

State of Alaska
Department of Natural Resources
Division of Oil and Gas

Cook Inlet Natural Gas Production Cost Study

by

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June, 2011

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Sean Parnell, *Governor*
Daniel Sullivan, *Commissioner*
William C. Barron, *Director*

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EXECUTIVE SUMMARY

Conducted primarily by DNR staff from the Division of Oil and Gas in collaboration with the Alaska Gasline Development Authority (AGDC), this study builds on the 2009 Department of Natural Resources (DNR) report titled *Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Reserves* (Hartz and others, 2009). The 2009 report attempted to quantify remaining gas reserves in the Cook Inlet Basin, but did not address the commercial viability of producing the natural gas to meet the demand of south-central Alaska. This report addresses commercial viability of the remaining gas by postulating conceptual plans to produce natural gas from the Cook Inlet Basin to meet a demand of 90 billion cubic feet (BCF)/yr.

This study uses a bottom up approach to investigate the investment requirements, geologic, and engineering uncertainty around the various targeted reserves. Economic analysis is performed to address commercial viability of the reserves required to meet the demand by calculating the internal rate of return (IRR) and expected monetary value (EMV); not all targets met the positive EMV criteria based on currently available information. This investigation is not exhaustive as it focuses on reserves identified in the DNR 2009 report and does not include unconventional resource, yet to be discovered resource, or natural gas imports. In addition, the report considers only two of many economic metrics to determine economic viability. Other economic metrics might include: capital efficiency ratios, return on capital employed (ROCE), earnings before interest, tax, and amortization (EBITA). The report stops short of providing a price forecast as this would require modeling a range of upstream and downstream uncertainties which are not addressed in this study. This study provides two key conclusions:

- Based on currently available information, the assumptions made in this study, and absent any exploration success, the Cook Inlet basin is capable given sufficient continued investments of supplying the regional natural gas needs until 2018-2020 at a price below that of currently contemplated alternatives (see Figure 12). However, failure to make appropriate investments in lockstep with demand requirements will necessitate alternative sources of natural gas to be made available sooner. Therefore, transition to alternative sources of natural gas may begin to occur before the 2018-2020 time frame as part of a comprehensive supply and risk management plan.
- Natural gas storage will play an increasingly important role in optimizing and managing deliverability and economics of the natural gas supply for south-central Alaska. Just-in-time production reduces the amount of time between investment and return, and improves the economics of supplying natural gas. If gas purchases can be made in summer in advance of peak winter needs, storage allows these dynamics to be managed effectively by allowing production in summer to exceed the demand and storing the excess production until it is needed in winter.

While the south-central Alaska natural gas market has not been as commercially active as the contiguous United States (“lower 48”) market, it has worked to meet the needs of local residents. To date producers have fulfilled all their contractual requirements and are expected to do so in the future. The basin-wide economic analysis based on IRR and net present value (NPV) parameters suggests that natural gas from the Cook Inlet basin could be available to meet intermediate term needs.

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INTRODUCTION

Purpose of This Study

South-central Alaska has relied on production from Cook Inlet gas fields to meet demand for electrical power generation, heating, and industrial use since commercial production increased abruptly in the late 1960s. After fully supplying the needs of the region for more than 50 years, it is unlikely that the Cook Inlet gas fields will continue to be the only natural gas source needed to meet south-central Alaska's long term demand requirements. However, before long term solutions can be fully debated, the cost and production profile for the intermediate time frame (five to fifteen years) and especially for extensions of the currently producing Cook Inlet fields, should be understood. This report builds on the work of the study *Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves* released by the Department of Natural Resources (DNR) in 2009. The study focused on the remaining Cook Inlet gas reserves and serves as starting point for this study.

This study builds on the previous to better understand the economic drivers of developing known and potential reserves to meet near and intermediate term south-central Alaska demand. This is the first time a basin-wide economic evaluation of Cook Inlet remaining reserves has been attempted. The level of scope is appropriate for evaluating long term alternatives, but we also recognize that generalizations needed for a basin-wide analysis may not always be appropriate for drawing conclusions about any specific project. For example, different owners and operators have different economic drivers and requirements. However, evaluating these drivers and requirements for a study time frame of fifteen years is virtually impossible. If nothing else, it is unlikely that the current ownership struc-

ture of Cook Inlet upstream assets will remain unchanged during this time frame. Therefore, while a one size fits all simplification is needed to manage the breath of the investigation, it is also appropriate given the uncertainty of the future. In summary, this study focuses on one central question:

What investment and associated producer revenue would be required to generate specific rates of return from developing DNR-identified Cook Inlet gas reserves to meet existing Cook Inlet natural gas demand requirements of 90 billion cubic feet (BCF)/yr through 2025?

This question was chosen as the focus of this study as it should lend itself to insights that were not apparent at the outset of the study. Given the extent of this topic, the question will only start to address some of the complexities of the market. Other perspectives are also welcome as the future of south-central Alaska natural gas supply is contemplated, discussed, and debated.

Cook Inlet Natural Gas Market

Historically, the natural gas reserves base in Cook Inlet was greatly influenced by oil exploration. In the 50 years following discovery of Alaska's first commercially viable oil at Swanson River in 1957, nine of ten exploration wells targeted oil, not natural gas; nine of the biggest gas fields were discovered exploring for oil, not natural gas. Cook Inlet exploration drilling peaked in 1966. After the discovery of Prudhoe Bay in 1968 exploration in Cook Inlet declined and has remained at reduced levels.

While the peak exploration drilling occurred in 1966, peak gross natural gas production occurred in 1994 with approximately

311 BCF produced that year. The surplus of natural gas over an extended period created a buyer's market. Cook Inlet gas traded at a discount to contiguous United States ("lower 48") price indexes. Until this dynamic shifted in the mid 2000s this competitive advantage allowed for the operation of the Collier (Agrium) fertilizer plant. Liquefied natural gas (LNG) exports also created an end use for the surplus gas. Contracts to meet regional needs were long term and included both base load and peak demand gas. Demand swings were managed at the well; no storage existed.

The Cook Inlet market structure started to change approximately ten years ago. Long term contracts, which largely closed the market to new entrants, began to give way to shorter term contracts. First, the Agrium fertilizer plant and more recently, the LNG export facility received only intermittent supply and interruptions of their supply were used to meet winter demand peaks. This winter Enstar accepted bids on a day ahead basis, taking a step towards formation of a spot market to meet winter peak requirements. The south-central Alaska market will continue to evolve as new storage capacity is added to manage winter peak demand.

The roles of the producers and utilities have been changing. Early full service contracts obligated producers to manage all aspects of deliverability before entering the pipeline. The future suggests that various parties will own and operate storage, and deliverability will no longer be managed solely at the well or through curtailments to industrial customers. Hence the volumetric risk of not being able to monetize natural gas production will be mitigated by natural gas storage, albeit with the addition of storage costs. A future major gas find could change this dynamic yet again.

None of these market structures resemble

the ones in the lower 48. Their natural gas market is highly dynamic with market value being established continuously. The south-central Alaska market will always be fundamentally different. Market size in this region is relatively fixed. As the south-central region natural gas market does not represent a truly open market, market value will remain elusive to establish. While this study does perform various forms of economic evaluations, they should not necessarily be interpreted as a measure of target price to incentivize investment.

Study Background

This study expands upon a prior DNR study, published in December 2009, *Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Gas Reserves*. The 2009 study investigated gas reserves in producing gas fields and potential gas in development leads¹. It must be emphasized that the study did not include undiscovered resources or unconventional gas resources (e.g. coal-bed methane, underground coal gasification, or very tight gas sand plays). Costs and economic evaluation were outside the scope of the 2009 engineering and geologic study.

During 2009, reservoir engineering and geological analyses were undertaken independently of one another to evaluate the volumes of gas remaining in existing Cook Inlet gas fields. All 28 of the currently producing Cook Inlet gas fields were evaluated by applying decline curve analysis (DCA) and material balance (MB) engineering methods using publicly available production data obtained from the Alaska Oil and Gas Conser-

¹ Development leads are defined as targets that have been drilled with at least one well but not fully delineated. Development leads do not include rank exploration or unconventional targets.

vation Commission (AOGCC). The four gas fields judged to have the greatest remaining potential received more refined analysis; a mathematical mapping methodology was applied to analyze pay (expected to be economically viable) and potential pay (potential to be economically viable) sandstone thickness for numerous producing zones in each of the four fields. The study also considered “development leads,” resources that await confirma-

tion and delineation in exploration prospects outside of producing areas where previous well penetrations suggest follow-up drilling may be warranted.

Figure 1 shows the locations of the Cook Inlet gas fields, and highlights the fields evaluated in-depth in the 2009 study. These fields are Beluga River, North Cook Inlet, Ninilchik, and the McArthur River Grayling Gas sands. The locations of development leads identified

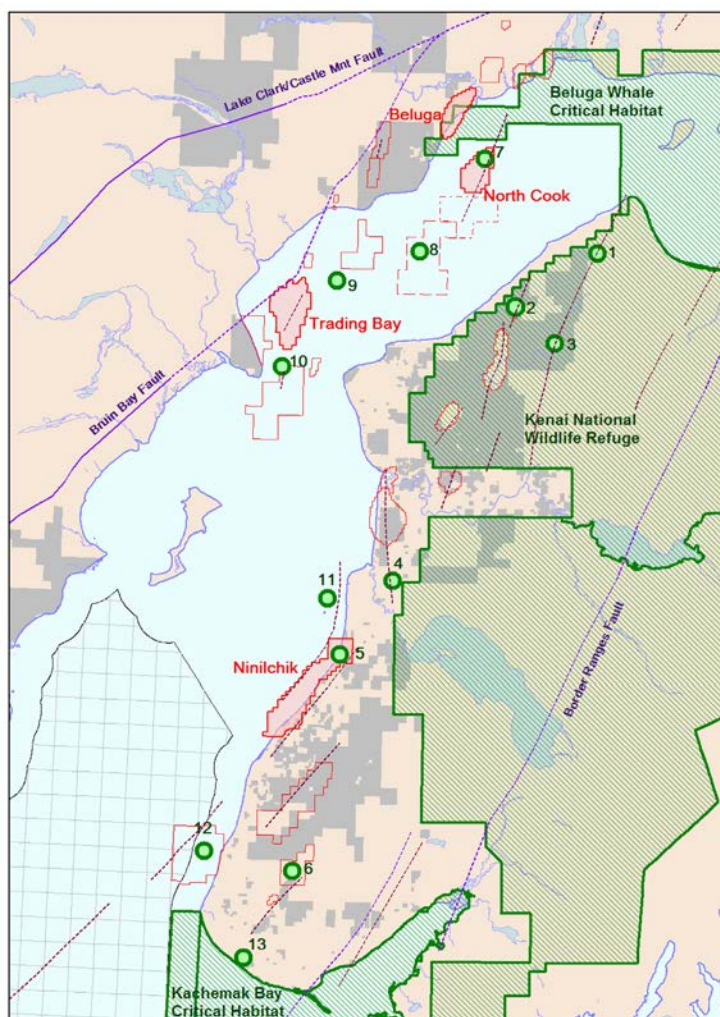


Figure 1. Location map of the central part of the Cook Inlet basin from the 2009 DNR study showing oil and gas producing units (the four major gas fields with geologic reserve estimates are highlighted with pink fill); major faults and fold axes; undeveloped exploration leads (numbered green dots); and areas with known or pending exploration access restrictions (green hachure).

in the report are noted by the green circles.

A production forecast was developed for each tranche of reserves and potential reserves. The tranches included reserves identified by decline curve analysis, reserves associated with the material balance volumes, potential resources from development of known pay intervals, and 50 percent risked potential pay, and “development leads.” The volumes and rates were not based on specific wells or drilling programs so they could not be refined.

The resulting forecast of the reserves tranches generated by the 2009 evaluation, shown in Figure 2, are displayed in order of progressively lower certainty of commerciality, volume, and timing of first production. The tranches show gas volume production and remaining reserve increments from basin-

wide decline curve analyses (red, 863 BCF), basin-wide material balance analyses (orange, incremental of 279 BCF), geologic mapping of Pay for Beluga River, North Cook Inlet, Ninilchik, and McArthur River Grayling gas sands (green, incremental 353 BCF) and 50 percent-risked Potential Pay for Beluga River, North Cook Inlet, Ninilchik, and McArthur River Grayling Gas sands (yellow 643 BCF incremental). The last tranche (gray, incremental 300 BCF) is a more speculative estimate of aggregated gas volumes that may be recoverable from the development leads. As shown in this plot, the decline curve analysis suggests that reserves shortages could occur in 2012 if development is either stalled or not pursued. Under this conservative assessment, if no new capital investment is made, and new gas is brought online, then production from currently producing wells at current condi-

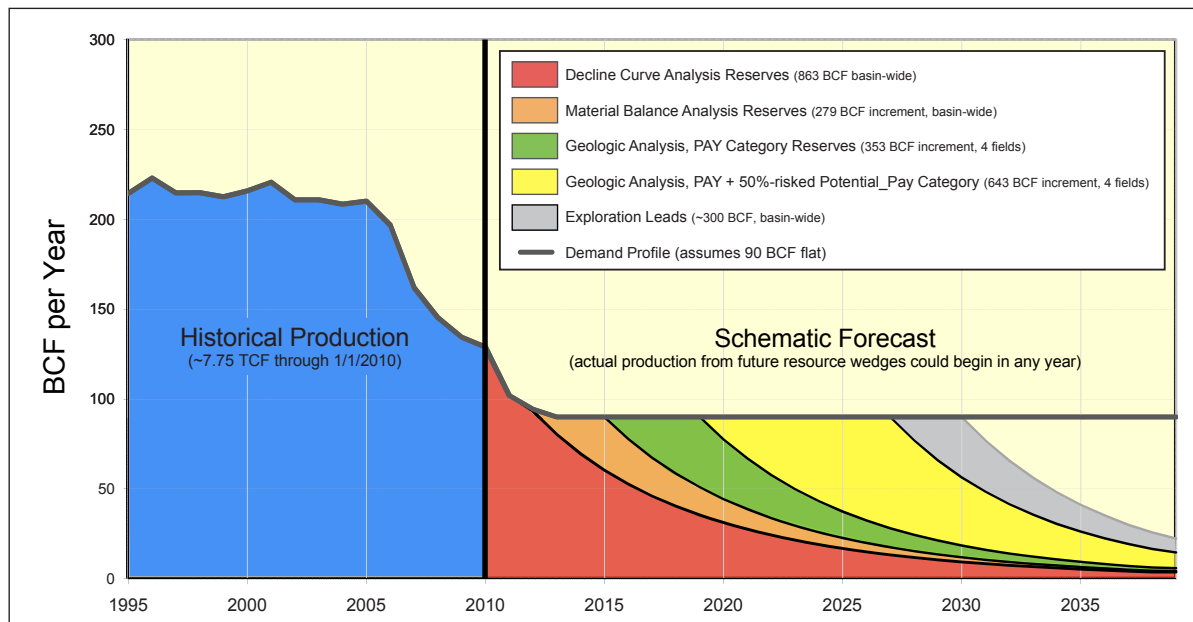


Figure 2. Hypothetical production forecast for the Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analyses in 2009 DNR Cook Inlet gas study. Note that the production through 2010 was affected by the additional market demand of the LNG and Agrium plants, while projections later assume only local market demand.

tions would be inadequate to meet existing demand by 2012. Each incremental production wedge would require increased investment. The full amount of existing reserves, as estimated through material balance methods, would delay the shortfall to approximately 2015. To recover the reserves attributed to material balance, evaluated at 100 pounds per square inch (psi) bottom-hole pressure limit, capital investments would be required for additional compression, facilities and infrastructure de-bottlenecking, workovers to mitigate water influx, and change of completion design to decrease the backpressure which limits productivity. Further drilling, re-completions, and stimulations would be needed to produce the additional potential geologic reserves. Development of the known pay in the four major fields would delay shortfalls to 2018, and potentially up to 2030 if reserves from potential pay and development leads were to materialize.

The current study builds on the prior DNR evaluation by constructing conceptual development plans² to better understand the economics of producing the natural gas potential identified in the 2009 DNR study. In so doing we assess whether the identified, risked tranches of gas in the ground might be developable and recoverable under reasonable economic conditions.

APPROACH

The 2009 study answered many key questions but left other key questions purposely for a follow-up study. The approach set forth in this study contemplates the economics of

² The conceptual development plans represent one possible development scenario to support representative economic characterization of the various fields and development leads. The actual development path may be different than the conceptual development plans, but should yield a similar economic result.

meeting south-central Alaska's natural gas needs with local resources. The 2009 study team was expanded to include two consulting firms familiar with Cook Inlet natural gas production. The study team was comprised of personnel from Ryder-Scott, SolstenXP, and the Alaska Department of Natural Resources.

Ryder-Scott is one of the largest, oldest and most respected reservoir-evaluation consulting firms in the industry. The Ryder-Scott consultant chosen to work with the team has over 25 years of reservoir engineering and operations experience within the Beluga River and North Cook Inlet units. His expertise in reserves determination and reporting, development planning, application of appropriate reservoir engineering techniques for determining reserves, well deliverability including effects of compression, and other decline analysis was critical for this study.

SolstenXP is a full service upstream oil and gas services company headquartered in Anchorage, Alaska. The company provides engineering and management services for exploration and production operations, including permitting and regulatory coordination, drilling engineering and supervision, well abandonments both on and offshore, facilities construction and decommissioning, production operations, Exploration, Production, Construction and Management (EPCM), and turnkey operations.

The DNR core team included two geophysicists, two geologists, three petroleum engineers, and two commercial analysts with over 150 years of combined oil and gas experience. The DNR team has access to a broader set of geological data in Cook Inlet than any individual company, and is well positioned to undertake a detailed, basin-wide evaluation.

Figure 3 illustrates the multidiscipline approach used in this study. The color scheme in the figure is representative of the various

production wedges shown in Figure 2. The remaining boxes illustrate the various techniques and processes that were utilized to provide an economic context for the 2009 study results. Each process will be discussed separately in the following sections.

Conceptual Development

The goal of the conceptual design phase was to identify a generic increment of development that could broadly be applied to the production of natural gas reserves for each of the identified targets. This provided the basis for estimating reserves, drilling and facilities cost, and production rates. Actual development may be different, but the inferences drawn from the conceptual development phase are expected to yield similar results to any final development plan.

Reserves and production rates. Infill development of existing producing fields was determined to provide the largest potential for additional reserves. Redevelopment in the Beluga/Upper Tyonek Gas Pool within the Kenai River Unit provides an example of how infill drilling and other well and field work can affect field rate and reserves. Figure 4 illustrates the effect of redevelopment in this field. Approximately 90 BCF of reserves were added through redevelopment.

In the 2009 study, field and pool material balance original gas-in-place (OGIP), remaining gas-in-place, and recoverable volumes were determined for the developed field and pools. In the process of this review it was found that in a few cases the 2009 material balance OGIP volumes required modification to better match the pressure/cumulative production history.

For the current study the reservoir models

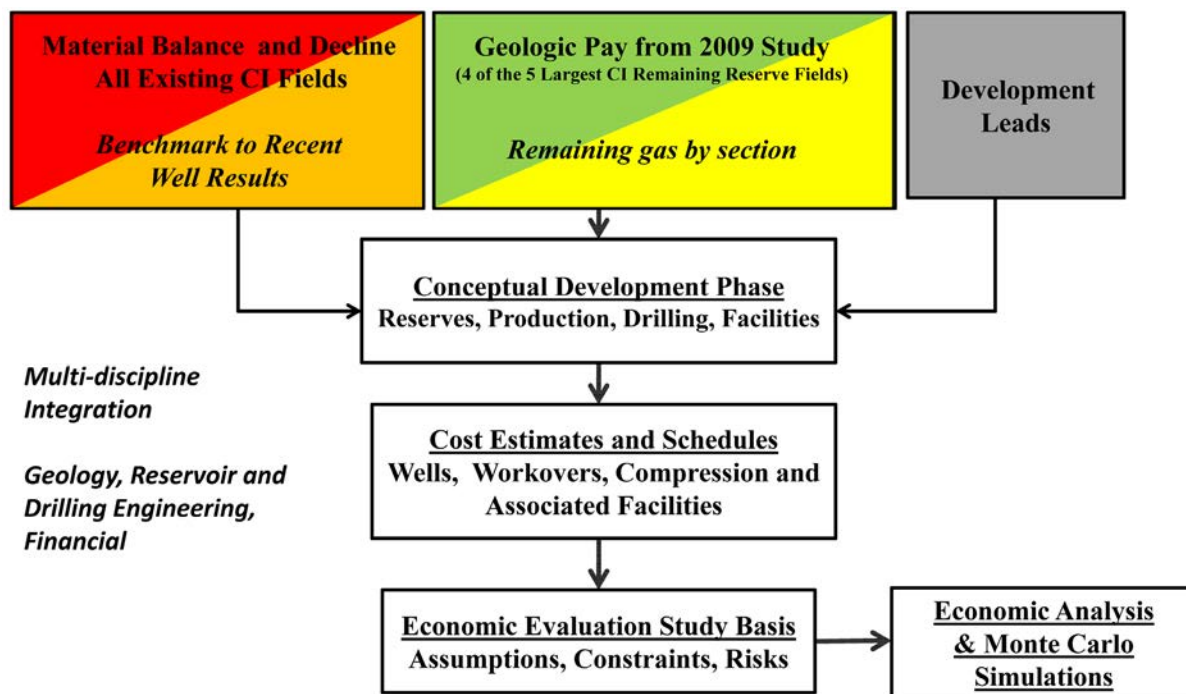


Figure 3. Illustration of the multi-discipline process used in this Cook Inlet Gas Production Cost Study.

for each existing field and pool were derived from material balance curves and calibrated against measured or predicted reservoir pressure at that date. The reference date for model calibration was chosen to be January, 2010 because this date offered consistent comparison with the prior study. Calibrating a simple deliverability model to each reservoir “tank” enables rates to be projected over time while honoring the material balance OGIP.

The constant C in the simple backpressure equation

$$q=C(P_r^2-P_{wf}^2)^n$$

was tuned to match January, 2010 rates (q) and average static reservoir pressure (P_r) for each material balance tank. The variable (P_{wf}) is flowing bottom-hole pressure determined from flowing tubing pressure corrected to bottom-hole conditions. All reservoir and flowing tubing pressures were obtained from AOGCC sources. These models were run forward in time, and checked for reasonability against the 2009 DNR study decline work. Decreasing the well head pressure at a future date invokes an increase in rate, decrease in final well head pressure and abandonment reservoir pressure. In this way, the “material balance” volumes could be rigorously scheduled

Cook Inlet - Field Redevelopment - Kenai River Unit Beluga/Upper Tyonek Effect of Infill Drilling and Well Work

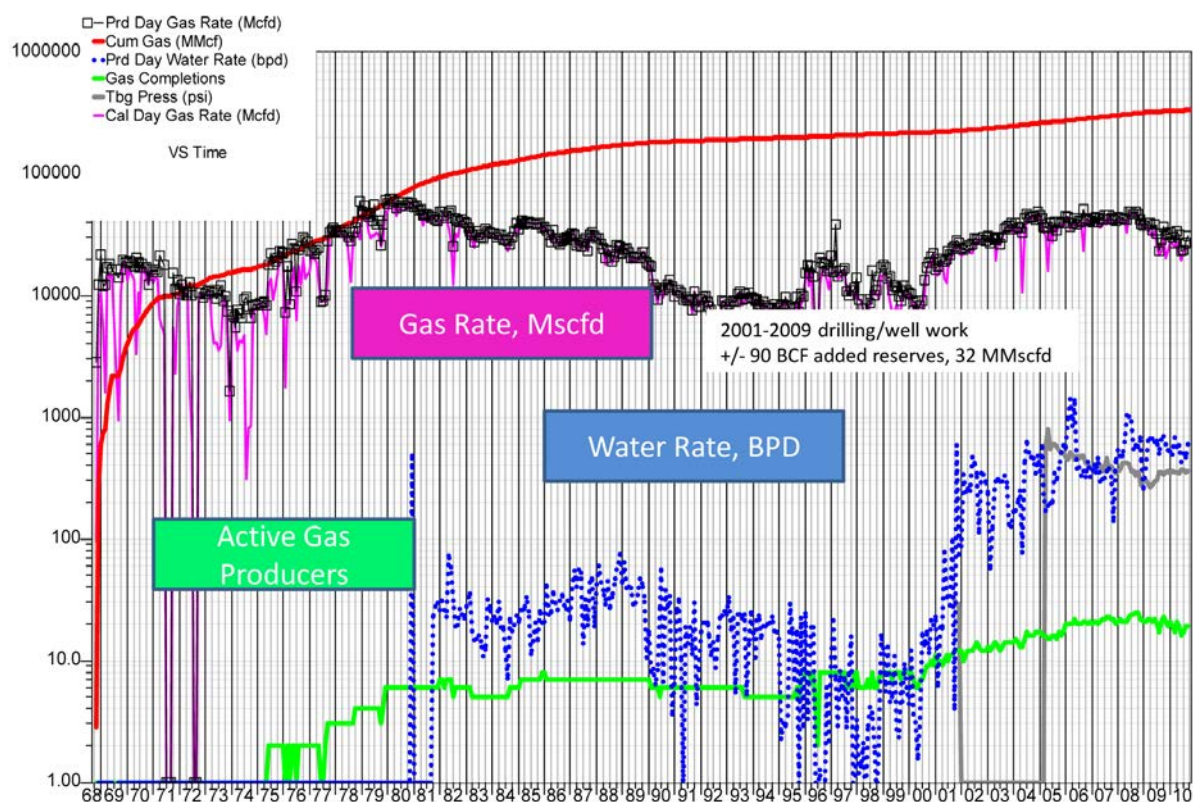


Figure 4. Major Kenai River Field redevelopment starting in 1995 and increasing in 2001-2008 resulted in a dramatic increase in rates and reserves. Increased investments included infill drilling, workovers, compression, water handling, etc.

and tied back to the wells that would recover these new volumes.

The resulting existing well recoverable volumes from this study are compared to that of the 2009 study in Figure 5. A limiting flowing tubing pressure of 80 psi was assumed for the current study, approximately equivalent to the 100 psi bottom-hole pressure limit for the 2009 material balance volumes. To recover these volumes, additional compression, well work, and de-bottlenecking will be required.

In order to determine the potential new wells and other investments required for field redevelopment, the detailed geologic pay volumes estimated in the 2009 DNR study were aurally distributed to estimate section remaining gas in place volumes. Production results of recently drilled wells provided the basis for rates and potential reserves with additional drilling. From the geologic and reservoir engineering analyses, conceptual development options were identified and sections with the most gas were selected as most likely for drilling. Potential reserves and rates of this new development were estimated and required drilling, completion, and associated facilities and infrastructure for cost estimation were identified. In addition, the rate and reserves benefits resulting from compression additions were evaluated. Figure 6 shows the resultant estimated remaining reserves for the existing fields (pay category new drilling plus existing well reserves by procedures described above). Note that these projected volumes have not been adjusted for Monte Carlo risk analysis and economics at this point in the process. It also excludes the “potential” geologic pay category (see Figure 2, yellow wedge).

Figure 7 shows the hypothetical production forecasts from this study prior to applying the Monte Carlo evaluation noted in the economics section of this report. It should be recognized that there is limited public infor-

mation available for the development leads and greater uncertainty in the volumes.

Drilling, Facilities, and Infrastructure.

Natural gas drilling activity has averaged approximately eleven wells per year with a minimum of four and a maximum of sixteen as shown in Figure 8. While not included on this figure, the workover program during this timeframe was substantial. This historical view was used to inform what activity level was possible in the future for Cook Inlet. To access the undrained gas resources identified in this study, 71 new wells or re-completions were assumed, an average eight wells per year during the period of 2011-2019. The required drilling schedule to meet the 90 BCF/year demand varies depending upon results of the Monte Carlo uncertainty evaluation and economic analyses described later.

To support new onshore wells, where infrastructure existed, determinations were made as to the need to modify existing gravel pads and expand facilities, or to construct new roads, pads, facilities, and pipelines. For each development scenario, costs were estimated based on need for expansion or completely new installations. Vertical wells were planned for most onshore developments. It was assumed that access would be on existing roads with contracting of existing land rigs to drill wells above bottom-hole locations. This was in agreement with the completion techniques of the areas with the most re-development or infill drilling potential.

Deviated wells were used in offshore platform developments. For these deviated wells it was assumed that the measured depth (MD) was no more than four times the true vertical depth (TVD). The radius of capability off of a platform was determined by estimating the maximum offset with which the top-most zone of interest could be penetrated, then vertically penetrating the sands below it to the bottom

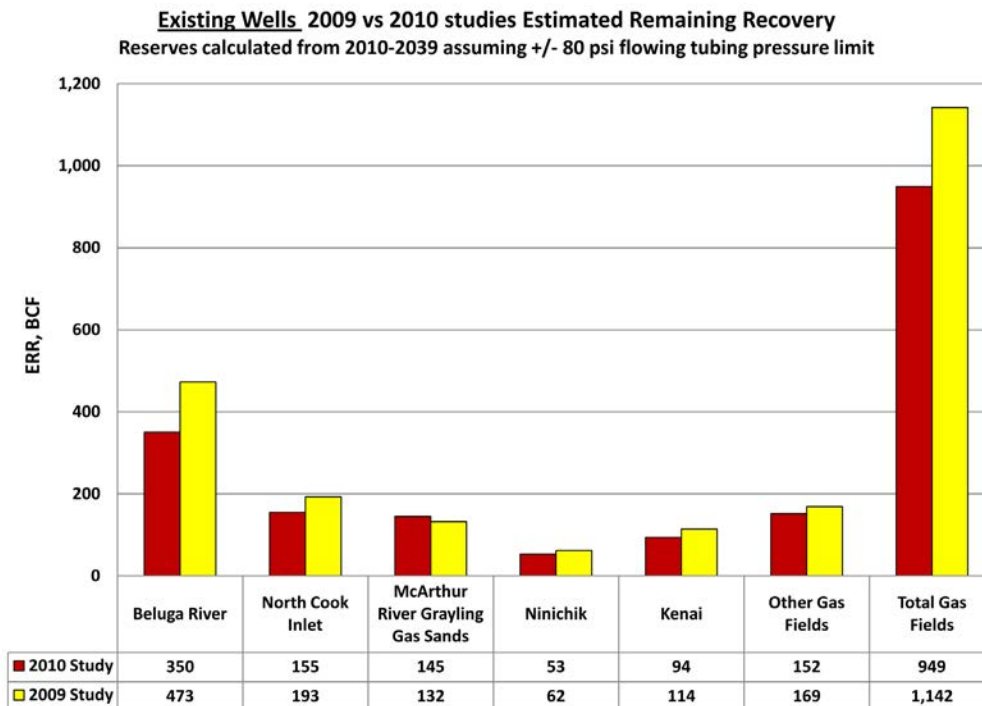


Figure 5. Comparison of 2009 and 2010 material balance estimated remaining reserves assuming 80 psi flowing tubing pressure (approximately 100 psi bottom-hole pressure).

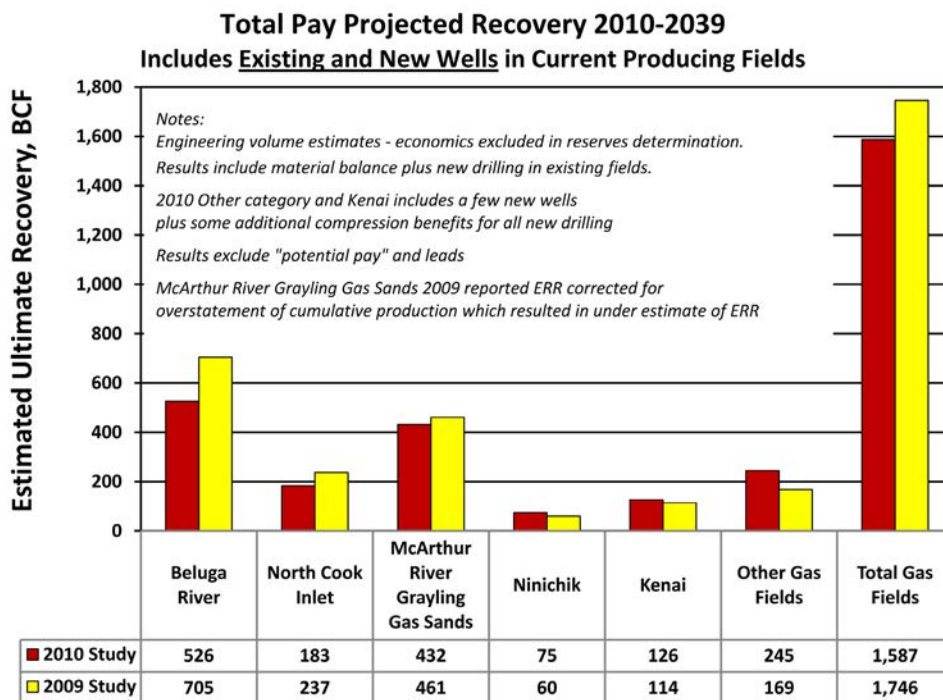


Figure 6. Total projected recovery for existing fields, included existing and new wells and compression.

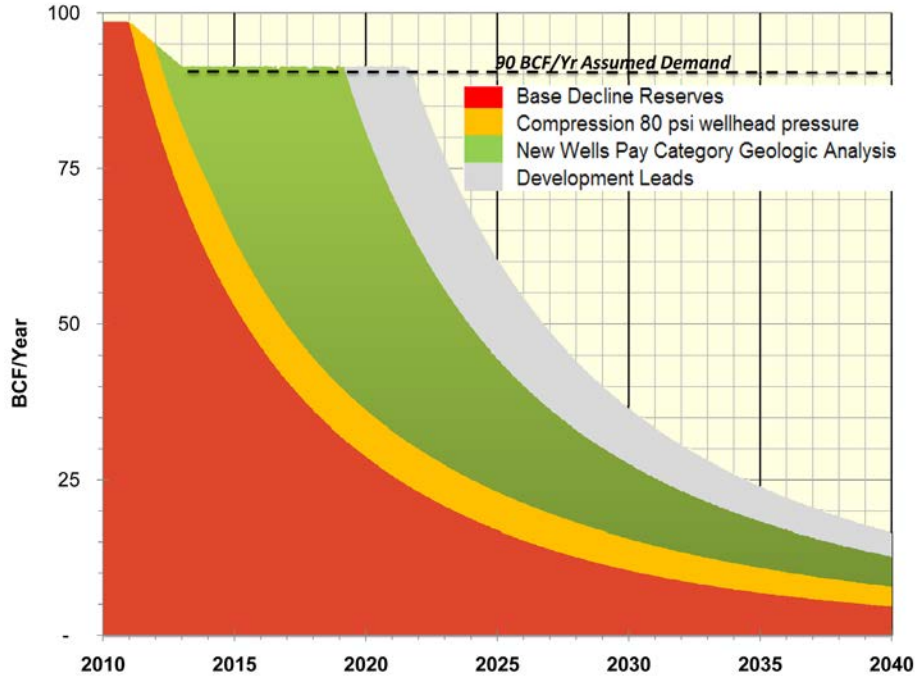


Figure 7. Hypothetical production forecasts resulting from this study for the Cook Inlet basin assuming a constant 90 BCF/Year demand after 2011. Production from future resource wedges could begin in any year. The projected “pay” volumes (green wedge) for this study are greater than that of the 2009 study (Figure 2) due to an error resulting in the understatement of McArthur River Grayling Gas Sands new well pay reserves potential. This error is corrected in this Figure.

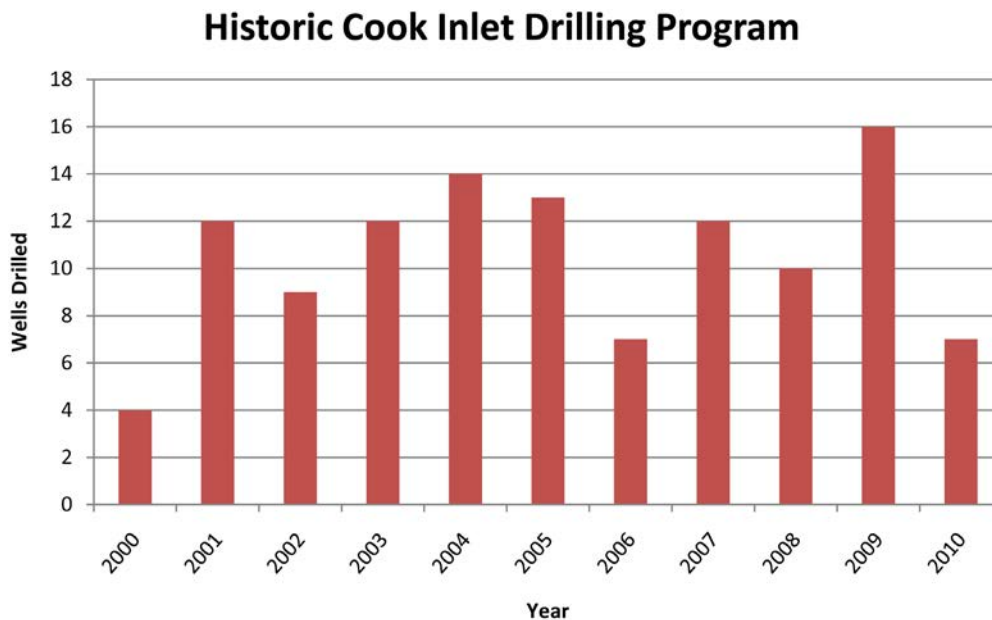


Figure 8. Recent Cook Inlet new natural gas well completions – does not include workover activity.

most zone of interest. If a current oil platform was to be converted to a gas producer, current gas handling equipment would be used in gas production.

Typical well characteristics were defined for purposes of cost estimation based upon the drilling and completion records of recent wells. Facilities and infrastructure requirements were determined and used as the basis for costs and schedule estimates. Scheduling of drilling, facilities investments, and associated production were performed based upon historical activity. This assured reasonable and achievable level of investments and timing of first production after investment activity begins.

Completions were designed to mirror the most recent completions for a field. Drilling and completion costs were estimated accordingly for depth, completion equipment, and stimulation needs required. Rig costs were estimated for the contracting of land rigs that were currently in the area. Rig mobilization and demobilization would be required for some existing platforms that currently do not have a rig. To date the Steelhead platform is the only one with a rig installed.

Compression needs were modeled in fields where it was known to currently exist. For most of the producing fields, minimum well producing pressures are about 300-350 psi with compression to increase the pressures to that required at the entrance to the transit lines (approximately 800-1100 psi). Future compression requirements were estimated to lower wellhead pressure to 80 psi. Potential incremental production and investment requirements for added compression were captured as a lump sum since the exact location of compression and its costs on a project by project basis is beyond the scope of this investigation and is not required to meet the objectives of the study.

Compression needs were estimated based on the total gas production of existing and new developments; total compression horsepower need was applied to this value, with costs estimated for the total horsepower required. Along with cost and horsepower requirements, the incremental benefits of compression were debited by six percent to account for compression fuel gas needs.

After the scope and cost estimation of initial installation of onshore or offshore production systems were considered in the first year of new developments, future water handling, intervention and maintenance were captured with estimates of operating costs for onshore and offshore facilities.

All projects were compared to recent drilling activity in Cook Inlet to assure feasibility. Those projects evaluated are only conceptual; operators in the Cook Inlet will need to plan and develop their areas.

Cost Estimates and Schedules

The conceptual designs for drilling, infrastructure, and facilities provided the basis for the cost estimates and associated schedules. All cost estimates are in constant 2010 dollars. This provides direct comparison to today's costs.

Authorization for Expenditure (AFE) quality drilling, rig work over, and completion costs were estimated by SolstenXP for conceptual design wells for the four fields of highest redevelopment potential. These costs (see example, Figure 9) were developed based on permitting and completion data from AOGCC for onshore and offshore representative wells for the Beluga River, North Cook Inlet, McArthur River Grayling Gas Sands, and Kenai River fields. Base costs were then estimated from rig rate (\$/day) and drilling

schedule for each well.

These base costs did not include fracturing, gravel packs, or velocity strings. These “accessory” operations were estimated separately and added to the base cost estimate to develop an all-in cost estimate. Review of recent wells in the four fields of primary interest was used to define the appropriate level of accessories for each field. Depending on location, depth, and “accessories”, the all-in cost estimates ranged from approximately \$10 million to \$20 million for on shore wells.

New well completions were assumed to occur only in sands that are not currently drained by existing wells. No new producing wells were included for the Sterling sands within the Beluga River, Kenai River, and North Cook Inlet fields which are being adequately drained. Conceptual well descriptions as determined from public data follow:

Beluga River Unit, Beluga Formation

A review of public well completions and practices indicates that a typical well in this field is currently completed with a dual tubing string. A review of thirteen public wells found four completed with gravel packs. Three had one gravel pack, one had three gravel packs. All wells had fracture stimulation jobs completed in the intervals that were packed. Given these findings, a type well in this field was designed with two tubing strings and two fracture stimulations and two gravel packs.

North Cook Inlet Unit Wells

A review of public data indicates that there are examples of these wells with up to five fracture stimulations and five gravel packs. For this reason, type wells for this category are estimated with three fracture stimulations and

three gravel packs.

Kenai River Unit Gas Wells

Review of public data indicates that a re-development of the field has been successful. A fit for purpose rig and the EXcape® multi-zone casing perforating system have been used for the re-development. There are three well types in the field:

Kenai River Unit Beluga Formation Wells: Exploit the Beluga sands with the EXcape® system. Wells are 3.5” monobore completions that require an 8.5” hole to fit the EXcape® system. These wells are fracture stimulated with no gravel packs. The assumption for these type wells in this study is one fracture treatment added to the drill and complete costs with a single tubing string. The one fracture treatment is viewed to cover what is assumed to be numerous “mini” fracture treatments over the various perforation intervals.

Kenai River Unit Tyonek Formation and Ninilchik Unit wells: These wells are simple monobore wells with a liner tied back to the surface with a monobore tubing string above it. Tyonek wells have been completed open hole in the reservoir, or with liners and perforations. Wells in both units are very simple monobore wells. They are perforated with no fracture stimulations or gravel packs which is how the type wells were estimated for this study.

Trading Bay Unit McArthur River Field Grayling Gas Sand Wells

Review of public data found that recent horizontal completions in this field had been completed with screens for sand control and no fracture stimu-

| Drilling Cost Estimate | | Date Prepared: | 1/4/2011 | | |
|---|---------------------|---|------------|---------|-----------------|
| Well Name: Beluga Generic 224-23 | | Drilling Engineer: | Solsten XP | | |
| Well Type | Development | Beluga Gas Well 427' 20" surface 3099' 13 3/8" intermediate 6150' 9 5/8" production Double-string completion 2 7/8" tubing | | | |
| Max Inclination | 0.00 | | | | |
| Pay Zone Inclination | 0.00 | | | | |
| Target (TVD feet) - top of zone | 0' | | | | |
| Vertical Section @ TD | 0' | | | | |
| Surface Casing? | yes | | | | |
| Intermediate Topset? | yes | | | | |
| Rig | Drilling rig | | | | |
| | Hole Size | Casing Size | MD | TVD | Mud Weight, ppg |
| Conductor | | 16" | 98' | 98' | N/A |
| Surface Casing | 26.000" | 20.000" | 427 ft | 427 ft | 9.6 |
| Intermediate Csg | 17.500" | 13.375" | 3099 ft | 3099 ft | 9.5 |
| Production Csg | 12.250" | 9.625" | 6150 ft | 6150 ft | 11.0 |

Beluga Gas Development Days vs Depth Chart

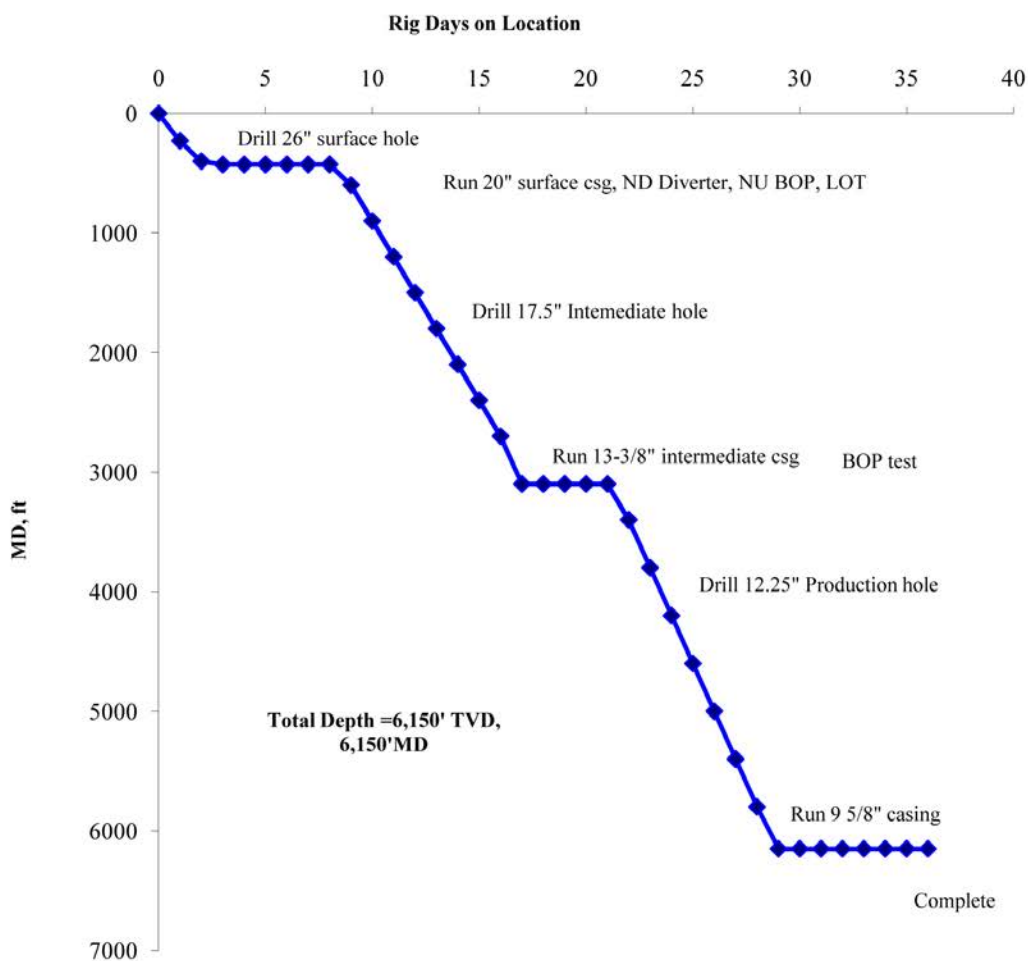


Figure 9. Example cost estimation methodology for typical well in Beluga River.

lation or gravel packs. At this time, the current operator appears to be exploiting most wells with horizontals aimed at specific zones. For this reason, a 12,000' type well with a target TVD of 3,000' and a horizontal screened completion was selected as the type well for the study with the assumption that its costs would be close to the extreme "S" shaped wells discussed above.

With conceptual wells determined for the fields, the number of these wells to be drilled for a capital project was determined based on the reserves estimate for the area. With the number of wells known, mobilization costs, new or existing infrastructure upgrades and expansion costs were estimated for an area based on the forecasted production rates for the wells and the well counts. Onshore facilities included gravel pads, pipeline installation, roads, buildings, tanks, metering, and generators. Offshore cost estimates included: rig mobilization/demobilization costs; pipeline construction if necessary; platform construction and installation; production equipment that included water handling and disposal; and power.

Compression will be required to maintain gas rates with declining reservoir pressures. A rough estimate of \$100 million was assumed for total Cook Inlet compression costs in existing developed fields based upon published compression upgrade costs of \$60 million for the Beluga Gas Field. For additional new wells, compression additions of \$1 million per 1,000 horsepower were assumed.

SolstenXP provided the cost estimates for the development projects based on their experiences and data. Costs were validated with contractors and operators where possible. Onshore facility costs were estimated by the SolstenXP construction group. Offshore facility costs were estimated with the input of a

consultant familiar with the area and whose work had been used by area operators to estimate platform development costs. Mobilization costs were checked with drilling contractors. Land rig rates used in the study were confirmed by an operator in the area.

Operating costs were developed from the general input of some operators in the area. The range of estimates showed considerable variability in magnitude and definition. A midpoint was chosen for the study estimates. Sensitivities were run to confirm that while operation costs have some influence on the economics, they are not a critical driver in determining the economic viability of a project.

Economic Evaluation Study Basis

Understanding and interpreting the results of any analysis must always be done in the context of the study basis. The study basis defines the assumptions made, uncertainties quantified (and not quantified), and the constraints for the study. Changing any of these parameters would yield different results. However, without adequately bounding the analysis through assumptions no results can be generated. DNR believes that the economic study basis presented here is reasonable based on currently available information and helps to generate important insights into market conditions (supply, demand, revenue requirements, deliverability, etc.) of south-central Alaska. The assumptions made and analysis constraints imposed here are not the only ones possible, and hence the analysis is not framed as the ultimate answer, but rather a tool which would enhance the dialog between the various stakeholders which could improve the current market conditions. This analysis reflects our best assessments of a reasonable study basis. As more information becomes available, it may be necessary to change or modify the study basis. Some of the conclu-

sions might change as additional information becomes available.

Key elements of the economic evaluation study basis include the following:

- Constant Dollars – All cost estimates and financial analysis is done in constant 2010 dollars.
- Natural Gas Storage – Sufficient natural gas storage is assumed such that wells are not shut in or production constrained in any manner other than by the average annual demand. Production is monetized when it is produced for all future years of production.
- Natural Gas Demand – As in the 2009 DNR study natural gas demand for south-central Alaska was estimated at 90 BCF per year. This recognizes the elimination of essentially all industrial and LNG export demand. In effect, the demand that would otherwise accompany economic growth is offset through end-use efficiency gains, fuel switching, or other means.
- Natural Gas Supply – Natural gas supply is assumed to be from currently producing wells and the development of prospects identified in the 2009 DNR geological evaluation of Cook Inlet reserves. This study does not address exploration that may occur during the study period. It also does not consider development of unconventional natural gas resources (e.g. coal bed methane, underground coal gasification, or development of very tight sands).
- Development – Natural gas projects are assumed to be developed with perfect coordination such that the most economical projects are brought on-line first and least economical well last with a schedule to manage the finite demand of 90 BCF per year. Any supply/demand mismatch is managed with deposits/withdrawals into/out of storage.
- Cost Estimate Uncertainty – When running Monte Carlo simulations, cost uncertainty was estimated at negative fifteen and forty percent.
- Risk Management – While dry hole risk and reserve risk were factored into the economic evaluation, other risks were not addressed. For example, fiscal policy, and operating risks were not addressed in the study. Market price risk was not addressed since the study solved for a revenue requirements necessary to generate specified rates of return.
- One Size Fits Most – The owners and operators with in Cook Inlet represent a very diverse set of players. While it is acknowledged that the decision criteria will not be the same for all Cook Inlet owner and operators, this complexity was not addressed.
- No Natural Gas Import – Although it is clear that activities are on-going to contemplate natural gas import via LNG, “bullet line”, or “spur line” the focus of the study is on resources identified in the 2009 DNR geological evaluation of Cook Inlet reserves. No import of natural gas is assumed.
- Study Boundaries – The study evaluation stops once the natural gas enters the nearest regulated pipeline. Costs associated with transportation and storage are not addressed.

Economic Analysis

This study focuses on two main economic indicators: internal rate of return (IRR) and net present value (NPV). For each project both IRR and NPV were estimated. One of the goals of economic analysis for this study is to create an integrated supply curve showing volumes produced at different revenue requirements (\$/million cubic feet) to earn specific rates of return. While the focus of the study is on new production, existing production must be addressed. To this end, production was separated into two categories: baseline and augmented production. Baseline production was defined as production from existing infrastructure and wells. This production was incorporated into the final integrated supply curve. Augmented production consisted of a set of conceptual development projects, which were defined as part of the conceptual development phase of the study.

Economic analysis was conducted for individual projects within the identified fields. A project was defined as one drilling season for new production from currently producing fields. For development leads (see Figure 1), some projects were defined as two drilling seasons. There were a total of 39 projects, 26 of which were in the existing fields, twelve in the fields identified as leads, and one lump sum area-wide compression project. Figure 10 summarizes the process.

For each project the economic analysis was based on project development costs, project schedule, probability of success and the monetization of the associated natural gas production. Probability of success was defined as the probability of producing at least some additional reserves, probability of failure was then defined as the probability of no additional reserves (one minus the probability of success). Three production forecasts were developed for each project. The production forecasts

were based on an estimate of reserves corresponding to three distribution values: P10 (10 percent probability of being lower), P50 (50 percent probability of being lower), and P90 (90 percent probability of being lower). Product development costs included royalties, capital expenditures, operating expenditures, as well as costs and benefits associated with the current fiscal system. Revenue requirements were calculated to satisfy three internal rates of return targets. The targets were set at 10, 15 and 20 percent to encompass a wide range of possible economic threshold requirements. Revenue requirements to achieve the required rate of return are assumed to be net of transportation or storage.

Structure of the Economic Analysis. Each project contained two cash flows (Figure 11): one for the success case and one for the failure case. The failure case assumed no production but did include costs associated with drilling. The success case assumed production based on P10, P50, or P90 reserves, drilling costs, and in some cases infrastructure costs. All cash flows and expenses were assumed to be in real 2010 dollars, implying no inflation adjustment was integrated into the model. Both success and failure cash flows were channeled through the fiscal system to obtain after-tax cash flows. Revenue from success case production for each year was tested against royalties, operating costs, allocated overheads, property tax, and production tax credits if any to see if producing gas for that project was still commercially viable; if not, production ceased. Success case after tax cash flow was weighted by the probability of success while the failure case after tax cash flow was weighted by the probability of failure. The two weighted after tax cash flows were then added to produce the expected after tax cash flow. The expected after tax cash flow for each project was discounted using the specified

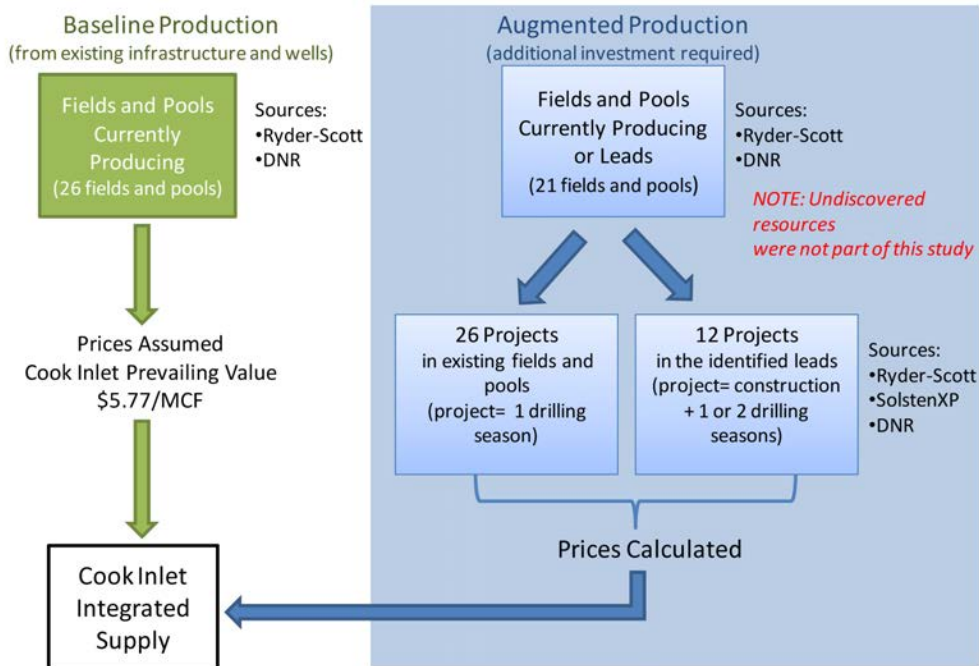


Figure 10. Economic Analysis Flowchart.

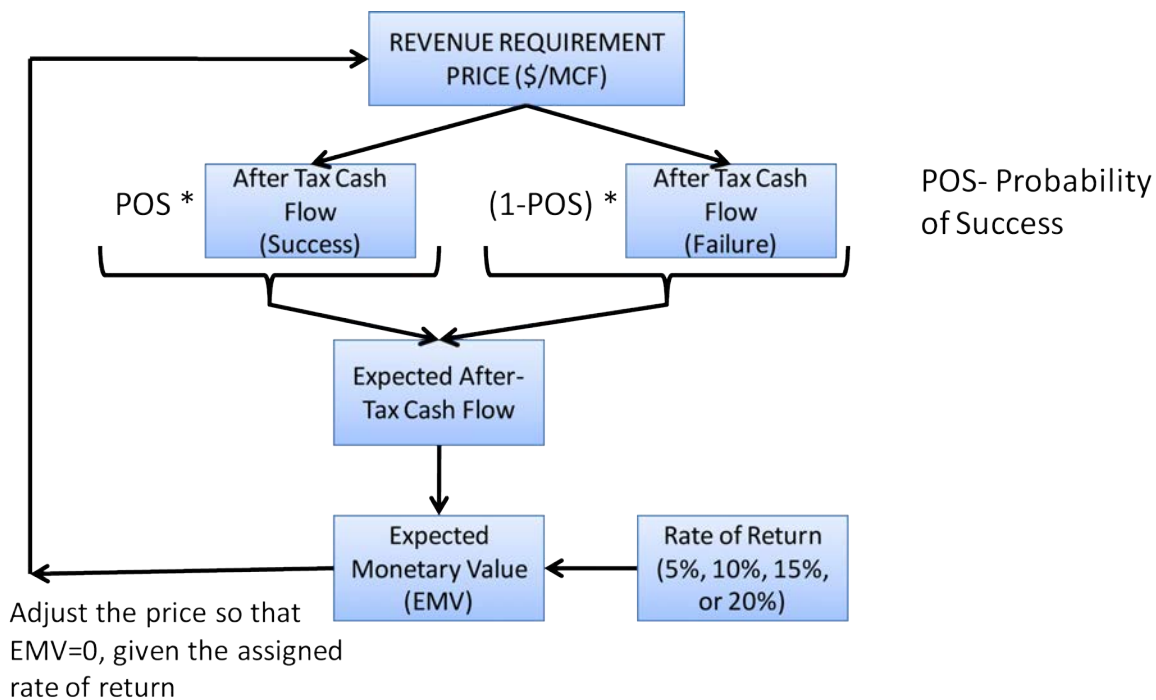


Figure 11. Revenue Requirement Calculation Flowchart.

rate of return, discounted expected after tax cash flow is referred to as expected monetary value or EMV. The revenue requirement in the form of \$/million cubic feet (MCF) was then calibrated so that the EMV at the assumed rate of return was equal to zero. The final revenue requirement (\$/MCF) is the required price that would allow earning the targeted rate of return. There were a total of 468 calibrated revenue requirement “prices” calculated for this study which came from 39 projects, three reserve-based production outcomes for each project, and three assumed rates of return (10, 15, and 20 percent) for each production outcome. In a similar process, EMVs (expected monetary value) were calculated based on discount rates of 10 and 15 percent, and a market value of current Cook Inlet prevailing value as reported by Department of Revenue (DOR) of \$5.77/MCF. In combination, revenue requirements as expressed as \$/MCF and NPVs provide two economic measures of potential future development projects in Cook Inlet.

Fiscal System. The current fiscal system was incorporated into the model to calculate after tax cash flows. The current fiscal system considerably mitigates the dry hole financial exposure. The revenue requirements generated in this study are net of transportation tariffs. Tax credits are applied in the year following the year in which qualification for these credits occurs. In cases where a tax credit is amortized over two years the last portion of the credit is applied two years after the year in which qualification occurs. The following summarizes the fiscal system used in this study.

- Royalties
 - 12.5% of Revenue
- Ad. Valorem Tax
 - 2% of undepreciated capital with utilization adjustment and a floor of

20% of gross capital

- Severance tax
 - Capped at 18 cents/MCF
 - Base = 25% of Revenue-Qualified Lease Expenditures
 - Progressivity
 - Progressivity capped at 50%
 - Below \$30/bbl³ equivalent = 0%
 - \$30 to \$92.5/bbl equivalent, 0.4% for every additional dollar above \$30
 - Above \$92.5/bbl equivalent, 25% + 0.1% for every additional dollar above \$92.5
 - Tax Credits Used
 - Well Lease Expenditure Credit (40% of qualified well lease expenditures). Applied as a transferable credit certificate.
 - Qualified Capital Credit (20% of qualified capital expenditures). Applied as two transferable credit certificates utilized in two consecutive years following qualification, each certificate for one-half the amount of total allowed credit amount.
 - Cook Inlet Jack Up Rig Credit (90% of costs to drill the first offshore well up to \$22.5 million) applied to three offshore projects with platform installation. Applied as a transferable credit certificate. If successful, 50 % of the credit repaid over ten years.
 - Loss Carry Forward Credit (25% of the loss from previous year which was not deductible). Applied against severance tax, the remaining amount applied as two transferable credit certifi-

cates utilized over two consecutive years following the loss, each certificate for one-half the amount of total allowed credit amount minus the amount that was applied against severance tax.

- State Income Tax
 - 9.4% of profit before federal tax, with ACRS⁴ based depreciation deduction.
- Federal Income Tax
 - 34% of profit after state income tax, with MACRS⁵ based depreciation deduction.

Monte Carlo Simulations

The previous sections of this report have outlined a tremendous amount of information gathering and some analysis to characterize the resources available to meet the natural gas demands of south-central Alaska. The characterization includes both point estimates and range estimates to gauge the level of uncertainty around the various resources (reserves, production rate) and the cost (capital, operations and maintenance) associated with bringing these resources to market. However, the previous sections have not addressed what resources will be needed when, how uncertainty affects timing and necessary revenue requirements, and what decision process will be used to allocate the resources to satisfy the demand. Monte Carlo simulation is a methodology that has been used in many applications to answer these questions and is utilized in this study.

- Basically, Monte Carlo simulations function by first admitting that the problem is too difficult to solve with traditional mathematical methods, and then forming a software model of

the system that represents the performance, capacities, and interdependencies of the system under investigation (Cook Inlet natural gas supply). The concept is that individual projects are characterized by statistical parameters that reflect their performance (probability of success, production rate, cost). Specific outcomes for each project are generated for each trial of the simulation by picking random values of these statistical parameters from the relevant statistical distribution. As the trial of the full simulation steps forward year by year it generates one possible future based on the uncertainty of each of the many project under consideration for meeting the demand requirements. The decision rules manage the simulated development path for each trial of the simulation such that the 90 BCF demand requirement is met with any excess supply being put into storage. The development plan for each simulation adjusted the project development timing as to minimize the use of storage.

The Monte Carlo simulators of this study generated 5,000 realizations (outcomes). After the simulation finishes, the accounting routine generates a percentile table based on the results of each or the 5,000 trials. The estimated cost variability and economic supply variability resulting from the simulations are presented as probability of non-exceedance graphs. For example, the 90th percentile value represents the value where there is a 90 percent probability that the value will be below the specified value.

The approach assumes the most economic project will be developed first and the least economic project last. It is also assumed that some projects with a revenue requirement greater than \$15/MCF are clearly uneconomic

⁴ ACRS - Accelerated Cost Recovery System

⁵ MACRS - Modified Accelerated Cost Recovery System

and will remain undeveloped in our modeling. For example, additional exploration is warranted for some “development leads” before development can be undertaken. As described previously, economics were evaluated at various rates of return to generate revenue requirements for the producers to recover their investment and achieve a particular rate of return. Utilizing the Monte Carlo Simulation technique, the individual project results are combined to generate a revenue requirement profile and an estimate when economic gas would no longer meet the demand requirements for south-central Alaska.

RESULTS

Following are the results of the analysis as described in the approach section of this report. The results are split into two areas of investigation: economic analysis and supply curve analysis.

Economic Analysis

This study considered two measures of economic viability: internal rate of return and expected monetary value, both as defined previously in this report. The first metric (IRR) is typically used to measure the rate of return of various investment targets given assumed price; this study uses an assigned IRR to obtain the revenue requirements measured in \$/MCF. The second metric (EMV) measures the size of the prize. As Monte Carlo analytic techniques were used for the IRR analysis (\$15/MCF cap), the results will be presented in two forms: expected values (Figure 12) and percentiles (Figure 13). The percentiles characterize uncertainty and therefore quantify an element of the total risk profile.

The cap of \$15/MCF screened out some of the conceptual projects. The projects that

exceeded the threshold were either subject to high geologic risk, based on currently available information, or were offshore gas-only new platform developments. New off-shore platforms and pipelines to onshore facilities require significant investment, and the offshore development leads evaluated in this study appear to be uneconomic if the sole source of revenue is gas production. Oil production is needed to supplement the revenue stream required to offset the high capital costs of new platforms and pipelines to onshore. As IRR is only one financial metric that must be met, the results for the revenue requirements to achieve these values should be interpreted as a measure of target price to incentivize investment. After all, sufficient investment may not be forthcoming. The 90th percentile chart (Figure 13) includes a measure of risk evaluation as it shows the revenue requirements at which 90 percent of the Monte Carlo results had a lower revenue requirement. As both geologic and cost uncertainty are incorporated in the Monte Carlo simulations, in some cases in the later years of the chart, the 90th percentile was influenced by the last economic project of the portfolio of projects that were completed in a prior year. Since this study is unable to address all the risks that producers face, the 90th percentile does not necessarily equate to a risk weighted price required to produce natural gas.

Expected monetary value was another metric used to evaluate project economics. Projects generally must meet both an IRR and EMV requirements at a minimum to secure investment funding. EMV was calculated at a price of \$5.77 (current Cook Inlet natural gas prevailing value as reported by the Alaska DOR) for all projects with a positive EMV at discount rates of 10 and 15 percent. Results are represented in the histogram of Figure 14, and should be considered alongside the IRR results of Figures 12 and 13.

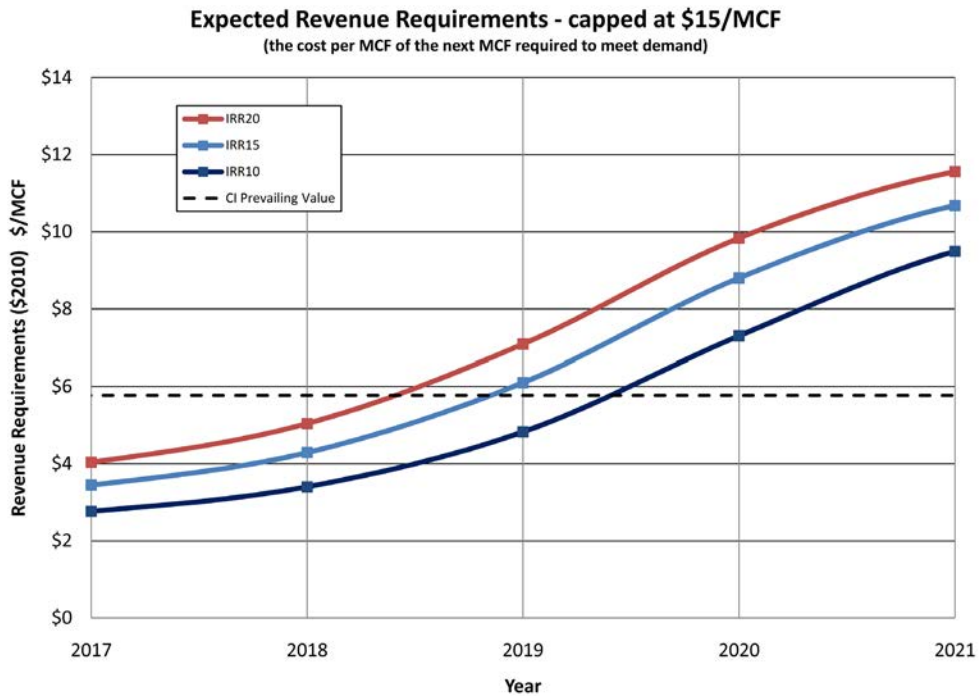


Figure 12. Expected (average) Revenue Requirements.

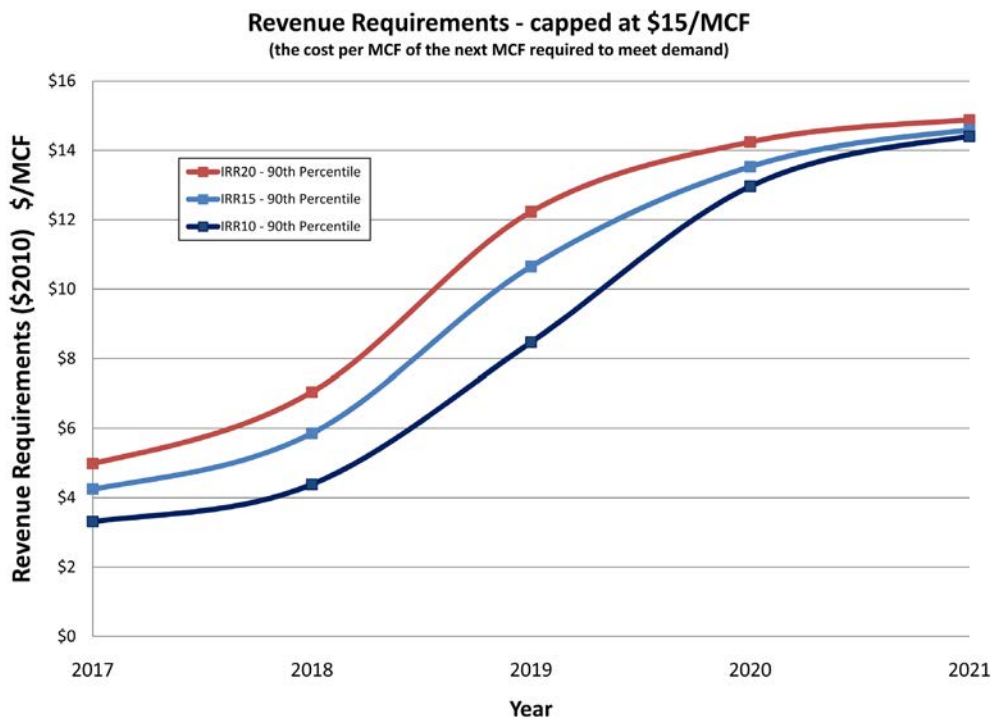


Figure 13. Revenue Requirements are at a 90th percentile. In the Monte Carlo simulation, 90% of the results were lower (10% higher).

The IRR results strongly suggest that economic natural gas is available to be produced from the Cook Inlet Basin. However, some of the EMVs are small compared to other projects available for investment worldwide; hence available capital may be reallocated elsewhere to projects with higher EMVs or require a price higher than suggested by a particular internal rate of return target to effectively spur capital investment in Cook Inlet.

Supply Curve Analysis

Supply curve analysis investigates when supply requirements can no longer be met from the Cook Inlet basin from resources identified in the 2009 DNR study Preliminary Engineering and Geological Evaluation of

Remaining Cook Inlet Gas Reserves as modified in this study (see “Conceptual Development” section, Figure 7). The Monte Carlo techniques employed in this study allow for quantification of the geologic and production uncertainties of the identified resources. The following supply curve (Figure 15) shows select percentiles by year of when Cook Inlet Basin will no longer be able to support the 90 BCF assumed consumption, given IRR requirements are met and projects above the \$15/MCF threshold are not included.

The supply curve reflects the level of geologic and engineering uncertainty. For example, if the targeted investments are made (this is not a certainty) and production is less than expected, there is an associated 90 percent probability that those capital investments

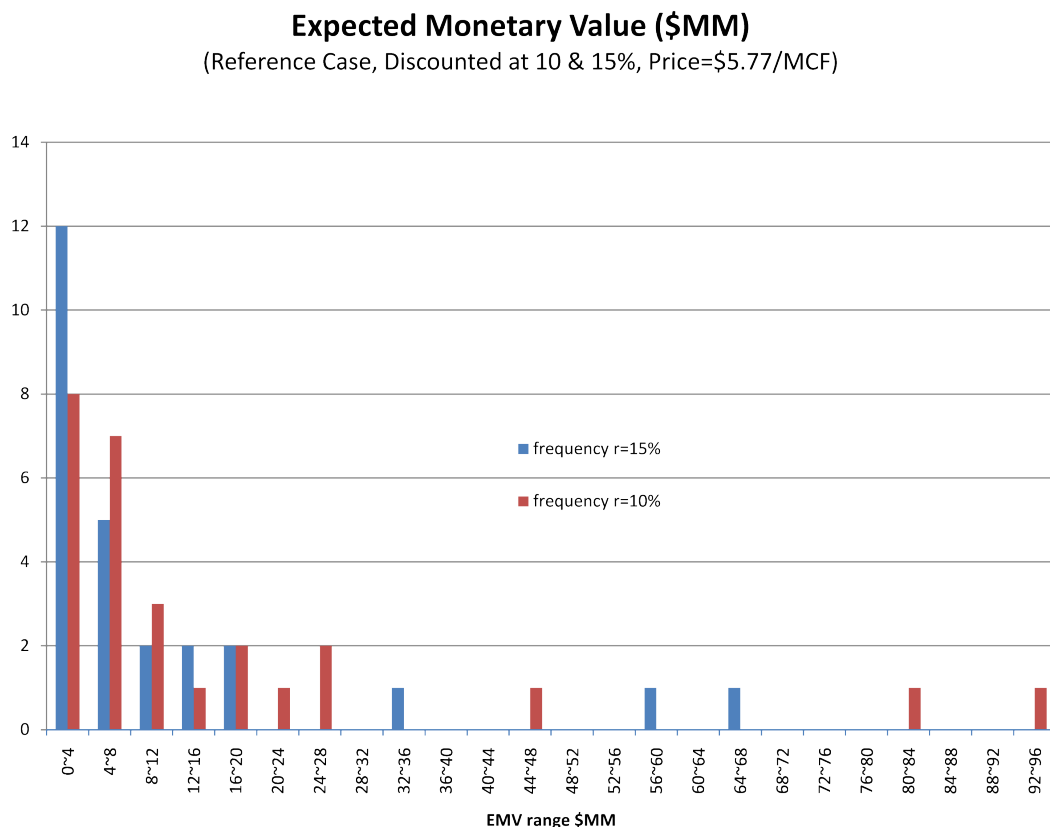


Figure 14. Expected monetary value for projects based on a prevailing value of \$5.77 at a discount rate of 10% and 15%.

will be sufficient to meet the 90 BCF/yr requirements until at least 2018. However, if production from these investments is greater than expected, there is an associated fifteen percent probability those same investments could supply the 90 BCF/yr requirements until 2021.

new one?” In both cases we have been served well and the prospect for more years is likely if we continue to invest. Failure to provide sufficient investment will accelerate the end date. Conversely, even if we were to continue to invest, at some point it will become more economical to buy a new truck or in case of gas supply to import natural gas from another source.

CONCLUSIONS

With over 40 percent of the state’s population residing in south-central Alaska, the question on our minds is “how long will it take before Cook Inlet basin will no longer provide sufficient natural gas to meet regional needs?” This is not unlike a similar question: “when will I replace my 1990 pickup truck with a

The results of this study provide two key conclusions:

- Given currently available information (and assumptions made in this study), absent any exploration success the Cook Inlet basin is capable given sufficient continued investments of supplying the regional natural gas needs

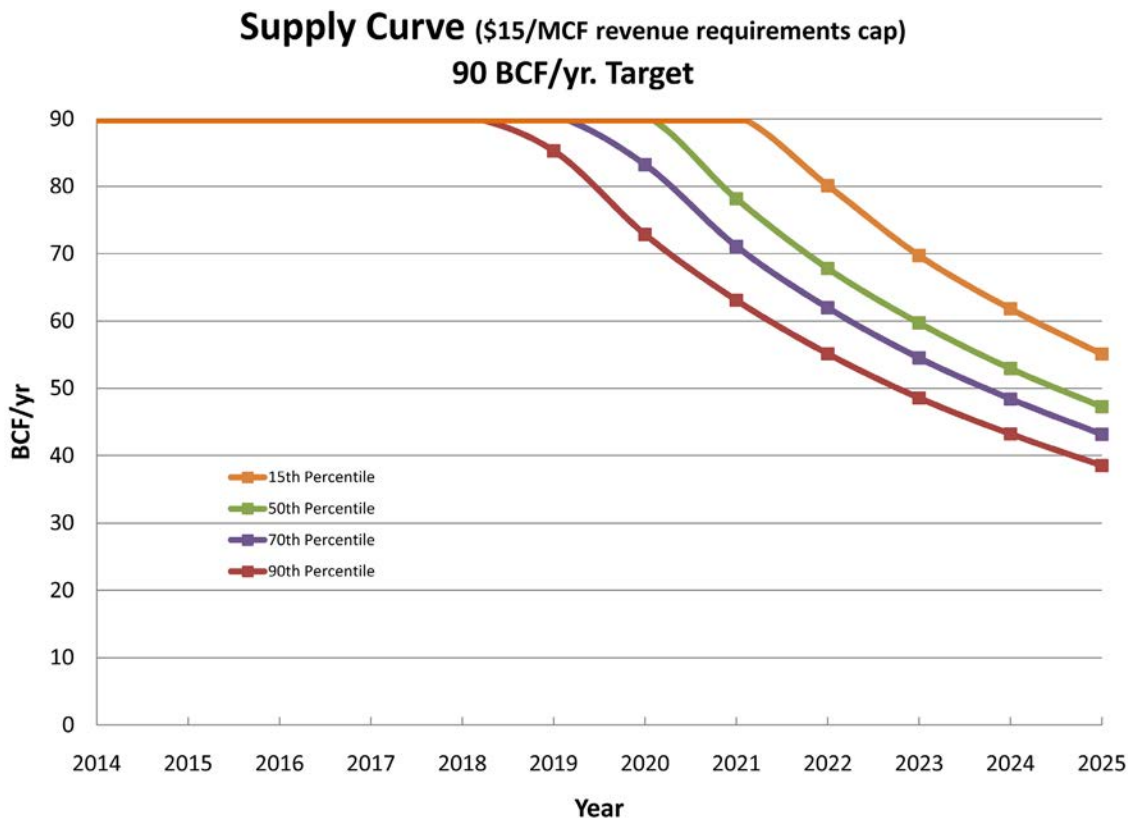


Figure 15. South-central Alaska natural gas supply curve. For the 90th percentile line, 90% of the Monte Carlo results exceeded the value plotted. For the 15th percentile line, 15% of the Monte Carlo results exceeded the value plotted (85% lower).

until 2018-2020 at a price below that of currently contemplated alternatives (Figure 13). However, failure to make appropriate investments in lockstep with demand requirements will necessitate alternative sources of natural gas to be made available sooner. Therefore, transition to alternative sources of natural gas may begin to occur before the 2018-2020 timeframe as part of a comprehensive supply and risk management plan.

- Natural gas storage will play an increasingly important role in optimizing and managing deliverability and economics of the natural gas supply for south-central Alaska. Just-in-time production (reducing the amount of time between investment and return) improves the economics of supplying natural gas. If gas purchases can be made in summer in advance of peak winter needs, storage allows these dynamics to be managed effectively by allowing production in summer to exceed the demand and storing the excess production until it is needed in winter.

While the south-central Alaska natural gas market has not been as commercially active as the lower 48, it has worked to meet the needs of residents. To date producers have fulfilled all their contractual requirements and are expected to do so in the future. The analysis stops short of producing a price forecast that includes all the complexities (NPV, IRR, contract terms and conditions, risk management policy, etc) influencing the regional natural gas market. However, the basin-wide economic analysis based on IRR and NPV parameters suggests that natural gas from the Cook Inlet basin could be available to meet intermediate term needs with continued investments.

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