, (1) the API gravity of the oil;[3] (2) engineering factors such as the number of wells and spacing of those wells; (3) facilities' costs—for example, whether a new field could be produced sharing existing facilities from a currently producing oil field or whether new facilities would be needed; (4) drilling costs; and (5) operating and future investment costs. Most of these assumptions were based on data available as of January 1990. Because DOE's report

[1]Production estimates from one other discovered but not producing field—Point Thompson—was not included in DOE's report. The Point Thompson field is located about 50 miles east of Prudhoe Bay. DOE did not consider Point Thompson economical to produce unless other large fields are produced nearby. Since DOE's report was written, there have been two new field discoveries east of Prudhoe Bay and two new field discoveries west of Prudhoe Bay—two onshore and two in the Beaufort Sea. Their production potential is unknown at this time.

[2]The production rate is the amount of oil that is produced at a specific point during an oil field's productive history.

[3]API gravity is the standard adopted by the American Petroleum Institute for measuring, in degrees, the density or weight of a petroleum liquid. In general, the lower the API gravity, the more dense or viscous the oil becomes, and the harder it is to produce.

attempted to project future oil development, the assumptions are subject to uncertainty, and changing any one of these assumptions could have an impact on DOE's projections.

Several experts that responded to our survey instrument—particularly those outside of the oil industry—indicated that they did not have sufficient knowledge to respond to all of our questions, particularly assumptions regarding known but nonproducing fields and areas with undiscovered fields. Most, however, did respond to questions regarding the amount of potential oil resources and reserves[4] and how much of that oil may be produced for fields that they had specific knowledge of. This type of information is publicly available in the literature for currently producing oil fields.

DOE's Assumptions for Producing and Potentially Producing Fields Are Generally Reasonable

Estimating future oil production becomes increasingly more reliable once a field's production has peaked and begun its decline. The Prudhoe Bay field, which alone accounted for about 75 percent of the North Slope's production in 1990, has a 15-year production history and is the only producing field that has begun to decline. For the most part, the experts and our own analysis indicated that DOE's range of geologic, engineering, and cost assumptions for Prudhoe Bay were generally reasonable.

The Kuparuk River, Lisburne, and Endicott fields have not operated as long as the Prudhoe Bay field and are not yet declining. Because DOE did not fully consider the limited capacity of Kuparuk River's water-injection and gas-handling facilities, we believe that its development and peak production rate may differ from levels identified by DOE. However, the experts and our analysis generally indicated that DOE's assumptions for Kuparuk River's long-term production were reasonable. The experts who addressed the Endicott field assumptions expressed some disagreement over development costs. However, we believe that these cost differences would not significantly affect DOE's long-term projection for Endicott. Some experts questioned DOE's assumptions regarding Milne Point's potential production because Schraeder Bluff, a producing area within the Milne Point field, was inadvertently left out of DOE's model. However, because production from Schraeder Bluff is small for a North Slope field—about 2,100 BPD in 1991—we believe that not including its production in the model would not have a major impact on DOE's

[4]Resources are concentrations of naturally occurring hydrocarbons in or on the earth's crust in such a form that extraction is currently or potentially feasible. Reserves are specific accumulations of oil whose location, quality, and quantity are estimated from geologic evidence and are legally and economically extractable at the time of determination.

projections for overall North Slope production and the life of TAPS. Experts generally found that the assumptions used for Lisburne and for Point McIntyre and Niakuk—the two potentially producing fields—were reasonable.

DOE's Production Estimates for Discovered but Nonproducing Fields Do Not Adequately Consider the Uncertainty of Development

More uncertainty exists for estimating production for discovered but nonproducing fields than for fields already under production. Incomplete geologic and engineering data, a lack of historic production data, a lack of information on the levels and timing of corporate investment for development, possible future technological breakthroughs, and oil price uncertainties combine to make production projections for nonproducing fields highly uncertain. Because of insufficient knowledge, few experts could comment about these fields. However, some of those who did comment believed that DOE's future production projection for the largest of these fields—West Sak—was conservative based on the available technical information. DOE and experts consider three of the four discovered but nonproducing fields—Gwydyr Bay, Seal Island, and Sandpiper—to be relatively small fields. The fourth field—West Sak—is considered to be potentially the largest discovery since Prudhoe Bay. Some experts questioned DOE's assumptions on resources and cost parameters for the West Sak field.

West Sak's Future Production Is Uncertain

The West Sak field, which may be the largest known accumulation of conventionally producible oil in the United States, overlays the currently productive Kuparuk River field. The leases for both fields are primarily owned by ARCO. However, West Sak's potential production is uncertain because of many unanswered questions about this difficult-to-produce field. Some experts believe and other data suggests that DOE's estimate of 8.5 billion barrels of oil potentially located in the West Sak field ("oil in place")[5] and DOE's estimate of a 5-percent recovery factor[6] were conservative.

The amount of oil that may be produced in West Sak will be significantly affected by economics, including the availability of existing facilities and environmental constraints. In this regard, ARCO could use facilities already in place for Kuparuk River development to produce West Sak.

[5]Oil in place is an estimate of the volume of oil in the ground for a given geologic area such as a defined oil field.

[6]Recovery factor is a measure of the percentage of oil in place that can be produced by primary or enhanced recovery techniques over an oil field's productive history.

Although West Sak's development is uncertain, ARCO has stated that its production may be phased in as Kuparuk River production declines. In 1989 ARCO estimated that the West Sak field contained from 13 billion to 20 billion barrels of oil. Another study available in 1990 estimated that West Sak's oil in place may be as much as 25 billion barrels.[7] However, that study was based on laboratory experiments and on well data from only 13 of the more than 250 wells that penetrate West Sak sands. We could not identify any studies that have evaluated all available well data to determine the accuracy of this estimate. In addition, experts told us that there could be as much as 40 billion barrels of oil in West Sak. By choosing to base West Sak's potential future production on a single resource estimate instead of a range of possible outcomes, DOE did not fully consider the uncertainties associated with projecting future oil development.

DOE estimated that 5 percent of West Sak's oil in place could be recovered. However, experts and available literature suggest as much as a 25-percent recovery factor. In addition, Conoco, the producer of Schraeder Bluff, a field with characteristics similar to West Sak's, projects a 20-percent recovery factor for its Schraeder Bluff field.

The potential contribution of West Sak to overall North Slope production is very uncertain. According to ARCO, API oil gravity for West Sak ranges from 10 to 22 degrees, which is much lower than almost all other North Slope fields and will reduce West Sak's market value. In addition, although ARCO would not provide us access to well cores, a review of geologic data from files of the Alaska Oil and Gas Conservation Commission and published articles supported statements that (1) the West Sak sands are generally unconsolidated and relatively impermeable and (2) the field is highly faulted and shallow, which adds to the difficulty of designing future production. Because of the oil's viscosity, wells will need to be spaced about 10 to 20 acres apart rather than the more conventional spacing of 160 acres apart.

On the basis of our review of engineering criteria and geologic data, much of the West Sak field could be produced using a hot waterflood process.[8] Steam flooding may be possible on a limited basis, but adverse effects on well casings and overlying permafrost may rule this out. The results of

[7] Development of Effective Gas Solvents Including Carbon Dioxide for the Improved Recovery of West Sak Oil, G.D. Sharma, University of Alaska, Fairbanks, 1990.

[8] This process involves injecting hot water into a well to heat the oil and to make it easier to move the oil into producing wells.

ARCO's 1984-1986 pilot hot waterflood production project at West Sak indicate that wells will likely produce low-quality oil at rates of below 300 BPD (compared with several thousand BPD at other Alaska fields) and high production costs may result in early well abandonments.

To demonstrate the uncertainty associated with developing West Sak, we reran DOE's model and used DOE's estimates of oil in place and recovery factor to represent the low end of a range and used other available estimates to represent the upper end of the range. Specifically, after conducting our analysis and talking to experts, we estimated that as much as 20 percent of 20 billion barrels of oil could be recovered at West Sak. The 20 percent recovery factor is primarily based on Conoco's projections for its Schraeder Bluff field and the 20 billion barrels of oil is based on the upper range of ARCO's projection of oil in place for West Sak. In addition, we increased the amount of acreage assumed to be developed from 50,000 to 100,000 acres for West Sak. If 100,000 acres are developed and using DOE's assumption of 20-acre well spacing we found that about 5,000 wells would be needed to produce the entire field. We estimate that this would take approximately 10 years of full-time drilling using 20 drilling rigs (more than are presently working the North Slope). Experts also told us that the $850,000 cost to drill each well assumed by DOE was too low and suggested that about $1.5 million per well would be more reasonable.

Development of West Sak would require overcoming challenging obstacles. Although West Sak is potentially the biggest discovery of oil since that found at Prudhoe Bay, its oil is expected to be difficult and costly to produce because of several unique characteristics. It is a heavy oil located in shallow unconsolidated sands, and thousands of wells will be required to produce the oil. According to DOE headquarters officials, in order for West Sak to be produced, several environmental and technical issues would have to be addressed. The officials stated that because of the number of wells required to produce this field, there would be environmental implications including how to meet existing wetlands requirements. In addition, because the oil located in the West Sak field is very heavy, it will be difficult to produce and move through TAPS. ARCO, West Sak's primary owner, may have to develop new procedures to produce the field.

Great Uncertainty Associated With Areas With Undiscovered Fields

DOE did not include areas with undiscovered fields in its low, "most likely, or high-case projections of future development and its impact on the viability of TAPS. Because so much is unknown about these areas and they are subject to so much uncertainty, we also did not attempt to project what impact the development of these fields may have on the viability of TAPS. However, to examine the possible outcomes of future exploration on the North Slope and the impact of future discoveries on TAPS' operation, the DOE report provided a number of speculative (what if...?) scenarios for the Chukchi Sea, NPRA, and ANWR. The scenarios did not evaluate the likelihood of finding oil, nor calculate the range of undiscovered potentially recoverable oil in these exploration areas. The DOE scenarios were developed using resource evaluations of prospective exploration areas conducted by other federal or state agencies.

DOE developed two production scenarios for the Chukchi Sea, which is located off the northwest coast of Alaska. Because of insufficient knowledge, few experts were able to address specific assumptions on resource or cost parameters. Of the experts that could address these issues, several believed that DOE overestimated the exploration cost for wells in the area, but underestimated the number (and operational cost) of production platforms necessary to produce the prospects delineated in the report; the effect of this would be to reduce the amount of economically producible oil.

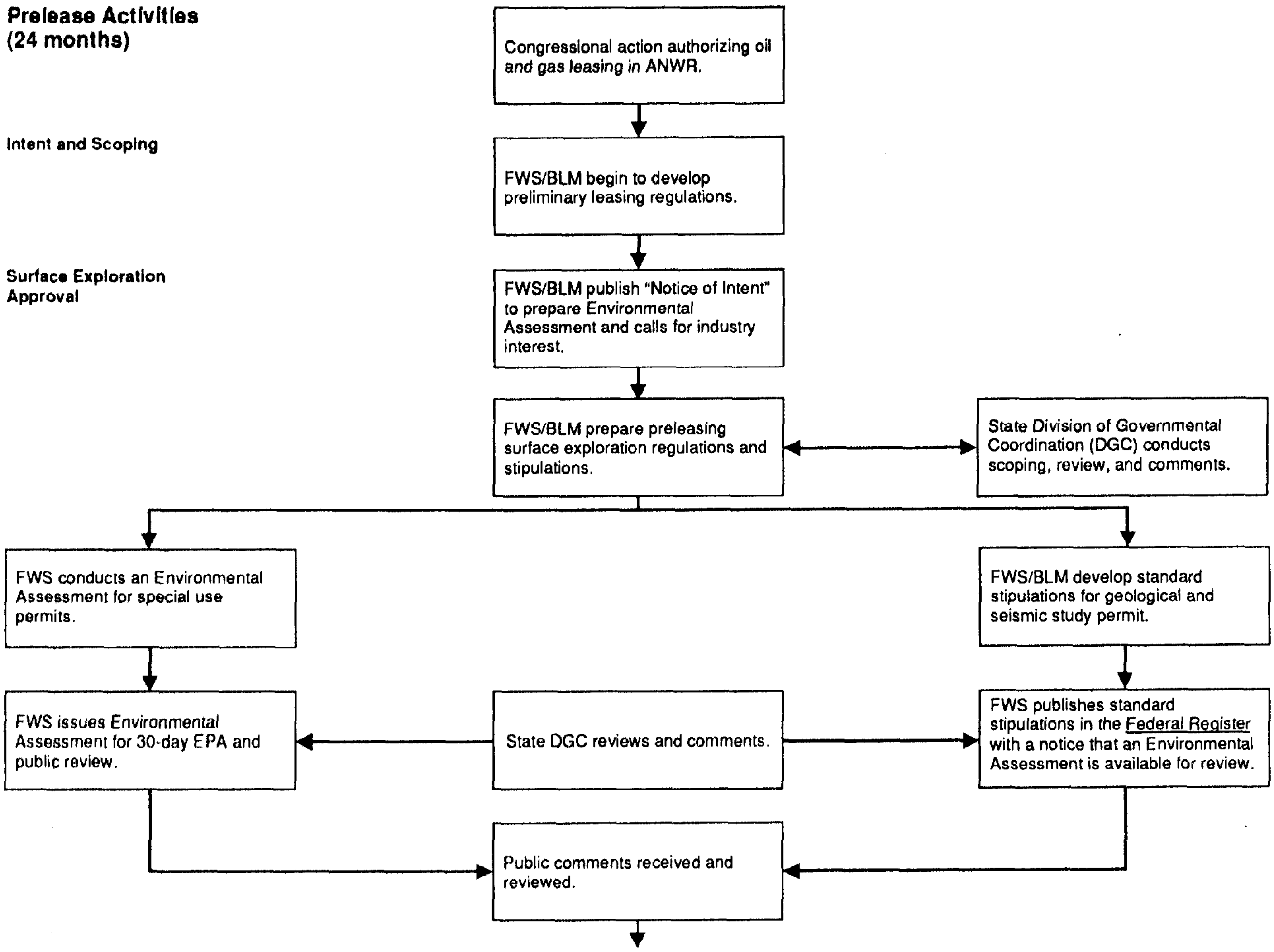
DOE developed production scenarios for two prospects (Meade Arch and Northern Foothills) in the NPRA. In order for these two prospects to be economically feasible, DOE assumed that feeder lines could be connected to a pipeline that was in place for transporting Chukchi Sea oil to TAPS' pump station No. 2. The U.S. Geological Survey believes, and we concur, that DOE's assumption about the amount of recoverable oil from the Meade Arch prospect was too high, and the assumption of drilling only one exploratory well per prospect was unreasonably optimistic.

To evaluate potential ANWR production, DOE developed two scenarios —a stand-alone scenario and a scenario dependent on the development of several small fields—to determine if the construction of a pipeline from ANWR to TAPS could be economically justified. To illustrate the possible production impacts of developing fields in ANWR, DOE set up both a small-resource multiple-field case, and a high-resource multiple-field case. Both of these scenarios were within the range of possible recoverable resources in ANWR as estimated by Interior. However, several experts who reviewed DOE's assumptions regarding potential ANWR development questioned DOE's costs for exploration, development, and/or operation, and questioned the timing and rates of production in the scenarios. These assumptions are important in assessing the validity of the production cases.

Procedures and Time Frames for Developing New Oil and Gas Fields in ANWR

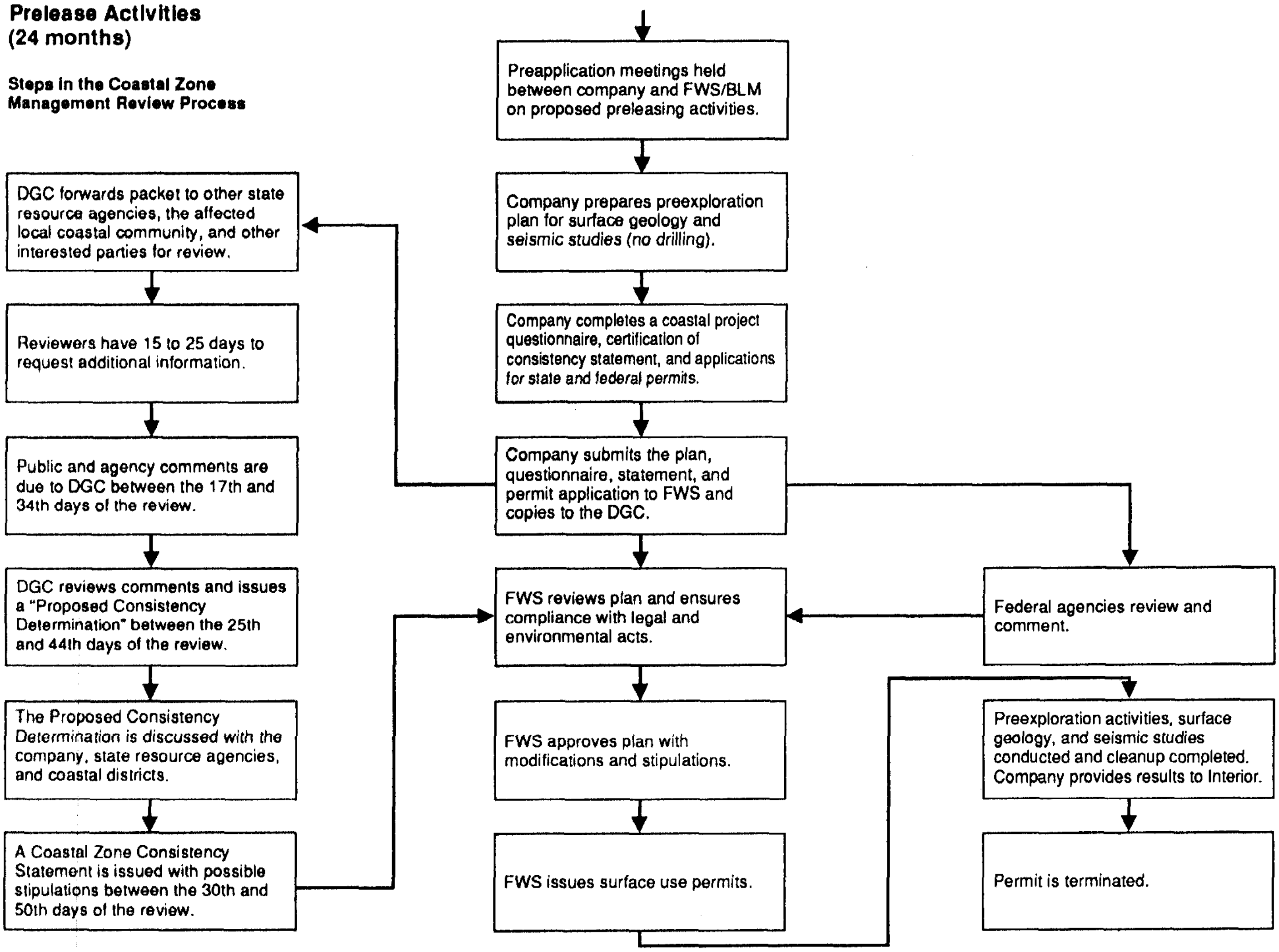
Federal and state agency officials generally agreed that it would take an oil company about 10 to 12 years to complete all of the government requirements and the development and construction activities from the time that congressional approval is granted for oil and gas leasing in ANWR until the time that commercial production begins. In order to assess what it would take to develop an oil field as large as ANWR on the North Slope, we met with numerous government officials. We also assumed that all development activity would take place on federal lands and that the federal agencies would take the lead in managing the development process. The following is a detailed flowchart of the four phases of development (prelease, lease sale, exploration, and development) and time frames identified by government officials as necessary to develop a new oil field in ANWR.

Figure IV.1: Flowchart of Procedures and Time Frames Necessary to Develop a New Oil Field in ANWR



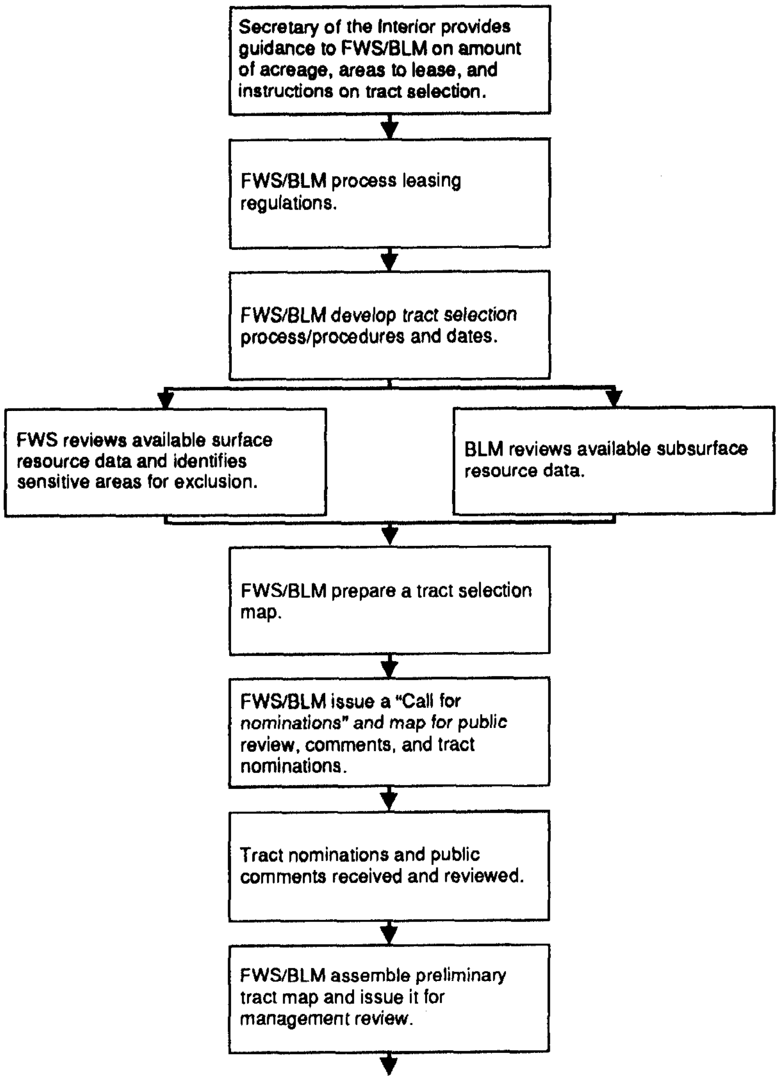
Prelease Activities (24 months)

Steps in the Coastal Zone Management Review Process

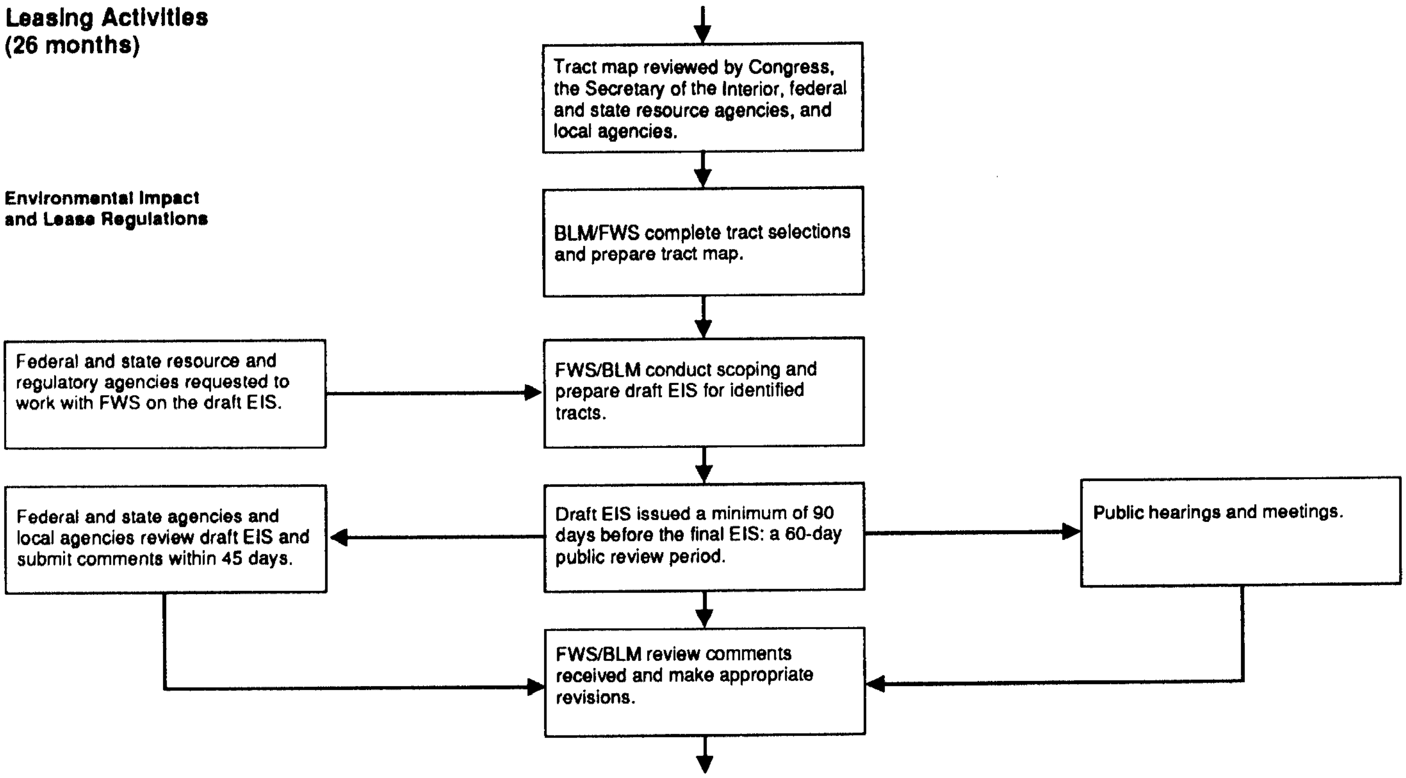


Leasing Activities (26 months)

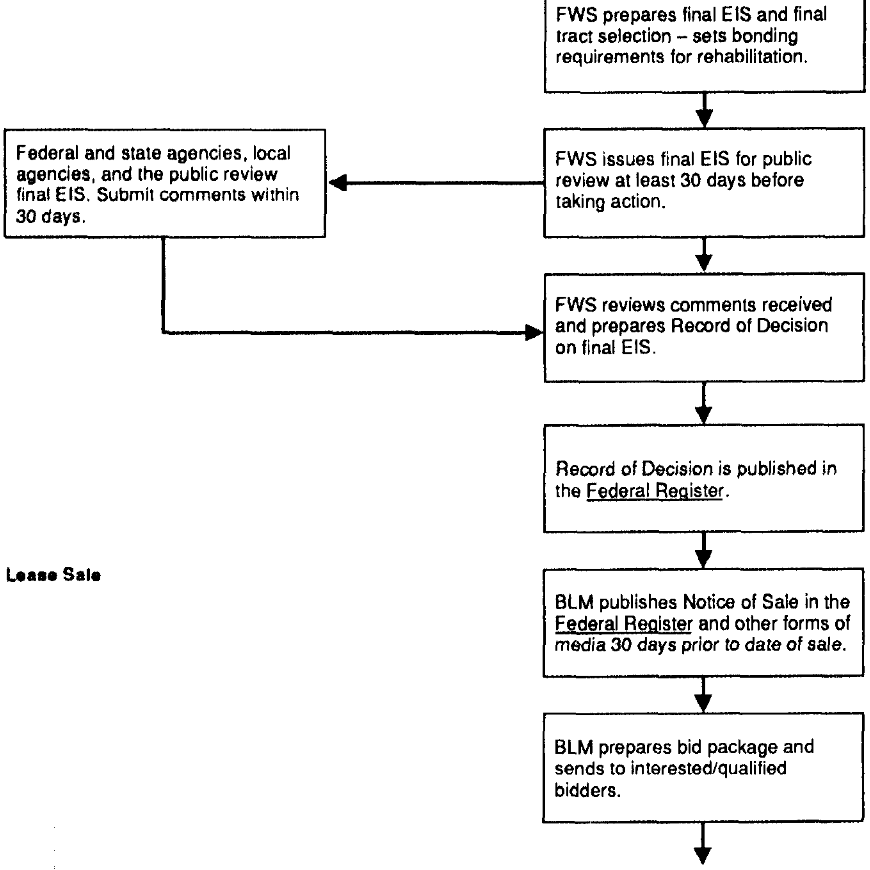
Tract Selection Process



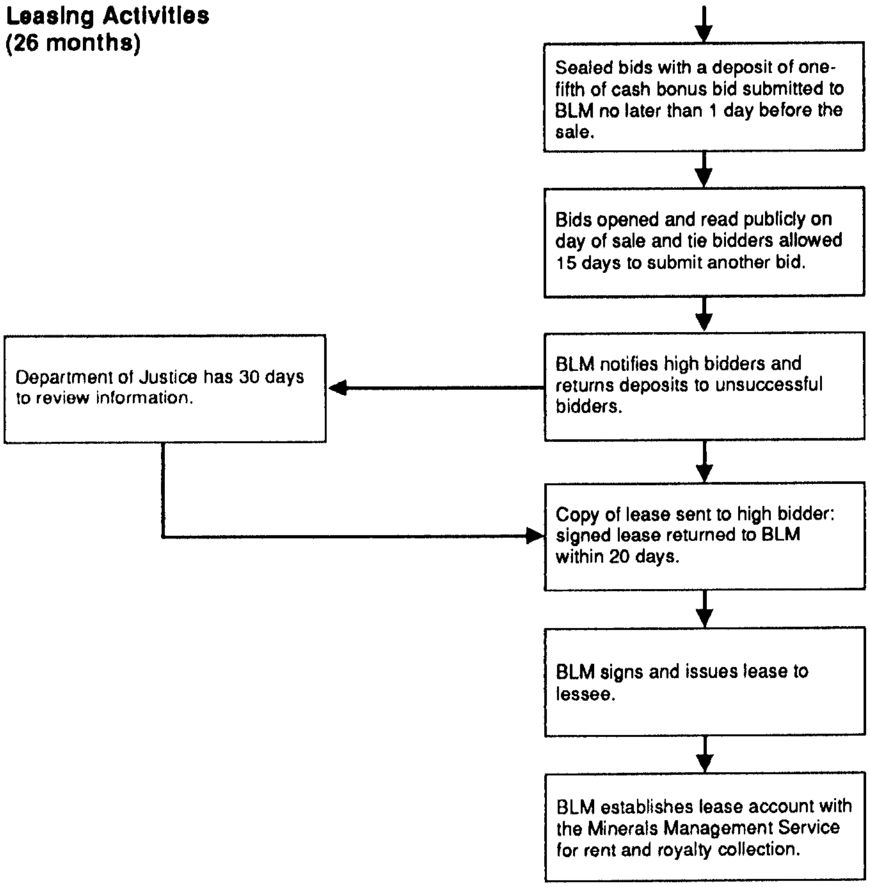
Leasing Activities (26 months)



Leasing Activities
(26 months)



Leasing Activities (26 months)

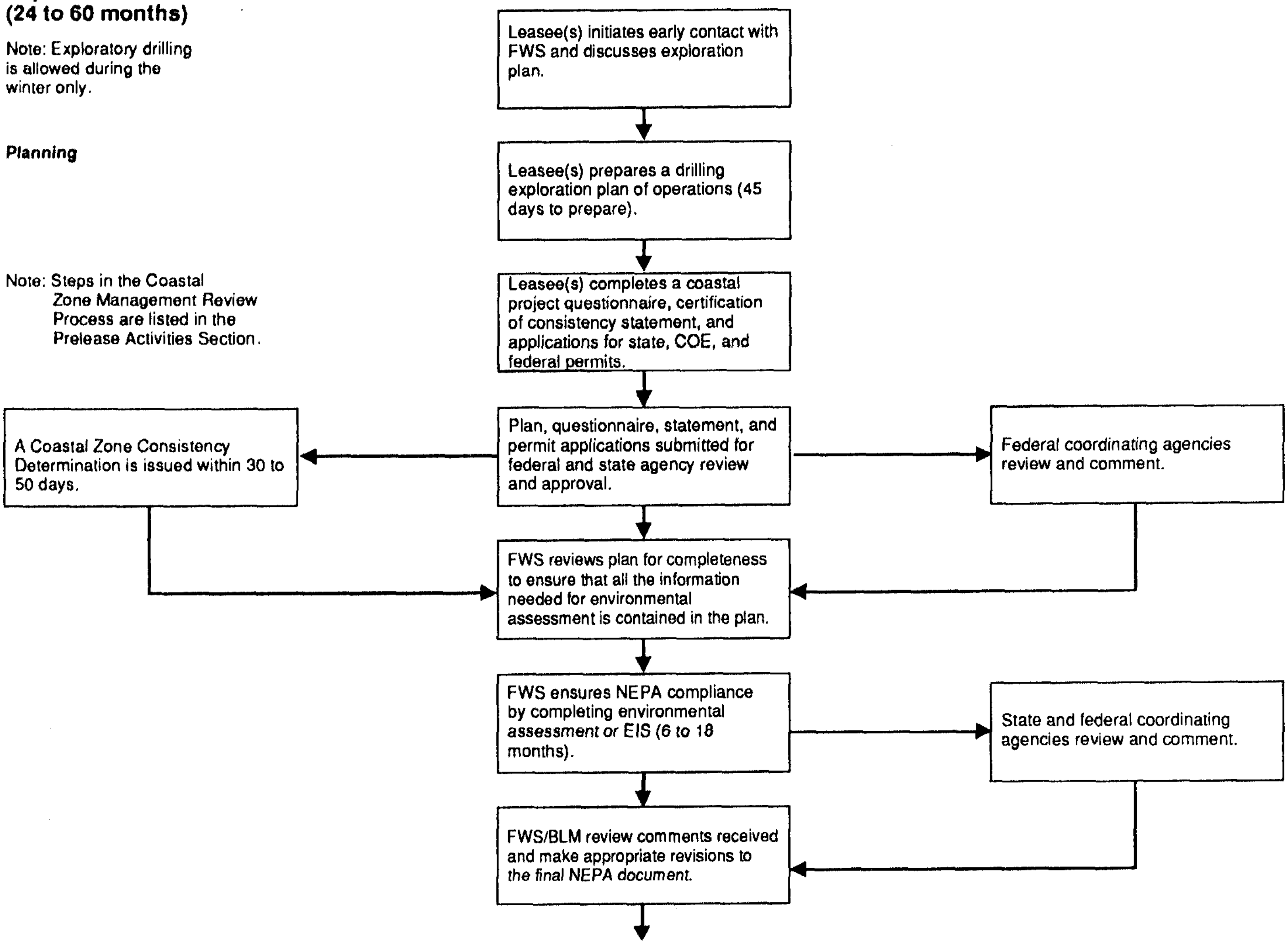


Exploration Activities (24 to 60 months)

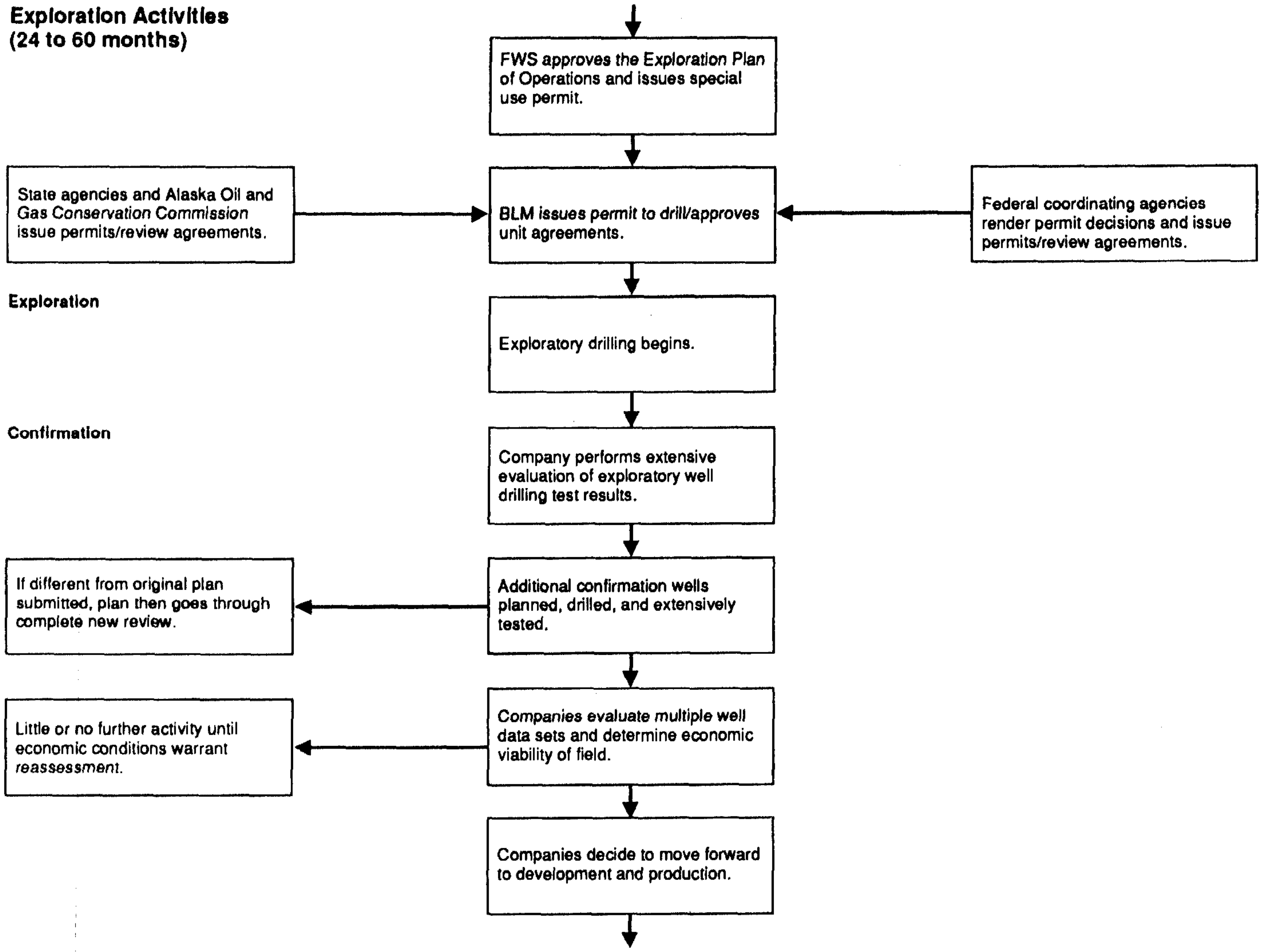
Note: Exploratory drilling is allowed during the winter only.

Planning

Note: Steps in the Coastal Zone Management Review Process are listed in the Prelease Activities Section.

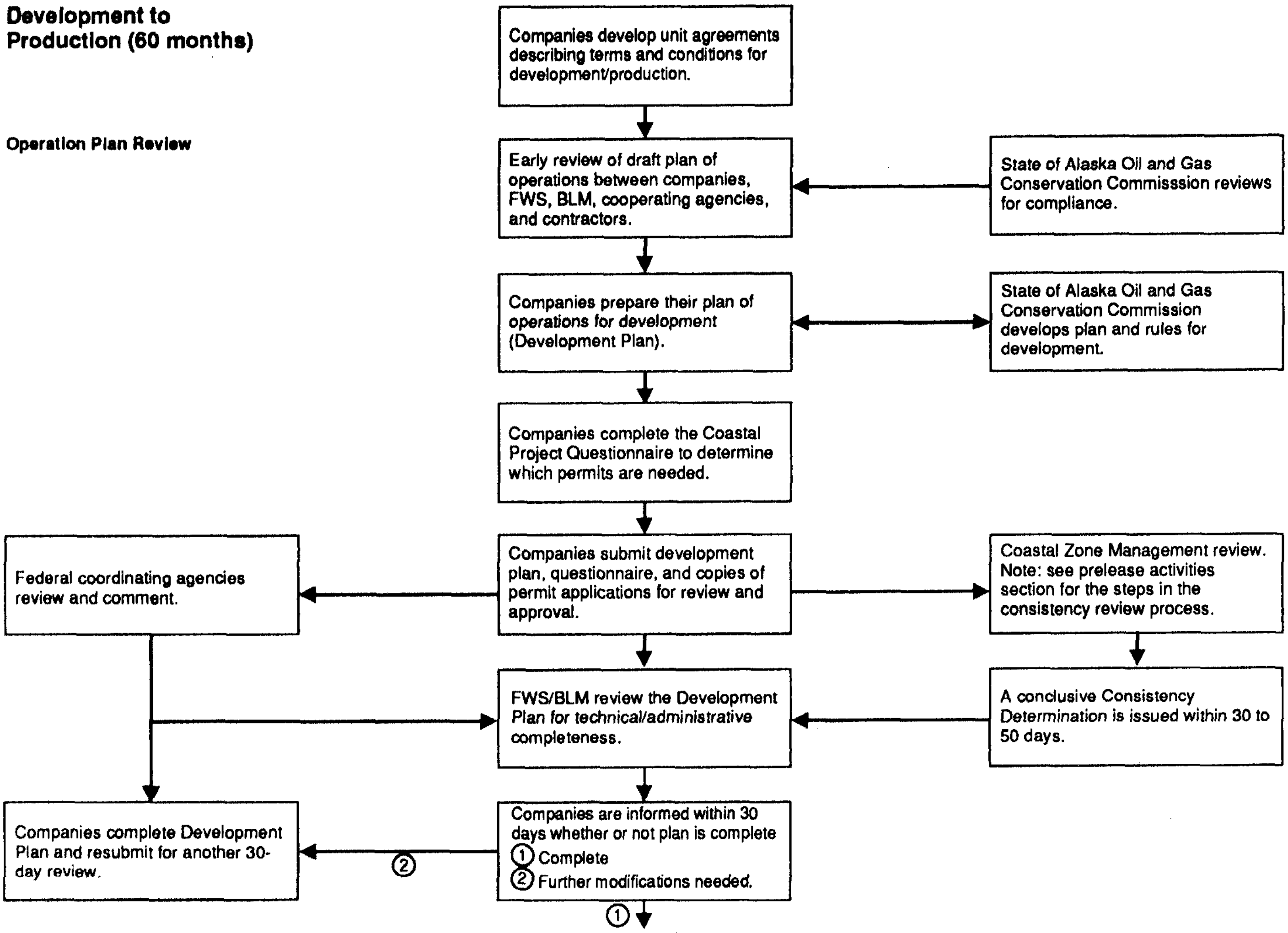


Exploration Activities (24 to 60 months)



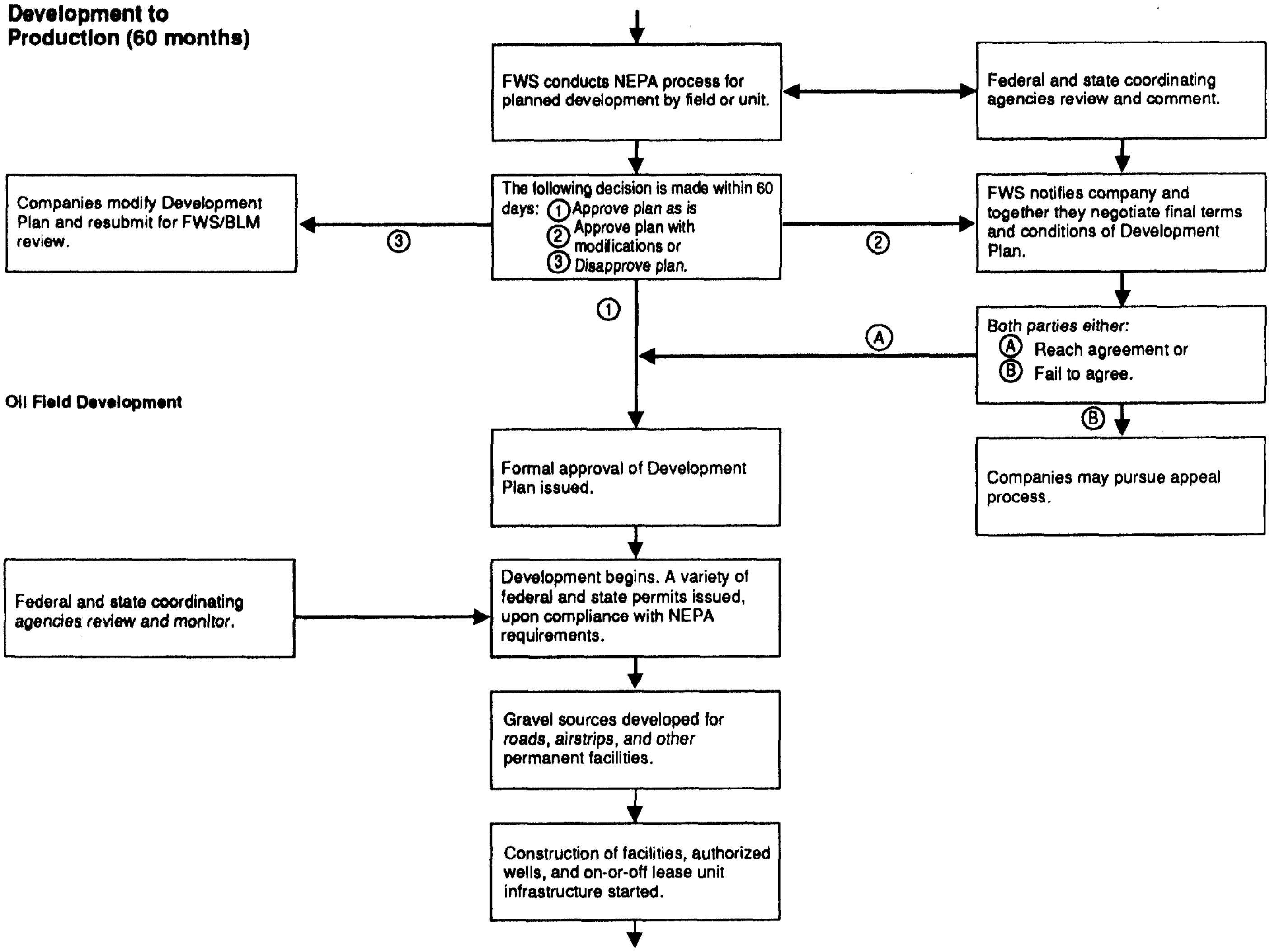
Development to Production (60 months)

Operation Plan Review



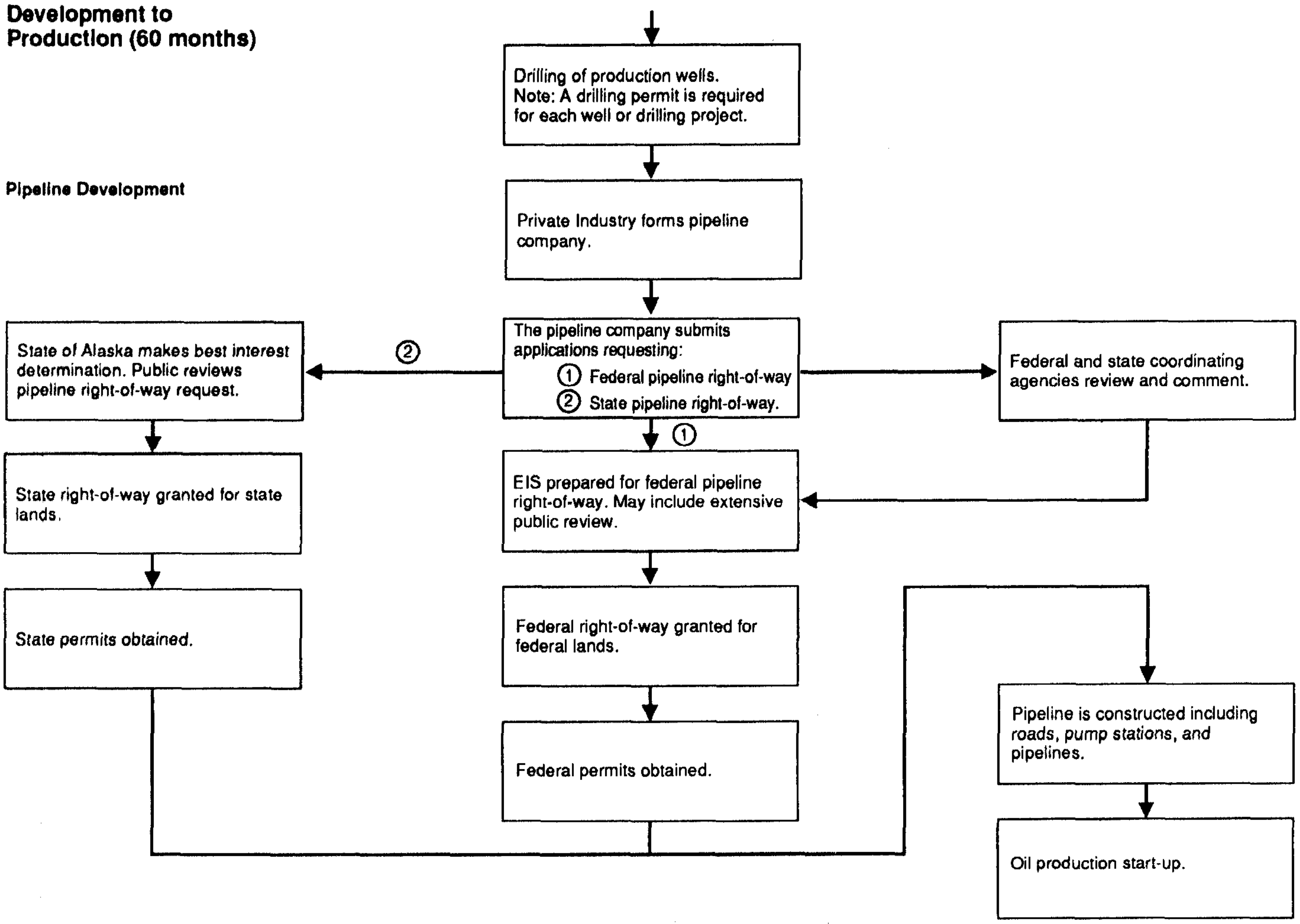
Development to Production (60 months)

Oil Field Development



Development to Production (60 months)

Pipeline Development



Comments From the Department of Energy

Department of Energy
Washington, DC 20585

MAR 2 1993

Mr. James Duffus III
Director, Natural Resources Management Issues
Resources, Community, and
Economic Development Division
U.S. General Accounting Office
Washington, D.C. 20548

Dear Mr. Duffus:

The Department of Energy appreciates the opportunity to review the General Accounting Office draft report, "Trans-Alaska Pipeline: Projections of Long-Term Viability Are Uncertain." This draft report is an assessment of the January 1991 report entitled "Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?"

As you are aware, oil and gas development on the North Slope of Alaska has been one of the most debated energy issues of the last several years. President Clinton has stated clearly his position that the ecological fragility of the Arctic National Wildlife Refuge should preclude opening it for exploration and production.

The Department has decided to offer no specific comments on the General Accounting Office draft report. While the report may express differences of opinion in the methodology and assumptions used by the Department in its original 1991 analysis, we believe both documents can be used constructively.

Thank you again for the opportunity to examine the draft report.

Sincerely,

Elizabeth E. Smedley

Elizabeth E. Smedley
Acting Chief Financial Officer

Major Contributors to This Report

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