Demand for Natural Gas in Southcentral Alaska

Prepared by

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Purpose

The purpose of this report is to review the availability of information on the demand for Cook Inlet natural gas in the short to medium term by assessing current use in heating, electricity, and industrial use and assess potential future trends or scenarios.

Executive Summary

Households and businesses in Southcentral Alaska have relied on gas from the Cook Inlet as their primary source of energy for decades. Now, faced with rising costs to secure gas from the Cook Inlet, utilities are weighing options that include a combination of alternatives to meet their energy needs such as liquified natural gas (LNG) imports, gas from the North Slope, alternative sources of fuel for electricity generation, and demand-side management programs. Utilities are weighing these options based on cost, timeliness, quantity, reliability, and economic sustainability.

While there are still considerable volumes of technically recoverable gas available in the Cook Inlet, they will likely come at increasingly higher prices than those that Southcentral has historically seen. The deficit between lower-cost Cook Inlet gas and demand will grow over time as the resource is further depleted. Currently identified projects for alternative energy are not sufficient on their own to close this deficit. This is especially true if one restricts alternative projects to a narrower portfolio of wind, solar, and geothermal projects.

Options which electrify commercial and residential heating (reducing direct gas demand) will increase the load on electricity. This means either increased load on gas-fired electricity generating units (creating an ambiguous level of potential gas savings) or alternative energy projects to be developed. These demand-side reductions are not being considered by utilities, but businesses and households in the region can weigh these investments.

Given the pace at which Cook Inlet gas costs are rising, it is difficult to configure scenarios that do not involve LNG imports of gas through at least the short term. In the medium- to long-term, more options become available, including further renewable deployment or gas from the North Slope that could partly or fully reduce the need for gas imports from LNG.

1. Current Demand Landscape

Natural gas serves as a key energy source for Southcentral Alaska. This has been true since the 1950's, when low-cost gas was available as a by-product of oil produced in the Cook Inlet. Natural gas is demanded by industrial users as part of a production process, by commercial facilities (businesses, government, and non-governmental users) for appliances and to heat space and water and in appliances, by power utilities to generate electricity at power plants, and by residential users for appliances and to heat space and water in their homes. It is also used in the oil and gas production process. Alaska Department of Natural Resources (AKDNR) estimates[1] that from 2016 to 2021, gas demand averaged 68 billion cubic feet (Bcf) per year and that this demand was roughly comprised of 21% commercial, 35% electricity, 28% for residential, and 15% for oil and gas operations.

The historic availability of low-cost gas allowed for its utilization in two important industrial applications: exported liquified natural gas (LNG) from the Kenai LNG facility and the production of ammonia at the Agrium Kenai Plant. Rising natural gas costs led to the mothballing of these facilities in 2007[2] for the Agrium plant and in 2015 for Kenai LNG.[3] Supply from the Cook Inlet peaked at around 200 Bcf of gas per year when these industrial sources of demand were in operation. Since their closure, demand has fallen to around 70 Bcf per year.[4] There are also volumes of industrial gas consumed as part of the oil and gas production process and at the Marathon Kenai Refinery.

On average, around 21-25 Bcf of Cook Inlet gas per year is used to produce electricity. Energy Information Administration data show that six Southcentral utilities or power plant operators run a total of 15 electricity-generating units. These units and utilities/operators are shown in Table 1. These operators are Chugach Electric Association (CEA), Matanuska Electric Association (MEA), Homer Electric Association (HEA), the City of Seward, Fire Island Wind LLC, and Energy 49 LLC (i.e. Houston Solar). Of the 15 generating units associated with the Southcentral power grid, 12 are natural gas boilers at 8 unique plants. For CEA, these are Beluga, George M Sullivan, Hank Nikkels, and Southcentral Power Project. For HEA, these are Bernice Lake, Nikiski Combined Cycle, and Soldotna; and for MEA, the Eklutna Station. Combined, these plants produced 2.9 million net megawatt hours (MWh) of electricity in 2024 using 25.2 Bcf of gas. Total net generation was 3.6 million MWh, meaning gas fueled 81% of electricity supply.

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[1] State of Alaska Department of Natural Resources, Division of Oil and Gas, 2022 Cook Inlet Gas Forecast, January 2023, pp. 10, ("2022 Cook Inlet Gas Supply Study").

[2]Reuters, *Agrium closes Alaska plant, blames gas shortage*, September 26, 2007, https://www.reuters.com/article/agriumalaska-idUSWEN126820070925.

[3] The Kenai LNG plant began operations in 1969, marking it the first supplier of LNG to Asian markets and among the earliest LNG exporters globally. Until 2012, it remained the only facility in the United States licensed to export natural gas overseas. EIA, Natural Gas Weekly Update, *Alaska is a major natural gas producer, but little of the natural gas reaches market*, May 27, 2021, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/05_27/.

[4] State of Alaska Department of Natural Resources, Division of Oil and Gas, 2022 Cook Inlet Gas Forecast, January 2023, pp. 17, ("2022 Cook Inlet Gas Supply Study").
http://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_vrs_mmcf_a.htm

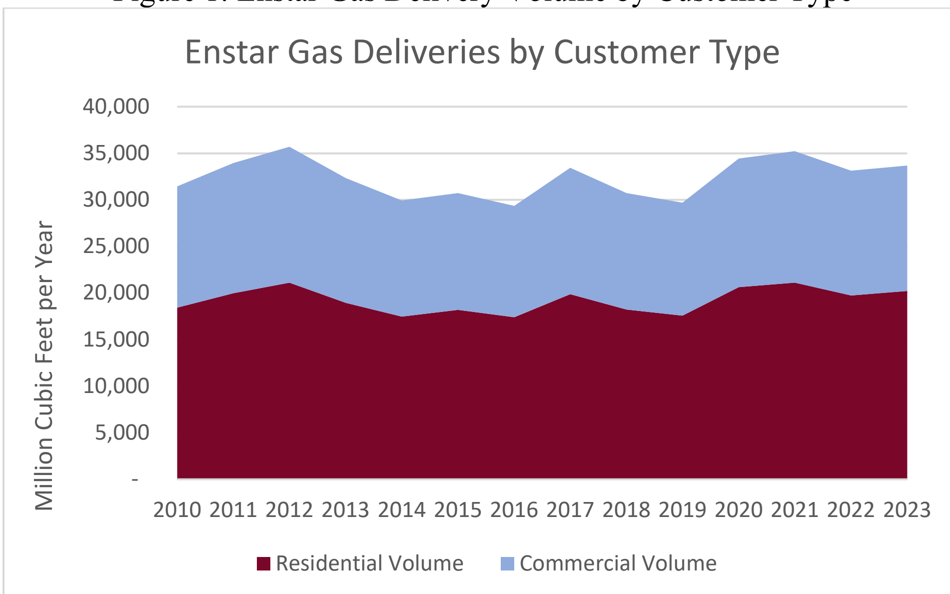
Table 1: Southcentral Alaska Generating Stations

	2024 Net Generation (Megawatt hours) by Fuel Source						
Operator/Facility	Natural Gas	Hydro	Wind	Solar	Fuel Oil	Battery	Total
Chugach Electric Assn Inc	1,957,337	158,487			307		2,116,131
Beluga	7,112						7,112
Cooper Lake		38,101					38,101
Eklutna Hydro Project		120,386					120,386
George M Sullivan	923,250				-		923,250
Hank Nikkels Plant	40,905				307		41,212
Southcentral Power Project	986,070						986,070
City of Seward - (AK)					393		393
Seward (AK)					393		393
Energy 49, LLC				7,770			7,770
Houston Solar				7,770			7,770
Fire Island Wind LLC			49,379				49,379
Fire Island Wind			49,379				49,379
Homer Electric Assn Inc	459,148	397,142			68	(986)	855,372
Bernice Lake	1,272						1,272
Bradley Lake		397,142					397,142
Nikiski Combined Cycle	414,785						414,785
Seldovia					68		68
Soldotna	43,091					(986)	42,105
Matanuska Electric Assn Inc	573,004				-		573,004
Eklutna Generation Station	573,004				-		573,004
Total	2,989,489	555,629	49,379	7,770	768	(986)	3,602,049

Source: EIA Form 923 and 860, Data from 2024. Homer Electric has a contract to operate and maintain the Bradley Lake facility from the State of Alaska.

Enstar is the natural gas utility that provides residential and commercial natural gas service to Southcentral Alaska. In 2023, Enstar delivered 20.2 Bcf to residential customers and 13.5 Bcf to commercial customers.[5] Since 2010, Enstar has supplied an average of 32.4 Bcf of gas per year to roughly 60% residential and 40% commercial customers (see Figure 1).

Figure 1: Enstar Gas Delivery Volume by Customer Type



Source EIA Form-176

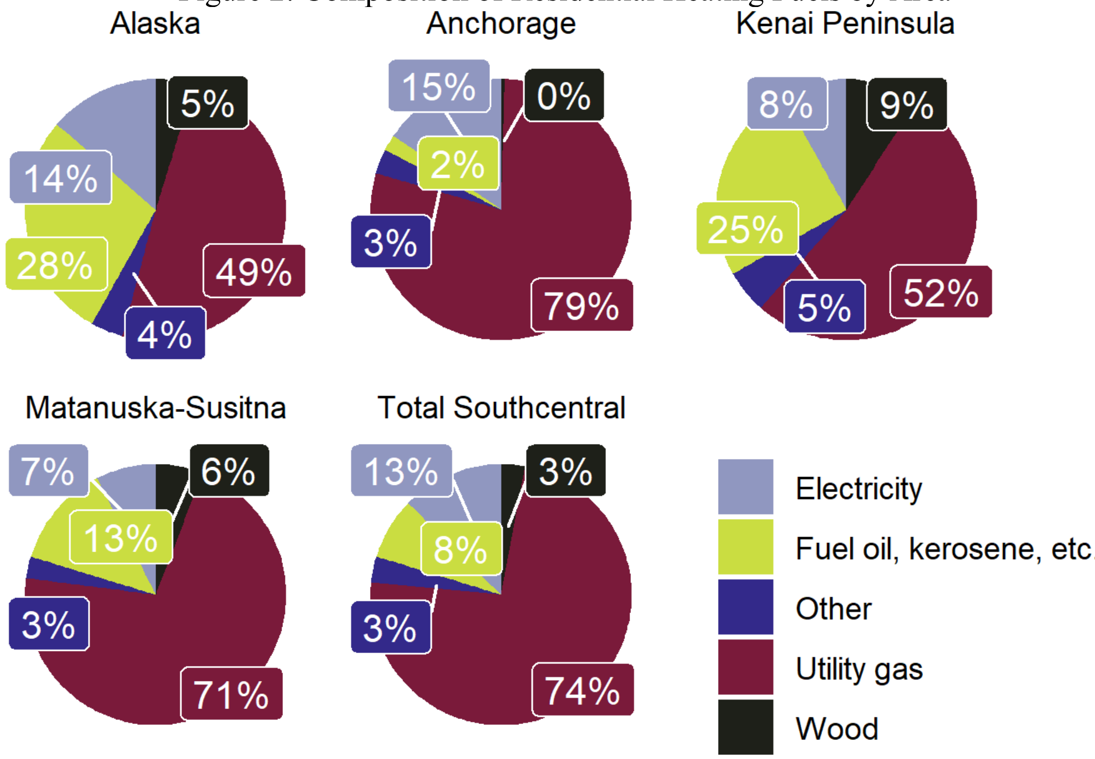
As shown in Figure 2, natural gas is the heating fuel used by about half of homes in Alaka, and three-in-four homes in Southcentral. Electric heating is the second most utilized energy source in Southcentral but is still relatively uncommon; only 13% of homes are heated using electric heat sources. While wood and fuel oil/kerosene heat around 33% of homes in the state, these fuels provide the main source of heating for only around 11% of Southcentral homes. The US Census estimates[6] that in 2024, there were 205,576 housing units in Southcentral Alaska: ~121,000 in Anchorage, ~33,000 in Kenai, and ~51,000 in Mat-Su. Given the breakdown in heating fuel from Figure 2, this implies around 149,400 homes in Southcentral use natural gas as their primary heating source. Enstar's website reports over 150,000 customers across residential and commercial.[7]

[5] Data come from Energy Information Administration Form-176.

[6] https://www.census.gov/data/tables/time-series/demo/popest/2020s-total-housing-units.html

[7] https://www.enstarnaturalgas.com/in-your-community/

Figure 2: Composition of Residential Heating Fuels by Area



Notes: Data: US Census American Community Survey 2022 5-year Estimates. Table B25040. Reported House Heating Fuel. Other includes: coal/coke, solar, tanked liquid propane, other fuels, and none. Southcentral Alaska includes Anchorage Municipality, the Kenai Peninsula Borough, and the Matanuska-Susitna Borough.

2. Outlook for Natural Gas Demand

2.1 Climate

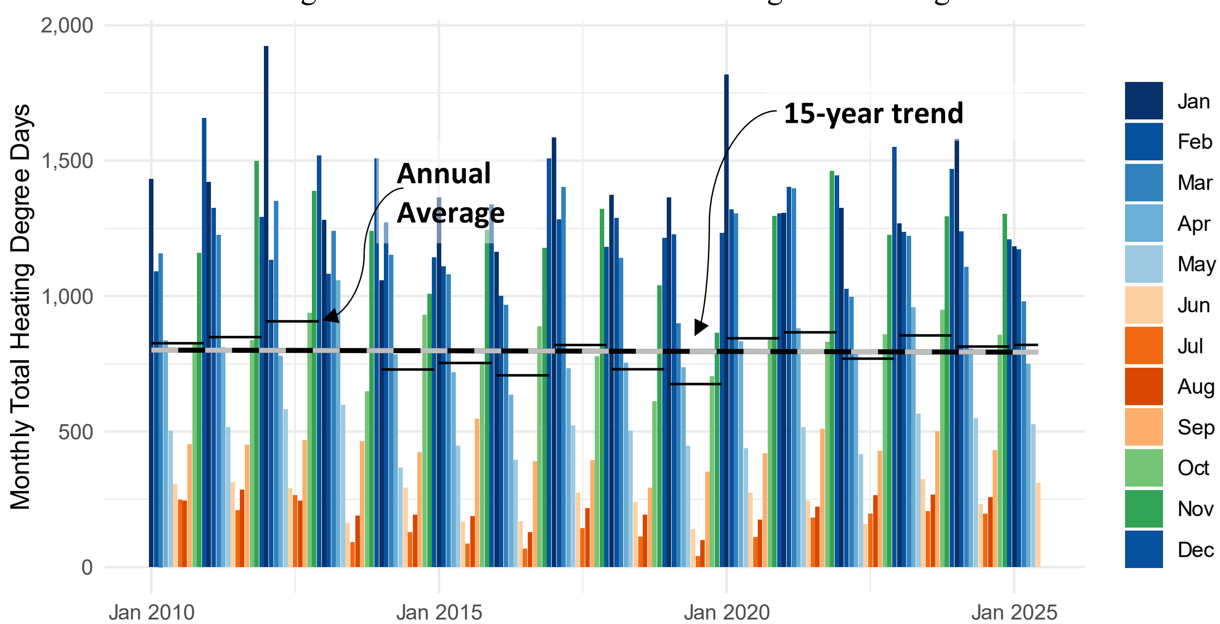
One important source of future change in gas demand comes from the trend and variability in average temperatures. Gas demand varies seasonally and based on temperature. Southcentral Alaska, with mild summers, requires limited energy to cool residential and commercial spaces. Instead, demand for temperature control comes almost exclusively from demand for heating during the colder winter months. As shown in Figure 2, 74% of Southcentral heating for residential buildings comes from utility gas. No data are available for commercial users.

One way to understand the relationship between temperature and energy demand is through a measure called heating degree days (HDD). HDDs are a measure of energy demand to heat residential and comerical buildings. They are computed by taking summations of negative differences between the mean daily temperature and 65°F over a month. If the temperature is 65°F or warmer every day, the month registers zero HDDs. If one day has an average temperature of 64°F and all other days are 65°F or higher, that month would record one HDD. A day with a mean temperature of 60°F contributes 5 HDDs. If that occurred every day in a 30-day period, the month would total 150 HDDs.

Figure 3 shows the monthly HDD index for Anchorage for the last 15 years. Anchorage HDDs tend to peak in December or January and are at their lowest in July and August. The index was the highest in January of 2012 with a value of 1,922 HDDs followed by January of 2020 with 1,817 HDDs. The annual average has varried from year to year, with 2019 having a monthly average of 675 HDDs and 2012 having a monthly average of 907. The 2012 calendar year had the highest number of HDDs at 10,880, while 2019 had the fewest at 8,102, a difference of 2,778.

While Anchorage has seen warm and cold winters over the last 15 years, the overall 15-year trend has been essentially flat. In considering the implications for future energy demand, one must consider both the longer-run trend and the year-to-year variation. In other words, if Anchorage's climate in the next 15-years continues on its previous 15-year trend, we would expect average heating demand to stay relatively stable. At the same time, Southcentral also has to prepare for colder-than-average years which will have above average levels of heating demand.

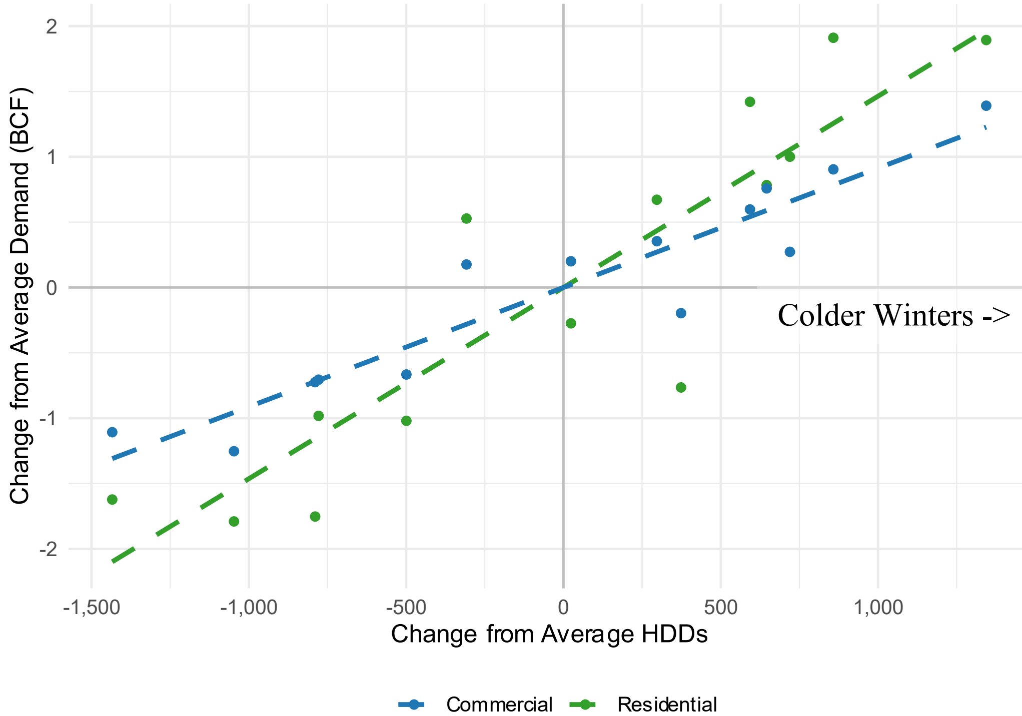
Figure 3: Seasonal Demand for Heating in Anchorage



Source: NOAA/Climate Prediction Center. *Index of Heating Degree Days — Monthly City*.

Figure 4 shows the relationship between average HDDs and the level of gas demand generated. The fitted trendlines show that residential customers are more responsive to temperature changes than commercial customers. The coldest winters in the last 15 years have required about 2 Bcf more gas than average for residential customers and about 1-1.5 Bcf more gas for commercial customers. Regression estimates in Table A1 show that every additional HDD is associated with approximatly 1.5 million cubic feet of additional residential demand and approximately 0.92 million cubic feet of additional commercial demand for a total of 2.4 million cubic feet of demand. These estimates imply that hypotehtically, if every winter into the future was as warm as 2019 (the warmest calendar year in the last 15-years), Southcentral gas demand might fall 3.5 Bcf below its average. However, as Figure 3 shows, the trend has been flat in HDDs.

Figure 4: Relationship Between Average Heating Degree Days and Annual Gas Demand



Source: Heating Degree Days from NOAA/Climate Prediction Center. *Index of Heating Degree Days — Monthly City*. Gas demand data are commerical and residential deliveries by Enstar as reported on Energy Information Administration Form-176.

2.2 Broad-based Economic Growth

Energy demand change might come from changes in aggregate levels of economic activity. Economic expansion or contraction could change energy use per capita or alter in or out-migration patterns. Additional population would create demand for additional housing units that would would need to be heated. Conversly, a shrinking popultion resulting in increased vacancy rates would reduce energy demand. Note, however, that decreases in population alone will not necessarily reduce gas demand. Instead, demand is more directly driven by the way that population is configured into housing units. It is possible for the population to shrink while the number of households grows by nature of demographic change or changes in preferences for shared living arrangements.

Economic growth can also lead to higher energy consumption. While energy might be income inelastic, it is still a normal good and higher levels of economic activity and income lead to higher levels of utilization.[8]

[8] Gao, Jiti, Bin Peng, and Russell Smyth. "On income and price elasticities for energy demand: A panel data study." *Energy Economics* 96 (2021): 105168.

Forecasts of economic growth are outside the scope of this report. However, Alaska Department of Labor (AKDOLWD) does create periodic population forecasts which could be used as a resonable proxy to understand how broad-based economic and demographic change might affect energy consumption (see Table 2). AKDOLWD's forecast shows modest population increase in Southcentral today, with growth of around 2,500 additional residents by 2030 or 2035, before leveling out and declining somewhat into 2050. The regression estimates in Table A1 imply that for each additional person, residential gas demand would increase by about 6.9 Mcf per year and commercial would increase by about 6.5 Mcf per year. However, these estimates are not statistically significant leading to a large confidence interval of potential effects (likely because of the household composition issues noted previously). These estimates imply (at the 95% level) that the population change forecasted by AKDOLWD could lead to between a 0.24 Bcf reduction in gas demand (which is economically unlikely) to a 0.3 Bcf increase in gas demand.

Table 2: Forecasted Southcentral Population Change, 2023-2050

			FORECAST					
	2010	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
ALASKA	710,231	736,812	738,365	742,758	742,801	739,010	731,849	722,806
ANCHORAGE	291,826	289,653	288,754	285,931	281,302	275,070	267,757	260,093
MATANUSKA-SUSITNA	88,995	113,920	115,481	123,548	131,003	137,520	142,665	146,262
KENAI	55,400	60,898	62,090	63,138	63,581	63,417	62,771	61,784
SOUTHCENTRAL	436,221	464,471	466,325	472,617	475,886	476,007	473,193	468,139
% CHANGE FROM 2023			0.4%	1.8%	2.5%	2.5%	1.9%	0.8%

Source: Alaska Department of Labor and Workforce Development.

What if economic and population growth were to change more dramatically than what DOLWD has forecasted in its base case scenario? One perspective is to look at the population growth that has occurred over the last 15 years in Southcentral as a reasonable, but more extreme case. Table 2 shows that over that time period, Southcentral population grew by about 32,000 people, which our estimates imply created no more than an additional 3.9 Bcf of gas demand.

This report does not quantify how changes in economic activity or population might affect natural gas demand through changes in electricity generation (as more people and economic activity, all else equal, would also require more electricity). Qualitatively, any such effect is likely to be smaller in aggregate than the effects estimated for direct residential and commercial natural gas heating demand, because electricity generation accounts for only about 70% of the natural gas consumed by those sectors. The aggregate impact could be further reduced if incremental electricity demand is met by non-gas sources such as renewables or other generation technologies.

2.3 New, Large-scale industry

There are several proposed projects or hypothetical scenarios that could change demand for energy from the Cook Inlet region that are large enough to discuss in their own right. Given their energy intensity, many of these projects' economics will be sensitive to the cost of electricity or natural gas. Two examples of such hypothetical projects would be a restart of the Agrium or existing Kenai LNG facilities. Both facilities were shuttered (in part) because of higher gas prices. When the Agrium facility closed in 2007, the real prevailing price of gas in the Cook Inlet was $8.48 Mcf in 2025 dollars. Just two years before, in 2005, the prevailing price was $5.45 Mcf. There was just a single year prior to 2005 when prices ever exceeded $4 Mcf. Today, the real prevailing price of Cook Inlet gas is $8.20 Mcf. Ammonia prices (Agrium's key output) over this period were flat or rising (in real terms).[9] Ammonia prices today[10] are around the same real level as in 2007, so it is reasonable to think that the plant would only be economic to restart if ammonia prices rose sigificantly and durably or if gas prices fell back to their pre-2005 levels. Agrium, and by the same token, Kenai LNG, would likely only restart if supply of gas expands enough to push prices back to their levels twenty years ago. Put differently, these projects would represent movement along the demand curve rather than a shift in the demand curve. This distinction is important because if future supply expands enough to push prices down, Southcentral will no longer be in a world where gas availability is a concern.

Another category of projects with high energy demand are datacenters. While no specific projects have been proposed, policymakers in Alaska have been making the case that the state's colder tempetures can help to offset higher energy costs.[11] Whether such projects would represent a shift in the demand curve or a movement along it would likely depend on the constraints that datacenter build-outs face in other jursdictions from energy costs, natural disaster risk, and zoning regulations.

A third category of potential industrial demand is from proposed mining operations. The proposed Dolin mine would require approximately 12 Bcf[12] of gas per year for its facilities and operation. Other mining projects at earlier stages of development in the West-Su region might also induce new energy demand. Mining projects differ from Agrium or datacenters because these projects might shift demand (increasing prices) as opposed to only being viable if prices fall.

2.4 Efficiency Improvements

Over time, technology tends to allow households and businesses to maintain a fixed level of output while reducing the required energy input via improvements in technology that use energy more efficiently. Important examples include energy efficent lighting, weatherization, more efficient appliances like washers, dryers, refrigerators and water heaters, improved construction techniques, and window treatements. Despite the presumption that we should see a declining trend in energy use over time via techological change, the estimates in Table A1 imply the opposite. Controlling for weather and population, residential and commerical gas demand have increased over time (though increases in commerial demand are statistically insignificant).

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[9] National Agricultural Statistics Service.
[10] National Agricultural Statistics Service.
[11] https://www.datacenterknowledge.com/data-center-site-selection/alaska-governor-pitches-state-as-a-data-center-hub-for-ai-era-compute
[12] State of Alaska Department of Natural Resources, Division of Oil and Gas, 2022 Cook Inlet Gas Forecast, January 2023, pp. 10, ("2022 Cook Inlet Gas Supply Study").

There are a number of local, state, and federal programs designed to promote energy efficiency investments. One such program is the Alaska Housing Finance Corporation's (AHFC) Weatherization program. In 2024, AHFC reported the organization had provided capital to help weatherize 258 homes across Alaska. The budget for the program was $5 million or ~$19,000/home. AHFC reports energy savings of 30%.

2.5 Electrification

Electric vehicle (EV) adoption in Southcentral would increase total electricity demand because (under the assumption that incremental load is served by natural-gas-fired generators) more EV penetration would directly raise natural gas consumption in the power sector. Each new EV shifts transportation energy use from gasoline or diesel to the electric grid, adding several thousand kilowatt-hours[13] of annual demand per vehicle. Even modest EV market penetration therefore represents a material new load for utilities. If that load is met by gas generation, utilities must burn additional gas proportionate to the new electricity required, increasing total system gas demand.

By contrast, household conversions of gas appliances such as switching from natural gas furnaces, boilers, water heaters, and stoves to electric heat pumps and induction ranges produce a different but similarly important shift in the energy system. Electrifying these end-uses naturally raises electricity demand because homes now rely on the electric grid rather than the gas distribution network for core thermal services. If new electrical load continues to be served by natural gas generation, Southcentral gas-fired power plants would see increased fuel requirements. Space heating, in particular, is energy intensive in Alaska's climate; even when heat pumps operate efficiently, the total annual electricity needed to replace direct fuel use can be substantial. As a result, electrification would increase gas consumption at power plants, at least in the near term, until non-gas generation expands or heat pumps achieve higher levels of efficiency. This creates a mixed system-level effect: gas-fired electricity generation might rises, but direct gas consumption for end-use consumers shrinks. Overall, the net impact depends on appliance efficiency, the relative heat rates of power plants, and the seasonal timing of loads.

2.6 Demand-Supply Balance Outlook

The net effect of a changing climate, economic shifts, new industrial demand, efficiency, and electrification is somewhat ambigous given the uncertainties surrounding each component. None are likely to dramatically reduce natural gas use on their own nor are they likely to reduce demand in the aggregate. AKDNR used an assumption of no-change in its future demand outlook for the 2022 gas supply study.[14] In consultation with Southcentral utilties, the Berkeley Research Group ("BRG")[15] constructed a high demand scenario associated with cold winters and

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[13] The average US household with an EV used 2,363 kilowatt-hours (kWh) per year in 2020. https://www.energy.gov/eere/vehicles/articles/fotw-1307-september-11-2023-electric-vehicle-charging-consumed-less-energy?utm_source=chatgpt.com

[14] State of Alaska Department of Natural Resources, Division of Oil and Gas, 2022 Cook Inlet Gas Forecast, January 2023, pp. 17, ("2022 Cook Inlet Gas Supply Study").

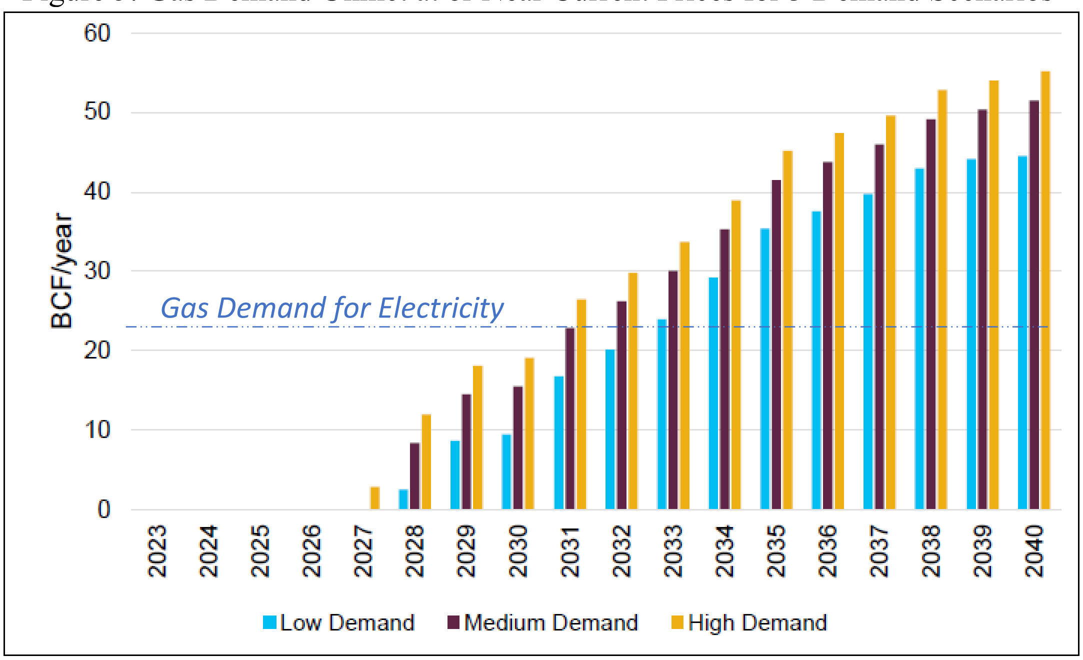
[15] BRG Energy & Climate. (2023) Alaska Utilities Working Group, Phase 1 Assessment: Cook Inlet Gas Supply Project. June 28th.

low renewable adoption for which gas demand would be flat at just under 70 Bcf/year, medium scenario of ~65 Bcf of demand per year, and a low scenario (high renewable, mild winters) of 58-60 Bcf of gas/year. These scenarios are shown in Figure 5.

BRG compared these three scenarios to projected gas supply available at or near current prices for gas. The difference between demand and supply at or near current prices is what BRG refered to as demand "Unmet at or near current prices." This report will also refer to this quantity as the gas deficit for simplicity. However, it is important to note that this is not a structural deficit of gas. After all, markets do not exist in a perpetual structural deficit; prices rise to signal scarcity and supply and demand rebalance accordingly. Cook Inlet likely has sufficent quantities of gas to close this imbalance but only at prices much higher than currently prevail and potentially higher than some combination of alternatives.

Some alternatives are limited in their capacity to offset gas demand or supply new gas. For example, electricity only accounts for 21-25 Bcf of gas demand per year. Even if demand for gas as an electricity-generating fuel source were reduced to zero through more efficient use and alternative sources of power generation, this would not be sufficient to close the total gap that will open by 2033 (See Figure 5). For this reason, it is important to evaluate alternatives based on the quantity of gas they might offset.

Figure 5: Gas Demand Unmet at or Near Current Prices for 3 Demand Scenarios



Source: "Figure 8" of BRG (2023) Alaska Utilities Working Group, Phase 1 Assessment: Cook Inlet Gas Supply Project.

3. Demand-reducing investments

3.1 Residential Heating

Reductions in residential gas demand could come from weatherization, electrification of home heating, or large-scale installation of heat pumps. Using the Alaska Housing Finance Corporation's (AHFC) weatherization program as a template for understanding costs and efficiency gains, we can roughly estimate the potential scale of savings. Under these assumptions, weatherizing 20,000 homes would reduce gas demand by approximately 1 BCF per year, at a total cost of about $388 million.

Larger reductions are theoretically possible, but they quickly become challenging in practice. Even if residential gas demand were eliminated entirely by retrofitting all ~150,000 gas-heated homes in Southcentral Alaska, this would require substantial upgrades including furnace replacements, weatherization, ducting, and in many cases electrical service increases. Completing work at this scale would place significant strain on the available workforce. To retrofit the full housing stock within ten years (a timeframe that is already too slow to close the projected gas deficit through this strategy alone), roughly 288 homes would need to be retrofitted every week for a decade. For context, AHFC's program completed weatherization upgrades on 258 homes in all of 2024.

If such a program were somehow completed by 2035, retrofits might offset more significant gas demand. However, the electrification component of home heating would increase electricity consumption and could offset some or all of these gas savings depending on the generation mix needed to meet the new electric load. If that new generation is primarily natural gas-fired, the reductions in residential gas demand could be partially or fully reintroduced through the power sector.

3.2 Alternative Electricity

Table 3 shows the most complete list available of the publicly announced alternative energy projects as well as five hypothetical/what-if scenarios that would reduce gas demand.[16] Nine are primarly renewable/clean energy projects.

CEA community solar was completed in 2025, but gas savings from the project were generously estimated at no more than 0.01 Bcf/year. The Puppy Dog Lake solar project would have similarly modest savings of around 0.4 Bcf/year, has no public cost of capital estiamte, and was recently placed on hold due to uncertainty around federal tax credits. CEA is also considering a $15M solar project on the site of its Beluga plant with a capacity of around 5MW. If that project achieved similar gas savings on a per-megawatt basis to the estimates used for the Puppy Dog lake project, savings could be ~0.07BCF/year.

The Bradley Lake – Dixon Diversion project is currently underway at an estiamted cost of around $350 million. This project is designed to increase the capacity of the Bradley Lake hydroelectric plant. The additional capacity will offset around 1.5 Bcf of gas demand per year.

[16] Other projects which have appeared in recent planning documents include the Great Land Solar Project and the Godwin and Battle Creek hydro projects.

Two large wind projects—Shovel Creek near Fairbanks and Little Susitna near Anchorage—are being advanced by Alaska Renewables. Neither project has publicly available cost estimates, and both face additional headwinds following the recent repeal of federal clean-energy tax credits. Together, these projects could offset as much as 8 Bcf of gas demand annually, though the allocation of Shovel Creek's output between the Southcentral utilities and Golden Valley Electric Association would ultimately depend on utility-to-utility negotiations and transmission capacity.

GeoAlaska is pursuing a geothermal project with a proposed capacity that could offset up to 5 Bcf of gas per year, but the project remains in relatively early development stages and lacks a published cost estimate. Tidal and nuclear concepts are even more speculative and are unlikely to come online within the timeframe required to address utilities' near-term supply needs.

The largest renewable proposal is the Susitna–Watana hydroelectric project, originally costed at $5.2 billion in 2014. Given a decade of construction-cost inflation, this figure is almost certainly an underestimate of present-day capital requirements. Nevertheless, the project could displace approximately 15 Bcf of annual gas demand once operational. Like Shovel Creek, some electrity would likely be sent north to Fairbanks (reducing Southcentral gas savings). It is also difficult to imagine a project at this scale would be completed on a timeline necessary to avoid the short to medium term deffict in gas.

The final project under active consideration is the Terra Energy coal-generation proposal. While Table 3 lists only capital costs (excluding operating expenses), a facility built at the representative $2.2 billion scale could reduce gas consumption by roughly 10 Bcf per year.

Even before timing and cost are considered, what is clear from evaluating these project options is the current portfolio of wind, geothermal, and solar projects are not, on their own, sufficent for offseting the gas supply-demand gap in the medium term. Only when combined with a larger project like the Susitna Watana or Terra Coal project do these combined offsets meaningfuly close the gap faced by Southcentral. To be more specific, BRG's demand-supply forecast in its status quo medium-demand scenario estimates a shortfall of 16 Bcf in 2030, 23 Bcf in 2031, and 30 Bcf in 2033. By comparison, the cumulative offset of the existing wind, geothermal, solar, and Dixon Diversion projects is only 14 Bcf per year, short of bridging the projected gap that will open as soon as 5 years from now.

Table 3: Cook Inlet Proposed and Hypothetical Energy Projects

Notes	*Type*	*Electricity Projects*	*Capital Cost*	*BCFY*
1	Solar	Chugach Community Solar	*	0.01
2	Hydro	Bradley Lake Dixon Diversion	$342m	1.5
3	Solar	Solstice Energy Puppy Dog Lake	?	0.4
4	Geothermal	GeoAlaska Mt. Augustine	?	5
5	Wind	Alaska Renewables Shovel Creek	?	3
6	Wind	Alaska Renewables Little Susitna	?	4
7	Coal/Biomass	Terra Energy Center coal/biomass	$2.2B	10
8	Tidal/Nuclear	ORPC Tidal Power (Cook Inlet), Micronuclear	?	?
9	Hydro	Susitna Watana	$5.19B	15
10	Solar	Beluga	$15m	0.07
	Hypothetical Projects/"What ifs"			
11	Wind	Quadruple Fire island Wind	$356m	1.056
12	Weather	Warmest Year - 2019 - 1,434 fewer HDDs	0	4
13	Weather	Coldest Year - 2012 - 10,880 HDDs	0	4
14	Home	Weatherize 20,000 Homes	$388m	1

Sources: (2-8) from Southcentral Mayors' Energy Coalition. Cook Inlet Energy Overview. Presentation to Anchorage Assembly Energy and Infrastructure Workshop. Dec 5th, 2024. Peter Micciche. Others are author's calculations from various sources. (1) Chugach community solar rental cost is $9.21/panel/month x 12 months x 1,560 panels. Fuel offset is assumed same as reported Puppy Dog on BCF/MW basis. (9) Susitna Watana source susitna-watanahydro.org. Cost in $2014. Fuel offset is assumed same as reported Dixon Diversion on BCF/MW basis. (10) Fuel offset is assumed same as reported Puppy Dog on BCF/MW basis. https://www.chugachelectric.com/sites/default/files/meetings/document_packets/08%2013%2025%20Operations%20Committee%20Meeting%20-%20PUBLIC%20PACKET_2.pdf#page=17 (11) Fire Island capacity and cost from: alaskasnewssource.com/2022/10/15/fire-island-wind-project-enters-11th-year-operation/. Fuel offset is assumed same as reported for Alaska Renewable's wind projects on a Bcf/MW basis. (12-13) HDD from National Weather Service Climate Prediction Center for Anchorage, AK were used in a simple linear regression model to predict total fuel delivered by Enstar and consumed in residential and commercial natural gas volumes, data reported from the Energy Information Administration. (14) In 2024, AHFC weatherized 258 homes at a cost of $5m according to their annual report for that year., or ~$19k/home. AHFC reports energy savings of 30%. ~20,000 homes weatherized under these assumptions approximately 1 Bcf of gas saved and total cost $388m.

4. Short-term solutions for closing the gas deficit

Regardless of medium or long term strategies, Southcentral will need to find ways to close the gas deficit in the short-term of three to five years. These short-term strategies involve some combination of LNG imports, demand reduction (both residential and commercial utility gas and gas used for power generation), and additional development of Cook Inlet gas resources.

The BRG working group study anticipated that under status quo conditions, an 8 Bcf gas deficit would emerge by 2028 and a 16 Bcf gas deficit would emerge by 2030.

The previous section of this report outlined several potential options for closing the projected gas deficit. A key consideration in evaluating these options is timing. Which option could be brought online before 2028 and 2030 in order to address this deficit? Or more specifically, how quickly can each option be scaled relative to the pace at which the deficit grows. Some demand-reduction measures can be deployed relatively quickly, while larger infrastructure solutions require longer lead times. For example, if a decision were made today to pursue the Susitna–Watana hydropower project, the necessary studies, reviews, permitting, and construction would take many years. Estimates from the 2014 project timeline suggested that this process would require roughly nine years to complete.[17] The Terra coal project anticipates a four year development timeline after a final investment decision is made. Mid-sized renewable projects such as the Shovel Creek or Little Susitna wind projects anticipated development timelines of closer to three to four years as of December 2024, but it is unclear how much work was completed toward these timelines in 2025.[18]

There is no combination of projects currently under consideration that would be operational and that would provide enough gas demand offset to cover the deficit that emerges by 2028. That leaves two options to meet the near-term shortfall, additional gas development from the Cook Inlet and LNG imports.

A separate report discusses the challenges of addressing the Cook Inlet natural gas deficit through increased local production. The core issue is cost, not necessarily resource availability. Under current market conditions, utilities would need to pay substantially higher prices to incentivize producers to invest in new development.

A second challenge is the growing reluctance of Cook Inlet producers to sign firm-delivery gas contracts, which obligate producers to deliver specific quantities at agreed-upon prices. Instead, utilities have increasingly been offered only interruptible contracts, which carry no guaranteed volumes.[19] Interruptible contracts are usually cheaper because they shift supply risk from producers to utilities.

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[17] https://www.susitna-watanahydro.org/schedule.html

[18] Southcentral Mayors' Energy Coalition. Cook Inlet Energy Overview. Presentation to Anchorage Assembly Energy and Infrastructure Workshop. Dec 5th, 2024. Peter Micciche.

[19] https://alaskabeacon.com/2025/01/22/rolling-blackouts-could-loom-for-urban-alaska-as-natural-gas-crunch-intensifies/

Given these constraints, LNG imports remain the only short run option that can reliably provide the quantities of natural gas needed while ensuring uninterrupted service. LNG imports for Southcentral Alaska would draw from the global liquefied natural gas market, with potential supply originating from major exporting regions such as the Canada, Australia, or Asia.[20] LNG would be transported to Alaska aboard specialized carriers, arriving at a marine terminal equipped to offload and regasify the product. One option for offloading the LNG would be to store it in supercooled tanks and later regasified to enter ENSTAR's existing natural gas transmission and distribution system. Once integrated into the pipeline network, regasified LNG would flow to utilities and commercial and residential customers in much the same way as Cook Inlet gas is currently delivered.

Both Chugach Electric Association (CEA) and Enstar have recently taken steps toward developing the infrastructure required to import LNG.[21] CEA is working with Harvest Alaska on conversion of the existing Kenai LNG terminal (which formally liquifed and loaded natural gas for export) into a facility capable of receiving shipments of LNG imports. This would exploit existing dock and storage facility infrastructure and allow Chugach to begin procuring LNG gas on a timeline that would not be possible from a greenfield facility.

Enstar is working with Glenfarne, the developer of the Alaska LNG project, on a greenfield LNG port facility capable of receiving imports at a larger scale. This facility would take longer to construct than the CEA and Harvest Alaska re-development. However, Enstar has gas contracts sufficient to cover its needs through March of 2033, four to five years later than when CEA's contracts become insuffficent to meet its needs. So, while this greenfield facility will take longer to construct, its operation is not required imediately. Additionally, this facility is co-located at the site intended for future LNG exports as part of the Alaska LNG project Phase II development. This allows Enstar to enter into longer-term contracts with Glenfarne to spread costs to import LNG over a longer period, while also returning to in-state gas if the LNG pipeline is completed before the import terminal contract term expires.

LNG imports have a few important features. LNG is a globally traded commodity. This means that Southcentral would have access to volumes of gas in signficant excess of utilization, effectively relaxing gas *production* constraints that Southcentral utilties currently face. Instead, supply would be constrained by terminal capacity and storage. Additionally, while specific contract terms would need to be negotiated, Southcentral would essentially face a global gas price (plus local liquefaction, shipping, and terminal costs). Typical LNG contracts index delivered prices to oil or gas spot market prices, making prices volitilie. Southcentral would also be able to access the LNG spot market to procure gas in the event of unexpected demand spikes (subject to vessel availability, shipping timelines, and terminal capacity constraints).

5. Medium and long-term solutions for closing the gas deficit

In the medium (4-7 years) to long term (8+ years), more options are available for offsetting gas demand, particularly demand for gas in electricity generation. Strategies which entail adding

[20] Sourcing gas from elsewhere in the United States would be complicated with Jones Act compliance.
[21] https://www.northernjournal.com/utilities-say-alaska-needs-an-lng-import-terminal-heres-how-consumers-could-end-up-paying-not-for-one-but-two/

additional renewable energy production while electrifying residential and commercial heating are more viable at longer time horizons as these technologies improve. Longer lead time also provides for relaxed capital constraints, possible changes to the regulatory enviornment, etc. Some of the energy projects listed in Table 3 could be feasibly completed in the medium term (e.g. Little Susitna Wind), while others might only be available in the long term (e.g. Susitna-Watana or nuclear). Further, there are likely a number of options that could be available in the 10+ year timeframe that are not currentlly under active consideration.

The Alaska LNG project is the most significant project under current consideration. This project, if sucessfuly developed, has the potentially to fully cover the gas deficit for the medium to long term. The project is currently conceived in two phases. Phase 1 would address in-state gas demand through the construction of the greenfield port facility described in Section 4 and a 765-mile long, 42" diamater mainline pipeline. The port facility would be capable of receiving imports of LNG in the short run and then exporting LNG once the project's second phase is completed. Phase 2 would add the facilities required to treat and liquify natural gas for export. On the North Slope, a gas treatment plant would be built to remove CO_2 and other impurities before the gas could be piped south. A 42-mile connecting segement would be built to extend the pipeline from its Phase 1 terminus to the LNG plant site in Nikiski. Finally, an LNG liquefaction facility (called a train), would be built with capacity of 6.6 million tons of LNG per year ("Mtpa"). The ultimate goal would be to scale this 6.6 Mtpa facility with an additonal two trains for a total capacity of almost 20 Mtpa.[22]

As of Februrary 2026, work on the gasline's front-end enginering and design is currently ongoing. Project developers expect this work to be completed soon. It will provide an updated estiamte of the project cost and construction timeline necessary for a final investment decision to be made. A report conducted by Wood Mackenzie on behalf of Alaska Gasline Development in 2024[23] escalated previous cost projections and estimated a capital cost of the Phase 1 mainline at $10.8B. This did not include a $0.6B potential extension line to the Pt. Thomson field, which might be necessary to procure gas supplies if prefered fields are not available. Previous estimates of the full project are typically quoted at $44B,[24] which includes the mainline, North Slope treatment plan, and Kenai liquefaction facilities.

With respect to the potential timeframe, the 2024 WoodMackenzie study assumes that project construction begins in 2026 and first commercial gas is delivered in 2031. Glenfarne has more recently spoken to a faster timeline, with construction completed by 2028, and first commercial gas deliveries in 2029.[25] In a December 2025 report[26] prepared for the Alaska Legislative Budget and Audit Committee, GaffneyCline noted that contracting issues between Southcentral utilities, construction and enginnering firms, and pipeline developers/owners would need to be resolved before Phase 1 could proceed.

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[22] https://alaska-lng.com/project-overview/liquefaction-facility/
[23] https://agdc.us/wp-content/uploads/2024/09/2024.09.10-WM-AGDC-Alaska-LNG-Phase-1.pdf
[24] https://www.adn.com/business-economy/energy/2025/12/15/governor-to-propose-lower-property-tax-to-support-alaska-lng-mega-project/
[25] Ibid
[26] https://lba.akleg.gov/wp-content/uploads/Key-Issues_Legislative-Policy-Options-for-Alaska-LNG-GaffneyCline-FINAL-COPY-issued-December-2025.pdf

6. Conclusion

This review highlights the importance of timing, cost, and uncertainty as utilities navigate the Cook Inlet gas supply deficient. While some gas demand might be offset through efficiency, warmer climate, renewable generation, and electrification, these options are not cumulatively sufficient to address the full deficit of low cost Cook Inlet gas that will arise by 2033. As contracts expire, Cook Inlet gas will likely still be available in some quantities, but at higher prices than those historically or potentially available from LNG imports or North Slope pipeline gas.

Technical Appendix

Table A1 summarizes a set of simple regression models that relate annual natural gas demand to weather, population, and time trends for residential and commercial users. Across all specifications (models which include additional variables), heating degree days (HDDs) are the dominant driver of demand: colder years are associated with substantially higher gas consumption in both the residential and commercial sectors, underscoring the central role of climate in shaping energy needs. For residential demand, the year trend is positive and statistically significant in most specifications, suggesting a gradual underlying increase in gas use over time that is not explained by weather alone—potentially reflecting changes in housing stock, appliance use, or building intensity. In contrast, the time trend is smaller and generally not statistically significant for commercial demand, indicating less systematic growth once weather is accounted for. Population, when included, does not appear to have a statistically meaningful effect on annual gas demand in either sector, likely because population changes over this period are modest relative to year-to-year weather variation. The high adjusted R^2 values indicate that these models explain a large share of observed variation, and the results highlight that near-term fluctuations in gas demand are driven far more by temperature than by population growth.

Table A1: Regression Estimates of the Effects of Climate and Population on Annual Gas Demand

	Residential Demand (mcfs)			Commercial Demand (mcfs)		
	(1)	(2)	(3)	(4)	(5)	(6)
HDDs	1,463.622***	1,519.700***	1,537.717***	913.096***	919.976***	937.053***
	(203.394)	(134.319)	(158.522)	(94.022)	(96.592)	(113.744)
Year Trend		108,186.3***	97,943.89*		13,273.3	3,565.982
		(26,391.44)	(50,072.98)		(18,978.6)	(35,928.65)
Population			6.897			6.537
			(28.135)			(20.188)
Constant	5,247,219**	3,901,059**	660,600.5	4,500,606***	4,335,447***	1,264,275
	(1,946,262)	(1,320,102)	(13,290,689)	(899,685.800)	(949,311.9)	(9,536,411)
Observations	14	14	14	14	14	14
Adjusted R^2	0.796	0.912	0.904	0.878	0.872	0.861

Note: *p**p***p<0.01

Coefficient estimates and standard errors of a regression.
The units, "mcfs," are thousand cubic feet of gas. Year trend is a linear time trend. Population data from Alaska Department of Labor and are totals for Anchorage, Mat-Su, and Kenai.