# Supply of Natural Gas in Southcentral Alaska

Prepared by

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**Purpose**

The purpose of this report is to review estimates of the availability of Cook Inlet Gas, reconcile different estimates with one another, define resource availability, and assess the availability of Cook Inlet gas based on the best available information today.

**Executive Summary**

Cook Inlet has been the primary source of natural gas for Southcentral Alaska for over half a century. While significant volumes of gas remain in the subsurface, the share of that gas that is physically, technically, economically, and socially available at prevailing prices is necessarily smaller. This report evaluates Cook Inlet gas availability using a four-dimensional resource framework, reconciles multiple estimates of remaining reserves and resources, and assesses the implications for future supply security in the region.

This report focuses particular attention on the economic availability of Cook Inlet gas, specifically the prices that would need to prevail in order to make extraction profitable for firms operating in the basin. The Alaska Department of Natural Resources estimates that the cost of developing reserves in the near to medium term will be significantly higher than the prices which prevail today.

This report estimates historical gas production costs to develop an illustrative cumulative availability curve for the Cook Inlet. This analysis makes clear that Cook Inlet's lowest-cost gas resources have already been developed, and current production costs are substantially higher than in past decades. The region is now at a transitional moment where each incremental unit of gas will be more expensive to produce. Imports into the region (via North Slope piped-gas or liquefied natural gas) could soon offer a more cost-competitive option than new local developments under current technological and market conditions. Although large volumes of prospective gas remain, uncertainty over their recoverability and cost creates major planning and investment risk.

## Resource Availability

What does it mean for a natural resource like gas to be available? Resource economists tend to characterize availability for natural resources like natural gas in four dimensions:

### Physical availability

***What is the physical quantity and characteristics of resource present in the ground***? What form is the resource? Is natural gas trapped in a conventional accumulation onshore? A coal-bed? Shale? Or in an offshore formation? What is the depth of the resource? Is the resource associated with large or small associated oil volumes? Is it trapped deep below or nearer the surface?

### Technical availability

***Given the physical characteristics of the gas in place, is technology available today to extract, process, and transport the resource to the relevant market?*** Have these technologies been proven consistently and reliably at scale and in a similar geologic environment? For more speculative technologies, how soon might they be proven? How do depth, pressure, and other reservoir characteristics affect the complexity of drilling and completion operations? What are the reliability and maintenance requirements for key technologies over the project's expected life?

### Economic availability

***Given the physical characteristics of a resource, does its current price exceed the cost to use the best available technology to extract, process and transport it to market?*** Does the volatility of prices create uncertainty to commit capital to develop the resource? How do infrastructure constraints (e.g., pipeline capacity, distance to market, LNG export capacity) affect total delivered costs? What scale of production is required for the project to be financially viable? What are the required upfront capital expenditures, and how do they compare with anticipated revenues? How sensitive is project viability to changes in prices, input costs, or financing terms? What competing energy sources or substitute fuels might affect demand and price trajectories? How do fiscal regimes—tax structures, royalty rates, incentives, or subsidies—affect project economics? How do financing conditions, discount rates, and investor risk tolerances influence whether the project moves forward?

### Social availability

> ***Given the physical and technical configurations of an economically viable project to extract, process and transport a resource, does society allow this activity both formally (through laws, regulations, and permits) and informally (through a community's social license to operate)?*** What legal and regulatory approvals are required for exploration, development, and transportation infrastructure? How complex, lengthy, or uncertain are permitting and review processes? Which agencies and jurisdictions have authority over different stages of the project, and how do their priorities align or conflict? How do Indigenous, local, and regional governments view the project? What mechanisms exist for community consultation, and how might local input shape project design or timing? What forms of opposition (e.g., protests, litigation, public campaigns) could emerge, and how likely are they to affect project outcomes? What compensation, benefit-sharing, or mitigation measures might be necessary to secure community support?

While there are potentially significant quantities of gas that could be physically available, this does not mean that natural gas from the Cook Inlet would be technically, economically, or socially available at *current* prices, technology, and regulatory environment. Of course, technology, production costs, and the regulatory environment could change in the future, reducing the cost of production, increasing technical feasibility, or allowing development in previously closed areas.

When economists and geologists try to estimate the quantities of resources like natural gas that are potentially available, they rely on the above conceptions using a classification framework. The classification framework wildly used by the Society of Petroleum Engineers is called the Petroleum Resources Management System (PRMS).[1] PRMS uses a standard two axis geologic classification framework. One axis measures the degree of physical, technical, economical, and social availability of a resource in place (a concept PRMS calls *commerciality*), The second axis measures the geologic uncertainty over how large the physical quantities of resource in a given stage of commerciality might be. The purpose of PRMS is to estimate the quantities of resources that a resource development firm owns in a standardized way so that they may be evaluated by the firm's investors. While this differs from the purpose of say, a regulator or a policy maker, the same classification concepts generally apply in these settings such that they are useful.

Broadly speaking, natural gas that might exist in place can be classified as either discovered or undiscovered. A discovery occurs when a well is drilled and testing demonstrates hydrocarbons are present. Discovered petroleum can be further classified based on its commercial viability. If petroleum is physically, technically, economically, and socially available and a company would like to pursue its commercialization in the near term, the petroleum volume is considered a "reserve." A drilled discovery may fall short of being physically, technically, economically, and socially available or a commercial target for a company in the near term, but under conditions that could plausibly change over a reasonable time period, a company might be interested in pursuing commercialization. These resources are classified as "contingent." Undiscovered resources are estimated on the basis of seismic surveys or mapping, which identify areas where

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[1] https://www.spe.org/en/industry/reserves/

petroleum could exist, but has not been confirmed with drilling. These resources are classified as "prospective."

Regardless of petroleum's commerciality, reserves, contingent resources and prospective resources can be further classified based on the level of geologic confidence that a given quantity is available in each level of commerciality. For example, a company may be very confident that a small portion of the larger discovery it has made will be recoverable with today's technology and costs. This portion would be classified as a reserve, while the remainder are contingent resources. The level of confidence that a company places on these respective quantities further classifies reserves in proved (reserves quantities with the highest levels of confidence), probable (reserves quantities with the moderate levels of confidence), and possible resources (those with the least confidence). Contingent and prospective resources receive similar further classification based on geologic confidence to their size.

Figure 1: Petroleum Resource Classification

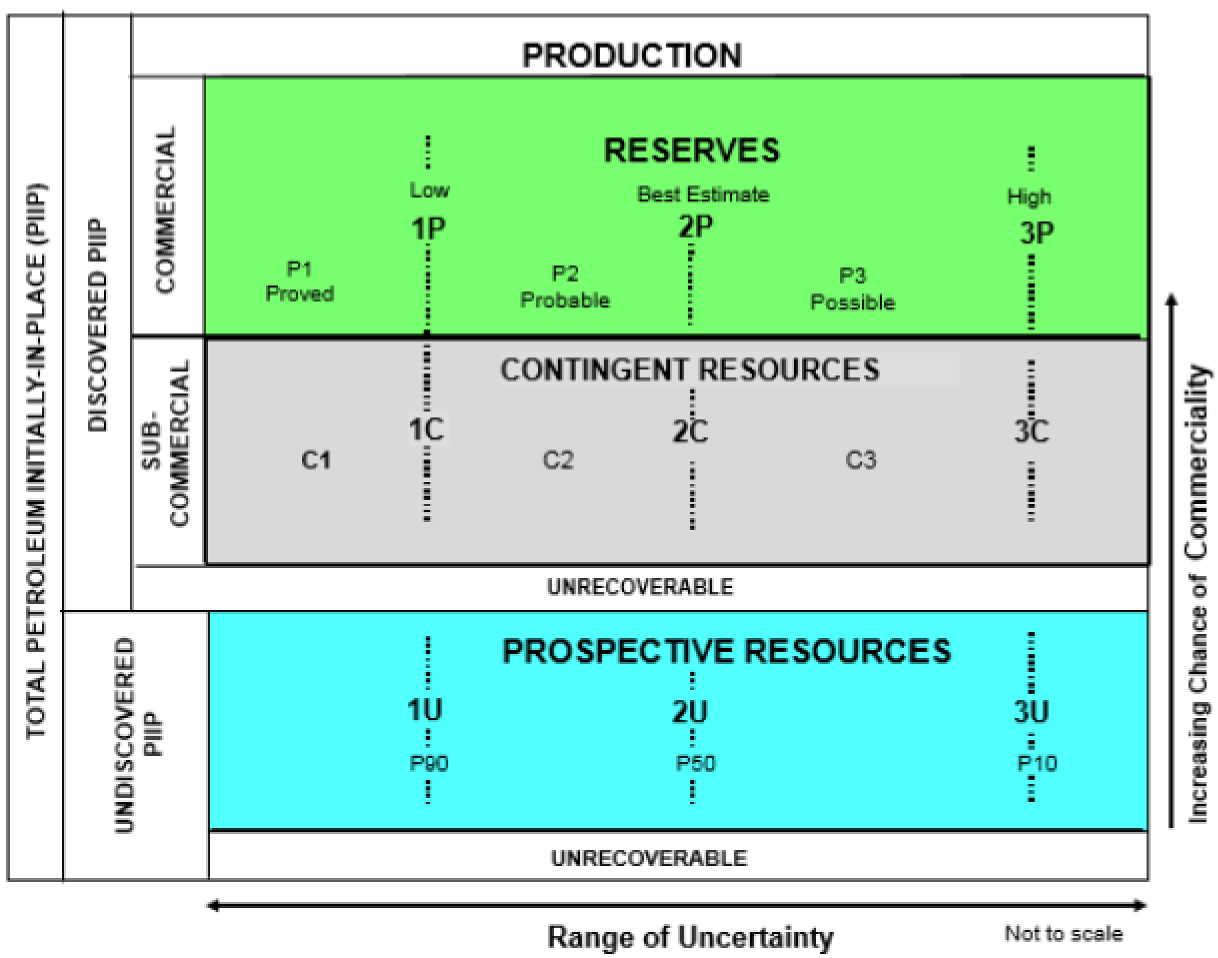



Image source: DiLuzio, Daniel. (2025) "Petroleum Resources Management System (PRMS): Maintaining the Global Standard and Addressing Key Issues" [https://ryderscott.com/wp-content/uploads/2025/01/Dan-DiLuzio.pdf](https://ryderscott.com/wp-content/uploads/2025/01/Dan-DiLuzio.pdf)

## Different estimates of Cook Inlet Gas

There are various estimates of the quantity of gas that currently remains in the Cook Inlet. These estimates differ by what they are attempting to measure and why (i.e. reserves versus resources). Operating firms will produce estimates of natural gas reserves for the purpose of planning their exploration and development activities, their contracting, and their balance sheets and broader financial position. Government organizations produce estimates of gas-in-place to serve some type of public interest function (e.g. creating a public information good for firms to understand commercial opportunities or to guide policy).

*Estimates from Firms Operating in the Cook Inlet*

As described above, firms operating in the Cook Inlet produce estimates of their petroleum reserves and resources in a standardized way to satisfy requirements for disclosure for their investors. Three of the major firms operating in the Cook Inlet (Hilcorp, Hex/Furie, and BlueCrest) are privately held; information about their reserve and resource estimates are not typically disclosed publicly.

*Recent Estimates from the Alaska Department of Natural Resources*

The Alaska Department of Natural Resources (AKDNR) periodically produces estimates of proved and probable natural gas reserves for the Cook Inlet. In 2015, AKDNR produced a report finding 711 billion cubic feet (BCF) of gas in the proved reserves category and 472 BCF of gas in the Probable Reserves category for a total of 1,183 BCF of gas reserves in the so-called "1P+2P" category.

In 2022, AKDNR assessed proved reserves between 843 BCF and 1,404 BCF. As of this writing, these were the most recent estimates available.

As part of their 2022 reserve estimates, AKDNR assumed, based on the average pace of development well drilling from 2009-2019 and private conversations with Cook Inlet operators that 15 development wells would be drilled per year. In the time since (2020-2024), average development wells completed in the Cook Inlet were extremely close to AKDNR's projections at 14.6 per year.

*Historical Estimates*

We identified 9 public studies which have quantified Cook Inlet gas reserves, summarized in Table 1. Most of the recent estimates come from the Alaska Department of Natural Resources. There are important methodological differences between different efforts over time to quantify Cook Inlet gas, which somewhat limits our ability to directly to compare these estimates over time. Notwithstanding these methodological differences between studies, there is a declining trend in estimated reserves from 1996 through 2009; estimates since exhibit less trend and have averaged 860 BCF of gas. Estimates of the ultimately recoverable quantities (EUR) of gas (which measures the estimated reserves + the total cumulative production to date) have risen somewhat from 1996 to 2022. The Geoquest and Malkwicz studies conducted in 1996 and 1997 found an average of 8,400 BCF of ultimately recoverable gas while the three most recent studies from Alaska DNR have all estimated EUR above 9,200 BCF.

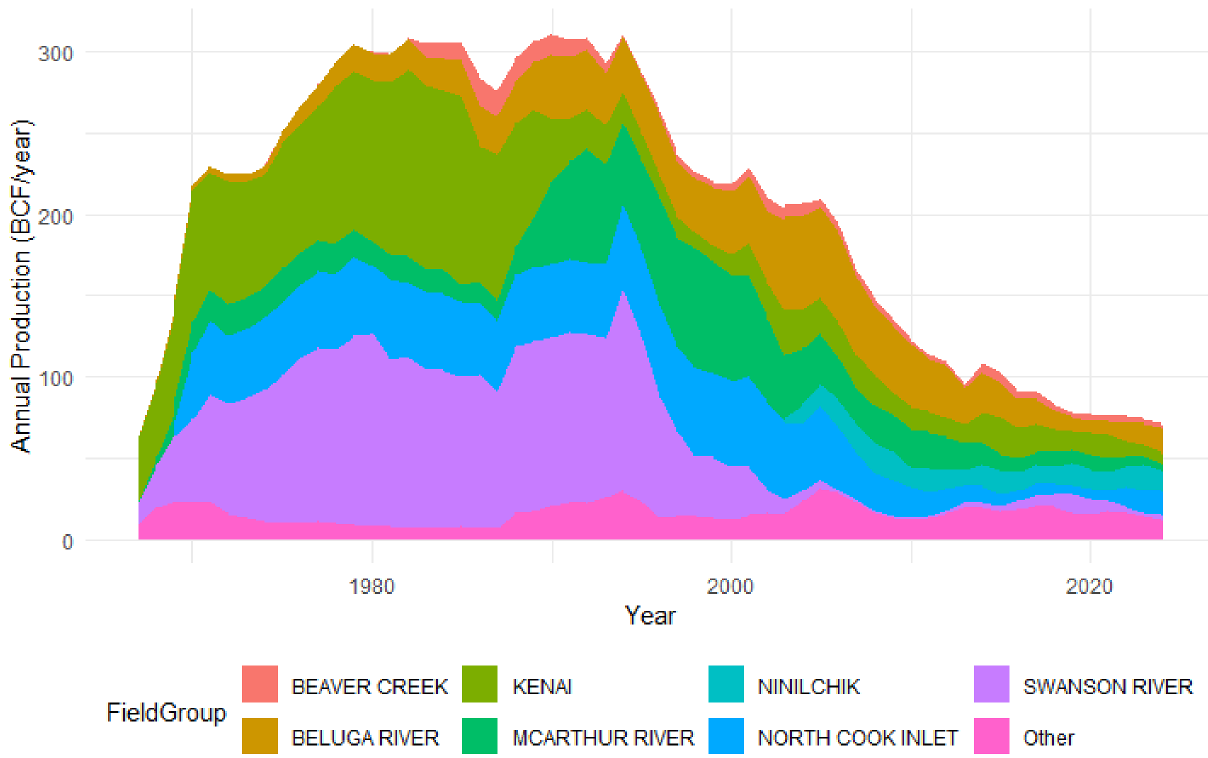
Table 1: Estimates of Cook Inlet Gas Reserves by Study

| Year | Study Short Name | Cumulative Production[1] | Total Reserves[1] | Estimated Ultimate Recovery[1] | Annual Production[2] | R/P Ratio[3] |
|---|---|---|---|---|---|---|
| 1996 | Geoquest | 5,097 | 3,787 | 8,884 | 266 | 14.2 |
| 1997 | Malkwicz | 5,473 | 2,436 | 7,909 | 238 | 10.2 |
| 2004 | DOE | 6,849 | 1,714 | 8,563 | 208 | 8.2 |
| 2007 | Netherland et al. | 7,414 | 1,726 | 9,140 | 166 | 10.4 |
| 2009 | DNR | 7,756 | 1,142 | 8,898 | 136 | 8.4 |
| 2010 | Petrotechnical Rec | 7,694 | 729 | 8,423 | 123 | 5.9 |
| 2015 | DNR | 8,308 | 1,183 | 9,491 | 103 | 11.5 |
| 2018 | DNR | 8,542 | 700 | 9,242 | 83 | 8.4 |
| 2022 | DNR | 8,876 | 820 | 9,696 | 78 | 10.5 |

1 Reported by Study
2 Calculated from AKOGCC Production Data
3 Total Reserves/Annual Production

The general decline in reserves has coincided with a decline in production. The ratio of these to values, annual production and reserves represents the Reserve Production ratio (R/P), which could be thought of as the number of years that current reserves will support current annual production. Over the 30-year period of the studies included in Table 1, the R/P ratio has averaged about 9.8 years. In other words, reserves over this period would be sufficient to cover about ten years' worth of production. The fluctuation of the R/P ratio across studies and over time highlights that it should be thought of as a measure of "working inventory." As known reserves are produced and depleted, exploration finds and adds new reserves over time. Firms generally like to keep some relatively fixed "buffer stock." In other words, as their R/P falls, they might invest more heavily in exploration. At a certain point, the additional inventory does not provide additional near-term benefit to continue to justify exploration spending.

Figure 2: Cook Inlet Gas Production by Major Field




There is limited public data on field level reserve estimates nationally. However, the US Energy Information Administration (EIA) has data on reserve and production estimates by 'area' as part of their form EIA-23L reporting. US total natural gas production in 2023 was 41,946 BCF, total reserves were 603,651 (416,539 from producing fields), for a national R/P ratio of 9.9 years (14.4 years from producing fields). Looking across the 48 areas in the EIA data, R/P ratios varied from less than two years in Michigan and Montana, to greater than 14 years in New Mexico, Oklahoma, and West Virginia. In other words, the R/P ratio for the Cook Inlet of 5.9-14.2 over the last 30 years and of 10.5 in the most recent study are consistent with those of area-level R/P ratios nationally.

*Estimates from the US Geological Survey (USGS)*

As a public science agency, the USGS takes a different perspective on their assessment of resources from private firms. For example, the USGS has limited information about producer's extraction costs which are necessary to understand economic availability and commerciality of a petroleum resource. Further, the agency does not as a general principal take on exploration drilling activity that would be required to constitute a petroleum discovery (and therefore contingent resources or reserves). The agency instead focuses their assessment on quantifying undiscovered resources, which can be estimated using the agencies expertise in geologic mapping and other survey techniques.

USGS assessments do consider commerciality in three respects.[2] First, their assessment methodology screens out petroleum accumulations that are too small to be viably produced. Second, resources are categorized into geologic formations with quantitative information about cumulative historical production from these formations (demonstrating such geology has been commercialized in the past, and thus might be viable in the future). It also provides qualitative descriptions of the geologic formations which could inform the technology required to produce from them and thus their commercial viability. Finally, the USGS petroleum assessments are designed to capture resources that have the potential to be discovered in the next 30 years.

However, without drilling to confirm discoveries and with limited information on economic availability, USGS assessments focus exclusively on estimation of undiscovered or prospective resources.

The USGS categorizes undiscovered resources in two categories: conventional and unconventional. Historically, as the name implies, most production from the Cook Inlet has come from conventional resources. Like reserve estimates, undiscovered resource estimates are probabilistic. Models incorporate the uncertainty that is inherent to the process. This uncertainty is presented with associated levels of confidence in the estimates; we can be most confident that the size of a resource is at least as large as a conservative estimate at the low end and be more speculative that the size of a resource might exceed some higher value at the top end. In the case of the Cook Inlet: the USGS estimates that with 95% confidence at least 3,138 BCF of gas might be undiscovered, with 50% confidence that at least 12,497 BCF of gas might be undiscovered, and 5% confidence that at least 28,414 BCF of might be undiscovered in conventional resources. USGS further estimates, with 90% confidence, that unconventional resources might hold between 1,838 and 11,323 BCF of gas. Because the quantity of undiscovered gas right-skew (practically speaking it cannot be less than zero, but theoretically could take very large values) the expected quantity of undiscovered of gas is slightly higher than the estimate associated with 50% confidence. The expected value of undiscovered conventional gas is estimated to be 13,726 BCF and the expected value of undiscovered unconventional gas is estimated to be 5,311 for a total of 19,037 BCF of gas between conventional and unconventional resources.

With current demand, does this mean Anchorage has 272 years-worth of implied supply? There are several reasons why this calculation provides an incomplete picture of the situation at best. First, without exploration drilling to confirm the presence of this gas in place, we lack confidence about the ability to produce this gas. Second, Anchorage utility companies, by regulation, have a duty to serve. This means that they must take 'risk averse' positions and plan for worst-case scenarios rather than the most likely scenarios. Of course, even if we consider the

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[2] Schmoker, J. W., & Klett, T. R. (1999). *US Geological Survey Assessment Model for Undiscovered Conventional Oil, Gas, and NGL Resources--the Seventh Approximation* (Vol. 2165). US Department of the Interior, US Geological Survey.

uncertainty of the USGS estimates, USGS has an implied 95% confidence that 4,976 BCF are undiscovered – nearly 71 years of supply at current demand. Asking why this implied 71-year horizon would not be sufficient brings us to the second potential issue which is commerciality of the resource. These estimates include unconventional resources that have not seen commercial development in the past. Less these, the undiscovered resource estimate falls to at least 3,138 BCF (45 years of supply at current demand) of gas in the kinds of geologic formations that have seen commercial production before.

Regardless of exactly the resource type and level of confidence selected, none of these resources can be counted on until they are actually discovered through drilling. Similarly, while the distinction between conventional and unconventional resources speaks in-part to commerciality, it is far from a complete assessment of the economic, technical, and social availability of the resource.

The question is not "how much gas might physically be in place in the Cook Inlet," rather, it is "how much will it cost to extract gas at various quantities." To answer this question, we need to deploy a tool resource economists refer to as a cumulative availability curve assessment.

**The cumulative availability curve**

The cumulative availability curve, sometimes called the cumulative supply curve, varies over time with price. It is distinct from a traditional supply curve that might be found in an introductory economics text because a traditional supply curve reports supply for a given time period (a given week, month, or year) and describes how the flow of a good might be transacted between buyers and sellers at various price points. The cumulative availability curve, in contrast, describes a stock of good over all time (past and future). This representation only makes sense in the context of a non-renewable resource like natural gas.

Different natural gas units will have different production costs driven by geologic, technical, and social factors. Quantities of associated oil, distance from existing infrastructure, characteristics of the geologic formation, and depth all play a role in determining the extraction costs. Like any product, a natural gas producer will only explore and develop gas for which the price they can receive exceeds their various costs to bring gas to market. Producers with access to higher quality resources based on geology or location will have an advantage and supply more of the market. Herfindahl sequencing describes the process by which society uses its highest quality/lowest cost natural resources first, then moves along to the next best resources and so on as increasingly marginal resources are depleted. This is efficient due to the time value of money; wealth today is more valuable than future wealth, so extracting from low-cost resources first is socially optimal.

The cumulative availability curve framework assumes that all factors affecting production costs are fixed over time. This includes production technology, labor and capital costs, geology, etc. New and unforeseen technological developments might shift the portions or all of the curve downward, such that more resources can be produced at a lower cost. This was the case with the coinciding technological “shocks” of hydraulic fracturing and horizontal drilling, which reduced the production costs of oil and gas from shale formations below these resources’ market price.

Portions or all the cumulative availability curve can shift down with unexpected innovation. The cost of land, labor, capital, or energy might also change shifting the curve up or down. The curve might also widen or contract with the discovery of unexpected geological information.

Figure 3 below is an illustrative representation of the Cook Inlet Cumulative Availability curve. Producing detailed technical estimates of the production costs for each past and hypothetical future producing units was outside the scope of this report. Instead, this illustrative example uses several simplifying assumptions to estimate the historical production portion of the curve (the resources to the left of the vertical dashed line) and recent estimates for prices required to bring gas onto market in the short to medium term (from proved and probable reserves and contingent resources). For future production that might come from undiscovered possible resources, this is obviously considerable uncertainty as the quantities of these resources and even more uncertainty as to the price required to bring them to market. However, exploiting the underlying Herfindahl sequencing hypothesis implies that, all else equal, it will be more expensive to exploit unproduced resources than it was to extract historically produced resources. This creates a price floor somewhere between $15/mcf and $22/mcf as these are the prices that are projected to be necessary to bring on incremental supply in the short to medium term (DNR 2018 augmented supply scenario). However, there is no available estimate as to how expensive these resources might actually be to produce in practice. To illustrate this uncertainty, this report has used a hypothetical upper bound of +100% for tertiary sandstone resources estimate from the USGS, 119% for Mesozoic Sandstone, 130% for Tuxedni-Naknek continuous gas, and 161% for coal bed gas. However, it is ***imperative*** to note that this upper bound number is only provided to make the point that prices necessary to profitably produce from these resources (with today's technology and costs) could be high, and necessarily higher than prevailing prices today and in the near future.

The cumulative availability curve demonstrates 4 important stylized facts. (1) Historical production of Cook Inlet Gas was much lower cost (in inflation adjusted terms) than costs today. (2) Our position today (the dashed vertical line) shows we are currently in a period of rapid transition; the cumulative availability curve is quite steep. (3) In the near future, the costs of importing LNG (the dashed horizontal line) might be lower than new developments in the Cook Inlet. (4) There are still significant volumes of prospective gas in the Cook Inlet with considerable uncertainty about their production costs.

Figure 3: Cook Inlet Cumulative Availability Curve

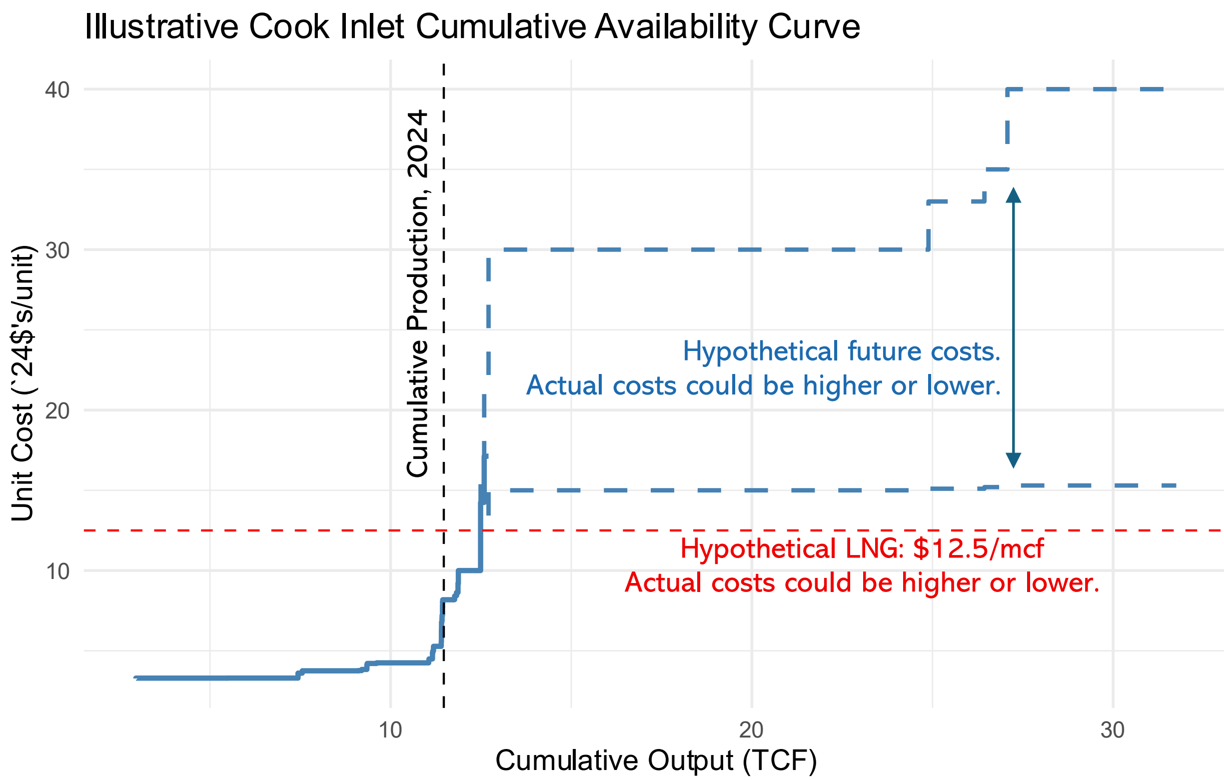


Figure Notes: Hypothetical cumulative availability curve for Cook Inlet Gas. Unit costs are in inflation adjusted 2024 dollars per thousand cubic feet of gas ($/mcf). Cumulative output is in trillions of cubic feet of gas (TFC). The horizontal dashed red line represents hypothetical import prices of liquified natural gas (LNG) at $12.5/mcf, consistent with Wood Mackenzie (2024) estimates of an import cost range of $10.21 to $13.72, excluding any fixed cost for import infrastructure. The dashed vertical black line represents the current costs/prices and cumulative production. The solid blue line represents historical production, and unproduced reserves + contingent resources. The dashed blue lines show hypothetical future costs of producing undiscovered gas resources in a low-cost and high-cost case. Consistent with availability curve assumptions, undiscovered resources (represented in the dashed blue line) cannot be produced at lower cost than discovered reserves and resources (which AKDNR estimates cost $13-21/mcf). We assume $15/mcf for the low-cost scenario for undiscovered resources. The high scenario assumes that these costs might be $15 to $25 (2-3x) more expensive than the low-cost scenario.

## Conclusion

While physical quantities of gas in place in the Cook Inlet are likely significant, the share of reserves that are technically, economically, and socially available at prevailing prices is much smaller. Reserve estimates from the Alaska Department of Natural Resources and other studies suggest a working inventory consistent with patterns observed in other U.S. producing basins, with an average reserve-to-production ratio of about a decade. Yet the cumulative availability curve highlights a more sobering reality: low-cost resources have already been depleted, leaving a steep cost structure for future development.

Uncertainty remains particularly large for undiscovered and unconventional resources. U.S. Geological Survey assessments show that, while potentially vast quantities of gas may exist, these resources cannot be considered available until proven by drilling and shown to be commercially viable. In the near term, Cook Inlet utilities face the possibility that the cost of developing new local gas could exceed the cost of imported liquefied natural gas (LNG) or the cost of bringing gas down from the North Slope. This prospect underscores that future supply security for the region will depend not only on the geology of Cook Inlet but also on technology, market prices, regulatory decisions, and social acceptance.

Even in a world where LNG gas is being imported, gas production from the Cook Inlet could, and likely will, continue well into the future. Gas producible from the Cook Inlet at cost lower than the LNG import price will certainly have a market, but absent new technology or geologic discovery, that market share will contract over time.

Cook Inlet's gas future is in a period of transition. Given what we know about technology and geology, the period of low-cost Cook Inlet gas that could be exported as LNG or used in industrial processes (which prevailed for much of the area's history) seems squarely in the region's past. Policymakers, utilities, and communities will need to balance the diminishing affordability of local supply against the infrastructure requirements, price volatility, and long-term commitments associated with non-local supply (whether those are LNG imports or North Slope gas). The challenge is not whether there is gas in the ground remaining, but whether it can be delivered reliably and at a price competitive with alternatives.

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## Technical Appendix

Estimating the Cook Inlet Cost Curve

Data on production costs are not directly observed. Instead, we assume a historically perfectly competitive market for Cook Inlet gas to use prices as an approximation for marginal production cost + natural resource user cost.

Our objective was to create a continuous annual series of Cook Inlet natural gas prices from 1967–2024. The Alaska Department of Revenue (DOR) reports “prevailing values,” which represent wholesale gas prices net of delivery and customer charges. These prevailing values are conceptually the most appropriate measure of the resource’s price, but they are available only from 1994–2024. Two related series from the U.S. Energy Information Administration (EIA) provide longer historical coverage: (1) wellhead prices (1967–2010), which closely approximate prevailing values, and (2) residential consumer prices (1967–2024), which reflect utility charges inclusive of delivery and service fees.

To impute missing prevailing values prior to 1994, we developed a state space modeling approach that combines the information in these EIA series with the observed dynamics of the prevailing values themselves.

We specified dynamic regression models where prevailing values ($y_t$) are expressed as a function of both the EIA wellhead price series ($x1_t$) and the residential consumer price series ($x2_t$), while also allowing for unobserved time series components. Specifically, we estimated two complementary state space models using the KFAS package in R:

1. Linear model:

$$y_t = \beta 1 * x1_t + \beta 2 * x2_t + \mu_t + \varepsilon_t$$

2. Log-linear model:

$$\log(y_t) = \beta 1 * x1_t + \beta 2 * x2_t + \mu_t + \varepsilon_t$$

Here, $\mu_t$ is a stochastic trend component, and $\varepsilon_t$ follows an autoregressive process of order one (AR(1)). The log-linear specification constrains fitted values to be positive after back-transformation.

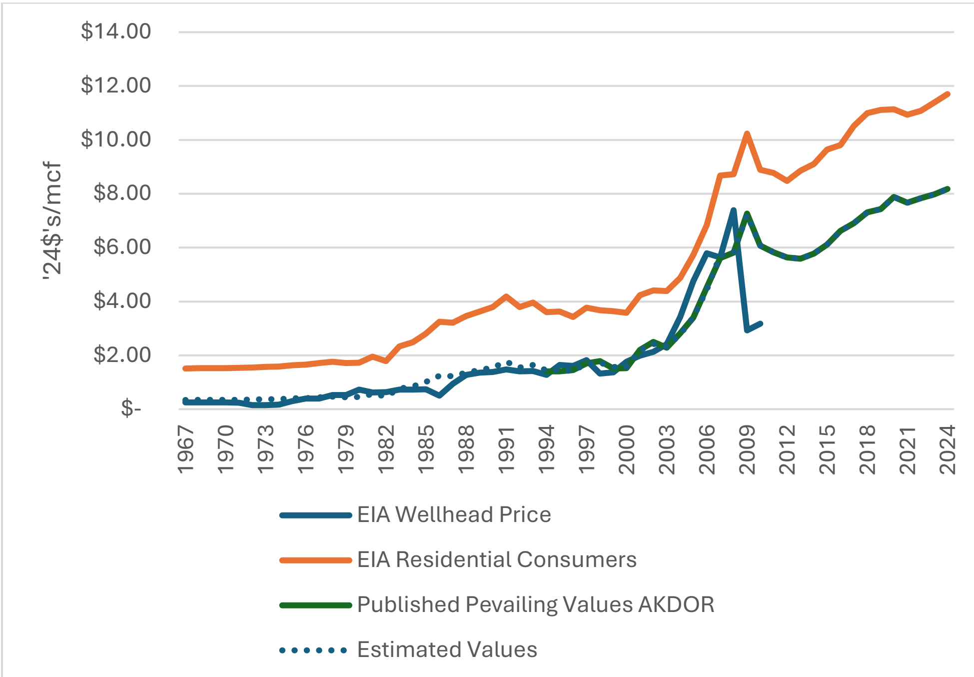
Both models were estimated via maximum likelihood, with hyperparameters of the state disturbance variances estimated jointly. We applied the Kalman filter and smoother to each model. This procedure uses the information in the available DOR prevailing values (1994–2024) to optimally infer missing values of the series, conditional on both the covariates and the estimated time series structure. The smoothed estimates provide an internally consistent imputation of $y_t$ over the entire 1967–2024 period.

Because the linear and log-linear specifications offer different strengths—the linear model preserves scale comparability while the log-linear model ensures positivity—we averaged the two sets of smoothed estimates. The resulting blended series is defined as:

$\hat{y}\_t^{final} = 0.5 * (\hat{y}\_t^{linear} + \exp\{\hat{y}\_t^{log\text{-}linear}\})$

The fitted (estimated) values approximate the historical EIA Wellhead value series reasonably well:

Figure TA 1: Actual and Fitted Real Prices for Cook Inlet Gas




Allocating Basin Prices/Costs to Field Prices/Cost

To translate basin-level natural gas prices (used as a proxy for unit costs, given assumptions about completion) into estimates of average unit costs of production at the field level, we employed a weighted regression framework using well-month-level production data spanning 1965–2024. The dependent variable was the inflation-adjusted basin price in year t, which is common across all wells. Explanatory variables included well-level production characteristics and field-specific fixed effects:

$y\_{it} = \beta_0 + \beta_1 \log(OilProduced\_{it} + 1) + \beta_2 \log(WaterProduced\_{it} + 1) + \gamma\_{Field(i)} + \delta\, Age\_{it} + \varepsilon\_{it}$

where $y\_{it}$ is the observed basin-level real natural gas price in year t assigned to well i, $\gamma\_{Field(i)}$ denotes field fixed effects, OilProduced is the quantity of oil produced by a well and WaterProduced is the water volume produced; Age is the number of months since first production for well i. The regression was estimated by weighted least squares, with weights equal to the share of each well's production in total basin production in year t. This weighting ensures that the fitted values reflect production-weighted basin averages.

(Table TA 1) shows the estimated coefficient values. Gas prices are negatively related to co-product production (oil), positive in waste product production (water), and positive in well age. These are all consistent with theoretical predictions, providing credibility to modeled estimates.

Predicted values($\hat{y}\_it$) from this regression were interpreted as well-level unit costs of production, conditional on production characteristics and field affiliation. To construct field-level estimates, we aggregated predicted values across wells within each field, weighting by well-level gas output. This produces production-weighted field averages of predicted costs, which can be ordered to build cumulative supply curves.

This analysis relies on several assumptions. First, it assumes a competitive market equilibrium, in other words: basin-level natural gas prices approximate the marginal cost of supply, such that variation in price across time can be decomposed into cost components associated with well characteristics and field-specific factors. Second, field dummies capture persistent differences in gathering, processing, transport charges, basis adjustments, and gas quality across fields. Third, that associated oil production and water production serve as proxies for variable costs (e.g., water handling/disposal, liquids processing). We consider oil production as a by-product of gas, so by product credits will reduce gas production costs. Well age controls for declining productivity and increased operating intensity over the life cycle. We assume exogeneity of covariates: oil and water outputs, as well as field affiliation, are assumed to reflect underlying geological and technical cost drivers rather than being jointly determined with price shocks at the basin level.

In equilibrium, average variable costs (lease operating expenses, compression, water handling, and gathering/processing fees) are approximately equal to marginal costs. Thus, regression-predicted values can be read as estimates of per-unit operating costs rather than full-cycle costs including capital expenditures.

Table TA 1: Regression Estimates of NG Prices

| | Weighted OLS |
|---|---|
| log(Oil + 1) | -0.096*** |
| | (0.024) |
| log(Water + 1) | 0.087+ |
| | (0.049) |
| Well age (years) | 0.003* |
| | (0.001) |
| Num.Obs. | 201,116 |
| R2 Adj. | 0.320 |
| Field fixed effects | Yes (not shown) |
| Weights | Production-share (well-year) |
| SE type | Clustered by Field |

+ $p < 0.1$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$