# PRELIMINARY REPORT ON FISCAL DESIGNS FOR THE DEVELOPMENT OF ALASKA NATURAL GAS

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## Section 4.2

## Characteristics of ten hypothetical gas and oil fields modelled with production, cost and price assumptions

# Part 4: Analysis of Alternative Upstream Fiscal Models for Alaska

## 4.2 Characteristics of ten hypothetical gas and oil fields modelled

In order to evaluate Alaska's fiscal design with respect to upstream natural gas projects it is necessary to consider the spectrum of natural gas fields that might be discovered and considered for future development. This involves evaluating a range of reserves sizes, production rates, field development and operating costs, treatment, transport and tariff costs and timing of the capital investment period with respect to first gas. The evaluation also requires consideration of natural gas revenues in conjunction with revenues from liquid petroleum production streams, i.e. crude oil, condensate/C5+ natural gas liquids (NGLs), which are referred to in this study as crude oil and pentanes plus or oil (C5+). That is distinguished from the lighter gases (e.g. ethane (C2)) and lighter natural gas liquids comprising propane (C3) and butane (C4) also referred to as liquid petroleum gas (LPG). The following table summarizes the terminology referring to the different types of hydrocarbons used in this report:

| | |
|---|---|
| Crude oil | Hydrocarbons that are C5 and heavier (C5) |
| Condensate | Heavier NGLs that are C5+ |
| Natural Gas Liquids | Liquids extracted from natural gas (C3+) |
| Lighter Gas (except methane) | Ethane (C2) |
| LPG | Lighter NGLs that are C3 and C4 |

These condensed and liquefied products frequently form integral and important components of upstream field developments.

As natural gas infrastructure (i.e. gas pipelines and gas conditioning, processing and treatment facilities) evolves in Alaska, some projects may be in a position to commercialize the associated gas in addition to natural gas liquids produced from oil fields. Hence fiscal design for natural gas must consider how gas revenues are to be treated in large and small non-associated fields (i.e. natural gas not associated with crude oil in the subsurface reservoir) and also large and small oil fields producing associated gas across a wide range of volumes.

For the above reasons, this study uses ten hypothetical fields to evaluate existing and potential fiscal designs. These fields, five non-associated gas fields and five oil fields with associated gas, are described in quantitative terms in this section of the study. The cost profiles and production profiles of these ten fields are used in conjunction with a range of price forecasts to generate revenue streams for detailed fiscal analysis and multiple sensitivity cases establishing the impacts of price, cost and production variations on Alaska and company revenue streams.

The production, timing and reserves characteristics for five hypothetical gas fields are listed in Figure 4.2.1. These fields vary in reserve size from 500 bcf (Field #1) to 10 tcf (Field #5) of gas and yield between 10 mmb (Field #1) and 200 mmb (Field #10) of oil (C5+). It is assumed that each field takes two years to appraise but variable periods to develop. The 10 tcf field assumes a 6-year development period, whereas for the 500 bcf field only a two-year development period is assumed. For each gas field a build-up period, plateau-production period and blow-down period is assumed. The plateau production rate for the 10 tcf field is 1.75 bcf/day whereas for the three smallest fields plateau-production rate for gas varies between 100 mmcf/day and 225 mmcf/day.

The five gas fields are considered to yield condensate (C5+) at a constant rate of 20 barrels/million cubic feet, which is recovered in a gas processing plant and shipped with oil (C5+). Lighter natural gas liquids (C3 to C4) and ethane are assumed to remain in the wet gas and are transported as high calorific value gas (i.e. 1,118 btu/cf) with the value recovered when extracted at a cryogenic LPG plant in the destination market (e.g. AECO Canada).

**Why this Study Uses Starting-point Assumptions Rather than Forecasts**

The assumptions for costs, prices and their inflation used for the base-case analysis in this study are not drawn from the forecasts of one particular organization or agency, but bear scrutiny in comparison with several such forecasts. Moreover these assumptions are not intended as base-case forecasts, merely starting points for broad sensitivity analysis with which to stress test the performance of the several elements of the Alaska fiscal design.

Very few forecasts stand the test of time, and the starting assumptions used here are likely to suffer the same fate. Because no organization can adequately predict future costs and prices, it is important when testing fiscal designs to use as wide a range of variables (production, reserves, gas/oil ratios, costs, tariffs, and especially prices) as can be conceived without being tied into specific forecasts or giving more weight to specific values at the expense of others. The reader should consider the base-case assumptions presented here as starting points for analysis that will be as much as trebled on the high side and halved on the low side in the analysis that follows.

The author does not wish to give specific weight, in terms of a likely or best-guess forecast, to any of the sensitivity case values including the base-case assumptions. All sensitivity case values are considered possible to occur at some point during the next three to four decades. The main objective of the quantitative part of this study is how the Alaska fiscal design might best cope with an extremely wide range of potential future values. With this objective in mind it is important to treat all values as possible rather than likely.

For work on specific facilities and field development projects it is important to express variable uncertainties in terms of probability distributions with means, percentiles and levels of confidence in order to identify the most likely commercial values, their ranges and make appropriate decisions based upon them. Forecasts and simulations based upon probability distributions with best-guess central values are appropriate for such analysis. That is not what is required when the objective is to test the limits of robustness of a fiscal design.

For similar reasons the hypothetical field development and production projects used to test fiscal designs in this study do not lock into specific start years or a specific date when a gas pipeline might be available to carry gas production to Canada and the Lower 48 states. Each field has a base-case development schedule specified in years starting at year 1 across project lengths varying upwards of 30 years.

Uncertainty remains surrounding the future availability of a gas pipeline and other gas treatment facilities to transport Alaska gas to the Lower 48 states. Unless otherwise specified this study assumes that gas will get to market (a) in an 4.5 bcf a day line to Alberta, (b) owned by a combination of large producers and other stakeholders which (c) will start up no later than 2020 (Black and Veatch, 2008). With the award of an AGIA licence expected in November 2008 it seems that a gas pipeline could be in operation in Alaska no earlier than 2018, which warrants an unspecified date associated with the start of the gas field developments analyzed in this report. Moreover, it is likely that gas from the large proven reserves base of Prudhoe Bay and Point Thomson fields will dominate gas pipeline capacity for about 12 years after it begins to ship gas. This suggests that field developments of major new gas reserves discovered are unlikely to commence until well into the 2020s and possibly even 2030s, if they depend on the pipeline for market access. Of course, alternative facilities development, such as new gas liquefaction capacity built in addition to a gas pipeline prior to 2025, could lead to more accelerated field development scenarios.

**Gas (with NGL) Field Characteristics (Field Numbers 1 to 5)**

| | Non-associated Gas Fields | | | | |
|---|---|---|---|---|---|
| **Field Number** | **1** | **2** | **3** | **4** | **5** |
| Treat as "Gas" fields =0; Treat as "Oil" fields =1 | 0 | 0 | 0 | 0 | 0 |
| Initial Oil (C5+) Reserves Estimate (millions barrels- mmbbl) | 10.0 | 15.0 | 20.0 | 100.0 | 200.0 |
| Initial Gas Reserves Estimate (billions cubic feet - bcf) | 500.0 | 750.0 | 1000.0 | 5000.0 | 10000.0 |
| Initial Petroleum Reserves Estimate (millions barrels- mmboe) | 93.3 | 140.0 | 186.7 | 933.3 | 1866.7 |
| Exploration Start Year | 1 | 1 | 1 | 1 | 1 |
| Exploration / Appraisal Duration (years) | 2 | 2 | 2 | 2 | 2 |
| First Development Capital Investment (Start of Year) | 3 | 3 | 3 | 3 | 3 |
| Development Duration (years) | 2 | 3 | 4 | 5 | 6 |
| End of Development Capital Investment (End of Year) | 4 | 5 | 6 | 7 | 8 |
| Production Start-up (Start of Year) | 4 | 5 | 5 | 6 | 6 |
| End of Build-up Phase (End of Year) | 6 | 7 | 7 | 8 | 8 |
| Gas Production Daily Rate at Start-up (mmcf/d) | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| Gas Production Daily Rate at Plateau (mmcf/d) | 100.0 | 160.0 | 225.0 | 1250.0 | 1750.0 |
| Incremental Daily Gas Added / Year in Build Up Phase (mmcf/d) | 25.0 | 45.0 | 66.7 | 408.3 | 575.0 |
| End of Plateau Phase (End of Year) | 17 | 17 | 17 | 17 | 22 |
| End of Blowdown Phase (End of Year) | 22 | 22 | 22 | 22 | 27 |
| Shut-in Gas Rate (mmcf/d) | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| Incremental Daily Gas lost / Year in Blow Down Phase (mmcf/d) | 18.0 | 30.0 | 43.0 | 248.0 | 348.0 |

***Figure 4.2.1. Reserves and production characteristics of five hypothetical gas fields used for fiscal design evaluation.***

This report makes no claims as to whether such additional gas treatment and transportation facilities development will occur, simply that they are possibilities worthy of consideration. Clearly, with a pipeline in place with some spare capacity and third-party access provisions, the development of some smaller gas fields, including those held by companies that do not hold equity interests in the gas pipeline or its possible expansion phases, could be encouraged to supply gas by 2020. Exact start-up dates for the fields studied here in unspecified terms could vary between about 2018 and 2035.

Future annual profiles for oil and gas prices, capital and operating costs and transportation tariffs are based on year 0 dollar figures, which are escalated in real terms at varying rates, and by inflation assumptions, to yield money of the day (MOD) figures used to calculate MOD cash flows, subsequently deflated to calculate cash flows in real terms.

Each hypothetical field is assumed to start production from a small number of initial wells at the same rate and then ramp up production over a build-up period to plateau-production rates that are appropriate for the reserve size. The gas fields studied are assumed to be quite rich in condensate in order to test the impact of both a condensate revenue stream (treated as crude oil for fiscal purposes) and a natural gas stream.

| | | Non-associated Gas Fields | | | | |
|---|---|---|---|---|---|---|
| | Field Number | 1 | 2 | 3 | 4 | 5 |
| NGL + Water | Condensate (C5+) Yield (barrels/mmcf) | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| | LPG (C3 & C4) Yield (barrels/mmcf) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | Water Production Start Year | 8 | 8 | 8 | 8 | 8 |
| | Start Year Water Production (percent of total petroleum boe) | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% |
| | Growth Rate for Water Production (% / year) | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Capital Costs | Exploration & Appraisal Investment ($ millions) | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| | Capital Investment $/ mcf (reserves) of Gas Reserves Estimated | 1.0 | 1.0 | 0.8 | 0.5 | 0.5 |
| | Capital Investment $/ barrel (reserves) of Oil or C5+ estimated | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| | Capital Investment $millions for Gas / NGL Processing Plant | 50.0 | 75.0 | 100.0 | 350.0 | 500.0 |
| | Incremental Capital for Compression / lift / workover ($/boe productio | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| | Incremental Capital (Start Beginning of Year) | 10 | 10 | 10 | 10 | 10 |
| | Decommisioning Capital ($ millions) | 50.0 | 50.0 | 75.0 | 75.0 | 150.0 |
| | Decommissioning Year (Provisional Start Year) | 22 | 22 | 22 | 22 | 22 |
| Operating Costs | Fixed Field Operating Costs (wells, platform / site) $ millions/year | 5.0 | 6.5 | 8.0 | 15.0 | 20.0 |
| | Variable Field Operating Cost ($/boe+bwater production) | 3.5 | 3.0 | 2.5 | 2.0 | 1.5 |
| TT&T Costs | Treatment, Transportation and Tariff gas ($/mcf) | 4.5 | 4.5 | 4.5 | 4.5 | 4.5 |
| | Treatment, Transportation and Tariff Oil(C5+) ($/barrel) | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 |
| | Gas Consumed as Fuel and Process (percent daily production) | 8.0% | 8.0% | 8.0% | 8.0% | 8.0% |

***Figure 4.2.2. Associated liquid production (NGL, LPG and water) and base case cost assumptions of five hypothetical gas fields (identified by numbers: #1 to #5) used for fiscal design evaluation.***

Capital costs for each field are divided into an exploration and appraisal component (US$100 million in each case) and into several development components:

**Upfront wells and facilities capex:**

- US$/mcf gas reserves
- US$/barrel oil (C5+) reserves
- US$ millions for upstream gas processing and conditioning plant (an amount which varies according to plant capacity/field size)

**Incremental and late-life components:**

- US$/boe compression/pumping/work over/sidetrack costs
- US$ millions for decommissioning
- (no costs for carbon capture or re-injection are included)

Note that it is an issue of historical definition in Alaska that onshore gas conditioning and processing plants are considered as upstream facilities where gas is separated, some heavier natural gas liquids extracted, dehydrated, stabilized and compressed prior to either re-injection back into the reservoir (status quo at Prudhoe Bay) or entry into a pipeline (once built and operational). In contrast, gas treatment plants where lighter NGLs are extracted from the gas by cryogenic or other means and lighter gases are liquefied are considered as downstream facilities, and their costs are considered as part of the downstream fiscal cash flow. Flexibility for investors to treat these facilities differently (e.g. as integrated investments) according to their financing arrangements and long-term operating strategies may be appropriate in the future. The US$/mcf gas reserves capital component is assumed to include all upstream facilities costs (i.e. wells, platforms, field processing and flowlines to gas processing facilities and pipeline terminals).

Operating costs are assumed to have a fixed component (e.g. staff, overheads, planned maintenance and fixed consumables) and a variable component (i.e. energy costs linked to capacity and variable consumables). It is assumed that 8% of the gas produced is consumed by the operation in delivering it to its market destination and each field produces for 360 days per year.

Downstream costs associated with TT&T components are identified in Figure 4.1.2 for both gas and oil (C5+). The models assume separate natural gas and oil tariffs to combine treatment, transportation and tariff. In reality these may need to be dealt with separately from a fiscal perspective (i.e. natural gas TT&T costs deducted from gas destination value and oil TT&T costs deducted from oil destination value) to yield separate production point values (PPV). In the models evaluated the TT&T costs are fully deductible (i.e. expensed in the year in which they are incurred) from destination values for taxation purposes.

All three cost components are held constant in real terms at year 0 dollars (i.e. 0% per year real escalation) but inflated at 2% per year to provide money of the day (nominal) costs across the field life. In unit money of the day (MOD) terms averaged over the gas fields' lives: the total capital costs incurred vary from US$9.05/boe (small Field #1) to US$ 4.35/boe (large Field #5); the total operating costs incurred vary from US$5.97/boe (Field #1) to US$ 2.46/boe (Field #5); and the total gas TT&T costs incurred vary from US$30.68/boe (Field #1) to US$ 32.97/boe (Field #5), that is to say roughly $5 per mcf or mmbtu .

**Gas Pipeline TT&T Cost Assumptions**

Black and Veatch (June 2008) -- for purposes of reviewing the AGIA license applications -- applied as a P50 assumption US$4.73 per mmbtu as a levelized nominal figure not including fuel for a gas pipeline tariff from the North Slope to Alberta, Canada. TransCanada, in its 2008 representations to Alaska, included a forecast pipeline tariff of US$2.76 per mmbtu inclusive of fuel and US$2.41 per mmbtu excluding fuel (levelized nominal rates). TransCanada estimated fuel at $0.35 in year one. The **US$4.5 per mmbtu gas TT&T tariff** (year 0 dollars) used in this study is held constant in real terms at year 0 dollars (i.e. 0% per year real escalation) but inflated at 2% per year to provide MOD (nominal) costs across the field life.

**Oil Pipeline TT&T Cost Assumptions**

Alaska's Fall 2007 Revenue Sources Book suggests nominal netback oil (C5) TT&T costs of US$4.91 per barrel in 2010. (This estimate takes into account the expiration of the TAPS Settlement Methodology (TSM) for calculating tariffs as it includes a post-TSM estimate for carriage on TAPS of $3.13 a barrel, compared to 2009 when the department used a much higher TSM-based estimate of $5.08 a barrel.) The **US$4.6 per barrel oil (C5+) tariff** (year 0 dollars) used in this study is held constant in real terms at year "0" dollars (i.e. 0% per year real escalation) but inflated at 2% per year to provide money of the day (nominal) costs across the field life.

The models assume that 8% of natural gas produced is consumed in fields' upstream operations at no cost to the operator (i.e. it is neither taxed nor is it subject to royalty) and is dealt with simply as a reduction in gross production volume. Such "free use of gas" does not extend downstream, i.e. natural gas consumed as part of TT&T operations is taxed and subject to royalty (e.g. natural gas used to power the TAPS pump stations).

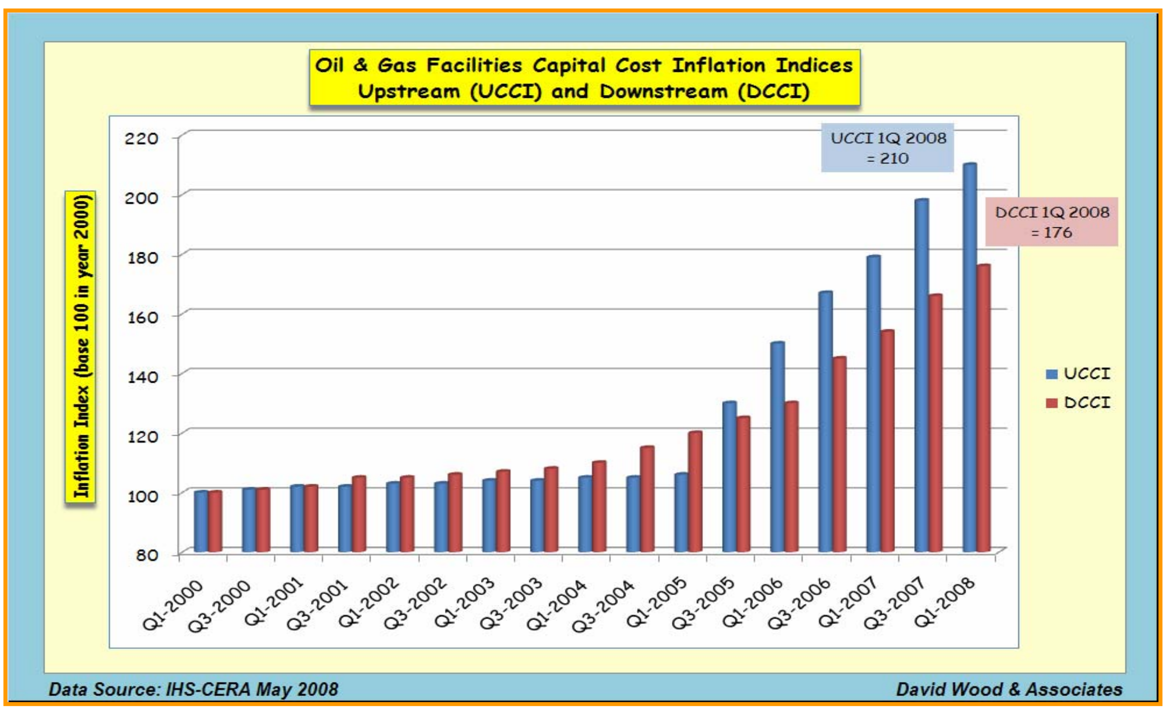


***Figure 4.2.3. Oil and gas industry cost inflation trends for upstream (UCCI index of IHS-CERA) and downstream (DCCI index of IHS-CERA) show costs worldwide have doubled since 2000 and continue to increase in 2008. Source: David Wood, World Oil Feb 2008.***

The cost and tariff values stated in Figure 4.2.2 are base-case assumptions and are tested in the models by broad sensitivity cases. The global oil and gas industry is experiencing an inflationary period (Figure 4.2.3), and it is recognised that both capital and operating costs associated with real field developments over the next decade could be substantially higher than the costs quoted. The sensitivity analysis cases are designed to address the impacts of cost inflation on both field profitability and Alaska's share of economic rent.

The hypothetical fields span finding and development (F&D) cost ranges of US$3/boe and US$ 7.5/boe in these base cases. The capital costs are somewhat lower than global F&D and reserves acquisition cost averages reported in recent years (Figure 4.2.4). In some sensitivity cases considered for these fields these capital costs are tripled to ensure that high-cost scenarios are also evaluated.

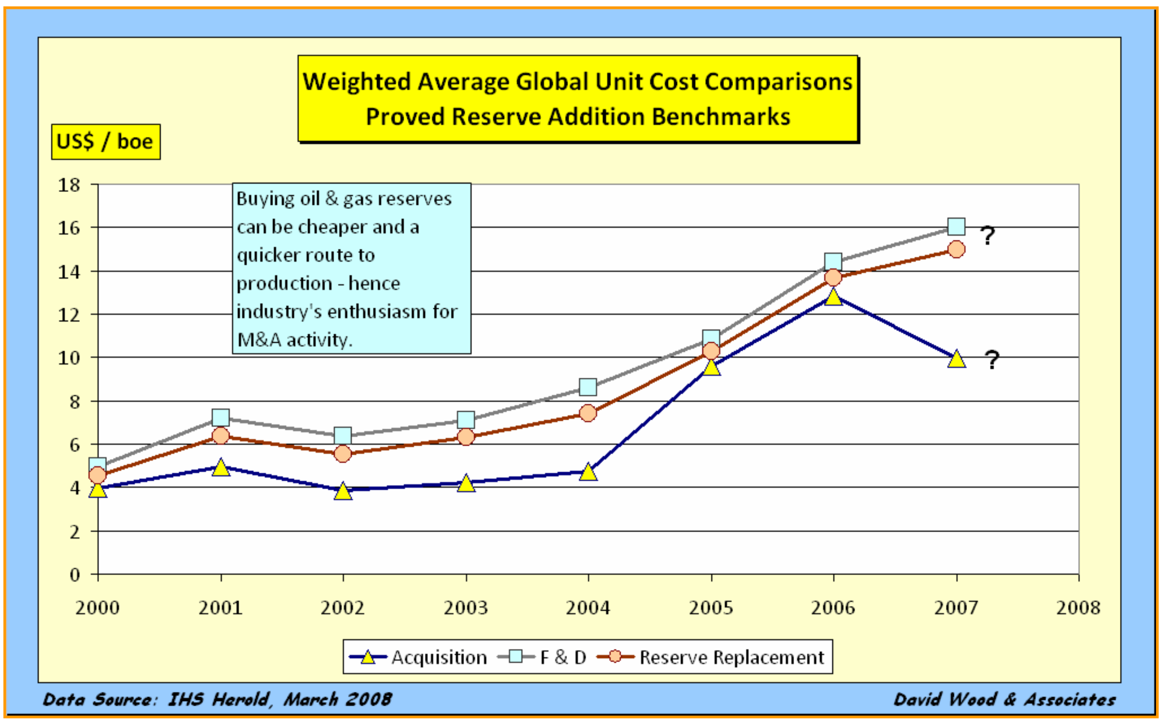


***Figure 4.2.4. Weighted average global capital cost benchmarks are instructive about general industry trends, but regional variations are large. These trends suggest that base costs in some of the model fields used in this study are on the low-side of industry averages.***

### Oil (with Associated Gas) Field Characteristics (Field Numbers 6 to 10)

The five hypothetical oil fields with associated natural gas production (Figure 4.2.5) vary from small to large reserve sizes. The fields vary in reserves from 28 million boe (25 million barrels of oil; 20 bcf of associated gas) to 615 million boe (500 million barrels of oil; 690 bcf of associated gas). These fields are used in this study to see how fiscal terms for natural gas impact their profitability and evaluate Alaska's take of economic rent from associated gas in such fields. It is assumed that each field takes two to three years to appraise, but variable periods to develop (i.e. up to five years for the largest oil field).

| | Oil Fields with Associated Gas | | | | |
|---|---|---|---|---|---|
| Field Number | 6 | 7 | 8 | 9 | 10 |
| Treat as "Gas" fields =0; Treat as "Oil" fields =1 | 1 | 1 | 1 | 1 | 1 |
| Initial Oil (C5+) Reserves Estimate (millions barrels- mmbbl) | 25.0 | 75.0 | 100.0 | 150.0 | 500.0 |
| Initial Gas Reserves Estimate (billions cubic feet - bcf) | 20.0 | 50.0 | 60.0 | 150.0 | 750.0 |
| Initial Petroleum Reserves Estimate (millions barrels- mmboe) | 28.3 | 83.3 | 110.0 | 175.0 | 625.0 |
| Exploration Start Year | 1 | 1 | 1 | 1 | 1 |
| Exploration / Appraisal Duration (years) | 2 | 2 | 2 | 3 | 3 |
| First Development Capital Investment (Start of Year) | 3 | 3 | 3 | 4 | 4 |
| Development Duration (years) | 2 | 3 | 4 | 4 | 5 |
| End of Development Capital Investment (End of Year) | 4 | 5 | 6 | 7 | 8 |
| Production Start-up (Start of Year) | 4 | 5 | 5 | 6 | 7 |
| End of Build-up Phase (End of Year) | 7 | 7 | 7 | 7 | 10 |
| End of Plateau Phase (End of Year) | 9 | 9 | 9 | 11 | 15 |
| Daily Oil Production at Start-up (bopd) | 4,000 | 10,000 | 10,000 | 20,000 | 40,000 |
| Daily Oil Production at Plateau (bopd) | 7,500 | 25,000 | 30,000 | 40,000 | 100,000 |
| Incremental Daily Oil Added / Year in Build Up Phase (bopd) | 875.0 | 5000.0 | 6666.7 | 10000.0 | 15000.0 |
| Gas to Oil Ratio (GOR - cf/bbl) | 750 | 700 | 600 | 1250 | 1500 |
| Decline Exponent (assume Exponential decline from plateau) | 0.1400 | 0.1750 | 0.1400 | 0.1550 | 0.1400 |
| [Annual Decline rate (% / year)] - model uses exponent | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Daily Oil Production at Shut-in (bopd) | 1,000 | 2,000 | 3,000 | 3,000 | 3,500 |

***Figure 4.2.5. Reserves and production characteristics of five hypothetical oil (with associated gas) fields used for fiscal design evaluation.***

| | Oil Fields with Associated Gas | | | | |
|---|---|---|---|---|---|
| Field Number | 6 | 7 | 8 | 9 | 10 |
| Condensate (C5+) Yield (barrels/mmcf) | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| LPG (C3 & C4) Yield (barrels/mmcf) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Water Production Start Year | 8 | 8 | 8 | 8 | 8 |
| Start Year Water Production (percent of total petroleum boe) | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% |
| Growth Rate for Water Production (% / year) | 5.0% | 5.0% | 5.0% | 5.0% | 5.0% |
| Exploration & Appraisal Investment ($ millions) | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Capital Investment $/ mcf (reserves) of Gas Reserves Estimated | 1.0 | 1.0 | 0.8 | 0.8 | 0.8 |
| Capital Investment $/ barrel (reserves) of Oil or C5+ estimated | 3.0 | 2.5 | 2.0 | 2.0 | 2.0 |
| Capital Investment $millions for Gas / NGL Processing Plant | 25.0 | 50.0 | 75.0 | 100.0 | 350.0 |
| Incremental Capital for Compression / lift / workover ($/boe productic | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Incremental Capital (Start Beginning of Year) | 10 | 10 | 10 | 10 | 10 |
| Decommisioning Capital ($ millions) | 50.0 | 75.0 | 75.0 | 100.0 | 350.0 |
| Decommisioning Year (Provisional Start Year) | 22 | 22 | 22 | 22 | 30 |
| Fixed Field Operating Costs (wells, platform / site) $ millions/year | 5.0 | 8.0 | 10.0 | 20.0 | 50.0 |
| Variable Field Operating Cost ($/boe+bwater production) | 3.5 | 3.0 | 2.5 | 2.0 | 2.0 |
| Treatment, Transportation and Tariff gas ($/mcf) | 4.5 | 4.5 | 4.5 | 4.5 | 4.5 |
| Treatment, Transportation and Tariff Oil(C5+) ($/barrel) | 4.6 | 4.6 | 4.6 | 4.6 | 4.6 |
| Gas Consumed as Fuel and Process (percent daily production) | 8.0% | 8.0% | 8.0% | 8.0% | 8.0% |

***Figure 4.2.6. NGL and LPG yields, water production and base case cost assumptions of five hypothetical oil fields (identified by numbers: #6 to #10) used for fiscal design evaluation.***

The 175 million boe field assumes a 4-year development period, whereas for the 28 million boe field only a two-year development period is assumed. For each oil field a start-up oil flow rate, a plateau oil flow rate and a decline curve linked to a decline exponent is assumed. Associated gas production is controlled by a gas-to-oil ratio (GOR), which is high for the largest field (1500 cf/barrel), but lower for the smaller fields (600 to 750 cf/barrel) to test the commercial viability of small volumes of gas production produced over short production lives.

The five oil fields are assumed to have small-scale C5+ yields from their associated gas streams (base case assumptions in Figure 4.1.6) and also to be progressively impacted by water production. Capital costs for each field are divided into an exploration and appraisal component (US$100 million in each case) and into several similar development components to the gas fields:

**Upfront wells and facilities capex:**
- US$/mcf gas reserves
- US$/barrel NGL reserves
- US$ millions for upstream gas processing and conditioning plant (an amount which varies according to plant capacity/field size)

**Incremental and late-life components:**
- US$/boe compression/pumping/work over/sidetrack costs
- US$ millions for decommissioning
- (no costs for carbon capture or re-injection are included)

Breakdown of components for operating costs and TT&T for the hypothetical oil fields are similar to those made for the five gas fields.

**Reservoir & Facilities Engineering Issues to Address for the Fiscal Impact on Real Fields**

The following technical issues also require consideration from fiscal design perspectives for real oil and gas field developments:

- Alternative field facility development options: Some engineering designs may have better chances of mitigating reservoir risks, but could cost more and have implications for taxation revenues. Fiscal designs need to evaluate whether specific fiscal instruments are neutral for alternative engineering solutions and whether it is appropriate to apply limits, such as the freezing of operating cost deductions for Prudhoe and Kuparuk at 2006 levels plus 3% inflation.
- Oil and gas reservoirs with different drive mechanisms (i.e., gas-cap drive, solution gas drive, water drive and hybrid/combination drives) require distinctive primary reservoir depletion strategies and have different numbers of wells, facilities and production profiles associated with them. The engineering solutions selected will have cost and fiscal implications and different timing to the expenditure profiles.

- Secondary recovery/water injection requirements as incremental investment opportunities.

- Enhanced oil recovery (EOR) opportunities and late-life capital investment opportunities associated with as yet undeveloped new technologies.

- Carbon capture and sequestration (CCS) opportunities (or mandatory requirements).

- Future capital investment efficiencies required to optimize oil, gas and NGL recoveries.

- Opportunities for strategic infrastructure installations (i.e. gas gathering and/or processing facilities) associated with (or integral to) certain upstream projects that have the potential to be used as hubs for additional field developments.

These issues need to be considered to ensure the analysis of hypothetical field models does assess a realistic range of investment and revenue outcomes for oil and gas field developments that are anticipated in Alaska in the future. The Alaska Oil and Gas Conservation Commission (AOGCC) has an important responsibility in this process: To protect the public's interest by preventing waste and ensuring greater ultimate recovery of oil and gas. To fulfil this role, the AOGCC has an input to determining what gas offtake rates should be allowed from new and existing North Slope oil and gas fields.

**Hypothetical Field Base Case Production and Cost Outcomes**

From the field assumptions listed in the above figures, the field cost profiles and initial production rates and unit values per boe of production tabulated for all ten fields are included in Appendix 4.