Outlook for Yet-to-Find North Slope Natural Gas Resources

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by

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1. Introduction

The State's analysis of stakeholder net present value (NPV Model) depends on many factors, including the availability of undiscovered Alaska North Slope (ANS) gas resources that may be economically recoverable in the future when the inventory of existing, proved-developed-producing gas is depleted. This report considers the potential quantities and locations of undiscovered or "yet-to-find" (YTF) gas reserves, the order that YTF reserves may be developed, and the cost if bring YTF reserves into production. And it explains the treatment of YTF reserves and production in the State's NPV Model.

The State is not equipped to generate its own assessment of economically recoverable reserves. Accordingly, it looked to outside studies. The State's NPV modeling of YTF gas draws extensively from findings in the recent study: *Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline?,* published by the U.S. DOE, National Energy Technology Laboratory (NETL, 2007). The State chose to rely on the NETL study to guide its modeling of YTF gas because NETL offers the only recent, publicly available, and comprehensive study of economically recoverable North Slope reserves. Unless otherwise noted, data and NPV model inputs associated with YTF gas are sourced from the NETL study. Extensions to the NETL study to address the timing of development and production flows from reserves, as well as minor refinement of their cost assumptions, are explained.

2. Summary of Major Findings from NETL (2007)

The total near- and long-term undiscovered ANS gas recoverable resource additions are estimated in NETL (2007) to be 137.3 trillion cubic feet (Tcf).[1] These resource estimates are based on probable, economically-developable discoveries and draw from a detailed assimilation of a variety of published technical assessments primarily undertaken by the U.S. Geologic Survey (USGS) and the U.S. Department of Interior, Minerals Management Service (MMS).[2]

The schedule of discoveries is premised on a North Slope gas pipeline being operational by 2015-16, with gas explorers having ready access to the project so that they can timely monetize their discoveries. Most of the resource discoveries will occur during the long-term period 2015-50. A smaller share (10-12 Tcf) is expected to be discovered in the near term (2005-2015),

[1] These results are consistent with the interpretation and ranges enumerated in the ConocoPhillips Proposal, Tables IV.1 and IV.2 (Section IV, page 2) based on the same original sources. Summing across all provinces implies a range of 74–to–430 Tcf of economically developable ANS gas additions.
[2] See references in Appendix A, below.

primarily on state lands in the gas-prone, southern Colville-Canning Area, Brooks Range Foothills. The distribution of long-term economic resource discoveries is divided roughly evenly across the four of the five geographic assessment provinces considered in the NETL study (Table 1). The 1002 Area of ANWR is considered to be oil prone and highly uncertain with respect to industry access and gas prospectivity.

Table 1. Summary of Probable Economically Developable ANS Gas Additions

Exploration Province	Near Term 2005 to 2015	Long Term 2015 to 2050	Total 2005 to 2050
Colville-Canning & State Beaufort Sea	10.0 TCF	23.3 TCF	33.3 TCF
Beaufort Sea OCS	1.0 TCF	20.0 TCF	21.0 TCF
Chukchi Sea OCS	0	50.0 TCF	50.0 TCF
NPRA	1.0 TCF	30.0 TCF	31.0 TCF
ANWR 1002 Area	0	2.0 TCF	2.0 TCF
TOTAL ARCTIC ALASKA	**12.0 TCF**	**125.3 TCF**	**137.3 TCF**

Source: NETL, 2007.

The NETL study characterizes the North Slope as an under-explored hydrocarbon province in which new discoveries and development of oil and gas fields are expected as older fields continue to decline. Several over-arching assumptions are incorporated in the NETL methodology. They are:

1. Future oil and gas prices will be sustained at levels sufficient to warrant continued exploration and development. Most of the resource assessments referenced in Appendix A are based economically recoverable hydrocarbons using a $22-$30 oil price equivalent. The NETL study concludes that, because price is likely to remain above $30 in the foreseeable future, these estimates are conservative. NETL sensitivity analysis indicates that, for example, 90% of technically recoverable oil in the 1002 Area of the Arctic national Wildlife Refuge (ANWR) would be economically recoverable at $51 oil.

2. Climate change will not be material to North Slope development during the next 50 years.

3. Technology gains in hydrocarbon exploration and extraction will be non-negative.

4. New entrants will enhance competition and result in exploration outreach to a greater variety of play types.

5. Several major proposed year-round gravel roads will be constructed. These include:

   a. A 20-mile western extension with Colville River bridge crossing will link the existing Spin Road with NPRA.
   b. A 55-mile coastal eastern road to the boundary of ANWR.

c. A western spur off the Haul Road near the Upper Kuparuk River drainage providing assess to the Foothills province. Ditto to the east.

3. Gas Development Scenarios

The path of future ANS gas discovery and development is unknown and highly uncertain. Many discovery and development outcomes are possible. The NETL (2007) study describes a yet-to-find ANS gas development future based on a plausible set of assumptions about factors that will drive and/or impede development. They are:

1. The most economic development while occur first and that development is likely to be path dependent. Drilling, processing, and transmission infrastructure associated with a given discovery and development will become proximal to sequential development.

2. Gas is connected with oil development. The NETL study assumes that oil is the primary near-term target. Drilling for oil is expected to continue at a pace comparable to the past decade. Discovery frequency and size are at the same respective rates and magnitudes as those observed in recent years. Near term gas development is assumed to be associated with oil, especially in the northern Colville-Canning area (including Beaufort Sea State lands within 3 miles), the National Petroleum Reserve-Alaska (NPRA), and the Beaufort Sea OCS. NETL estimates approximately 2.85 billion barrels of oil (BBO) of near-term discovery and development in the Colville-Canning area with the following breakdown:

    - 1.1 BBO – Brooks Range Foothills
    - 1.1 BBO – NPRA
    - 0.65 BBO – Beaufort OCS

3. The interface between oil development and gas development will affect the timing, location, minimum economic field size, and, ultimately, the pace and magnitude of YTF gas development. This, in turn, will affect the timing and scale of future gas pipeline expansions.

4. On-shore exploration will continue to progress westward toward NPRA and southward toward the Brooks Range Foothills. Offshore exploration will progress at an incremental pace and depend on success rates onshore and on the eventual commercialization of ANS gas and third-party access to infrastructure. The timing and location of drilling will depend, again, on proximity to existing infrastructure. Gas discoveries and development will await opening of the Alaska Gas Pipeline

    - 10 TCF of near-term discoveries in the gas-prone Foothills
    - 1.0 TCF from NPRA[3]
    - 1.0 TCF from the Beaufort OCS

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[3] A plausible variation on this theme would be greater near-term gas discovery in the NPRA.

5. Gas will become the dominant target in the long term. Approval for the major gas pipeline project is assumed in the NETL study to be in late 2006 with an in-service target date of 2015-16. By 2040, 50-to-75% of technically recoverable assessment volumes will be discovered and developed. Exploration and development activity will span all five sub-provinces yielding a mean estimate of 28.0 BBO and 125.3 TCF between now and 2050.

Equipped with these major assumptions and the resource assessments cited in Appendix A, the NETL study estimated the mean case, economically developable gas volumes for each of the major provinces in the Near Term (2005-15) and Long Term (2015-50).

4. Specific Development Assumptions by Major Hydrocarbon Province

Specific assumptions pertaining to location, magnitude, field size, infrastructure and timing are summarized for both near term (present to 2015) and long term (2015 to 2050) as follows:

Near Term Development

- Foothills (Colville-Canning)
  - Gas prone; exploration starting in 2011 (based on 2015 pipeline start-up). Four exploration wells drilled by 2013; two major discoveries prior to 2012-13. Development drilling to start 2014. Production to commence in within one year of pipeline startup.
  - Four-to-five fields of varying size located between 30–60 miles west of pipeline corridor. Smaller accumulations found by 2015.
  - Minimum economic field size (MEFS) ranges from 96 Bcf (low price) to 3 Tcf (high price).[4]
- NPRA
  - These areas not likely to be explored until gas pipeline is approved; construction committed.
  - Six-to-eight non-associated gas discoveries confined to southern NPRA.
- Beaufort OCS
  - Only associated gas in the near term.
  - One small-med size oil field plus several small satellite fields (oil). Expect 3-4 exploration wells over next decade.
- Chukchi OCS
  - No significant oil & gas exploration and development until after 2015.
- ANWR 1002 Area
  - If 1002 Area is opened to exploration, first lease sale expected not before 2014; production 2017-22.
  - Primarily oil development.

[4] Low ($25) and high ($60) price for ANS WC, flat in real 2005 dollars. Source; NETL, (2007:3-149).

Long Term Development Assumptions

- Foothills (Colville-Canning)
    - MEFS ranges from 96 Bcf (low price) to 3 Tcf (high price).
    - First eight gas field discoveries
        - Varying size (1.5-to-2.5 TCF)
        - 50-150 mile pipeline to MGS pipeline
        - Discoveries and development timeline: 2015-2030

    - Eight additional smaller gas field discoveries
        - Average field size is 0.75 TCF
        - Within 10-20 miles of existing development
        - Timeframe 2016-40
- NPRA
    - MEFS ranges from 96 Bcf (low price) to 12.3 Tcf (high price).
    - Ten larger gas discoveries on two structural plays
        - 1st discovery between 2010-12
        - Field size ranges from 1.25 – 6.0 TCF
        - 7-year lead time until production;
        - Majority discovered 2020-30.
    - 7-to-8 additional stratigraphic-play discoveries
        - Average field size ranges from 0.75 – 1.70 TCF
        - Targets after larger structure plays discovered.
        - Smaller accumulations; only those close to infrastructure developed.
- Beaufort OCS
    - MEFS ranges from 0.8 to 12.3 Tcf.
    - Four major plays; gas same as oil.
    - Gas not priority; by-product of oil.
        - Eight fields discovered
            - Three large (2.0 – 7.0 TCF)
            - Five small (0.5 – 2.0 TCF)
    - Gas exploration “stand-alone” by 2025.
    - Discoveries require 7-10 years to develop.
- Chukchi OCS
    - MEFS ranges from 3.1 to 98.3 Tcf.
    - Depends on developed NPRA infrastructure; sustained high prices; & oil/gas pipelines.
    - Development before 2015-20 is improbable due to remoteness and dependence on infrastructure expansion.
    - 11-13 gas fields development; varying sizes (1.5 – 10 TCF)
- ANWR 1002 Area
    - MEFS ranges from 0.2 to 12.3 Tcf.
    - Gas exploration/ development as a by-product of oil exploration.
    - Gas is not expected to be a major contribution to future production.

The State translated the NETL (2007) assessment of Near and Long Term field developments, described above, into a schedule of gas flow available (Figure 1). The schedule reflects the NETL (2007) contemplated resource prospectivity, location, energy price, minimum economic field size, and infrastructure dependence.

Figure 1. Yet-to-Find North Slope Gas Production Development Scenario

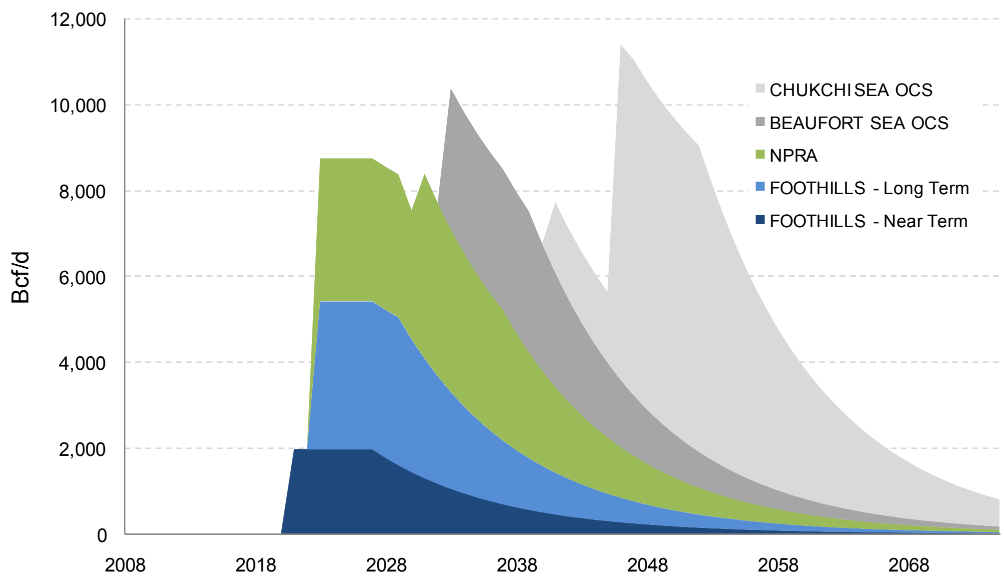

Figure 1 does not show predicted gas flows. It depicts the production volumes that could be available given the timing of resource plays and the corresponding scenario assumptions presented in NETL (2007) and summarized Tables 2 and 3 (below). These production rate estimates are based on resource prospectivity and minimum economic field size and are not subject to limitations that may be imposed by Alaska gas pipeline capacity constraints.[5]

The estimates in Figure 1 are generated by first selecting a start-up date – in this case, 2020 for near term development.[6] The production profile from any particular field is assumed to ramp up to a maximum rate equal to 6% of recoverable reserves expressed in million cubic feet per day

[5] The production and corresponding recoverable reserves estimates in Figure 1 are based on a 100% discovery success probability with respect to the outcome of exploration drilling. Thus, exploration costs are included in the cost structure assumptions, as explained in Section 5 below. The discovery failure leg probability is zero and related dry-hole costs are not considered. A detailed analysis of exploration risk is addressed in Appendix L, *The Prospecting Exploration Model*.

[6] This assumption pertains to Near-term Foothills development and is deferred five years from the start-up date of 2015 assumed in the NETL study. The 2020 date is based on NPV Model scenario analysis and is applied here for exposition purposes, only. The assumed start-up dates for Long-term development in other provinces illustrated in Figure 1 are: Foothills (2022), NPRA-structural (2024), NPRA-stratigraphic (2030), Beaufort Sea (2032) and Chuckchi Sea (2040-super large field and 2045-other). In general, the timing assumptions embedded in Figure 1 parallel those in NETL (2007) with a five-year displacement in start-up.

(MMCFD). Production continues at this rate until 60% of recoverable reserves are produced, at which point a decline of 10% per year sets in. The 6%-60%-10% driver assumptions are operational rules of thumb that are intended as reasonable approximations of the typical or expected reserves-production relationships. Incorporating more detail is difficult and not relevant given the level of resolution in the analysis. Assumptions similar to these are parameters in the NPV Model and may be altered by the user. The "call" on YTF gas in the NPV model draws from the available reserves indicated in Figure 1. (See section 6, below, for more on the treatment of reserves and production in the NPV Model.)

NPRA production does not come on line in Figure 1 until after near-term development underway, contrary to what is depicted in for NPRA near term in Table 1. The NPV Model includes the simplifying assumption that near-term production is divided 50-50 between onshore state lands (primarily Foothills) and onshore federal lands at NPRA.[7]

Similarly, Beaufort OCS production is not triggered during the immediate near term in part because the NETL study's own minimum economic field size requirements do not support relatively small scale development from this economically-challenged, Outer Continental Shelf (OCS) province in the near term. It isn't plausible from the standpoint of infrastructure path dependence to assume Beaufort Sea production start-up prior to 2020. However, as depicted in Figure 1, Beaufort Sea comes on line in 2032, well before near-term YTF reserves are exhausted.[8]

Table 2 (Near Term) and Table 3 (Long Term) provide more detail on the number of play types, the number and size distribution of fields, technical and economic recovery, proximity to infrastructure and production timing.

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[7] Also, the estimate of proved and developed reserves contained in State Existing production in the NPV Model is assumed to include some production from NPRA lands.

[8] The timing and composition of production in Figure 1 assumes that 30% of near term YTF reserves are still in situ in 2032, when Beaufort Sea production comes on line.

Table 2. Characteristics of ANS Gas Development in the Near Term, 2005-2015

Region	No. Plays	Probable Economically Developable Discoveries		Recoverable (Tcf)		Associated/ Non-Assoc	Proximity to Infrastructure	Production Timeframe
		No. Fields	Avg Size or Range (Tcf)	Technical[a]	Economic[b]			
Colville-Canning & State Beaufort Sea	Northern: Oil is primary target. 1 or 2 of 15 gas plays possible but not likely.	-na-	-na-	-na-	0	Associated	-na-	No exploration directed exclusively for gas is expected.
	Southern (Foothills): 13 of 15 plays with mean recoverable resource ranging from 0.5 to 6.5 Tcf. Of these, 8 hold 80% of technically recoverable	1 1 2-3 4-5	5.0 2.5 0.5 – 1.5	32.9	10.0	Non Assoc	Between 30–60 miles west of pipeline corridor. Smaller accumulations found by 2015.	Gas exploration by 2009-11; two major discoveries prior to 2012. Production to commence in within one year of pipeline startup.
NPRA	Gas as a by-product of oil; Torok and Brookian Topset Structural plays represent major NPRA gas potential; 4 Stratigraphic plays w/ 3+ Tcf technically recoverable.	2 4-6	250-500 MMB 50-100 MMB	59.7[c]	1.0	Associated	Non-associated gas confined to southern NPRA.	These areas not likely to be explored until gas pipeline is approved; construction committed.
Beaufort Sea	Gas exploration not the near-term objective; but gas discovery as by-product of oil is likely.	4 (oil)	-na-	5.2	1.0	Associated	1 small-med size field plus several small satellite fields (oil). Expect 3-4 exploration wells over next decade.	2005-2015
Chukchi Sea	No significant oil & gas exploration and development until after 2015.	-na-	-na-	-na-	0	-na-	-na-	-na-
ANWR 1002 Area	Primarily oil	-na-	-na-	3.8 – 4.8 -	0	Non Assoc Assoc	5-10 years until open for exploration; at least 10 years to complete development.	If 1002 Area opened to exploration, first lease sale expected in 2014; production 2017-22.
					∑=12.0			

[a] Risked, conventionally recoverable, undiscovered resources.
[b] Probable, economically developable discoveries.
[c] Does not count State offshore lands bordering NPRA.
Source: NETL, 2007.

Table 3. Characteristics of ANS Gas Development in the Long Term, 2015-2050

Region	No. Plays	Probable Economically Developable Discoveries		Recoverable (Tcf)		Associated/ Non-Assoc	Proximity to Infrastructure	Production Timeframe
		No. Fields	Avg Size or Range (Tcf)	Technical[a]	Economic[b]			
Colville-Canning & State Beaufort Sea	Northern: 4 plays primary oil targets expected to hold 75% of Associated gas.	-na-	-na-	4.2	2.3	Associated	Satellites	Gas as a by-product of oil; fields producing by 2020 and fully developed by 2035.
	Southern: 4 plays hold 50% of mean non-assoc. technically recoverable.	3 5 8 16	2.5 1.5 0.75	33.3	7.5 7.5 6.0 21.0	Non Assoc	50-150 mi PL; Small fields w/in 10-20 mi of existing development.	2015-30 2015-30 2016-40
NPRA	2 Structural plays; pure gas-oriented.	1 3 6 10	6.0 2.25 1.25	28.5	20.2	Non Assoc	NPRA to be a major component of ANS gas exploration if gas pipeline approved and built.	1st discovery between 2010-12; 7-year lead time until production; Majority discovered 2020-30.
	4 Stratigraphic plays	7-8	0.75 – 1.70	19.5	9.8		Smaller accumulations; only those close to infrastructure developed.	Targets after larger structure plays discovered.
Beaufort Sea OCS	4 major plays; same as oil. Gas not priority; by-product of oil. Gas exploration "stand-alone" by 2025.	3 5 8	2.0 – 7.0 0.5 – 2.0	29.3	15 5 20	Non Assoc	Discoveries require 7-10 years to develop.	Bulk of gas discovered post-2030
Chukchi Sea OCS	22 plays; 7 of these (4 major and 3 secondary) 90% of aggregated mean non-assoc. technically recoverable.	1 3 5-6 2-3 11–13	10.0 6.5 3.0 1.5	60.1	50.0	Non Assoc	Depends on developed NPRA infrastructure; sustained high prices; & oil/gas pipelines.	Production prior to 2015-20 is improbable due to remoteness and dependence on infrastructure expansion.
ANWR 1002 Area	3 plays comprise 75% of assoc gas. Topset (1.7 Tcf), Turbidite (1.4), and Thomson (0.46).	-na-	-na-	4.7	2.0	Associated	Gas exploration/ development as a by-product of oil exploration.	Gas is not expected to be a major contribution to future production.
					∑=125.3			

[a] Risked, conventionally recoverable, undiscovered resources.
[b] Probable, economically developable discoveries.
Source: NETL, 2007.

5. Cost Structure

The mean case gas development contemplated in Figure 1 would span five or more decades and require nearly $69 billion (in constant 2008 dollars) in upstream capital investment for finding and development. Lifecycle operating and maintenance (O&M) charges are projected to be $42 billion. As indicated above, the ultimate path that YTF development will take is unknown. The pace may be faster or slower, the magnitude may be greater or less, and development may be more concentrated in certain provinces than that depicted above. In order to evaluate the effects and plausibility of various YTF gas development scenarios, a set of detailed assumptions about the YTF cost structure were incorporated into the analysis and used to inform the treatment of net cash flow for YTF producers in the NPV model. The formulation of the YTF cost structure draws extensively from the NETL (2007) study. The cost structure is defined in terms of capital expenditures (CapEx) for finding and development and operating expenditures (OpEx) for production.

Capital Expenditure

Capital expenditure is broadly divided into facilities CapEx and drilling CapEx. The main elements of each and the respective driving factors are summarized in Table 4. Detailed CapEx assumptions pertaining to the drivers in Table 4 are contained in Appendices B.1 and B.2.

Table 4. Key Determinants of Capital Expenditures

	Category	Factors that Determine Cost
Facility Costs	Appraisal	Based on number of fields developed
	Platform, Pad and Processing	Based on number of fields developed
	Pipeline	Pipeline size (diameter); cost per inch-foot; distance; onshore v. offshore
Well Costs (Drilling)	Exploration	Well count is based on number of fields developed
	Development	Well count based on cumulative production of field and well productivity

The CapEx total outlays (in constant 2008 dollars) by major province are summarized in Table 5. The estimates pertain to gas field development only; condensate and oil are not considered. These estimates incorporate all of the elements depicted in Table 4.[9] Other than factors relating to escalation, the only departure from NETL cost assumptions pertains to the treatment of platform, pad and processing costs for Foothills and NPRA development. We substitute the NETL cost factor of $37.5 per Mcfd peak rate[10] with facility cost estimates for gas development

[9] Abandonment charges are assumed to be imbedded in respective facility categories.
[10] This factor appears to under estimate processing facility capital costs. (Charles Thomas, NETL, Personal communication with Division of Oil and Gas, April 11, 2008.)

based on well productivity method employed by Attanasi and Freeman (2005).[11] Details are found in Table 5, and Appendix B.1.

The CapEx estimates for the OCS areas are not dissimilar to those generated by MMS in connection with development of the Burger Gas Field (Chukchi Sea).[12]

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[11] Attanasi, E. and P. Freeman. *Economics of Undiscovered Oil and Gas in the Central North Slope, Alaska*. (Reston: U.S. Geological Survey), Open-File Report 2005-1276, p. 37.

[12] For example, the MMS estimated $11.2B ($2004) to develop and produce 11.5 Tcf of gas and 587 million barrels of oil in the Burger prospect, representing 2.6 billion barrels of oil equivalent (BOE), overall. This total development cost converts to about $22.2 billion in $2008. By comparison, the total cost to develop 11 Chukchi fields containing 47.5 Tcf of recoverable reserves (about 7.8 billion BOE) is estimated to be $46.5 billion ($2008), as shown in Table 5. This implies $8.46 per BOE (Burger) versus $5.97 per BOE (NETL-Chukchi). See Craig, J. and K. Sherwood. *Economic Study of the Burger Gas Discover, Chukchi Shelf, Northwest Alaska*, (Anchorage: U.S. Department of Interior, Minerals Management Service), Dec. 2004.

Table 5. Summary of Capital Expenditures for Yet-to-Find North Slope Gas Development
(Constant 2008 dollars)

	Facilities[1]	Drilling[2]	Total[2]
	State Lands Onshore and within Three Miles		
Foothills			
Total ($ Millions)	$15,017	$7,692	$22,710
$ Per Mcf	$0.48	$0.25	$0.73
Lead Time (years)	5	2	
	Federal Lands Onshore		
NPRA			
Total ($ Millions)	$12,765	$10,250	$23,014
$ Per Mcf	$0.42	$0.34	$0.77
Lead Time (years)	6	4	
	Federal Waters Offshore		
Beaufort Sea			
Total ($ Millions)	$10,342	$7,772	$18,114
$ Per Mcf	$0.52	$0.39	$0.91
Lead Time (years)	7	5	
Chukchi Sea			
Total ($ Millions)	$30,518	$15,940	$46,458
$ Per Mcf	$0.64	$0.34	$0.98
Lead Time (years)	7	5	
	Total Yet-to-Find		
All Provinces[3]			
Total ($ Millions)	$68,642	$41,653	$110,295
$ Per Mcf	$0.53	$0.32	$0.86

Table Notes

[1] Facilities cost estimates are derived from NETL (2007) and Attanasi and Freeman (2005). For Foothills and NPRA, the platform, pad, and facilities processing estimates are based on well productivity method employed by Attanasi and Freeman (2005) for a 2.5 Tcf field having 450 MMCFD max rate. See Appendix B for details.

[2] Drilling costs are derived from NETL (2007). (See Appendix B.)

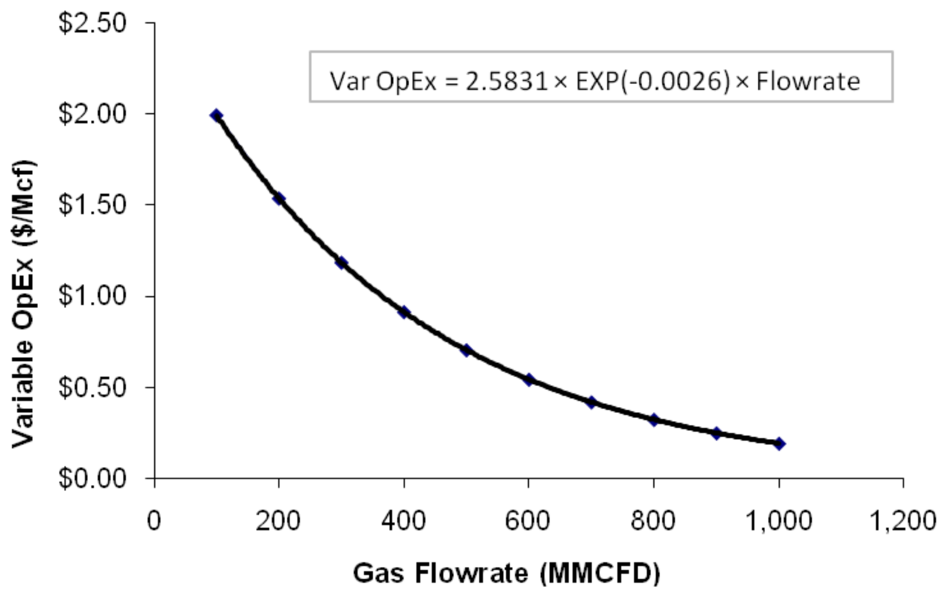
[3] In addition to the effects of general inflation, the facilities and drilling cost estimates are adjusted upward by a factor of 1.8 to reflect the significant cost spike recognized in the upstream industry sector since 2005 based on Cambridge Energy Research Associates' upstream Capital Cost Index (UCCI) factor.

[3] Excludes Near-term NPRA the ANWR.

Operating Expenditure

Operating expenditure (OpEx) is divided into variable and fixed elements. Variable OpEx is driven by an exponential decline function shown in Figure 2 that allows for scale diseconomies later in field life when water rates increase, pursuant to methods used in NETL (2007).[13]

Figure 2. Variable Operating Costs Versus Gas Flow-rate



When mapped against production, by province from Figure 1, variable OpEx ranges from a low of $0.75 per Mcf to a high of $1.79 per Mcf over field life, expressed in 2008$ (Table 6). And when expressed as a proportion of cumulative total CapEx by major province the time profile of variable OpEx, tied to the production rates in Figure 1, vary from less than ¼% to over 10%, as shown in Figure 3.[14]

Fixed operating expenditure is assumed to equal $50 million per year expressed in 2008$ for State and Federal onshore development and $100 million per year for Federal offshore development.[15]

In order to account for the sensitivity of operating cost to crude oil prices, real fixed and variable operating expenditures in future years are functionally tied to the real market price of Alaska

[13] See *South-Central Alaska Natural Gas Study*, (Fairbanks: U.S. Department of Energy, National Energy Technology Laboratory), June 2004, p. 158.
[14] The proportions depicted in Figure 3 are used as inputs to the NPV Model, as explained in section 6, below.
[15] This is an approximation on the NETL study assumption for fixed operating costs of $1 million per well per year, expressed in constant 2005$ (NETL Summary Report, 2007:39). The count of wells would vary depending on the size of the call on YTF reserves.

North Slope crude oil on the U.S. West Coast using a 0.55 price elasticity of cost adjustment factor.[16]

Table 6. Variable OpEx Average Over Field Life by Major Province

($2008 per Mcf)

Foothills - Near Term	$ 1.20
Foothills - Long Term	$ 1.72
NPRA - Structural	$ 1.36
NPRA - Stratigraphic	$ 1.79
NPRA (Combined)	$ 1.50
Beaufort Sea OCS	$ 1.14
Chukchi Sea OCS	$ 0.75

Table Notes

Derived from Figure 2 (above) based on NETL (2007) with escalation for general inflation from 2005-08.

Figure 3. Variable OpEx as a Proportion of Cumulative Total CapEx by Major Province

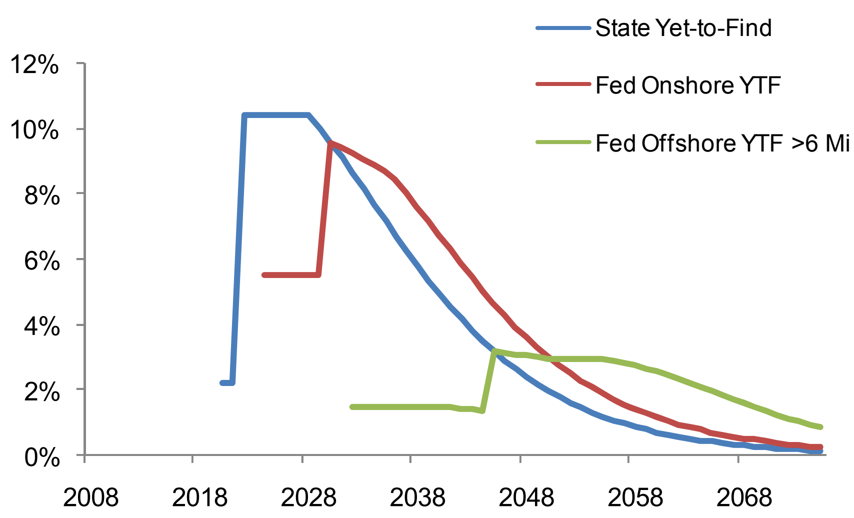


Table Notes

Derived from Figure 2 (above) based on NETL (2007) with escalation for general inflation from 2005-08.

[16] This elasticity coefficient reflects the historic relationship (1997-2006) between upstream operating costs (using an index for Oil and Gas Support Service from the U.S. Department of Commerce, Bureau of Labor Statistics as a proxy) and the spot price of ANSWC crude oil. See discussion of NPV Model in Section 3 of the Findings and Determination document, and Appendix G1.

6. NPV Model

Several simplifying assumptions were introduced in order to incorporate the YTF production profile and cost structure elements described above into the NPV Model for purposes of evaluating stakeholder NPV effects associated with interaction of YTF development with the production from proved and developed ANS gas reserves.

The YTF production profiles by major province depicted in Figure 1 represent an assessment of resource potential independent of the limitations associated with capacity in any particular major gas pipeline system linking the North Slope with broader markets. This assessment provides a platform with which to examine the plausible scenario paths involving YTF development, taking into account the nature of YTF prospectivity, the timing and magnitude of gas production from existing North Slope proved reserves, as well as relevant engineering and economic factors associated with pipeline expansion alternatives. As a general rule, it must first be the case that incremental YTF gas production required to fill available pipeline unused capacity in future years or to drive pipeline expansions cannot exceed the YTF resource potential from a given location or province at a particular point in time.

Second, the “call” on YTF gas would occur only when aggregate production from the Prudhoe Bay, Point Thomson, and other State Existing fields falls below the rate required to fill the pipeline design capacity in a given scenario. Aggregate production from known, producing fields is expected to transition into decline before the end of the initial firm transportation contracting period in all of the project scenarios under consideration. YTF gas will then be developed to fill the incremental (and growing) “wedge” in available pipeline capacity. For example, the wedge volume required from YTF fields in the 4.5 Bcf/d Proposal Base Case over the 25-year FT period is estimated to be about 10 TCF. Production from YTF fields, as a proportion of total throughput, would continue to increase over project life beyond the initial FT commitment period.

Third, a “just-in-time” approach to incremental production from YTF fields is employed in the NPV Model. Once decline from proved-developed-producing fields is triggered, YTF wedge volumes are assumed to come on line sequentially, in step with periodic incremental increases in available pipeline capacity. Wedge volumes come initially from State and Federal On-Shore YTF in equal shares, and when these are no longer sufficient, volumes begin to come on-line from Federal On-shore, if necessary.[17] It is assumed that during the initial 25-year FT period, YTF wedge volumes will be generated by incumbent producers with established working interests at PBU, Point Thomson, and other State Existing fields because these operators have an incentive to achieve their respective billing determinant targets.[18]

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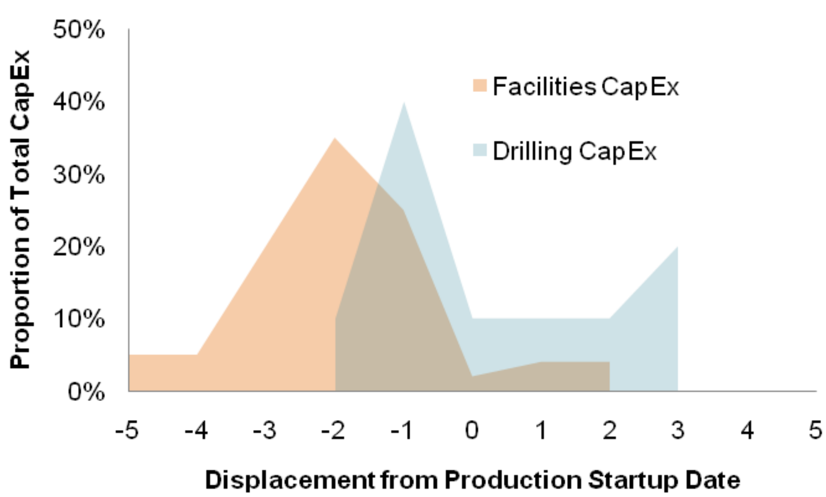
[17] It is assumed in the NPV Model that during the initial 25-year FT period, YTF wedge volumes will be generated by incumbent producers with established working interests at PBU, Point Thomson, and other State Existing fields because these operators have an incentive to achieve their respective billing determinant targets. See discussion of Upstream Model in Section 3 of the Findings and Determination document, and in Appendix G1.

The “just-in-time” approach was extended from wedge volumes to include expansion volumes.

Fourth, for any particular development scenario in the NPV Model, if the assumed YTF production volumes, including the wedge volumes described above, are less than those depicted in Figure 1, then the corresponding CapEx and OpEx costs must be appropriately scaled back. If the wedge volumes required are greater than that shown in Figure 1, or if there is an expansion, CapEx and OpEx must be scaled up. The scaling is based on the average cost of bringing on a trillion cubic feet (TCF) of reserves for State YTF, Federal On-Shore YTF, and Federal Off-Shore YTF. The reserves needed to fill a daily production short-fall are determined based on an assumed 20 to 1 reserve to production ratio. As a simplifying assumption, the average cost per TCF remains constant over the life of the pipeline, and over different levels of reserve additions.

Fifth, some simplifications were introduced to the treatment of cost scheduling. In general, the NPV Model assumes that it takes about six years to bring YTF gas on line. Thus, facilities capital expenditure (CapEx) begins six years before first gas and continues two years after production begins for a particular YTF prospect. Drilling CapEx is launched three years before start-up and continues three years after. The allocation of total facilities and drilling CapEx is illustrated in the spend profiles contained in Figure 4. It spans an eight year period and roughly accounts for the lead times indicated in Table 5 between the timing of initial capital outlays and first production by province.

Figure 4. YTF Facilities and Drilling CapEx Spend Profile in NPV Model



Sixth, it is recognized that initial YTF development that is brought into production in future years from a particular prospect will, itself, eventually succumb decline. This in turn will create the requirement for further “second-tier” incremental YTF reserves development with associated

CapEx in order to sustain YTF production rates and keep the pipeline full. It is assumed that the all-in lifecycle CapEx associated with this second tier of YTF production is equal to 45% of that generated in the initial increment in YTF reserves and that this second-tier CapEx is delayed by a period of 12 years from the date of initial YTF production startup. The smaller level of second-tier YTF CapEx follows from the reduced scale of require reserves and production in subsequent increments of YTF development relative to the scale of “first generation” YTF gas.

Lastly, the treatment of operating expenditures (OpEx) in the NPV Model is based on the assumption that variable OpEx in any year can be expressed as a proportion of cumulative CapEx over project life. This treatment preserves the OpEx-CapEx scale and timing relationships and simplifies modeling requirements. The variable OpEx proportions to CapEx generated in the NETL study described above are depicted in Figure 3 for each province. This approach permits variable OpEx to automatically adjust to the scale of YTF production for a given production scenario. These OpEx assumptions are for the base case and will adjust over time in response to assumed rates of oil price escalation rates.[19]

[19] See the price elasticity of cost discussion in the upstream NPB Model assumptions (Bidwell).

Appendix A. References

Geographic Region	Reference
Colville-Canning & State Beaufort Sea: Northern	Garrity, C. P., Houseknecht, D. W., Bird, K. J., Potter, C. J., Moore, T. E., Nelson, P. H., and Schenk, C. J. (2005). U. S. Geological Survey 2005 Oil and Gas Resource Assessment of the Central North Slope, Alaska: Play Maps and Results, U.S. Geological Survey, Open-File Report, 2005 – 1182.
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NPRA	Bird, K. J., and Houseknecht, D. W. (2002). U.S. Geological Survey 2002 Petroleum Resource Assessment of the National Petroleum Reserve Alaska (NPRA): U.S. Geological Survey, USGS Fact Sheet 045-02, 6 p. Houseknecht, D. W. (2003a). Brookian Stratigraphic Plays in the National Petroleum Reserve Alaska (NPRA): U. S. Geological Survey, Open-File Report, 03-039, 70 p. Houseknecht, D. W. (2003b). Beaufortian Stratigraphic Plays in the National Petroleum Reserve Alaska (NPRA): U.S. Geological Survey, Open-File Report, 03-040, 97 p. Petroleum News (2004e). Phase 2 of Alpine capacity expansion approved, Vol. 7, No. 10, March 7, 2004. Petroleum News (2006b). Alaska Could Play Pivotal Gas Role: Petroleum News, Vol. 11, No. 10.
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Chukchi Sea	Craig, J. D., and Sherwood, K. W. (2005). Summary of Economic Study of the Berger Gas Discovery, Chukchi Shelf, Northwest Alaska: Minerals Management Service, Alaska Region. Sherwood, K. W., Comer, C. D., Martin, C., Craig, J. D., and Banet, A. C. (1998a). Oil and Gas Plays, National Petroleum Reserve Alaska, Play Analysis for National Petroleum Reserve in Alaska: MMS/BLM, 35 p.
ANWR 1002 Area	Bird, K. J., and Houseknecht, D. W., 1998, Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998: U.S. Geological Survey, USGS Fact Sheet 04-98, 6 p.
NETL 2007	Thomas, C. P., Doughty, T. C., Faulder, D. D., Hite, D. M., White, G. J. *Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline?* (Fairbanks: U.S. Department of Energy, National Energy Technology Laboratory, DOE/NETL-2007/1279), August 2007 (pp 2-102 – 2-154).

Appendix B.1. Detailed CapEx Assumptions for Foothills and NPRA Provinces

			Foothills (Near and Long Term)			NPRA (Long Term)		
Number of Fields			**20**			**17**		
		Productivity	Rec Res	Well Count		Rec Res	Well Count	
Field Size	(BCF)	(BCF/well)	(TCF)			(TCF)		
Large	GT 2,500	170	15.0	88		6.0	35	
Medium	1,000-2,500	100	10.0	100		6.8	68	
Small	LT 1,000	50	6.0	120		17.3	346	
			31.0	**308**		30.1	**449**	
($2005)			Distance	Cost/Field ($mm)	Total Cost ($mm)	Distance	Cost/Field ($mm)	Total Cost ($mm)
Appraisal				$50	$1,000		$50	$850
Platform/ Pad	Cost per Field		75	$139[1]	$2,773	75	$139[1]	$2,357
Processing	Cost per Field	150						
Pipelines	PL Diameter (in.)	24						
	$ per inch-foot	($/in-ft)		Cost/Field	Total Cost		Cost/Field	Total Cost
	Offshore	50						
	Onshore	20	75	$190	$3,802	75	$190	$3,231
Transmission								
Well Cost		Each ($mm)	Well Count	Cost/Field	Total Cost	Well Count	Cost/Field	Total Cost
	Exploration		2	$40	$800	2	$40	$680
	BS	25						
	CS	50						
	FH & NPRA	20						
	Development		308		$3,080	449		$4,490
	BS	20						
	CS	20						
	FH & NPRA	10						

[1] For Foothills and NPRA, the platform, pad, and facilities processing estimates are based on well productivity method employed by USGS (2005) for a 2.5 Tcf field having 450 MMCFD max rate.

Appendix B.2. Detailed CapEx Assumptions for Foothills and NPRA Provinces

			Beaufort			Chukchi		
Number of Fields			**8**			**11**		
		Productivity	Rec Res	Well Count		Rec Res	Well Count	
Field Size	(BCF)	(BCF/well)	(TCF)			(TCF)		
Large	GT 2,500	170	12.0	71		44.5	262	
Medium	1,000-2,500	100	7.5	75		3.0	30	
Small	LT 1,000	50	0.5	10				
			20.0	**156**		47.5	**292**	
($2005)			Distance	Cost/Field ($mm)	Total Cost ($mm)	Distance	Cost/Field ($mm)	Total Cost ($mm)
Appraisal				$50	$400		$50	$550
Platform/ Pad	Cost per Field		20	$300	$2,400	50	$750	$8,250
Processing	Cost per Field	150			$1,200			$1,650
Pipelines	PL Diameter (in.)	24						
	$ per inch-foot	($/in-ft)		Cost/Field	Total Cost		Cost/Field	Total Cost
	Offshore	50	20	$127	$1,014	50	$317	$3,485
	Onshore	20	10	$25	$203	25	$63	$697
Transmission						300	$762	$762
Well Cost		Each ($mm)	Well Count	Cost/Field	Total Cost	Well Count	Cost/Field	Total Cost
	Exploration		4	$100	$800	4	$200	$2,200
	BS	25						
	CS	50						
	FH & NPRA	20						
	Development		156		$3,120	292		$5,840
	BS	20						
	CS	20						
	FH & NPRA	10						

Source: Derived from NETL (2007) and Attanasi and Freeman (2005).