Cook Inlet Natural Gas Market Outlook with Incremental Demand from Donlin Mine

Developed for: Cook Inletkeeper

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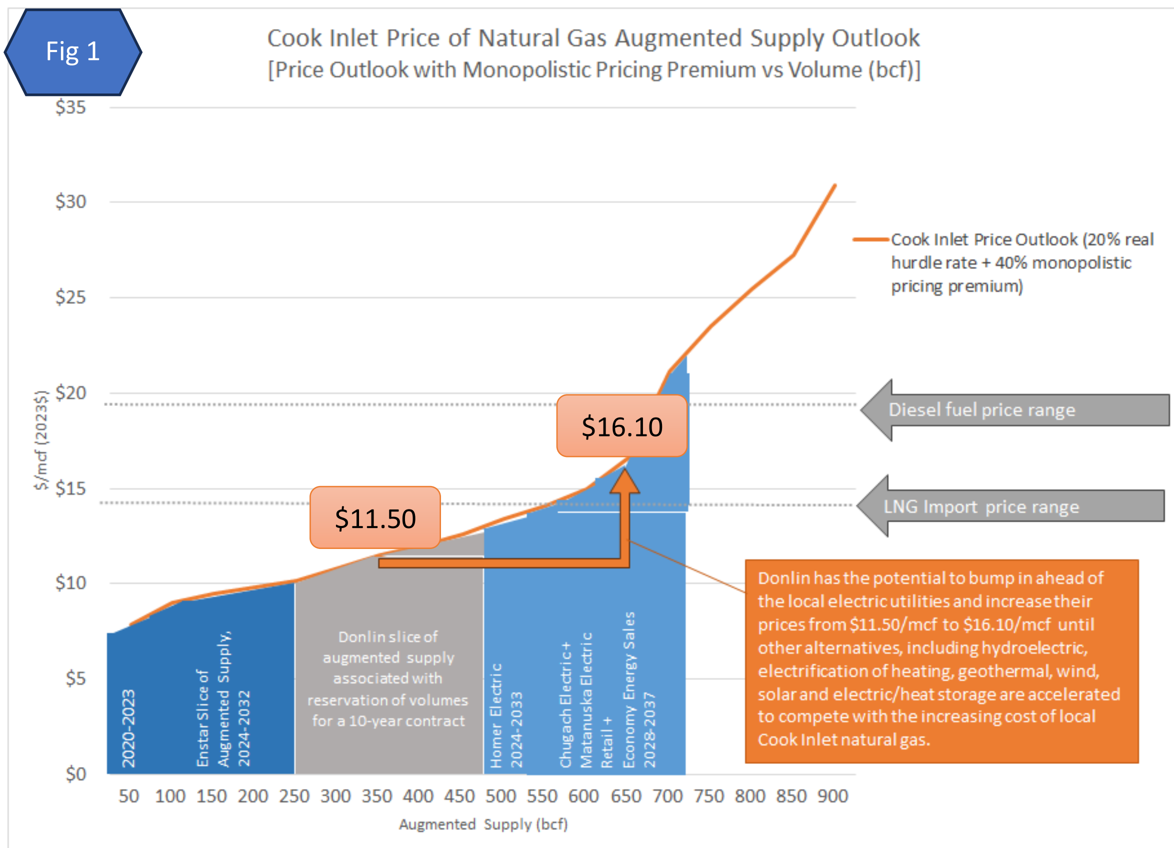
Executive Summary

The Donlin Mine's most recent technical report calls for an increase in its proposed natural gas pipeline to a 14-inch diameter line designed to supply the Donlin operation with 1,550,000 cubic meters per day or 20 bcf per year – which is roughly 30% more than the current natural gas demand from heating, electric and refinery sector customers.[1]

If Dolin's investors seek competitively priced natural gas supplies to support a favorable economic outlook for their investment in the mine, they will seek to procure the portion of the limited remaining local Cook Inlet natural gas supplies that are less expensive than importing LNG into the Cook Inlet. Unfortunately, with increasingly limited local natural gas supply *at below LNG import prices*, Donlin may effectively buy out the last of the affordable local Cook Inlet natural gas and bump the local electric utilities to paying a premium above LNG import prices – until such time as competitive LNG import volumes can be secured. The net result could be to drive local electric utility gas supply costs from $11.50 to $16.10/mmbtu [see Figure 1 below].



[1] The 20 bcf/year demand estimate is for the mine and its operations and does not including any natural gas used in oil & gas field operations associated with that demand or any natural gas required to run compression systems to enable transport of natural gas from Cook Inlet to the Donlin Mine via a 315-mile pipeline. The combination of oil & gas field operations and pipeline transportation energy could amount to ~3 bcf/year for a total natural gas wellhead demand of 23 bcf/year associated with the Donlin Mine. See Figure 4 Potential Source of Cook Inlet Natural Gas Demand below.

Source: MAFA Analysis (2023)

The Donlin Mine's purchase of a competitively priced natural gas supply option sufficient to meet its *projected demand for natural gas from the increasingly limited local supply available in the Cook Inlet* within the next few years has the potential to increase local natural gas prices for Homer, Anchorage, Mat-Su and Fairbanks electric utilities and their customer's electrical bills on the order of $265 per year per household prior to effective competition from LNG imports – or new renewable to displace declining local natural gas.

In *partial* mitigation of Donlin's demand triggering a significant increase in Cook Inlet electric bills, Donlin Mine LLC and its owners, Barrick Gold US Inc and NovaGold Resources Alaska Inc, could adopt a good neighbor policy and:

- provide funding to help pay down the price of importing LNG into the Cook Inlet *by paying for its fair share of the cost of LNG import infrastructure and associated storage* in the Cook Inlet[2], and
- provide funding for converting neighboring Calista Region village power plants to
    - natural gas and converting neighboring village residential, commercial, and school heating systems to natural gas [analogous to the development of local natural gas energy systems for the Alaska North Slope Village of Nuiqsut], or
    - converting local villages to electric heat based on local wind/hydro renewable energy resource development [analogous to Kodiak], and
- provide a contribution to an escrowed mitigation fund to cover the cost of GHG emissions abatement (reduce flaring, recycle gas, potential development of methanol production) from the methane supply chain (local and imported LNG).

[2] By paying a fair share of the capital and operating costs of local infrastructure to support LNG imports and storage, Donlin could help reduce local gas and electric bills on the order of $50 a year.

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Introduction

The purpose of this study is to estimate the impact of the Donlin Gold Mine natural gas demand on the prevailing prices for Cook Inlet natural gas and the associated impact on local residential natural gas heating and residential electric bills.

This study updates and extends prior studies of Cook Inlet Natural Gas supply, demand, break-even prices and develops market prices and estimates the change in price associated with Dolin demand for natural gas by:

- Updating Cook Inlet natural gas demand projections
- Updating the estimated costs for the exploration and development of local Cook Inlet natural gas
- Estimating the "monopolistic pricing premium" associated with the market power of the dominant supplier, Hilcorp, which has consolidated the market over the past decade and now has roughly 90% of the production in the Cook Inlet.
- Updating and extending cost estimates and a market price premium associated with importing LNG into the micro market of Cook Inlet from potential LNG supplies on the Pacific Rim.
- Comparing the updated and extended Cook Inlet natural gas price outlook with and without the incremental demand associated with the Donlin Mine and extending those the price increases / decreases associated with Donlin Mine to estimate their impact on annual residential electric and heating bills for local electric and natural gas utilities.

Updating Cook Inlet natural gas demand

- In a prior study of Cook Inlet Natural Gas Availability [2016], Redlinger, et al., assumed the "base consumption" associated with electric generation, residential and commercial (heating) use, oil and gas operations, existing industrial users [Nikiski oil refinery], and the then current Interior gas use at roughly 80 Bcf per year.[2] Since then, the Interior Gas Utility (IGU) has entered into a long-term agreement to procure natural gas supplies from Hilcorp Alaska North Slope supplies and local consumption has cycled through a COVID lull and recovery. In addition, local electric utilities have announced plans to accelerate their exploration and development of renewable electric generation options which are slated to further reduce natural gas demand. This report updates and extends prior demand estimates and synthesizes an independent estimate of demand outlook in the **Cook Inlet Natural Gas Demand** section of the report.

Updating Estimated costs for the exploration and development of local Cook Inlet natural gas

- In a prior study of Cook Inlet Natural Gas Availability [2016], Redlinger, et al, estimated the "break-even price" for augmented supply over a range of real hurdle rates and probability cases. This report updates and extends the prior price-volume supply curve estimates based on: upstream sector price inflation, changes in upstream capital market risk adjusted hurdle rate requirements, changes in well workover and new well productivity and activity levels. The updates and extensions are described in the **Cook Inlet Natural Gas Supply** section of the report.

Estimating the monopolistic pricing premium

- Prior Cook Inlet natural gas market studies have elided the extent to which the quantum leap (2012-2014) and continued trend toward increased market concentration on the Cook Inlet local natural gas exploration and development leasehold production supply side (now roughly 90%, HHI ~8100) may yield incremental monopolistic pricing power above what is required to cover the incremental risk-adjusted cost of capital. This report develops an estimate of the "monopolistic price premium" as a function of market concentration and applies that to the forward-looking price of supply estimates in the **Cook Inlet Supply / Demand Balance – Monopolistic Price Premium** section below.

Updating and extending the estimates for the cost of importing LNG into the Cook Inlet

- Chugach Electric engaged Black & Veatch to conduct a Chugach Gas Supply Option and Market Assessment (June 2023) that describes cost estimates for importing LNG into the Cook Inlet. This report updates and extends those LNG import cost estimates to include an explicit allowance for local natural gas storage and a small market price premium. If and when imported LNG options get developed, the resulting imported LNG price competes with local energy sources and provides a price umbrella under which various energy resource alternatives compete.

Estimating the incremental impact of Donlin Mine on Natural Gas Market Outlook

- NOVAGOLD engaged Wood Canada Limited for a Technical Report on the Dolin Gold Project (2021) which indicates the volume of natural gas transported from the Cook Inlet to Donlin Mine is roughly 20 bcf/year. The report describes a six-year development time frame following a final investment decision (FID). This report assumes the Donlin enters into a contract to reserve competitively priced local Cook Inlet natural gas volumes prior to a Final Investment Decision (FID) in the mid-2020s. The incremental impact of the Donlin natural gas demand on Cook Inlet natural gas prices and electric and gas heating bills is then derived from the impact of Dolin's reserved demand on the price of supply estimate.

Cook Inlet Natural Gas Demand Outlook

The base production over the past three years has been running near 76-77 bcf/year in the Cook Inlet [MAFA review of AOGCC Production Data and DNR reports, through October 2023].[3]

For this study, we've assumed that the "base consumption" from natural gas and electric utilities, oil refining, and associated oil and gas lease operations in the Cook Inlet will, especially in light of the potential for local price increases, appears likely to trend *below* 76 bcf/year in the next decade – especially in light of further demand erosion associated with conservation/efficiency gains in the face of increasing prices and increases in renewable electric generation resources in the next decade supported by substantial federal investment tax credits for clean energy.

Given the relatively high price of Cook Inlet natural gas and the outlook for price increases, we do not expect either the Kenai Fertilizer Plant or a Kenai LNG export facility to return to consume local Cook Inlet natural gas supplies.

For this study, we note that the *Wood Canada Limited (Donlin), S-K-1300 Technical Report Summary on the Donlin Gold Project*, Section 15.10 Natural Gas Pipeline, Alaska, USA, November 30, 2021, reports:

> *15.10 Natural Gas Pipeline*
>
> *The 14-inch (356 mm) natural gas pipeline proposed for the Project would be approximately 507 km long. It would commence at the west end of the Beluga Gas Field, approximately 53 km west of Anchorage at a tie-in near Beluga and would run to the Project site. Donlin Gold LLC advised Wood that the proposed pipeline route crosses an area with no significant pre-existing infrastructure and does not follow any existing utility corridors.*
>
> *The pipeline would receive booster compression supplied by one compressor station located at approximately mile post 0.4. No additional compression along the pipeline route would be required.* ***The pipeline would transport approximately 1.55 million m^3/d of natural gas****.* ***[MAFA emphasis added]***

Based on this public record disclosure, we assume that the Donlin Mine consumption is roughly 20 bcf/year.[4] Working up the supply chain from the natural gas demand at Donlin, we assume that the compression station plus upstream oil & gas lease operations associated with sustaining new incremental demand from the Donlin Mine may total on the order of 1.5 bcf/year for a total local Cook Inlet natural gas production requirement of 21.5 bcf/year to serve the Donlin Mine.

For context, the resulting Donlin Gold natural gas demand estimate of 21.5 bcf/year is ~**50% larger** than that of the Chugach Electric Cooperative (~14 bcf/year) and approaches ~30% of the base consumption for the Cook Inlet [See Figure 2 Potential sources of Cook Inlet natural gas demand below].

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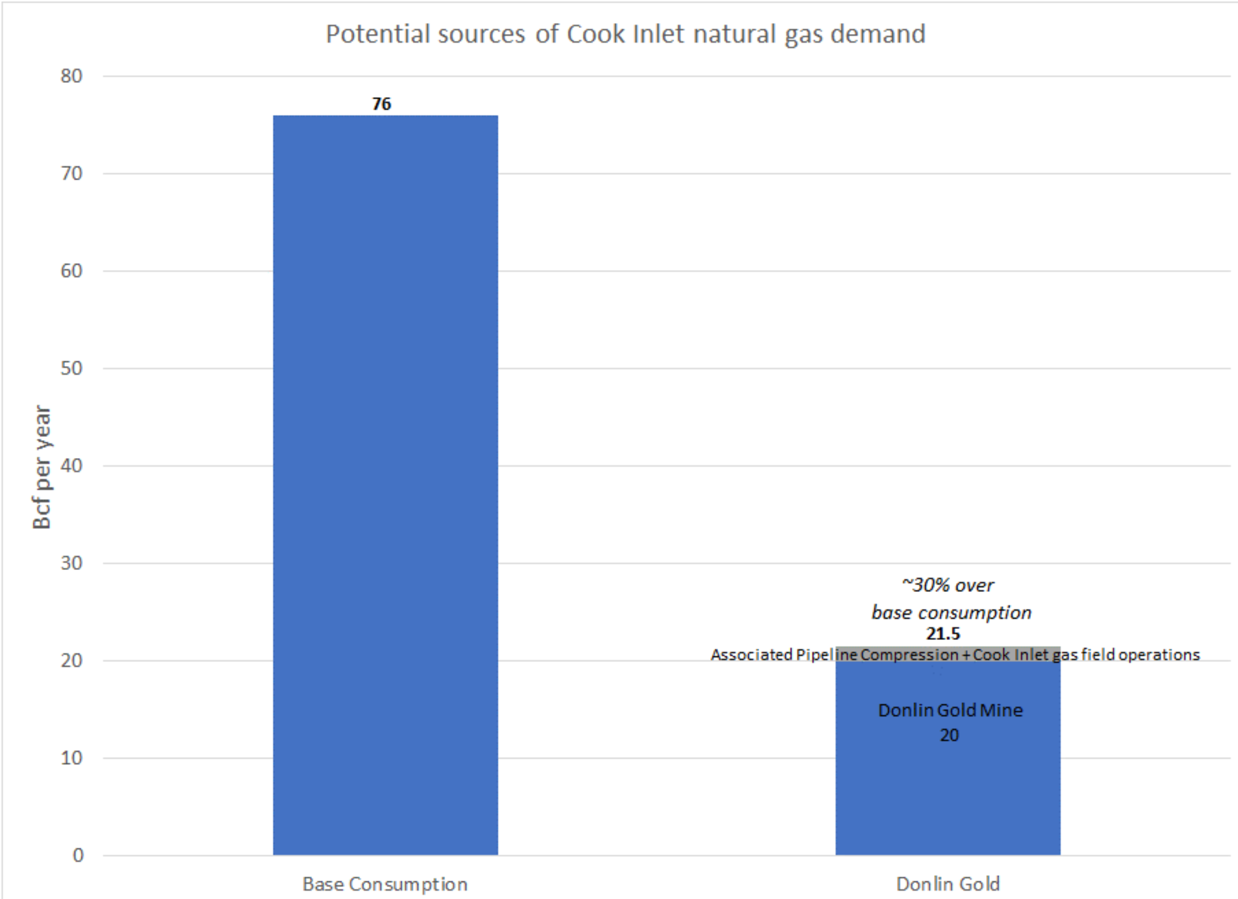
[3] Base production = consumption + transport + field operations

[4] 1.55×10^6 m^3/day * 365 days/year * 3.532×10^{-8} bcf/m^3 = 20 bcf/year

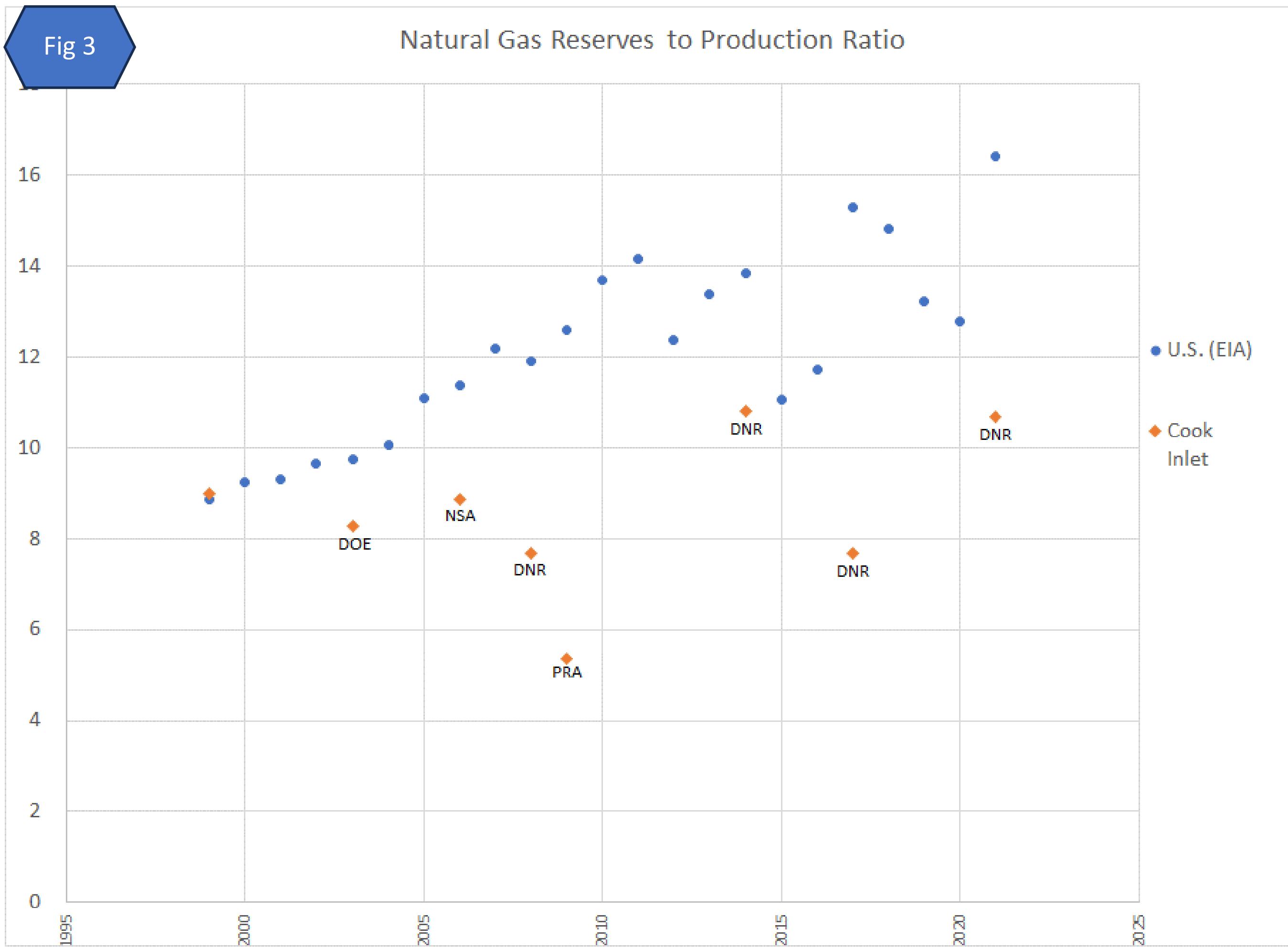
Figure 2. Potential sources of Cook Inlet natural gas demand (MAFA 2023)



Sources: MAFA Estimates (2023) based on AOGCC Cook Inlet Production Data; EIA Alaska Natural Gas consumption, RCA Public Utility Cost of Power / Cost of Gas Quarterly Reports; DNR Reports to the Legislature (2023), §15.10 Natural Gas Pipeline, S-K-1300 Technical Report Summary on the Donlin Gold Project, Alaska, USA, November 30, 2021, Wood Canada Limited (Donlin)

Cook Inlet Natural Gas Supply Outlook

While recent headlines may suggest that the Cook Inlet may be running out of natural gas in response to the dominant supplier, Hilcorp, expressing malaise with local Cook Inlet natural gas market prospects[5] – the history of natural gas in the Cook Inlet suggests that while the reserves to production ratio has periodically dipped below 8, *price increases combined with the deployment of new capital and new technology have driven the natural gas reserves to production ratio to levels comparable to the highest levels estimated over the past 20 years* – as evidenced in the most recent estimate from DNR which placed the reserves to production ratio at over 10 in its 2022 report. [See Figure 3 Natural Gas Reserves to Production Ratio, U.S. and Cook Inlet below].



Source: MAFA Compilation of Reserves, Production and Reserves/Production Ratio Reports (2023).

This study starts from the premise that the local Cook Inlet region continues to contain significant energy resources across the subsurface (oil, natural gas, geothermal), ocean currents (Forelands high velocity

[5] See Petroleum News, "Hilcorp says we're bored with the Cook Inlet, we're excited about [taking your Cook Inlet subsidies for natural gas and getting out of our Cook Inlet asset retirement obligations – Commissioner Boyle has signed off on allowing us to walk away and let our Cook Inlet platforms rust in place rather than cleaning up after ourselves and financing]56 growth on the North Slope and beyond", date

currents), snow/ice/water falling back to the ocean (hydro and pumped storage hydro), and surface (wind, solar PV).

This study builds on the geologic and economic studies of the Department of Natural Resources developed in their Cook Inlet Natural Gas Availability (2018 report, 2016$ data) that indicate that the Cook Inlet is highly likely to contain additional natural gas reserves associated with higher prices that enable more exploration, development and well workover and productivity enhancement work – a classic supply curve.

INSERT SUPPLY CURVE

Figure 4

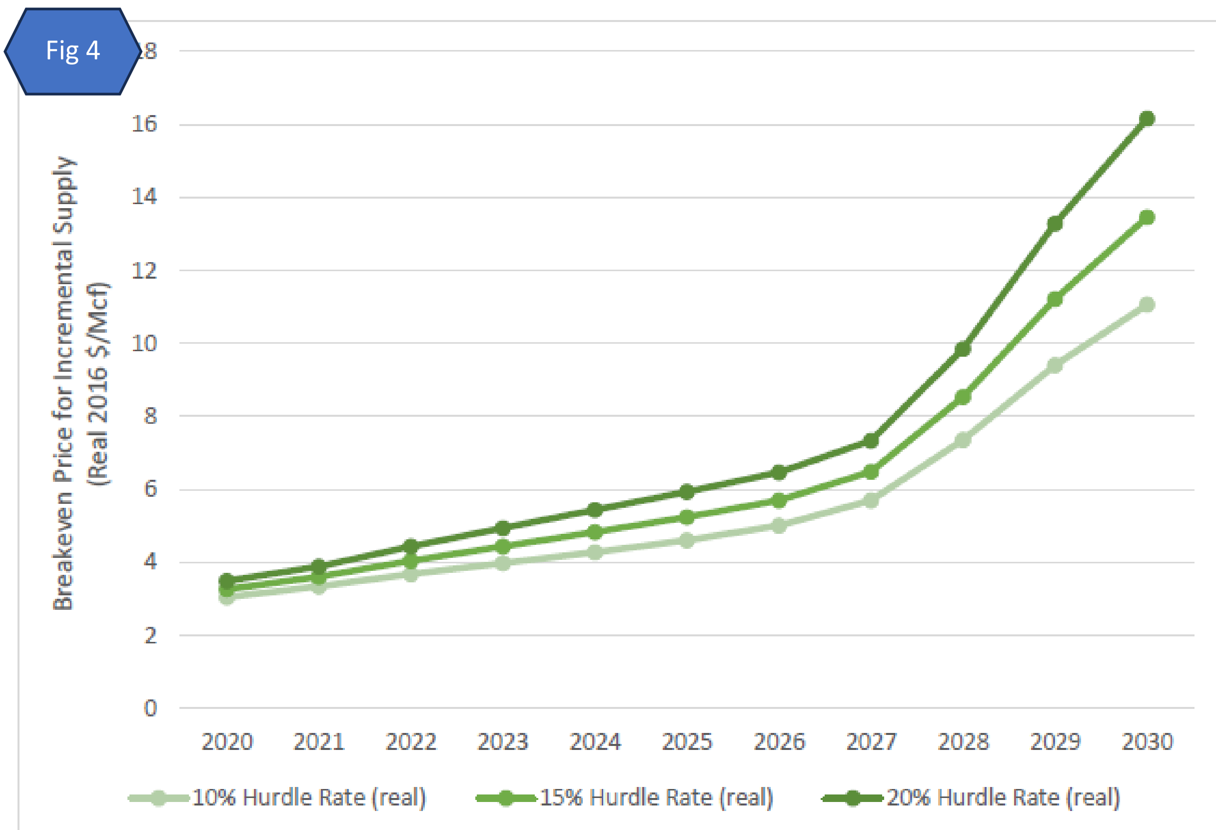


Figure 13. Natural gas breakeven prices (mean case) over time under 80 Bcf/year demand

Source: Cook Inlet Natural Gas Availability, State of Alaska, Dept. of Natural Resources, Division of Oil & Gas, Redlinger, Burdick, Gregersen, with contributions from Raisharma, Kroushkop, March 2018

MAFA Synthesis of Supply / Demand Outlook (2023)

Introduction

Once again, Cook Inlet energy consumers and local politicos have been encouraged to believe that they are poised on the precipice of a local Cook Inlet natural gas shortage.[6]

If we look carefully at the public record, we can observe the Cook Inlet natural gas to reserves estimates from the previous 20 years, from which we note that **the Cook Inlet natural gas reserves to production estimate from the most recent State of Alaska Department of Natural Resources, Division of Oil & Gas Reserves 2022 Study (January 2023) was 10.7**, a ratio which is:

- ***the highest*** *Reserves/Production ratio across the period of record (2000-2023)*
- **25% above the average** over the period (2000-2023), and
- 99% above the lowest Reserves/Production estimate of 5.4 from PRA in 2009, an estimate which:
    - precipitated a substantial run on the public treasury to provide subsidies to support Cook Inlet natural gas exploration [HB280] which:
        - cost the State of Alaska on the order of $1-2 billion[7] and
        - appears to have shifted drilling activity from production toward exploration wells without any material impact on natural gas reserves relative to production[8]

What's different in 2023 and beyond?

- Supply Side
    - Increasingly high concentrated near monopoly market
    - The dominant near monopolist supplier, Hilcorp, announces disinterest in continued exploration and development, notwithstanding the DNR DOG 2018 Cook Inlet Natural Gas Availability study which suggests the next tranche of augmented supply may be yielding on the order of 60% returns [Figure 11].
    - The remaining micro-cap natural gas exploration and development enterprises appear challenged by a variety of local market conditions, highly variable local labor, supply chain variability and a high and increasing cost of capital.
- Demand Side
    - Demand has continued to decline relative to prior projections (post LNG and Fertilizer plan exits) – with local demand down by roughly 20% from 2009 projections that

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[6] See Petroleum News, "running out of natural gas in the Cook Inlet", string cite…

[7] Cite Petroleum News estimates of the total amount of the State of Alaska Cook Inlet Natural Gas Exploration subsidies under HB280 (2010).

[8] See Table XX in Appendix XX.

included estimates of the natural gas demand reductions associated with new higher efficiency natural gas turbines deployed by ML&P and Chugach Electric in the 2010s.

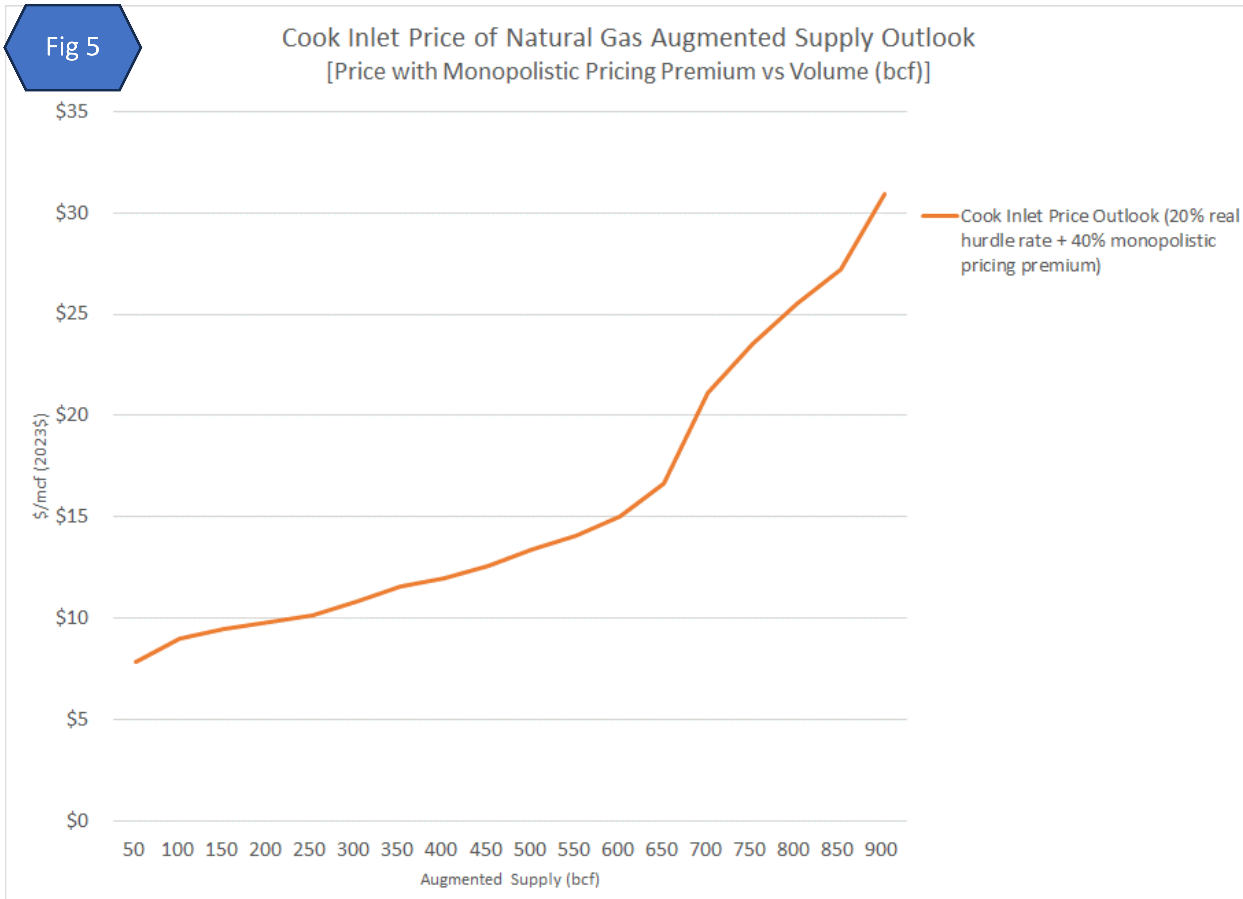
- Supply & Demand Balance
  - In contrast to the relatively robust estimates from DNR in 2018 and 2022, prior estimates of the prevailing values for Cook Inlet natural gas in the 2010 era appear to have consistently overestimated future prices (on the order of 50%) due in part to:
    - 1) overestimating upstream inflation,
    - 2) underestimating productivity improvements associated with development wells relative to the previous trend line, e.g., PRA March 2010, Figure 13: BCF/well completion,
    - 3) underestimating the efficiency gains by local electric utilities associated with replacing old natural gas turbines with new high efficiency units,
    - 4) underestimating local natural gas heating price sensitivity,
    - 5) underestimating local electric utility substitution away from natural gas, e.g., Fire Island Wind Farm, Bradley Lake Battle Creek.
- Beyond 2023[9]
  - Chugach Electric has accelerated its exploration of:
    - Renewable energy alternatives to diversify away from natural gas fuel supply, e.g., Wind, Solar and Hydro resource project assessments, and
    - LNG import options
  - Golden Valley Electric is exploring the closure of the 50MW Healy 2 coal fired power plant and adding 40MW of natural gas and 40MW of wind.
  - Homer Electric is exploring increasing renewables, including hydro, wind and solar
  - Matanuska Electric is exploring carbon intensity reductions, including hydro, wind, solar and fossil fuel with carbon capture and sequestration options.

[9] See "Goals and Plans of Alaska's Railbelt Utilities", McKittrick and Higman, 2023

Estimated costs & prices for increasing local Cook Inlet natural gas reserves

Combining inflation, increase in cost of capital and local monopolistic pricing to update the DNR supply curve from 2016$ to 2023$, we estimate the local Cook Inlet Natural Gas supply curve (2023$) starting at $8/mmbtu at 60 bcf of increment supply that ramps up to $20/mmbtu at 600 bcf of incremental supply:

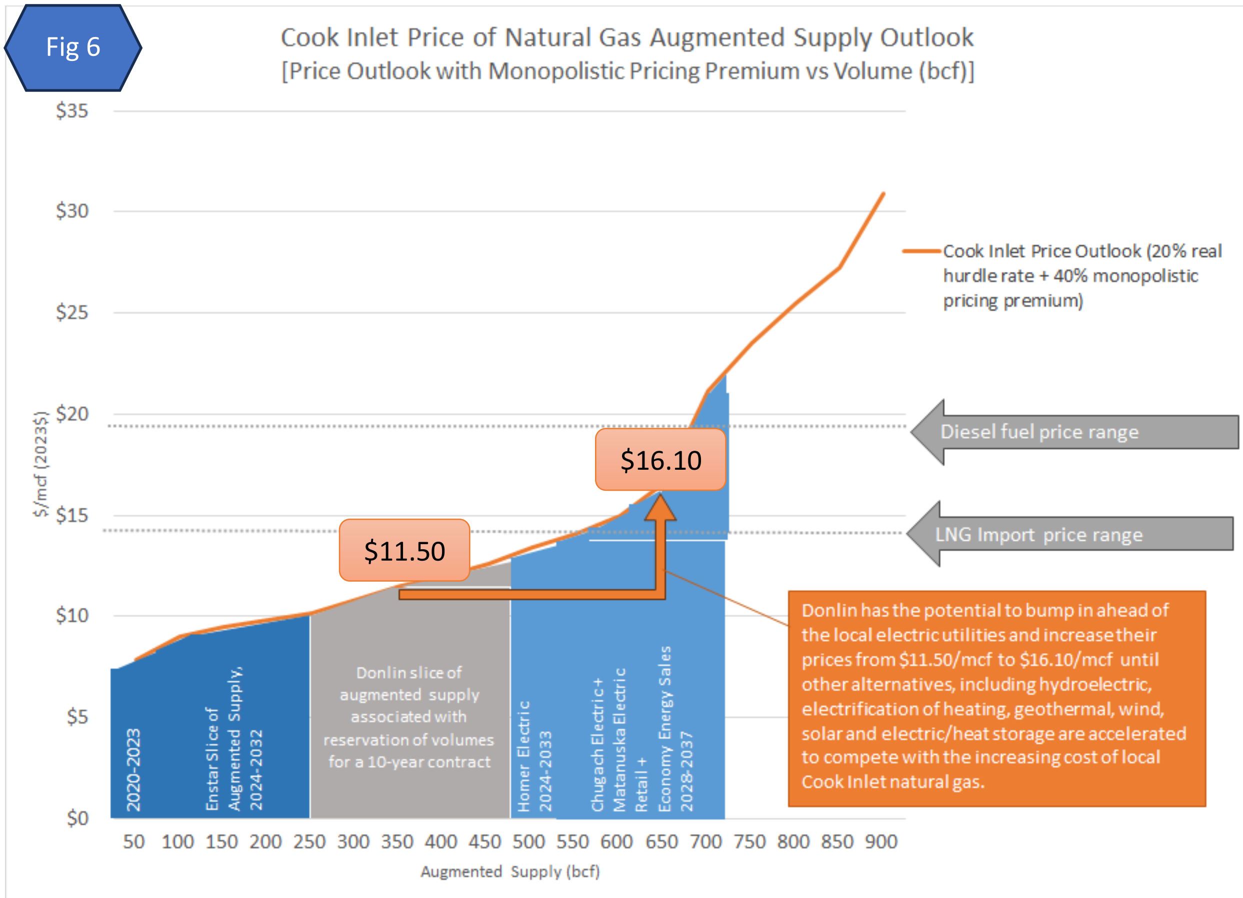
Fig 5



Source: MAFA Analysis, Appendix (2023)

Supply Curve Update With Donlin

If we now add the prospect of a supply contract option for the Donlin Mine from the remaining competitively priced [below LNG imports] local Cook Inlet Supplies, we find that Donlin demand has the potential to bump in line and increase *local* electric utility natural gas prices from $11.50/mcf to $16.10/mcf – resulting in an increase of roughly $265/year for a typical residential electric utility customer.



Source: MAFA Analysis, Appendix (2023)

Eventually LNG imports and other energy diversification strategies, e.g., low impact hydro, electrification of heating (comparable to SE Alaska), geothermal, wind, solar and electric/heat storage may be accelerated to compete with the increasing cost of local natural gas from the Cook Inlet and mitigate the impact of Donlin's potential procurement of competitively priced local Cook Inlet natural gas.

Findings & Conclusions

If Donlin proceeds through permitting and development stages according to the timeline described in the NOVAGOLD Technical Report Summary (November 2021), it will generate on the order of 22 bcf/year in new demand for natural gas in the Cook Inlet, roughly 50% more than the current level of demand from Alaska's largest electric utility, Chugach Electric, within the 2030-time frame.

If Donlin, consistent with its obligation to provide a return to shareholders, reserves a competitively priced natural gas supply option *prior to* a final investment decision (circa 2024-2026), it has the potential to effectively reserve the remaining local Cook Inlet natural gas supplies that are priced below current LNG import price estimates (Black & Veatch, 2023; MAFA, 2023).

Because local natural gas buyers, e.g, local electric utilities, Marathon oil refinery, local gas utility, do not yet appear to have committed to an LNG import project, the earliest a competitive LNG import project might be expected to come to fruition is on the order of four years (Black & Veatch, 2023; MAFA, 2023). This leaves the local electric utilities, e.g., Homer, Chugach, Matanuska and Golden Valley, facing the prospect of paying a monopolistic premium for local Cook Inlet gas supplies that could very well exceed an LNG import price umbrella until such time as other energy supply alternatives, e.g., an LNG import prospect, other local energy resources, e.g, hydro, geothermal, wind, solar and electric/heat energy storage become more fully developed alternatives to local Cook Inlet supplies.

Homer, Chugach, Matanuska and Golden Valley Electric may be paying a local Cook Inlet monopolistic premium until such time as local buyers of gas have a viable LNG import alternative, circa 2029-2030.

The net effect of Donlin buying up local Cook Inlet CH_4 supply is an increase in local electric bills on the order of $265 per year until such time as LNG imports ramp up to effectively cap the local monopolistic premium.

Donlin has the potential to modestly mitigate Cook Inlet LNG import prices if it constructively joins the negotiations and invests in an LNG import infrastructure project and import supply chain to help spread fixed costs across more demand and reduce unit prices for all buyers (residential, commercial, electric utility, refinery, oil & gas operations). **If** Donlin shares its contribution to the economies of scale of LNG import infrastructure with other buy-side stakeholders (electric & gas utilities, oil refinery), the price of importing LNG could be lower and translate to a decrease in the median household expenditure on *electric and natural gas heating* on the order of $50 per year.

Appendices

Cook Inlet Natural Gas Demand History

Cook Inlet Natural Gas Supply History

Cook Inlet Natural Gas Supply & Demand Balance History & Review of Prior Projections

Renewable Energy Alternatives

Federal Renewable Energy Investment Tax Credits

Estimated costs and prices for the exploration and development of local Cook Inlet natural gas resources

- Historic local Cook Inlet natural gas supply curve
- Adjustments to 2016$ Supply Curve to update it to 2023$ Supply Curve
  - Capital & Operating Cost Inflation (2016 to 2023)
  - Cost of Capital (2016 to 2023)
  - Exploration and development well productivity (2016-2023)
  - Monopolistic Supply Side Price Premium (2023+)

Donlin Gold Mine Natural Gas Pipeline, Plan of Development, Revision 1, December 2013

References

Mark A Foster (MAFA), Selected Experience

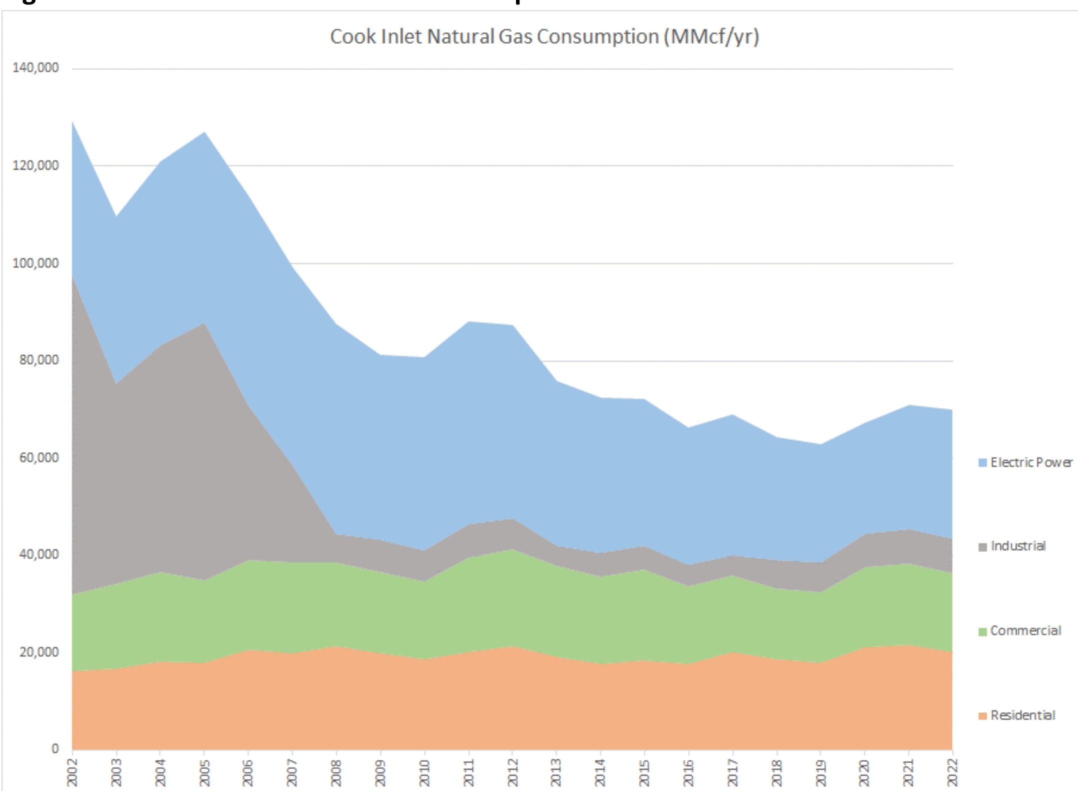
Cook Inlet Natural Gas Demand History

For decades prior to 2005, an LNG export facility and a fertilizer export plant were the largest industrial customers of local Cook Inlet natural gas. More recently, the industrial category currently includes oil & gas lease and plant production as well as continued oil refining activities.

Local electric utility consumption has declined by 39% from its peak in 2006, largely as a result of local electric utilities switching to new higher efficiency gas turbines in their central station power plants over the past decade. LED lighting has also contributed to reduced electric utility consumption.

While local residential and commercial facilities (including local schools, university buildings and hospitals) have become more energy efficient on a per square foot basis due to weatherization, doors, windows insulation improvements and more efficient heating and ventilating equipment, heated residential square footage per resident has increased (including heated garages). The net result is that residential gas consumption has declined on the order of 2% from its peak in the mid-2000s and commercial gas consumption has declined on the order of 13% from the mid-2000s.

Figure A1. Cook Inlet Natural Gas Consumption



Sources: EIA Alaska Natural Gas Consumption 2023, DNR DOG Reports to the Legislature 2023, AOGCC Cook Inlet Production Reports 2023, RCA Quarterly Cost of Power / Cost of Gas Electric/Natural Gas Utility filings (2023)

In a recent State of Alaska, Department of Natural Resources, Division of Oil & Gas **Cook Inlet Natural Gas Availability** study (March 2018), the report assumed:

- a base (local electric + natural gas utility + associated oil & gas lease consumption and oil refining) consumption of 80 bcf/year

- the potential for a restart of the Kenai Fertilizer Plant at 27 bcf/year
- the potential for a restart of the Kenai LNG export plant at 21 bcf/year
- the potential for Donlin Gold to require 12 bcf/year, and
- the potential for Interior Natural Gas to require 5 bcf/year.

Figure A2. Previous Cook Inlet Natural Gas Availability Study Demand Estimates

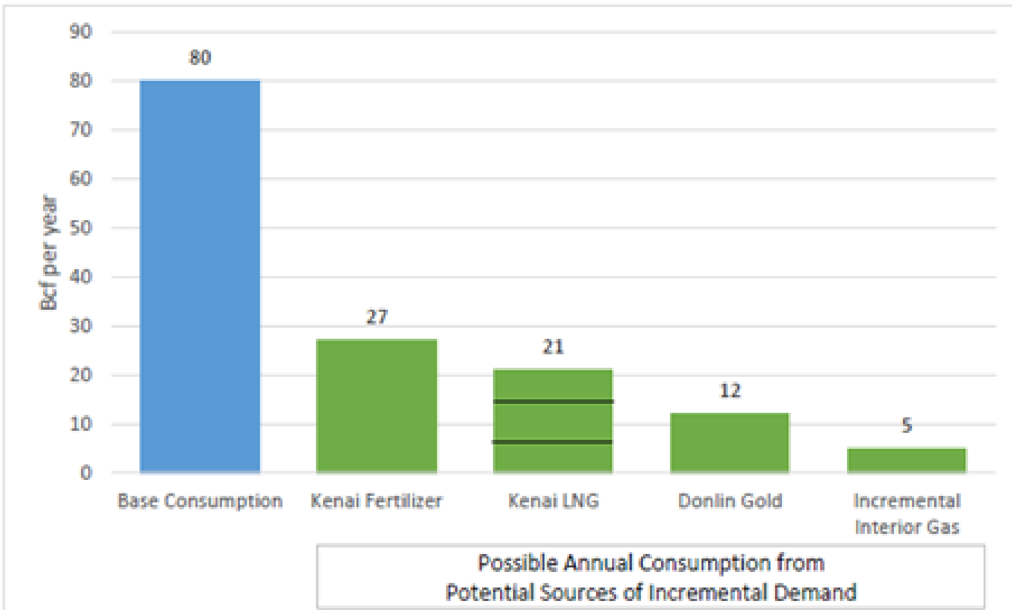


Figure 5. Potential incremental sources of Cook Inlet natural gas demand

Note: Base consumption includes electric generation, residential and commercial use, oil and gas operations, existing industrial users, and current Interior gas use. Kenai LNG consumption with the number of export cargos ranging from two to six cargos per year, where each cargo consumes 3.5 Bcf of natural gas (only 2.8 Bcf is exported due to losses that occur in liquefaction).

Source: State of Alaska, Department of Natural Resources, Division of Oil & Gas, Cook Inlet Natural Gas Availability Study (March 2018)

Cook Inlet Natural Gas Supply History

The combination of large industrial customers, including the Kenai Fertilizer and Kenai LNG plants serving export markets, and the Kenai Oil Refinery and the local electric and natural gas utilities were sufficient to attract and retain multiple large market capitalization oil & gas exploration and development enterprises for decades beginning in the 1960s.

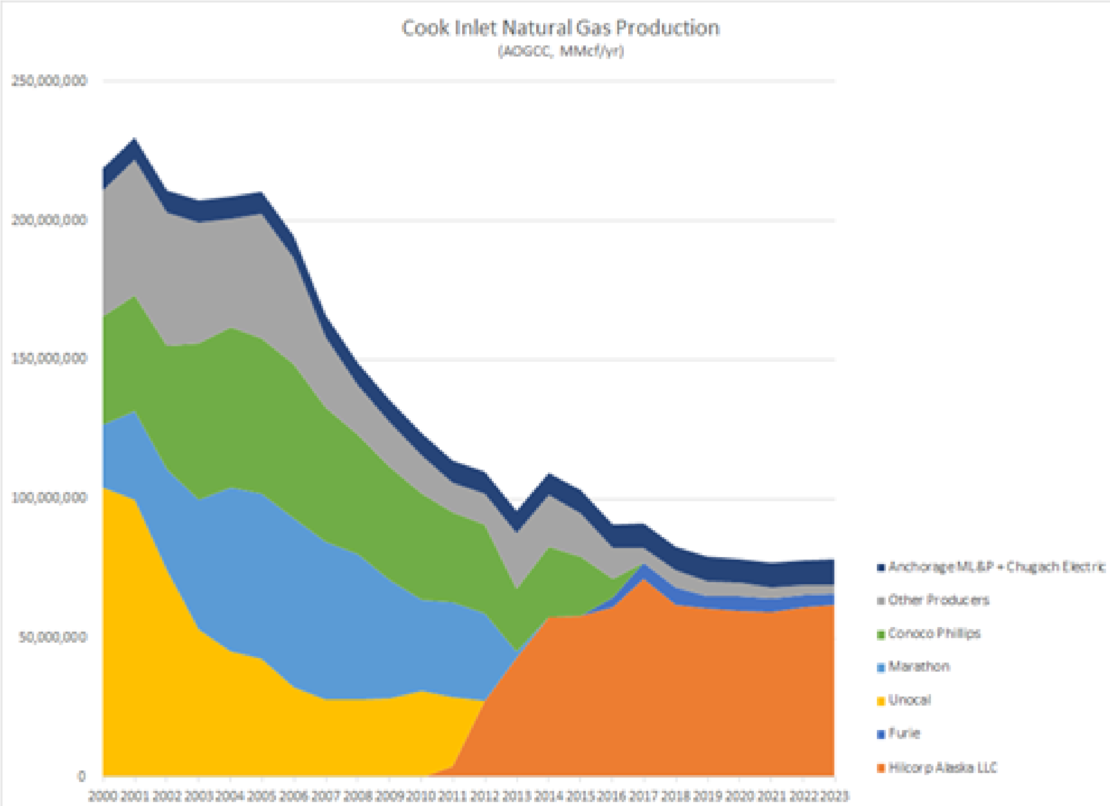
As local Cook Inlet natural gas prevailing values increasingly decoupled from U.S. oil and gas benchmark market indices *following* the CONUS oil and natural gas price run-up from 2002-2008, the large industrial customers with export markets found their natural gas supply costs were significantly higher than competing opportunities in the Americas, Asia and Australia. And after searching for economies and scale and scope associated with local business development opportunities, e.g., Agrium "Blue Sky" natural gas combined heat & power plant, the industrial customers with more competitively priced natural gas supply chains in other locations departed the market. Concurrently, large cap oil & gas exploration and development enterprises *began* to exit the market. From 2011 to 2018, Unocal, Marathon and Conoco-Phillips exited and Hilcorp entered the market.

In summary, the local Cook Inlet natural gas supply side was a marginally competitive market in 2002-2008 run up in oil & gas prices era with multiple suppliers and no single dominant supplier. The Herfindahl-Hirshfeld Index ("HHI" a measure of market concentration = sum of the squares of market share by supplier) was in the 2500 range.[10] By 2018, the Cook Inlet natural gas supply market had rapidly consolidated into an *unregulated* near *monopoly* (HHI approaching 8100) under Hilcorp [see Figure 4 Cook Inlet Natural Gas Production by supplier below].[11]

[10] For comparison, CONUS estimates of natural gas supply HHI have been in the range of 300-600 for decades following the deregulation of natural gas supplies and growth of competition that commenced with the deregulation of the wellhead price of natural gas initiated by the Natural Gas Policy Act of 1978.

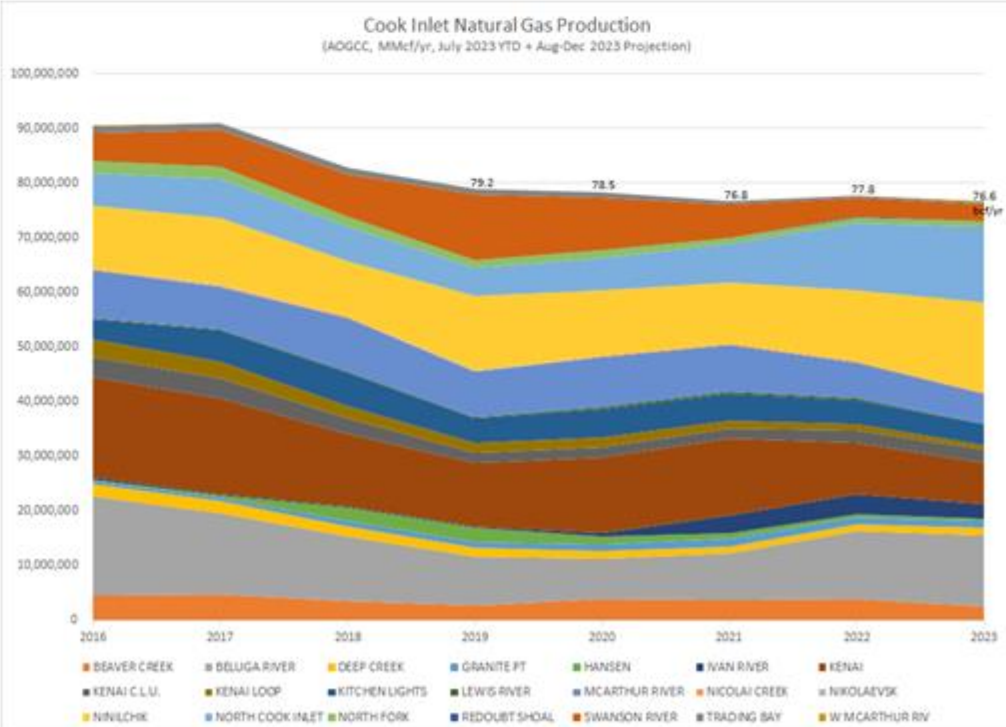
[11] Given the rapid consolidation of the Cook Inlet natural gas supply market toward HHI in the 8000 range and limited local competition, exacerbated by infrequent transactions associated with long term supply contracts, the Regulatory Commission of Alaska may wish to revisit its authority to monitor and potentially consider regulation of natural gas prices on a parallel track to the authority embodied in the definitions and legislative intent behind AS42.05.990(6)(E) which appears to enable the APUC/RCA to regulate petroleum or petroleum product prices in the absence of effective competition ["when the consumer has no alternative in the choice of supplier of a comparable product and service *at an equal or lesser price*."]

Figure A3. Cook Inlet Natural Gas Production



Sources: AOGCC Cook Inlet Natural Gas Production (2000-2023), DNR DOG Legislative Presentations (2023)

Figure A4. Cook Inlet Natural Gas Production by Field



Sources: AOGCC Cook Inlet Natural Gas Production (2000-2023)

Figure A5. Cook Inlet Top Natural Gas Producing Fields

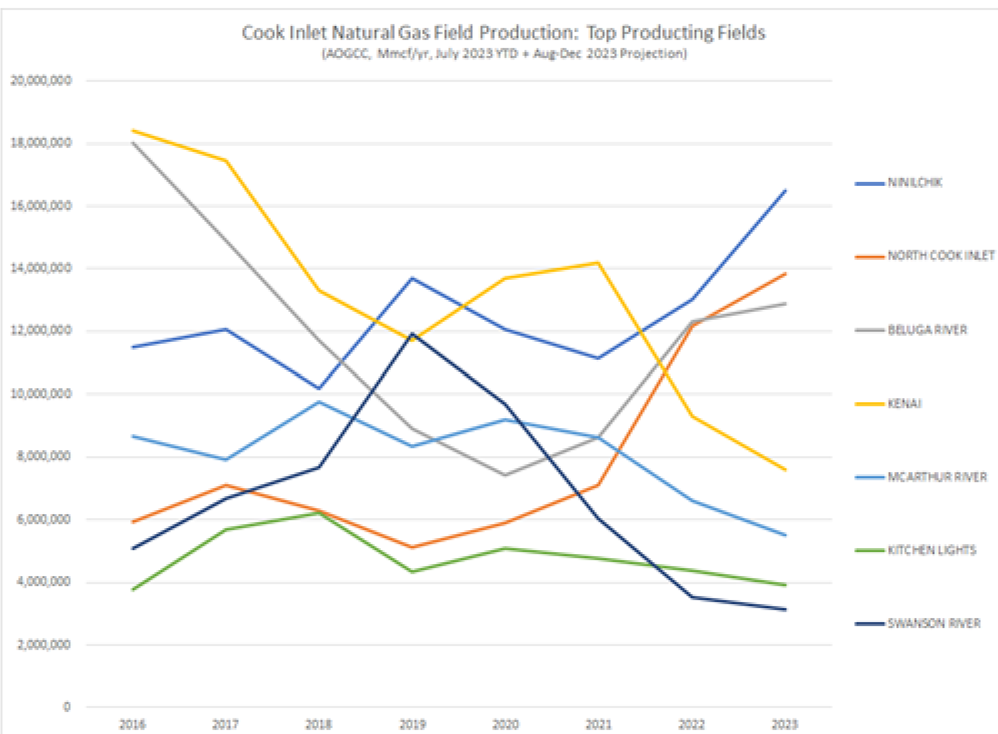
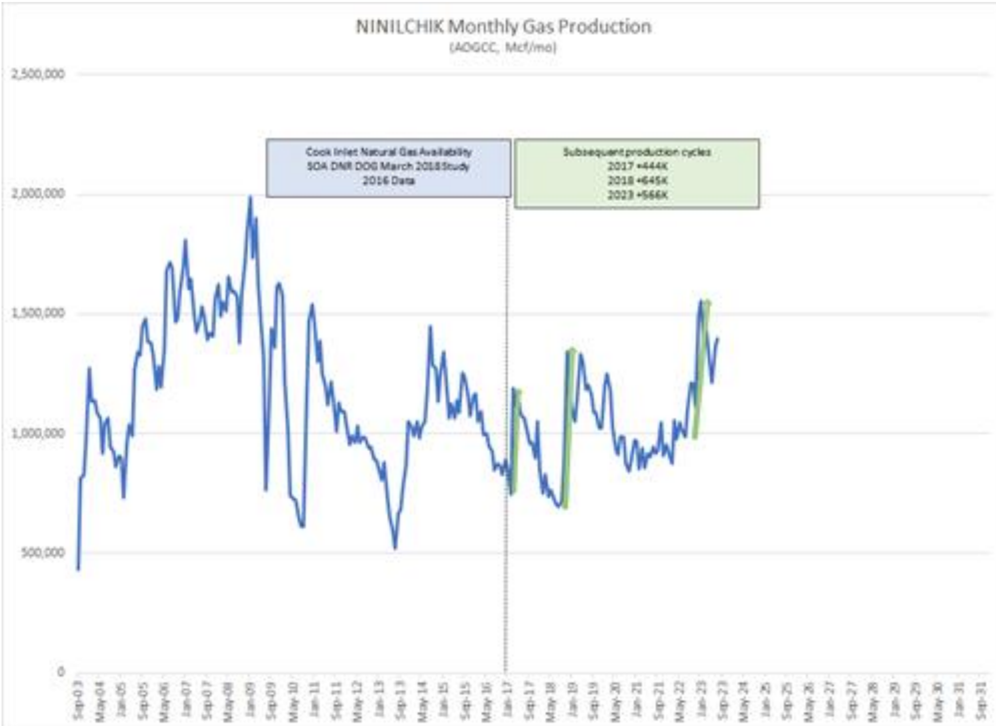


Figure A6. Ninilchik & North Cook Inlet Gas Production
(have seen substantial growth in production since 2016)



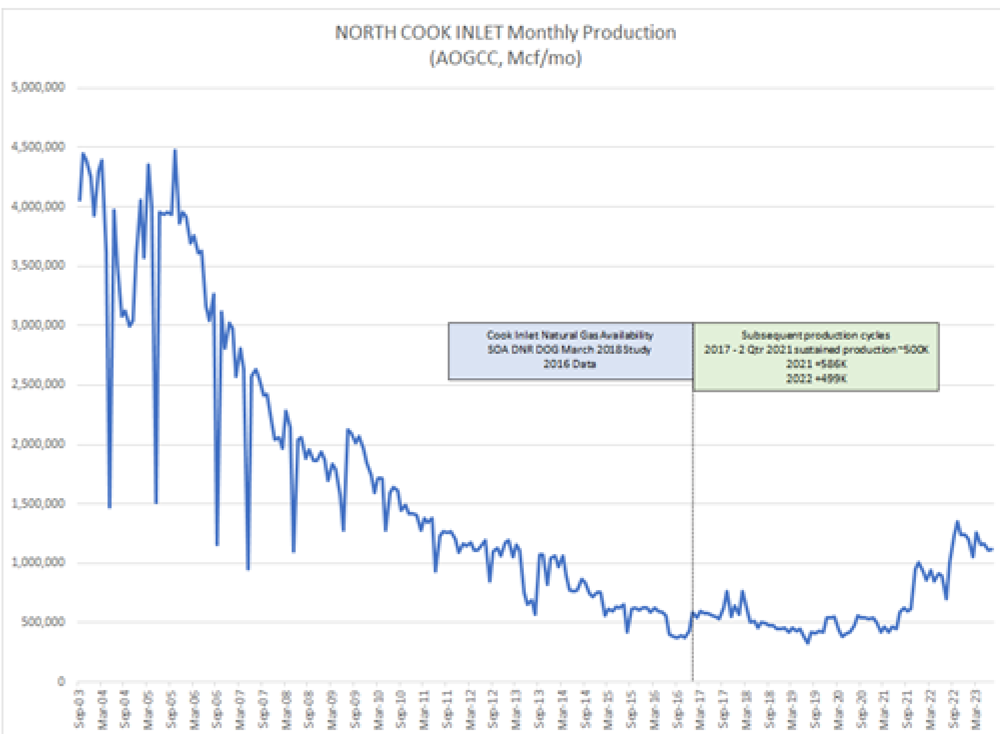


Figure A7. Beluga production has rebounded from a low in 2020.

Figure A8. Kenai production has fallen by half in 7 years.

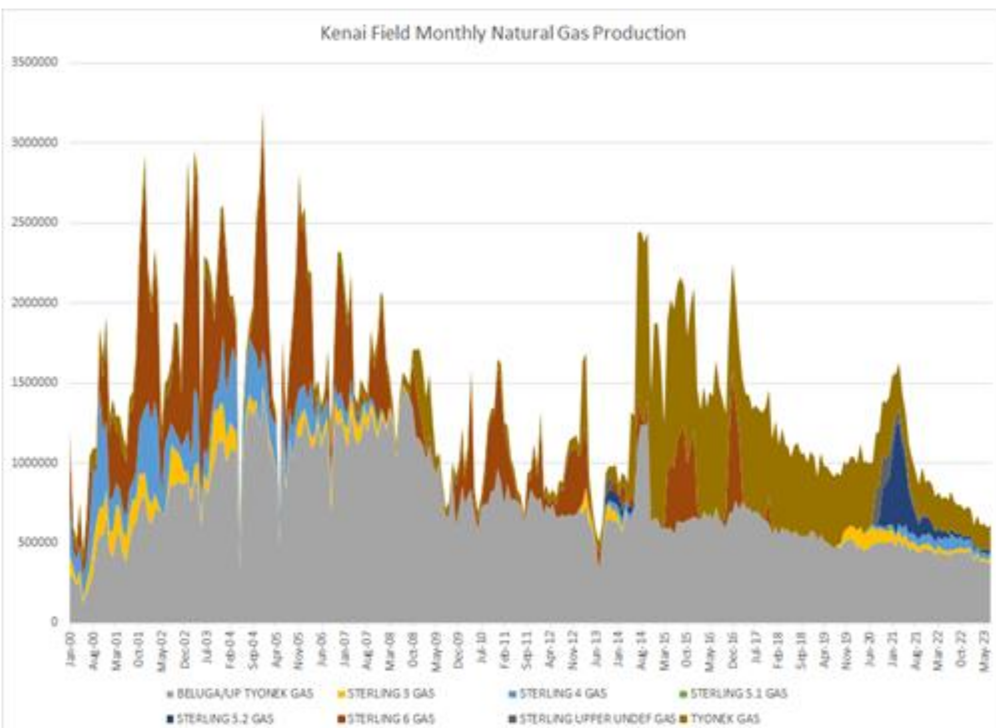
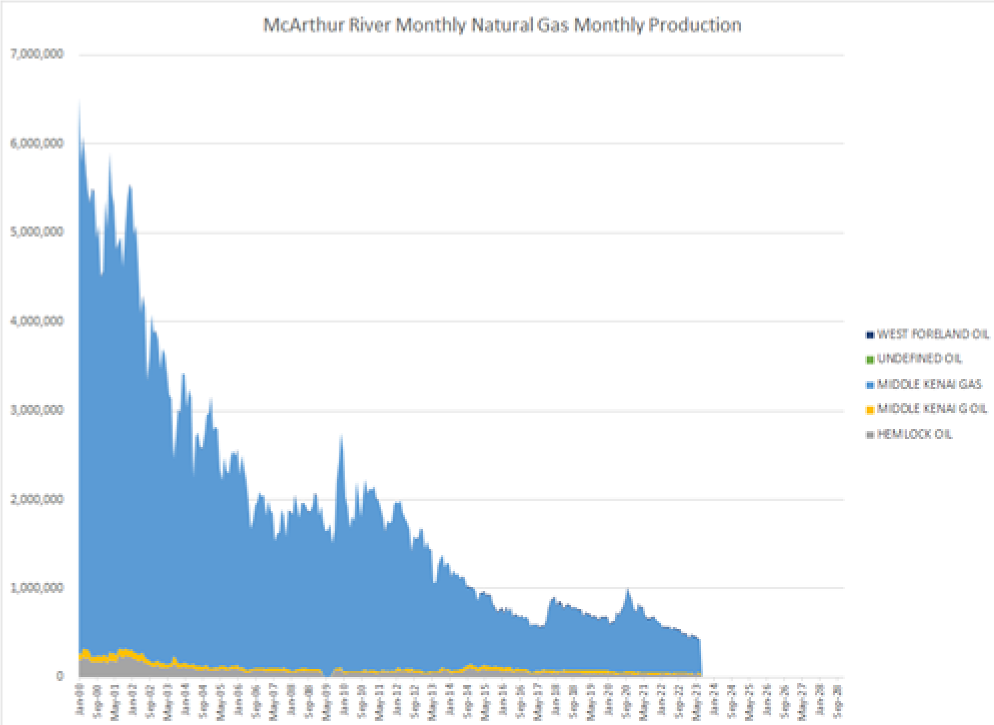


Figure A9. McArthur River and Swanson River remain in decline following revitalization in 2018 - 2020



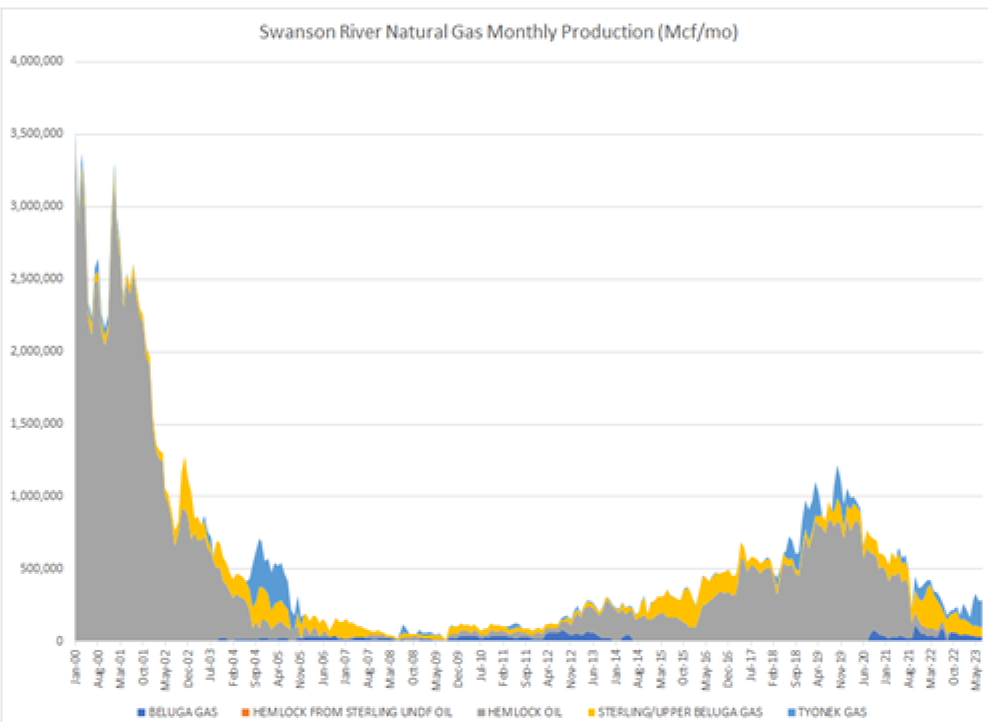
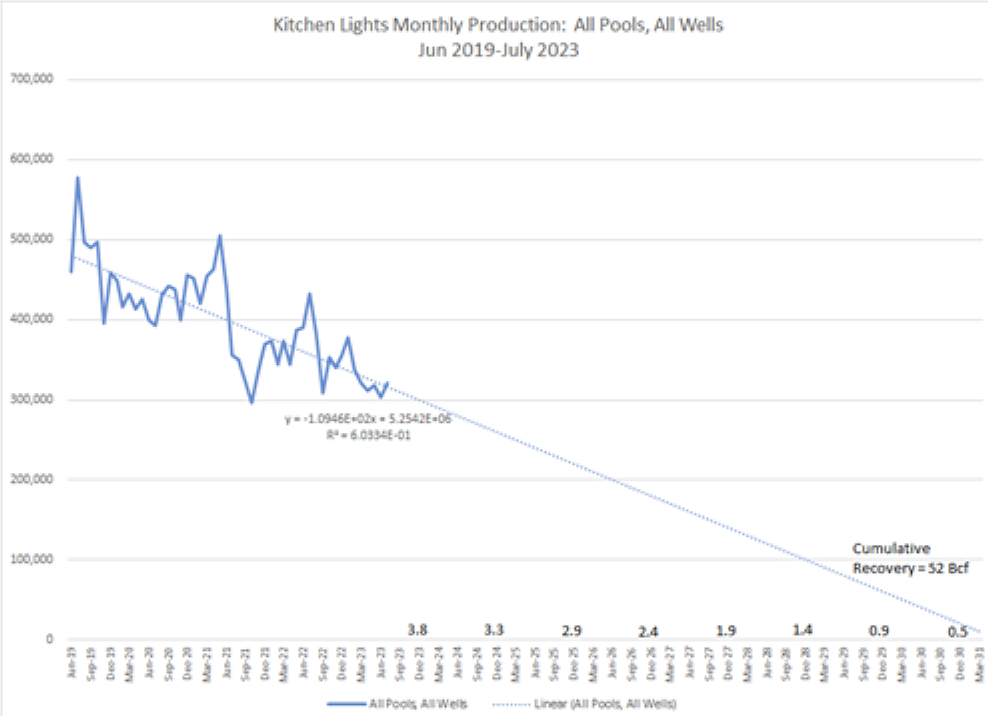


Figure A10. Kitchen Lights has struggled to stay even.



Cook Inlet Natural Gas Supply & Demand Balance History & Review of Prior Projections

Introduction

Local electric utility reliance on local Cook Inlet natural gas supplies has attracted several substantive assessments of alternatives to natural gas that have typically been triggered by a confluence of a state government revenue surplus, local energy supply price spikes (which have often flowed from fuel contract price provisions indexed to oil, diesel and CONUS natural gas prices, e.g., Henry Hub), the anticipation of future price spikes, and, in a recent iteration, the announcement of future supply challenges by a near monopolist and parallel pleas of poverty by micro-cap enterprises trying to harvest subsidies from local politicos seeking to “do something” about potential shortages and high prices.

It may be useful to consider those previous assessments to help inform our current assessment of the challenges associated with reliance on local natural gas supplies and the implications for residential customers if the Donlin Mine follows through on its development timeline and begins to procure natural gas for its energy requirements from a natural gas pipeline from the Cook Inlet.

Prior Century History

Susitna Hydroelectric (1980s)

Within 30 months of the start of Alaska North Slope Crude Oil flowing through the Trans Alaska Pipeline System in June 1977, oil prices had spiked to $130/bbl (2023$) in December 1979, and crude oil indexed natural gas contract prices followed, albeit less drastically. The combination of the rapid growth in State of Alaska oil revenue and the prospects for high and escalating natural gas prices, lead to the resurrection of consideration of large hydroelectric projects on the Susitna River that were first proposed by the U.S. Army Corps of Engineers in the late 1940s. After extended reconnaissance studies, the Alaska Energy Authority proposed an 1880 MW, 8,234,400 GWh/year, two dam (Devils Canyon and Watana) development project on the Susitna River that had the potential to provide all of the Railbelt’s electric demand plus a contribution toward new industrial developments – drawing comparisons to the large ambitious hydro developments on the Columbia and Frasier Rivers in the Pacific Northwest from the 1930s-1960s.

Oil prices peaked at $149/bbl (2023$) in April 1980 and then fell steadily to $76/bbl (2023$) by June 1985, then collapsed to $29/bbl (2023$) in March 1986 – effectively removing both the revenue stream that might have supported a mega-project scale hydro development and the justification that natural gas prices were high and would continue to escalate at a rate well above inflation for decades into the future.

Bradley Lake Hydroelectric (1990s)

In the wake of the imminent demise of the Susitna Hydroelectric Development which Governor Sheffield attributed to "we could not get financing from Wall Street to support the project in the face of declining oil revenues and declining natural gas prices and escalating capital cost estimates",[12] the Governor and Legislature subsequently pivoted to the Bradley Lake Hydroelectric project whose initial projected cost of power (c/kWh) was on the order of 2X Susitna and 3X local Cook Inlet Natural Gas as prices associated with oil price indexed natural gas supply contracts moderated. As the capital cost estimates grew and eventually doubled from initial estimates raising the prospects that the new State sponsored Alaska Energy Authority hydroelectricity from Bradley Lake would be the highest cost generation resource on the Railbelt, the hydro project advocates and political supporters sought to mitigate the high cost by rationalizing that the State could still "afford" to cover 50% of the capital cost because after 30 to 50 years the hydro cost would be paid off and that power from the project should then be a low cost resource.

Ironically, the 50% state grant for Bradley Lake came at the expense of a K-12 education endowment (1987-1991). Even after the 50% state grant for Bradley Lake, the highly subsidized **price** of power for the first 20+ years was well in excess of the **cost** of local natural gas fired electricity, especially as natural gas turbines became roughly 30% more efficient (with increased scale and heat rate improvements from aero derivative gas turbines) over the decades. And the total **cost** (not price) of power from Bradley Lake, roughly 9c/kWh (2023$), remains above the **cost** of local natural gas fired electricity in the Cook Inlet, 6c/kWh (2023$). Bradley Lake power began to "look competitive" because the Governor, AEA and Legislature have continued to ignore the huge opportunity cost to public education, public safety, food supply, public health, and future dividends that has occurred over the past 30 years and has lead to a precipitous decline in public education funding in favor of the fiction that Bradley Lake provided "low cost" power. In reality, Bradley Lake hydro was and remains an expensive public works project that continues to lead to misleading nostalgia and continued efforts to chase more "free money" that has proven time and again to be extremely expensive.[13]

[12] Personal communication with Governor Sheffield, circa 1990.

[13] See for example Gregg Erickson, x x, and Ginny Fay, Cite Report

Cook Inlet Gas Supply / Demand Balance History (2010-2023)

Historic Report Coverage

- AEA Black & Veatch Railbelt Integrated Resource Plan (February 2010)
- Cook Inlet Gas Study – An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers (March 2010)
- DNR DOG Cook Inlet Natural Gas Production Cost Study (June 2011)
- Updated Engineering Evaluation of Remaining Cook Inlet Gas Reserves (September 2015)
- DNR DOG Cook Inlet Natural Gas Availability Study (March 2018)
- Chugach Electric Association, Beluga River Unit Gas Transfer Price Update with Reserve Study and Asset Retirement Obligation Updates (August 2022)
- DNR DOG Cook Inlet Natural Gas Forecast (January 2023)
- Goals & Plans of Alaska's Railbelt Electric Utilities (McKittrick & Higman, 2023)
- Chugach Electric Association Black & Veatch Chugach Gas Supply Option and Market Assessment (June 2023)

Introduction

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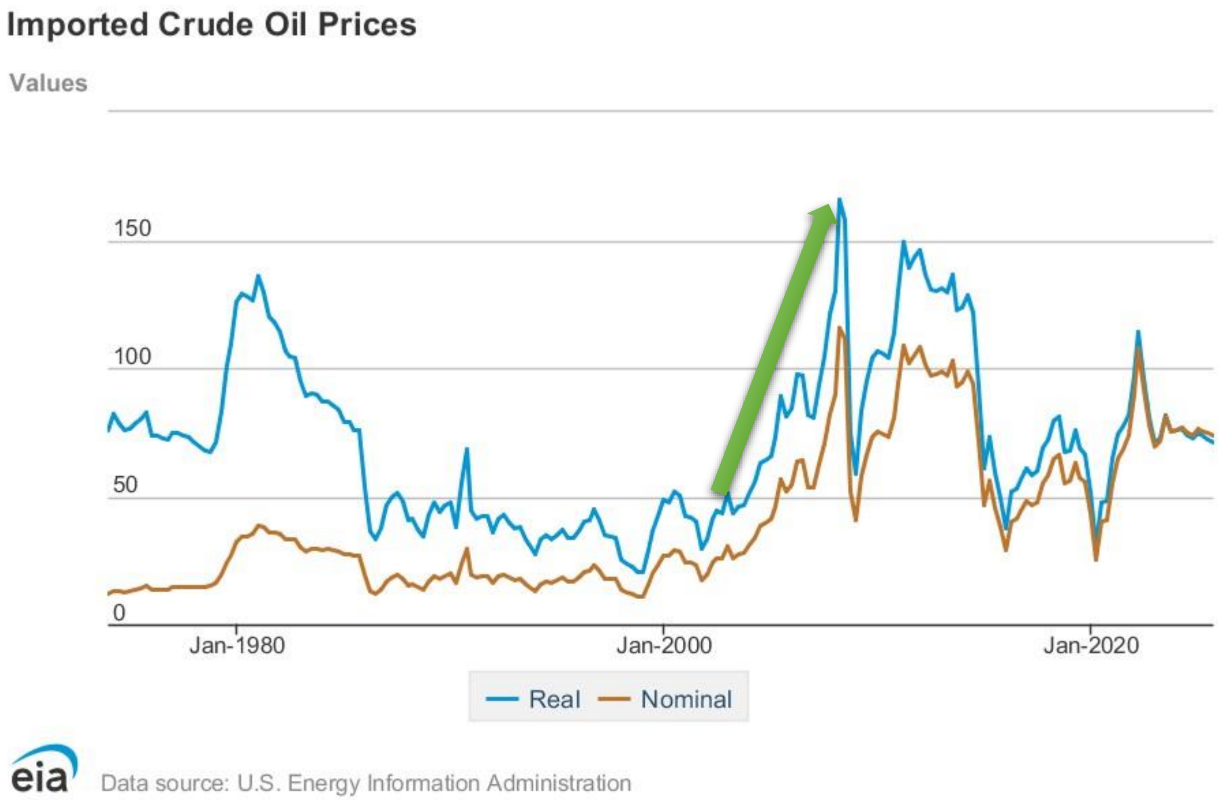
AEA Black & Veatch Railbelt Integrated Resource Plan (B&V 2010)

When oil prices took another upward run from 2002-2008, rising from $30/bbl (2023$) to $180/bbl (2023$) over the six-year period (See green arrow in Figure 7 below), Steve Haagenson, GVEA General Manager (2000s) and AEA Executive Director (2007-2011), lead an effort to develop one of the Susitna River hydro sites at Watana Creek into a roller compacted concrete dam as a cost competitive alternative to diesel/naphtha (Golden Valley peaking units at North Pole) and eventually Cook Inlet natural gas, especially if one took the view that the cost of natural gas would track oil indices and its GHG potential would eventually be internalized in a carbon tax or regulation.

Figure A11. Imported Crude Oil Price History



To lay the groundwork for the advocacy in favor of developing a large hydro project near the geographic center of the Railbelt and accelerate the diversification of the domestic electric sector away from the rapidly rising price for local natural gas, coal and diesel options whose fossil fuel supply contracts were indexed to fossil fuel market price benchmarks, the AEA under Haagenson contracted with Black & Veatch to development a Railbelt Integrated Resource Plan. The resulting Railbelt Integrated Resource Plan (2010) found the development of wind, geothermal and hydro resources became increasingly competitive with fossil fuels, including natural gas, even if one assumed that natural gas prices *fell* after increasing to an LNG import price umbrella comparable to the price of LNG imports into Tokyo – a market roughly 100X larger and much more competitive than the Cook Inlet. See Figure 8 below.

Table A1. AEA Black & Veatch Railbelt Integrated Resource Plan (2010):
Rapid Development of Renewable Energy Resources with Large 51% Reserve Margins & 68% Reduction in Natural Gas Usage

Scenario

Year	Additions	Retirements	Reserve Margin (%)	Renewable Generation (%)
2011	Nikiski Wind; HCCP	Beluga - 1; Beluga - 2; International - 1; International - 2	55.82%	11.92%
2012	Fire Island	International - 3	47.47%	15.18%
2013	Anchorage 1x1 6FA		62.51%	14.98%
2014	Glacier Fork	Beluga - 3; Beluga - 6/8; Beluga - 7/8; Bernice - 2; Bernice - 3	71.52%	15.94%
2015	Anchorage MSW		55.23%	24.72%
2016			59.21%	24.60%
2017	GVEA MSW	Beluga - 5; NP1	60.91%	24.85%
2018	GVEA 1X1 NPole Retrofit	NP2	54.30%	24.83%
2019			47.96%	24.62%
2020	Mount Spurr	Beluga - 6; MLP 5; MLP 5/6; MLP 7/6	46.22%	31.89%
2021	Anchorage 1x1 6FA	Beluga - 7	55.99%	31.60%
2022	Mount Spurr	Healy - 1	51.00%	38.52%
2023			46.86%	38.33%
2024			45.69%	38.18%
2025	Chakachamna:Chakachamna	GVEA Aurora Purchase - Tier I	84.55%	62.32%
2026		Nikiski	75.13%	62.52%
2027			73.98%	63.00%
2028			72.66%	63.06%
2029			71.37%	61.83%
2030	Kenai Hydro	DPP - 6; MLP 7; MLP 8; Zen1; Zen2	50.97%	63.97%

Scenario 1A/1B Plan - P50 Natural Gas Forecast

Annual Natural Gas Usage (mmBtu)

Year	Anchorage	Interior	Matanuska	Kenai	Total Railbelt
2011	33,720	0	0	4,304	38,024
2012	31,553	0	0	5,310	36,863
2013	31,457	0	0	3,877	35,334
2014	30,904	0	0	3,241	34,145
2015	22,249	0	0	2,555	24,803
2016	21,201	0	0	2,757	23,957
2017	21,919	0	0	2,645	24,563
2018	18,693	9,034	0	2,741	30,468
2019	18,656	8,262	0	2,780	29,697
2020	14,852	8,087	0	2,803	25,742
2021	15,866	7,311	0	2,215	25,391
2022	14,094	6,846	0	2,041	22,980
2023	14,741	7,727	0	2,070	24,538
2024	15,267	7,366	0	2,197	24,830
2025	10,081	4,435	0	1,328	15,844
2026	10,393	5,170	0	956	16,519
2027	10,646	5,243	0	0	15,889
2028	10,638	5,289	0	0	15,927
2029	10,865	5,792	0	0	16,657
2030	5,914	6,410	0	0	12,324

51% Reserve Margins

68% reduction in natural gas usage

Source: Black & Veatch, Plan 1A_1B P50 Summary, pages 1 & 2, February 18, 2010

A subsequent change in Gubernatorial administrations lead to the shelving of the Susitna hydro permitting project in favor of pursuit of a large diameter natural gas pipeline from Alaska's North Slope to tidewater at Nikiski to support an LNG export facility and NGLs development.

Cook Inlet Gas Study (PRA, March 2010)

Shortly after the release of the Alaska Energy Authority Black & Veatch Railbelt Integrated Resource Plan in early 2010, local utilities released a Cook Inlet Gas Supply Study from PRA which suggested natural gas reserves to production levels were significantly below recent 2009 DNR DOG studies and that natural gas production was rapidly declining and on the order of $2 to $3 billion in capital investment would be required to support the demand for natural gas over the next decade.

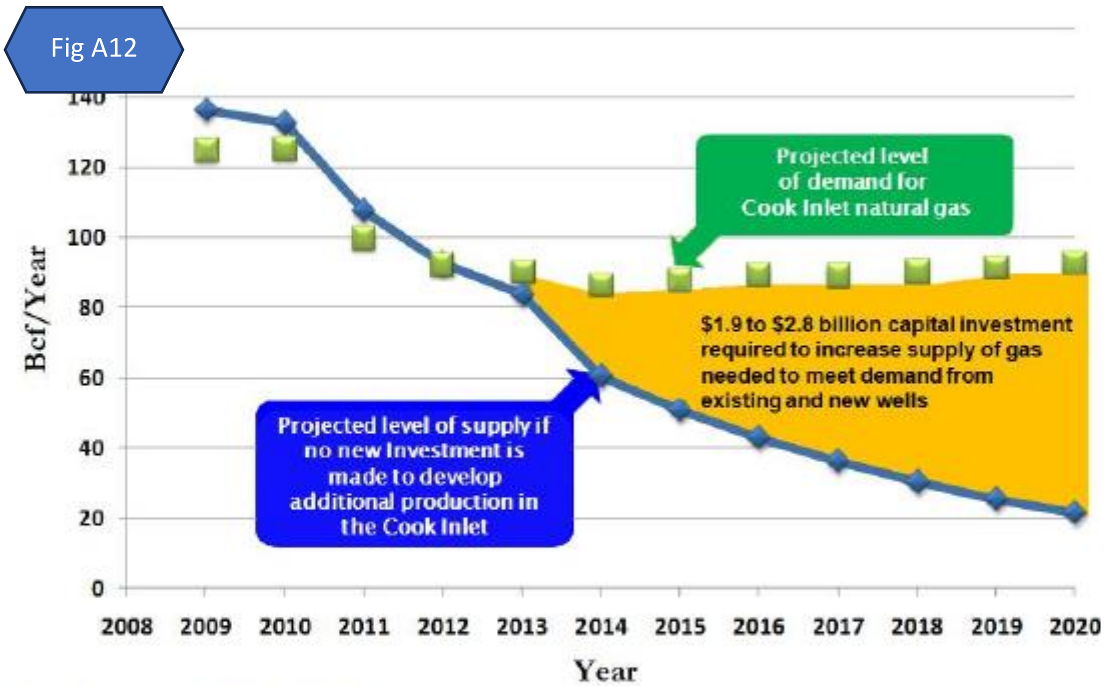


Figure 1 – Cook Inlet Supply & Demand

Source: PRA 2010

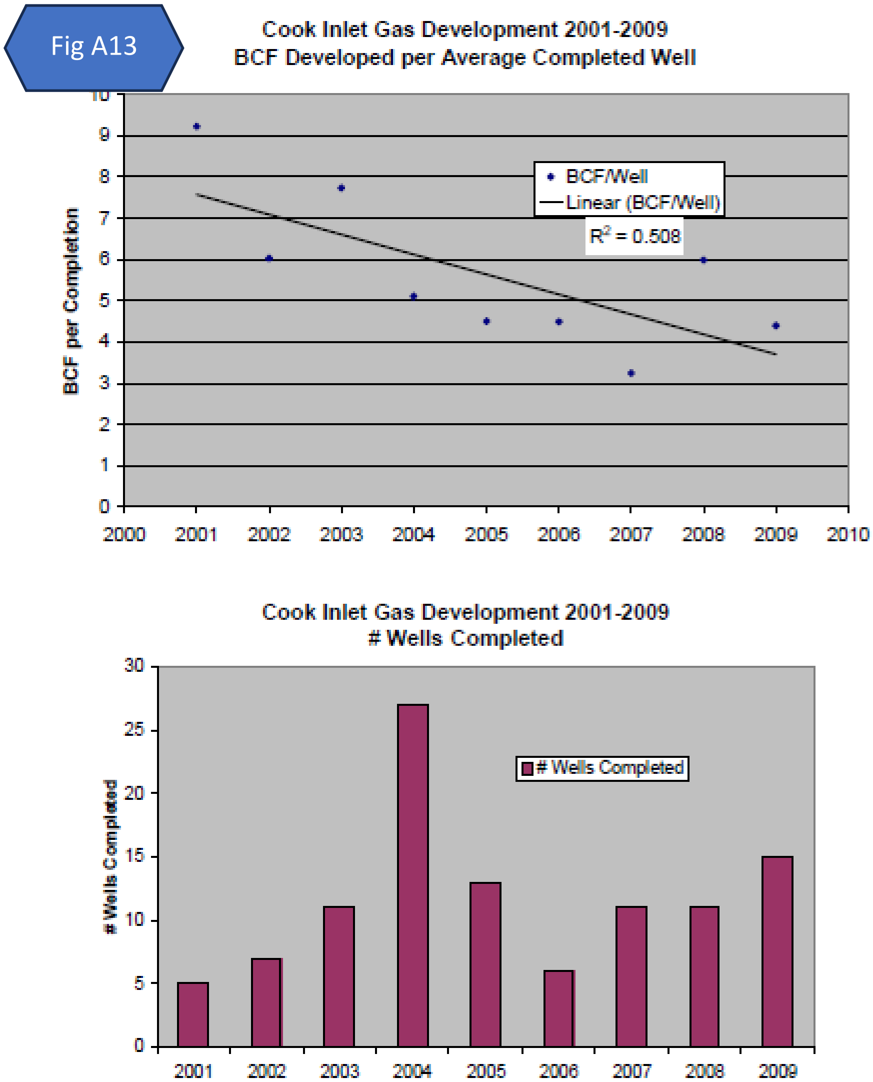


Figure 13: Cook Inlet gas development 2001-2009

Source: PRA 2010

MAFA Note:

Complete data development/analysis of the Bcf per completion for 2010-2023 as time allows and compare Cook Inlet well productivity to CONUS (EIA Shale Gas 2023).

Estimate of Cook Inlet Gas Development Costs 2001 to 2009

Table A2

Net Wells Drilled from AOGCC Records

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009	
Marathon	3.6	5.2	6.1	13.8	8.8	6.2	8.9	6.8	6	
Chevron/Unocal	3.4	4.8	2.9	13.2	1.2	0.8	2.1	3.9	4.3	
ConocoPhillips			1					0.7	3.3	
MOA								0.7	0.3	
Aurora		1	2	2	5	2			3	
Armstrong								1		
Others				2	1	1				**Total**
Total	7	11	12	31	16	10	11	13.1	16.9	**128**

Average Cost Per Well Capital and Facilities Estimate, million*

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009
Marathon	$ 5.0	$ 5.1	$ 8.9	$ 8.9	$ 8.9	$ 8.9	$ 8.9	$ 8.9	$ 9.1
Chevron/Unocal	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.4	$ 8.6
ConocoPhillips			$ 5.0					$ 23.0	$ 23.0
MOA								$ 23.0	$ 23.0
Aurora		$ 3.0	$ 3.1	$ 3.1	$ 3.2	$ 3.2			$ 3.3
Armstrong								$ 8.0	
Others				$ 6.8	$ 6.8	$ 6.8			

** - Assumes 2% Inflation, $5,000,000 per initial well, except for Aurora at $3,000,000 per well, "Others" use yearly average cost*
Chevron/Unocal 2001-2007 and Marathon 2003-2008 are estimates from publically discussed expenditures.
MOA & ConocoPhillips are from publically discussed well costs for Beluga River Unit.

Baseline Annual Cost Per Well Estimate, million

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009	
Marathon	$ 18	$ 27	$ 54	$ 123	$ 78	$ 55	$ 79	$ 60	$ 54	
Chevron/Unocal	$ 28	$ 40	$ 24	$ 109	$ 10	$ 7	$ 17	$ 33	$ 37	
ConocoPhillips	$ -	$ -	$ 5	$ -	$ -	$ -	$ -	$ 16	$ 76	
MOA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16	$ 7	
Aurora	$ -	$ 3	$ 6	$ 6	$ 16	$ 6	$ -	$ -	$ 10	
Armstrong	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8	$ -	
Others	$ -	$ -	$ -	$ 14	$ 7	$ 7	$ -	$ -	$ -	**Total**
Total Baseline	$ 46	$ 69	$ 89	$ 252	$ 111	$ 75	$ 97	$ 134	$ 184	**$ 1,057**
High Estimate 110% of Baseline	**50.7**	**76.2**	**98.3**	**276.9**	**122.0**	**82.6**	**106.2**	**146.9**	**202.6**	**1162.4**
Low Estimate 95% of Baseline	**43.8**	**65.8**	**84.9**	**239.1**	**105.3**	**71.3**	**91.7**	**126.9**	**175.0**	**1003.9**

Table 5: Cost estimate of Cook Inlet gas development 2001-2009.

The current cost for onshore wells is typically $5-10 million; offshore wells can be $10-20 million. Costs vary based on remoteness of location and how exotic a completion is required for the well.

MAFA NOTE:
Upstream capital cost inflation in the oil & gas industry from 2003-2008 was extraordinary with the S&P Global Commodity Insights Upstream Capital Cost Index rising from 100 to 220 over that time period.

In contrast, it would appear from the average cost per well capital and facilities estimates by PRA for Marathon and Chevron/Unocal for Cook Inlet upstream capital costs were essentially flat from 2003-2008, while the S&P UCCI index increased 90%, from 105 to 200 over that time period. It seems unlikely that the Cook Inlet was completely insulated from industry cost inflation over that time period.

It seems plausible that the publicly discussed expenditures for Chevron and Marathon were from more recent 2007-2008 data as industry inflation approached the peak in 2009.

Adding inflation and contingencies assuming continued extraordinary inflation on top of the publicly disclosed data, $9M/well (circa 2009), to reach $15M/well for the next decade (2010-2020) may have overestimated the going forward cost of development wells by 67% or roughly $1 billion. The capital cost per Mcf appears to have risen from $2.00 to $2.50 over the next decade, not the $2 to $4 projected in the March 2010 study.

PRA Notes:
ii. Drivers for future gas Exploration and Development
Based on conversations with current gas producers and public data, the following are required drivers to explore for and develop gas in Cook Inlet:

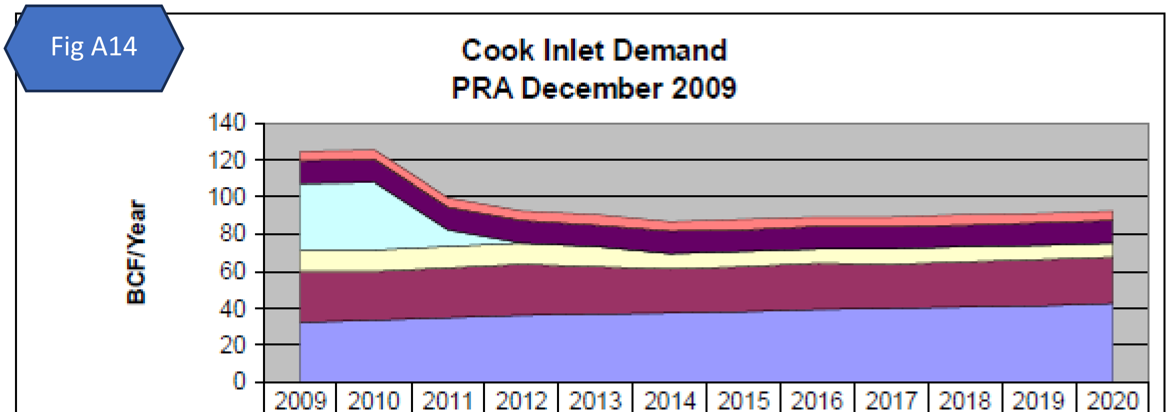
- Marathon needs certainty in contract approvals & larger markets to enable growth
  - Market is too small to support 10-15 wells in Cook Inlet (Peninsula Clarion 1/17/10)
- Chevron needs better exploration success
  - Had recent success on TBU Grayling Gas sands, but poor results at Deep Creek
  - Concerned about meeting future winter deliverabilities
  - No future exploration planned (Peninsula Clarion 1/17/10)
- Conoco Phillips does not view the market as large enough to commit major capital to new reserves exploration and development costs.
  - Not looking to explore or develop other than to service LNG and Chugach contracts.

MAFA Notes:

Neither Marathon nor Chevron's talking points about the small size of the market being insufficient for further capital investment have stood the test of time. While Marathon and Chevron may not have found the market to be sufficiently attractive to remain, other new entrants bought into the market and made additional investments which have yielded increased reserves.

After Marathon and Chevron exited the market, subsequent investments *after* the Cook Inlet natural gas exploration subsidies (HB280 CIRA) expired yielded a reserves to production ratio estimate in 2022 of 10.7 (DNR DOG 2023) that was on the order of 99% higher than the Cook Inlet Reserves to Production Ratio estimated by PRA to be 5.4 in 2010.

For context, the "shale revolution" in the continental U.S. increased the CONUS natural gas reserves to production ratio from 9.2 in 2000 to 15.3 in 2017, an increase of 66%.



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Tesoro	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Field Operations	12	12	12	12	12	12	12	12	12	12	12	12
LNG	36.4	36.4	9.1									
ML&P	11.54	11.56	11.58	11.62	11.07	8.05	8.06	8.09	8.11	8.14	8.20	8.20
CEA/Railbelt	27.5	26.3	26.9	27.7	25.4	23.8	24.2	25	23.9	24.2	24.5	25
ENSTAR	32.1	33.7	34.9	35.8	36.6	37.4	38.2	39.0	39.8	40.6	41.4	42.2

Figure 15: Forecasted Annual Demand for Cook Inlet Gas

MAFA Note: Total forecasted annual demand for Cook Inlet Gas of 92.7 bcf in 2020 was 15% above the actual demand of 79.2 bcf.

Fig A15

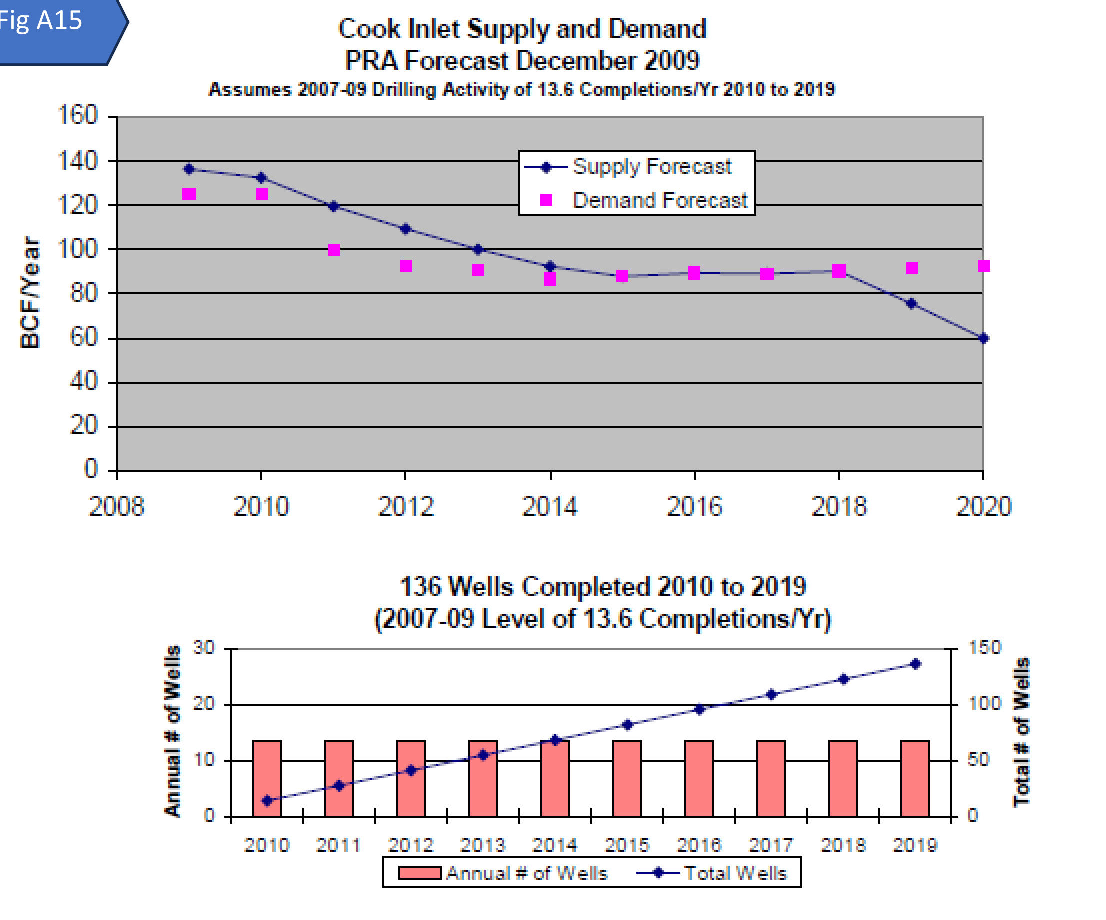


Figure 17: CI Supply-Demand assuming 2007-09 drilling of 13.6 completions per year 2010-2019

For the case of 2007-09 activity levels projected into the future, the demand exceeds supply in 2019.

Assuming $10-15MM per well, this would require $1.4 to 2.1 Billion in unrisked capital to drill these wells, resulting in capital costs of $2.67 to $4.00 per MCF, as compared to an estimated $1.78 to $2.06 /MCF capital cost for 2001-2009.

MAFA Notes:

The S&P Global Commodity Insights Upstream Capital Cost Index was flat from 2009-2015 and fell by 20% from 2016-2021. The estimate developed by PRA in 2009 appears to have significantly overestimated inflation and capital required over the period 2010-2021.

The subsequent State subsidies (HB280 CIRA) on the order of $1 to $2 billion to address the dire predictions of natural gas shortages and continued rapid escalation in the cost to develop new reserves do you appear to have yielded any net gain in reserves. It appears that reserves to production ratios were flat over the Cook Inlet natural gas subsidy period. It was not until after the expiration of Cook

Inlet natural gas subsidies in 2016 that Cook Inlet natural gas investments yielded an increase in the reserves to production ratio – on the order of 39% over the results from the "subsidy" period.

Cook Inlet Natural Gas Production Cost Study (DNR DOG June 2011)

Normal

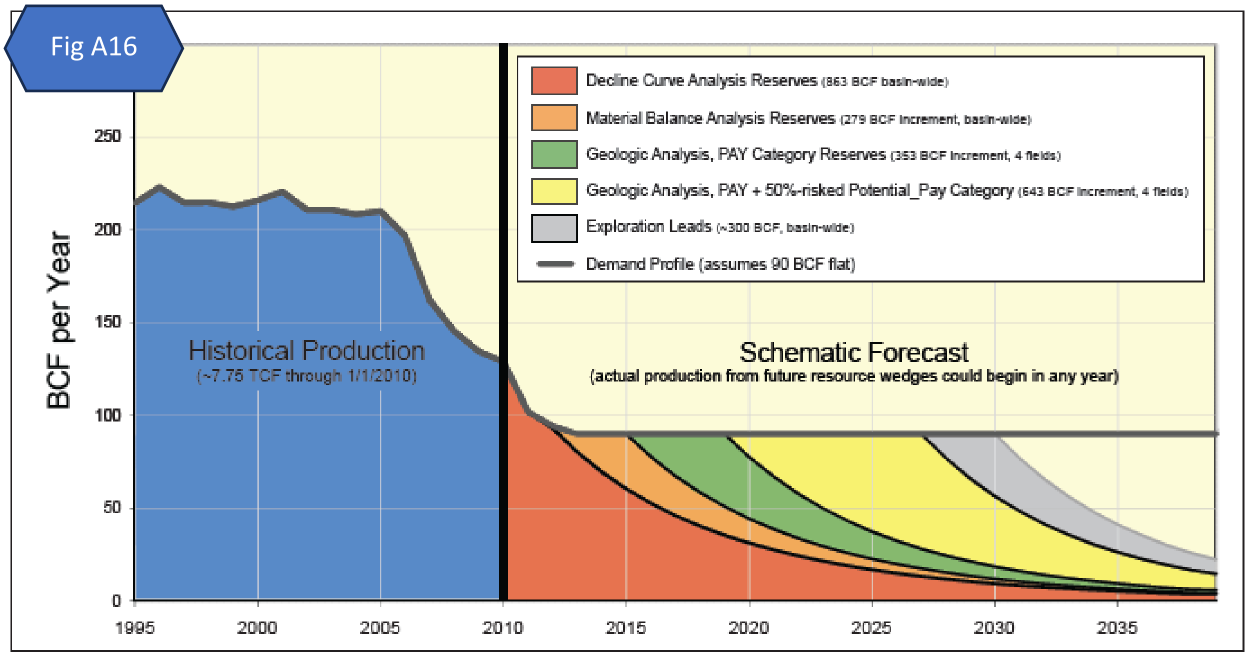


Figure 2. Hypothetical production forecast for the Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analyses in 2009 DNR Cook Inlet gas study. Note that the production through 2010 was affected by the additional market demand of the LNG and Agrium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

MAFA Note:

- Assumes 90 bcf/year flat demand outlook for "Local Market Demand", e.g., Tesoro Oil Refinery, Oil & Gas Field Operations, Enstar, Railbelt Electric Utilities
- Demand outlook by DNR DOG is roughly comparable to demand outlook by PRA

Fig A17

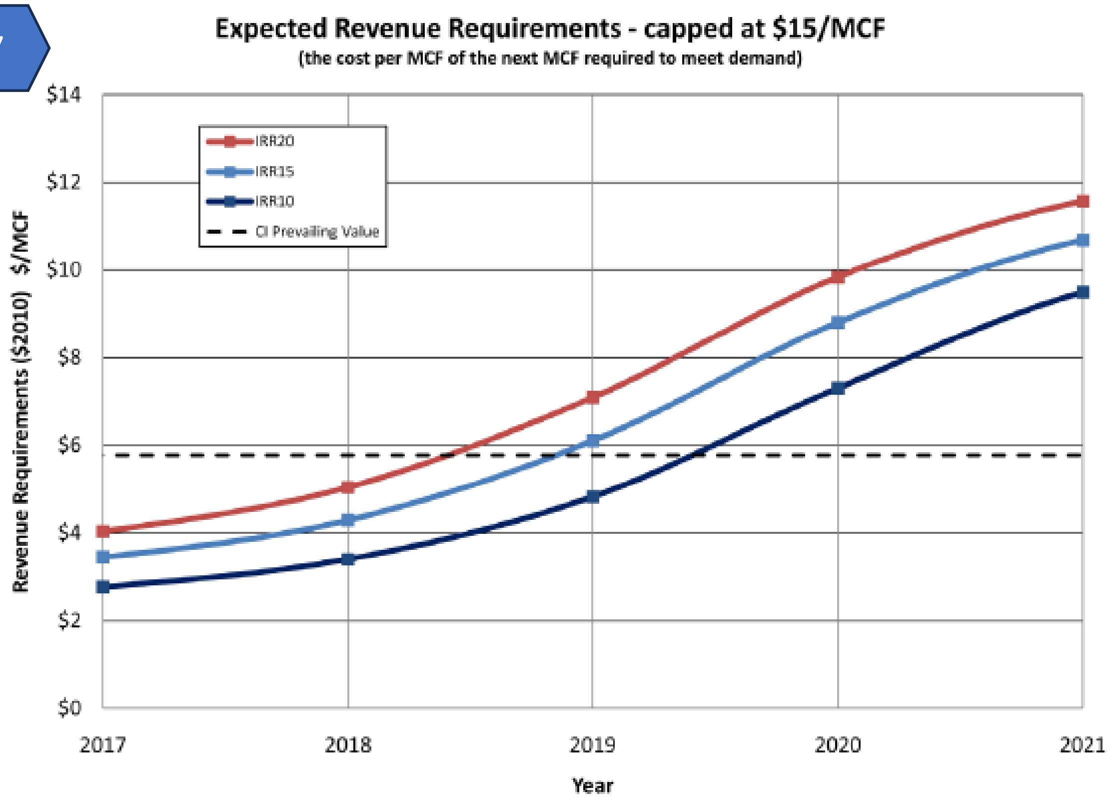


Figure 12. Expected (average) Revenue Requirements.

MAFA Note: In 2023, the actual prevailing value in the Cook Inlet was roughly $8/MCF while the DNR DOG Projected Expected Revenue Requirement (IRR15, adjust 2010$ to 2021$) was on the order of $13/MCF. In short, the projected expected price in 2021 was on the order of 60% over the actual prevailing value price.

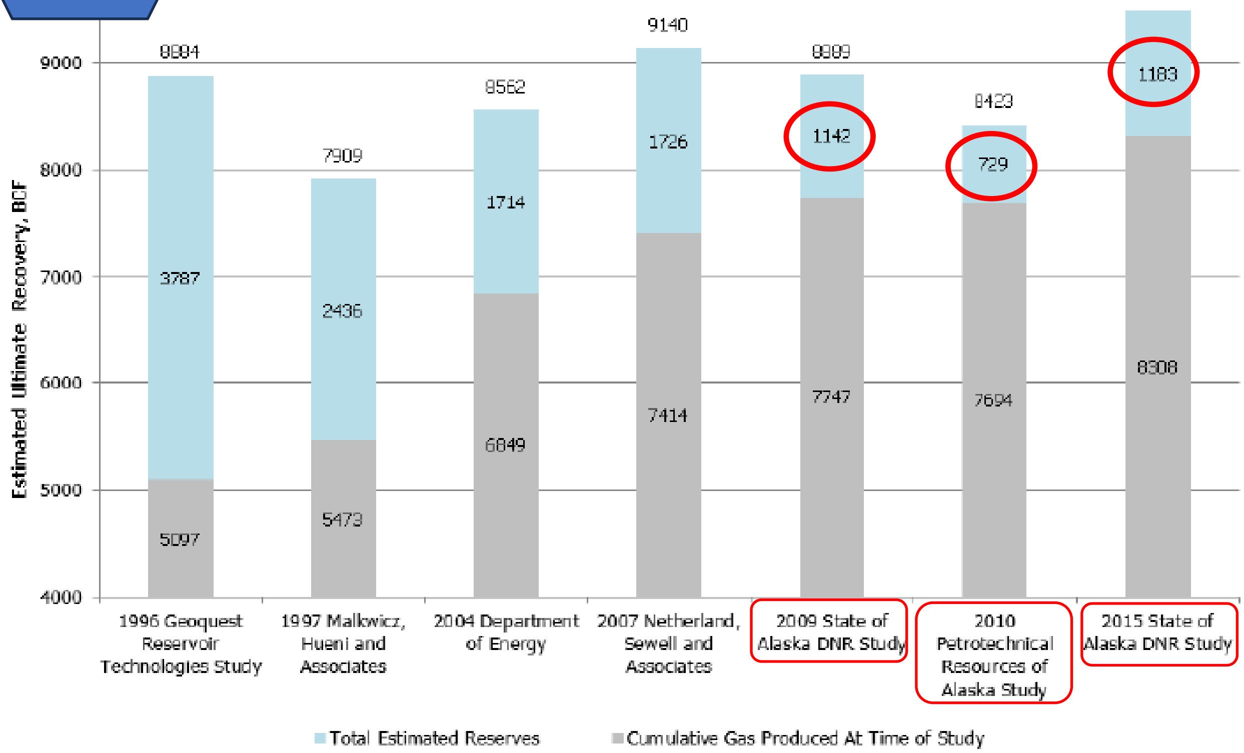
The large overestimate of price in the 2021-time frame can be attributed to:

- Overestimating future demand
- Overestimating future inflation
- Underestimating/ignoring productivity improvements driven by experience with new well development technologies which lead to substantial improvements in the reserves to production ratio with incremental investments in new development wells and more efficient well workover activities.

Engineering Evaluation of Remaining Cook Inlet Gas Reserves (DNR DOG 2015)

Normal

Fig A18



Comparison of Different Cook Inlet Natural Gas Studies

*2009 Study cumulative estimated from May 31, 2009 to December 31, 2009. Actual cumulative was 7,694 BCF.

Figure 3-1. Comparison of Cook Inlet gas reserve estimates over time. Numbers above the bars show Estimated Ultimate Recovery by study. Summed values may disagree slightly with component values due to rounding.

MAFA Note:

PRA reserves estimates (Cook Inlet 2010 and BRU 2022) appear markedly conservative relative to DNR DOG estimates (2009, 2015, 2018, 2022) over the same time period.

Fig A19

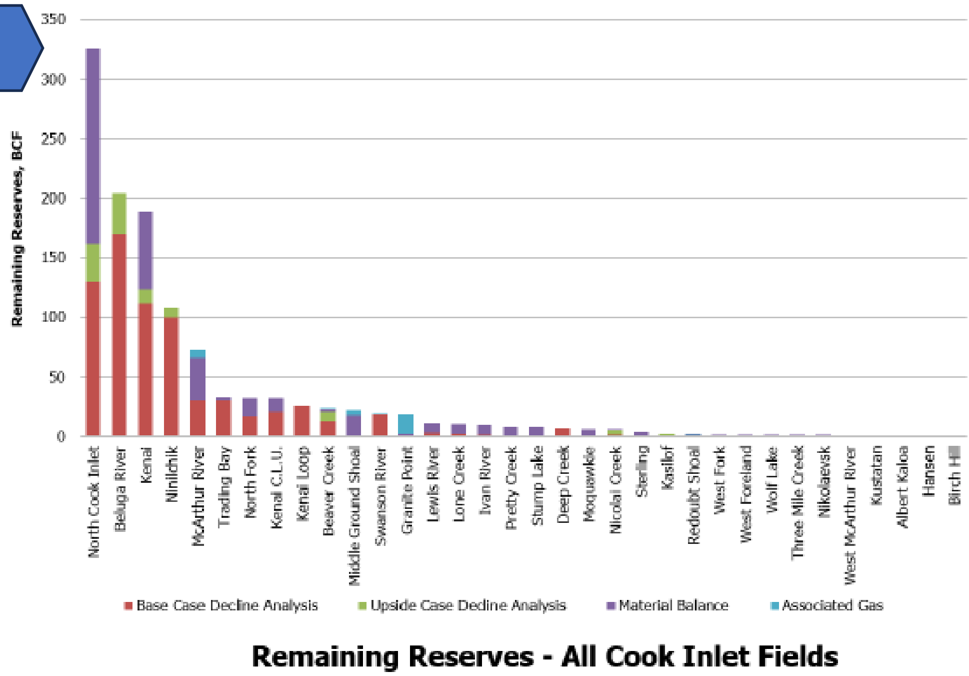


Figure 4-2. Remaining reserves of the Cook Inlet basin, including fields where remaining reserves are greater than 100 BCF (North Cook Inlet, Beluga River, Kenai, and Ninilchik).

MAFA Note:

Develop 2023 Estimates vs 2015 Study by Field as time allows.

DNR Cook Inlet Natural Gas Availability Study (DNR DOG March 2018)

In 2017, the Division of Oil & Gas team at the Department of Natural Resources conducted a detailed well by well assessment of the geologic and engineering potential of remaining resources to ascertain when they might become commercial reserves under various market prices and hurdle rates. The report was published in early 2018 and was tied back to real 2016$.

The supply curve ($/mcf vs. volume of supply) is summarized in Figure 10 from that study.

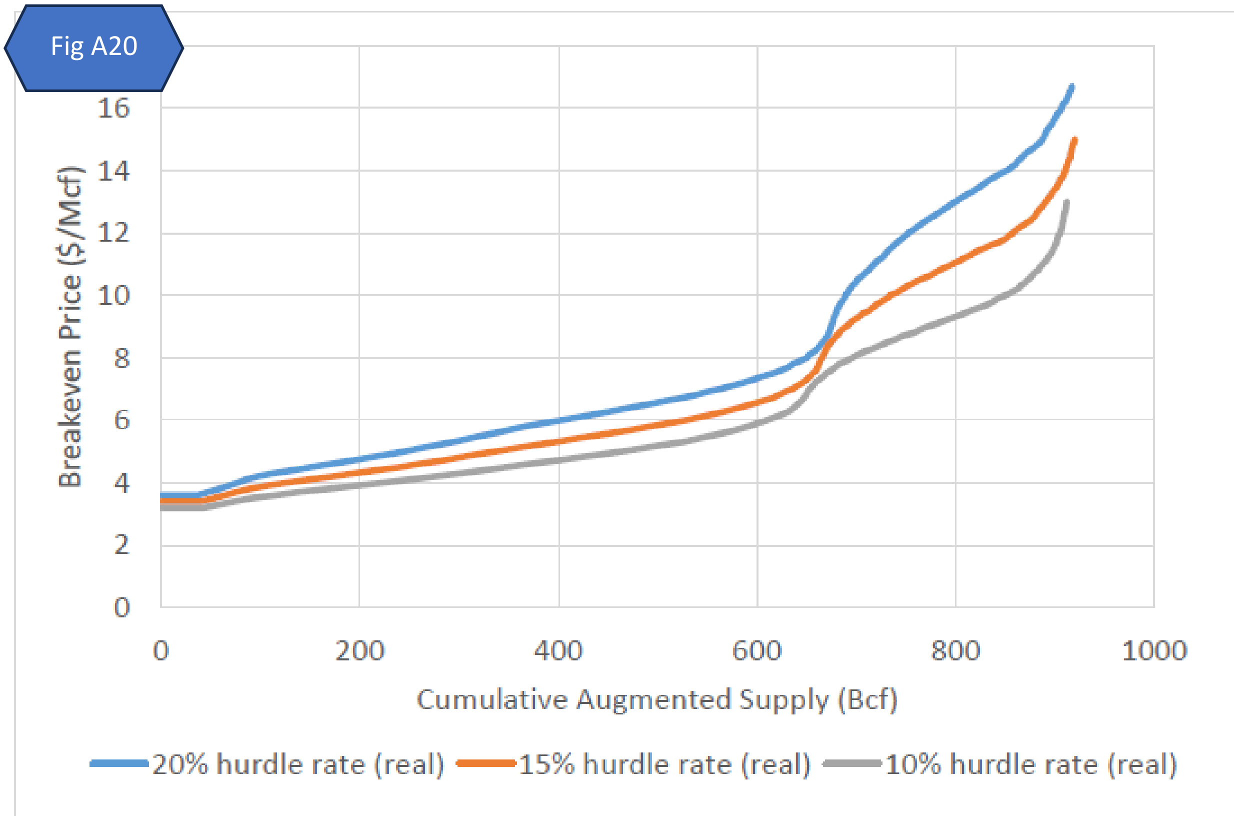


Figure 10. Cumulative availability of augmented production under varying hurdle rates (median case)

We will endeavor to update and extend this insightful analysis to shed light on the prospects for future prices of natural gas for local Cook Inlet production – see section MAFA Synthesis of Supply / Demand Outlook (2023) below.

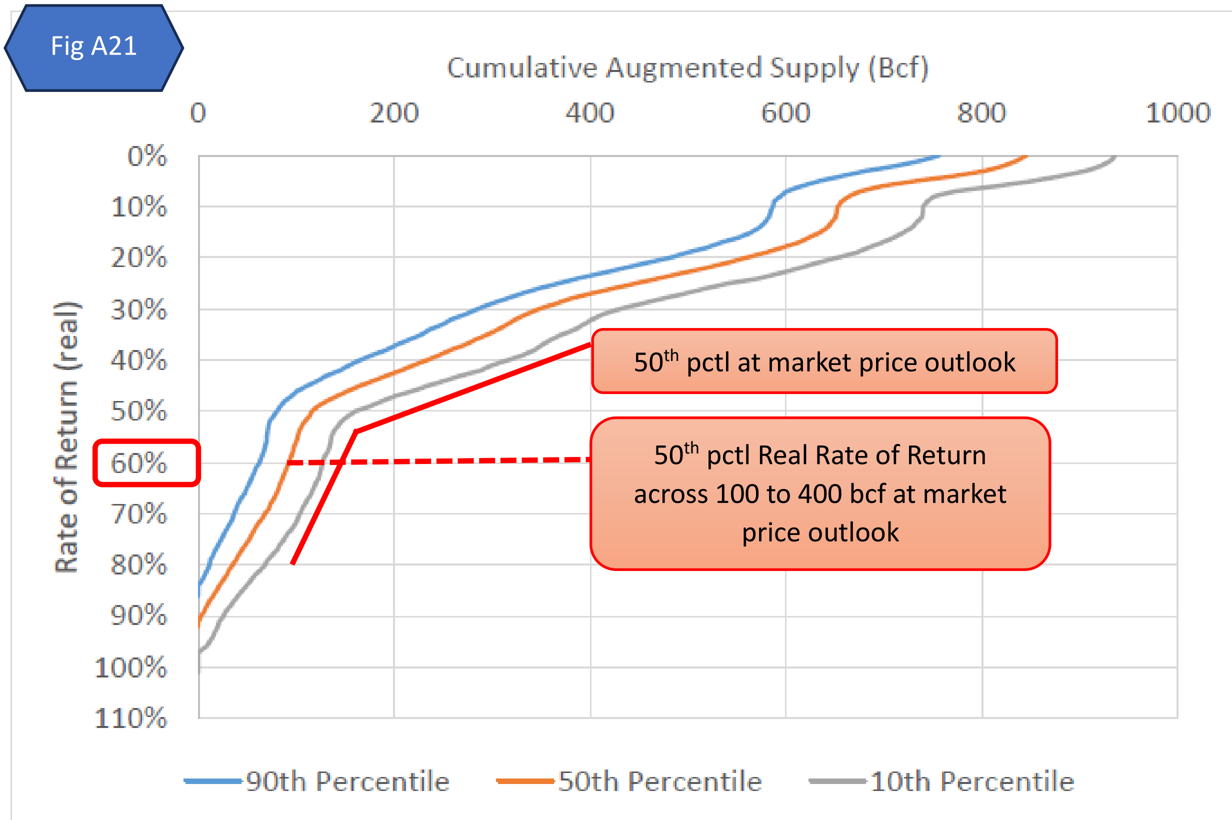


Figure 11. Rate of return (real) for cumulative supplies from augmented production

Note: This figure assumes a natural gas price of $7 per Mcf (real 2016$).

Building on Figure 11 from that study, if we shift the natural gas price to match the market price outlook of $13 per Mcf (2023$) in anticipation of LNG imports as a price umbrella, [equivalent to $10.40 per mcf (2016$)], roughly 48% above the $7 per Mcf (2016$) in Figure 11, the **real rate of return** for the 100 to 400 bcf tranche of augmented supply averages roughly **60%**.

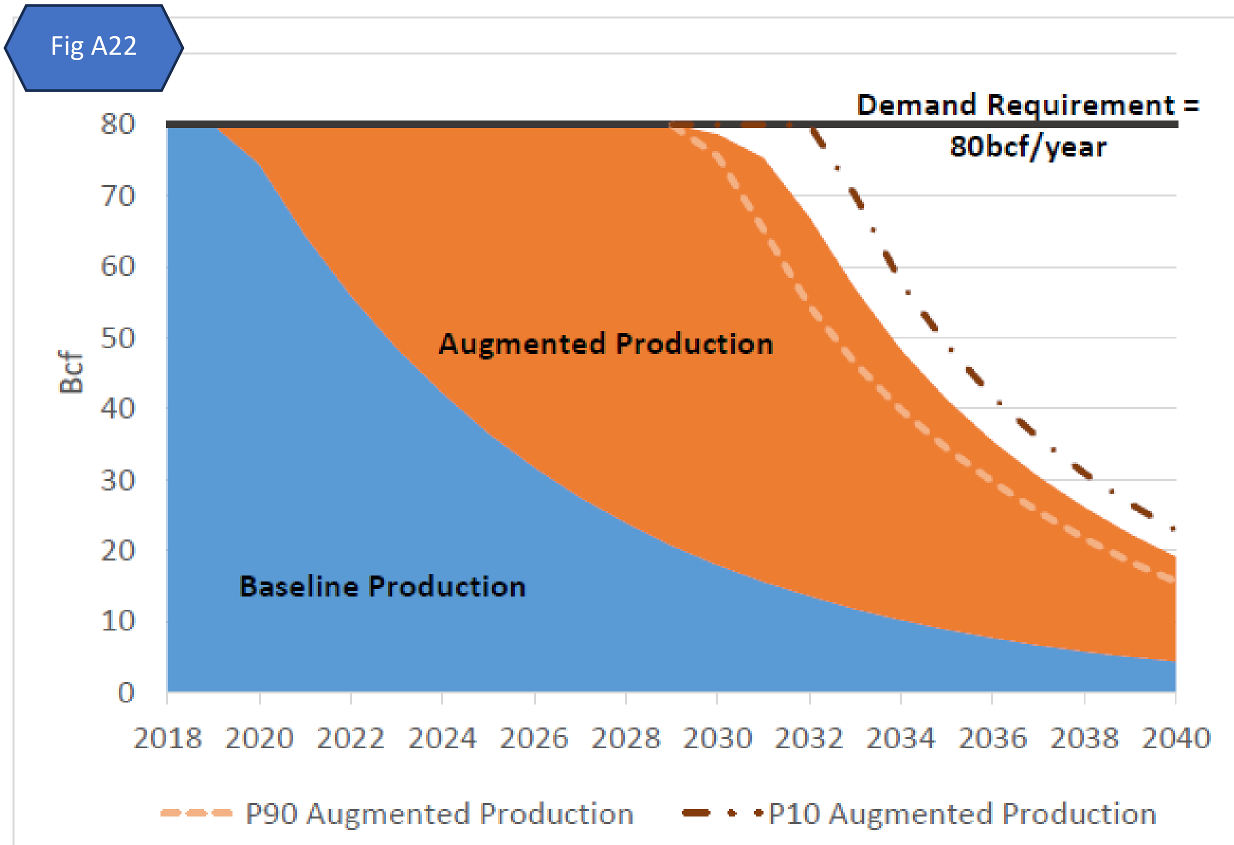


Figure 12. Cook Inlet supply and demand balance

As described in Figure 12 from that study, we treat the gas production from existing wells as "baseline production" and treat new wells, new compression and well workover activities as generating "augmented production".

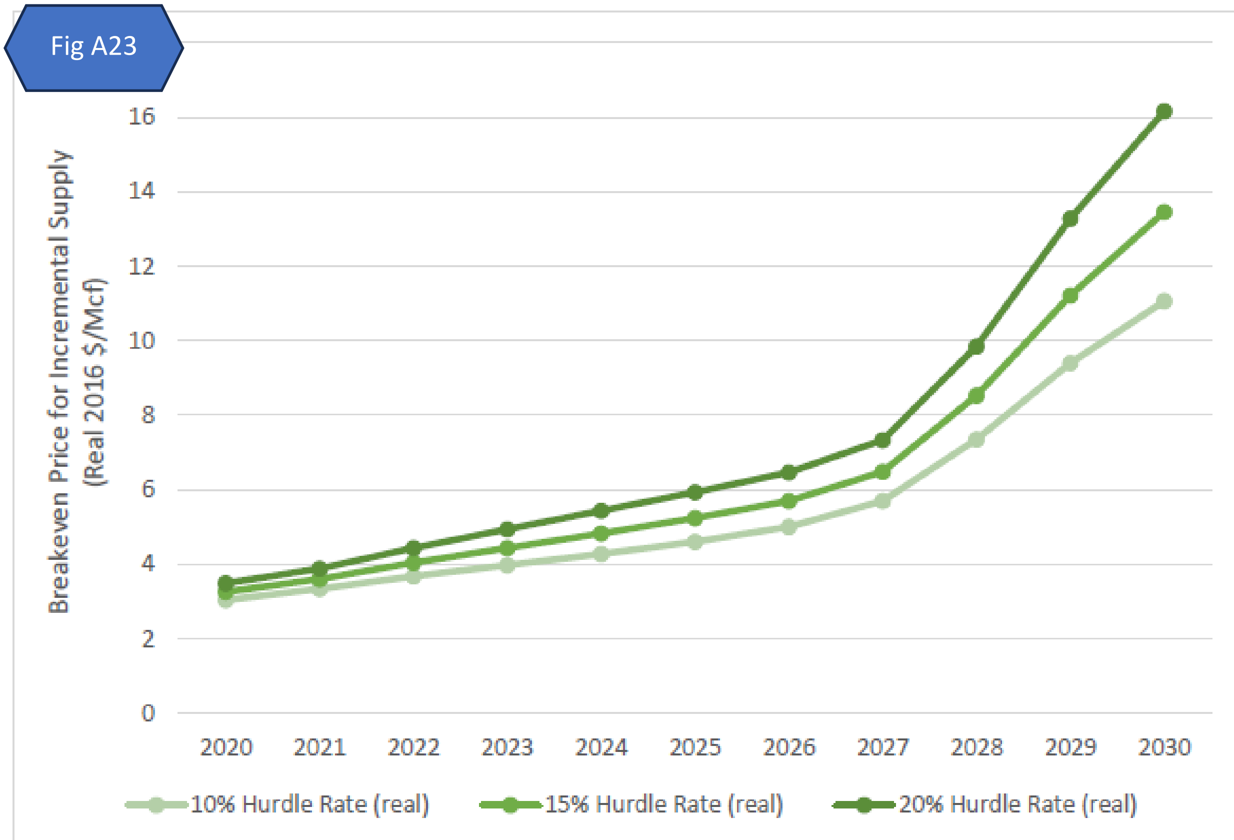


Figure 13. Natural gas breakeven prices (mean case) over time under 80 Bcf/year demand

MAFA Note:

The DNR DOG 2022 study assumed 70 bcf/year demand compared to the 80 bcf/year demand assumed in this figure from the 2018 study.

Chugach Electric Association, Beluga River Unit Transfer Price Update with Reserves Study and Asset Retirement Obligations updates (PRA 2022)

Chugach Electric engaged PRA to develop and updated reserves estimate. The updated reserves estimate was predicated on a $7.67/Mscf gas price (2022); roughly $6/Mcf (2016$).

The net result of the PRA update was to reduce estimated reserves and associated reserves to production ratio by roughly 20%.

Table A3

Table 1: BRU Field Remaining Reserves
Comparison of 2022 and 2019 Reserve Studies

	Remaining Reserves (Bcf)	
Reserve Study	Total Field	Chugach's Share
2022 Study	109	69
2019 Study (adj)	132	81
Difference	(23)	(12)

Table A4

	2P Proved+Probable		Royalty Gas (12.5%) (historically available to CEA)		Fuel Gas Consumption		100% WIO Gross Volume		Net Gas to CEA Interest	
Year	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Ann. Avg. MMSCF/D	Gross Volume MMSCF	Net Ann. Avg. MMSCF/D	Net Gas Volume MMSCF
2022	35.1	12,822	4.4	1,603	1.3	455	29.5	10,765	19.7	7,176
2023	41.4	15,094	5.2	1,887	1.3	455	34.9	12,752	23.3	8,501
2024	39.2	14,336	4.9	1,792	1.3	456	33.0	12,088	22.0	8,058
2025	36.1	13,171	4.5	1,646	1.3	455	30.3	11,069	20.2	7,380
2026	33.3	12,137	4.2	1,517	1.3	455	27.8	10,165	18.6	6,776
2027	28.4	10,372	3.6	1,297	1.3	455	23.6	8,621	15.7	5,747
2028	22.5	8,223	2.8	1,028	1.3	456	18.4	6,739	12.3	4,493
2029	17.8	6,511	2.2	814	1.3	455	14.4	5,242	9.6	3,495
2030	14.2	5,193	1.8	649	1.3	455	11.2	4,089	7.5	2,726
2031	11.4	4,161	1.4	520	1.3	455	8.7	3,186	5.8	2,124
2032	9.2	3,358	1.1	420	1.3	456	6.8	2,482	4.5	1,655
2033	7.4	2,709	0.9	339	1.3	455	5.2	1,915	3.5	1,277
2034	6.3	1,148	0.8	144	1.3	225	4.3	780	2.8	520
Total Volume		109,235		13,654		5,689		89,892		59,928

Table 4. Estimated Yearly Gas Deductions as Yearly Average Rates and Total Gross Volumes

As highlighted in the DNR DOG Cook Inlet Natural Gas Availability Study (2018), the projected volume of commercially viable reserves increases with increasing prices.

The DNR DOG Study (2018) assumes that local Cook Inlet supply across the basin will increase on the order of 320 bcf if the price increases from $6 to $12 (2016$) [Figure 10 above].

Cook Inlet Gas Forecast (DNR DOG January 2023)

The DNR DOG Cook Inlet Gas Forecast relied on EIA data to estimate Cook Inlet natural gas demand at roughly 70 bcf/year as described in their Figure 4.

Fig A24

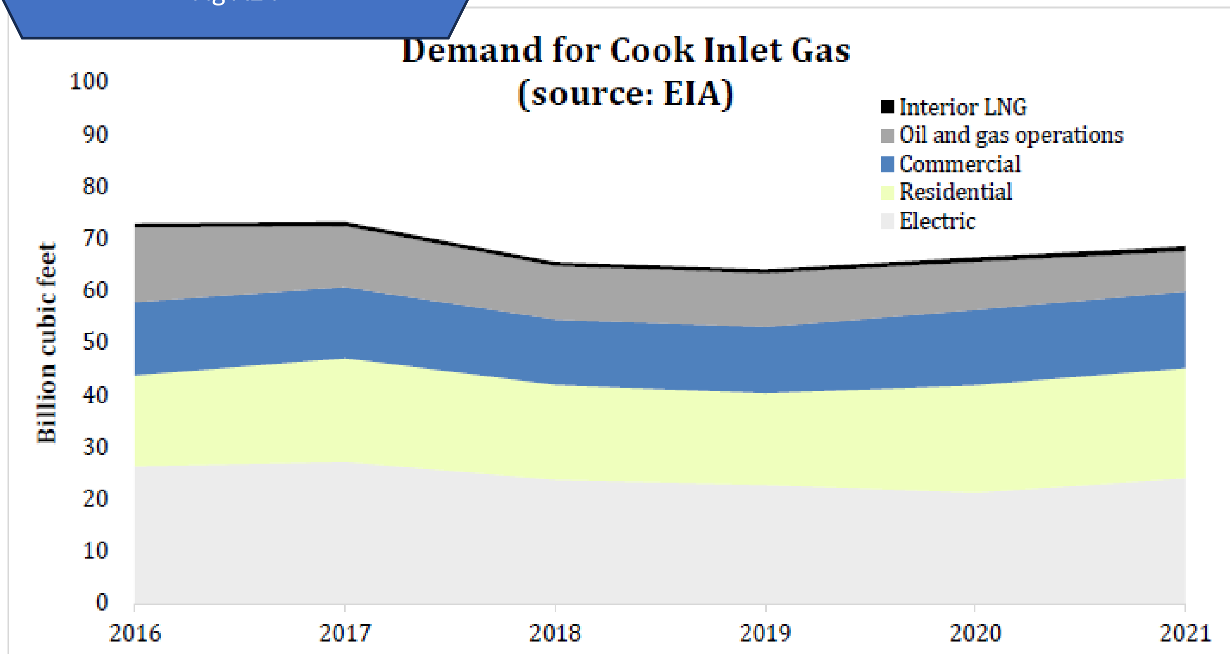


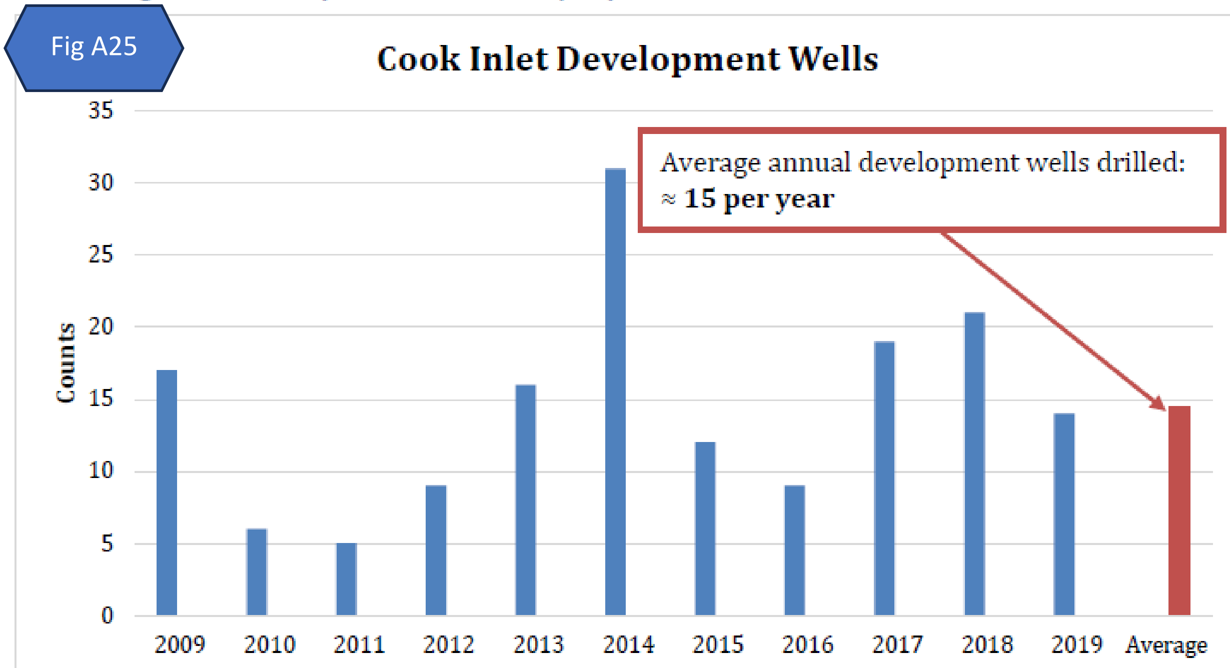
Figure 4 shows the demand for Cook Inlet gas by end use sector on an annual basis for the period 2016-2021, averaging approximately 70 bcf per year. The scope of this study does not include the modeling of the factors driving the demand for Cook Inlet gas in the future.

The focus is constrained to the supply side. However, in considering the outlook for economically feasible gas production from Cook Inlet, this study assumes that the observed demand profile of 70 bcf per year will remain largely unchanged. In other words, this means that, for the forecast period, consumers will not find substitutes for Cook Inlet gas or that they will not reduce their energy consumption.

Projects such as Donlin Gold could increase the demand for Cook Inlet natural gas by approximately 12 bcf/year resulting from the need to provide power to its proposed facilities and mining operations.[14] [MAFA emphasis added]

[14] The 2022 DNR DOG report on Cook Inlet Natural Gas appears to have retained an old, outdated demand estimate from Donlin Gold from the 2010 era. Donlin's public record disclosures from 2021 indicate Donlin Gold demand would be on the order of 20bcf/year which would increase the demand for local Cook Inlet natural gas (taking into account gas for field operations and compression to power the Donlin Gold natural gas pipeline) on the order of 23bcf/year; roughly double the previous estimate.

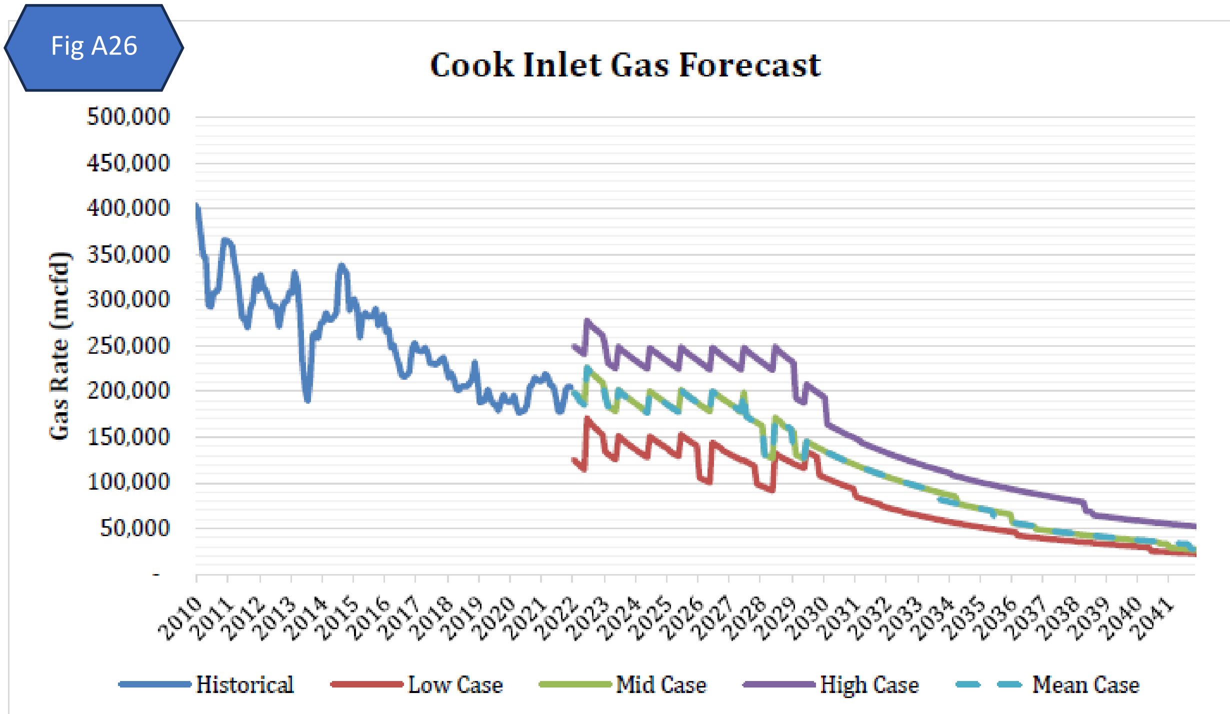
Figure 5. Historical development wells drilled in the Cook Inlet basin between 2009 and 2019 with an average of 15 development wells drilled per year



The probabilistic range of total remaining gas volumes at Cook Inlet ***with economics factored (Truncated)*** *is 1,109 bcf (High Case), 824 bcf (Mid Case), 603 bcf (Low Case), and* ***820 bcf (calculated Mean Case)****, including associated gas from oil production (see Figure 7, page 15). Forecasted associated gas accounts for 1–4% of total gas being forecasted between the Low and High Cases, respectively. The next graph (Figure 7, page 15) shows the impact of the economic limit test. Contrary to the case of the previous graph (Figure 6), not every field would continue producing until the last year of the forecast period. Specifically, some fields making up the Cook Inlet basin aggregate gas forecast would experience negative cash flows, which will cause the operators to shut down these fields and thus cease the production of gas to the market.*

MAFA Note: 15 wells/year X $12 million/well = $180 million a year in cap ex.

Figure 7. Truncated High-Mid-Low-Mean Streams in thousands of cubic feet per day (mcfd)



High Case (P1)		Mid Case (P1)		Low Case (P1)		Mean Case (P1)	
Total Gas Reserves (bcf)	1,108.9	Total Gas Reserves (bcf)	823.9	Total Gas Reserves (bcf)	602.5	Total Gas Reserves (bcf)	820.2
Gas (bcf)	1,066.6	Gas (bcf)	807.9	Gas (bcf)	597.2	Gas (bcf)	803.2
Associated Gas (bcf)	42.3	Associated Gas (bcf)	16.0	Associated Gas (bcf)	5.3	Associated Gas (bcf)	17.0

DNR DOG Study implicit reserves to production ratios for each of their P1 cases:

High	Mid	Low	Mean
14.3	10.7	7.8	10.7

Figure 11. Proved developed & undeveloped Cook Inlet gas in billion cubic feet per year

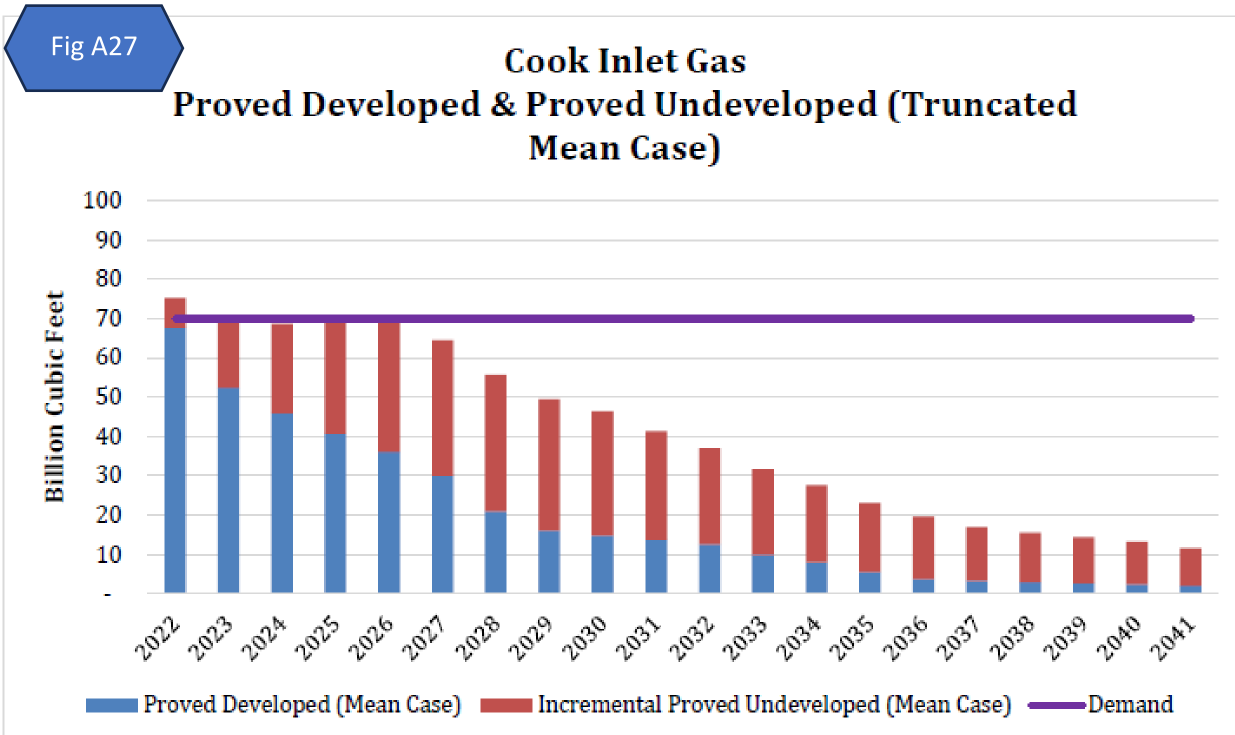
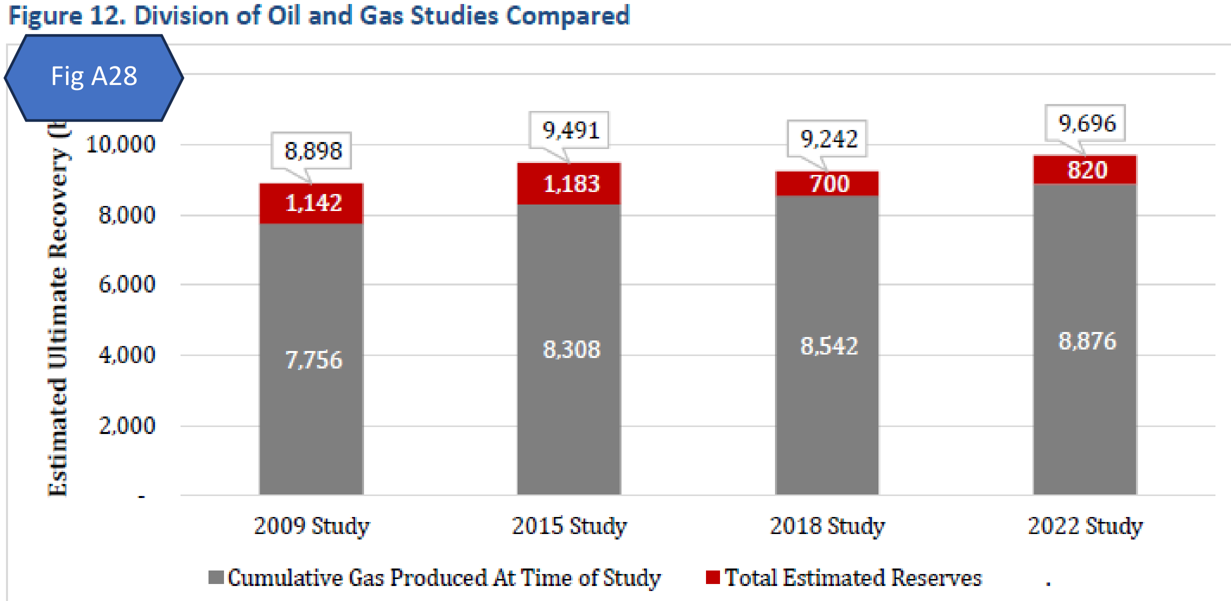


Figure 12. Division of Oil and Gas Studies Compared



MAFA Note: The 2022 Study mean reserves (820) to production (77) ratio of 10.7 is the highest ratio of reserves to production over the past two decades.

DNR DOG 2022 Cook Inlet Gas Forecast Legislative Presentations (2023)

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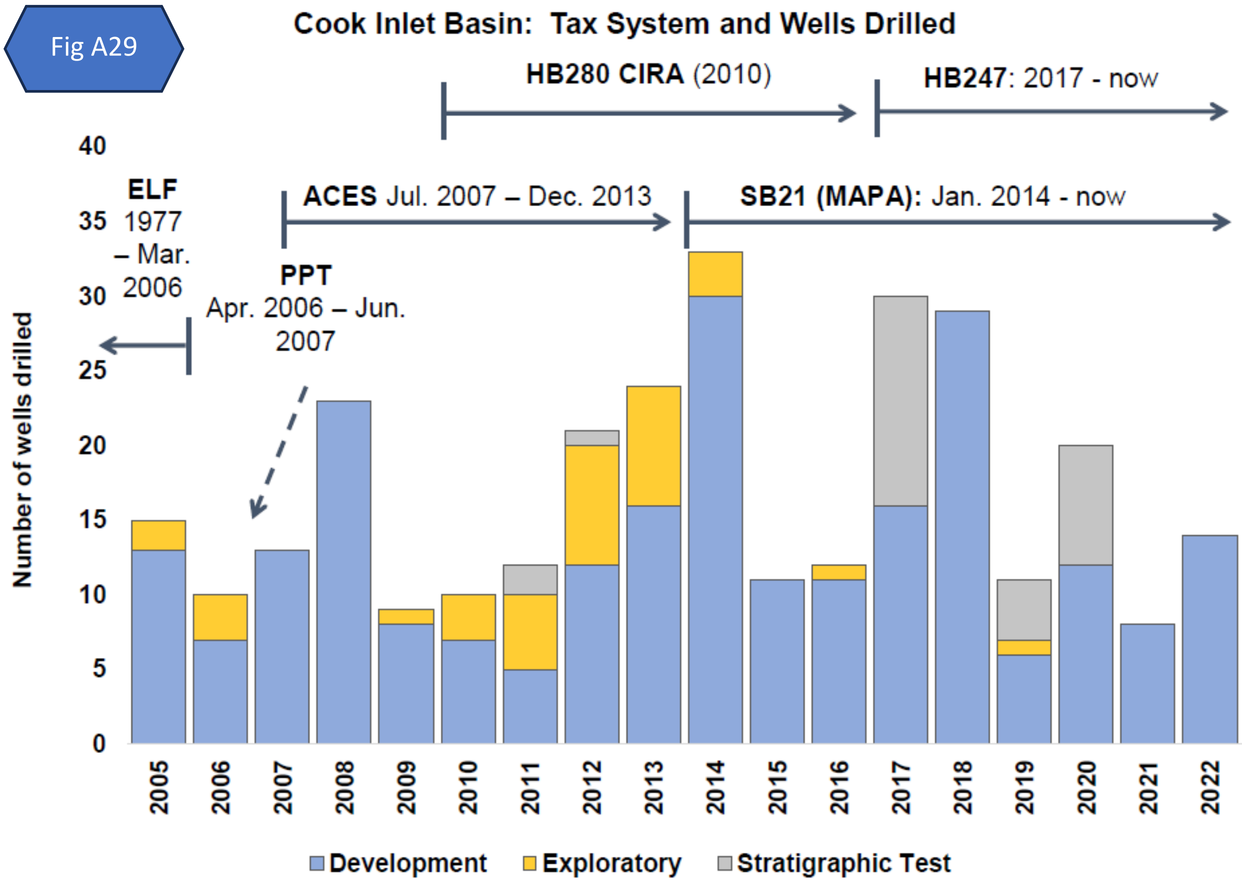
Fig A29



MAFA Notes:

Let's try to penetrate the fog of the DNR DOG Cook Inlet Gas Forecast presentations to the Senate Resources Committee in January 2023 by comparing Cook Inlet basin natural gas and oil & gas wells and the total driller depth from each of the three time periods within 2000-2023, before (2000-2009), during (2010-2016) and after (2017-2023) HB280, and review the natural gas **reserves to production ratio** at the conclusion of each of the respective investment cycles.

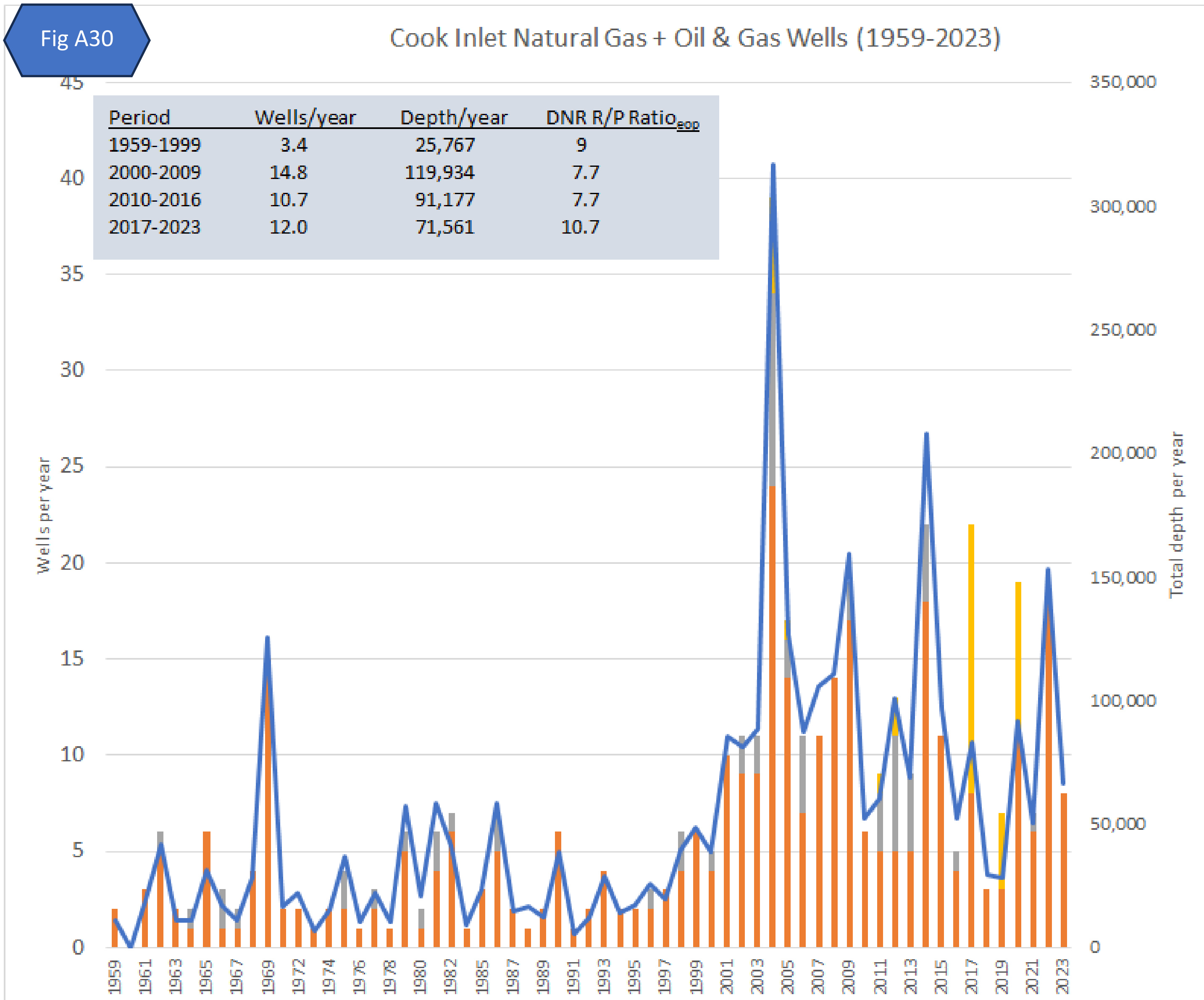


Fig A30
Cook Inlet Natural Gas + Oil & Gas Wells (1959-2023)
Period Wells/year Depth/year DNR R/P Ratio eop
1959-1999 3.4 25,767 9
2000-2009 14.8 119,934 7.7
2010-2016 10.7 91,177 7.7
2017-2023 12.0 71,561 10.7
Wells per year
Total depth per year
0
5
10
15
20
25
30
35
40
45
0
50,000
100,000
150,000
200,000
250,000
300,000
350,000
1959
1961
1963
1965
1967
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2017
2019
2021
2023

Summary:

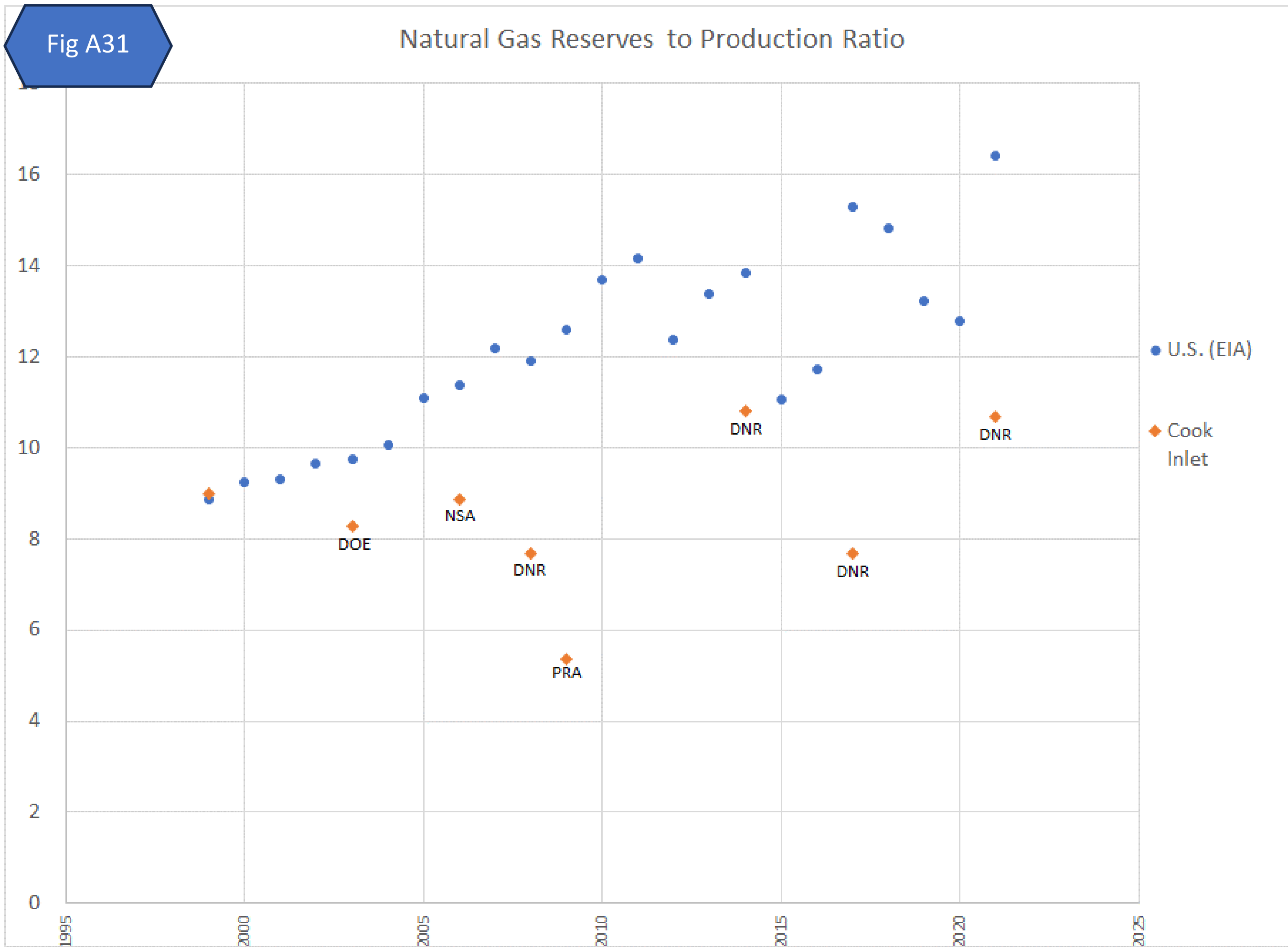


Fig A31
Natural Gas Reserves to Production Ratio
16
14
12
10
8
6
4
2
0
1995
2000
2005
2010
2015
2020
2025
DOE
NSA
DNR
PRA
DNR
DNR
DNR
U.S. (EIA)
Cook Inlet

Summary:

Table A5. Summary of Cook Inlet Well Completions / Reserves to Production Ratio at End of Investment Cycle

Time Period (Before/During/After HB280 Cook Inlet Natural Gas Subsidies)	Average Natural Gas Well Completions Per Year	DNR DOG Reserves to Production Ratio at End of Investment Cycle
2000-2009 (Before)	14.8	7.7
2010-2016 (During)	10.7	7.7
2017-2023 (After)	12.0	10.5

It appears that the Cook Inlet Natural Gas Exploration Incentives (HB280) shifted drilling from development to exploration wells and the *net* effect was fewer wells, higher cost per well associated with longer drill lengths, and no net increase in reserves per production ratios.

In contrast, after the State subsidy program to encourage exploration wells in the Cook Inlet was discontinued, well drilling reverted toward relatively higher value development wells which subsequently resulted in a marked increase in reserves to production ratio estimates by 2022.

The evidence suggests that State of Alaska Cook Inlet oil and gas incentives may have driven *shifts* in well drilling activity *but did not yield any net gains in the reserves to production ratios*.

It is also noteworthy that subsequent oil & gas exploration and development activities *after the expiration of the subsidies* have become markedly more efficient at developing more reserves relative to the annual production required to meet local demand.

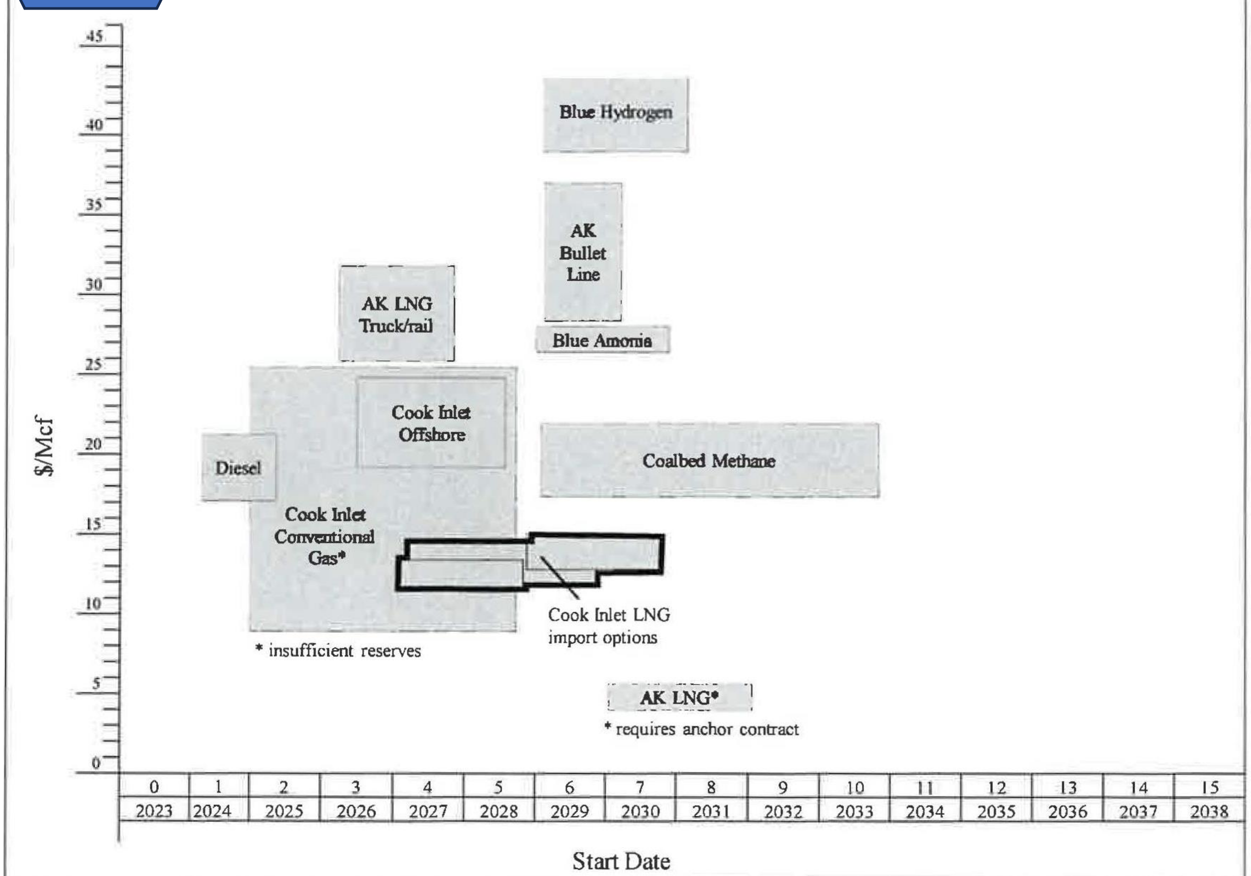
Chugach Electric Future Natural Gas Supply (August 2023) & Black & Veatch Chugach Gas Supply Option and Market Assessment (June 2023)

Chugach Electric has initiated a process to evaluate its future gas supply options in light of current gas supply contracts expiring in 2027 and the prospects of limited availability of local natural gas and increases in local prices.

In that context importing LNG appears to be a competitive option relative to future "Cook Inlet Conventional Gas" with what they have identified as "*insufficient reserves" – see Figure 2. Gas Supply Options Dashboard from the Chugach Future National Gas Supply cover memo to the Regulatory Commission of Alaska.

Fig A32

Figure 2: Gas Supply Options Dashboard



MAFA Note: While the Figure 2 Gas Supply Options Dashboard suggests **AK LNG*requires anchor tenant** may be $5/Mcf in 2030, the most recent EIA Annual Energy Outlook: Natural Gas Market Module (March 2023) indicates the liquefaction and pipe fee for Alaska LNG for export is $7.50 [Table 6, 2022$ per million btu]. If we add wellhead values in the $4/Mcf range [consistent with TransCanada/Exxon project development cost estimates circa 2010] and regasification and incremental storage in the Cook Inlet on the order of $1.50/Mcf, the total comes to $13/Mcf – roughly comparable to the low end of the range of Cook Inlet LNG import options described in the dashboard.

We note that Chugach has offered three demand/supply scenarios to frame their natural gas supply assessment:

1. Base Case: 12bcf/year demand with a 7 to 11 bcf/year "supply gap" emerging in 2030
2. Medium Gap: Moderate demand growth to 13 bcf/year offset by increased investment in renewables resulting in a 6 bcf/year "supply gas" emerging in 2034-2035 (slightly after the expiration of existing gas supply contracts between Enstar and Hilcorp)
3. Large Gap: Aggressive load growth and limited renewables with a large gap of 9 bcf/year emerging in 2030 and expanding to 15 bcf/year by 2039
4. Small Gap: Flat demand and increased investment in renewables with a small gap of 5bcf/year emerging in 2035 (again, slightly after the expiration of existing gas supply contracts between Enstar and Hilcorp)

We provide the base case, medium gap and small gap charts for reference below.

We highlight the potential for the small gap scenario to be met or exceeded due to the increasingly attractive prices that appear likely to result from investments in renewable energy with firming resources where a substantial portion of the federal financial support and investment tax credits are shared with the local electric utilities and their customers.

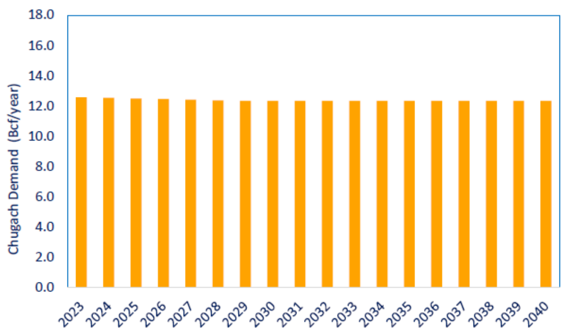
We note that the wind and solar prospects are significantly enhanced by the development of small low impact hydro projects, including pumped storage located near large wind farm(s).

Fig A33

Chugach Demand and Supply – Scenario 1 (Base Case)

Demand [1]

- Chugach base gas demand from historical demand
- No load growth from heat pumps or electrical vehicles



Supply

- Gas Supply Portfolio

Hilcorp Contract	March 2028
BRU Projection	December 2033
CINGSA Contract[2]	March 2032

- New Renewables from 2025

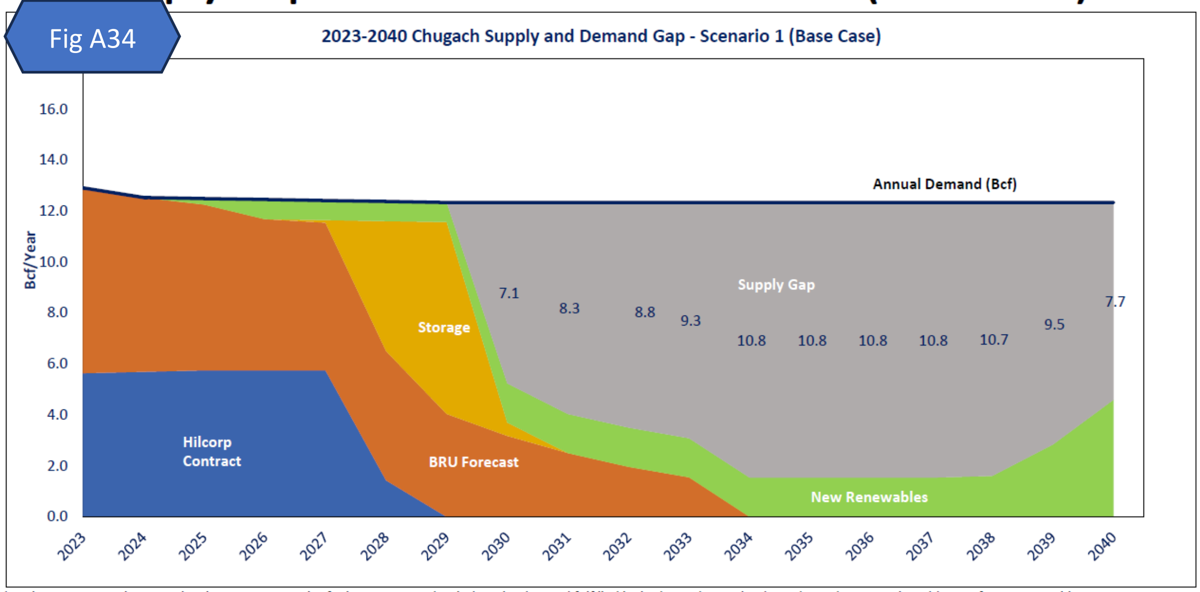
100,000 MWh Board Goal	2025	100,000 MWh
200,000 MWh Total	2030	200,000 MWh
Battle Creek	2038	9,350 MWh
50% Emissions Reduction Goal	2040	588,161 MWh

  - Total by 2040: 588,161 MWh (approx. 4.6 Bcf/year equivalent[3])

(1) Demand fulfilled by existing hydro and wind farm resources has been excluded in this analysis.
(2) For storage of excess BRU production
(3) Assuming a heat rate of 7,680 Btu/kWh for conversion

Gas Supply Gap Annual Profile – Scenario 1 (Base Case)

Fig A34



*Fuel requirement shown in the chart represents the fuel requirement (excluding the demand fulfilled by hydro and Fire Island Wind Farm) prior to the addition of new renewables

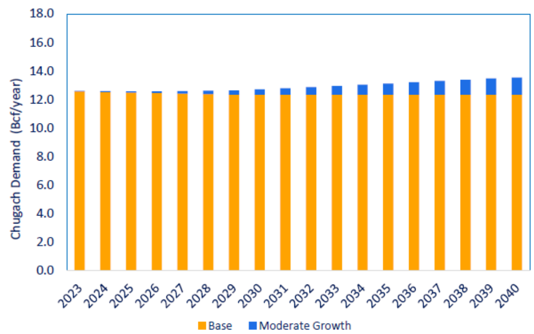
Scenario 1: Gas supply gap initially starts from July 2027, which is expected to be offset by strategic planning of storage for excess BRU production through January 2030. Gas supply gap from January 2030 (after new renewables addition) is approximately 7.1 Bcf/year in 2030, increasing to 10.8 Bcf/year in 2034 due to cease of BRU supply and decreasing to 7.7 Bcf/year in 2040 due to increasing renewable penetration.

Fig A35

Chugach Demand and Supply – Scenario 2 (Medium Gap)

Demand (1)

- Chugach base gas demand from historical demand
- Moderate load growth compared to Base Case due to increasing consumption for electrical vehicles and heat pumps. This would be an estimated additional 42k EV and 3.3% buildings with heat pumps.



Supply

- Gas Supply Portfolio

Hilcorp Contract	March 2028
BRU Projection	December 2033
CINGSA Contract(2)	March 2032

- New Renewables from 2025

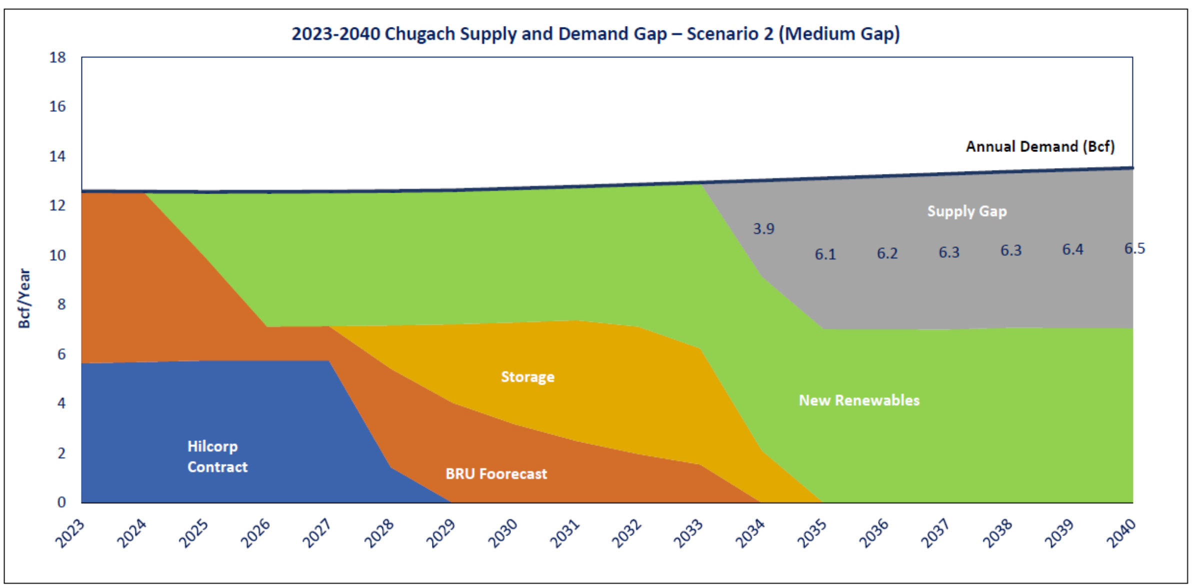
Little Mt. Susitna Wind	2025	415,000 MWh(4)
Great Lands Solar	2025	194,000 MWh(4)
Godwin Creek	2032	125,000 MWh
Dixon Creek	2032	89,600 MWh
Battle Creek	2038	9,350 MWh

- Total by 2040: 832,950 MWh (approx. 6.4 Bcf/year equivalent(3))

(1) Demand fulfilled by existing hydro and wind farm resources has been excluded in this analysis.
(2) For storage of excess BRU production
(3) Assuming a heat rate of 7,680 Btu/kWh for conversion
(4) Subject to power regulation limitations

Fig A36

Gas Supply Gap Annual Profile – Scenario 2 (Medium Gap)



*Fuel requirement shown in the chart represents the fuel requirement (excluding the demand fulfilled by hydro and Fire Island Wind Farm) prior to the addition of new renewables

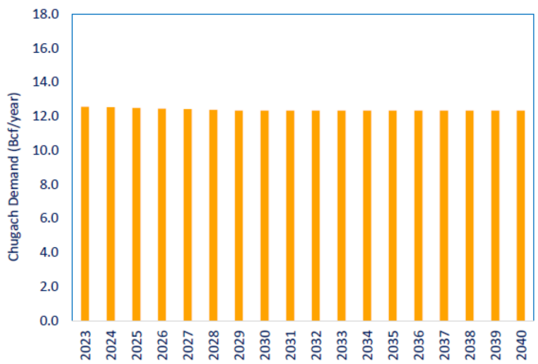
Scenario 2: Gas supply gap initially starts from April 2028, which is expected to be offset by strategic planning of storage for excess BRU production through 2034. Gas supply gap from April 2034 (after new renewables addition) is approximately 3.9 Bcf/year in 2034, increasing to 6.5 Bcf/year in 2040.

Fig A37

Chugach Demand and Supply – Scenario 4 (Small Gap)

Demand (1)

- Chugach base gas demand from historical demand
- No load growth from heat pumps or electrical vehicles



Supply

- Gas Supply Portfolio

Hilcorp Contract	March 2028
BRU Projection	December 2033
CINGSA Contract[2]	March 2032

- New Renewables from 2025

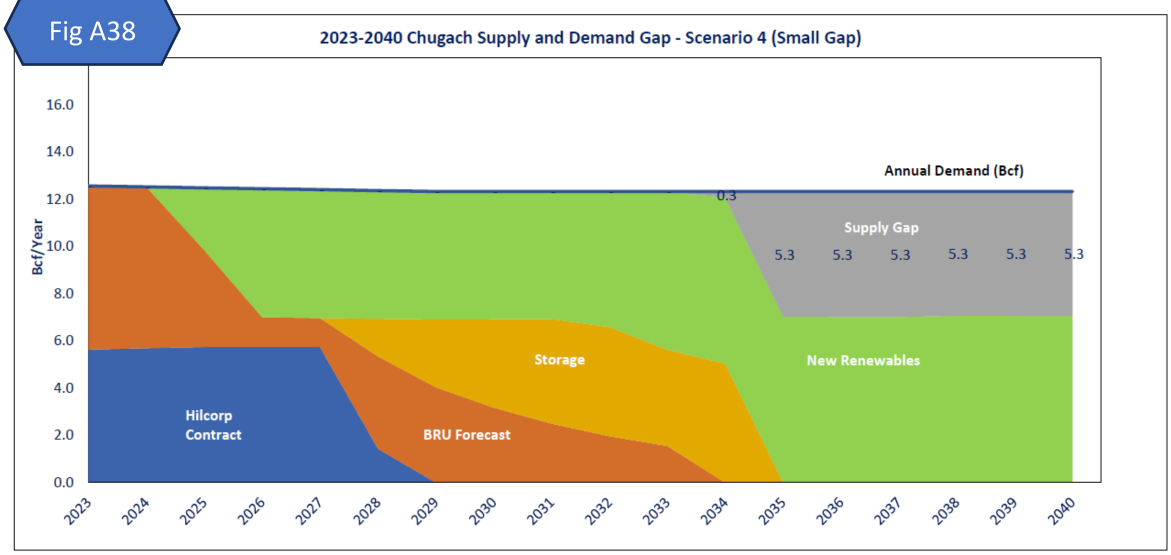
Little Susitna	2025	415,000 MWh[4]
Great Land Solar	2025	194,000 MWh[4]
Godwin Creek	2032	125,000 MWh
Dixon Creek	2032	89,600 MWh
Battle Creek	2038	9,350 MWh

- Total by 2040: 832,950 MWh (approx. 6.4 Bcf/year equivalent[3])

(1) Demand fulfilled by existing hydro and wind farm resources has been excluded in this analysis.
(2) For storage of excess BRU production
(3) Assuming a heat rate of 7,680 Btu/kWh for conversion
(4) Subject to power regulation limitations

Gas Supply Gap Annual Profile – Scenario 4 (Small Gap)

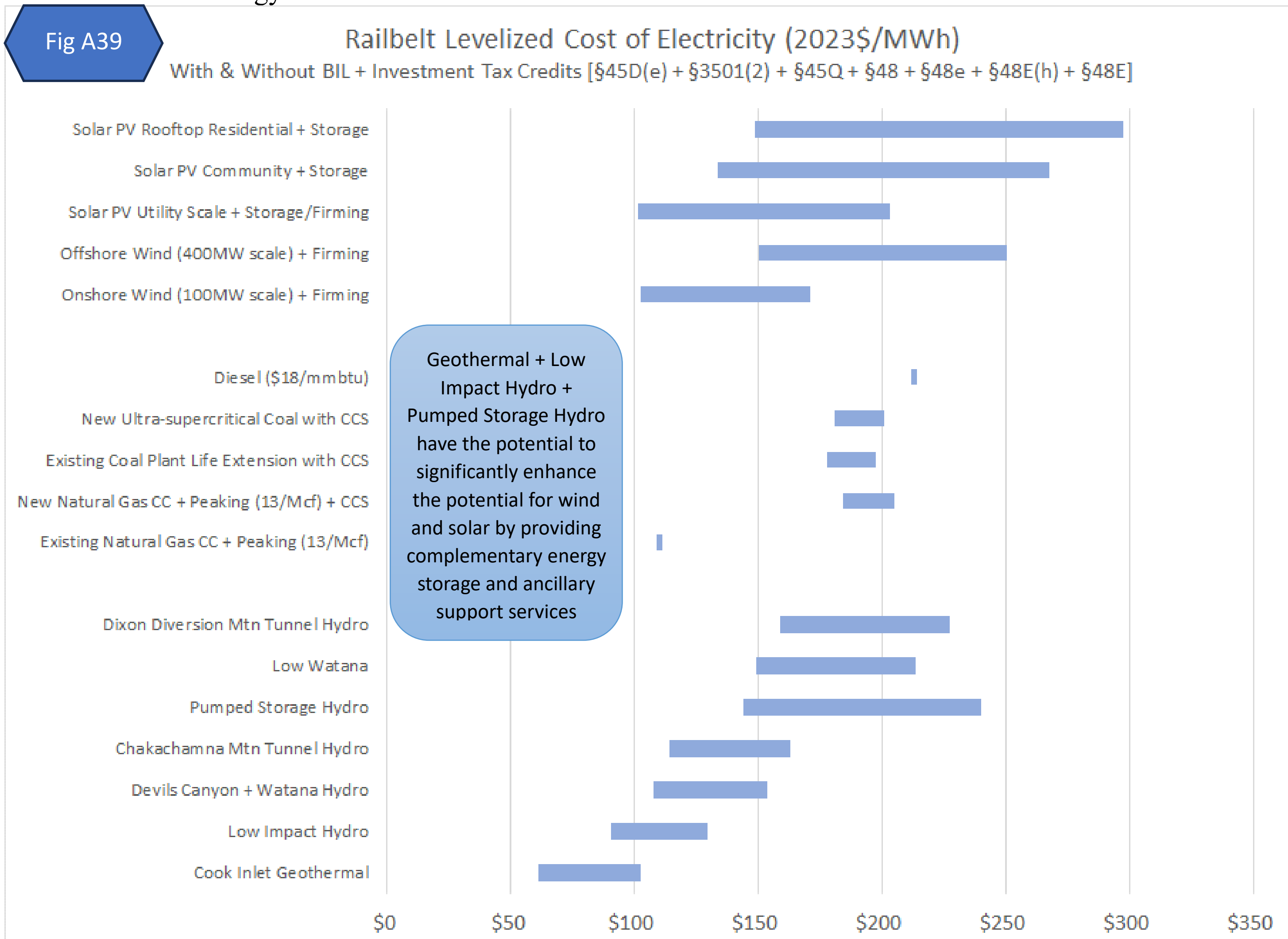
Fig A38



*Fuel requirement shown in the chart represents the fuel requirement (excluding the demand fulfilled by hydro and Fire Island Wind Farm) prior to the addition of new renewables

Scenario 4: Gas supply gap initially starts from April 2028, which is expected to be offset by strategic planning of storage for excess BRU production through December 2034. The gas supply gap (after new renewables addition) is approximately 0.3 Bcf/year in 2034, increasing to approximately 5.3 Bcf/year in 2035.

Renewable Energy Alternatives



Federal Renewable Energy Investment Tax Credits

Intro

Clean Electricity Investment Tax Credit (26 U.S. Code §48E)

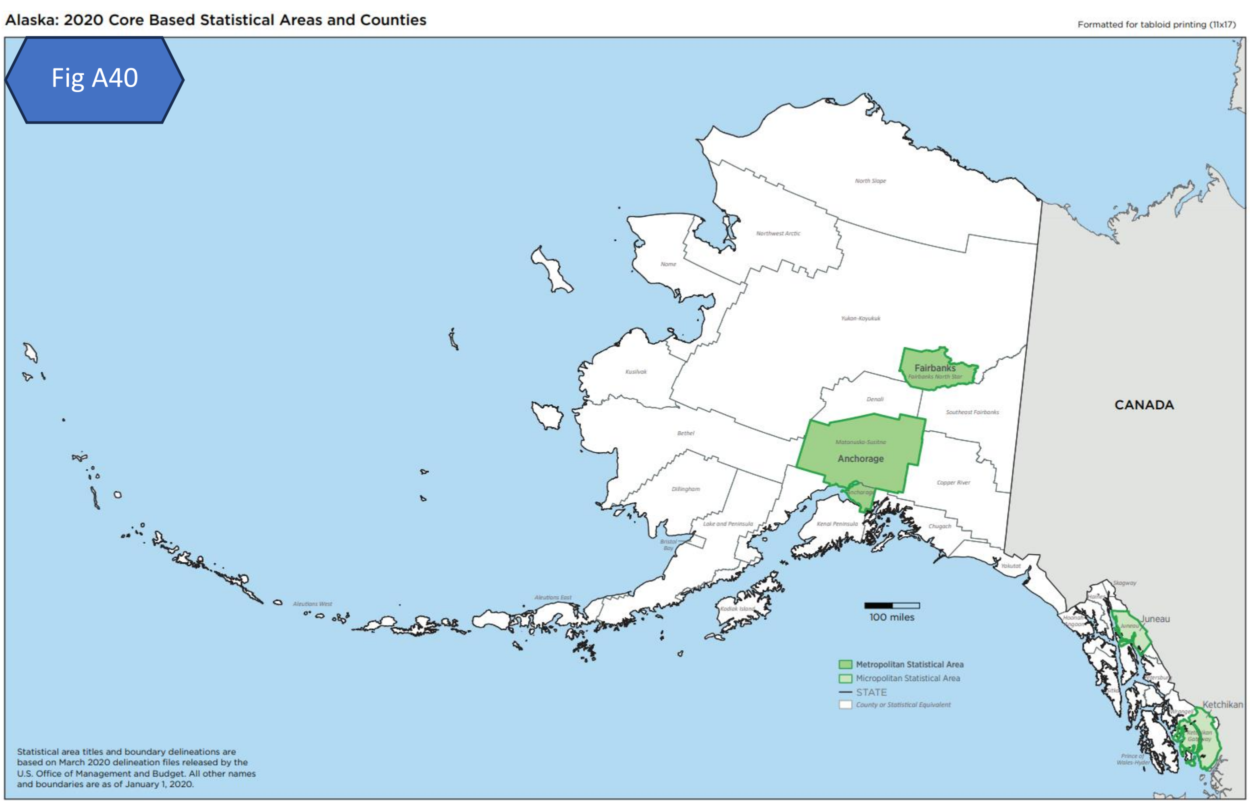
30% investment tax credit

Indian Land

10-percentage point bonus of investment credit for qualified solar and wind facilities located on Indian land (26 U.S. Code §48(e)(2))

Energy Communities

All communities / boroughs in Alaska, except the Anchorage Metropolitan Statistical Area which includes the Muni of Anchorage + Mat-Su Borough), have qualified as “energy communities” eligible for a 10 percentage point bonus clean energy investment tax credit.



Estimated costs and prices for the exploration and development of local Cook Inlet natural gas resources

Historic local Cook Inlet natural gas supply curve

Adjustments to 2016$ Supply Curve to update it to 2023$ Supply Curve

Capital & Operating Cost Inflation (2016 to 2023)

Cost of Capital (2016 to 2023)

Exploration and development well productivity (2016-2023)

Monopolistic Supply Side Price Premium (2023+)

Cook Inlet Natural Gas Supply Curve

Historic Baseline (DNR DOG Cook Inlet Natural Gas Availability, 2018)

This study starts with the Cook Inlet Natural Gas Supply Curve (volume vs. price) developed by DNR DOG in its March 2018 report "Cook Inlet Natural Gas Availability" and updates and extends those supply curve estimates.

We start with the Cook Inlet Natural Gas Availability Study (2018 study / 2016 data and 2016$) Figure A-1: Cumulative supply from augmented production sources (assuming a 15% real hurdle rate and 50th percentile probability case).

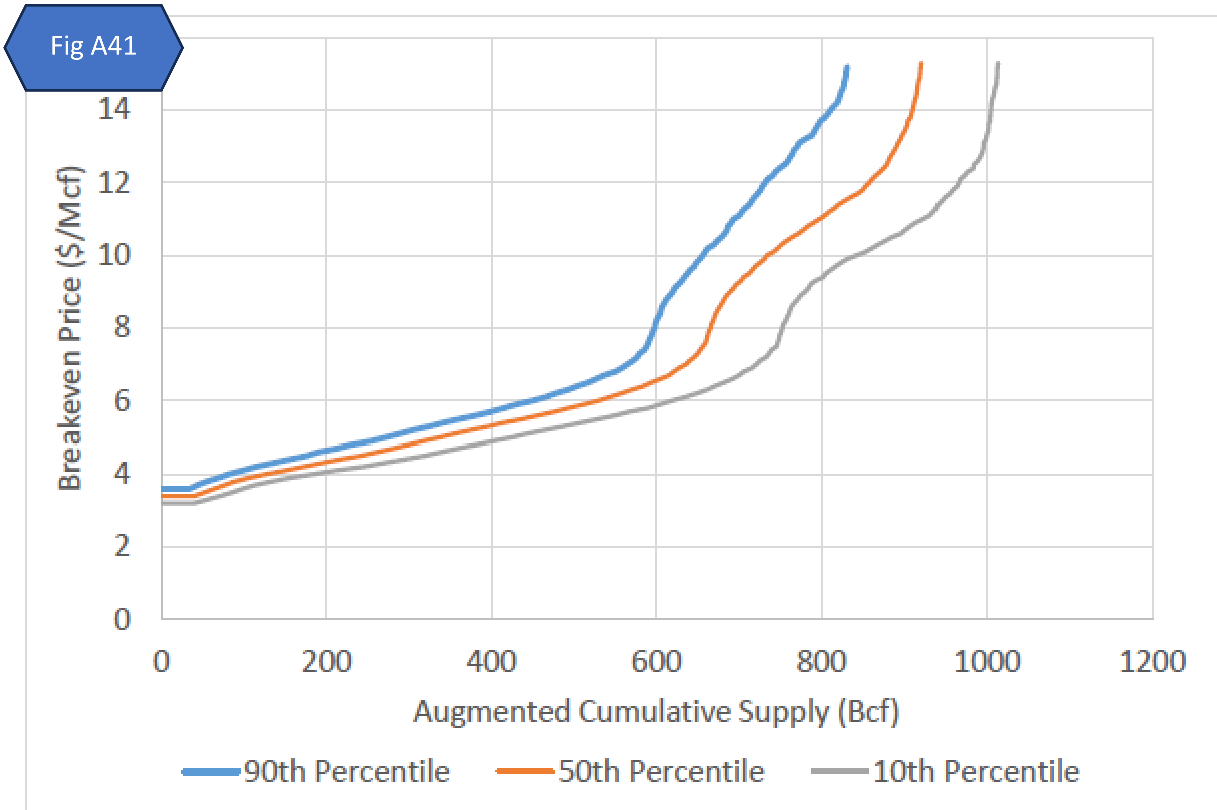


Figure A-1. Cumulative supply from augmented production sources (15% real hurdle rate)

MAFA Notes on Figure A-1: We start with a 50th percentile probability case, a 15% real hurdle rate and 2016 real $ estimate. We will update this to adjust the 2016$ to 2023$ based on oil and gas sector capital and operating cost inflation and then adjust the cost curves to reflect a 2023 outlook for the cost of capital and associated hurdle rate.

2023 vs 2016 upstream oil & gas sector capital and operating cost inflation

MAFA Notes on Upstream Capital Costs Index: The upstream capital costs index (S&P Global Commodity Insights) experienced a rapid decline in 2015 which roughly stabilized across 2016-2021 and then jumped on the order of 30% from 2021 to 3rd/4th quarter 2023. The upstream operating cost index exhibited a similar, albeit less pronounced decline in 2015 and more moderate resurgence on the order of 20% from 2021 to 2023. We estimate the weighted average of capital and operating upstream costs to have increased 1.24X the 2016 baseline by 2023.

2023 vs 2016 Cost of Capital History & Outlook

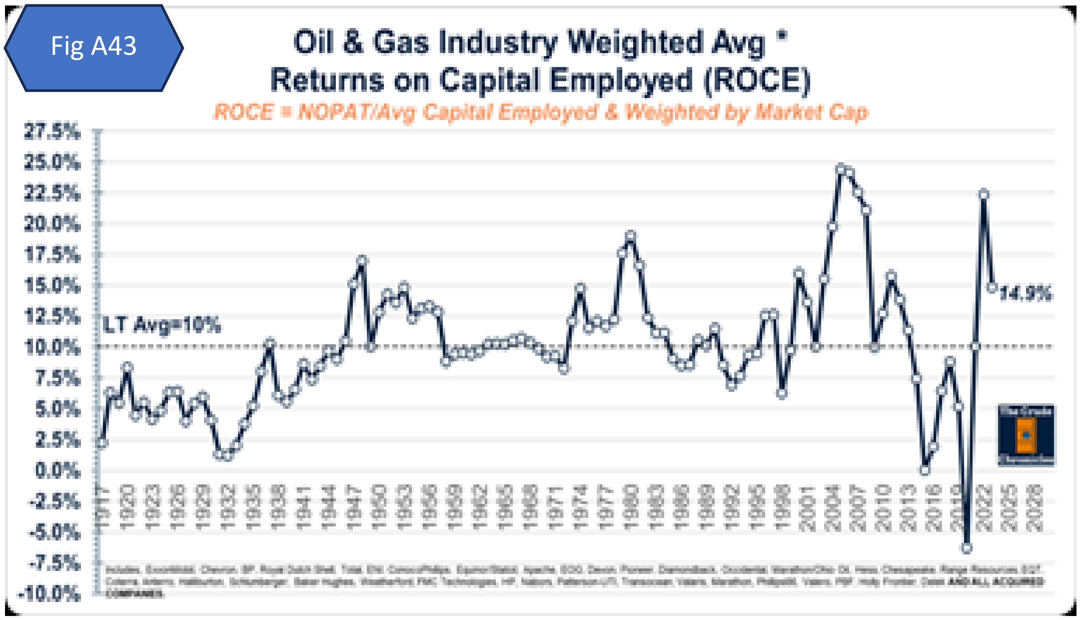
We next review the cost of capital for the oil and gas industry in the U.S. and then estimate a Cook Inlet premium in order to identify a real Internal Rate of Return supply curve that most closely approximates a reasonable estimate based on the current outlook.

Oil & Gas Industry Cost of Capital Background

Chevron CEO Mike Wirth, "…through the [price] cycle[s], it's an industry that generates kinda 10%-ish returns on capital employed…", January 4, 2023, Chevron CEO Defends Record Profits as 'Modest Return' Over Time", Bloomberg Business, January 4, 2023.

This long-term view is captured in the Crude Chronicle Energy Index (CCEI), August 18, 2023, Oil and Gas Industry Weighted Average Returns on Capital Employed (ROCE) long term (1917-2023) average approximately 10%, below.

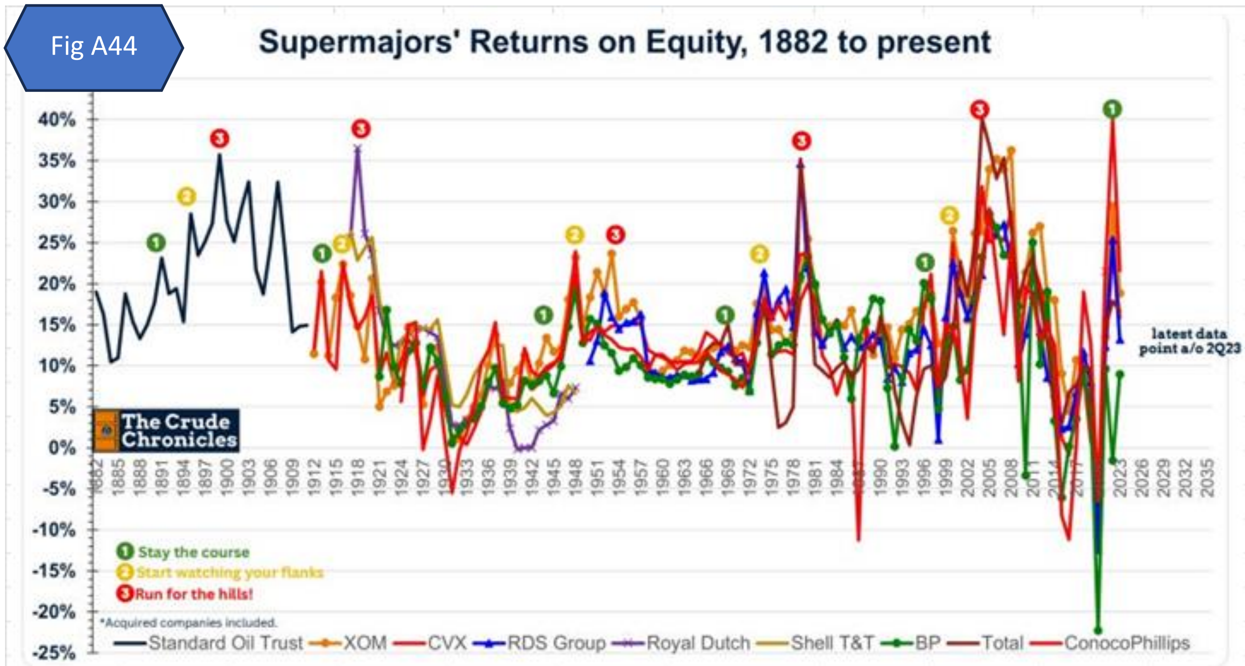
Fig A43



Within this long-term view, it is useful to note that the price/production controls associated with the Texas Railroad Commission regulation of U.S. oil and gas industry skews the 1930s – 1972 period ahead of the 1973 Arab OPEC oil embargo period toward lower returns and low volatility.

Modern (1973-2023), more open competitive markets, with the Saudis as swing producer over much of the period, have exhibited a market cap weighted ROCE in the -5% to +25% range with marked increase in volatility around an average of ~13%. Returns on Capital Employed (ROCE) estimates through the second quarter of 2023 have been ~14-15% nominal, which includes Shell at 10% and Exxon at 16%.

Fig A44

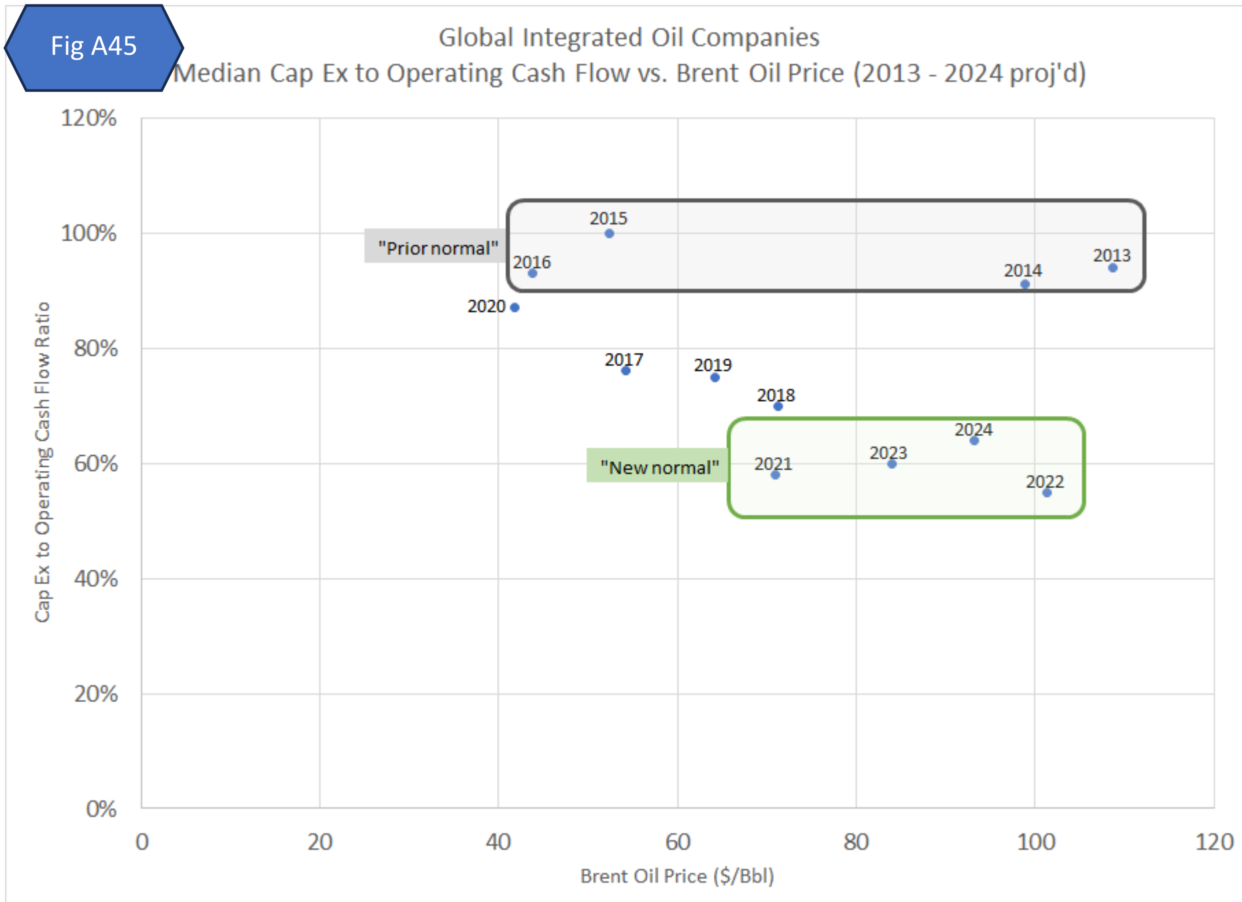


16.10%	14.10%	9.90%		10.70%
XOM	CVX	SHEL		BP
Global Average from Oil & Gas (Production & Exploration)			14.31%	

Next, we consider whether the accumulating recent changes in oil industry reinvestment levels across the 2013-2024 time period indicates a change in the cost of accessing capital.

Global Integrated Oil Companies have transitioned from median cap ex to operating cash flow ratio of roughly 95% down to roughly 60% across the 2016-2021 period.[15]

[15] See for example S&P Global Ratings Oil & Gas Producers Access to External Financing (November 2023)



Sources: S&P Global Ratings and S&P Global Commodity Insights "Will Oil & Gas Producers Lose Access to External Financing as Lenders Decarbonize?", November 2023, with MAFA corrections to cap ex to cash flow ratios and brent crude oil average prices

Notwithstanding the reduction in capital investment to operating cash flow ratios (internally generated capital financing), S&P Global Ratings November 2023 Financial Outlook report finds:[16]

- We have not seen a material impact to the near- and medium-term funding environment for International Oil Companies and *independents* in terms of *access to capital and cost of capital [MAFA emphasis added]*.
- Despite longer-term pressures on funding sources, a focus on cash flow generation and debt repayment, along with higher oil prices and slower demand growth, *has reduced external financing needs for the sector*, a trend we expect to continue for the foreseeable future *[MAFA emphasis added]*.
- During the *back half of the 2030s* in particular, there is a scenario in which capital market access could become increasingly difficult for *some oil and gas companies – especially for small independents that have higher marginal production costs* – and *could manifest*

[16] ibid

> *itself in the form of higher funding costs, tighter credit terms or some sources of capital becoming partially or totally inaccessible [MAFA emphasis added].*

Cook Inlet Oil & Gas Province Cost of Capital Estimates

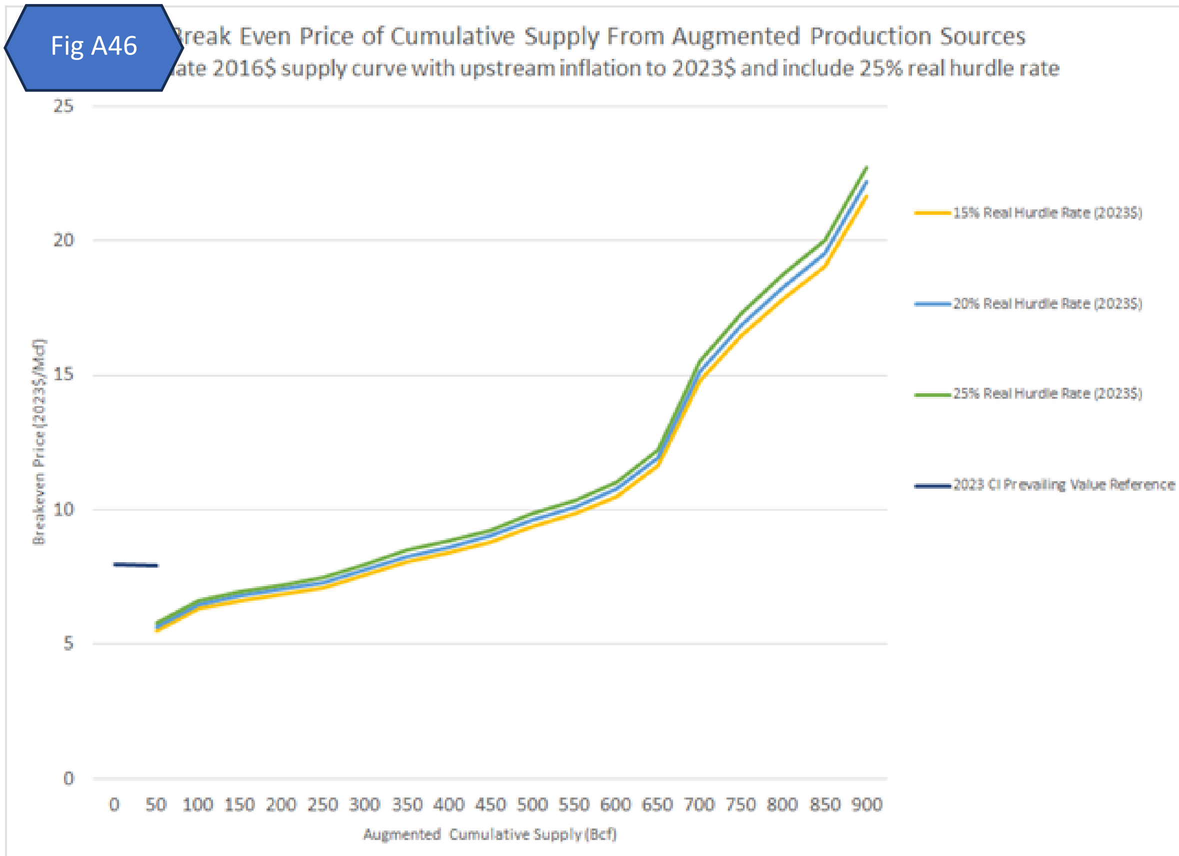
MAFA estimates current **Cook Inlet oil and gas province** market cap weighted *cost of capital* may be on the order of 25-35% nominal, somewhere in the range of 10-20% percentage points above the oil and gas industry aggregate, spanning the wide range of the market capitalization mix of Cook Inlet enterprises operating within a micro scale (70bcf/year) addressable market.[17]

Assuming forward looking inflation of 2.2% (PCE 10-year Projection, Philadelphia FED Survey of Professional Forecasters, November 2023), the *real cost of capital* may be in the range of 22%-32%, with a market cap weighted value in the range of **25%**.

Due to the particular circumstances of the Cook Inlet natural gas market, which include an unregulated near monopoly (~90% market share) dominant supplier, infrequent term contracts, extremely limited spot market, and a limited group of small micro-cap challengers, the Cook Inlet oil and gas sector already exhibits a small tail of small independents with higher marginal production costs with a higher funding costs. **The risks highlighted by S&P Global Rankings (November 2023) slated for the "back half of the 2030s" may emerge in the back half of the 2020s for the small microcap independents.**

Combining 2023 vs. 2016 inflation and cost of capital considerations and applying those to the DNR DOG Cook Inlet Support Curves, Figure A-2, we estimate the break-even price for Cumulative Supply from Augmented Production Sources Cook Inlet as follows:

[17] For reference, the U.S. imports 3,000 bcf/year from Canada. The Eastport Idaho port of entry imports on the order of 900 bcf/year from Canada [EIA U.S. Natural Gas Imports by Port of Entry, Annual Pipeline Volumes, 2022].



We note that the prevailing values for the augmented supply remain on the order of 40% above the break-even price even after we take into account inflation and a 25% real hurdle rate (2023$).

2023 vs 2016 Exploration & Development Productivity

Next we consider whether local natural gas exploration and development and well workover activities have become more or less productive than the 2016 baseline in the DNR/DOG study.

Our initial review of the increase in local Cook Inlet natural gas production that has emerged from the Ninilchik, North Cook Inlet and Beluga River Units suggest that Hilcorp's productivity (Mcf/foot of new well drilling; Mcf/well workover activity) may be increasing, notwithstanding that some of the activities in those fields may simply be accelerating recovery and not adding new reserves.

However, the aggregate production from other fields, e.g., Kenai, McArthur River, Swanson River, Kitchen Lights, that include both production developed by Hilcorp and other operators, appears to reflect flat to declining productivity.

A complete analysis of oil and gas productivity from across each of the wells and fields in the Cook Inlet compared to prior studies is beyond the scope of this immediate study.

Based on that initial high-level reconnaissance, we believe it is reasonable to assume that the net production productivity from across the Cook Inlet is roughly comparable to the productivity assumptions developed in the DRN DOG 2018 Cook Inlet Gas Availability study and may remain so in our outlook.

This leaves us with a gap between the estimated break-even price of supply in 2023 of roughly $5.50-5.60/mcf and the prevailing value of roughly $8/mcf.

We attribute that $2.40/Mcf on $5.60/Mcf (~40%) gap to the monopolistic pricing power that Hilcorp has given its dominant market share, the small number and infrequency of electric and natural gas utility natural gas supply contract transactions, and the limited competition from the current slate of micro-enterprises competing against Hilcorp in the Cook Inlet.

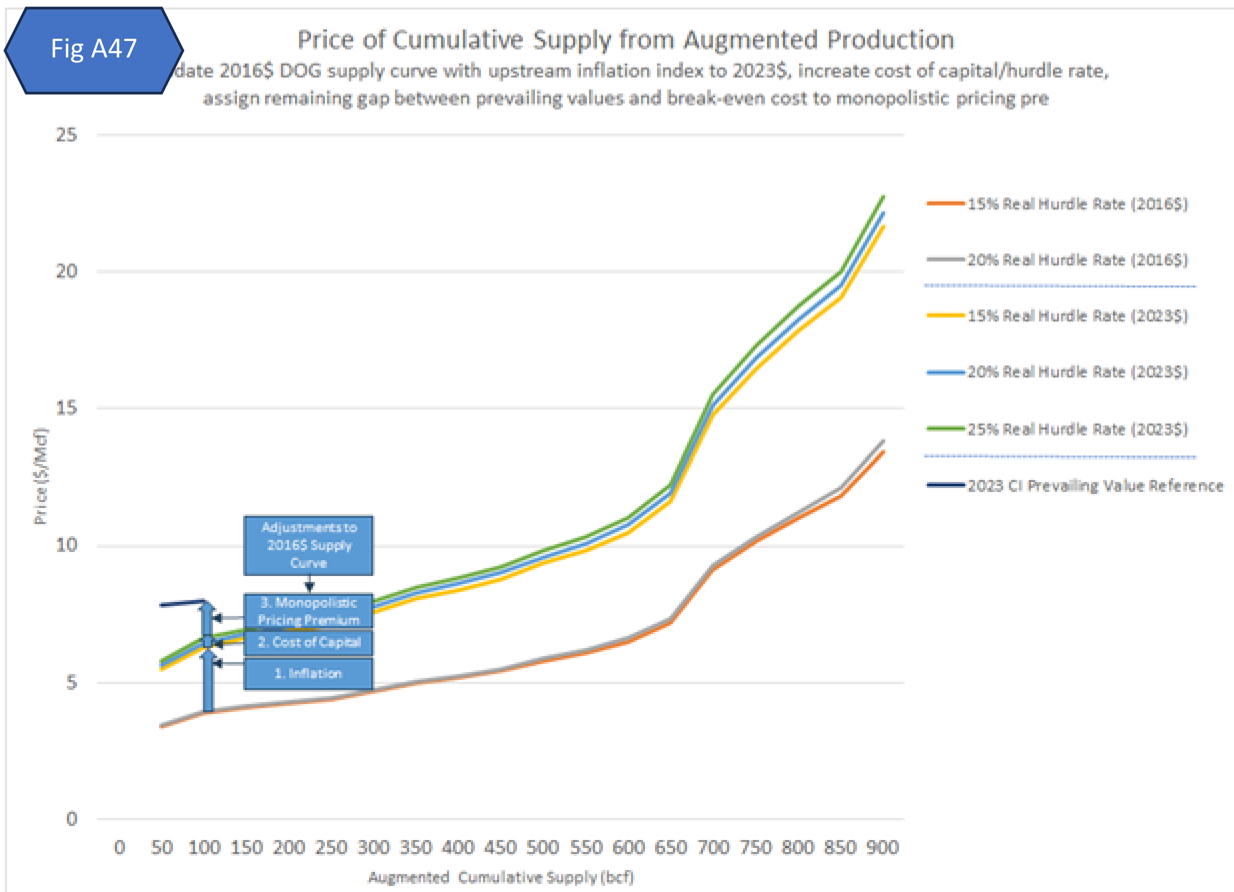
Monopolistic Supply Side Market Price Premium

In the absence of:

- a major change in market structure and concentration,
- the emergence of a modest spot market, or
- major policy intervention,

the current estimated gap in the cost of capital between the micro-enterprises in the Cook Inlet and Hilcorp's estimated private market capitalization of a "major independent" would suggest that Hilcorp seems likely to sustain its monopolistic pricing power in the Cook Inlet unless/until local pricing is effectively capped by competitively priced LNG imports.

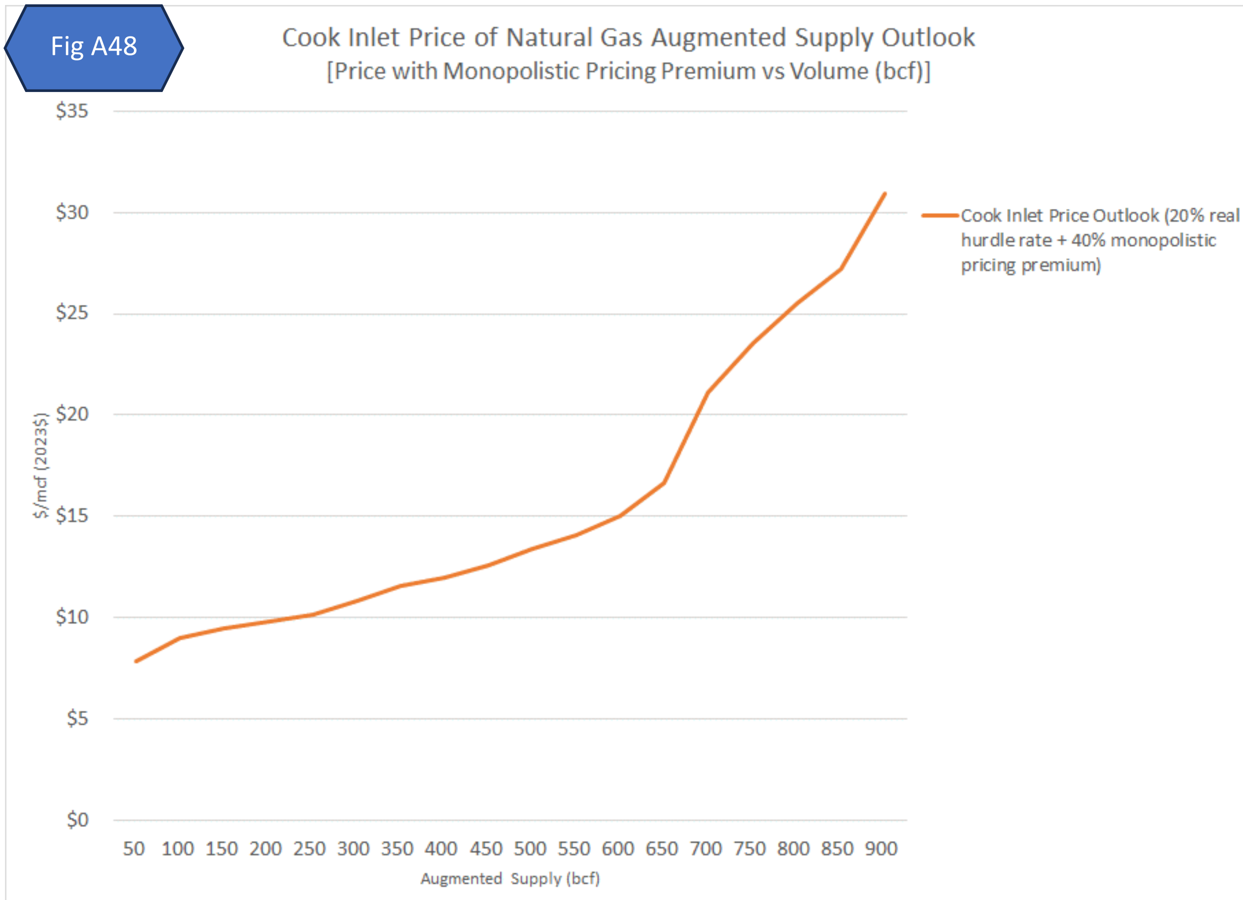
Fig A47



Supply Curve Update Summary

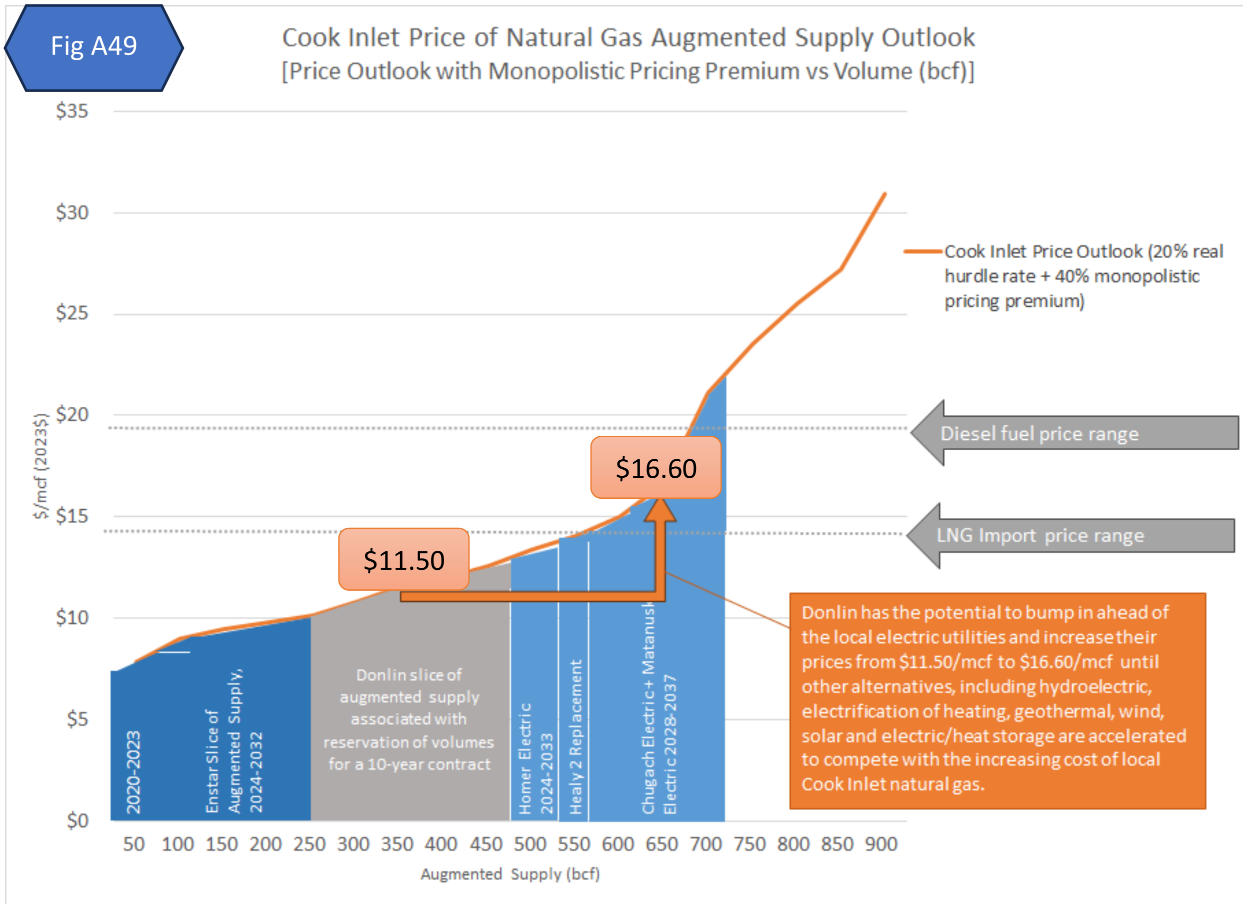
Combining inflation, increase in cost of capital and local monopolistic pricing, we estimate the local Cook Inlet Natural Gas supply curve (2023$) as:

Fig A48



Supply Curve Update Plus Donlin

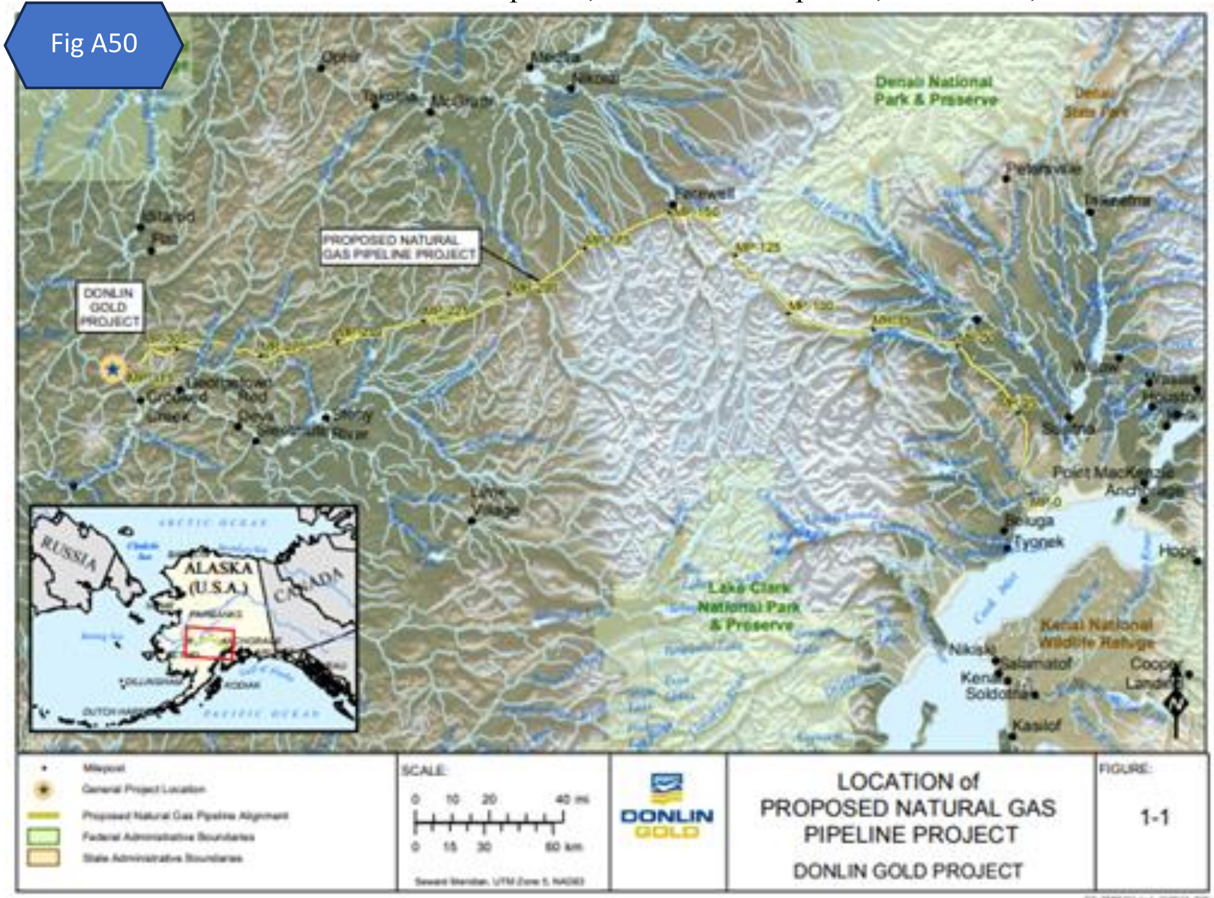
If we now add the prospect of a supply contract option for the Donlin Mine from the remaining competitively priced [below LNG imports] local Cook Inlet Supplies, we find that Donlin demand has the potential to bump in line and increase *local* electric utility natural gas prices from $11.50/mcf to $16.60/mcf – resulting in an increase of roughly $290/year for a typical residential electric utility customer.



Eventually LNG imports and other energy diversification strategies, e.g., low impact hydro, electrification of heating (comparable to SE Alaska), geothermal, wind, solar and electric/heat storage may be accelerated to compete with the increasing cost of local natural gas from the Cook Inlet and mitigate the impact of Donlin's potential procurement of competitively priced local Cook Inlet natural gas.

Donlin Gold Mine Natural Gas Pipeline, Plan of Development, Revision 1, December 2013

Fig A50



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- Chair, Board Audit Committee, Anchorage Municipal Light & Power (2009)
  - Review of ML&P Integrated Resource Plan and Final Investment Decision to install new high efficiency LM2500+ and LM6000 CC units
- Chief Financial Officer, Anchorage School District (2013-2016)
  - Due diligence analysis of energy expenditures including: heating and electric requirements for 7.7 million square feet of facilities and school bus transportation services for Anchorage School District (diesel, natural gas, electric options); potential investments in independent power production and power wheeling arrangements to mitigate future natural gas fired electric generation price escalation; combined heat & power projects to serve high schools, including municipal swimming pools; HVAC & building envelope capital replacement cycles
  - Implemented program to accelerate LED lighting replacements
- Chief Financial Officer, Peter Pan Seafood LLC (2021)
  - Due diligence analysis of marine transportation (tender fleet, fishing fleet) and fish processing plant power plant capacity and energy efficiency improvement options