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May 2, 2025

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501

Subject: Tariff Advice Letter TA354-4, Interim and Permanent Rate Increase

Dear Commissioners:

ENSTAR Natural Gas Company, LLC ("ENSTAR" or "Company")[1] transmits this filing in compliance with the Alaska Public Utilities Regulatory Act (AS 42.05) and Sections 3 AAC 48.200 - 3 AAC 48.430 of the Alaska Administrative Code, and as required by the stipulation approved by the Regulatory Commission of Alaska ("RCA" or "Commission") in Order U-22-081(11).[2]

I. INTERIM TARIFF SHEETS

Tariff Sheet		Cancels Sheet		
Number	**Revision**	**Number**	**Revision**	**Schedule or Rule Number**
255	Second	255	First	Rates – Section 2001 G1
256	Second	256	First	Rates – Section 2002 G2
257	Second	257	First	Rates – Section 2003 G3
258	Second	258	First	Rates – Section 2004 G4
271	Second	271	First	Rates – Section 2145 MSFT
272	Second	272	First	Rates – Section 2150 VLFT
273	Second	273	First	Rates – Section 2150 VLFT
275	First	275	Original	Rates – Schedule 2160 SCPPFT
277	First	277	Original	Rates – Schedule 2160c(2) SCPPFT
282	Second	282	First	Rates – Section 2201 IIT
284	Second	284	First	Rates – Section 2251 ITS

[1] The terms "ENSTAR Natural Gas Company, LLC," "ENSTAR," and "Company" are used collectively to include Alaska Pipeline Company, LLC and ENSTAR, which are regulated as a single entity.

[2] Order U-22-081(11), *Order Accepting Partial Stipulation, Rescheduling Hearing, Denying Motion for Expedited Consideration, Amending Docket Caption, and Redesignating Commission Panel*, Oct. 11, 2024.

II. PERMANENT TARIFF SHEETS

Tariff Sheet		Cancels Sheet		
Number	**Revision**	**Number**	**Revision**	**Schedule or Rule Number**
6	Second	6	First	Index
127	First	127	Original	Section 708c – Gas Cost Balance Account
130	First	130	Original	Section 708g – Gas Cost Balance Account Quarterly Report
244	Third	244	Second	Section 1900 – Special Contracts
255	Third	255	Second	Rates – Section 2001 G1
256	Third	256	Second	Rates – Section 2002 G2
257	Third	257	Second	Rates – Section 2003 G3
258	Third	258	Second	Rates – Section 2004 G4
271	Third	271	Second	Rates – Section 2145 MSFT
272	Third	272	Second	Rates – Section 2150 VLFT
273	Third	273	Second	Rates – Section 2150 VLFT
275	Second	275	First	Rates – Schedule 2160 SCPPFT
277	Second	277	First	Rates – Schedule 2160c(2) SCPPFT
279	First	279	Original	Section 2170 VLFT/ SCPPFT Peak Reduction Credit
279.1	Original			Section 2170 VLFT/ SCPPFT Peak Reduction Credit
279.2	Original			Section 2170 VLFT/ SCPPFT Peak Reduction Credit
282	Third	282	Second	Rates – Section 2201 IIT
284	Third	284	Second	Rates – Section 2251 ITS

On April 22, 2025 the Commission issued Order U-25-004(5), relating to the regulatory asset authorized in Order U-22-090(2), stating that "… ENSTAR agreed to file a rate case in 2025 or in 2026 based on a 2024 or 2025 test year, respectively. ENSTAR may seek to recover the costs of the $4.6 million regulatory asset in that rate case."[3] To accommodate the order, ENSTAR is withdrawing its rate case filing under TA352-4 (dated April 15, 2024) and refiling its 2024 test year rate case in this tariff advice filing.

III. OVERVIEW

As ENSTAR approaches nearly 65 years of operation, the Company is proud of its sterling safety record and reputation for reliable natural gas service. Over the decades, ENSTAR has provided uninterrupted gas service to its customers despite natural disasters, economic downturns,

[3] Order U-25-004(5) at 51, *Order Closing Regulatory Asset Authorized By Order U-22-090(2), Approving New Regulatory Asset, Denying TA350-4, Finding Motions For Confidential Discovery Orders And Motion For Expedited Consideration Moot, Requiring Filings, Vacating Remaining Procedural Schedule And Hearing, And Appointing Administrative Law Judge*, April, 22 2025.

extreme weather conditions, and operational challenges. This is due, in part, to the industry-leading maintenance and operation of this pipeline system and oversight from ENSTAR's team of highly trained and well-qualified employees. At the same time, portions of ENSTAR's system are aging and in need of replacement in order to maintain that same reliable service into the future. These capital-intensive programs require ready-access to capital. These programs coupled with rising costs result in ENSTAR not having an opportunity to earn its authorized rate of return. Access to capital and the ability to achieve its revenue requirement are critical for ENSTAR's financial health and its ability to invest and support a pipeline system that provides more than half of Alaskans with heat and fuel.

ENSTAR meticulously monitors its system to ensure pipeline integrity and proactively mitigate identified risks, either through enhanced monitoring, repairs, or replacement, as required. Accordingly, ENSTAR invested over $127 million in its system since its last rate case, which was based on a 2021 test year.[4] The substantial capital investment coupled with high inflation,[5] as well as increasing costs for labor, healthcare, and compliance with federal regulations for cybersecurity and pipeline operations, have increased operating costs, resulting in ENSTAR under-earning by a significant margin.

ENSTAR's completed capital projects and investments were based on overall system need, safety and reliability, and driven by customer requirements. Since 2021, ENSTAR also expanded its system significantly, bringing natural gas to more than 5,000 new customers. All of the projects and capital investment included in this rate case were complete and in service to customers by the end of the test year.

ENSTAR's 2024 capital expenditures follow 63 years of prudent investment in a system that is vital to Southcentral Alaska. ENSTAR has provided high-value, low-cost energy to Alaskans since 1961, when it turned on the valve from the Kenai Gas Fields to its pipelines to serve its first customers. ENSTAR has grown with Southcentral Alaska and now reliably meets the natural gas demands of over 155,000 customers. ENSTAR provides this reliable service while maintaining an impeccable safety record. Since the last rate case, ENSTAR's safety and reliability metrics have consistently improved from its already high levels, and in 2024, was recognized by the American Gas Association as an industry leader in safety for the sixth year in a row. Its safety protocols for pipeline operations exceed national standards. Providing this consistent level of safety and reliability requires ongoing investment in ENSTAR's gas transmission and distribution systems.

IV. REQUEST

ENSTAR requests that the Commission authorize an overall annual rate increase of approximately $24.9 million, which will increase the average customer bill by 5.77% per year,

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[4] Docket U-22-081.

[5] According to the CPI Index release by the State of Alaska, Department of Labor and Workforce Development, Urban Alaska has experience a total of 11.8% inflation since ENSTAR's last rate case (2022 to 2024) https://live.laborstats.alaska.gov/cpi/table, last accessed April 4, 2025.

equating to $8.95 per month. The revenue requirement study included with this filing demonstrates ENSTAR is extensively under-earning, and that its current rates are confiscatory. ENSTAR's current rates resulted in an effective 5.82% return on equity ("ROE") in 2024, compared to its approved ROE of 11.875%. Therefore, a rate adjustment is necessary.

ENSTAR proposes to increase its rates in two steps: (1) an interim rate increase of approximately 5.00% of total revenues to be effective for billings on or after July 1, 2025; and (2) an additional 0.77% upon final approval or acceptance, bringing a permanent rate increase of approximately 5.77% of total normalized annual revenues. This filing is not for any new service, will not result in the termination of any existing service, or conflict with any other rate or schedule.

The Commission observed in Order U-16-066(19) that "[d]uring this proceeding it was undisputed that ENSTAR operates a safe and reliable utility whose cost to distribute gas to its customers is well below the average cost nationwide." This statement is a source of pride and a guiding principle in ENSTAR's ongoing operations. If ENSTAR's filing is approved, its cost of natural gas delivery service (customer charge and service charge, excluding gas commodity cost) for an average G1 Gas Sales customer will be $3.70 per Mcf.[6] This is well below the national average cost for natural gas distribution service during 2024 as reported by the Energy Information Administration of $13.14 per Mcf.

ENSTAR respectfully requests interim and permanent rate relief to allow the Company an opportunity to recover its just and reasonable costs while earning a fair return on its prudent capital investments.

V. SUMMARY OF RATE CHANGES

ENSTAR is filing this rate case and lead-lag study based on a 2024 test year and in compliance with the stipulation approved in Order U-22-081(11). ENSTAR's revenue requirement study demonstrates that due to its prudent capital investments in its transmission and distribution system, increased operating expenses, and other factors, ENSTAR is significantly underearning, and an adjustment is necessary to reflect the investments made on its customers' behalf. ENSTAR therefore requests interim and permanent increases to its base rates. Base rates recover ENSTAR's costs of delivering gas to over 155,000 residential and commercial, and several transport customers, in Anchorage, the Matanuska-Susitna Valley, and the Kenai Peninsula. This filing requests a permanent revenue increase of approximately $24.9 million, representing a 5.77% increase in ENSTAR's total revenues including gas costs (which represents a 26.79% increase in base rates), with an across-the-board interim rate increase of 5.00% (approximately $21.6 million).

[6] Bcf is 1,000,000 Mcf or 1 billion cubic feet. Mcf is one thousand cubic feet. Ccf is one hundred cubic feet.

VI. COMPONENTS OF THE BASE RATE FILING

Included with this tariff advice letter are the revised tariff sheets identified above and the prefiled testimony of ENSTAR's witnesses, who address ENSTAR's request for both interim and permanent rate relief.

Attachment A is an index of the attachments, testimony, and exhibits supporting ENSTAR's rate request. The revenue requirement study required by 3 AAC 48.275(a) with rate base calculated on a 13-month average (with certain adjustments) is included as Attachment B. Attachment C contains the cost-of-service ("COS") study information required by 3 AAC 48.275(h) along with its rate design. Attachment D contains the rate schedules with the interim increase applied on an across-the-board basis, and rate schedules with the requested permanent rates are included as Attachment E. The supporting testimony of ENSTAR's witnesses, along with their attachments and exhibits, are also included as required by 3 AAC 48.275(a) and (h).

VII. PROPOSED COST OF CAPITAL

ENSTAR is proposing to use its actual capital structure as of December 31, 2024, which consists of 41.43% debt and 58.57% equity. ENSTAR proposes an overall rate of return of 9.91%, which is calculated using ENSTAR's current actual cost of debt, 5.55%, and a proposed 13.00% return on equity, as recommended by ENSTAR witness, Ms. Jennifer E. Nelson. The Commission typically approves the use of a public utility's actual capital structure and actual cost of debt.

ENSTAR's requested rate of return is appropriate because ENSTAR is a unique transmission and distribution utility that is operating in an environment filled with increasing uncertainty. As described in more detail by Ms. Nelson, ENSTAR's requested rate of return is appropriate based on the quantitative modeling and the unique operational, geographic, and logistic risks ENSTAR faces, many of which have increased since ENSTAR's last rate case. ENSTAR President, Mr. John D. Sims' prefiled testimony identifies some of the business and operational risks ENSTAR currently faces, including: (1) maintaining and operating transmission assets in Alaska that require significant capital investment coupled with increasing regulation; (2) volatility in local economic conditions; (3) unmitigated weather fluctuations; (4) small size; (5) declining use per customer; (6) remote geographical location and relatively harsh operating environment; and (7) natural gas supply risk.

Commission approval of the revenue requirement and rates proposed by ENSTAR, based on its requested cost of capital, will enable ENSTAR to maintain its financial health and better position the Company to address these significant challenges.

VIII. RATE BASE AND REVENUE REQUIREMENT ADJUSTMENTS

A. Infrastructure and Capacity Improvements

As discussed in greater detail in the direct testimony of Mr. Nathan T. Burke, ENSTAR has made substantial capital investments since the end of the test year in ENSTAR's last rate case (December 31, 2021) to the end of the test year in this case (December 31, 2024). During that

time, the Company invested approximately $127 million in capital to maintain and improve its natural gas transportation and distribution system. Some of the major projects are described below, all of which were complete and in service to customers at 2024 test year-end. The projects completed by ENSTAR include:

- **Kenai A&B Pipeline MP30.9 Valve Replacement (2022):** ENSTAR replaced and relocated the buried isolation and crossover valves at milepost 30.9 along the Kenai to Anchorage "A" and "B" Pipelines that transport gas from Kenai to Anchorage, which were originally installed in 1961 and 1974, respectively. The new valves were installed above ground to enhance the reliability and safety of operating these valves and connected pipelines.
- **Welaka Lake and Holt Lamplight Regulator Station Replacements (2022**): ENSTAR replaced pressure-regulating stations in Nikiski that posed significant reliability risks due to aged equipment and the stations' under performance.
- **Oilwell Pipeline Valve Upgrades and Launching Facility Installation (2023):** This transmission project upgraded the valve connections of two segments of the Oilwell Lateral in Anchorage so that an internal inspection device could be used to inspect and monitor the line for system integrity.
- **Moose River Horizontal Directional Drill (2023):** For this project, ENSTAR installed approximately 1,000 feet of new 12-inch steel pipe on the Kenai B-Line to replace a section of the pipeline that had become exposed at the bottom of the Moose River in Sterling and was considered to be a potential public safety hazard. A link to the video describing this project and its benefits can be accessed here: Moose River Project Video.
- **Nikiski Microwave Tower Project (2023):** ENSTAR installed an additional microwave tower to bridge a gap and help provide an alternate communication path for the Company's Supervisory Control and Data Acquisition ("SCADA") system to control and monitor data, including pipeline pressures, compressor station status, ENSTAR IT communications between divisions, and ENSTAR's mobile radio system used for emergency communication.
- **SCADA Replacement (2023 and 2024):** Due to increased federal requirements for pipeline control room management and ongoing support problems with an old SCADA system, ENSTAR replaced its SCADA system.
- **Kenai B-Line Segment K6 Replacement (2024):** ENSTAR replaced approximately 2,600 feet of one of only two pipelines that bring gas to Anchorage from Kenai (the 16-inch Kenai to Anchorage B-Line). Recent in-line inspections revealed that the line contained significant amounts of corrosion. This substantial replacement project, which ENSTAR completed with a horizontal directional drill, was necessary to improve safety and reliability on a major line that is critical to ensuring deliverability of gas to Anchorage.
- **Seward Meridian Parkway Reinforcements, Transmission Extension, and Regulator Station (2024):** ENSTAR completed this group of projects in coordination with Phase II of the Alaska Department of Transportation's federally-funded Seward Meridian Parkway Road Improvements Project. The Company installed a new 8-inch distribution system feed from the Palmer-Wasilla Highway to the Seldon Road area, extended a new 4-inch transmission line from the Parks

Highway to the Seldon Road area, and installed a new pressure regulator station to improve pressures in the northern areas of the Mat-Su Valley.

- **Reliability Infrastructure Replacement Program ("RIRP") Project:** In 2024, ENSTAR implemented a large-scale program to replace steel mains and services (and other metallic pipes) across the Company's system, beginning in Kenai. As part of this initial project phase, ENSTAR replaced more than 26,000 feet of steel mains and 130 service lines installed primarily in the 1960s, on a portion of ENSTAR's system that the Company acquired from Kenai Utility Service Corporation ("KUSCO") in 1985.

B. Lead-Lag to Determine Cash Working Capital

As part of the stipulation accepted by the Commission in Order U-22-081(11) that resolved all issues excluding ROE in ENSTAR's last rate case, ENSTAR agreed to exclude deferred income tax, depreciation, and the common equity return component of net income from its cash working capital calculation for this case. Consistent with this agreement, ENSTAR's witness Mr. Harold Walker, III conducted a lead-lag study to determine ENSTAR's cash working capital allowance for inclusion in rate base. This lead-lag study demonstrates a revenue lag of 41.3 days and an expense lag of various durations, resulting in a cash working capital requirement of $6,950,657 for the test year.

C. Pro Forma Schedules

ENSTAR's revenue requirement is calculated using a 2024 test year with pro forma adjustments, including those for known and measurable changes, as necessary to arrive at the "normalized" test year data included in this filing. Normalizing test year data is a standard regulatory practice followed by the Commission and is intended to produce rates which more accurately portray ENSTAR's expected annual costs and revenues for the period when the rates will be in effect. Schedules A through Q of ENSTAR's 275(a) filing (Attachment B) present the pro forma adjustments to ENSTAR's revenues, expenses, and rate base. The adjustments are supported by the prefiled direct testimony of Ms. Chelsea N. Guintu, Ms. Inna B. Johansen, Ms. Abigail L. Riggs, and Dr. Bruce H. Fairchild.

D. Weather Normalization

The weather in the 2024 test year, as measured in heating degree days ("HDD"), was 5.4% colder than average. There is a strong correlation between HDD and ENSTAR's General Service customer usage; as HDD increase, so does natural gas consumption. As such, 2024 was not representative of the volumetric revenues ENSTAR is likely to earn in the rate-effective period. As Ms. Johansen details in her prefiled testimony, ENSTAR proposes to weather normalize the test year use per consuming customer for its General Service customer classes, to arrive at a normalized use per customer. ENSTAR does not propose to weather normalize its medium transportation, large transportation, and power plant customer volumes. The overall impact of ENSTAR's weather normalization adjustment is a reduction of 1,564,296 Mcf to test year volumes and $1,934,650 to test year revenue (excluding gas cost).

IX. COST OF SERVICE STUDY

Attachment C to this TA filing contains the COS study information required by 3 AAC 48.275(h), which is sponsored in testimony by Dr. Fairchild. The COS study is an engineering, accounting, and economic analysis designed to allocate ENSTAR's total cost of providing service to specific customers or customer classes. Many of a utility's operating expenses along with much of its capital investment are incurred to serve all customers. Because these joint and common costs cannot be directly tied to specific customers, they must be apportioned among customers and/or customer classes. This apportionment is accomplished through a COS study, in which operating and capital costs are allocated using factors developed from operating data reflecting cost causation. The sum of the costs allocated to each customer and/or customer class in the COS study represents class revenue requirements, or that portion of the utility's total costs for which a particular customer or customer class is responsible.

The COS study presented here follows the methodology approved by the Commission in Order U-16-066(19). Most capacity-related costs, which are primarily related to transmission activities, are apportioned between customer classes using an allocation factor. This is calculated by weighting equally the relative contributions of each customer class to the test year coincident system peak demand and average day demand, which is the equivalent of volumes. Administrative and general expenses and general plant are apportioned using a payroll allocator; uncollectible accounts expenses are borne solely by the general service customer classes; and none of the measuring and regulating expenses or related plant are allocated to the mid-sized firm transport class.

X. RATE DESIGN

Consistent with the stipulation accepted in Order U-22-081(11), ENSTAR has not proposed any changes to its existing rate design as adjudicated in Docket U-16-066, and modified in TA303-4, in its next rate case. As explained by Ms. Johansen, in this filing ENSTAR proposes to offer VLFT/SCPPFT customers having alternative fuel capability and meeting other requirements a monthly Peak Reduction Credit if they agree to reduce consumption when ENSTAR needs gas to meet other customers' requirements. This credit is intended to provide qualifying customers an incentive to reduce consumption, allow gas to be diverted, and partially compensate for the costs of having alternative fuel capability available.

XI. INTERIM RATE RELIEF

If the Commission suspends ENSTAR's permanent rate increase request pending additional investigation, ENSTAR requests the Commission allow an across-the-board interim and refundable increase of 23.21% to its base rates (approximately 5.00% on total revenues including gas cost) which is expected to generate an increase in annual revenue of approximately $21.6 million effective for billings on or after July 1, 2025, which is the beginning of the first month

following the statutory 45-day review period.[7] Ms. Guintu sponsors ENSTAR's request for interim rate relief in her prefiled testimony.

The refundable nature of the rates fully protects customers against over-recovery; ENSTAR, by contrast, has no protection against an under-recovery. The interim rate increase ENSTAR has requested is consistent with Alaska Supreme Court precedent and should be granted.

A. ENSTAR's current rates do not afford a reasonable return.

In *Alaska Public Utilities Commission v. Greater Anchorage Area Borough*, the Alaska Supreme Court stated, "Rates which do not afford a reasonable return on the value of property used in the public service have been held to be confiscatory."[8] Similarly, the United States Supreme Court has made clear that rates—whether permanent or interim—cannot be confiscatory. Specifically, the Court has explained that:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[9]

The Court has also recognized that:

> From the . . . company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt . . . .[10]

In keeping with state, federal, and Commission precedent, in the event the Commission suspends this TA filing into a docket, ENSTAR is entitled to rates throughout the proceeding that include a return sufficient to support its continued financial health. The rates in effect today do not meet that legal standard. ENSTAR's continued success depends on adequate earnings, and consistent earnings require interim rates established at the requested level. As explained in Ms. Guintu's prefiled testimony, ENSTAR's current rates do not afford ENSTAR the opportunity to earn its authorized ROE.

B. ENSTAR has demonstrated the need for interim rate relief under Alaska law.

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[7] In calculating the amount of the across-the-board interim increase request, ENSTAR recalculated its revenue requirement request utilizing its last authorized return on equity (11.875% set in Order U-22-081(14)) on its revenue requirement study calculated with a 13-month average rate base in accordance with Commission precedent.

[8] 534 P.2d 549, 558 n.26 (Alaska 1975).

[9] *Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 693 (1923).

[10] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944).

Alaska law, in particular *Greater Anchorage Area Borough*, echoes the legal standard set forth in U.S. Supreme Court precedent.[11] The Alaska Supreme Court has held that utilities should be protected against irreparable harm if, in fact, interim and refundable rates are too low. In this case, ENSTAR has demonstrated through its supporting schedules, at Exhibit CNG-3 to Ms. Guintu's prefiled testimony, that its currently effective rates are confiscatorily low. This evidence is not "frivolous or obviously without merit."[12] Indeed, the evidence shows that the revenue resulting from ENSTAR's current rates is below the amount necessary for ENSTAR to recover its current costs of providing service (including its opportunity to earn its authorized return on its capital investments). Moreover, the currently effective rates are likely to remain in effect for at least 450 days, the statutory deadline for adjudicating ENSTAR's rate case. The period of time the confiscatory rate levels will remain in effect would be unreasonably long if an interim rate increase were not granted.

ENSTAR's requested interim rate relief is essential to avoid the continuation of confiscatory rates and meets the standards set out in *Greater Anchorage Area Borough*. Since the refundable nature of the rates protects consumers in the event that the permanent rate approved is less than the interim rate, ENSTAR respectfully requests approval of the requested interim rate increase.

XII. CONCLUSION

ENSTAR has engaged in significant infrastructure investment since its previous 2021 test-year and must continue to make investment to sustain safety and reliability. ENSTAR also faces significant uncertainty and volatility given Cook Inlet gas supply shortages and Alaska's current economic status. With Commission approval of ENSTAR's filing, the Company will be positioned to attract the necessary capital required to provide safe, efficient, and reliable service to 155,000 customers in Southcentral Alaska and other communities in Alaska that desire natural gas utility service.

ENSTAR respectfully requests that this filing become effective immediately upon the expiration of the statutory notice period. If the Commission suspends ENSTAR's permanent base rate increase request pending additional investigation, ENSTAR respectfully requests that the Commission allow an across-the-board interim increase of 23.21% to base rates (approximately 5.00% to an average gas sales customer's monthly bill), effective for billings on or after July 1,

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[11] 534 P.2d 549, 559 (Alaska 1975) (affirming superior court injunction where there was a "substantial showing that the existing rates are confiscatory . . . .").

[12] *See* Order U-10-101(7) at 5; *see also* Order U-80-027(1) ("[T]he 'not frivolous or obviously without merit standard' . . . is not intended to be difficult to pass. Therefore, in assessing [the utility's] instant interim rate increase requests, the Commission must focus first on whether the existing rates, as supplemented with the interim increases that have previously been granted, qualify as 'confiscatorily low.'") (quoting, in part, *Municipality of Anchorage d/b/a Anchorage Telephone Utility v. Alaska Public Utilities Commission*, No. 76-2322, Memorandum of Decision and Order, March 30, 1976, Slip Op. at 7).

2025. ENSTAR further requests that the Commission approve permanent rates consistent with this filing.

Sincerely,

ENSTAR Natural Gas Company, LLC

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Attachments:
Attachment A – Filing Index
Attachment B – 275(a) Filing on 13-Month Average Rate Base
Attachment C – Cost of Service Study and Rate Design
Attachment D – Interim Tariff Sheets
Attachment E – Permanent Tariff Sheets
Supporting Testimony

ATTACHMENT A

TA354-4 Filing Index

Tariff Advice Letter 354-4

Attachment A – TA354-4 Filing Index

Attachment B – 3 AAC 48.275(a) Filing

Attachment C – 3 AAC 48.275(h) Filing / Rate Design

Attachment D – Interim Rate Tariff Sheets

Attachment E – Permanent Rate Tariff Sheets

Prefiled Direct Testimony of John D. Sims, including 8 exhibits:

Exhibit JDS-1:	Resume of John D. Sims
Exhibit JDS-2:	Gas – The Magazine of the Natural Gas Industry, August 1964
Exhibit JDS-3:	ENSTAR Transmission System Map
Exhibit JDS-4:	2019-2023 AGA Safety Awards
Exhibit JDS-5:	AEDC 2025 Anchorage Economic Forecast Report
Exhibit JDS-6:	NARUC Resolution
Exhibit JDS-7:	Alaska Statute 42.05.511(c) and 42.05.441(c)
Exhibit JDS-8:	Corporate and Shared Services Costs

Prefiled Direct Testimony of Chelsea N. Guintu, including 4 exhibits:

Exhibit CNG-1:	Resume of Chelsea N. Guintu
Exhibit CNG-2:	Year End Capital Plant Calculation
Exhibit CNG-3:	Calculation of Normalized Rate of Return at Current Rates
Exhibit CNG-4:	Calculation of Interim Rates

Prefiled Direct Testimony of Inna B. Johansen, including 4 exhibits:

Exhibit IBJ-1:	Resume of Inna B. Johansen
Exhibit IBJ-2:	Calculation of Weather Normalization Adjustments
Exhibit IBJ-3:	GL List of Gas Supply Reg Asset Invoices
Exhibit IBJ-4:	Phase I Assessment
Exhibit IBJ-5:	Phase II Assessment: Summary of Results (Public Issue)

Prefiled Direct Testimony of Nathan T. Burke, including 1 exhibit:

Exhibit NTB-1:	Resume of Nathan T. Burke

Prefiled Testimony of Abigail L. Riggs, including 2 exhibits:

Exhibit ALR-1:	Resume of Abigail L. Riggs
Exhibit ALR-2:	Cost Allocation Manual

Prefiled Testimony of Andrea D. Jackson, including 5 exhibits:

Exhibit ADJ-1:	Resume of Andrea D. Jackson
Exhibit ADJ-2:	Organizational Chart of TriSummit Utilities Inc. Showing Ownership of ENSTAR
Exhibit ADJ-3:	Select Alaska Statutes
Exhibit ADJ-4:	Amended and Restated Services Agreement between TriSummit Utilities Inc. and ENSTAR Natural Gas Company, LLC
Exhibit ADJ-5:	Summary of Costs to ENSTAR to Perform All Corporate and Shared Services Activities

Prefiled Testimony of Jennifer E. Nelson, including 11 exhibits:

Exhibit JEN-1:	Résumé and Testimony Listing of Jennifer E. Nelson
Exhibit JEN-2:	Constant Growth DCF Results
Exhibit JEN-3:	Quarterly Growth DCF Results
Exhibit JEN-4:	Expected Market Return Calculations
Exhibit JEN-5:	CAPM and Empirical CAPM Results
Exhibit JEN-6:	Bond Yield Plus Risk Premium Analysis
Exhibit JEN-7:	Small Size Premium Analysis
Exhibit JEN-8:	Regulatory Risk
Exhibit JEN-9:	LDC Proxy Group Capital Structure Analysis
Exhibit JEN-10:	LDC Proxy Group Authorized Equity Ratio Analysis
Exhibit JEN-11:	Map of U.S. Shale Gas Basins and Proxy Group Natural Gas Distribution Companies

Prefiled Testimony of Bruce H. Fairchild, including 1 exhibit:

Exhibit BHF-1:	Resume of Bruce H. Fairchild

Prefiled Direct Testimony of Harold Walker III, including 2 exhibits:

Exhibit HW-1:	Professional Qualifications
Exhibit HW-2:	Lead-Lag Study

Attachment B

ENSTAR NATURAL GAS COMPANY, LLC

TEST YEAR AND NORMALIZED OPERATING REVENUES AND EXPENSES
For the Year Ended December 31, 2024

	Test Year Books	Summary of Adjustments	Normalized
OPERATING REVENUE			
Gas Sales			
Residential & Commercial (G1)	238,573,843	(5,707,844)	232,865,998
Residential & Commercial (G2)	23,718,593	(537,214)	23,181,379
Residential & Commercial (G3)	47,970,855	(967,902)	47,002,953
Residential & Commercial (G4)	79,947,130	(1,097,039)	78,850,091
Gas Sales - Other	38,200,722	1,667,038	39,867,761
Total Gas Sales	428,411,143	(6,642,961)	421,768,182
Transport Revenue			
HEA - Bernice Lake	10,800	(10,800)	-
HEA - Soldotna	27,488	(27,488)	-
MEA - Eklutna	2,157,542	-	2,157,542
Hilcorp Alaska	152,021	-	152,021
Interior Gas Utility (Titan)	331,681	(331,681)	-
Furie Operating Alaska	-	-	-
CEA VLFT Plants	5,596,200	-	5,596,200
Bluecrest Energy	16,118	-	16,118
Vision Resources	-	-	-
Total Transport Revenues	8,291,851	(369,969)	7,921,882
Miscellaneous Revenues	1,665,207	(108,532)	1,556,675
Total Operating Revenue	438,368,201	(7,121,462)	431,246,738
OPERATING EXPENSES			
Cost of Purchased Gas	343,294,122	(4,966,152)	338,327,971
Production and Gathering	171,941	905	172,846
Transmission Expense	5,498,511	113,891	5,612,402
Distribution Expense	10,748,477	303,310	11,051,787
Customer Accounting	7,331,057	196,490	7,527,548
Uncollectible Accounts	574,271	(30,688)	543,583
Sales	63,870	1,938	65,808
Administrative and General	22,328,380	(268,521)	22,059,859
Depreciation and Amortization	19,947,693	784,228	20,731,921
Total Operating Expenses	409,958,324	(3,864,599)	406,093,725
STATE AND FEDERAL TAXES			
Ad Valorem & Miscellaneous	4,493,232	-	4,493,232
State Income Tax	1,598,902	1,902,310	3,501,212
Federal Income Tax	2,404,676	3,850,357	6,255,033
Total State and Federal Taxes	8,496,810	5,752,668	14,249,477
NET UTILITY OPERATING INCOME	19,913,068		10,903,536

ENSTAR NATURAL GAS COMPANY, LLC

TEST YEAR AND NORMALIZED RATE BASE
For the Year Ended December 31, 2024

PLANT IN SERVICE	Test Year Books	Summary of Adjustments	Normalized
Gas Utility Plant	693,449,072	9,928,722	703,377,794
Depreciation Reserve	(391,064,586)	(122,841)	(391,187,427)
Completed Not Classified	-	-	-
Construction Work in Progress	17,270,338	(17,270,338)	-
Total Plant in Service	319,654,824	(7,464,456)	312,190,367
OTHER ASSETS			
Gas Stored Underground	52,204,057	-	52,204,057
Unamortized Software	4,927,047	-	4,927,047
ROU Finance	2,301,233	(2,301,233)	-
ROU Assets	444,623	(444,623)	-
Total Other Assets	59,876,960	(2,745,856)	57,131,104
WORKING CAPITAL			
Cash Working Capital	-	6,950,657	6,950,657
Materials and Supplies	15,038,013	-	15,038,013
Prepayments	5,174,966	-	5,174,966
Total Working Capital	20,212,979	6,950,657	27,163,636
REGULATORY ASSETS			
Homer CIAC Surcharge	1,787,236	(1,787,236)	-
Reg Asset-LT Gas Supply (RCA)	3,944,458	607,374	4,551,832
Rate Case - 2024	10,654	(10,654)	-
Homer Uncollected Carrying Cost	448,698	(448,698)	-
Earthquake Costs	762,138	-	762,138
2021 TY Rate Case	1,261,114	(1,261,114)	-
Other Deferred Assets	602,689	(602,689)	-
Demand Side Management	-	-	-
Total Regulatory Assets	8,816,986	(3,503,016)	5,313,970
NON-INVESTOR SUPPLIED CAPITAL			
Construction Advances	(29,371,143)	-	(29,371,143)
Deferred Income Taxes	(11,103,723)	-	(11,103,723)
Net Asset Retirement Obligation	(274,384)	-	(274,384)
Total Non-Investor Supplied Capital	(40,749,251)	-	(40,749,251)
TOTAL RATE BASE	367,812,499		361,049,827

ENSTAR NATURAL GAS COMPANY, LLC

REQUESTED WEIGHTED COST OF CAPITAL
For the Year Ended December 31, 2024

Component	December 31, 2024	Percent of Total	Amount	Component Cost	Weighted Cost	Return
Long-term Debt	163,683,558	41.43%	149,582,943	5.55%	2.30%	8,305,915
Common Equity	231,356,040	58.57%	211,466,884	13.00%	7.61%	27,490,695
Total	395,039,597	100.00%	361,049,827		9.91%	35,796,610
Due to Parent Series A			50,000,000	5.34%		2,670,000
Due to Parent Series B			25,000,000	5.38%		1,345,000
Due to Parent Series C			90,000,000	5.41%		4,869,000
Amortization of Debt Expense			(1,316,442)			204,882
Loss on Reacquired Debt			-			-
			163,683,558	5.55%		9,088,882

ENSTAR NATURAL GAS COMPANY, LLC

NORMALIZED TEST YEAR REVENUE REQUIREMENT AND REVENUE DEFICIENCY
For the Year Ended December 31, 2024

OPERATING EXPENSES	Test Year Books	Summary of Adjustments	Normalized
Cost of Purchased Gas	343,294,122	(4,966,152)	338,327,971
Production and Gathering	171,941	905	172,846
Transmission Expense	5,498,511	113,891	5,612,402
Distribution Expense	10,748,477	303,310	11,051,787
Customer Accounting	7,331,057	196,490	7,527,548
Uncollectible Accounts	574,271	(30,688)	543,583
Sales	63,870	1,938	65,808
Administrative and General	22,328,380	(268,521)	22,059,859
Depreciation and Amortization	19,947,693	784,228	20,731,921
Total Operating Expenses	409,958,324	(3,864,599)	406,093,725
STATE AND FEDERAL TAXES			
Ad Valorem & Miscellaneous	4,493,232	-	4,493,232
State Income Tax	1,598,902	1,902,310	3,501,212
Federal Income Tax	2,404,676	3,850,357	6,255,033
Total State and Federal Taxes	8,496,810	5,752,668	14,249,477
RATE BASE			
Plant In Service	319,654,824	(7,464,456)	312,190,367
Other Assets	59,876,960	(2,745,856)	57,131,104
Working Capital	20,212,979	6,950,657	27,163,636
Regulatory Assets	8,816,986	(3,503,016)	5,313,970
Non-Investor Supplied Capital	(40,749,251)	-	(40,749,251)
Total Rate Base	367,812,499	(6,762,671)	361,049,827
REQUESTED RATE OF RETURN			9.91%
RETURN ON INVESTMENT			35,796,610
REVENUE REQUIREMENT			456,139,812
NORMALIZED OPERATING REVENUE			431,246,738
REVENUE REQUIREMENT WITHOUT COST OF GAS			117,811,841
NORMALIZED OPERATING REVENUE WITHOUT COST OF GAS			92,918,768
DEFICIENCY (SURPLUS)			24,893,073
PERCENT CHANGE (W/O COST OF GAS)			26.79%
PERCENT CHANGE (W/ COST OF GAS)			5.77%

ENSTAR NATURAL GAS COMPANY, LLC

13-MONTH AVERAGE AND TEST YEAR BALANCE OF RATE BASE ITEMS
For the Year Ended December 31, 2024

	PLANT IN SERVICE				OTHER ASSETS				WORKING CAPITAL	
	Gas Utility Plant	Depreciation Reserve	Completed Not Classified	Construction Work in Progress	Gas Stored Underground	Unamortized Software	ROU Finance	ROU Assets	Materials and Supplies	Prepayments
1/1/2024	696,470,937	(383,964,587)	-	2,266,643	52,684,120	5,063,170	2,617,714	510,487	13,197,863	3,441,162
1/31/2024	696,295,890	(385,164,289)	-	3,888,874	47,318,935	4,919,287	2,537,095	497,956	13,358,429	2,910,778
2/29/2024	683,659,841	(386,229,933)	-	5,631,645	46,171,794	5,366,772	2,575,122	485,316	14,020,938	2,233,187
3/31/2024	684,022,665	(387,421,037)	-	10,012,353	47,029,117	5,231,897	2,497,692	472,760	14,845,344	7,358,011
4/30/2024	684,526,146	(388,657,613)	-	16,400,509	42,418,408	5,098,135	2,420,263	460,145	14,988,828	7,742,820
5/31/2024	685,884,447	(389,953,167)	-	18,179,221	43,215,422	4,988,013	2,342,833	447,726	15,093,612	7,202,976
6/30/2024	688,004,331	(391,391,718)	-	19,949,555	50,543,072	4,864,996	2,266,430	435,249	14,996,191	6,590,841
7/31/2024	689,599,072	(392,548,537)	-	22,819,365	58,211,393	4,727,346	2,251,175	422,806	16,348,853	6,214,257
8/31/2024	693,454,787	(393,687,095)	-	23,936,775	64,524,373	4,645,494	2,175,801	410,352	16,207,626	5,649,218
9/30/2024	697,069,546	(394,953,782)	-	24,383,911	66,020,215	4,519,977	2,169,197	397,839	16,200,385	4,991,317
10/31/2024	697,281,515	(395,838,895)	-	29,632,594	58,517,712	4,373,942	2,093,744	387,977	15,618,625	4,616,220
11/30/2024	698,031,751	(397,070,737)	-	34,219,729	52,274,589	4,238,533	2,020,371	378,070	15,357,334	4,235,671
12/31/2024	720,537,006	(396,958,231)	-	13,193,216	49,723,591	6,014,050	1,948,594	473,415	15,260,143	4,088,102
Average	693,449,072	(391,064,586)	-	17,270,338	52,204,057	4,927,047	2,301,233	444,623	15,038,013	5,174,966

	REGULATORY ASSETS							Non-Investor Supplied Capital		
	Homer CIAC Surcharge	Reg Asset-LT Gas Supply (RCA)	Rate Case - 2024	Homer Uncollected Carrying Cost	Earthquake Costs	2021 TY Rate Case	Other Deferred Assets	Construction Advances	Deferred Income Taxes	Net Asset Retirement Obligation
1/1/2024	1,919,506	3,258,482	-	476,741	931,502	1,373,781	844,283	(38,646,519)	(9,412,093)	(278,933)
1/31/2024	1,884,426	2,810,624	-	472,067	903,275	1,319,963	804,017	(38,412,855)	(9,153,902)	(278,933)
2/29/2024	1,847,799	2,810,624	-	467,393	875,047	1,319,963	763,751	(26,440,391)	(9,298,545)	(278,933)
3/31/2024	1,806,309	3,695,747	-	462,719	846,820	1,372,647	723,486	(26,444,281)	(9,965,805)	(276,245)
4/30/2024	1,789,055	3,872,309	-	458,045	818,593	1,372,647	683,220	(26,482,601)	(10,423,841)	(276,245)
5/31/2024	1,775,047	4,206,896	-	453,371	790,365	1,335,536	642,954	(26,948,737)	(10,467,184)	(276,245)
6/30/2024	1,761,008	4,268,279	-	448,698	762,138	1,297,378	602,689	(27,294,776)	(10,478,955)	(273,557)
7/31/2024	1,759,045	4,276,446	-	444,024	733,911	1,262,757	562,423	(27,590,573)	(11,694,248)	(273,557)
8/31/2024	1,761,113	4,276,446	-	439,350	705,683	1,224,492	522,157	(28,048,246)	(11,873,617)	(273,557)
9/30/2024	1,756,079	4,411,484	-	434,676	677,456	1,186,226	481,892	(28,254,134)	(12,116,952)	(270,869)
10/31/2024	1,750,252	4,411,960	-	430,002	649,229	1,147,961	441,626	(28,876,692)	(12,189,008)	(270,869)
11/30/2024	1,733,384	4,413,460	26,860	425,328	621,001	1,109,696	401,360	(29,181,583)	(13,320,580)	(270,869)
12/31/2024	1,691,047	4,565,200	111,643	420,654	592,774	1,071,430	361,095	(29,203,471)	(13,953,674)	(268,181)
Average	1,787,236	3,944,458	10,654	448,698	762,138	1,261,114	602,689	(29,371,143)	(11,103,723)	(274,384)

ENSTAR NATURAL GAS COMPANY, LLC

SUMMARY OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

	Schedule A	Schedule B	Schedule C	Schedule D	Schedule E	Schedule F
OPERATING REVENUE	**REMOVE DISALLOWED REG ASSETS**	**REMOVAL OF MISC. REVENUES AND EXPENSES**	**REMOVAL OF OTHER ASSETS**	**GAS COST ADJUSTMENT**	**REMOVAL OF CWIP**	**INCOME TAX ADJUSTMENT**
Residential & Commercial (G1)	-	-	-	(4,248,130)	-	-
Residential & Commercial (G2)	-	-	-	(439,360)	-	-
Residential & Commercial (G3)	-	-	-	(783,797)	-	-
Residential & Commercial (G4)	-	-	-	(978,626)	-	-
Gas Sales - Other	-	-	-	378,052	-	-
HEA - Bernice Lake	-	-	-	-	-	-
HEA - Soldotna	-	-	-	-	-	-
MEA - Eklutna	-	-	-	-	-	-
Hilcorp Alaska	-	-	-	-	-	-
Interior Gas Utility (Titan)	-	-	-	-	-	-
Furie Operating Alaska	-	-	-	-	-	-
CEA VLFT Plants	-	-	-	-	-	-
Bluecrest Energy	-	-	-	-	-	-
Vision Resources	-	-	-	-	-	-
Miscellaneous Revenues	-	(108,532)	-	-	-	-
OPERATING EXPENSES						
Cost of Purchased Gas	-	-	-	(14,720,843)	-	-
Production and Gathering	-	-	-	-	-	-
Transmission Expense	-	-	-	-	-	-
Distribution Expense	-	-	-	-	-	-
Customer Accounting	-	-	-	-	-	-
Uncollectible Accounts	-	-	-	-	-	-
Sales	-	-	-	-	-	-
Administrative and General	(465,786)	(1,748,457)	-	-	-	-
Depreciation and Amortization	-	-	-	-	-	-
STATE AND FEDERAL TAXES						
Ad Valorem & Miscellaneous	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	1,902,310
Federal Income Tax	-	-	-	-	-	3,850,357
PLANT IN SERVICE						
Gas Utility Plant	-	-	-	-	-	-
Depreciation Reserve	-	-	-	-	-	-
Completed Not Classified	-	-	-	-	-	-
Construction Work in Progress	-	-	-	-	(17,270,338)	-
OTHER ASSETS						
Gas Stored Underground	-	-	-	-	-	-
Unamortized Software	-	-	-	-	-	-
ROU Finance	-	-	-	-	-	-
ROU Assets	-	-	-	-	-	-
WORKING CAPITAL	-	-	-	-	-	-
Cash Working Capital	-	-	-	-	-	-
Materials and Supplies	-	-	-	-	-	-
Prepayments	-	-	-	-	-	-
REGULATORY ASSETS						
Homer CIAC Surcharge	-	-	(1,787,236)	-	-	-
Reg Asset-LT Gas Supply (RCA)	-	-	-	-	-	-
Rate Case - 2024	-	-	(10,654)	-	-	-
Homer Uncollected Carrying Cost	-	-	(448,698)	-	-	-
Earthquake Costs	-	-	-	-	-	-
2021 TY Rate Case	-	-	(1,261,114)	-	-	-
Other Deferred Assets	(232,893)	-	(369,796)	-	-	-
Demand Side Management	-	-	-	-	-	-
NON-INVESTOR SUPPLIED CAPITAL						
Construction Advances	-	-	-	-	-	-
Deferred Income Taxes	-	-	-	-	-	-
Net Asset Retirement Obligation	-	-	-	-	-	-
TESTIMONY WITNESS	**Guintu**	**Guintu**	**Guintu**	**Johansen**	**Guintu**	**Fairchild**

ENSTAR NATURAL GAS COMPANY, LLC

SUMMARY OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

	Schedule G	Schedule H	Schedule I	Schedule J	Schedule K	Schedule L
OPERATING REVENUE	**UNCOLLECTIBLE ACCOUNT ADJUSTMENT**	**OTHER REVENUE ADJUSTMENTS**	**ADDITIONAL COST OF GAS**	**RATE CASE EXPENSE**	**REMOVAL OF ROU LEASE**	**PENSION EXPENSES**
Residential & Commercial (G1)	-	-	-	-	-	-
Residential & Commercial (G2)	-	-	-	-	-	-
Residential & Commercial (G3)	-	-	-	-	-	-
Residential & Commercial (G4)	-	74,564	-	-	-	-
Gas Sales - Other	-	1,288,986	-	-	-	-
HEA - Bernice Lake	-	(10,800)	-	-	-	-
HEA - Soldotna	-	(27,488)	-	-	-	-
MEA - Eklutna	-	-	-	-	-	-
Hilcorp Alaska	-	-	-	-	-	-
Interior Gas Utility (Titan)	-	(331,681)	-	-	-	-
Furie Operating Alaska	-	-	-	-	-	-
CEA VLFT Plants	-	-	-	-	-	-
Bluecrest Energy	-	-	-	-	-	-
Vision Resources	-	-	-	-	-	-
Miscellaneous Revenues	-	-	-	-	-	-
OPERATING EXPENSES						
Cost of Purchased Gas	-	-	9,754,691	-	-	-
Production and Gathering	-	-	-	-	-	-
Transmission Expense	-	-	-	-	-	-
Distribution Expense	-	-	-	-	-	-
Customer Accounting	-	-	-	-	-	-
Uncollectible Accounts	(30,688)	-	-	-	-	-
Sales	-	-	-	-	-	-
Administrative and General	-	-	-	660,758	1,019,260	48,907
Depreciation and Amortization	-	-	-	-	(921,884)	-
STATE AND FEDERAL TAXES						
Ad Valorem & Miscellaneous	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-
Federal Income Tax	-	-	-	-	-	-
PLANT IN SERVICE						
Gas Utility Plant	-	-	-	-	-	-
Depreciation Reserve	-	-	-	-	-	-
Completed Not Classified	-	-	-	-	-	-
Construction Work in Progress	-	-	-	-	-	-
OTHER ASSETS						
Gas Stored Underground	-	-	-	-	-	-
Unamortized Software	-	-	-	-	-	-
ROU Finance	-	-	-	-	(2,301,233)	-
ROU Assets	-	-	-	-	(444,623)	-
WORKING CAPITAL	-	-	-	-	-	-
Cash Working Capital	-	-	-	-	-	-
Materials and Supplies	-	-	-	-	-	-
Prepayments	-	-	-	-	-	-
REGULATORY ASSETS						
Homer CIAC Surcharge	-	-	-	-	-	-
Reg Asset-LT Gas Supply (RCA)	-	-	-	-	-	-
Rate Case - 2024	-	-	-	-	-	-
Homer Uncollected Carrying Cost	-	-	-	-	-	-
Earthquake Costs	-	-	-	-	-	-
2021 TY Rate Case	-	-	-	-	-	-
Other Deferred Assets	-	-	-	-	-	-
Demand Side Management	-	-	-	-	-	-
NON-INVESTOR SUPPLIED CAPITAL						
Construction Advances	-	-	-	-	-	-
Deferred Income Taxes	-	-	-	-	-	-
Net Asset Retirement Obligation	-	-	-	-	-	-
TESTIMONY WITNESS	**Johansen**	**Johansen**	**Johansen**	**Guintu**	**Guintu**	**Riggs**

ENSTAR NATURAL GAS COMPANY, LLC

SUMMARY OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

	Schedule M	Schedule N	Schedule O	Schedule P	Schedule Q	Total
OPERATING REVENUE	**PAYROLL ADJUSTMENT**	**CASH WORKING CAPITAL**	**YEAR-END PLANT ADJUSTMENT**	**WEATHER NORMALIZATIO N**	**LT GAS SUPPLY REG ASSET**	
Residential & Commercial (G1)	-	-	-	(1,459,714)	-	(5,707,844)
Residential & Commercial (G2)	-	-	-	(97,854)	-	(537,214)
Residential & Commercial (G3)	-	-	-	(184,105)	-	(967,902)
Residential & Commercial (G4)	-	-	-	(192,977)	-	(1,097,039)
Gas Sales - Other	-	-	-	-	-	1,667,038
HEA - Bernice Lake	-	-	-	-	-	(10,800)
HEA - Soldotna	-	-	-	-	-	(27,488)
MEA - Eklutna	-	-	-	-	-	-
Hilcorp Alaska	-	-	-	-	-	-
Interior Gas Utility (Titan)	-	-	-	-	-	(331,681)
Furie Operating Alaska	-	-	-	-	-	-
CEA VLFT Plants	-	-	-	-	-	-
Bluecrest Energy	-	-	-	-	-	-
Vision Resources	-	-	-	-	-	-
Miscellaneous Revenues	-	-	-	-	-	(108,532)
OPERATING EXPENSES						
Cost of Purchased Gas	-	-	-	-	-	(4,966,152)
Production and Gathering	905	-	-	-	-	905
Transmission Expense	113,891	-	-	-	-	113,891
Distribution Expense	303,310	-	-	-	-	303,310
Customer Accounting	196,490	-	-	-	-	196,490
Uncollectible Accounts	-	-	-	-	-	(30,688)
Sales	1,938	-	-	-	-	1,938
Administrative and General	216,797	-	-	-	-	(268,521)
Depreciation and Amortization	-	-	188,835	-	1,517,277	784,228
STATE AND FEDERAL TAXES						
Ad Valorem & Miscellaneous	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	1,902,310
Federal Income Tax	-	-	-	-	-	3,850,357
PLANT IN SERVICE						
Gas Utility Plant	-	-	9,928,722	-	-	9,928,722
Depreciation Reserve	-	-	(122,841)	-	-	(122,841)
Completed Not Classified	-	-	-	-	-	-
Construction Work in Progress	-	-	-	-	-	(17,270,338)
OTHER ASSETS						
Gas Stored Underground	-	-	-	-	-	-
Unamortized Software	-	-	-	-	-	-
ROU Finance	-	-	-	-	-	(2,301,233)
ROU Assets	-	-	-	-	-	(444,623)
WORKING CAPITAL	-	-	-	-	-	-
Cash Working Capital	-	6,950,657	-	-	-	6,950,657
Materials and Supplies	-	-	-	-	-	-
Prepayments	-	-	-	-	-	-
REGULATORY ASSETS						
Homer CIAC Surcharge	-	-	-	-	-	(1,787,236)
Reg Asset-LT Gas Supply (RCA)	-	-	-	-	607,374	607,374
Rate Case - 2024	-	-	-	-	-	(10,654)
Homer Uncollected Carrying Cost	-	-	-	-	-	(448,698)
Earthquake Costs	-	-	-	-	-	-
2021 TY Rate Case	-	-	-	-	-	(1,261,114)
Other Deferred Assets	-	-	-	-	-	(602,689)
Demand Side Management	-	-	-	-	-	-
NON-INVESTOR SUPPLIED CAPITAL						
Construction Advances	-	-	-	-	-	-
Deferred Income Taxes	-	-	-	-	-	-
Net Asset Retirement Obligation	-	-	-	-	-	-
TESTIMONY WITNESS	**Guintu**	**Guintu**	**Guintu**	**Johansen**	**Johansen**	

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule A

REMOVE DISALLOWED REG ASSETS
Testimony Witness: Guintu

Line No.	Description	Amount
1	**Annual Amortization:**	
2	Administrative and General	(465,786)
3	**Removal of Asset from Rate Base:**	
4	Other Deferred Assets	(232,893)

To remove the costs associated with Bullet Line amortization and asset per Docket U-09-069. Bullet Line was fully-amortized in December of 2024.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule B

REMOVAL OF MISC. REVENUES AND EXPENSES
Testimony Witness: Guintu

Line No.	Description	Amount
1	Lobbying Expense	(60,000)
2	Charitable Contributions	(358,206)
3	Building Maintance	(17,617)
4	Miscellanous Expenses	(1,312,450)
5	Penalties	(184)
6	Administrative and General	(1,748,457)
7	Homer Surcharge	(108,532)
8	Miscellaneous Revenues	(108,532)

To remove miscellaneous revenues and expenses including charitable contributions, penalties, lobbying expenses, and others.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule C

REMOVAL OF OTHER ASSETS
Testimony Witness: Guintu

Line No.	Description	Amount
1	Other Deferred Assets	(369,796)
2	Homer CIAC Surcharge	(1,787,236)
3	Homer Uncollected Carrying Cost	(448,698)
4	2021 TY Rate Case	(1,261,114)
5	Rate Case - 2024	(10,654)
6	Total	(3,877,497)

To remove the unamortized amount of the Anchor Point litigation costs as agreed upon in the U-14-111 stipulation. Also, to remove other regulatory assets from rate base.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule D

GAS COST ADJUSTMENT
Testimony Witness: Johansen

Line No.	Description	Amount
1	**G1 Sales Customers:**	
2	Test Year GCA Revenue	180,364,883
3	GCA Revenue at Current Rate	176,116,753
4	Residential & Commercial (G1)	(4,248,130)
5	**G2 Sales Customers:**	
6	Test Year GCA Revenue	19,113,759
7	GCA Revenue at Current Rate	18,674,399
8	Residential & Commercial (G2)	(439,360)
9	**G3 Sales Customers:**	
10	Test Year GCA Revenue	38,775,550
11	GCA Revenue at Current Rate	37,991,753
12	Residential & Commercial (G3)	(783,797)
13	**G4 Sales Customers:**	
14	Test Year GCA Revenue	68,394,106
15	GCA Revenue at Current Rate	67,415,480
16	Residential & Commercial (G4)	(978,626)
13	**Gas Sales Other Customers:**	
14	Normalized Test Year GCA Revenue	27,996,842
15	GCA Revenue at Current Rate	28,374,894
16	Gas Sales - Other	378,052
17	Normalized Cost of Gas	328,573,279
18	Test Year Cost of Gas	343,294,122
19	Cost of Purchased Gas	(14,720,843)

To update revenues to reflect current GCA rate and volume change due to the weather normalization adjustment and removed GVEA volumes from Cost of Purchased Gas.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule E

REMOVAL OF CWIP
Testimony Witness: Guintu

Line No.	Description	Amount
1	Construction Work in Progress	(17,270,338)

To remove construction work in progress from rate base.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule F

INCOME TAX ADJUSTMENT
Testimony Witness: Fairchild

Line No.	Description	Amount
1	After Tax Return on Equity	27,490,695
2	Amortization of Excess ADIT	(831,570)
3	After Tax Net Requested Return on Equity	26,659,125
4	Composite Gross Up State/Federal Income Tax Factor	0.3971554
5	Income Tax Provision before Excess ADIT Amort.	10,587,816
6	State Taxable Income	37,246,941
7	State Income Tax Rate	9.4%
8	State Income Taxes as Calculated	3,501,212
9	State Income Taxes on Books	1,598,902
10	State Income Tax	1,902,310
11	Taxable Federal Income	33,745,728
12	Federal Income Tax Rate	21.0%
13	At Tax Rate	7,086,603
14	Amortization of Excess Deferred Taxes	(831,570)
15	Federal Income Taxes as Calculated	6,255,033
16	Federal Income Taxes on Books	2,404,676
17	Federal Income Tax	3,850,357
18	**Annual Excess Deferred Amortization:**	
19	Protected Excess ADIT Liability	(861,431)
20	Unprotected Excess ADIT Asset	499,965
21	Regulatory Excess ADIT Liability	(470,104)
22	Total	(831,570)

To recalculate federal and state income tax at the normalized revenues. To amortize EADIT as approved by Order U-22-081(14).

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule G

UNCOLLECTIBLE ACCOUNT ADJUSTMENT
Testimony Witness: Johansen

Line No.	Description	Amount
1	**Revenues at Requested Rate Increase:**	
2	G1 Sales Customers	248,103,272
3	G2 Sales Customers	25,303,875
4	G3 Sales Customers	48,782,742
5	G4 Sales Customers	81,735,798
6	Total Normalized Retail Revenues	403,925,687
7	Other Income Related to Gas Sales	1,591,618
8	Total Normalized Retail and Other Income Revenues	405,517,305
9	Uncollectible Account Expense Ratio	0.0013
10	Normalized Uncollectible Account Expense	543,583
11	Test Year Uncollectible Expense	574,271
12	Uncollectible Accounts	(30,688)

To adjust uncollectibles (bad debt) with new GCA sales revenues and weatherized volumes.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule H

OTHER REVENUE ADJUSTMENTS
Testimony Witness: Johansen

Line No.	Description	Amount
1	**Normalize 2024 IGU Revenue**	
2	Test Year IGU Transport Revenues	331,681
3	Estimated Future Transport Revenues	-
4	Interior Gas Utility (Titan)	(331,681)
5	Test Year IGU Gas Sales Revenue	-
6	Estimated Cost of Gas Sales Revenue	63,501
7	Estimated Gas Sales Margin	11,063
8	Residential & Commercial (G4)	74,564
9	**Removes 2024 GVEA Revenue**	
10	Test Year Gas Sales Revenue From GVEA	8,830,559
11	Estimated Future Revenues	-
12	Removal of GVEA Test Year Gas Sales	(8,830,559)
13	**Normalize 2024 HEA Gas Sales Revenue**	
14	HEA Test Year Gas Sales Revenue	29,370,164
15	Estimated Addl Gas Sales Revenue (Jan - March)	10,119,545
17	Annualized Gas Sales Revenue	39,489,708
18	HEA Test Year Gas Sales Revenue	29,370,164
19	Annualized Gas Sales Revenue	39,489,708
20	Additional Gas Sales Revenue	10,119,545
21	Gas Sales - Other	1,288,986
22	**Removes HEA Bernice Lake Transport Revenue**	
23	HEA - Bernice Lake	(10,800)
24	**Removes HEA Soldotna Plant Transport Revenue**	
25	HEA - Soldotna	(27,488)

To normalize known revenue adjustments related to GVEA, HEA and IGU transportation and gas sales.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule J

RATE CASE EXPENSE
Testimony Witness: Guintu

Line No.	Description	Amount
1	Revenue Requirement Study Costs	2,900,000
2	Amortization (years)	3
3	Annual Amortization Amount	966,667
4	Amount of U-22-081 Rate Case Expenses in Test Year	305,909
5	Administrative and General	660,758

This adjustment reflects the projected legal and consulting costs that ENSTAR will incur for the preparation and presentation of this rate case. The expense is based on outside legal and consulting fees and direct in-house costs associated with the rate case. This adjustment nets against previous rate case expense in test year.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule I

ADDITIONAL COST OF GAS
Testimony Witness: Johansen

Line No.	Description	Amount
1	**Normalized Cost of Purchased Gas**	
2	IGU Estimated Cost of Gas Sales Revenue	63,501
3	HEA Estimated Cost of Gas Sales Revenue	9,691,190
4	Cost of Purchased Gas	9,754,691

To include the cost of gas associated with the normalization of IGU and HEA revenues found on PF H.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule K

REMOVAL OF ROU LEASE
Testimony Witness: Guintu

Line No.	Description	Amount
1	**Removal from Rate Base:**	
2	ROU Finance	(2,301,233)
3	ROU Assets	(444,623)
	Total Rate Base Removal	(2,745,856)
4	**Removal of Amortization Expense:**	
5	Depreciation and Amortization (389-398)	(921,884)
6	**Inclusion of Lease Payment:**	
7	Administrative and General	1,019,260
	Total Expense Adjustment	97,375

This adjustment removes the assets and accumulated amortization associated with ROU Finance leases. Prior to ASC 842, these leases were classified as operating leases and were not included on the balance sheet.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule L

PENSION EXPENSES
Testimony Witness: Riggs

Line No.	Description	Amount
1	5 Year Average Pension Expense	66,443
2	Test Year Pension Expense	(11,738)
3	Difference	78,181
4	A&G Allocation To Capital and Reimbursable Projects%	37.4%
5	Allocation to Reimbursable Construction	29,274
6	Administrative and General	48,907

This is a five year average expense of pension costs from 2020-2024 giving a more representative cost of pension expense that is anticipated in the rate effective period.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule M

PAYROLL ADJUSTMENT
Testimony Witness: Guintu

Line No.	Description	Amount
1	Increase to Production and Gathering	905
2	Increase to Transmission Expense	113,891
3	Increase to Distribution Expense	303,310
4	Increase to Customer Accounting	196,490
5	Increase to Sales	1,938
6	Increase to Administrative and General	216,797
	Total Adjustment	833,331

To adjust test year payroll expenditures to reflect known and measurable changes consistent with prior Commission precedent.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule N

CASH WORKING CAPITAL
Testimony Witness: Guintu

Line No.	Description	Amount
1	Cash Working Capital	6,950,657

To reflect the results of the lead-lag study performed on the 2024 test year and in compliance with the Stipulation approved in Order U-22-081(11)

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule O

YEAR-END PLANT ADJUSTMENT
Testimony Witness: Guintu

Line No.	Description	Amount
1	**Year End Treatment to Gas Utility Plant:**	
2	Gas Utility Plant (366)	16,218
3	Gas Utility Plant (367)	7,215,041
4	Gas Utility Plant (369)	1,001,988
5	Gas Utility Plant (376)	1,084,974
6	Gas Utility Plant (380)	494,912
7	Gas Utility Plant (389-398)	115,588
8	Total Addition to Gas Plant	9,928,722
9	**Year End Treatment to Accumulated Depreciation:**	
10	Depreciation Reserve (366)	(162)
11	Depreciation Reserve (367)	(67,902)
12	Depreciation Reserve (369)	(13,403)
13	Depreciation Reserve (376)	(18,678)
14	Depreciation Reserve (380)	(21,523)
15	Depreciation Reserve (389-398)	(1,173)
16	Total Addition to Accum Depr.	(122,841)
17	**Year End Treatment to Depreciation Expense:**	
18	Depreciation and Amortization (366)	301
19	Depreciation and Amortization (367)	126,103
20	Depreciation and Amortization (369)	23,992
21	Depreciation and Amortization (376)	21,089
22	Depreciation and Amortization (380)	15,512
23	Depreciation and Amortization (389-398)	1,838
24	Total Addition to Depr Expense	188,835

To adjust test year 2024 capital expenditures to reflect year-end treatment for safety and reliability projects that qualify for annualized treatment pursuant to Commission precedent.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule P

WEATHER NORMALIZATION
Testimony Witness: Johansen

Line No.	Description	Amount
1	**G1 Weather Normalization Adjustment:**	
2	Normalized Volumes (Mcf)	19,414,078
3	Test Year Volumes (Mcf)	20,388,390
4	Excess Weather-related Volumes	(974,312)
5	G1 Volumetric Rate per Mcf	1.4982
6	Residential & Commercial (G1)	(1,459,714)
7	**G2 Weather Normalization Adjustment:**	
8	Normalized Volumes (Mcf)	2,058,556
9	Test Year Volumes (Mcf)	2,160,467
10	Excess Weather-related Volumes	(101,910)
11	G2 Volumetric Rate per Mcf	0.9602
12	Residential & Commercial (G2)	(97,854)
13	**G3 Weather Normalization Adjustment:**	
14	Normalized Volumes (Mcf)	4,187,988
15	Test Year Volumes (Mcf)	4,382,828
16	Excess Weather-related Volumes	(194,840)
17	G3 Volumetric Rate per Mcf	0.9449
18	Residential & Commercial (G3)	(184,105)
19	**G4 Weather Normalization Adjustment:**	
20	Normalized Volumes (Mcf)	7,431,487
21	Test Year Volumes (Mcf)	7,724,721
22	Excess Weather-related Volumes	(293,234)
23	G4 Volumetric Rate per Mcf	0.6581
24	Residential & Commercial (G4)	(192,977)

To adjust test year 2024 gas sales volumes for gas sales customers to reflect a weather normalization adjustment based on a 10 year historical average.

ENSTAR NATURAL GAS COMPANY, LLC

EXPLANATION OF PRO FORMA ADJUSTMENTS
For the Year Ended December 31, 2024

Schedule Q

LT Gas Supply Reg Asset
Testimony Witness: Johansen

Line No.	Description	Amount
1	Long Term Gas Supply Study Costs	3,944,458
2	Reg Asset-LT Gas Supply (RCA)	607,374
3	Long Term Gas Supply Study Costs as of Dec 17, 2024	4,551,832
3	Long Term Gas Supply Study Costs as of Dec 17, 2024	4,551,832
4	Amortization (years)	3
5	Amortization of Reg Asset (407.3)	1,517,277

This adjustment reflects the third-party costs ENSTAR incurred studying and securing long-term gas supplies in the Cook Inlet as approved in Order U-22-090(2) and adjusts test year 2024 to reflect the costs incurred to the regulatory asset as of December 17, 2024

ENSTAR NATURAL GAS COMPANY, LLC

COMPARATIVE STATEMENT OF ASSETS, LIABILITIES & OTHER CREDITS
For the Years Ended December 31, 2024 and 2023

ASSETS & OTHER DEBITS	**2023**	**2024**
UTILITY PLANT		
Utility Plant	725,488,260	762,636,388
Accumulated Provision for Depreciation	(402,523,897)	(417,428,336)
Net Utility Plant	322,964,363	345,208,052
Net Goodwill in Subsidiary	-	-
CURRENT ASSETS		
Cash and Cash Equivalents	9,119,881	21,462,116
Receivables	60,136,431	37,572,436
Accrued Revenues	35,338,542	34,404,948
Materials and Supplies	13,197,863	15,260,143
Gas in Storage	52,684,120	49,723,591
Prepayments	3,441,162	4,088,102
Other Current Assets	275,875	69,075
Total Current Assets	174,193,873	162,580,411
DEFERRED DEBITS		
Deferred Taxes	15,113,594	14,059,061
Unamortized Debt Expenses	1,521,324	1,316,442
Other Deferred Charges	24,832,590	29,788,054
Total Deferred Debits	41,467,508	45,163,557
TOTAL ASSETS AND OTHER DEBITS	538,625,744	552,952,020
LIABILITIES & OTHER CREDITS		
CAPITAL		
Other Paid-in Capital	110,127,758	117,027,758
Retained Earnings	101,991,728	114,328,282
Total Capital	212,119,486	231,356,040
LONG-TERM DEBT	165,000,000	165,000,000
OTHER NONCURRENT LIABILTIES	3,970,135	3,571,233
CURRENT LIABILITIES		
Payable (Receivable)	76,031,629	79,190,682
Cur Maturities of LTD & Capital Lease	1,083,702	942,555
Customer Advance Payments	605,062	567,871
Taxes Accrued	5,111,349	1,690,337
Other Current Liabilities	5,254,761	7,324,023
Total Current Liabilities	88,086,503	89,715,468
OTHER DEFERRED CREDITS		
Customer Advances	38,581,075	29,156,643
Accumulated Deferred Income Taxes	24,525,686	28,012,736
Other Deferred Credits	6,342,858	6,139,900
Total Deferred Credits	69,449,619	63,309,279
Total Liabilities and Other Credits	538,625,744	552,952,020

ENSTAR NATURAL GAS COMPANY, LLC

COMPARATIVE STATEMENT OF INCOME & OPERATING EXPENSES
For the Years Ended December 31, 2024 and 2023

	2023	2024
OPERATING REVENUE	693,583,479	790,127,612
OPERATING EXPENSES		
Operating Expenses	644,153,255	741,541,572
Depreciation and Amortization Expense	18,914,857	19,947,693
State and Federal Income Taxes	(315,722)	4,003,578
Property and Other Taxes	4,488,845	4,493,232
Total Operating Expenses	667,241,235	769,986,075
NET UTILITY OPERATING INCOME	26,342,243	20,141,537
OTHER INCOME AND (DEDUCTIONS)		
Interest Income and Other Income	310,825	1,684,808
Interest Expense	(8,863,279)	(8,818,520)
Amortization of Debt Expenses	(232,125)	(252,882)
Other Deductions	(362,134)	(418,390)
Total Interest Charges	(9,146,713)	(7,804,983)
NET INCOME	17,195,530	12,336,553

ENSTAR NATURAL GAS COMPANY, LLC

COMPARATIVE STATEMENT OF CHANGES IN EQUITY POSITION
For the Years Ended December 31, 2024 and 2023

	2023	2024
Beginning Paid-in-Capital	110,127,758	110,127,758
Beginning Retained Earnings	84,796,198	101,991,728
Beginning Equity	194,923,956	212,119,486
Net Income	17,195,530	12,336,553
Contribution	-	6,900,000
Changes in Stockholders Equity	17,195,530	19,236,553
ENDING STOCKHOLDER'S EQUITY	212,119,486	231,356,040

ENSTAR NATURAL GAS COMPANY, LLC

PLANT IN SERVICE AND ACCUMULATED DEPRECIATION
For the Year Ended December 31, 2023

Acct. No.	Description	Plant Investment	Accumulated Depreciation	Net Plant
301.0	Organization (Includes ARO)	507,670	(224,038)	283,632
302.0	Franchises and Consents	-	7,710	7,710
332.0	Field Lines	203,832	(242,548)	(38,716)
334.0	Field M&R Station Equipment	176,482	(153,126)	23,356
	Total Production and Gathering	887,984	(612,001)	275,983
365.1	Land and Land Rights	290,755	-	290,755
365.2	Rights-of-Way	250,119	(175,056)	75,063
366.0	Structures and Improvements	11,613,646	(3,404,725)	8,208,921
367.0	Mains	175,353,067	(111,422,932)	63,930,135
368.0	Compressor Station Equipment	19,184,424	(6,200,170)	12,984,255
369.0	M&R Station Equipment	32,047,569	(9,030,077)	23,017,492
370.0	Communication Equipment	7,607,020	(3,557,217)	4,049,803
	Total Transmission	246,346,600	(133,790,177)	112,556,423
374.0	Land and Land Rights	353,338	32,453	385,790
375.0	Structures and Improvements	72,739	(70,783)	1,955
376.0	Mains	201,078,515	(104,821,666)	96,256,849
376.1	Cathodic Protection Main/Svc	2,341,440	(799,656)	1,541,784
378.0	M&R Station Equipment - General	1,922,394	(1,347,080)	575,314
379.0	M&R Station Equipment - City Gate	1,968,033	(596,154)	1,371,879
380.0	Services	124,826,270	(81,979,338)	42,846,931
381.0	Meters	28,598,490	(6,709,731)	21,888,760
382.0	Meter Installations	31,494,355	(15,695,366)	15,798,989
383.0	House Regulators	255,505	(412,557)	(157,052)
385.0	Industrial M&R Station Equipment	2,429,220	(706,852)	1,722,368
387.0	Other Equipment	6,752,557	(3,270,807)	3,481,749
	Total Distribution	402,092,854	(216,377,538)	185,715,317
389-398	General Plant	47,143,499	(33,185,455)	13,958,043
106.0	Completions Not Classed	-	583	583
107.0	Construction Work in Progress	2,266,643	-	2,266,643
	TOTAL	698,737,580	(383,964,587)	314,772,992

ENSTAR NATURAL GAS COMPANY, LLC

PLANT IN SERVICE AND ACCUMULATED DEPRECIATION
For the Year Ended December 31, 2024

Acct. No.	Description	Plant Investment	Accumulated Depreciation	Net Plant
301.0	Organization (Includes ARO)	507,670	(234,790)	272,880
302.0	Franchises and Consents	-	7,710	7,710
332.0	Field Lines	203,832	(246,785)	(42,953)
334.0	Field M&R Station Equipment	-	(144,511)	(144,511)
	Total Production and Gathering	711,502	(618,376)	93,126
365.1	Land and Land Rights	290,755	-	290,755
365.2	Rights-of-Way	250,119	(178,531)	71,588
366.0	Structures and Improvements	11,842,625	(3,557,814)	8,284,812
367.0	Mains	186,698,775	(114,259,877)	72,438,897
368.0	Compressor Station Equipment	19,677,514	(6,534,796)	13,142,718
369.0	M&R Station Equipment	33,926,424	(9,545,524)	24,380,900
370.0	Communication Equipment	7,259,016	(3,899,290)	3,359,727
	Total Transmission	259,945,229	(137,975,832)	121,969,397
374.0	Land and Land Rights	361,179	31,340	392,519
375.0	Structures and Improvements	72,739	(71,440)	1,298
376.0	Mains	199,376,113	(107,885,120)	91,490,993
376.1	Cathodic Protection Main/Svc	2,516,187	(858,433)	1,657,754
378.0	M&R Station Equipment - General	1,688,460	(1,372,833)	315,627
379.0	M&R Station Equipment - City Gate	2,234,719	(615,455)	1,619,264
380.0	Services	131,686,660	(85,651,180)	46,035,480
381.0	Meters	30,041,708	(7,299,062)	22,742,646
382.0	Meter Installations	31,998,346	(15,796,902)	16,201,444
383.0	House Regulators	251,663	(415,244)	(163,581)
385.0	Industrial M&R Station Equipment	2,428,830	(751,790)	1,677,041
387.0	Other Equipment	6,979,548	(3,443,823)	3,535,724
	Total Distribution	409,636,151	(224,129,943)	185,506,208
389-398	General Plant	50,244,125	(34,234,663)	16,009,462
106.0	Completions Not Classed	-	583	583
107.0	Construction Work in Progress	13,193,216	-	13,193,216
	TOTAL	733,730,223	(396,958,231)	336,771,993

ENSTAR NATURAL GAS COMPANY, LLC

DEPRECIATION EXPENSE
For the Year Ended December 31, 2023

Acct. No.	Description	Depreciation Method	Asset Life, Years	Depreciation Rate	Depreciation Expense
301.0	Organization	Straight Line	0	0.00%	-
302.0	Franchises and Consents	Straight Line	0	0.00%	-
332.0	Field Lines	Unit of Production	48	2.08%	4,241
334.0	Field M&R Station Equipment	Unit of Production	42	2.36%	4,167
	Total Production and Gathering				8,408
365.1	Land and Land Rights	Straight Line	0	0.00%	-
365.2	Rights-of-Way	Straight Line	72	1.39%	2,478
366.0	Structures and Improvements	Straight Line	53	1.87%	198,636
367.0	Mains	Straight Line	57 / 36	2.27%	3,047,832
368.0	Compressor Station Equipment	Straight Line	46	2.16%	415,545
369.0	M&R Station Equipment	Straight Line	41	2.42%	718,093
370.0	Communication Equipment	Straight Line	19	5.22%	299,909
	Total Transmission				4,682,493
374.0	Land and Land Rights	Straight Line	46	2.19%	1,053
375.0	Structures and Improvements	Straight Line	36	2.77%	671
376.0	Mains	Straight Line	50	2.05%	3,615,379
376.1	Cathodic Protection Main/Svc	Straight Line	34	2.93%	60,106
378.0	M&R Station Equipment - General	Straight Line	37	2.67%	44,340
379.0	M&R Station Equipment - City Gate	Straight Line	48 / 45	2.17%	42,346
380.0	Services	Straight Line	36	3.71%	3,934,348
381.0	Meters	Straight Line	41	4.05%	875,035
382.0	Meter Installations	Straight Line	41	2.43%	689,119
383.0	House Regulators	Straight Line	52	1.92%	4,300
385.0	Industrial M&R Station Equipment	Straight Line	38	2.63%	57,256
387.0	Other Equipment	Straight Line	34	2.91%	172,151
	Total Distribution				9,496,104
389.0	Land and Land Rights	--	0	0.00%	-
390.0	Structures and Improvements	Straight Line	38 / 61	2.13%	241,544
391.0	Office Furniture and Equipment	Straight Line	17 / 7	10.14%	675,623
392.0	Transportation Equipment	Straight Line	10	10.37%	482,435
393.0	Stores Equipment	Straight Line	17	5.80%	4,668
394.0	Tools, Shop, and Garage Eqp.	Straight Line	16 / 27	4.88%	240,667
395.0	Laboratory Equipment	Straight Line	0	0.00%	-
396.0	Power Operated Equipment	Straight Line	14	6.90%	323,465
397.0	Communications Equipment	Straight Line	9 / 18	8.65%	227,334
398.0	Miscellaneous Equipment	Straight Line	9 / 13	9.37%	152,474
	Total General Plant				2,348,210
	TOTAL DEPRECIATION EXPENSE				16,535,217

ENSTAR NATURAL GAS COMPANY, LLC

DEPRECIATION EXPENSE
For the Year Ended December 31, 2024

Acct. No.	Description	Depreciation Method	Asset Life, Years	Depreciation Rate	Depreciation Expense
301.0	Organization	Straight Line	0	0.00%	-
302.0	Franchises and Consents	Straight Line	0	0.00%	-
332.0	Field Lines	Unit of Production	48	2.08%	4,238
334.0	Field M&R Station Equipment	Unit of Production	42	2.36%	1,921
	Total Production and Gathering				6,159
365.1	Land and Land Rights	Straight Line	0	0.00%	-
365.2	Rights-of-Way	Straight Line	72	1.39%	3,475
366.0	Structures and Improvements	Straight Line	53	1.87%	218,213
367.0	Mains	Straight Line	57 / 36	2.27%	3,125,772
368.0	Compressor Station Equipment	Straight Line	46	2.16%	420,211
369.0	M&R Station Equipment	Straight Line	41	2.42%	780,359
370.0	Communication Equipment	Straight Line	19	5.22%	352,941
	Total Transmission				4,900,971
374.0	Land and Land Rights	Straight Line	46	2.19%	1,113
375.0	Structures and Improvements	Straight Line	36	2.77%	657
376.0	Mains	Straight Line	50	2.05%	3,528,878
376.1	Cathodic Protection Main/Svc	Straight Line	34	2.93%	60,801
378.0	M&R Station Equipment - General	Straight Line	37	2.67%	42,008
379.0	M&R Station Equipment - City Gate	Straight Line	48 / 45	2.17%	44,286
380.0	Services	Straight Line	36	3.71%	4,058,967
381.0	Meters	Straight Line	41	4.05%	885,108
382.0	Meter Installations	Straight Line	41	2.43%	682,574
383.0	House Regulators	Straight Line	52	1.92%	4,276
385.0	Industrial M&R Station Equipment	Straight Line	38	2.63%	56,144
387.0	Other Equipment	Straight Line	34	2.91%	173,016
	Total Distribution				9,537,828
389.0	Land and Land Rights	--	0	0.00%	-
390.0	Structures and Improvements	Straight Line	38 / 61	2.13%	264,954
391.0	Office Furniture and Equipment	Straight Line	17 / 7	10.14%	802,831
392.0	Transportation Equipment	Straight Line	10	10.37%	516,413
393.0	Stores Equipment	Straight Line	17	5.80%	2,809
394.0	Tools, Shop, and Garage Eqp.	Straight Line	16 / 27	4.88%	245,259
395.0	Laboratory Equipment	Straight Line	0	0.00%	-
396.0	Power Operated Equipment	Straight Line	14	6.90%	340,892
397.0	Communications Equipment	Straight Line	9 / 18	8.65%	283,921
398.0	Miscellaneous Equipment	Straight Line	9 / 13	9.37%	139,049
	Total General Plant				2,596,128
	TOTAL DEPRECIATION EXPENSE				17,041,087

ENSTAR NATURAL GAS COMPANY, LLC

LONG-TERM DEBT OUTSTANDING
For the Year Ended December 31, 2023

Description	Date of Issue	Date of Maturity	Face Amount	Amount Outstanding	Interest Rate	Annual Expense
ENSTAR Natural Gas Company	2/24/2023	12/15/2027	36,500,000	36,186,853	5.34%	1,624,250
ENSTAR Natural Gas Company	2/24/2023	3/31/2030	18,250,000	18,063,401	5.38%	818,208
ENSTAR Natural Gas Company	2/24/2023	3/31/2033	65,700,000	65,089,180	5.41%	2,961,975
Alaska Pipeline Company	2/24/2023	12/15/2027	13,500,000	13,384,179	5.34%	600,750
Alaska Pipeline Company	2/24/2023	3/31/2030	6,750,000	6,680,984	5.38%	302,625
Alaska Pipeline Company	2/24/2023	3/31/2033	24,300,000	24,074,080	5.41%	1,095,525

Note: Debt was issued in 2/2023; therefore a full year of interest is not reflected in 2023.

For the Year Ended December 31, 2024

Description	Date of Issue	Date of Maturity	Face Amount	Amount Outstanding	Interest Rate	Annual Expense
ENSTAR Natural Gas Company	2/24/2023	12/15/2027	36,500,000	36,258,729	5.34%	1,949,100
ENSTAR Natural Gas Company	2/24/2023	3/31/2030	18,250,000	18,089,075	5.38%	981,850
ENSTAR Natural Gas Company	2/24/2023	3/31/2033	65,700,000	65,141,193	5.41%	3,554,370
Alaska Pipeline Company	2/24/2023	12/15/2027	13,500,000	13,410,763	5.34%	720,900
Alaska Pipeline Company	2/24/2023	3/31/2030	6,750,000	6,690,480	5.38%	363,150
Alaska Pipeline Company	2/24/2023	3/31/2033	24,300,000	24,093,318	5.41%	1,314,630

ENSTAR NATURAL GAS COMPANY, LLC

EFFECTIVE PROPOSED RATE INCREASES PER 3 AAC 48-275(a)(4)
For the Year Ended December 31, 2024

	Existing	Interim			Proposed		
	Tariff Rates $	Increase $	Change in $	Change in %	Permanent Increase $	Change in $	Change in %
GENERAL SERVICE							
G1							
Monthly Customer Charge	16.25	20.00	3.75	23.08%	21.00	4.75	29.23%
Base Rate (per Ccf)	0.14982	0.18459	0.03477	23.21%	0.18662	0.03680	24.56%
G2							
Monthly Customer Charge	35.50	43.75	8.25	23.24%	46.00	10.50	29.58%
Base Rate (per Ccf)	0.09602	0.11830	0.02228	23.21%	0.16259	0.06657	69.33%
G3							
Monthly Customer Charge	112.00	138.00	26.00	23.21%	118.00	6.00	5.36%
Base Rate (per Ccf)	0.09449	0.11642	0.02193	23.21%	0.13060	0.03611	38.22%
G4							
Monthly Customer Charge	538.00	662.75	124.75	23.19%	575.00	37.00	6.88%
Base Rate (per Ccf)	0.06581	0.08108	0.01527	23.21%	0.09822	0.03241	49.25%
MID-SIZED FIRM TRANSPORTATION							
Monthly Customer Charge	9,140	11,260	2,120	23.19%	0	(9,140)	-100.00%
Base Rate (per Mcf)	0.1629	0.2007	0.0378	23.21%	0.0000	(0.1629)	-100.00%
VERY LARGE FIRM TRANSPORTATION							
Base Rate (per Mcf)	0.1762	0.2171	0.04089	23.21%	0.2704	0.09421	53.46%
Customer Charge per Delivery Point	2,540	3,130	590	23.23%	2,400	(140)	-5.51%
Demand Charge per Mcf of Contracted Peak Demand per Month	4.26	5.25	0.99	23.21%	4.87	0.61000	14.32%
SOUTH CENTRAL POWER POOL FIRM TRANSPORTATION							
Base Rate (per Mcf)	0.1762	0.2171	0.04089	23.21%	0.2704	0.09421	53.46%
Customer Charge per Delivery Point	2,540	3,130	590	23.23%	2,400	(140)	-5.51%
Demand Charge per Mcf of Contracted Peak Demand per Month	4.26	5.25	0.99	23.21%	4.87	0.61	14.32%
INTERRUPTIBLE INDUSTRIAL TRANSPORTATION							
Mcf/Month							
< 100000	17,660	21,760	4,100	23.22%	34,700	17,040	96.49%
Remaining Volumes	0.1770	0.2181	0.0411	23.21%	0.3471	0.170	96.08%
INTERRUPTIBLE STORAGE TRANSPORTATION							
Mcf/Month							
All Volumes	0.1770	0.2181	0.0411	23.21%	0.3471	0.170	96.08%
Minimum charge for each Year	16,100	19,800	3,700	22.98%	34,700	18,600	115.53%

Attachment C

ENSTAR NATURAL GAS COMPANY, LLC

COST OF SERVICE STUDY
For the Year Ended December 31, 2024

	Total System	G1	G2	G3	G4	VLFT	MSFT	IIT/ITS
Normalized Revenues (net of gas cost)	91,362,093	56,749,246	4,506,980	9,011,201	11,450,729	9,491,917	-	152,021
Allocated Expenses (net of gas costs)	116,255,167	71,986,519	6,629,476	10,790,990	14,336,436	12,213,671	-	298,075
Revenues Under (Over) of Allocated Costs	24,893,073	15,237,274	2,122,496	1,779,789	2,885,707	2,721,754	-	146,054
Percent of Normalized Base Rate Revenues	**27%**	**27%**	**47%**	**20%**	**25%**	**29%**	**0%**	**96%**

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G1 Customer	G1 Capacity	G1 Commodity	G1 Total	G2 Customer	G2 Capacity	G2 Commodity	G2 Total
	COST OF SERVICE											
	Production and Gathering											
756	Field M&R Station Expense	Commodity	-	E.1	-	-	-	-	-	-	-	-
800	Natural Gas Well Head Purchases	Commodity	-	E.1	-	-	-	-	-	-	-	-
807	Purchased Gas Expenses	Commodity	172,846	E	-	-	57,957	57,957	-	-	6,145	6,145
	Total		172,846		-	-	57,957	57,957	-	-	6,145	6,145
	Transmission Expense											
850	Operation Supervision & Engnr.	Allocation	290,411	T	-	115,453	-	115,453	-	11,925	-	11,925
851	System Control & Load Dispatching	Capacity	435,444	S	-	173,110	-	173,110	-	17,880	-	17,880
852	Communication System Expenses	Capacity	280,393	S	-	111,469	-	111,469	-	11,513	-	11,513
853	Compressor Station Labor & Expenses	Capacity	727,885	S	-	289,369	-	289,369	-	29,888	-	29,888
856	Mains Expenses	Capacity	895,348	S	-	355,944	-	355,944	-	36,764	-	36,764
857	M&R Station Expenses	Capacity	917,496	S	-	364,749	-	364,749	-	37,673	-	37,673
859	Other Expenses	Capacity	92,368	S	-	36,721	-	36,721	-	3,793	-	3,793
860	Rents	Capacity	259,101	S	-	103,005	-	103,005	-	10,639	-	10,639
861	Maintenance Supervision & Engnr.	Capacity	156,430	S	-	62,189	-	62,189	-	6,423	-	6,423
862	Maint. of Structure and Improvements	Capacity	507,391	S	-	201,712	-	201,712	-	20,834	-	20,834
863	Maintenance of Mains	Capacity	446,950	S	-	177,684	-	177,684	-	18,352	-	18,352
864	Maint. of Compressor Station Equip.	Capacity	22,750	S	-	9,044	-	9,044	-	934	-	934
865	Maintenance of M&R Station Equip.	Capacity	166,403	S	-	66,153	-	66,153	-	6,833	-	6,833
866	Maintenance of Communication Equip.	Capacity	414,031	S	-	164,597	-	164,597	-	17,000	-	17,000
	Total		5,612,402		-	2,231,199	-	2,231,199	-	230,450	-	230,450
	Distribution Expense											
870	Operation Supervision & Engnr.	Allocation	1,054,044	J	450,245	266,059	-	716,303	45,695	27,336	-	73,031
871	Distribution Load Dispatching	Capacity	742,443	D.1	-	452,589	-	452,589	-	45,838	-	45,838
874	Mains and Services Expenses	Allocation	2,978,919	K	759,112	1,182,927	-	1,942,038	77,042	122,565	-	199,606
875	M&R Station Expenses - General	Capacity	535,246	D.2	-	246,098	-	246,098	-	24,925	-	24,925
876	M&R Station Expenses - Industrial	Capacity	1,749	D.2	-	804	-	804	-	81	-	81
878	Meter and House Regulator Expenses	Customer	2,015,045	B.1	1,528,321	-	-	1,528,321	155,108	-	-	155,108
879	Customer Installations Expenses	Customer	1,184,165	B.1	898,136	-	-	898,136	91,151	-	-	91,151
880	Other Expenses	Allocation	417,082	J	178,160	105,279	-	283,439	18,081	10,817	-	28,898
881	Rents	Allocation	301,192	J	128,657	76,026	-	204,683	13,057	7,811	-	20,869
882	Temporary Service Line Expense	Allocation	-	B.1	-	-	-	-	-	-	-	-
885	Maintenance Supervision & Engnr.	Allocation	-	L	-	-	-	-	-	-	-	-
887	Maintenance of Mains	Allocation	630,257	U	-	376,910	-	376,910	-	39,052	-	39,052
889	Maint. M&R Stn. Equip. General	Capacity	29,771	D.2	-	13,688	-	13,688	-	1,386	-	1,386
890	Maint. M&R Stn. Equip. Indust.	Capacity	-	D.2	-	-	-	-	-	-	-	-
892	Maintenance of Services	Customer	870,320	B.1	660,099	-	-	660,099	66,993	-	-	66,993
893	Maint. of Meter & House Regulators	Customer	291,554	B.1	221,130	-	-	221,130	22,442	-	-	22,442
	Total		11,051,787		4,823,859	2,720,379	-	7,544,238	489,570	279,812	-	769,382

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G3 Customer	G3 Capacity	G3 Commodity	G3 Total	G4 Customer	G4 Capacity	G4 Commodity	G4 Total
	COST OF SERVICE											
	Production and Gathering											
756	Field M&R Station Expense	Commodity	-	E.1	-	-	-	-	-	-	-	-
800	Natural Gas Well Head Purchases	Commodity	-	E.1	-	-	-	-	-	-	-	-
807	Purchased Gas Expenses	Commodity	172,846	E	-	-	12,502	12,502	-	-	22,221	22,221
	Total		172,846		-	-	12,502	12,502	-	-	22,221	22,221
	Transmission Expense											
850	Operation Supervision & Engnr.	Allocation	290,411	T	-	23,578	-	23,578	-	41,588	-	41,588
851	System Control & Load Dispatching	Capacity	435,444	S	-	35,353	-	35,353	-	62,358	-	62,358
852	Communication System Expenses	Capacity	280,393	S	-	22,765	-	22,765	-	40,154	-	40,154
853	Compressor Station Labor & Expenses	Capacity	727,885	S	-	59,096	-	59,096	-	104,237	-	104,237
856	Mains Expenses	Capacity	895,348	S	-	72,692	-	72,692	-	128,218	-	128,218
857	M&R Station Expenses	Capacity	917,496	S	-	74,490	-	74,490	-	131,390	-	131,390
859	Other Expenses	Capacity	92,368	S	-	7,499	-	7,499	-	13,228	-	13,228
860	Rents	Capacity	259,101	S	-	21,036	-	21,036	-	37,105	-	37,105
861	Maintenance Supervision & Engnr.	Capacity	156,430	S	-	12,700	-	12,700	-	22,402	-	22,402
862	Maint. of Structure and Improvements	Capacity	507,391	S	-	41,194	-	41,194	-	72,661	-	72,661
863	Maintenance of Mains	Capacity	446,950	S	-	36,287	-	36,287	-	64,006	-	64,006
864	Maint. of Compressor Station Equip.	Capacity	22,750	S	-	1,847	-	1,847	-	3,258	-	3,258
865	Maintenance of M&R Station Equip.	Capacity	166,403	S	-	13,510	-	13,510	-	23,830	-	23,830
866	Maintenance of Communication Equip.	Capacity	414,031	S	-	33,615	-	33,615	-	59,291	-	59,291
	Total		5,612,402		-	455,663	-	455,663	-	803,724	-	803,724
	Distribution Expense											
870	Operation Supervision & Engnr.	Allocation	1,054,044	J	61,970	53,735	-	115,705	35,724	94,628	-	130,353
871	Distribution Load Dispatching	Capacity	742,443	D.1	-	88,635	-	88,635	-	155,381	-	155,381
874	Mains and Services Expenses	Allocation	2,978,919	K	104,482	243,194	-	347,676	60,231	429,368	-	489,599
875	M&R Station Expenses - General	Capacity	535,246	D.2	-	48,196	-	48,196	-	84,490	-	84,490
876	M&R Station Expenses - Industrial	Capacity	1,749	D.2	-	158	-	158	-	276	-	276
878	Meter and House Regulator Expenses	Customer	2,015,045	B.1	210,353	-	-	210,353	121,263	-	-	121,263
879	Customer Installations Expenses	Customer	1,184,165	B.1	123,616	-	-	123,616	71,262	-	-	71,262
880	Other Expenses	Allocation	417,082	J	24,521	21,263	-	45,784	14,136	37,444	-	51,580
881	Rents	Allocation	301,192	J	17,708	15,355	-	33,063	10,208	27,040	-	37,248
882	Temporary Service Line Expense	Allocation	-	B.1	-	-	-	-	-	-	-	-
885	Maintenance Supervision & Engnr.	Allocation	-	L	-	-	-	-	-	-	-	-
887	Maintenance of Mains	Allocation	630,257	U	-	77,488	-	77,488	-	136,807	-	136,807
889	Maint. M&R Stn. Equip. General	Capacity	29,771	D.2	-	2,681	-	2,681	-	4,699	-	4,699
890	Maint. M&R Stn. Equip. Indust.	Capacity	-	D.2	-	-	-	-	-	-	-	-
892	Maintenance of Services	Customer	870,320	B.1	90,854	-	-	90,854	52,375	-	-	52,375
893	Maint. of Meter & House Regulators	Customer	291,554	B.1	30,436	-	-	30,436	17,545	-	-	17,545
	Total		11,051,787		663,940	550,702	-	1,214,642	382,744	970,134	-	1,352,878

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	VLFT Customer	VLFT Capacity	VLFT Commodity	VLFT Total	MSFT Customer	MSFT Capacity	MSFT Commodity	MSFT Total
	COST OF SERVICE											
	Production and Gathering											
756	Field M&R Station Expense	Commodity	-	E.1	-	-	-	-	-	-	-	-
800	Natural Gas Well Head Purchases	Commodity	-	E.1	-	-	-	-	-	-	-	-
807	Purchased Gas Expenses	Commodity	172,846	E	-	-	71,456	71,456	-	-	-	-
	Total		172,846		-	-	71,456	71,456	-	-	-	-
	Transmission Expense											
850	Operation Supervision & Engnr.	Allocation	290,411	T	-	95,714	-	95,714	-	-	-	-
851	System Control & Load Dispatching	Capacity	435,444	S	-	143,514	-	143,514	-	-	-	-
852	Communication System Expenses	Capacity	280,393	S	-	92,412	-	92,412	-	-	-	-
853	Compressor Station Labor & Expenses	Capacity	727,885	S	-	239,897	-	239,897	-	-	-	-
856	Mains Expenses	Capacity	895,348	S	-	295,089	-	295,089	-	-	-	-
857	M&R Station Expenses	Capacity	917,496	S	-	302,389	-	302,389	-	-	-	-
859	Other Expenses	Capacity	92,368	S	-	30,443	-	30,443	-	-	-	-
860	Rents	Capacity	259,101	S	-	85,395	-	85,395	-	-	-	-
861	Maintenance Supervision & Engnr.	Capacity	156,430	S	-	51,556	-	51,556	-	-	-	-
862	Maint. of Structure and Improvements	Capacity	507,391	S	-	167,226	-	167,226	-	-	-	-
863	Maintenance of Mains	Capacity	446,950	S	-	147,306	-	147,306	-	-	-	-
864	Maint. of Compressor Station Equip.	Capacity	22,750	S	-	7,498	-	7,498	-	-	-	-
865	Maintenance of M&R Station Equip.	Capacity	166,403	S	-	54,843	-	54,843	-	-	-	-
866	Maintenance of Communication Equip.	Capacity	414,031	S	-	136,456	-	136,456	-	-	-	-
	Total		5,612,402		-	1,849,739	-	1,849,739	-	-	-	-
	Distribution Expense											
870	Operation Supervision & Engnr.	Allocation	1,054,044	J	-	18,652	-	18,652	-	-	-	-
871	Distribution Load Dispatching	Capacity	742,443	D.1	-	-	-	-	-	-	-	-
874	Mains and Services Expenses	Allocation	2,978,919	K	-	-	-	-	-	-	-	-
875	M&R Station Expenses - General	Capacity	535,246	D.2	-	131,538	-	131,538	-	-	-	-
876	M&R Station Expenses - Industrial	Capacity	1,749	D.2	-	430	-	430	-	-	-	-
878	Meter and House Regulator Expenses	Customer	2,015,045	B.1	-	-	-	-	-	-	-	-
879	Customer Installations Expenses	Customer	1,184,165	B.1	-	-	-	-	-	-	-	-
880	Other Expenses	Allocation	417,082	J	-	7,381	-	7,381	-	-	-	-
881	Rents	Allocation	301,192	J	-	5,330	-	5,330	-	-	-	-
882	Temporary Service Line Expense	Allocation	-	B.1	-	-	-	-	-	-	-	-
885	Maintenance Supervision & Engnr.	Allocation	-	L	-	-	-	-	-	-	-	-
887	Maintenance of Mains	Allocation	630,257	U	-	-	-	-	-	-	-	-
889	Maint. M&R Stn. Equip. General	Capacity	29,771	D.2	-	7,316	-	7,316	-	-	-	-
890	Maint. M&R Stn. Equip. Indust.	Capacity	-	D.2	-	-	-	-	-	-	-	-
892	Maintenance of Services	Customer	870,320	B.1	-	-	-	-	-	-	-	-
893	Maint. of Meter & House Regulators	Customer	291,554	B.1	-	-	-	-	-	-	-	-
	Total		11,051,787		-	170,647	-	170,647	-	-	-	-

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	IIT/ITS Customer	IIT/ITS Capacity	IIT/ITS Commodity	IIT/ITS Total
	COST OF SERVICE							
	Production and Gathering							
756	Field M&R Station Expense	Commodity	-	E.1	-	-	-	-
800	Natural Gas Well Head Purchases	Commodity	-	E.1	-	-	-	-
807	Purchased Gas Expenses	Commodity	172,846	E	-	-	2,564	2,564
	Total		172,846		-	-	2,564	2,564
	Transmission Expense							
850	Operation Supervision & Engnr.	Allocation	290,411	T	-	2,154	-	2,154
851	System Control & Load Dispatching	Capacity	435,444	S	-	3,230	-	3,230
852	Communication System Expenses	Capacity	280,393	S	-	2,080	-	2,080
853	Compressor Station Labor & Expenses	Capacity	727,885	S	-	5,399	-	5,399
856	Mains Expenses	Capacity	895,348	S	-	6,641	-	6,641
857	M&R Station Expenses	Capacity	917,496	S	-	6,805	-	6,805
859	Other Expenses	Capacity	92,368	S	-	685	-	685
860	Rents	Capacity	259,101	S	-	1,922	-	1,922
861	Maintenance Supervision & Engnr.	Capacity	156,430	S	-	1,160	-	1,160
862	Maint. of Structure and Improvements	Capacity	507,391	S	-	3,763	-	3,763
863	Maintenance of Mains	Capacity	446,950	S	-	3,315	-	3,315
864	Maint. of Compressor Station Equip.	Capacity	22,750	S	-	169	-	169
865	Maintenance of M&R Station Equip.	Capacity	166,403	S	-	1,234	-	1,234
866	Maintenance of Communication Equip.	Capacity	414,031	S	-	3,071	-	3,071
	Total		5,612,402		-	41,627	-	41,627
	Distribution Expense							
870	Operation Supervision & Engnr.	Allocation	1,054,044	J	-	-	-	-
871	Distribution Load Dispatching	Capacity	742,443	D.1	-	-	-	-
874	Mains and Services Expenses	Allocation	2,978,919	K	-	-	-	-
875	M&R Station Expenses - General	Capacity	535,246	D.2	-	-	-	-
876	M&R Station Expenses - Industrial	Capacity	1,749	D.2	-	-	-	-
878	Meter and House Regulator Expenses	Customer	2,015,045	B.1	-	-	-	-
879	Customer Installations Expenses	Customer	1,184,165	B.1	-	-	-	-
880	Other Expenses	Allocation	417,082	J	-	-	-	-
881	Rents	Allocation	301,192	J	-	-	-	-
882	Temporary Service Line Expense	Allocation	-	B.1	-	-	-	-
885	Maintenance Supervision & Engnr.	Allocation	-	L	-	-	-	-
887	Maintenance of Mains	Allocation	630,257	U	-	-	-	-
889	Maint. M&R Stn. Equip. General	Capacity	29,771	D.2	-	-	-	-
890	Maint. M&R Stn. Equip. Indust.	Capacity	-	D.2	-	-	-	-
892	Maintenance of Services	Customer	870,320	B.1	-	-	-	-
893	Maint. of Meter & House Regulators	Customer	291,554	B.1	-	-	-	-
	Total		11,051,787		-	-	-	-

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G1 Customer	G1 Capacity	G1 Commodity	G1 Total	G2 Customer	G2 Capacity	G2 Commodity	G2 Total
901-910	**Customer Accounting**	Customer	7,527,548	C	6,192,601	-	-	6,192,601	420,006	-	-	420,006
904	**Uncollectible Accounts**	Customer	543,583	C.1	460,188	-	-	460,188	31,212	-	-	31,212
911-912	**Sales**	Customer	65,808	C	54,138	-	-	54,138	3,672	-	-	3,672
920-931	**Administrative and General**	Allocation	22,059,859	F	11,653,445	4,214,278	-	15,867,723	803,909	433,996	-	1,237,905
	Depreciation and Amortization	Allocation	20,731,921		6,766,216	5,165,822	508,760	12,440,797	608,009	533,869	53,946	1,195,824
	TOTAL OPERATING EXPENSES		67,765,754		29,950,446	14,331,679	566,717	44,848,842	2,356,377	1,478,128	60,091	3,894,596
	Ad Valorem & Miscellaneous											
	Ad Valorem	Allocation	4,493,695	N	1,019,366	1,534,430	-	2,553,796	99,938	158,678	-	258,616
	Miscellaneous	Allocation	(463)	M	(194)	(104)	(1)	(298)	(16)	(11)	(0)	(27)
	Total		4,493,232		1,019,173	1,534,326	(1)	2,553,498	99,922	158,667	(0)	258,589
	RETURN ON INVESTMENT	Allocation	35,796,610	P	6,115,283	13,878,364	174,054	20,167,701	570,002	1,435,646	18,456	2,024,104
	INCOME TAXES	Allocation	9,756,246	P	1,666,700	3,782,502	47,438	5,496,639	155,352	391,281	5,030	551,663
	REVENUE REQUIREMENT W/O GAS COST		117,811,841		38,751,602	33,526,870	788,208	73,066,680	3,181,653	3,463,721	83,577	6,728,951
	OTHER REVENUES											
	Miscellaneous Revenues	Allocation	(1,556,675)	O.1	(572,874)	(495,635)	(11,652)	(1,080,161)	(47,035)	(51,205)	(1,236)	(99,476)
	HEA - Bernice Lake	Allocation	-	O	-	-	-	-	-	-	-	-
	TOTAL COST OF SERVICE		116,255,167		38,178,728	33,031,235	776,556	71,986,519	3,134,618	3,412,517	82,341	6,629,476
	GAS UTILITY PLANT											
	Production and Gathering Plant											
301	Organization	Capacity	507,670	D	-	233,419	-	233,419	-	23,641	-	23,641
302	Franchises and Consents	Capacity	-	D	-	-	-	-	-	-	-	-
332	Field Lines	Capacity	203,832	D	-	93,719	-	93,719	-	9,492	-	9,492
334	Field M&R Station Equipment	Capacity	81,453	D	-	37,451	-	37,451	-	3,793	-	3,793
	Total		792,955		-	364,589	-	364,589	-	36,926	-	36,926
	Transmission Plant											
365.1	Land and Land Rights	Capacity	290,755	S	-	115,589	-	115,589	-	11,939	-	11,939
365.2	Rights-of-Way	Capacity	250,119	S	-	99,434	-	99,434	-	10,270	-	10,270
366	Structures and Improvements	Capacity	11,690,811	S	-	4,647,659	-	4,647,659	-	480,034	-	480,034
367	Mains	Capacity	183,519,870	S	-	72,957,960	-	72,957,960	-	7,535,479	-	7,535,479
368	Compressor Station Equipment	Capacity	19,463,332	S	-	7,737,609	-	7,737,609	-	799,181	-	799,181
369	M&R Station Equipment	Capacity	33,263,313	S	-	13,223,764	-	13,223,764	-	1,365,819	-	1,365,819
370	Communication Equipment	Capacity	6,764,495	S	-	2,689,212	-	2,689,212	-	277,756	-	277,756
	Total		255,242,696		-	101,471,228	-	101,471,228	-	10,480,478	-	10,480,478

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G3 Customer	G3 Capacity	G3 Commodity	G3 Total	G4 Customer	G4 Capacity	G4 Commodity	G4 Total
901-910	**Customer Accounting**	Customer	7,527,548	C	463,400	-	-	463,400	238,820	-	-	238,820
904	**Uncollectible Accounts**	Customer	543,583	C.1	34,436	-	-	34,436	17,747	-	-	17,747
911-912	**Sales**	Customer	65,808	C	4,051	-	-	4,051	2,088	-	-	2,088
920-931	**Administrative and General**	Allocation	22,059,859	F	897,280	855,316	-	1,752,595	465,807	1,507,308	-	1,973,115
	Depreciation and Amortization	Allocation	20,731,921		784,478	1,056,302	109,749	1,950,530	441,543	1,863,501	195,059	2,500,103
	TOTAL OPERATING EXPENSES		67,765,754		2,847,585	2,917,983	122,252	5,887,819	1,548,750	5,144,667	217,279	6,910,696
	Ad Valorem & Miscellaneous											
	Ad Valorem	Allocation	4,493,695	N	133,742	314,177	-	447,919	76,621	554,369	-	630,990
	Miscellaneous	Allocation	(463)	M	(20)	(21)	(0)	(42)	(11)	(37)	(0)	(49)
	Total		4,493,232		133,722	314,156	(0)	447,878	76,610	554,332	(0)	630,941
	RETURN ON INVESTMENT	Allocation	35,796,610	P	747,226	2,843,552	37,547	3,628,325	423,879	5,017,962	66,732	5,508,574
	INCOME TAXES	Allocation	9,756,246	P	203,654	775,000	10,233	988,888	115,527	1,367,629	18,188	1,501,343
	REVENUE REQUIREMENT W/O GAS COST		117,811,841		3,932,187	6,850,691	170,032	10,952,909	2,164,765	12,084,590	302,199	14,551,555
	OTHER REVENUES											
	Miscellaneous Revenues	Allocation	(1,556,675)	O.1	(58,130)	(101,275)	(2,514)	(161,919)	(32,002)	(178,649)	(4,467)	(215,119)
	HEA - Bernice Lake	Allocation	-	O	-	-	-	-	-	-	-	-
	TOTAL COST OF SERVICE		116,255,167		3,874,056	6,749,416	167,518	10,790,990	2,132,763	11,905,941	297,732	14,336,436
	GAS UTILITY PLANT											
	Production and Gathering Plant											
301	Organization	Capacity	507,670	D	-	45,713	-	45,713	-	80,137	-	80,137
302	Franchises and Consents	Capacity	-	D	-	-	-	-	-	-	-	-
332	Field Lines	Capacity	203,832	D	-	18,354	-	18,354	-	32,175	-	32,175
334	Field M&R Station Equipment	Capacity	81,453	D	-	7,334	-	7,334	-	12,858	-	12,858
	Total		792,955		-	71,401	-	71,401	-	125,169	-	125,169
	Transmission Plant											
365.1	Land and Land Rights	Capacity	290,755	S	-	23,606	-	23,606	-	41,638	-	41,638
365.2	Rights-of-Way	Capacity	250,119	S	-	20,307	-	20,307	-	35,818	-	35,818
366	Structures and Improvements	Capacity	11,690,811	S	-	949,160	-	949,160	-	1,674,183	-	1,674,183
367	Mains	Capacity	183,519,870	S	-	14,899,704	-	14,899,704	-	26,280,970	-	26,280,970
368	Compressor Station Equipment	Capacity	19,463,332	S	-	1,580,199	-	1,580,199	-	2,787,247	-	2,787,247
369	M&R Station Equipment	Capacity	33,263,313	S	-	2,700,599	-	2,700,599	-	4,763,474	-	4,763,474
370	Communication Equipment	Capacity	6,764,495	S	-	549,199	-	549,199	-	968,710	-	968,710
	Total		255,242,696		-	20,722,774	-	20,722,774	-	36,552,040	-	36,552,040

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	VLFT Customer	VLFT Capacity	VLFT Commodity	VLFT Total	MSFT Customer	MSFT Capacity	MSFT Commodity	MSFT Total
901-910	**Customer Accounting**	Customer	7,527,548	C	189,085	-	-	189,085	-	-	-	-
904	**Uncollectible Accounts**	Customer	543,583	C.1	-	-	-	-	-	-	-	-
911-912	**Sales**	Customer	65,808	C	1,653	-	-	1,653	-	-	-	-
920-931	**Administrative and General**	Allocation	22,059,859	F	358	1,205,210	-	1,205,569	-	-	-	-
	Depreciation and Amortization	Allocation	20,731,921		74	1,952,595	627,256	2,579,926	-	-	-	-
	TOTAL OPERATING EXPENSES		67,765,754		191,171	5,178,191	698,712	6,068,074	-	-	-	-
	Ad Valorem & Miscellaneous											
	Ad Valorem	Allocation	4,493,695	N	3	589,452	-	589,455	-	-	-	-
	Miscellaneous	Allocation	(463)	M	(3)	(42)	(1)	(46)	-	-	-	-
	Total		4,493,232		0	589,410	(1)	589,409	-	-	-	-
	RETURN ON INVESTMENT	Allocation	35,796,610	P	32,014	4,120,285	213,896	4,366,196	-	-	-	-
	INCOME TAXES	Allocation	9,756,246	P	8,725	1,122,970	58,297	1,189,992	-	-	-	-
	REVENUE REQUIREMENT W/O GAS COST		117,811,841		231,911	11,010,856	970,904	12,213,671	-	-	-	-
	OTHER REVENUES											
	Miscellaneous Revenues	Allocation	(1,556,675)	O.1	-	-	-	-	-	-	-	-
	HEA - Bernice Lake	Allocation	-	O	-	-	-	-	-	-	-	-
	TOTAL COST OF SERVICE		116,255,167		231,911	11,010,856	970,904	12,213,671	-	-	-	-
	GAS UTILITY PLANT											
	Production and Gathering Plant											
301	Organization	Capacity	507,670	D	-	124,761	-	124,761	-	-	-	-
302	Franchises and Consents	Capacity	-	D	-	-	-	-	-	-	-	-
332	Field Lines	Capacity	203,832	D	-	50,092	-	50,092	-	-	-	-
334	Field M&R Station Equipment	Capacity	81,453	D	-	20,017	-	20,017	-	-	-	-
	Total		792,955		-	194,870	-	194,870	-	-	-	-
	Transmission Plant											
365.1	Land and Land Rights	Capacity	290,755	S	-	95,827	-	95,827	-	-	-	-
365.2	Rights-of-Way	Capacity	250,119	S	-	82,434	-	82,434	-	-	-	-
366	Structures and Improvements	Capacity	11,690,811	S	-	3,853,064	-	3,853,064	-	-	-	-
367	Mains	Capacity	183,519,870	S	-	60,484,580	-	60,484,580	-	-	-	-
368	Compressor Station Equipment	Capacity	19,463,332	S	-	6,414,736	-	6,414,736	-	-	-	-
369	M&R Station Equipment	Capacity	33,263,313	S	-	10,962,941	-	10,962,941	-	-	-	-
370	Communication Equipment	Capacity	6,764,495	S	-	2,229,446	-	2,229,446	-	-	-	-
	Total		255,242,696		-	84,123,029	-	84,123,029	-	-	-	-

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	IIT/ITS Customer	IIT/ITS Capacity	IIT/ITS Commodity	IIT/ITS Total
901-910	**Customer Accounting**	Customer	7,527,548	C	23,636	-	-	23,636
904	**Uncollectible Accounts**	Customer	543,583	C.1	-	-	-	-
911-912	**Sales**	Customer	65,808	C	207	-	-	207
920-931	**Administrative and General**	Allocation	22,059,859	F	45	22,907	-	22,951
	Depreciation and Amortization	Allocation	20,731,921		9	42,225	22,507	64,742
	TOTAL OPERATING EXPENSES		67,765,754		23,896	106,759	25,071	155,727
	Ad Valorem & Miscellaneous							
	Ad Valorem	Allocation	4,493,695	N	0	12,918	-	12,918
	Miscellaneous	Allocation	(463)	M	(0)	(1)	(0)	(1)
	Total		4,493,232		0	12,917	(0)	12,917
	RETURN ON INVESTMENT	Allocation	35,796,610	P	4,002	90,033	7,675	101,710
	INCOME TAXES	Allocation	9,756,246	P	1,091	24,538	2,092	27,721
	REVENUE REQUIREMENT W/O GAS COST		117,811,841		28,989	234,248	34,838	298,075
	OTHER REVENUES							
	Miscellaneous Revenues	Allocation	(1,556,675)	O.1	-	-	-	-
	HEA - Bernice Lake	Allocation	-	O	-	-	-	-
	TOTAL COST OF SERVICE		116,255,167		28,989	234,248	34,838	298,075
	GAS UTILITY PLANT							
	Production and Gathering Plant							
301	Organization	Capacity	507,670	D	-	-	-	-
302	Franchises and Consents	Capacity	-	D	-	-	-	-
332	Field Lines	Capacity	203,832	D	-	-	-	-
334	Field M&R Station Equipment	Capacity	81,453	D	-	-	-	-
	Total		792,955		-	-	-	-
	Transmission Plant							
365.1	Land and Land Rights	Capacity	290,755	S	-	2,157	-	2,157
365.2	Rights-of-Way	Capacity	250,119	S	-	1,855	-	1,855
366	Structures and Improvements	Capacity	11,690,811	S	-	86,711	-	86,711
367	Mains	Capacity	183,519,870	S	-	1,361,176	-	1,361,176
368	Compressor Station Equipment	Capacity	19,463,332	S	-	144,360	-	144,360
369	M&R Station Equipment	Capacity	33,263,313	S	-	246,716	-	246,716
370	Communication Equipment	Capacity	6,764,495	S	-	50,173	-	50,173
	Total		255,242,696		-	1,893,147	-	1,893,147

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G1 Customer	G1 Capacity	G1 Commodity	G1 Total	G2 Customer	G2 Capacity	G2 Commodity	G2 Total
	Distribution Plant											
374	Land and Land Rights	Allocation	357,560	G	128,419	111,566	-	239,986	13,033	11,552	-	24,585
375	Structures and Improvements	Allocation	72,739	G	26,124	22,696	-	48,820	2,651	2,350	-	5,001
376	Mains	Allocation	197,022,713	S.1	-	117,824,645	-	117,824,645	-	12,207,970	-	12,207,970
377	Cathodic Protection Main/Svc	Capacity	-	S.1	-	-	-	-	-	-	-	-
378	M&R Station Equipment - General	Capacity	1,791,521	D.2	-	823,715	-	823,715	-	83,426	-	83,426
379	M&R Station Equipment - City Gate	Capacity	2,089,740	D.2	-	960,831	-	960,831	-	97,313	-	97,313
380	Services	Customer	127,356,493	B.1	96,594,162	-	-	96,594,162	9,803,269	-	-	9,803,269
381	Meters	Customer	19,713,735	B.1	14,951,980	-	-	14,951,980	1,517,465	-	-	1,517,465
382	Meter Installations	Customer	41,234,128	B.1	31,274,228	-	-	31,274,228	3,173,998	-	-	3,173,998
383	House Regulators	Customer	253,596	B.1	192,341	-	-	192,341	19,521	-	-	19,521
385	Industrial M&R Station Equipment	Capacity	2,430,764	D.2	-	1,117,629	-	1,117,629	-	113,194	-	113,194
387	Other Equipment	Allocation	6,770,018	G	2,431,488	2,112,388	-	4,543,876	246,770	218,719	-	465,489
	Total		399,093,006		145,598,743	122,973,470	-	268,572,213	14,776,707	12,734,525	-	27,511,231
389-398	**General Plant**	Allocation	48,249,137	F	25,488,315	9,217,434	-	34,705,749	1,758,303	949,233	-	2,707,536
	Completed Not Classified	Allocation	-	H	-	-	-	-	-	-	-	-
	Construction Work in Progress	Allocation	-	H	-	-	-	-	-	-	-	-
	TOTAL GROSS GAS UTILITY PLANT		703,377,794		171,087,059	234,026,720	-	405,113,779	16,535,010	24,201,161	-	40,736,171
	DEPRECIATION RESERVE											
	Production and Gathering Plant											
301	Organization	Capacity	(228,587)	D	-	(105,101)	-	(105,101)	-	(10,645)	-	(10,645)
302	Franchises and Consents	Capacity	7,710	D	-	3,545	-	3,545	-	359	-	359
332	Field Lines	Capacity	(244,651)	D	-	(112,487)	-	(112,487)	-	(11,393)	-	(11,393)
334	Field M&R Station Equipment	Capacity	(148,406)	D	-	(68,235)	-	(68,235)	-	(6,911)	-	(6,911)
	Total		(613,933)		-	(282,277)	-	(282,277)	-	(28,589)	-	(28,589)
	Transmission Plant											
365.1	Land and Land Rights	Capacity	-	S	-	-	-	-	-	-	-	-
365.2	Rights-of-Way	Capacity	(176,781)	S	-	(70,279)	-	(70,279)	-	(7,259)	-	(7,259)
366	Structures and Improvements	Capacity	(3,504,926)	S	-	(1,393,376)	-	(1,393,376)	-	(143,915)	-	(143,915)
367	Mains	Capacity	(113,084,817)	S	-	(44,956,645)	-	(44,956,645)	-	(4,643,357)	-	(4,643,357)
368	Compressor Station Equipment	Capacity	(6,402,099)	S	-	(2,545,142)	-	(2,545,142)	-	(262,876)	-	(262,876)
369	M&R Station Equipment	Capacity	(9,337,011)	S	-	(3,711,910)	-	(3,711,910)	-	(383,385)	-	(383,385)
370	Communication Equipment	Capacity	(3,731,513)	S	-	(1,483,456)	-	(1,483,456)	-	(153,219)	-	(153,219)
	Total		(136,237,148)		-	(54,160,808)	-	(54,160,808)	-	(5,594,011)	-	(5,594,011)

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G3 Customer	G3 Capacity	G3 Commodity	G3 Total	G4 Customer	G4 Capacity	G4 Commodity	G4 Total
	Distribution Plant											
374	Land and Land Rights	Allocation	357,560	G	17,675	22,904	-	40,579	10,189	40,429	-	50,619
375	Structures and Improvements	Allocation	72,739	G	3,596	4,659	-	8,255	2,073	8,225	-	10,297
376	Mains	Allocation	197,022,713	S.1	-	24,223,213	-	24,223,213	-	42,766,885	-	42,766,885
377	Cathodic Protection Main/Svc	Capacity	-	S.1	-	-	-	-	-	-	-	-
378	M&R Station Equipment - General	Capacity	1,791,521	D.2	-	161,316	-	161,316	-	282,795	-	282,795
379	M&R Station Equipment - City Gate	Capacity	2,089,740	D.2	-	188,169	-	188,169	-	329,869	-	329,869
380	Services	Customer	127,356,493	B.1	13,294,899	-	-	13,294,899	7,664,163	-	-	7,664,163
381	Meters	Customer	19,713,735	B.1	2,057,941	-	-	2,057,941	1,186,349	-	-	1,186,349
382	Meter Installations	Customer	41,234,128	B.1	4,304,481	-	-	4,304,481	2,481,421	-	-	2,481,421
383	House Regulators	Customer	253,596	B.1	26,473	-	-	26,473	15,261	-	-	15,261
385	Industrial M&R Station Equipment	Capacity	2,430,764	D.2	-	218,876	-	218,876	-	383,700	-	383,700
387	Other Equipment	Allocation	6,770,018	G	334,662	433,661	-	768,323	192,924	765,488	-	958,412
	Total		399,093,006		20,039,726	25,252,797	-	45,292,523	11,552,381	44,577,391	-	56,129,772
389-398	**General Plant**	Allocation	48,249,137	F	1,962,522	1,870,739	-	3,833,261	1,018,810	3,296,771	-	4,315,581
	Completed Not Classified	Allocation	-	H	-	-	-	-	-	-	-	-
	Construction Work in Progress	Allocation	-	H	-	-	-	-	-	-	-	-
	TOTAL GROSS GAS UTILITY PLANT		703,377,794		22,002,248	47,917,711	-	69,919,959	12,571,191	84,551,372	-	97,122,563
	DEPRECIATION RESERVE											
	Production and Gathering Plant											
301	Organization	Capacity	(228,587)	D	-	(20,583)	-	(20,583)	-	(36,083)	-	(36,083)
302	Franchises and Consents	Capacity	7,710	D	-	694	-	694	-	1,217	-	1,217
332	Field Lines	Capacity	(244,651)	D	-	(22,029)	-	(22,029)	-	(38,619)	-	(38,619)
334	Field M&R Station Equipment	Capacity	(148,406)	D	-	(13,363)	-	(13,363)	-	(23,426)	-	(23,426)
	Total		(613,933)		-	(55,281)	-	(55,281)	-	(96,910)	-	(96,910)
	Transmission Plant											
365.1	Land and Land Rights	Capacity	-	S	-	-	-	-	-	-	-	-
365.2	Rights-of-Way	Capacity	(176,781)	S	-	(14,353)	-	(14,353)	-	(25,316)	-	(25,316)
366	Structures and Improvements	Capacity	(3,504,926)	S	-	(284,560)	-	(284,560)	-	(501,923)	-	(501,923)
367	Mains	Capacity	(113,084,817)	S	-	(9,181,188)	-	(9,181,188)	-	(16,194,316)	-	(16,194,316)
368	Compressor Station Equipment	Capacity	(6,402,099)	S	-	(519,777)	-	(519,777)	-	(916,813)	-	(916,813)
369	M&R Station Equipment	Capacity	(9,337,011)	S	-	(758,058)	-	(758,058)	-	(1,337,107)	-	(1,337,107)
370	Communication Equipment	Capacity	(3,731,513)	S	-	(302,956)	-	(302,956)	-	(534,372)	-	(534,372)
	Total		(136,237,148)		-	(11,060,891)	-	(11,060,891)	-	(19,509,846)	-	(19,509,846)

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	VLFT Customer	VLFT Capacity	VLFT Commodity	VLFT Total	MSFT Customer	MSFT Capacity	MSFT Commodity	MSFT Total
	Distribution Plant											
374	Land and Land Rights	Allocation	357,560	G	-	1,791	-	1,791	-	-	-	-
375	Structures and Improvements	Allocation	72,739	G	-	364	-	364	-	-	-	-
376	Mains	Allocation	197,022,713	S.1	-	-	-	-	-	-	-	-
377	Cathodic Protection Main/Svc	Capacity	-	S.1	-	-	-	-	-	-	-	-
378	M&R Station Equipment - General	Capacity	1,791,521	D.2	-	440,270	-	440,270	-	-	-	-
379	M&R Station Equipment - City Gate	Capacity	2,089,740	D.2	-	513,558	-	513,558	-	-	-	-
380	Services	Customer	127,356,493	B.1	-	-	-	-	-	-	-	-
381	Meters	Customer	19,713,735	B.1	-	-	-	-	-	-	-	-
382	Meter Installations	Customer	41,234,128	B.1	-	-	-	-	-	-	-	-
383	House Regulators	Customer	253,596	B.1	-	-	-	-	-	-	-	-
385	Industrial M&R Station Equipment	Capacity	2,430,764	D.2	-	597,365	-	597,365	-	-	-	-
387	Other Equipment	Allocation	6,770,018	G	-	33,918	-	33,918	-	-	-	-
	Total		399,093,006		-	1,587,266	-	1,587,266	-	-	-	-
389-398	**General Plant**	Allocation	48,249,137	F	784	2,636,025	-	2,636,809	-	-	-	-
	Completed Not Classified	Allocation	-	H	-	-	-	-	-	-	-	-
	Construction Work in Progress	Allocation	-	H	-	-	-	-	-	-	-	-
	TOTAL GROSS GAS UTILITY PLANT		703,377,794		784	88,541,192	-	88,541,976	-	-	-	-
	DEPRECIATION RESERVE											
	Production and Gathering Plant											
301	Organization	Capacity	(228,587)	D	-	(56,176)	-	(56,176)	-	-	-	-
302	Franchises and Consents	Capacity	7,710	D	-	1,895	-	1,895	-	-	-	-
332	Field Lines	Capacity	(244,651)	D	-	(60,123)	-	(60,123)	-	-	-	-
334	Field M&R Station Equipment	Capacity	(148,406)	D	-	(36,471)	-	(36,471)	-	-	-	-
	Total		(613,933)		-	(150,875)	-	(150,875)	-	-	-	-
	Transmission Plant											
365.1	Land and Land Rights	Capacity	-	S	-	-	-	-	-	-	-	-
365.2	Rights-of-Way	Capacity	(176,781)	S	-	(58,264)	-	(58,264)	-	-	-	-
366	Structures and Improvements	Capacity	(3,504,926)	S	-	(1,155,156)	-	(1,155,156)	-	-	-	-
367	Mains	Capacity	(113,084,817)	S	-	(37,270,557)	-	(37,270,557)	-	-	-	-
368	Compressor Station Equipment	Capacity	(6,402,099)	S	-	(2,110,007)	-	(2,110,007)	-	-	-	-
369	M&R Station Equipment	Capacity	(9,337,011)	S	-	(3,077,297)	-	(3,077,297)	-	-	-	-
370	Communication Equipment	Capacity	(3,731,513)	S	-	(1,229,834)	-	(1,229,834)	-	-	-	-
	Total		(136,237,148)		-	(44,901,115)	-	(44,901,115)	-	-	-	-

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	IIT/ITS Customer	IIT/ITS Capacity	IIT/ITS Commodity	IIT/ITS Total
	Distribution Plant							
374	Land and Land Rights	Allocation	357,560	G	-	-	-	-
375	Structures and Improvements	Allocation	72,739	G	-	-	-	-
376	Mains	Allocation	197,022,713	S.1	-	-	-	-
377	Cathodic Protection Main/Svc	Capacity	-	S.1	-	-	-	-
378	M&R Station Equipment - General	Capacity	1,791,521	D.2	-	-	-	-
379	M&R Station Equipment - City Gate	Capacity	2,089,740	D.2	-	-	-	-
380	Services	Customer	127,356,493	B.1	-	-	-	-
381	Meters	Customer	19,713,735	B.1	-	-	-	-
382	Meter Installations	Customer	41,234,128	B.1	-	-	-	-
383	House Regulators	Customer	253,596	B.1	-	-	-	-
385	Industrial M&R Station Equipment	Capacity	2,430,764	D.2	-	-	-	-
387	Other Equipment	Allocation	6,770,018	G	-	-	-	-
	Total		399,093,006		-	-	-	-
389-398	**General Plant**	Allocation	48,249,137	F	98	50,101	-	50,199
	Completed Not Classified	Allocation	-	H	-	-	-	-
	Construction Work in Progress	Allocation	-	H	-	-	-	-
	TOTAL GROSS GAS UTILITY PLANT		703,377,794		98	1,943,249	-	1,943,347
	DEPRECIATION RESERVE							
	Production and Gathering Plant							
301	Organization	Capacity	(228,587)	D	-	-	-	-
302	Franchises and Consents	Capacity	7,710	D	-	-	-	-
332	Field Lines	Capacity	(244,651)	D	-	-	-	-
334	Field M&R Station Equipment	Capacity	(148,406)	D	-	-	-	-
	Total		(613,933)		-	-	-	-
	Transmission Plant							
365.1	Land and Land Rights	Capacity	-	S	-	-	-	-
365.2	Rights-of-Way	Capacity	(176,781)	S	-	(1,311)	-	(1,311)
366	Structures and Improvements	Capacity	(3,504,926)	S	-	(25,996)	-	(25,996)
367	Mains	Capacity	(113,084,817)	S	-	(838,755)	-	(838,755)
368	Compressor Station Equipment	Capacity	(6,402,099)	S	-	(47,485)	-	(47,485)
369	M&R Station Equipment	Capacity	(9,337,011)	S	-	(69,253)	-	(69,253)
370	Communication Equipment	Capacity	(3,731,513)	S	-	(27,677)	-	(27,677)
	Total		(136,237,148)		-	(1,010,477)	-	(1,010,477)

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G1 Customer	G1 Capacity	G1 Commodity	G1 Total	G2 Customer	G2 Capacity	G2 Commodity	G2 Total
	Distribution Plant											
374	Land and Land Rights	Allocation	31,903	G	11,458	9,955	-	21,413	1,163	1,031	-	2,194
375	Structures and Improvements	Allocation	(71,108)	G	(25,539)	(22,187)	-	(47,726)	(2,592)	(2,297)	-	(4,889)
376	Mains	Allocation	(106,496,744)	S.1	-	(63,687,789)	-	(63,687,789)	-	(6,598,777)	-	(6,598,777)
377	Cathodic Protection Main/Svc	Allocation	(829,526)	S.1	-	(496,078)	-	(496,078)	-	(51,399)	-	(51,399)
378	M&R Station Equipment - General	Capacity	(1,359,437)	D.2	-	(625,049)	-	(625,049)	-	(63,305)	-	(63,305)
379	M&R Station Equipment - City Gate	Capacity	(605,192)	D.2	-	(278,258)	-	(278,258)	-	(28,182)	-	(28,182)
380	Services	Customer	(83,829,932)	B.1	(63,581,227)	-	-	(63,581,227)	(6,452,811)	-	-	(6,452,811)
381	Meters	Customer	(6,981,014)	B.1	(5,294,785)	-	-	(5,294,785)	(537,364)	-	-	(537,364)
382	Meter Installations	Customer	(15,672,362)	B.1	(11,886,781)	-	-	(11,886,781)	(1,206,380)	-	-	(1,206,380)
383	House Regulators	Customer	(413,866)	B.1	(313,899)	-	-	(313,899)	(31,857)	-	-	(31,857)
385	Industrial M&R Station Equipment	Capacity	(731,129)	D.2	-	(336,162)	-	(336,162)	-	(34,047)	-	(34,047)
387	Other Equipment	Allocation	(3,356,248)	G	(1,205,414)	(1,047,220)	-	(2,252,634)	(122,337)	(108,431)	-	(230,767)
	Total		(220,314,655)		(82,296,186)	(66,482,789)	-	(148,778,975)	(8,352,178)	(6,885,408)	-	(15,237,586)
389-398	**General Plant**	Allocation	(34,021,691)	F	(17,972,458)	(6,499,447)	-	(24,471,905)	(1,239,824)	(669,328)	-	(1,909,153)
	TOTAL DEPRECIATION RESERVE		(391,187,427)		(100,268,644)	(127,425,321)	-	(227,693,965)	(9,592,002)	(13,177,336)	-	(22,769,338)
	NET GAS UTILITY PLANT IN SERVICE		312,190,367		70,818,414	106,601,400	-	177,419,814	6,943,008	11,023,825	-	17,966,833
	Other Assets											
	Gas Stored Underground	Allocation	52,204,057	S.1	-	31,219,368	-	31,219,368	-	3,234,681	-	3,234,681
	Unamortized Software	Allocation	4,927,047	B	3,525,959	-	-	3,525,959	357,847	-	-	357,847
	ROU Finance	Allocation	-	B	-	-	-	-	-	-	-	-
	ROU Assets	Allocation	-	B	-	-	-	-	-	-	-	-
	Total		57,131,104		3,525,959	31,219,368	-	34,745,327	357,847	3,234,681	-	3,592,528
	Working Capital											
	Cash Working Capital	Allocation	6,950,657	R	2,978,995	1,526,165	54,513	4,559,673	236,274	157,445	5,780	399,499
	Materials and Supplies	Allocation	15,038,013	Q	6,646,354	3,180,367	125,761	9,952,482	522,908	328,014	13,335	864,256
	Prepayments	Allocation	5,174,966	Q	2,287,181	1,094,446	43,278	3,424,904	179,946	112,878	4,589	297,413
	Total		27,163,636		11,912,530	5,800,978	223,551	17,937,060	939,127	598,337	23,704	1,561,168
	Regulatory Assets											
	Homer CIAC Surcharge	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Reg Asset-LT Gas Supply (RCA)	Allocation	4,551,832	E	-	-	1,526,280	1,526,280	-	-	161,838	161,838
	Rate Case - 2024	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Homer Uncollected Carrying Cost	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Earthquake Costs	Allocation	762,138	O.1	280,475	242,660	5,705	528,840	23,028	25,070	605	48,703
	2021 TY Rate Case	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Other Deferred Assets	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Demand Side Management	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Total		5,313,970		280,475	242,660	1,531,985	2,055,120	23,028	25,070	162,443	210,540

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G3 Customer	G3 Capacity	G3 Commodity	G3 Total	G4 Customer	G4 Capacity	G4 Commodity	G4 Total
	Distribution Plant											
374	Land and Land Rights	Allocation	31,903	G	1,577	2,044	-	3,621	909	3,607	-	4,516
375	Structures and Improvements	Allocation	(71,108)	G	(3,515)	(4,555)	-	(8,070)	(2,026)	(8,040)	-	(10,067)
376	Mains	Allocation	(106,496,744)	S.1	-	(13,093,380)	-	(13,093,380)	-	(23,116,797)	-	(23,116,797)
377	Cathodic Protection Main/Svc	Allocation	(829,526)	S.1	-	(101,987)	-	(101,987)	-	(180,062)	-	(180,062)
378	M&R Station Equipment - General	Capacity	(1,359,437)	D.2	-	(122,409)	-	(122,409)	-	(214,590)	-	(214,590)
379	M&R Station Equipment - City Gate	Capacity	(605,192)	D.2	-	(54,494)	-	(54,494)	-	(95,531)	-	(95,531)
380	Services	Customer	(83,829,932)	B.1	(8,751,108)	-	-	(8,751,108)	(5,044,786)	-	-	(5,044,786)
381	Meters	Customer	(6,981,014)	B.1	(728,757)	-	-	(728,757)	(420,109)	-	-	(420,109)
382	Meter Installations	Customer	(15,672,362)	B.1	(1,636,057)	-	-	(1,636,057)	(943,144)	-	-	(943,144)
383	House Regulators	Customer	(413,866)	B.1	(43,204)	-	-	(43,204)	(24,906)	-	-	(24,906)
385	Industrial M&R Station Equipment	Capacity	(731,129)	D.2	-	(65,834)	-	(65,834)	-	(115,410)	-	(115,410)
387	Other Equipment	Allocation	(3,356,248)	G	(165,909)	(214,988)	-	(380,897)	(95,642)	(379,492)	-	(475,134)
	Total		(220,314,655)		(11,326,973)	(13,655,604)	-	(24,982,577)	(6,529,705)	(24,106,313)	-	(30,636,019)
389-398	**General Plant**	Allocation	(34,021,691)	F	(1,383,824)	(1,319,105)	-	(2,702,930)	(718,389)	(2,324,637)	-	(3,043,026)
	TOTAL DEPRECIATION RESERVE		(391,187,427)		(12,710,797)	(26,090,881)	-	(38,801,678)	(7,248,094)	(46,037,707)	-	(53,285,801)
	NET GAS UTILITY PLANT IN SERVICE		312,190,367		9,291,451	21,826,830	-	31,118,281	5,323,097	38,513,665	-	43,836,762
	Other Assets											
	Gas Stored Underground	Allocation	52,204,057	S.1	-	6,418,296	-	6,418,296	-	11,331,713	-	11,331,713
	Unamortized Software	Allocation	4,927,047	B	485,301	-	-	485,301	279,764	-	-	279,764
	ROU Finance	Allocation	-	B	-	-	-	-	-	-	-	-
	ROU Assets	Allocation	-	B	-	-	-	-	-	-	-	-
	Total		57,131,104		485,301	6,418,296	-	6,903,597	279,764	11,331,713	-	11,611,477
	Working Capital											
	Cash Working Capital	Allocation	6,950,657	R	286,775	310,902	11,759	609,436	156,345	548,192	20,900	725,437
	Materials and Supplies	Allocation	15,038,013	Q	631,912	647,534	27,129	1,306,576	343,686	1,141,662	48,217	1,533,564
	Prepayments	Allocation	5,174,966	Q	217,457	222,833	9,336	449,626	118,271	392,875	16,593	527,739
	Total		27,163,636		1,136,144	1,181,270	48,224	2,365,639	618,302	2,082,729	85,710	2,786,740
	Regulatory Assets											
	Homer CIAC Surcharge	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Reg Asset-LT Gas Supply (RCA)	Allocation	4,551,832	E	-	-	329,248	329,248	-	-	585,176	585,176
	Rate Case - 2024	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Homer Uncollected Carrying Cost	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Earthquake Costs	Allocation	762,138	O.1	28,460	49,584	1,231	79,275	15,668	87,465	2,187	105,321
	2021 TY Rate Case	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Other Deferred Assets	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Demand Side Management	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Total		5,313,970		28,460	49,584	330,478	408,522	15,668	87,465	587,363	690,497

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	VLFT Customer	VLFT Capacity	VLFT Commodity	VLFT Total	MSFT Customer	MSFT Capacity	MSFT Commodity	MSFT Total
	Distribution Plant											
374	Land and Land Rights	Allocation	31,903	G	-	160	-	160	-	-	-	-
375	Structures and Improvements	Allocation	(71,108)	G	-	(356)	-	(356)	-	-	-	-
376	Mains	Allocation	(106,496,744)	S.1	-	-	-	-	-	-	-	-
377	Cathodic Protection Main/Svc	Allocation	(829,526)	S.1	-	-	-	-	-	-	-	-
378	M&R Station Equipment - General	Capacity	(1,359,437)	D.2	-	(334,084)	-	(334,084)	-	-	-	-
379	M&R Station Equipment - City Gate	Capacity	(605,192)	D.2	-	(148,727)	-	(148,727)	-	-	-	-
380	Services	Customer	(83,829,932)	B.1	-	-	-	-	-	-	-	-
381	Meters	Customer	(6,981,014)	B.1	-	-	-	-	-	-	-	-
382	Meter Installations	Customer	(15,672,362)	B.1	-	-	-	-	-	-	-	-
383	House Regulators	Customer	(413,866)	B.1	-	-	-	-	-	-	-	-
385	Industrial M&R Station Equipment	Capacity	(731,129)	D.2	-	(179,676)	-	(179,676)	-	-	-	-
387	Other Equipment	Allocation	(3,356,248)	G	-	(16,815)	-	(16,815)	-	-	-	-
	Total		(220,314,655)		-	(679,499)	-	(679,499)	-	-	-	-
389-398	**General Plant**	Allocation	(34,021,691)	F	(553)	(1,858,728)	-	(1,859,281)	-	-	-	-
	TOTAL DEPRECIATION RESERVE		(391,187,427)		(553)	(47,590,218)	-	(47,590,770)	-	-	-	-
	NET GAS UTILITY PLANT IN SERVICE		312,190,367		231	40,950,974	-	40,951,205	-	-	-	-
	Other Assets											
	Gas Stored Underground	Allocation	52,204,057	S.1	-	-	-	-	-	-	-	-
	Unamortized Software	Allocation	4,927,047	B	247,267	-	-	247,267	-	-	-	-
	ROU Finance	Allocation	-	B	-	-	-	-	-	-	-	-
	ROU Assets	Allocation	-	B	-	-	-	-	-	-	-	-
	Total		57,131,104		247,267	-	-	247,267	-	-	-	-
	Working Capital											
	Cash Working Capital	Allocation	6,950,657	R	18,389	554,791	67,209	640,390	-	-	-	-
	Materials and Supplies	Allocation	15,038,013	Q	42,423	1,149,101	155,052	1,346,577	-	-	-	-
	Prepayments	Allocation	5,174,966	Q	14,599	395,435	53,358	463,392	-	-	-	-
	Total		27,163,636		75,411	2,099,327	275,619	2,450,358	-	-	-	-
	Regulatory Assets											
	Homer CIAC Surcharge	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Reg Asset-LT Gas Supply (RCA)	Allocation	4,551,832	E	-	-	1,881,769	1,881,769	-	-	-	-
	Rate Case - 2024	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Homer Uncollected Carrying Cost	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Earthquake Costs	Allocation	762,138	O.1	-	-	-	-	-	-	-	-
	2021 TY Rate Case	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Other Deferred Assets	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Demand Side Management	Allocation	-	O.1	-	-	-	-	-	-	-	-
	Total		5,313,970		-	-	1,881,769	1,881,769	-	-	-	-

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	IIT/ITS Customer	IIT/ITS Capacity	IIT/ITS Commodity	IIT/ITS Total
	Distribution Plant							
374	Land and Land Rights	Allocation	31,903	G	-	-	-	-
375	Structures and Improvements	Allocation	(71,108)	G	-	-	-	-
376	Mains	Allocation	(106,496,744)	S.1	-	-	-	-
377	Cathodic Protection Main/Svc	Allocation	(829,526)	S.1	-	-	-	-
378	M&R Station Equipment - General	Capacity	(1,359,437)	D.2	-	-	-	-
379	M&R Station Equipment - City Gate	Capacity	(605,192)	D.2	-	-	-	-
380	Services	Customer	(83,829,932)	B.1	-	-	-	-
381	Meters	Customer	(6,981,014)	B.1	-	-	-	-
382	Meter Installations	Customer	(15,672,362)	B.1	-	-	-	-
383	House Regulators	Customer	(413,866)	B.1	-	-	-	-
385	Industrial M&R Station Equipment	Capacity	(731,129)	D.2	-	-	-	-
387	Other Equipment	Allocation	(3,356,248)	G	-	-	-	-
	Total		(220,314,655)		-	-	-	-
389-398	**General Plant**	Allocation	(34,021,691)	F	(69)	(35,328)	-	(35,397)
	TOTAL DEPRECIATION RESERVE		(391,187,427)		(69)	(1,045,805)	-	(1,045,874)
	NET GAS UTILITY PLANT IN SERVICE		312,190,367		29	897,443	-	897,472
	Other Assets							
	Gas Stored Underground	Allocation	52,204,057	S.1	-	-	-	-
	Unamortized Software	Allocation	4,927,047	B	30,908	-	-	30,908
	ROU Finance	Allocation	-	B	-	-	-	-
	ROU Assets	Allocation	-	B	-	-	-	-
	Total		57,131,104		30,908	-	-	30,908
	Working Capital							
	Cash Working Capital	Allocation	6,950,657	R	2,299	11,512	2,412	16,222
	Materials and Supplies	Allocation	15,038,013	Q	5,303	23,691	5,564	34,558
	Prepayments	Allocation	5,174,966	Q	1,825	8,153	1,915	11,892
	Total		27,163,636		9,426	43,356	9,890	62,672
	Regulatory Assets							
	Homer CIAC Surcharge	Allocation	-	O.1	-	-	-	-
	Reg Asset-LT Gas Supply (RCA)	Allocation	4,551,832	E	-	-	67,522	67,522
	Rate Case - 2024	Allocation	-	O.1	-	-	-	-
	Homer Uncollected Carrying Cost	Allocation	-	O.1	-	-	-	-
	Earthquake Costs	Allocation	762,138	O.1	-	-	-	-
	2021 TY Rate Case	Allocation	-	O.1	-	-	-	-
	Other Deferred Assets	Allocation	-	O.1	-	-	-	-
	Demand Side Management	Allocation	-	O.1	-	-	-	-
	Total		5,313,970		-	-	67,522	67,522

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G1 Customer	G1 Capacity	G1 Commodity	G1 Total	G2 Customer	G2 Capacity	G2 Commodity	G2 Total
	Non-Investor Supplied Assets											
	Construction Advances	Customer	(29,371,143)	B.1	(22,276,689)	-	-	(22,276,689)	(2,260,844)	-	-	(2,260,844)
	Deferred Income Taxes	Allocation	(11,103,723)	N	(2,518,810)	(3,791,509)	-	(6,310,318)	(246,943)	(392,086)	-	(639,029)
	Net Asset Retirement Obligation	Allocation	(274,384)	N	(62,242)	(93,692)	-	(155,934)	(6,102)	(9,689)	-	(15,791)
			(40,749,251)		(24,857,741)	(3,885,201)	-	(28,742,941)	(2,513,890)	(401,775)	-	(2,915,665)
	TOTAL RATE BASE		361,049,827	S.1	61,679,638	139,979,205	1,755,536	203,414,380	5,749,120	14,480,137	186,147	20,415,404
	DEPRECIATION AND AMORT.											
	Production and Gathering Plant											
301	Organization	Capacity	-	D	-	-	-	-	-	-	-	-
302	Franchises and Consents	Capacity	-	D	-	-	-	-	-	-	-	-
332	Field Lines	Capacity	4,238	D	-	1,948	-	1,948	-	197	-	197
334	Field M&R Station Equipment	Capacity	1,921	D	-	883	-	883	-	89	-	89
	Total		6,159		-	2,832	-	2,832	-	287	-	287
	Transmission Plant											
365.1	Land and Land Rights	Capacity	-	S	-	-	-	-	-	-	-	-
365.2	Rights-of-Way	Capacity	3,475	S	-	1,381	-	1,381	-	143	-	143
366	Structures and Improvements	Capacity	218,514	S	-	86,870	-	86,870	-	8,972	-	8,972
367	Mains	Capacity	3,251,875	S	-	1,292,776	-	1,292,776	-	133,525	-	133,525
368	Compressor Station Equipment	Capacity	420,211	S	-	167,054	-	167,054	-	17,254	-	17,254
369	M&R Station Equipment	Capacity	804,351	S	-	319,768	-	319,768	-	33,027	-	33,027
370	Communication Equipment	Capacity	352,941	S	-	140,311	-	140,311	-	14,492	-	14,492
	Total		5,051,368		-	2,008,161	-	2,008,161	-	207,413	-	207,413
	Distribution Plant											
374	Land and Land Rights	Allocation	1,113	G	400	347	-	747	41	36	-	77
375	Structures and Improvements	Allocation	657	G	236	205	-	441	24	21	-	45
376	Mains	Allocation	3,549,966	S.1	-	2,122,971	-	2,122,971	-	219,964	-	219,964
377	Cathodic Protection Main/Svc	Allocation	60,801	S.1	-	36,361	-	36,361	-	3,767	-	3,767
378	M&R Station Equipment - General	Capacity	42,008	D.2	-	19,315	-	19,315	-	1,956	-	1,956
379	M&R Station Equipment - City Gate	Capacity	44,286	D.2	-	20,362	-	20,362	-	2,062	-	2,062
380	Services	Customer	4,074,478	B.1	3,090,308	-	-	3,090,308	313,633	-	-	313,633
381	Meters	Customer	885,108	B.1	671,315	-	-	671,315	68,131	-	-	68,131
382	Meter Installations	Customer	682,574	B.1	517,702	-	-	517,702	52,541	-	-	52,541
383	House Regulators	Customer	4,276	B.1	3,243	-	-	3,243	329	-	-	329
385	Industrial M&R Station Equipment	Capacity	56,144	D.2	-	25,814	-	25,814	-	2,614	-	2,614
387	Other Equipment	Allocation	173,016	G	62,140	53,985	-	116,124	6,307	5,590	-	11,896
	Total		9,574,429		4,345,343	2,279,360	-	6,624,703	441,006	236,011	-	677,017
389-398	**General Plant**	Allocation	4,582,688	F	2,420,872	875,469	-	3,296,342	167,003	90,158	-	257,161
407.3	**Amortization of Reg Asset**	Allocation	1,517,277	E	-	-	508,760	508,760	-	-	53,946	53,946
	TOTAL DEPRECIATION AND AMORT.		20,731,921		6,766,216	5,165,822	508,760	12,440,797	608,009	533,869	53,946	1,195,824

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	G3 Customer	G3 Capacity	G3 Commodity	G3 Total	G4 Customer	G4 Capacity	G4 Commodity	G4 Total
	Non-Investor Supplied Assets											
	Construction Advances	Customer	(29,371,143)	B.1	(3,066,089)	-	-	(3,066,089)	(1,767,521)	-	-	(1,767,521)
	Deferred Income Taxes	Allocation	(11,103,723)	N	(330,470)	(776,318)	-	(1,106,789)	(189,327)	(1,369,822)	-	(1,559,149)
	Net Asset Retirement Obligation	Allocation	(274,384)	N	(8,166)	(19,184)	-	(27,350)	(4,678)	(33,850)	-	(38,528)
			(40,749,251)		(3,404,726)	(795,502)	-	(4,200,228)	(1,961,527)	(1,403,671)	-	(3,365,198)
	TOTAL RATE BASE		361,049,827	S.1	7,536,631	28,680,477	378,703	36,595,811	4,275,304	50,611,902	673,073	55,560,278
	DEPRECIATION AND AMORT.											
	Production and Gathering Plant											
301	Organization	Capacity	-	D	-	-	-	-	-	-	-	-
302	Franchises and Consents	Capacity	-	D	-	-	-	-	-	-	-	-
332	Field Lines	Capacity	4,238	D	-	382	-	382	-	669	-	669
334	Field M&R Station Equipment	Capacity	1,921	D	-	173	-	173	-	303	-	303
	Total		6,159		-	555	-	555	-	972	-	972
	Transmission Plant											
365.1	Land and Land Rights	Capacity	-	S	-	-	-	-	-	-	-	-
365.2	Rights-of-Way	Capacity	3,475	S	-	282	-	282	-	498	-	498
366	Structures and Improvements	Capacity	218,514	S	-	17,741	-	17,741	-	31,292	-	31,292
367	Mains	Capacity	3,251,875	S	-	264,015	-	264,015	-	465,685	-	465,685
368	Compressor Station Equipment	Capacity	420,211	S	-	34,116	-	34,116	-	60,176	-	60,176
369	M&R Station Equipment	Capacity	804,351	S	-	65,304	-	65,304	-	115,187	-	115,187
370	Communication Equipment	Capacity	352,941	S	-	28,655	-	28,655	-	50,543	-	50,543
	Total		5,051,368		-	410,113	-	410,113	-	723,381	-	723,381
	Distribution Plant											
374	Land and Land Rights	Allocation	1,113	G	55	71	-	126	32	126	-	158
375	Structures and Improvements	Allocation	657	G	32	42	-	75	19	74	-	93
376	Mains	Allocation	3,549,966	S.1	-	436,455	-	436,455	-	770,576	-	770,576
377	Cathodic Protection Main/Svc	Allocation	60,801	S.1	-	7,475	-	7,475	-	13,198	-	13,198
378	M&R Station Equipment - General	Capacity	42,008	D.2	-	3,783	-	3,783	-	6,631	-	6,631
379	M&R Station Equipment - City Gate	Capacity	44,286	D.2	-	3,988	-	3,988	-	6,991	-	6,991
380	Services	Customer	4,074,478	B.1	425,340	-	-	425,340	245,197	-	-	245,197
381	Meters	Customer	885,108	B.1	92,398	-	-	92,398	53,265	-	-	53,265
382	Meter Installations	Customer	682,574	B.1	71,255	-	-	71,255	41,076	-	-	41,076
383	House Regulators	Customer	4,276	B.1	446	-	-	446	257	-	-	257
385	Industrial M&R Station Equipment	Capacity	56,144	D.2	-	5,055	-	5,055	-	8,862	-	8,862
387	Other Equipment	Allocation	173,016	G	8,553	11,083	-	19,635	4,930	19,563	-	24,493
	Total		9,574,429		598,079	467,952	-	1,066,031	344,777	826,021	-	1,170,798
389-398	**General Plant**	Allocation	4,582,688	F	186,400	177,682	-	364,082	96,766	313,126	-	409,893
407.3	**Amortization of Reg Asset**	Allocation	1,517,277	E	-	-	109,749	109,749	-	-	195,059	195,059
	TOTAL DEPRECIATION AND AMORT.		20,731,921		784,478	1,056,302	109,749	1,950,530	441,543	1,863,501	195,059	2,500,103

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	VLFT Customer	VLFT Capacity	VLFT Commodity	VLFT Total	MSFT Customer	MSFT Capacity	MSFT Commodity	MSFT Total
	Non-Investor Supplied Assets											
	Construction Advances	Customer	(29,371,143)	B.1	-	-	-	-	-	-	-	-
	Deferred Income Taxes	Allocation	(11,103,723)	N	(8)	(1,456,510)	-	(1,456,518)	-	-	-	-
	Net Asset Retirement Obligation	Allocation	(274,384)	N	(0)	(35,992)	-	(35,992)	-	-	-	-
			(40,749,251)		(8)	(1,492,501)	-	(1,492,510)	-	-	-	-
	TOTAL RATE BASE		361,049,827	S.1	322,901	41,557,800	2,157,388	44,038,089	-	-	-	-
	DEPRECIATION AND AMORT.											
	Production and Gathering Plant											
301	Organization	Capacity	-	D	-	-	-	-	-	-	-	-
302	Franchises and Consents	Capacity	-	D	-	-	-	-	-	-	-	-
332	Field Lines	Capacity	4,238	D	-	1,041	-	1,041	-	-	-	-
334	Field M&R Station Equipment	Capacity	1,921	D	-	472	-	472	-	-	-	-
	Total		6,159		-	1,514	-	1,514	-	-	-	-
	Transmission Plant											
365.1	Land and Land Rights	Capacity	-	S	-	-	-	-	-	-	-	-
365.2	Rights-of-Way	Capacity	3,475	S	-	1,145	-	1,145	-	-	-	-
366	Structures and Improvements	Capacity	218,514	S	-	72,018	-	72,018	-	-	-	-
367	Mains	Capacity	3,251,875	S	-	1,071,755	-	1,071,755	-	-	-	-
368	Compressor Station Equipment	Capacity	420,211	S	-	138,493	-	138,493	-	-	-	-
369	M&R Station Equipment	Capacity	804,351	S	-	265,098	-	265,098	-	-	-	-
370	Communication Equipment	Capacity	352,941	S	-	116,323	-	116,323	-	-	-	-
	Total		5,051,368		-	1,664,833	-	1,664,833	-	-	-	-
	Distribution Plant											
374	Land and Land Rights	Allocation	1,113	G	-	6	-	6	-	-	-	-
375	Structures and Improvements	Allocation	657	G	-	3	-	3	-	-	-	-
376	Mains	Allocation	3,549,966	S.1	-	-	-	-	-	-	-	-
377	Cathodic Protection Main/Svc	Allocation	60,801	S.1	-	-	-	-	-	-	-	-
378	M&R Station Equipment - General	Capacity	42,008	D.2	-	10,324	-	10,324	-	-	-	-
379	M&R Station Equipment - City Gate	Capacity	44,286	D.2	-	10,883	-	10,883	-	-	-	-
380	Services	Customer	4,074,478	B.1	-	-	-	-	-	-	-	-
381	Meters	Customer	885,108	B.1	-	-	-	-	-	-	-	-
382	Meter Installations	Customer	682,574	B.1	-	-	-	-	-	-	-	-
383	House Regulators	Customer	4,276	B.1	-	-	-	-	-	-	-	-
385	Industrial M&R Station Equipment	Capacity	56,144	D.2	-	13,797	-	13,797	-	-	-	-
387	Other Equipment	Allocation	173,016	G	-	867	-	867	-	-	-	-
	Total		9,574,429		-	35,880	-	35,880	-	-	-	-
389-398	**General Plant**	Allocation	4,582,688	F	74	250,369	-	250,443	-	-	-	-
407.3	**Amortization of Reg Asset**	Allocation	1,517,277	E	-	-	627,256	627,256	-	-	-	-
	TOTAL DEPRECIATION AND AMORT.		20,731,921		74	1,952,595	627,256	2,579,926	-	-	-	-

ENSTAR NATURAL GAS COMPANY, LLC

COST ALLOCATION BY CUSTOMER CLASS
For the Year Ended December 31, 2024

Acct No.	Description	Cost Classification	Total	Alloc. Factor	IIT/ITS Customer	Capacity	Commodity	Total
	Non-Investor Supplied Assets							
	Construction Advances	Customer	(29,371,143)	B.1	-	-	-	-
	Deferred Income Taxes	Allocation	(11,103,723)	N	(1)	(31,920)	-	(31,921)
	Net Asset Retirement Obligation	Allocation	(274,384)	N	(0)	(789)	-	(789)
			(40,749,251)		(1)	(32,708)	-	(32,709)
	TOTAL RATE BASE		361,049,827	S.1	40,363	908,091	77,412	1,025,865
	DEPRECIATION AND AMORT.							
	Production and Gathering Plant							
301	Organization	Capacity	-	D	-	-	-	-
302	Franchises and Consents	Capacity	-	D	-	-	-	-
332	Field Lines	Capacity	4,238	D	-	-	-	-
334	Field M&R Station Equipment	Capacity	1,921	D	-	-	-	-
	Total		6,159		-	-	-	-
	Transmission Plant							
365.1	Land and Land Rights	Capacity	-	S	-	-	-	-
365.2	Rights-of-Way	Capacity	3,475	S	-	26	-	26
366	Structures and Improvements	Capacity	218,514	S	-	1,621	-	1,621
367	Mains	Capacity	3,251,875	S	-	24,119	-	24,119
368	Compressor Station Equipment	Capacity	420,211	S	-	3,117	-	3,117
369	M&R Station Equipment	Capacity	804,351	S	-	5,966	-	5,966
370	Communication Equipment	Capacity	352,941	S	-	2,618	-	2,618
	Total		5,051,368		-	37,466	-	37,466
	Distribution Plant							
374	Land and Land Rights	Allocation	1,113	G	-	-	-	-
375	Structures and Improvements	Allocation	657	G	-	-	-	-
376	Mains	Allocation	3,549,966	S.1	-	-	-	-
377	Cathodic Protection Main/Svc	Allocation	60,801	S.1	-	-	-	-
378	M&R Station Equipment - General	Capacity	42,008	D.2	-	-	-	-
379	M&R Station Equipment - City Gate	Capacity	44,286	D.2	-	-	-	-
380	Services	Customer	4,074,478	B.1	-	-	-	-
381	Meters	Customer	885,108	B.1	-	-	-	-
382	Meter Installations	Customer	682,574	B.1	-	-	-	-
383	House Regulators	Customer	4,276	B.1	-	-	-	-
385	Industrial M&R Station Equipment	Capacity	56,144	D.2	-	-	-	-
387	Other Equipment	Allocation	173,016	G	-	-	-	-
	Total		9,574,429		-	-	-	-
389-398	**General Plant**	Allocation	4,582,688	F	9	4,759	-	4,768
407.3	**Amortization of Reg Asset**	Allocation	1,517,277	E	-	-	22,507	22,507
	TOTAL DEPRECIATION AND AMORT.		20,731,921		9	42,225	22,507	64,742

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	G1 Customer	G1 Capacity	G1 Commodity	G2 Customer	G2 Capacity	G2 Commodity
	Customers						
	Number of Customers	141,889			5,947		
A	Allocation Factor	0.92968			0.03896		
	Weighted Delivery Points						
	Delivery Points	141,889			5,947		
	Customer Weighting Factor	1.0000			2.4216		
	Weighted Delivery Points	141,889			14,400		
B	Allocation Factor	0.71563			0.07263		
	Weighted Delivery Points (Ex. Large Customers)						
	Delivery Points	141,889			14,400		
B.1	Allocation Factor	0.75845			0.07698		
	Combined Customer Factor						
	One-half Factor A	0.4648			0.0195		
	One-half Factor B	0.3578			0.0363		
C	Allocation factor	0.8227			0.0558		
	Combined Factor (Ex. Large Customers)						
	Combined Customer Factor	0.8227			0.0558		
C.1	Allocation Factor	0.8466			0.0574		
	Peak Demand						
	3-Day Average 2/1/2024 - 2/3/2024						
	Peak Demand		147,445			14,933	
D	Allocation Factor		0.4598			0.0466	
	Peak Demand (Ex. Large Customers)						
	3-Day Average 2/1/2024 - 2/3/2024						
	Peak Demand		147,445			14,933	
D.1	Allocation Factor		0.6096			0.0617	
	Peak Demand (Ex. MSFT)						
	3-Day Average 2/1/2024 - 2/3/2024						
	Peak Demand		147,445			14,933	
D.2	Allocation Factor		0.4598			0.0466	

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	G3 Customer	G3 Capacity	G3 Commodity	G4 Customer	G4 Capacity	G4 Commodity
	Customers						
	Number of Customers	3,758			1,018		
A	Allocation Factor	0.02462			0.00667		
	Weighted Delivery Points						
	Delivery Points	3,758			1,018		
	Customer Weighting Factor	5.1966			11.0572		
	Weighted Delivery Points	19,529			11,258		
B	Allocation Factor	0.09850			0.05678		
	Weighted Delivery Points (Ex. Large Customers)						
	Delivery Points	19,529			11,258		
B.1	Allocation Factor	0.10439			0.06018		
	Combined Customer Factor						
	One-half Factor A	0.0123			0.0033		
	One-half Factor B	0.0492			0.0284		
C	Allocation factor	0.0616			0.0317		
	Combined Factor (Ex. Large Customers)						
	Combined Customer Factor	0.0616			0.0317		
C.1	Allocation Factor	0.0634			0.0326		
	Peak Demand						
	3-Day Average 2/1/2024 - 2/3/2024						
	Peak Demand		28,876			50,620	
D	Allocation Factor		0.0900			0.1579	
	Peak Demand (Ex. Large Customers)						
	3-Day Average 2/1/2024 - 2/3/2024						
	Peak Demand		28,876			50,620	
D.1	Allocation Factor		0.1194			0.2093	
	Peak Demand (Ex. MSFT)						
	3-Day Average 2/1/2024 - 2/3/2024						
	Peak Demand		28,876			50,620	
D.2	Allocation Factor		0.0900			0.1579	

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	VLFT Customer	VLFT Capacity	VLFT Commodity	MSFT Customer	MSFT Capacity	MSFT Commodity
	Customers						
	Number of Customers	8			-		
A	Allocation Factor	0.00005			0.00000		
	Weighted Delivery Points						
	Delivery Points	8			-		
	Customer Weighting Factor	1,243.7958			-		
	Weighted Delivery Points	9,950			-		
B	Allocation Factor	0.05019			0.00000		
	Weighted Delivery Points (Ex. Large Customers)						
	Delivery Points						
B.1	Allocation Factor						
	Combined Customer Factor						
	One-half Factor A	0.0000			-		
	One-half Factor B	0.0251			-		
C	Allocation factor	0.0251			-		
	Combined Factor (Ex. Large Customers)						
	Combined Customer Factor						
C.1	Allocation Factor						
	Peak Demand						
	3-Day Average 2/1/2024 - 2/3/2024						
	Peak Demand		78,809			-	
D	Allocation Factor		0.2458			-	
	Peak Demand (Ex. Large Customers)						
	3-Day Average 2/1/2024 - 2/3/2024						
	Peak Demand						
D.1	Allocation Factor						
	Peak Demand (Ex. MSFT)						
	3-Day Average 2/1/2024 - 2/3/2024						
	Peak Demand		78,809				
D.2	Allocation Factor		0.2458				

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	Customer	IIT/ITS Capacity	Commodity
	Customers			
	Number of Customers	1		
A	Allocation Factor	0.00001		
	Weighted Delivery Points			
	Delivery Points	1		
	Customer Weighting Factor	1,243.7958		
	Weighted Delivery Points	1,244		
B	Allocation Factor	0.00627		
	Weighted Delivery Points (Ex. Large Customers)			
	Delivery Points			
B.1	Allocation Factor			
	Combined Customer Factor			
	One-half Factor A	0.0000		
	One-half Factor B	0.0031		
C	Allocation factor	0.0031		
	Combined Factor (Ex. Large Customers)			
	Combined Customer Factor			
C.1	Allocation Factor			
	Peak Demand			
	3-Day Average 2/1/2024 - 2/3/2024			
	Peak Demand		-	
D	Allocation Factor		-	
	Peak Demand (Ex. Large Customers)			
	3-Day Average 2/1/2024 - 2/3/2024			
	Peak Demand			
D.1	Allocation Factor			
	Peak Demand (Ex. MSFT)			
	3-Day Average 2/1/2024 - 2/3/2024			
	Peak Demand		-	
D.2	Allocation Factor		-	

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	G1 Customer	G1 Capacity	G1 Commodity	G2 Customer	G2 Capacity	G2 Commodity
	Commodity						
	Annual Volumes			19,414,078			2,058,556
E	Allocation Factor			0.3353			0.0356
	Commodity (Ex. Large Customers)						
	Annual Volumes			19,414,078			2,058,556
E.1	Allocation Factor			0.5865			0.0622
	Payroll						
	Distribution Expense Accounts	4,823,859	2,720,379	-	489,570	279,812	-
	Distribution Allocation Factor	0.4365	0.2461	-	0.0443	0.0253	-
	Weighted on 55% Payroll	0.2401	0.1354	-	0.0244	0.0139	-
	Transmission Expense Accounts	-	2,231,199	-	-	230,450	-
	Transmission Allocation Factor	-	0.3975	-	-	0.0411	-
	Weighted on 14% Payroll	-	0.0557	-	-	0.0057	-
	Number of Customers	0.9297	-	-	0.0390	-	-
	Weighted on 31% Payroll	0.2882	-	-	0.0121	-	-
	Sum of Factors	0.5283	0.1910	-	0.0364	0.0197	-
F	Allocation Factor	0.5283	0.1910	-	0.0364	0.0197	-
	Distribution Plant (Accts 376-386)						
	Amount	66,218,588	57,528,306	-	6,720,475	5,956,557	-
G	Allocation Factor	0.3592	0.3120	-	0.0365	0.0323	-
	Gross Plant (Ex. General Plant)						
	Amount	145,598,743	224,809,286	-	14,776,707	23,251,928	-
H	Allocation Factor	0.2222	0.3432	-	0.0226	0.0355	-
	Production and Gathering Expense (Ex. Purchased Gas and Accts 756 and 807)						
	Amount	-	-	57,957	-	-	6,145
I	Allocation Factor	-	-	0.3353	-	-	0.0356
	Distribution Expense (Accts 871-879)						
	Amount	3,185,568	1,882,418	-	323,301	193,409	-
J	Allocation Factor	0.4272	0.2524	-	0.0434	0.0259	-
	Distribution Expense (Accts 376 and 380)						
	Amount	36,103,244	56,259,827	-	3,664,091	5,829,156	-
K	Allocation Factor	0.2548	0.3971	-	0.0259	0.0411	-
	Distribution Expense (Accts 887-893)						
	Amount	881,229	390,598	-	89,435	40,438	-
L	Allocation Factor	0.4837	0.2144	-	0.0491	0.0222	-

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	G3 Customer	G3 Capacity	G3 Commodity	G4 Customer	G4 Capacity	G4 Commodity
	Commodity						
	Annual Volumes			4,187,988			7,443,359
E	Allocation Factor			0.0723			0.1286
	Commodity (Ex. Large Customers)						
	Annual Volumes			4,187,988			7,443,359
E.1	Allocation Factor			0.1265			0.2248
	Payroll						
	Distribution Expense Accounts	663,940	550,702	-	382,744	970,134	-
	Distribution Allocation Factor	0.0601	0.0498	-	0.0346	0.0878	-
	Weighted on 55% Payroll	0.0330	0.0274	-	0.0190	0.0483	-
	Transmission Expense Accounts	-	455,663	-	-	803,724	-
	Transmission Allocation Factor	-	0.0812	-	-	0.1432	-
	Weighted on 14% Payroll	-	0.0114	-	-	0.0200	-
	Number of Customers	0.0246	-	-	0.0067	-	-
	Weighted on 31% Payroll	0.0076	-	-	0.0021	-	-
	Sum of Factors	0.0407	0.0388	-	0.0211	0.0683	-
F	Allocation Factor	0.0407	0.0388	-	0.0211	0.0683	-
	Distribution Plant (Accts 376-386)						
	Amount	9,114,106	11,810,225	-	5,254,045	20,847,119	-
G	Allocation Factor	0.0494	0.0641	-	0.0285	0.1131	-
	Gross Plant (Ex. General Plant)						
	Amount	20,039,726	46,046,972	-	11,552,381	81,254,601	-
H	Allocation Factor	0.0306	0.0703	-	0.0176	0.1240	-
	Production and Gathering Expense (Ex. Purchased Gas and Accts 756 and 807)						
	Amount	-	-	12,502	-	-	22,221
I	Allocation Factor	-	-	0.0723	-	-	0.1286
	Distribution Expense (Accts 871-879)						
	Amount	438,451	380,182	-	252,756	669,514	-
J	Allocation Factor	0.0588	0.0510	-	0.0339	0.0898	-
	Distribution Expense (Accts 376 and 380)						
	Amount	4,969,130	11,566,288	-	2,864,574	20,420,665	-
K	Allocation Factor	0.0351	0.0816	-	0.0202	0.1441	-
	Distribution Expense (Accts 887-893)						
	Amount	121,289	80,168	-	69,920	141,507	-
L	Allocation Factor	0.0666	0.0440	-	0.0384	0.0777	-

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	VLFT Customer	VLFT Capacity	VLFT Commodity	MSFT Customer	MSFT Capacity	MSFT Commodity
	Commodity						
	Annual Volumes			23,935,854			-
E	Allocation Factor			0.4134			-
	Commodity (Ex. Large Customers)						
	Annual Volumes						
E.1	Allocation Factor						
	Payroll						
	Distribution Expense Accounts	-	170,647	-	-	-	-
	Distribution Allocation Factor	-	0.0154	-	-	-	-
	Weighted on 55% Payroll	-	0.0085	-	-	-	-
	Transmission Expense Accounts	-	1,849,739	-	-	-	-
	Transmission Allocation Factor	-	0.3296	-	-	-	-
	Weighted on 14% Payroll	-	0.0461	-	-	-	-
	Number of Customers	0.0001	-	-	-	-	-
	Weighted on 31% Payroll	0.0000	-	-	-	-	-
	Sum of Factors	0.0000	0.0546	-	-	-	-
F	Allocation Factor	0.0000	0.0546	-	-	-	-
	Distribution Plant (Accts 376-386)						
	Amount	-	923,710	-	-	-	-
G	Allocation Factor	-	0.0050	-	-	-	-
	Gross Plant (Ex. General Plant)						
	Amount	-	85,905,166	-	-	-	-
H	Allocation Factor	-	0.1311	-	-	-	-
	Production and Gathering Expense (Ex. Purchased Gas and Accts 756 and 807)						
	Amount	-	-	71,456	-	-	-
I	Allocation Factor	-	-	0.4134	-	-	-
	Distribution Expense (Accts 871-879)						
	Amount	-	131,968	-	-	-	-
J	Allocation Factor	-	0.0177	-	-	-	-
	Distribution Expense (Accts 376 and 380)						
	Amount	-	-	-	-	-	-
K	Allocation Factor	-	-	-	-	-	-
	Distribution Expense (Accts 887-893)						
	Amount	-	7,316	-	-	-	-
L	Allocation Factor	-	0.0040	-	-	-	-

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	Customer	IIT/ITS Capacity	Commodity
	Commodity			
	Annual Volumes			858,875
E	Allocation Factor			0.0148
	Commodity (Ex. Large Customers)			
	Annual Volumes			
E.1	Allocation Factor			
	Payroll			
	Distribution Expense Accounts	-	-	-
	Distribution Allocation Factor	-	-	-
	Weighted on 55% Payroll	-	-	-
	Transmission Expense Accounts	-	41,627	-
	Transmission Allocation Factor	-	0.0074	-
	Weighted on 14% Payroll	-	0.0010	-
	Number of Customers	0.0000	-	-
	Weighted on 31% Payroll	0.0000	-	-
	Sum of Factors	0.0000	0.0010	-
F	Allocation Factor	0.0000	0.0010	-
	Distribution Plant (Accts 376-386)			
	Amount	-	-	-
G	Allocation Factor	-	-	-
	Gross Plant (Ex. General Plant)			
	Amount	-	1,893,147	-
H	Allocation Factor	-	0.0029	-
	Production and Gathering Expense (Ex. Purchased Gas and Accts 756 and 807)			
	Amount	-	-	2,564
I	Allocation Factor	-	-	0.0148
	Distribution Expense (Accts 871-879)			
	Amount	-	-	-
J	Allocation Factor	-	-	-
	Distribution Expense (Accts 376 and 380]			
	Amount	-	-	-
K	Allocation Factor	-	-	-
	Distribution Expense (Accts 887-893)			
	Amount	-	-	-
L	Allocation Factor	-	-	-

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	G1 Customer	G1 Capacity	G1 Commodity	G2 Customer	G2 Capacity	G2 Commodity
	O&M Expense and Ad Valorem Taxes (Ex. Purchased Gas and A&G)						
	Amount	12,089,965	6,486,008	57,957	1,013,186	668,940	6,145
M	Allocation Factor	0.4180	0.2242	0.0020	0.0350	0.0231	0.0002
	Total Net Plant						
	Amount	70,818,414	106,601,400	-	6,943,008	11,023,825	-
N	Allocation Factor	0.2268	0.3415	-	0.0222	0.0353	-
	Revenue Requirement (Ex. Gas Costs and Other Revenue)						
	Amount	38,751,602	33,526,870	788,208	3,181,653	3,463,721	83,577
O	Allocation Factor	0.3289	0.2846	0.0067	0.0270	0.0294	0.0007
	Revenue Requirement (Ex. Gas Costs, Other Revenue and Large Customers)						
	Amount	38,751,602	33,526,870	788,208	3,181,653	3,463,721	83,577
O.1	Allocation Factor	0.3680	0.3184	0.0075	0.0302	0.0329	0.0008
	Total Rate Base						
	Amount	61,679,638	139,979,205	1,755,536	5,749,120	14,480,137	186,147
P	Allocation Factor	0.1708	0.3877	0.0049	0.0159	0.0401	0.0005
	O&M Expense (Ex. Purchased Gas)						
	Amount	29,950,446	14,331,679	566,717	2,356,377	1,478,128	60,091
Q	Allocation Factor	0.4420	0.2115	0.0084	0.0348	0.0218	0.0009
	O&M Expense and Ad Valorem (Ex. Purchased Gas)						
	Amount	30,969,812	15,866,108	566,717	2,456,315	1,636,805	60,091
R	Allocation Factor	0.4286	0.2196	0.0078	0.0340	0.0227	0.0008

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	G3 Customer	G3 Capacity	G3 Commodity	G4 Customer	G4 Capacity	G4 Commodity
	O&M Expense and Ad Valorem Taxes (Ex. Purchased Gas and A&G)						
	Amount	1,265,133	1,320,542	12,502	700,274	2,328,227	22,221
M	Allocation Factor	0.0437	0.0457	0.0004	0.0242	0.0805	0.0008
	Total Net Plant						
	Amount	9,291,451	21,826,830	-	5,323,097	38,513,665	-
N	Allocation Factor	0.0298	0.0699	-	0.0171	0.1234	-
	Revenue Requirement (Ex. Gas Costs and Other Revenue)						
	Amount	3,932,187	6,850,691	170,032	2,164,765	12,084,590	302,199
O	Allocation Factor	0.0334	0.0581	0.0014	0.0184	0.1026	0.0026
	Revenue Requirement (Ex. Gas Costs, Other Revenue and Large Customers)						
	Amount	3,932,187	6,850,691	170,032	2,164,765	12,084,590	302,199
O.1	Allocation Factor	0.0373	0.0651	0.0016	0.0206	0.1148	0.0029
	Total Rate Base						
	Amount	7,536,631	28,680,477	378,703	4,275,304	50,611,902	673,073
P	Allocation Factor	0.0209	0.0794	0.0010	0.0118	0.1402	0.0019
	O&M Expense (Ex. Purchased Gas)						
	Amount	2,847,585	2,917,983	122,252	1,548,750	5,144,667	217,279
Q	Allocation Factor	0.0420	0.0431	0.0018	0.0229	0.0759	0.0032
	O&M Expense and Ad Valorem (Ex. Purchased Gas)						
	Amount	2,981,327	3,232,160	122,252	1,625,371	5,699,036	217,279
R	Allocation Factor	0.0413	0.0447	0.0017	0.0225	0.0789	0.0030

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	VLFT Customer	VLFT Capacity	VLFT Commodity	MSFT Customer	MSFT Capacity	MSFT Commodity
	O&M Expense and Ad Valorem Taxes (Ex. Purchased Gas and A&G)						
	Amount	190,741	2,609,837	71,456	-	-	-
M	Allocation Factor	0.0066	0.0902	0.0025	-	-	-
	Total Net Plant						
	Amount	231	40,950,974	-	-	-	-
N	Allocation Factor	0.0000	0.1312	-	-	-	-
	Revenue Requirement (Ex. Gas Costs and Other Revenue)						
	Amount	231,911	11,010,856	970,904	-	-	-
O	Allocation Factor	0.0020	0.0935	0.0082	-	-	-
	Revenue Requirement (Ex. Gas Costs, Other Revenue and Large Customers)						
	Amount						
O.1	Allocation Factor						
	Total Rate Base						
	Amount	322,901	41,557,800	2,157,388	-	-	-
P	Allocation Factor	0.0009	0.1151	0.0060	-	-	-
	O&M Expense (Ex. Purchased Gas)						
	Amount	191,171	5,178,191	698,712	-	-	-
Q	Allocation Factor	0.0028	0.0764	0.0103	-	-	-
	O&M Expense and Ad Valorem (Ex. Purchased Gas)						
	Amount	191,174	5,767,642	698,712	-	-	-
R	Allocation Factor	0.0026	0.0798	0.0097	-	-	-

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	Customer	IIT/ITS Capacity	Commodity
	O&M Expense and Ad Valorem Taxes (Ex. Purchased Gas and A&G)			
	Amount	23,843	54,545	2,564
M	Allocation Factor	0.0008	0.0019	0.0001
	Total Net Plant			
	Amount	29	897,443	-
N	Allocation Factor	0.0000	0.0029	-
	Revenue Requirement (Ex. Gas Costs and Other Revenue)			
	Amount	28,989	234,248	34,838
O	Allocation Factor	0.0002	0.0020	0.0003
	Revenue Requirement (Ex. Gas Costs, Other Revenue and Large Customers)			
	Amount			
O.1	Allocation Factor			
	Total Rate Base			
	Amount	40,363	908,091	77,412
P	Allocation Factor	0.0001	0.0025	0.0002
	O&M Expense (Ex. Purchased Gas)			
	Amount	23,896	106,759	25,071
Q	Allocation Factor	0.0004	0.0016	0.0004
	O&M Expense and Ad Valorem (Ex. Purchased Gas)			
	Amount	23,897	119,677	25,071
R	Allocation Factor	0.0003	0.0017	0.0003

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	G1 Customer	G1 Capacity	G1 Commodity	G2 Customer	G2 Capacity	G2 Commodity
	Joint Peak and Average Day Demand						
	1/2 of Allocation Factor D		0.2299			0.0233	
	1/2 of allocation Factor V		0.1677			0.0178	
S	Allocation Factor		0.3975			0.0411	
	Joint Peak and Average Day Demand (Ex. Large Customers)						
	1/2 of Allocation Factor D.1		0.3048			0.0309	
	1/2 of allocation Factor V.1		0.2932			0.0311	
S.1	Allocation Factor		0.5980			0.0620	
	Transmission Expense (Accts 851-866)						
	Amount	-	2,115,747	-	-	218,525	-
T	Allocation Factor	-	0.3975	-	-	0.0411	-
	Distribution Plant (Acct 376)						
	Amount	-	56,259,827	-	-	5,829,156	-
U	Allocation Factor	-	0.5980	-	-	0.0620	-
	Average Day Demand						
	Annual Volume / 365		53,189			5,640	
V	Allocation Factor		0.3353			0.0356	
	Average Day Demand (Ex. Large Customers)						
	Annual Volume / 365		53,189			5,640	
V.1	Allocation Factor		0.5865			0.0622	

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	G3 Customer	G3 Capacity	G3 Commodity	G4 Customer	G4 Capacity	G4 Commodity
	Joint Peak and Average Day Demand						
	1/2 of Allocation Factor D		0.0450			0.0789	
	1/2 of allocation Factor V		0.0362			0.0643	
S	Allocation Factor		0.0812			0.1432	
	Joint Peak and Average Day Demand (Ex. Large Customers)						
	1/2 of Allocation Factor D.1		0.0597			0.1046	
	1/2 of allocation Factor V.1		0.0633			0.1124	
S.1	Allocation Factor		0.1229			0.2171	
	Transmission Expense (Accts 851-866)						
	Amount	-	432,084	-	-	762,136	-
T	Allocation Factor	-	0.0812	-	-	0.1432	-
	Distribution Plant (Acct 376)						
	Amount	-	11,566,288	-	-	20,420,665	-
U	Allocation Factor	-	0.1229	-	-	0.2171	-
	Average Day Demand						
	Annual Volume / 365		11,474			20,393	
V	Allocation Factor		0.0723			0.1286	
	Average Day Demand (Ex. Large Customers)						
	Annual Volume / 365		11,474			20,393	
V.1	Allocation Factor		0.1265			0.2248	

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	VLFT Customer	VLFT Capacity	VLFT Commodity	MSFT Customer	MSFT Capacity	MSFT Commodity
	Joint Peak and Average Day Demand						
	1/2 of Allocation Factor D		0.1229			-	
	1/2 of allocation Factor V		0.2067			-	
S	Allocation Factor		0.3296			-	
	Joint Peak and Average Day Demand (Ex. Large Customers)						
	1/2 of Allocation Factor D.1						
	1/2 of allocation Factor V.1						
S.1	Allocation Factor						
	Transmission Expense (Accts 851-866)						
	Amount	-	1,754,025	-	-	-	-
T	Allocation Factor	-	0.3296	-	-	-	-
	Distribution Plant (Acct 376)						
	Amount	-	-	-	-	-	-
U	Allocation Factor	-	-	-	-	-	-
	Average Day Demand						
	Annual Volume / 365		65,578			-	
V	Allocation Factor		0.4134			-	
	Average Day Demand (Ex. Large Customers)						
	Annual Volume / 365						
V.1	Allocation Factor						

ENSTAR NATURAL GAS COMPANY, LLC

ALLOCATION FACTORS
For the Year Ended December 31, 2024

Alloc. Factor	Description	Customer	IIT/ITS Capacity	Commodity
	Joint Peak and Average Day Demand			
	1/2 of Allocation Factor D		-	
	1/2 of allocation Factor V		0.0074	
S	Allocation Factor		0.0074	
	Joint Peak and Average Day Demand (Ex. Large Customers)			
	1/2 of Allocation Factor D.1			
	1/2 of allocation Factor V.1			
S.1	Allocation Factor			
	Transmission Expense (Accts 851-866)			
	Amount	-	39,473	-
T	Allocation Factor	-	0.0074	-
	Distribution Plant (Acct 376)			
	Amount	-	-	-
U	Allocation Factor	-	-	-
	Average Day Demand			
	Annual Volume / 365		2,353	
V	Allocation Factor		0.0148	
	Average Day Demand (Ex. Large Customers)			
	Annual Volume / 365			
V.1	Allocation Factor			

ENSTAR NATURAL GAS COMPANY, LLC

CUSTOMER WEIGHTINGS FOR PROPOSED CUSTOMER CLASSES
For the Year Ended December 31, 2024

Meter Size	Cost	G1	G2	G3	G4	MSFT	VLFT/IIT/ITS	Totals
G1	225	143,963						32,408,567
G2	545		6,087					3,318,336
G3L	973			1,359				1,322,709
G3M	1,047			2,034				2,129,025
G3H	2,343			441				1,033,430
G4L	2,172				586			1,272,551
G4XL	5,912				12			70,947
FNG/Cosmo	75,000				2	-		150,000
Power/Ind	280,000						9	2,520,000
Total Meters	**154,493**	**143,963**	**6,087**	**3,834**	**600**	**-**	**9**	
Total Cost of Meters		32,408,567	3,318,336	4,485,164	1,493,498	-	2,520,000	
Average Meter Cost		225	545	1,170	2,489	-	280,000	
Meter Weighting Factor		**1.0000**	**2.4216**	**5.1966**	**11.0572**	**0.0000**	**1243.7958**	

ENSTAR NATURAL GAS COMPANY, LLC

RATE DESIGN
For the Year Ended December 31, 2024

	GAS SALES CUSTOMERS			
	G1	**G2**	**G3**	**G4**
Customer	38,178,728	3,134,618	3,874,056	2,132,763
Capacity	33,031,235	3,412,517	6,749,416	11,905,941
Commodity	776,556	82,341	167,518	297,732
Total	71,986,519	6,629,476	10,790,990	14,336,436
Customers	141,889	5,947	3,758	1,018
Volumes	19,414,078	2,058,556	4,187,988	7,443,359
Fixed Cost	50%	50%	50%	50%
50 % Customer	19,089,364	1,567,309	1,937,028	1,066,382
50% Capacity	16,515,617	1,706,258	3,374,708	5,952,970
RR Amount Allocated to Customer Charge	35,604,982	3,273,567	5,311,736	7,019,352
Fixed Charge as % of Total RR	49%	49%	49%	49%
New Rates				
Customer Charge	$ 21.00	$ 46.00	$ 118.00	$ 575.00
Volume Charge	$ 1.8662	$ 1.6259	$ 1.3060	$ 0.9822
Current Rates				
Customer Charge	$ 16.25	$ 35.50	$ 112.00	$ 538.00
Volume Charge	$ 1.4982	$ 0.9602	$ 0.9449	$ 0.6581
% Change in Customer Charge	29%	30%	5%	7%
% Change in Volume Charge	25%	69%	38%	49%

ENSTAR NATURAL GAS COMPANY, LLC

RATE DESIGN
For the Year Ended December 31, 2024

	LARGE CUSTOMERS		
	VLFT	**MSFT**	**IIT/ITS**
Customer	231,911	-	28,989
Capacity	11,010,856	-	234,248
Commodity	970,904	-	34,838
	12,213,671	-	298,075
Number of Customer Locations	8	0	1
Volumes	23,935,854	-	858,875
IIT Volumes Imputed by TY Minimum Bills			-
IIT & ITS Volumes with Imputed Volumes		-	858,875
Capacity		-	
% in Fixed Cost		50%	
Fixed Amount Alloc to Customer Charge		-	
Contracted Peak Demand	94,300		
Customer Charge	$ 2,400	$ -	
Volume Charge	$ 0.2704	$ -	$ 0.3471
Capacity Charge	$ 4.87		
ITS Annual Minimum			$ 34,700
IIT Monthly Minimum			$ 34,700
Current IIT/ITS per Mcf Rate			$ 0.1770

Attachment D

Contains the following tariff sheets:

Tariff Sheet 255, Revision 2

Tariff Sheet 256, Revision 2

Tariff Sheet 257, Revision 2

Tariff Sheet 258, Revision 2

Tariff Sheet 271, Revision 2

Tariff Sheet 272, Revision 2

Tariff Sheet 273, Revision 2

Tariff Sheet 275, Revision 1

Tariff Sheet 277, Revision 1

Tariff Sheet 282, Revision 2

Tariff Sheet 284, Revision 2

ENSTAR Natural Gas Company, LLC

§2001 **Schedule G1 - General Service 1**

§2001a **Application**

This rate applies to natural gas service to any Customer through a single meter for any purpose where the meter has a maximum Company rated capacity of 400 cubic feet per hour (CFH) or less. The maximum capacity of a G1 meter can be increased to 590 CFH for locations with a single high efficiency, on demand water heater with a rated capacity of under 250,000 BTUH (250 CFH) and still qualify for a G1 rate.

§2001b **Character of Service**

Natural gas having a heating value of approximately 1,000 BTU per cubic foot, but not less than 950 BTU per cubic foot.

§2001c **Monthly Rate**

Service Charge (Base):	$0.18459 per hundred cubic feet (Ccf)	**I**
Customer Charge:	$20.00	**I**

§2001d Service hereunder may be discontinued at any time at the request of the Customer when the premises are vacated or the service is no longer required. Otherwise, the service is to be continuous and, if seasonally disconnected, will be subject to a reconnection charge as set forth in the Section 2501k.

§2001e Rates shall further be adjusted each month in conformance with Section 708 of this tariff to reflect the Company's varying cost of gas. Rates may also be subject to local sales taxes.

ENSTAR Natural Gas Company, LLC

§2002 **Schedule G2 - General Service 2**

§2002a **Application**

This rate applies to natural gas service to any Customer through a single meter for any purpose where the meter has a maximum Company rated capacity of 401 cubic feet per hour (CFH), but no more than 649 CFH. The maximum capacity of a G2 meter can be increased to 839 CFH for locations with a single high efficiency, on demand water heater with a rated capacity of under 250,000 BTUH (250 CFH) and still qualify for a G2 rate.

§2002b **Character of Service**

Natural gas having a heating value of approximately 1,000 BTU per cubic foot, but not less than 950 BTU per cubic foot.

§2002c **Monthly Rate**

Service Charge (Base):	$0.11830 per hundred cubic feet (Ccf)	**I**
Customer Charge:	$43.75	**I**

§2002d Service hereunder may be discontinued at any time at the request of the Customer when the premises are vacated or the service is no longer required. Otherwise, the service is to be continuous and, if seasonally disconnected, will be subject to a reconnection charge as set forth in the Section 2501k.

§2002e **Gas Sales Service**

Rates shall further be adjusted each month in conformance with Section 708 of this tariff to reflect the Company's varying cost of gas. Rates may also be subject to local sales taxes.

§2002f **Transportation Service**

Customers may take Transportation Service under this rate schedule subject to Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

ENSTAR Natural Gas Company, LLC

§2003 **Schedule G3 – General Service 3**

§2003a **Application**

This rate applies to natural gas service to any Customer through a single meter for any purpose where the meter has a maximum Company rated capacity of 650 cubic feet per hour (CFH), but no more than 3,000 CFH. The maximum capacity of a G3 meter can be increased to 3,190 CFH for locations with a single high efficiency, on demand water heater with a rated capacity of under 250,000 BTUH (250 CFH) and still qualify for a G3 rate.

§2003b **Character of Service**

Natural gas having a heating value of approximately 1,000 BTU per cubic foot, but not less than 950 BTU per cubic foot.

§2003c **Monthly Rate**

Service Charge (Base):	$0.11642 per hundred cubic feet (Ccf)	**I**
Customer Charge:	$138.00	**I**

§2003d **Service Term**

Service under this schedule shall be for not less than twelve (12) consecutive months, except for Construction Heat provided under Section 601b(2) or Temporary Service under Section 603. Following the twelve (12) consecutive months, service is to be continuous and may not be seasonally disconnected, but service may be discontinued at the request of the Customer when the premises are vacated or the service is no longer required on a permanent basis. The Customer Charge on this service shall not be subject to cancellation for seasonal periods.

§2003e **Gas Sales Service**

Rates for Customers taking Gas Sales Service shall further be adjusted each month in conformance with Section 708 of this tariff to reflect the Company's varying cost of gas. Rates may also be subject to local sales taxes.

§2003f **Transportation Service**

Customers may take Transportation Service under this rate schedule subject to Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

ENSTAR Natural Gas Company, LLC

§2004 **Schedule G4 – General Service 4**

§2004a **Application**

This rate applies to natural gas service to any Customer through a single meter for any purpose where the meter has a maximum Company rated capacity over 3,000 cubic feet per hour and the Customer does not qualify for service under the rate schedules set out in Sections 2045 through 2251.

§2004b **Character of Service**

Natural gas having a heating value of approximately 1,000 BTU per cubic foot, but not less than 950 BTU per cubic foot.

§2004c **Monthly Rate**

Service Charge (Base):	$0.08108 per hundred cubic feet (Ccf)	**I**
Customer Charge:	$662.75	**I**

§2004d **Service Term**

Service under this schedule shall be for not less than twelve (12) consecutive months, except for Construction Heat provided under Section 601b(2) or Temporary Service under Section 603. Following the twelve (12) consecutive months, service is to be continuous and may not be seasonally disconnected, but service may be discontinued at the request of the Customer when the premises are vacated or the service is no longer required on a permanent basis. The Customer Charge on this service shall not be subject to cancellation for seasonal periods.

§2004e **Gas Sales Service**

Rates for Customers taking Gas Sales Service shall further be adjusted each month in conformance with Section 708 of this tariff to reflect the Company's varying cost of gas. Rates may also be subject to local sales taxes.

§2004f **Transportation Service**

Customers may take Transportation Service under this rate schedule subject to Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

ENSTAR Natural Gas Company, LLC

§2145 **Schedule MSFT – Mid-Sized Firm Transportation Service**

§2145a **Application**

§2145a(1) This rate schedule applies to Firm Transportation Service to:

§2145a(1)(a) Interior Alaska Natural Gas Utility (Interior Gas Utility or IGU) LNG Plant #1 located along the Company's Beluga to Anchorage Pipeline.

§2145a(1)(b) Alaska Electric and Energy Cooperative, Inc. Soldotna Combustion Turbine power plant located along the Company's Kenai to Anchorage Pipeline.

§2145a(2) This service shall be supplied under Sections 1605 and 1640, and

§2145a(3) The Firm Transportation Service Agreement between the Customer and the Company.

§2145b **Monthly Rate**

Service Charge (Base)-Volumetric Rate:
$0.2007 per thousand cubic feet (Mcf) **I**

Customer charge:
$11,260 per Month **I**

§2145c **Rate Adjustments**

Rates for service under this Schedule are subject to various charges and adjustments as approved by the Regulatory Commission of Alaska including, but not limited to, the Regulatory Cost Charge as outlined in Section 2401 and the additional fees set out in Section 2561. Rates may also be subject to local sales taxes.

ENSTAR Natural Gas Company, LLC

§2150 **Schedule VLFT – Very Large Firm Transportation Service**

§2150a **Availability**

Service under this rate schedule requires execution of a Very Large Firm Transportation Service Agreement with the Company.

§2150a(1) Service under Schedule VLFT – Very Large Firm Transportation Service (Section 2150) – is available only for large-volume end-use Transportation customers served directly from the Company's transmission system and having an estimated load factor of 65% or greater and a minimum Contracted Peak Demand of 5,000 Mcf. Load factor is calculated as average daily volumes divided by Contracted Peak Demand. Locations listed in Sections 2145 and 2101 that have specific rates are not eligible for service under this Schedule.

§2150a(2) The Company may limit the amount of Contracted Peak Demand and the delivery pressure requested by the Customer.

§2150a(3) The monthly volumetric rate, customer charge and demand charge applies to each individual Delivery Point receiving service under Schedule VLFT except for Shipper Chugach Electric Association ("Chugach"). The Contracted Peak Demand, and demand charge for the Chugach Delivery Points receiving service under this rate schedule will be aggregated and Chugach will be charged four customer charges per month. Volumes from individual Delivery Points for all other locations will not be combined or aggregated unless it is for the convenience of the Company.

§2150a(4) Service under this Schedule VLFT is exclusive. Locations receiving service under Schedule VLFT cannot receive service at the same time under a different rate schedule.

§2150b **Monthly Rate**

Volumetric Rate For All Gas Delivered Per Month:	$0.2171 per Mcf	**I**
Customer Charge:	$3,130 per Delivery Point	**I**
Demand Charge:	$5.25 per Month per Mcf of Contracted Peak Demand	**I**

ENSTAR Natural Gas Company, LLC

§2150c **Excess Demand**

In the event that a Shipper's actual Mcf per Day demand on any Day exceeds the Shipper's Contracted Peak Demand, then the Shipper shall pay in that Month a penalty as calculated below:

§2150c(1) Calculation of Excess Demand Penalty

The Excess Demand penalty is calculated as the product of:

1. The Shipper's actual Mcf per Day demand less the Shipper's Contracted Peak Demand;
2. The Mcf per Day demand charge (in Section 2050b above);
3. The number of Months the Transportation Service Agreement has been in effect or twelve (12), whichever is less; and
4. Two (2).

§2150c(2) Example of Calculation of Excess Demand Penalty

Assume that a Shipper has contracted for 10,000 Mcf per Day of Contracted Peak Demand in a Transportation Service Agreement that has been in effect for more than twelve months and that the Shipper's actual Mcf per Day demand during a day of a month covered by the Transportation Service Agreement was 12,000 Mcf per Day. The Excess Demand penalty would be calculated as follows:

[(12,000 – 10,000) X $5.25 X 12 X 2] = [2,000 X $5.25 X 12 X 2] = $252,000 **C**

§2150c(3) The Company will waive the Excess Demand penalty for any qualifying volumes caused by Economy Energy Sales to other power utilities. "Economy Energy Sales" include sales of energy sold on a non-firm basis and any Gas volumes resulting from transactions among Customers who are members of the then-current Amended and Restated Operations Agreement for Power Pooling and Joint Dispatch. Volumes for Economy Energy Sales which, combined with the other volumes for the Customer, exceed the Customer's Contracted Peak Demand are interruptible by the Company. To qualify for waiver:

ENSTAR Natural Gas Company, LLC

§2160 **Schedule SCPPFT – South Central Power Pool Firm Transportation Service**

§2160a **Availability and Application**

Service under this rate schedule is only available to Shippers Chugach Electric Association, Inc. ("Chugach") and Matanuska Electric Association, Inc. ("MEA") which are the signatories to the Amended and Restated Operations Agreement for Power Pooling and Joint Dispatch dated August 7, 2020. This service is supplied under Sections 1605 and 1640 and requires execution of a South Central Power Pool Firm Transportation Service Agreement ("SCPPFT TSA") between the Shipper and the Company. **T**

§2160a(1) Service under this Schedule SCPPFT is only available to the following Delivery Points: **T**

§2160a(1)(a) For Shipper Chugach, this service is available to these Delivery Points: Southcentral Power Project and the former Anchorage Municipal Light and Power Generation Plants 1, 2 and 2A. The Contracted Peak Demand and demand charge for the Chugach Delivery Points will be aggregated and Chugach will be charged four customer charges per month.

§2160a(1)(b) For Shipper MEA, this service is available to Eklutna Generation Station Delivery Point.

§2160a(2) The Contracted Peak Demand for all Shippers receiving service under this Schedule SCPPFT will be aggregated in determining a SCPPFT Excess Demand Penalty, if necessary, as set out in §2160c below.

§2160a(3) Service under this Schedule SCPPFT is exclusive. Delivery Points receiving service under Schedule SCPPFT cannot receive service at the same time under a different rate schedule. **T**

§2160b **Monthly Rate**

Volumetric Rate For All Gas Delivered Per Month:	$0.2171 per Mcf	**I**
Customer Charge:	$3,130 per Delivery Point	**I**
Demand Charge:	$5.25 per Month per Mcf of Contracted Peak Demand	**I**

ENSTAR Natural Gas Company, LLC

§2160c(2) Example 1 of Calculation of SCPPFT Excess Demand Penalty

Assume that: (1) SCPPFT Shipper "A" has contracted for 20,000 Mcf per Day of Contracted Peak Demand in a SCPPFT TSA that has been in effect for more than twelve months and that the Shipper A's actual deliveries during a Day was 21,000 Mcf, and (2) SCPPFT Shipper "B" has contracted for 50,000 Mcf per Day of Contracted Peak Demand in a SCPPFT TSA that has been in effect for more than twelve months and that the Shipper B's actual deliveries during a Day was 52,000 Mcf. Thus, the aggregated SCPPFT Contracted Peak Demand is 70,000 Mcf per day and the SCPPFT Excess Demand is 3,000 Mcf per Day and both Shippers exceeded their Contracted Peak Demand.

§2160c(2)(a) Calculation of Excess Demand Penalty for SCPPFT Shipper A:

§2160c(2)(a)(i) SCPPFT Shipper A's portion of SCPPFT Excess Demand (in Mcf) = Shipper A's actual deliveries – Shipper A's Contracted Peak Demand = (21,000 Mcf - 20,000 Mcf) = 1,000.

§2160c(2)(a)(ii) Shipper A's SCPPFT Excess Demand Penalty:
[(1,000) X $5.25 X 12 X 2] = [1,000 X $5.25 X 12 X 2] = $126,000 **C**

§2160c(2)(b) Calculation of Excess Demand Penalty for SCPPFT Shipper B:

§2160c(2)(b)(i) SCPPFT Shipper B's portion of SCPPFT Excess Demand (in Mcf) = Shipper B's actual deliveries – Shipper B's Contracted Peak Demand = (52,000 – 50,000) = 2,000.

§2160c(2)(b)(ii) Shipper B's SCPPFT Excess Demand Penalty:
[(2,000) X $5.25 X 12 X 2] = [2,000 X $5.25 X 12 X 2] = $252,000 **C**

§2160c(3) Example 2 of Calculation of SCPPFT Excess Demand Penalty

Assume the same conditions as Example 1 except that SCPPFT Shipper A's actual deliveries during the Day was 19,000 Mcf. Thus, the SCPPFT Excess Demand is only 1,000 Mcf, which becomes SCPPFT Shipper B's portion of SCPPFT Excess Demand because Shipper B is the only Shipper to exceed its Contracted Peak Demand.

§2160c(3)(a) Calculation of Excess Demand Penalty for SCPPFT Shipper B:
[1,000 X $5.25 X 12 X 2] = $126,000 **C**

ENSTAR Natural Gas Company, LLC

§2201 **Schedule IIT - Interruptible Industrial Transportation Service**

§2201a **Application**

This rate schedule applies to Customers receiving service under Section 1620, Interruptible Transportation Service.

§2201b **Monthly Rate**

Charge For All Gas Delivered Per Month:

First	100,000 Mcf or less	$21,760	**I**
Remaining Volumes		$0.2181 Per Mcf	**I**

There is no charge for any month which volumes are not transported.

§2201c **Rate Adjustments**

Rates for service under Schedule IIT are subject to various charges and adjustments as approved by the Regulatory Commission of Alaska including, but not limited to, the Regulatory Cost Charge as outlined in Section 2401 and the additional fees set out in Section 2561. Rates may also be subject to local sales taxes.

ENSTAR Natural Gas Company, LLC

§2251 Schedule ITS - Interruptible Transportation Service to Storage

§2251a Application

This rate schedule is only available for Interruptible Transportation Service for deliveries of natural gas to the Pretty Creek underground storage fields. The terms and conditions for service are those provided in Section 1620, Terms and Conditions for Interruptible Transportation Service.

§2251b Rate

Volumetric Rate For All Gas Delivered Per Year:	$0.2181 per Mcf	**I**

There is no charge for any month which volumes are not transported, however there is a minimum charge of $19,800 for each Year in which gas is transported under this rate schedule. **I**

§2251c Rate Adjustments

Rates for service under Schedule ITS are subject to various charges and adjustments as approved by the Regulatory Commission of Alaska including, but not limited to, the Regulatory Cost Charge as outlined in Section 2401 and the additional fees set out in Section 2561. Rates may also be subject to local sales taxes.

Attachment E

Contains the following tariff sheets:

Tariff Sheet 6, Revision 2

Tariff Sheet 127, Revision 1

Tariff Sheet 130, Revision 1

Tariff Sheet 244, Revision 3

Tariff Sheet 255, Revision 3

Tariff Sheet 256, Revision 3

Tariff Sheet 257, Revision 3

Tariff Sheet 258, Revision 3

Tariff Sheet 271, Revision 3

Tariff Sheet 272, Revision 3

Tariff Sheet 273, Revision 3

Tariff Sheet 275, Revision 2

Tariff Sheet 277, Revision 2

Tariff Sheet 279, Revision 1

Tariff Sheet 279.1, Revision Original

Tariff Sheet 279.2, Revision Original

Tariff Sheet 282, Revision 3

Tariff Sheet 282, Revision 3

ENSTAR Natural Gas Company, LLC

Subject	Section	Sheet	
Transportation Service	**1600**	**169**	
General Terms and Conditions for Transportation Service	1605	169	
Terms and Conditions for Interruptible Transportation Service	1620	207	
Terms and Conditions of Firm Transportation Service	1640	218	
Schedule of Special Contracts	**1900**	**242**	
Rate Schedules – General Service	**2000**	**254**	
Schedule G1	2001	255	
Schedule G2	2002	256	
Schedule G3	2003	257	
Schedule G4	2004	258	
Rate Schedules – Large Transportation-Firm	**2100**	**269**	
Transportation Service to Power Plants	2101	270	
Schedule MSFT	2145	271	
Schedule VLFT	2150	272	
Schedule SCPPFT	2160	275	
VLFT/SCPPFT Peak Reduction Credit	2170	279	**N**
Rate Schedules – Large Transportation-Interruptible	**2200**	**281**	
Schedule IIT – Interruptible Industrial Transportation Service	2201	282	
Schedule ITS – Interruptible Transportation Service to Storage	2251	284	

ENSTAR Natural Gas Company, LLC

§708c(1)(d) The cost of Gas withdrawn from storage ("Gas Stored" FERC Account 164.1) for use in System Supply. The cost of Gas will be valued at the average unit cost of gas stored in the Gas Stored account calculated as of the end of the Month prior to the Month the Gas is withdrawn from storage. Costs to be included in the calculation of the average unit cost of gas stored include:

§708c(1)(d)(i) Cost of gas purchased and injected into storage;

§708c(1)(d)(ii) Transportation fees incurred for Gas transported to storage;

§708c(1)(d)(iii) FSS and ISS storage injection and withdrawal fees and related RCC charges; and

§708c(1)(d)(iv) Gas cost incurred for FSS and ISS storage fuel use reimbursement;

§708c(2) A credit entry equal to the total number of Mcf of gas sold during the month multiplied by the weighted average unit cost of gas as computed pursuant to Section 708e below.

§708c(3) A debit entry equal to the amount paid pursuant to Section 1205e (Interruption Cost Sharing) or to any Customer interrupted pursuant to Commission ordered sharing of the costs of interruptions or the amount paid pursuant to Section 2170 (VLFT/SCPPFT Peak Reduction Credit). Any amount so included in account 191 may not be included in the Determination of Gas Cost Adjustment filed pursuant to Section 708e below unless it has been reported to the Commission pursuant to 708g below not less than thirty (30) days prior to the filing of such Determination of Gas Cost Adjustment. **C C**

§708c(4) Debit or credit entries for adjustments for entries described in Sections 708c(1) through 708c(3) for prior periods.

ENSTAR Natural Gas Company, LLC

§708f **Supply**

§708f(1) Base Supply Contracts

The base supply contracts are those contracts specified in Section 708e(1) above. Subject to Commission approval, additional base contracts with a term exceeding 12 months and having the effect of increasing the current average cost of system base gas supply will be made by filing with the Commission, 45 days prior to the proposed effective date of such addition or revision, a copy of such addition or revision. New base supply contracts or revisions of base supply contracts having the effect of decreasing the current average cost of system base gas supply become effective immediately without notification.

§708f(2) Additional Supply Contracts and Competitive Bid Gas

Additional contracts of less than one year's duration become effective immediately without notification. Gas purchased through the Company's competitive bidding program does not require Commission approval. Gas purchased under these additional contracts and under the competitive bidding program is considered an approved cost element and may be included in the entries described in Section 708c(1).

§708g **Gas Cost Balance Account Quarterly Report**

The Company shall file a report on the status of the Gas Cost Balance Account fifteen (15) days after the end of each calendar year quarter commencing July 15, 1981, and every quarter thereafter.

This report shall include price and volume of gas purchased, with supporting invoices; volume of gas sold; amounts paid to any interruptible Customer pursuant to Commission ordered sharing of the costs of interruption with a supporting narrative description indicating dates, times and causes of interruptions; interruption cost sharing analyses supporting amounts paid, and the balance in said account; VLFT/SCPPFT Peak Reduction Credits; and/or quantitative support along with a narrative explanation of any disputes or billing corrections that the Company is aware of or anticipates. **C**

ENSTAR Natural Gas Company, LLC

Section 1900 - Schedule of Special Contracts

Customer	Contracted Service	Contract Effective Date	
Hilcorp Alaska, LLC	Contribution in Aid of Construction Agreement	August 16, 2012	
Chugach Electric Association	Transportation Service,	December 15, 2013	
Alaska Electric and Energy Cooperative	Transportation Service	January 1, 2014	
Alaska Electric and Energy Cooperative and Homer Electric Association, Inc.	Gas Sales Service	April 1, 2024	**D**
Chugach Electric Association, Inc. and Matanuska Electric Association, Inc.	Limited Scope South Central Power Pool Balancing Agreement	September 30, 2024	

D – Removed Gas Sales Service Agreement with Golden Valley Electric Association, Inc

ENSTAR Natural Gas Company, LLC

§2001 **Schedule G1 - General Service 1**

§2001a **Application**

This rate applies to natural gas service to any Customer through a single meter for any purpose where the meter has a maximum Company rated capacity of 400 cubic feet per hour (CFH) or less. The maximum capacity of a G1 meter can be increased to 590 CFH for locations with a single high efficiency, on demand water heater with a rated capacity of under 250,000 BTUH (250 CFH) and still qualify for a G1 rate.

§2001b **Character of Service**

Natural gas having a heating value of approximately 1,000 BTU per cubic foot, but not less than 950 BTU per cubic foot.

§2001c **Monthly Rate**

Service Charge (Base):	$0.18662 per hundred cubic feet (Ccf)	**I**
Customer Charge:	$21.00	**I**

§2001d Service hereunder may be discontinued at any time at the request of the Customer when the premises are vacated or the service is no longer required. Otherwise, the service is to be continuous and, if seasonally disconnected, will be subject to a reconnection charge as set forth in the Section 2501k.

§2001e Rates shall further be adjusted each month in conformance with Section 708 of this tariff to reflect the Company's varying cost of gas. Rates may also be subject to local sales taxes.

ENSTAR Natural Gas Company, LLC

§2002 **Schedule G2 - General Service 2**

§2002a **Application**
This rate applies to natural gas service to any Customer through a single meter for any purpose where the meter has a maximum Company rated capacity of 401 cubic feet per hour (CFH), but no more than 649 CFH. The maximum capacity of a G2 meter can be increased to 839 CFH for locations with a single high efficiency, on demand water heater with a rated capacity of under 250,000 BTUH (250 CFH) and still qualify for a G2 rate.

§2002b **Character of Service**
Natural gas having a heating value of approximately 1,000 BTU per cubic foot, but not less than 950 BTU per cubic foot.

§2002c **Monthly Rate**

Service Charge (Base):	$0.16259 per hundred cubic feet (Ccf)	**I**
Customer Charge:	$46.00	**I**

§2002d Service hereunder may be discontinued at any time at the request of the Customer when the premises are vacated or the service is no longer required. Otherwise, the service is to be continuous and, if seasonally disconnected, will be subject to a reconnection charge as set forth in the Section 2501k.

§2002e **Gas Sales Service**
Rates shall further be adjusted each month in conformance with Section 708 of this tariff to reflect the Company's varying cost of gas. Rates may also be subject to local sales taxes.

§2002f **Transportation Service**
Customers may take Transportation Service under this rate schedule subject to Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

ENSTAR Natural Gas Company, LLC

§2003 **Schedule G3 – General Service 3**

§2003a **Application**

This rate applies to natural gas service to any Customer through a single meter for any purpose where the meter has a maximum Company rated capacity of 650 cubic feet per hour (CFH), but no more than 3,000 CFH. The maximum capacity of a G3 meter can be increased to 3,190 CFH for locations with a single high efficiency, on demand water heater with a rated capacity of under 250,000 BTUH (250 CFH) and still qualify for a G3 rate.

§2003b **Character of Service**

Natural gas having a heating value of approximately 1,000 BTU per cubic foot, but not less than 950 BTU per cubic foot.

§2003c **Monthly Rate**

Service Charge (Base):	$0.13060 per hundred cubic feet (Ccf)	**I**
Customer Charge:	$118.00	**I**

§2003d **Service Term**

Service under this schedule shall be for not less than twelve (12) consecutive months, except for Construction Heat provided under Section 601b(2) or Temporary Service under Section 603. Following the twelve (12) consecutive months, service is to be continuous and may not be seasonally disconnected, but service may be discontinued at the request of the Customer when the premises are vacated or the service is no longer required on a permanent basis. The Customer Charge on this service shall not be subject to cancellation for seasonal periods.

§2003e **Gas Sales Service**

Rates for Customers taking Gas Sales Service shall further be adjusted each month in conformance with Section 708 of this tariff to reflect the Company's varying cost of gas. Rates may also be subject to local sales taxes.

§2003f **Transportation Service**

Customers may take Transportation Service under this rate schedule subject to Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

ENSTAR Natural Gas Company, LLC

§2004 **Schedule G4 – General Service 4**

§2004a **Application**

This rate applies to natural gas service to any Customer through a single meter for any purpose where the meter has a maximum Company rated capacity over 3,000 cubic feet per hour and the Customer does not qualify for service under the rate schedules set out in Sections 2045 through 2251.

§2004b **Character of Service**

Natural gas having a heating value of approximately 1,000 BTU per cubic foot, but not less than 950 BTU per cubic foot.

§2004c **Monthly Rate**

Service Charge (Base):	$0.09822 per hundred cubic feet (Ccf)	**I**
Customer Charge:	$575.00	**I**

§2004d **Service Term**

Service under this schedule shall be for not less than twelve (12) consecutive months, except for Construction Heat provided under Section 601b(2) or Temporary Service under Section 603. Following the twelve (12) consecutive months, service is to be continuous and may not be seasonally disconnected, but service may be discontinued at the request of the Customer when the premises are vacated or the service is no longer required on a permanent basis. The Customer Charge on this service shall not be subject to cancellation for seasonal periods.

§2004e **Gas Sales Service**

Rates for Customers taking Gas Sales Service shall further be adjusted each month in conformance with Section 708 of this tariff to reflect the Company's varying cost of gas. Rates may also be subject to local sales taxes.

§2004f **Transportation Service**

Customers may take Transportation Service under this rate schedule subject to Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

ENSTAR Natural Gas Company, LLC

§2145 **Schedule MSFT – Mid-Sized Firm Transportation Service**

§2145a **Application**

§2145a(1) This rate schedule applies to Firm Transportation Service to:

§2145a(1)(a) Reserved for Future Use. **D,C**

D

§2145a(2) This service shall be supplied under Sections 1605 and 1640, and

D

§2145a(3) The Firm Transportation Service Agreement between the Customer and the Company. **D**

§2145b **Monthly Rate**

Service Charge (Base)-Volumetric Rate:

D

Customer charge:

D

§2145c **Rate Adjustments**

Rates for service under this Schedule are subject to various charges and adjustments as approved by the Regulatory Commission of Alaska including, but not limited to, the Regulatory Cost Charge as outlined in Section 2401 and the additional fees set out in Section 2561. Rates may also be subject to local sales taxes.

D – Removed Interior Gas Utility and Alaska Electric and Energy Cooperative from Firm Transportation Service. No other Customers are currently served under this rate schedule. Additionally, Monthly Rates were removed.

ENSTAR Natural Gas Company, LLC

§2150 **Schedule VLFT – Very Large Firm Transportation Service**

§2150a **Availability**

Service under this rate schedule requires execution of a Very Large Firm Transportation Service Agreement with the Company.

§2150a(1) Service under Schedule VLFT – Very Large Firm Transportation Service (Section 2150) – is available only for large-volume end-use Transportation customers served directly from the Company's transmission system and having an estimated load factor of 65% or greater and a minimum Contracted Peak Demand of 5,000 Mcf. Load factor is calculated as average daily volumes divided by Contracted Peak Demand. Locations listed in Sections 2145 and 2101 that have specific rates are not eligible for service under this Schedule.

§2150a(2) The Company may limit the amount of Contracted Peak Demand and the delivery pressure requested by the Customer.

§2150a(3) The monthly volumetric rate, customer charge and demand charge applies to each individual Delivery Point receiving service under Schedule VLFT except for Shipper Chugach Electric Association ("Chugach"). The Contracted Peak Demand, and demand charge for the Chugach Delivery Points receiving service under this rate schedule will be aggregated and Chugach will be charged four customer charges per month. Volumes from individual Delivery Points for all other locations will not be combined or aggregated unless it is for the convenience of the Company.

§2150a(4) Service under this Schedule VLFT is exclusive. Locations receiving service under Schedule VLFT cannot receive service at the same time under a different rate schedule.

§2150b **Monthly Rate**

Volumetric Rate For All Gas Delivered Per Month:	$0.2704 per Mcf	**I**
Customer Charge:	$2,400 per Delivery Point	**R**
Demand Charge:	$4.87 per Month per Mcf of Contracted Peak Demand	**I**

ENSTAR Natural Gas Company, LLC

§2150c **Excess Demand**

In the event that a Shipper's actual Mcf per Day demand on any Day exceeds the Shipper's Contracted Peak Demand, then the Shipper shall pay in that Month a penalty as calculated below:

§2150c(1) Calculation of Excess Demand Penalty

The Excess Demand penalty is calculated as the product of:

1. The Shipper's actual Mcf per Day demand less the Shipper's Contracted Peak Demand;
2. The Mcf per Day demand charge (in Section 2050b above);
3. The number of Months the Transportation Service Agreement has been in effect or twelve (12), whichever is less; and
4. Two (2).

§2150c(2) Example of Calculation of Excess Demand Penalty

Assume that a Shipper has contracted for 10,000 Mcf per Day of Contracted Peak Demand in a Transportation Service Agreement that has been in effect for more than twelve months and that the Shipper's actual Mcf per Day demand during a day of a month covered by the Transportation Service Agreement was 12,000 Mcf per Day. The Excess Demand penalty would be calculated as follows:

[(12,000 – 10,000) X $4.87 X 12 X 2] = [2,000 X $4.87 X 12 X 2] = $233,760 **C**

§2150c(3) The Company will waive the Excess Demand penalty for any qualifying volumes caused by Economy Energy Sales to other power utilities. "Economy Energy Sales" include sales of energy sold on a non-firm basis and any Gas volumes resulting from transactions among Customers who are members of the then-current Amended and Restated Operations Agreement for Power Pooling and Joint Dispatch. Volumes for Economy Energy Sales which, combined with the other volumes for the Customer, exceed the Customer's Contracted Peak Demand are interruptible by the Company. To qualify for waiver:

ENSTAR Natural Gas Company, LLC

§2160 **Schedule SCPPFT – South Central Power Pool Firm Transportation Service**

§2160a **Availability and Application**

Service under this rate schedule is only available to Shippers Chugach Electric Association, Inc. ("Chugach") and Matanuska Electric Association, Inc. ("MEA") which are the signatories to the Amended and Restated Operations Agreement for Power Pooling and Joint Dispatch dated August 7, 2020. This service is supplied under Sections 1605 and 1640 and requires execution of a South Central Power Pool Firm Transportation Service Agreement ("SCPPFT TSA") between the Shipper and the Company.

§2160a(1) Service under this Schedule SCPPFT is only available to the following Delivery Points:

§2160a(1)(a) For Shipper Chugach, this service is available to these Delivery Points: Southcentral Power Project and the former Anchorage Municipal Light and Power Generation Plants 1, 2 and 2A. The Contracted Peak Demand and demand charge for the Chugach Delivery Points will be aggregated and Chugach will be charged four customer charges per month.

§2160a(1)(b) For Shipper MEA, this service is available to Eklutna Generation Station Delivery Point.

§2160a(2) The Contracted Peak Demand for all Shippers receiving service under this Schedule SCPPFT will be aggregated in determining a SCPPFT Excess Demand Penalty, if necessary, as set out in §2160c below.

§2160a(3) Service under this Schedule SCPPFT is exclusive. Delivery Points receiving service under Schedule SCPPFT cannot receive service at the same time under a different rate schedule.

§2160b **Monthly Rate**

Volumetric Rate For All Gas Delivered Per Month:	$0.2704 per Mcf	**I**
Customer Charge:	$2,400 per Delivery Point	**R**
Demand Charge:	$4.87 per Month per Mcf of Contracted Peak Demand	**I**

ENSTAR Natural Gas Company, LLC

§2160c(2) Example 1 of Calculation of SCPPFT Excess Demand Penalty

Assume that: (1) SCPPFT Shipper "A" has contracted for 20,000 Mcf per Day of Contracted Peak Demand in a SCPPFT TSA that has been in effect for more than twelve months and that the Shipper A's actual deliveries during a Day was 21,000 Mcf, and (2) SCPPFT Shipper "B" has contracted for 50,000 Mcf per Day of Contracted Peak Demand in a SCPPFT TSA that has been in effect for more than twelve months and that the Shipper B's actual deliveries during a Day was 52,000 Mcf. Thus, the aggregated SCPPFT Contracted Peak Demand is 70,000 Mcf per day and the SCPPFT Excess Demand is 3,000 Mcf per Day and both Shippers exceeded their Contracted Peak Demand.

§2160c(2)(a) Calculation of Excess Demand Penalty for SCPPFT Shipper A:

§2160c(2)(a)(i) SCPPFT Shipper A's portion of SCPPFT Excess Demand (in Mcf) = Shipper A's actual deliveries – Shipper A's Contracted Peak Demand = (21,000 Mcf - 20,000 Mcf) = 1,000.

§2160c(2)(a)(ii) Shipper A's SCPPFT Excess Demand Penalty:
[(1,000) X $4.87 X 12 X 2] = [1,000 X $4.87 X 12 X 2] = $116,880 **C**

§2160c(2)(b) Calculation of Excess Demand Penalty for SCPPFT Shipper B:

§2160c(2)(b)(i) SCPPFT Shipper B's portion of SCPPFT Excess Demand (in Mcf) = Shipper B's actual deliveries – Shipper B's Contracted Peak Demand = (52,000 – 50,000) = 2,000.

§2160c(2)(b)(ii) Shipper B's SCPPFT Excess Demand Penalty:
[(2,000) X $4.87 X 12 X 2] = [2,000 X $4.87 X 12 X 2] = $233,760 **C**

§2160c(3) Example 2 of Calculation of SCPPFT Excess Demand Penalty

Assume the same conditions as Example 1 except that SCPPFT Shipper A's actual deliveries during the Day was 19,000 Mcf. Thus, the SCPPFT Excess Demand is only 1,000 Mcf, which becomes SCPPFT Shipper B's portion of SCPPFT Excess Demand because Shipper B is the only Shipper to exceed its Contracted Peak Demand.

§2160c(3)(a) Calculation of Excess Demand Penalty for SCPPFT Shipper B:
[1,000 X $4.87 X 12 X 2] = $116,880 **C**

ENSTAR Natural Gas Company, LLC

§2170 **VLFT/SCPPFT Peak Reduction Credit** **N,D**

§2170a **Application**

This credit is available to Customers with executed VLFT (Section 2150) or SCPPFT (Section 2160) agreements with the Company or with approved special contracts with the Company that incorporate Schedule VLFT or Schedule SCPPFT as a portion of the rate. The eligibility for this credit requires execution of a VLFT/SCPPFT Peak Reduction Credit Agreement. Qualifying Customers must meet the following requirements:

§2170a(1) Gas Diversion: The Customer must commit to divert a designated gas quantity between 10,000 Mcf/Day and 30,000 Mcf/Day.

§2170a(2) Alternative Fuel Backup: The Customer must have alternative fuel backup available at one of its gas-fired power generation sites and demonstrate the ability to divert the gas quantity it designated in (1) above on a continuous basis for up to 72 consecutive hours.

§2170a(3) Contractual Ability: A Transportation Customer must have a gas supply arrangement that allows assignment or sale of the diverted gas to ENSTAR at cost either from the Customer or the Customer's gas supplier. Such agreements must meet all regulatory requirements and approvals.

§2170a(4) Commitment to Divert: When requested with the appropriate notice, the Customer must reduce its gas receipts from the ENSTAR system by the amount requested by ENSTAR, up to the maximum volume designated by the Customer in its VLFT/SCPPFT Peak Reduction Credit Agreement.

§2170b **Interruption Costs**

In the event of an Interruption, a participating VLFT/SCPPFT Customer receiving a Peak Reduction Credit may additionally qualify for reimbursement of its Interruption Expense, as set forth in Section 1205 (Interruption Cost Sharing).

D – Removed placeholder for reservation of future use.

ENSTAR Natural Gas Company, LLC

§2170c **Credit** **N**

A fifty (50) percent credit of the VLFT (or SCPPFT, as appropriate) Demand Charge will be applied to the quantity of gas diversion elected by the Customer in its Peak Reduction Credit Agreement with ENSTAR for the months of November, December, January, and February ("Peak Reduction Period").

§2170c(1) Calculation of VLFT/SCPPFT Peak Reduction Credit

The VLFT/SCPPFT Peak Reduction Credit is calculated as the product of:

1. The gas quantity the Customer designated for diversion under a Peak Reduction Credit Application ("Designated Diversion Volume");
2. Fifty (50) percent reduction of the Demand Charge under Section 2150b; (or Section 2160b, as appropriate);
3. The number of months identified in the Peak Reduction Period (in all cases, 4 months);

§2170c(2) Example Calculation of VLFT/SCPPFT Peak Reduction Credit

Assume that the Customer meets all requirements and elected a Designated Diversion Volume of 20,000 Mcf/Day. The VLFT/SCPPFT Peak Reduction Credit would be calculated as follows:

1. 20,000 X ($4.87 X ½) X 4 = $194,800 Annual Credit
2. $194,800 / 12 = $16,233 Monthly Credit

§2170c(3) Application of Credit

The calculated credit will be distributed over twelve (12) months and applied to the Customer's monthly service invoice.

ENSTAR Natural Gas Company, LLC

§2170d **Peak Reduction and Diversion Process** **N**

The Company will, in its sole discretion, call for peak reductions from Customers that have executed a VLFT/SCPPFT Peak Reduction Credit Agreement ("Peak Reduction Request") using the following procedure:

§2170d(1) The Company will determine the amount of peak reduction needed and allocate the identified volumes between Customers with a VLFT/SCPPFT Peak Reduction Credit Agreement, taking into account current operating conditions ("Diversion Volume").

§2170d(2) The Company will provide the Customer a minimum four (4) hour notice of intent to call upon peak reductions.

§2170d(3) The Company will notify the affected Customers at the conclusion of the event and discontinue peak reductions.

§2170d(4) Within thirty (30) days of the diversion of the gas by the Company the Customer shall provide supporting documentation for the reimbursement of the cost of gas.

§2170e **Failure to Comply with Peak Reduction Request**

§2170e(1) Following a properly noticed Peak Reduction Request, if the Customer, for any reason, including a Force Majeure Event, does not make its Designated Diversion Volume available to the Company per Section 2170a(4), the Company may pursue the following:

§2170e(1)(a) The Customer will be responsible for, and will pay the Company, the positive difference, if any, between the weighted average purchase price paid by the Company for replacement Gas purchased and the Gas price of the requested Diversion Volume, multiplied by the withheld Diversion Volume.

§2170e(1)(b) The Customer will refund any credits received in the credit year, defined as the 12 months starting the month of the executed agreement, and forfeit any remaining unpaid credits for the remainder of the credit year.

§2170e(1)(c) The Company will terminate the applicable Peak Reduction Credit Agreement.

ENSTAR Natural Gas Company, LLC

§2201 **Schedule IIT - Interruptible Industrial Transportation Service**

§2201a **Application**

This rate schedule applies to Customers receiving service under Section 1620, Interruptible Transportation Service.

§2201b **Monthly Rate**

Charge For All Gas Delivered Per Month:

First	100,000 Mcf or less	$34,700	**I**
Remaining Volumes		$0.3471 Per Mcf	**I**

There is no charge for any month which volumes are not transported.

§2201c **Rate Adjustments**

Rates for service under Schedule IIT are subject to various charges and adjustments as approved by the Regulatory Commission of Alaska including, but not limited to, the Regulatory Cost Charge as outlined in Section 2401 and the additional fees set out in Section 2561. Rates may also be subject to local sales taxes.

ENSTAR Natural Gas Company, LLC

§2251 Schedule ITS - Interruptible Transportation Service to Storage

§2251a **Application**

This rate schedule is only available for Interruptible Transportation Service for deliveries of natural gas to the Pretty Creek underground storage fields. The terms and conditions for service are those provided in Section 1620, Terms and Conditions for Interruptible Transportation Service.

§2251b **Rate**

Volumetric Rate For All Gas Delivered Per Year:	$0.3471 per Mcf	**I**

There is no charge for any month which volumes are not transported, however there is a minimum charge of $34,700 for each Year in which gas is transported under this rate schedule. **I**

§2251c **Rate Adjustments**

Rates for service under Schedule ITS are subject to various charges and adjustments as approved by the Regulatory Commission of Alaska including, but not limited to, the Regulatory Cost Charge as outlined in Section 2401 and the additional fees set out in Section 2561. Rates may also be subject to local sales taxes.

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chairman
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Consideration of the Revenue Requirement Designated as TA 354-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY
OF
JOHN D. SIMS

PREFILED DIRECT TESTIMONY
OF
JOHN D. SIMS

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EXHIBITS

Exhibit JDS-1	Resume of John D. Sims
Exhibit JDS-2	GAS – The Magazine of the Natural Gas Industry, August 1964
Exhibit JDS-3	ENSTAR Transmission System Map
Exhibit JDS-4	2019-2023 AGA Safety Awards
Exhibit JDS-5	AEDC 2025 Anchorage Economic Forecast Report
Exhibit JDS-6	NARUC Resolution
Exhibit JDS-7	Alaska Statute 42.05.511(c) and 42.05.441(c)
Exhibit JDS-8	Corporate and Shared Services Costs

I. POSITION AND QUALIFICATIONS

Q. Please state your name, business address, and present position.

A. My name is John D. Sims. My business address is 3000 Spenard Road, Anchorage, Alaska, 99503. I am President of ENSTAR Natural Gas Company, LLC and Alaska Pipeline Company, LLC ("APC"), as well as President of Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"). ENSTAR Natural Gas Company, LLC and APC are regulated as a single entity and will collectively be referred to in my testimony as "ENSTAR" or the "Company."

Q. Briefly describe your professional experience and educational background.

A. I have been employed by ENSTAR since 2005 and have held various management roles associated with the Customer Service, Credit, Human Resources, Business Development, and Public Affairs Departments. Immediately prior to my current position, I was the Vice President of Corporate Resources and Business Development for both ENSTAR and CINGSA. I hold a degree in Marketing Management from Hillsdale College and have a Master's Degree in Business Administration from the University of Alaska, Anchorage. My summary resume is attached hereto as Exhibit JDS-1.

Q. Briefly describe your current professional responsibilities with ENSTAR.

A. As President of ENSTAR, I am responsible for the management, operations and financial performance of the utility. I am the leader of the dedicated employees who perform services for ENSTAR and interface with stakeholders external to the Company, including the federal delegation, the Alaska State Legislature, the executive branch, and other business leaders in Alaska.

Q. Have you previously testified before the Regulatory Commission of Alaska ("RCA" or "Commission")?

A. Yes. I have provided testimony before the RCA on behalf of ENSTAR in Dockets U-08-025, U-16-066, U-18-004, U-19-014, and U-22-081, and on behalf of CINGSA in Dockets U-18-005, U-18-024, U-18-043, U-19-025, and U-21-058. I have also made several presentations before the Commission during my tenure with ENSTAR.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide a general overview of this rate filing; to describe the history and operations of ENSTAR and the value ENSTAR brings to its 155,000 customers in Southcentral Alaska; to provide an overview of the shared services provided by ENSTAR's indirect parent corporation, TriSummit Utilities Inc. ("TSU"); to describe the substantial capital plan that ENSTAR is looking to implement; and to describe the importance to ENSTAR and the State of Alaska of maintaining a proper utility investment environment, particularly given the unique risks that ENSTAR faces.

III. OVERVIEW OF ENSTAR'S FILING

Q. Why is ENSTAR making this rate filing?

A. ENSTAR was ordered by the Commission in Order U-22-081(11), which was an order approving a partial settlement of that proceeding, to file a rate case in 2025 or 2026 based on a 2024 or 2025 test year, respectively. This filing is being made in compliance with Order U-22-081(11).

Q. What is ENSTAR requesting in this rate filing?

A. ENSTAR is requesting an overall increase of 5.77% including the cost of gas and 26.79% on non-gas revenue requirements to allow the Company an opportunity to recover its just and reasonable costs and earn a fair return of and on prudent capital investments in ENSTAR's transmission and distribution system in Southcentral Alaska, all of which were used and useful to provide service to ENSTAR customers during the test year. Our rate filing includes a request to increase our return on equity ("ROE") to 13%, a capital structure using the actual structure at the end of the test year (December 31, 2024) of 41.43% debt and 58.57% equity, and ENSTAR's current actual cost of debt of 5.55%. Recovery of these expenses and investments will help ensure that ENSTAR will be able to provide the same safe and reliable service at reasonable rates that its customers have become accustomed to since it began operations in 1961.

ENSTAR further requests an interim and refundable increase of 5.00% of total revenues, to be effective July 1, 2025.

Q. Why is ENSTAR requesting an increase in base rates in 2025 as opposed to 2026 per the option in Order U-22-081(11)?

A. ENSTAR has made capital investments of $127 million and experienced increases in annual operating expenditures totaling approximately $8.8 million since the 2021 test year. These increases in investment and routine cost of doing business have resulted in ENSTAR under-earning by a significant margin as described later in my testimony. An adjustment is necessary to reflect the sizeable investments ENSTAR has made on its customers' behalf and its reasonable cost to provide safe and reliable service. Additionally, ENSTAR anticipates over the next five years (2025-2029) an increased

capital spend on system betterment and pipeline replacements to address the needs of a system that now has segments of pipe and infrastructure over 60 years old.

Q. Who are the other ENSTAR witnesses testifying in support of this filing?

A. In addition to my testimony, the following witnesses testify in support of ENSTAR's filing:

- ***Inna B. Johansen***, Vice President of Regulatory and Gas Supply, ENSTAR. Ms. Johansen discusses the significant challenges ENSTAR faces in obtaining gas supply from Cook Inlet, including the basin's declining production volumes, the Company's alternative efforts to ensure it has adequate supplies to meet customer demand going forward, and the impact of these conditions on the Company's risk. She also supports certain pro forma adjustments to ENSTAR's revenue requirement, including an adjustment to normalize the colder weather experienced during the 2024 test year, all of which are necessary to reflect known and measurable changes that will occur during the period when new rates are in effect. Additionally, she supports the pro forma adjustment to address Order U-25-004(2) regarding the ENSTAR's gas supply regulatory asset. Finally, Ms. Johansen supports ENSTAR's proposal to implement a credit to large transport and gas sales customers for the ability to redirect their gas supply to ENSTAR during periods of peak demand.
- ***Andrea D. Jackson***, Treasurer, TSU. Ms. Jackson discusses the relationship of TSU to ENSTAR, describes the necessary corporate support services that TSU provides to the Company, and supports the reasonableness and prudence of the

costs associated with those services. She also explains how TSU charges those costs to the Company.

- ***Abigail L. Riggs***, Vice President of Finance, ENSTAR. Ms. Riggs describes ENSTAR's Cost Allocation Manual, which establishes the procedures the Company uses to assign and allocate costs to certain affiliates. She also describes the manner in which ENSTAR receives debt financing and explains the Company's method for calculating its cost of debt. Finally, Ms. Riggs supports ENSTAR's deferred taxes on ENSTAR's books, and she sponsors the Company's proposed adjustment for pension costs on Schedule L.
- ***Nathan T. Burke***, Manager of Infrastructure and Planning, ENSTAR. Mr. Burke discusses the level of capital investments ENSTAR has made since its last rate case, and demonstrates that these projects are used and useful in providing gas utility service and that the costs are reasonable and prudent. He also supports ENSTAR's request for year-end rate base treatment for certain new investments the Company has made to ensure the safe and reliable transportation and distribution of natural gas. Finally, he discusses ENSTAR's proposed Reliability Infrastructure Replacement Program ("RIRP"), which will accelerate the replacement of high-risk, aging facilities and enhance the safety and reliability of the Company's transmission and distribution systems.
- ***Harold Walker, III***, Manager, Financial Studies, Gannett Fleming Valuation and Rate Consultants, LLC. Mr. Walker supports ENSTAR's proposed cash working capital allowance for inclusion in rate base in this proceeding.

- ***Jennifer E. Nelson***, Vice President, Concentric Energy Advisors. Ms. Nelson presents evidence on and provides her recommendation regarding ENSTAR's return on equity. She also assesses the reasonableness of the Company's actual capital structure and corresponding cost of capital.
- ***Chelsea N. Guintu***, Manager of Regulatory and Planning, ENSTAR. Ms. Guintu sponsors ENSTAR's proposed revenue requirement. She also sponsors the comparative financial schedules, and describes various pro forma adjustments to test-year data used in ENSTAR's 275(a) filing. Finally, Ms. Guintu sponsors the tariff sheets with ENSTAR's proposed interim and permanent rates.
- ***Bruce H. Fairchild***, Principal, Financial Concepts and Applications, Inc. Mr. Fairchild supports the reasonableness of the calculation of the adjustments to weather-normalize gas usage during the 2024 test year. He also sponsors the calculation of income tax expense, shown on Schedule F of Attachment B, included in the proposed revenue requirement in ENSTAR's 275(a) filing. Additionally, Dr. Fairchild presents ENSTAR's cost-of-service study, which allocates the proposed revenue requirement among the Company's customer classes. Finally, he develops specific rates for the customer classes, including the VLFT/SCPPFT Peak Reduction Credit.

Q. Is ENSTAR proposing any changes to its rate design in this proceeding?

A. No. Pursuant to Order U-22-081(11), ENSTAR is not proposing to change its rate design in this proceeding.

Q. What standard applies to the Commission's review of this filing?

A. Although I am not an attorney, my understanding is that Alaska Statute 42.05.141(a)(3) empowers the Commission to "make or require just, fair, and reasonable rates . . . for a public utility . . . ." The Commission also described the process to determine those rates, in Order U-18-043(15):

> To determine just and reasonable rates, we review a utility's proposed total annual required earnings, known as the revenue requirement. Conceptually, the revenue requirement is the sum of the utility's operating expenses, plus annual depreciation, plus a fair return on investment. The revenue requirement is derived from a normalized test year. The test year consists of historical data of actual, realized costs and property balances, which are then adjusted to reflect known and measurable changes and to delete or average the effect of unusual or nonrecurring events. The purpose of the normalized test year is to reasonably represent the costs of normal operations in the immediate future.[1]

To assist the Commission in determining "just and reasonable" rates and in compliance with Order U-22-081(11), ENSTAR has prepared a revenue requirement and cost-of-service studies that follow 3 AAC 48.275(a) and (h).

IV. HISTORY AND OPERATIONS OF ENSTAR

Q. Please provide a brief history of ENSTAR.

A. ENSTAR was first organized in 1959[2] and won franchise elections from the communities of Anchorage, Spenard, and Fairview that fall. Gas service began in the summer of 1961 after ENSTAR completed the construction of a twelve-inch pipeline across the Kenai Peninsula from the Kenai Gas field, under Turnagain Arm, and into Anchorage. During its early years, the Company faced severe competition from heating oil suppliers and coal at the power plants. On March 27, 1964, ENSTAR faced

[1] Order U-18-043(15), *Order Resolving Revenue Requirement And Cost-Of-Service Issues And Requiring Filings*, dated August 16, 2019 at 9.

[2] The Company was called Anchorage Natural Gas Corporation at that time; the Company was renamed ENSTAR Natural Gas Company in 1982.

its greatest challenge in Company history – the Good Friday Earthquake. A natural gas line broke at Second Avenue and Post Road, shutting down the main power plant. ENSTAR crews worked around the clock – from 5:30 p.m. on Friday through Monday – to run temporary lines above ground to restore service to the power plant. An article describing the event is attached to my testimony as Exhibit JDS-2. It took the rest of summer for ENSTAR to restore service to all of its service areas. In step with the Municipality of Anchorage, ENSTAR grew exponentially in the early 1970s. By 1971, it had become Anchorage's largest taxpayer, serving nearly 20,000 customers. In 1977, the same year the Trans-Alaska Pipeline delivered the first barrel of oil to Valdez, ENSTAR was awarded Anchorage's "Municipal Beautification Award" for its recently completed administration building at 3000 Spenard Road. As the years have passed, ENSTAR has prudently invested in its system to ensure natural gas demand is met 24 hours a day, 365 days a year to its customers, who now number approximately 155,000.

Q. Please describe ENSTAR's physical plant.

A. ENSTAR is an integrated, hybrid system, composed of both natural gas transmission and distribution assets. The transmission assets move gas from supply areas to large consumers (such as power generation facilities) and to our distribution system. Our distribution assets deliver gas to smaller end-users such as homes, schools, and hospitals. The Company's transmission system is comprised of approximately 300 miles of twelve- to twenty-inch diameter pipeline and approximately 120 miles of smaller diameter pipeline. The system's present design delivery capacity is approximately 405-460 million cubic feet per day ("MMcf/d"). The transmission system consists primarily of two pipeline systems that extend from various natural gas

fields on both sides of Cook Inlet into the Anchorage area. I have attached a simplified map to my direct testimony as Exhibit JDS-3.

The original pipeline system, the Kenai Pipeline System, serves the east side of Cook Inlet and enters Anchorage from the south through the Potter Gate Station. The other pipeline system, the Beluga Pipeline System, serves the west side of Cook Inlet and enters Anchorage from the north near Chugach Electric Association's George M. Sullivan Plant. The two pipeline systems are interconnected in Anchorage, allowing the distribution system to serve most customers from either pipeline system. The origination points of the two pipeline systems are also interconnected by means of a producer-owned pipeline system, creating a full loop of the transmission system.

The Kenai Pipeline System was placed into service in 1961 and currently receives gas from the Kenai, Beaver Creek, Swanson River, Ninilchik, Trading Bay, and McArthur River gas fields, among others, as well as gas stored in the CINGSA natural gas storage facility. The main trunk line of the Kenai Pipeline System originates at the Kenai Gas Field and extends for approximately 75 miles to Anchorage. It consists of two pipelines with diameters of twelve to 16 inches and operates at pressures of up to 1,050 pounds per square inch gauge ("psig"). ENSTAR also has a 25-mile, eight-inch diameter pipeline that connects KPL Junction to ENSTAR's main trunk line. The CINGSA storage facility is connected to the Kenai Pipeline System through a four-mile, 16-inch diameter pipeline that ENSTAR completed in 2015. The Kenai Pipeline System includes a nine-mile, twin twelve-inch diameter crossing of the Turnagain Arm of Cook Inlet, landing at Potter Gate Station. The crossing includes two separate pipelines that may be operated independently. Powered by two compressor stations

with an aggregate of 11,699 horsepower, the system on the east side of the Inlet has a present delivery capacity of approximately 235-260 MMcf/d.

The transmission system on the west side of the Inlet, the Beluga Pipeline System, was completed in 1984 and extends from the Beluga River gas field through the Pretty Creek gas field, passing the Lewis River and Ivan River/Stump Lake gas fields before reaching the Anchorage area. Along the mainline route, gas is provided to Matanuska-Susitna Borough and Eagle River customers. The mainline operates at pressures of up to 1,031 psig and consists of a single 102-mile, 20-inch diameter line with several smaller laterals extending service off of the main line. The Lewis River, Pretty Creek, Ivan River, Stump Lake, Trading Bay, and McArthur River gas fields are connected to the Beluga mainline by lines owned by the producers of the fields. The present delivery capacity of this portion of the system is approximately 170-200 MMcf/d.

ENSTAR's system has also seen several significant upgrades and additions over time. In 1991, ENSTAR connected its system to Harvest's Alaska, LLC (then Marathon's) newly constructed Granite Point to Beluga pipeline, which established a complete natural gas pipeline loop around Cook Inlet. In 1992, ENSTAR completed a series of upgrades to its transmission system to increase the amount and pressure of gas entering Anchorage. As a result of those upgrades, ENSTAR can reverse the flow of the Kenai Pipeline System and has often transported gas for industrial users from the Beluga Field through Anchorage to Nikiski. In 1995, ENSTAR was awarded a 33-year lease of the Department of Defense's Whittier to Elmendorf Air Force Base petroleum products pipeline. In 1996, the Company converted the line to natural gas use, tied it

into the ENSTAR system, and began providing natural gas service to communities along the Turnagain Arm.

ENSTAR's transmission pipelines are constructed of externally coated, welded steel, have impressed-current cathodic protection for corrosion prevention, and are leak-surveyed at least annually. Substantially all of ENSTAR's systems are constructed and run through property owned by public and private third parties pursuant to permits and right-of-way grants, which allow ENSTAR uninterrupted possession and use of its systems.

Within the Anchorage area, ENSTAR owns and operates approximately 55 miles of four-inch to 16-inch diameter transmission pipeline at a maximum operating pressure of 460 to 685 psig. The Company also owns and operates approximately 18 miles of four-inch through twelve-inch diameter pipelines with maximum operating pressures between 271 and 385 psig. These pipelines serve large customers and act as gas feeders for the distribution system within the Anchorage area.

ENSTAR distributes natural gas through a network of approximately 3,300 miles of distribution pipeline, with approximately 140,000 service lines connecting natural gas service to approximately 155,000 residential, commercial, and industrial customers. The cities and environs served include Anchorage, Anchor Point, Big Lake, Bird Creek, Butte, Eagle River, Girdwood, Homer, Houston, Indian, Kasilof, Kenai, Knik, Palmer, Nikiski, Nikolaevsk, Soldotna, Wasilla, and Whittier.

Regulator stations reduce either transmission or intermediate pressure pipeline gas to distribution pressure so that it may safely feed into the distribution system. Regulator station designs vary, but are generally dual-feed regulator stations with one

active pressure reduction run and a second backup run, with over-pressure protection provided by relief valves. Most areas are served by more than one regulator station interconnected by large diameter distribution pipelines. There are a few population centers that are served by a single regulator station, with Girdwood and Homer as examples of such larger communities.

The first distribution mains were placed into service in 1961. All mains are either steel or high-density polyethylene ("HDPE"). Mains installed before 1972 are made of steel. ENSTAR began installing HDPE mains in 1972, and by late 1974, distribution mains less than six inches in diameter were routinely installed using HDPE. Today, most six-inch mains and some eight-inch mains are installed using HDPE, with larger mains using externally-coated welded steel. Early service lines were constructed of copper or externally-coated welded steel. About 3,000 copper service lines were installed in the 1960s, of which some 500 remain in service today. Between 1966 and 1974, polyethylene-coated steel tubing was widely used. ENSTAR began using HDPE service lines in 1972, and by late 1974, service lines smaller than two inches in diameter were installed using HDPE. Over 126,000 HDPE service lines are in use today.

Q. Please provide a brief overview of ENSTAR's operations.

A. ENSTAR currently purchases, on average, 38 Bcf[3] of natural gas annually from three Cook Inlet producers and delivers the gas through its transmission and distribution system to residential, commercial, and industrial customers. Hilcorp Alaska LLC ("Hilcorp"), the largest producer, delivers approximately 85% of ENSTAR's gas on an

[3] Bcf is 1,000,000 Mcf or 1 billion cubic feet. Mcf is one thousand cubic feet. Ccf is one hundred cubic feet.

annual basis. Approximately 99% of ENSTAR's customer base (by meter count) consists of residential and similar small commercial customers, who have in common the relatively small meters and related facilities used to serve them. These customers typically use the gas delivered by ENSTAR for space heating, producing hot water, cooking, and similar purposes. The remainder of ENSTAR's customer base consists of larger commercial and transportation customers that use gas for the same purposes and for industrial purposes, such as generating power or running asphalt plants.

ENSTAR employs approximately 230 employees in various management, supervisory, administrative, and field positions on a full-time basis. This year-round Alaska workforce is supplemented in summer with an additional 60-70 temporary employees for the construction season. The Company's employees work out of five offices across ENSTAR's service territory. In addition, ENSTAR receives necessary services from TSU, as further described in the testimony of Ms. Jackson.

Q. Describe ENSTAR's status as a regulated public utility and the different kinds of rates it charges customers for natural gas service.

A. The Company is economically regulated by the Commission, in terms of the rates it charges and the terms and conditions under which it provides service to customers. The Company's revenues to cover the costs of providing service (including the return ENSTAR earns on investments in facilities to serve customers) come from Commission-authorized "base rates" that recoup the non-gas costs of delivering natural gas to customers. The Company purchases natural gas that it resells to customers at cost, without a profit margin or mark-up. The "Gas Cost Adjustment" (or "GCA") component of rates is set annually by the Commission and paid by what are termed

"gas sales customers." ENSTAR recovers its gas costs through the GCA dollar-for-dollar, in the absence of cost disallowances or exclusions. GCA charges comprise about 80% of the typical gas sales customer's bill.

In addition, we have a small number of customers (called "transportation customers") who purchase their own natural gas from third parties and ship it through ENSTAR's pipelines to their customer facilities. Because they purchase their own gas, transportation customers do not pay the GCA rate. Instead, they pay agreed-upon prices to their own suppliers for the gas the suppliers provide. Transportation customers do pay the Company for its delivery services at Commission-prescribed rates.

In this docket, the Commission will decide what base rates the Company should charge its customers. Our proposed base rate charges in this request comprise about 20% of the typical gas sales customer's bill, and as this filing illustrates, the proposed charges are significantly lower than the average cost when compared to other utilities across the nation.

Q. Please describe Docket U-22-081.

A. Docket U-22-081 was ENSTAR's last rate case, filed on August 1, 2022, and was based on a 2021 test year. The parties to the 2022 rate case reached a partial settlement and left only the issue of an appropriate ROE for adjudication. The Commission's order resolving the case after a hearing on the merits of an appropriate ROE was entered on April 8, 2024, Order U-22-081(14). As stated above, in Order U-22-081(11), which was the order approving the partial settlement, the Commission ordered ENSTAR to

file a rate case in 2025 or 2026 based on a 2024 or 2025 test year, respectively. This filing is being made in compliance with Order U-22-081(11).

Q. Have ENSTAR's costs to do business increased since the end of 2021, which was the end of the test year in its last rate case?

A. Yes. ENSTAR's total normalized operations and maintenance ("O&M") expenses, including administrative and general expenses, but excluding gas cost, depreciation and property taxes, in the last test year (2021) were approximately $38.3 million. Since then, O&M expenses have increased to approximately $47.0 million in the 2024 normalized test year. These increases are due to high inflation, the cost of labor, including contracted union wage increases and increasing health care costs, safety-related costs with increased Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulation regarding pipeline integrity, insurance, cybersecurity, and additional regulatory changes and compliance efforts. All of ENSTAR's O&M expenses as normalized are reasonable and necessary.

Q. Please describe key events that have occurred since the test year used in Docket U-22-081 through the end of the 2024 test year used in this filing.

A. Since the Company's 2021 test year used in Docket U-22-081, ENSTAR has experienced several significant events that impacted operations. Since the 2021 test year, those events are as follows:

- April 2022 – The American Gas Association recognized ENSTAR as an industry leader in accident prevention for 2021.

- April 2022 – Hilcorp, which supplies roughly 90% of the production in Cook Inlet, communicated to users of Cook Inlet gas that it was not interested in extending existing contracts at their same commitment level.
- February 2023 – In light of the significant supply challenges, the Commission approved the creation of a regulatory asset to allow ENSTAR to recover necessary costs it incurs to study and secure potential natural gas supplies.
- March 2023 – The transaction by which TSU acquired ENSTAR, APC, and CINGSA closed.
- April 2023 – The American Gas Association recognized ENSTAR as an industry leader in accident prevention for 2022.
- April 2023 – ENSTAR and Homer Electric Association ("HEA") signed a Gas Supply Procurement Agreement.
- November 2023 – ENSTAR and CINGSA signed an Expansion Precedent Agreement.
- Winter 2023/2024 – CINGSA issued operational flow order reducing facility deliverability by 30%.
- January 2024 – ENSTAR and Hilcorp amended APL-14 gas sales contract to meet HEA's needs.
- January 2024 – HEA became a Gas Sales customer of ENSTAR with deliveries of 4 Bcf/year starting on April 1, 2024.
- Summer construction season of 2024 – ENSTAR implemented a large-scale program to begin replacing its steel distribution main in the City of Kenai. This is the first of multiple phases to replace high-risk main in its pipeline system.

- April 2024 – The American Gas Association recognized ENSTAR as an industry leader in accident prevention for 2023.
- October 2024 – ENSTAR and Furie Operating Alaska, LLC ("Furie") agreed to amend their contract to allow for more firm deliveries beginning 2026 through 2031.
- December 2024 – ENSTAR and Glenfarne Infrastructure Holdings OpCo, LLC ("Glenfarne") signed an Exclusivity Agreement to develop a liquid natural gas import project in Kenai.

Q. Notwithstanding the increases in O&M costs, how does the cost of ENSTAR's service compare to other jurisdictions in the United States, exclusive of gas commodity cost?

A. ENSTAR provides natural gas delivery service to our customers at one of the lowest costs in the entire country. Assuming ENSTAR's application is approved as filed, the cost of natural gas delivery service (combining the customer charge and service charge, and excluding gas commodity costs) for ENSTAR's G1 General Service customers will be $3.70 per Mcf. This is well below the national average cost for natural gas distribution service during 2024 as reported by the Energy Information Administration of $13.14 per Mcf.[4]

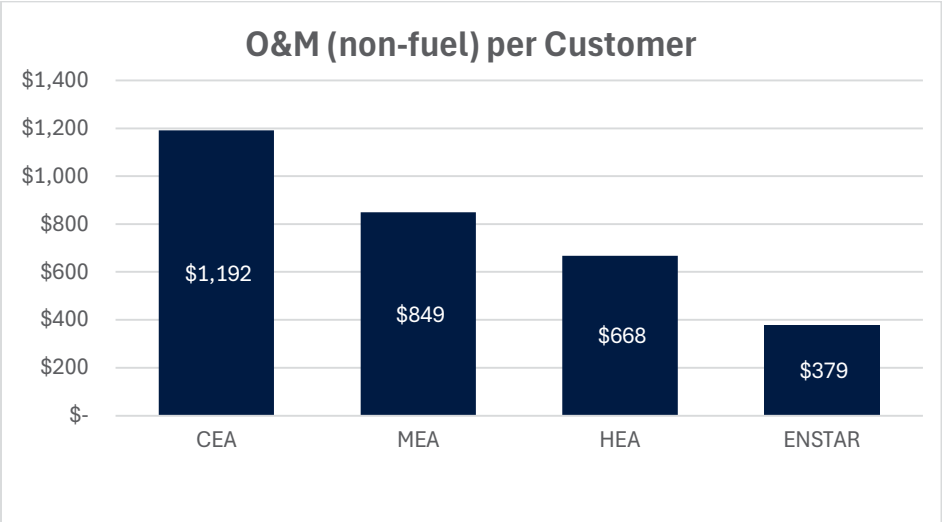
Q. How do ENSTAR O&M costs compare to those of the other Railbelt Utilities within ENSTAR's service territory?

A. It is somewhat of an unfair comparison, as we operate very different businesses and business models, but when you compare 2023 O&M costs between ENSTAR and the

[4] EIA: https://www.eia.gov/state/data.php?sid=AK#Prices, last accessed April 13, 2025.

Railbelt Utilities' 2023 Annual Operating Reports within ENSTAR's service territory you will find that ENSTAR spends significantly less per customer. Figure 1 below breaks out each utility's O&M cost per customer.

FIGURE 1[5]

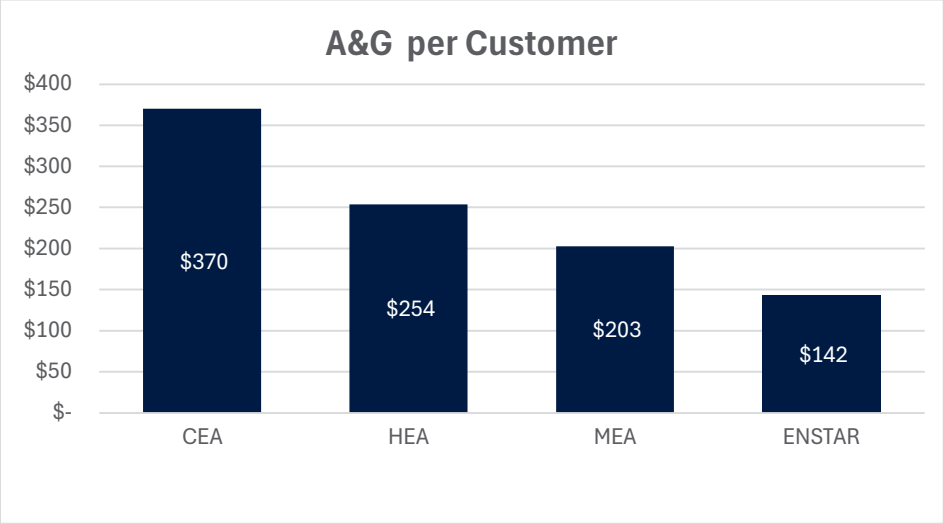


Q. How do ENSTAR A&G costs compare to those of the other Railbelt Utilities in ENSTAR's service territory?

A. When you compare 2023 A&G costs between ENSTAR and the Railbelt Utilities' 2023 Annual Reports within ENSTAR's service territory you will also find that ENSTAR spends significantly less per customer. Figure 2 below breaks out each utility's A&G cost per customer.

[5] O&M expense is exclusive of fuel and purchased power.

FIGURE 2



Q. Are there any items listed above you would like to expand upon or other issues not listed above that you would like to communicate regarding ENSTAR's operations since the last rate case?

A. Yes, most of the items listed above have been communicated to the Commission before in one fashion or another. However, there are a few areas of our business that I would like to expand upon, and some I would like to highlight not listed above, including overall safety and reliability improvements, technological improvements, and inflation. ENSTAR believes in its mission, and we are proud of our record of managing costs, over an extremely difficult time period, to remain one of the lowest cost providers of natural gas in the United States.

A. ENSTAR's Safety and Reliability Improvements

Q. Has ENSTAR's commitment to safety and reliability changed since it received the final order setting rates in Docket U-22-081?

A. No. Public, customer, and employee safety and the reliability of our service have remained the top priorities for ENSTAR, and we continue to place high expectations

on all our employees to consistently improve. ENSTAR conducts annual trainings for employees and contractors, conducts a safe digging conference prior to the construction season, and spends significant resources on communications and public outreach programs to educate homeowners and contractors on the danger of not calling for locates and the importance of following safe digging practices. Since the last rate case, our safety and reliability metrics have consistently improved from already high levels, and we were honored to receive recognition as one of the safest companies in our industry by the American Gas Association for the sixth year in a row in 2024. The awards are attached to my testimony as Exhibit JDS-4.

Q. What other areas of safety would you like to address with the Commission?

A. For decades, to no fault of the Company, ENSTAR's pipeline system has experienced a significantly higher number of third-party damages by customers and contractors than experienced in other states. In 2021, this number was 6.16 damages per thousand locate requests. Third-party damages are dangerous for the public, our customers, and our employees. They also result in additional costs and fugitive emissions of methane from ENSTAR's pipelines until ENSTAR personnel can safely shut off the damaged gas line.

Q. Has there been an improvement to the third-party damage rate since the last rate case?

A. Yes. Through multiple initiatives and communications that we have prioritized since the last rate case, we have been able to reduce the third-party damage rate from 6.16 damages per thousand locate requests in 2021 to 5.27 damages per thousand locate

requests in 2024. This decrease improves public safety and the reliability of our distribution system.

B. Technological Improvements

Q. What technological improvements has ENSTAR made since Docket U-22-081?

A. ENSTAR has made several significant cybersecurity improvements since the test year in its last rate case. The Company has increased operational and technical labor resources to safeguard our system against ransomware attacks that could take control of the system and shut down pipeline operations, similar to the one experienced by Colonial Pipeline in 2021. The main focus was to segregate the Operations Technology ("OT") networks and related systems from ENSTAR's business IT networks.

Q. What specifically was done in these efforts?

A. In 2022, ENSTAR invited the Cybersecurity and Infrastructure Security Agency (a component of the U.S. Department of Homeland Security) to conduct a voluntary Validated Architecture Design Review to identify key focus areas in which to improve cybersecurity on OT networks and systems. Based on this review, ENSTAR made several investments in cybersecurity enhancements, including isolated authentication services, a Security Information and Event Management/Security Orchestration, Automation, and Response system, and around-the-clock security monitoring services. These efforts have greatly improved ENSTAR's detection and response capabilities to cyberattacks, and have lowered the overall risk to critical infrastructure.

Q. Is there an ongoing threat of a cybersecurity attack against ENSTAR?

A. Yes, and we continue to identify it as one of the main risks we face as a transmission pipeline operator and natural gas distribution utility. Just as a representative and recent

example, from January 1 through March 31, 2025, ENSTAR's IT systems successfully thwarted over 18,000 attempts to hack our systems with malware via email. Additionally, the Company experienced an attack in December 2024 in which there were over one million attempts to gain entry into our remote access systems. Due to ENSTAR's diligence and investment in cybersecurity protections, these attempts were unsuccessful. These threats are real and ever-present. We are in a constant state of defense and regularly combat bad actors in our mission to maintain the safety and reliability of our utility.

Q. What are the other technological improvements you would like to bring to the Commission's attention?

A. In 2024, a new Supervisory Control and Data Acquisition (SCADA) system went into service, replacing a legacy system that was nearly 20 years old. The upgraded system added much improved cybersecurity and high availability mechanisms to ensure our resilience to a cyberattack and brought it into a more compliant posture with PHMSA Control Room Management requirements.

Q. Does the Company have any technology projects planned for 2025 that you would like to highlight for the Commission?

A. ENSTAR is planning to spend approximately $7.7 million in 2025 for improvements in technology, of which about 55% (approximately $4.3 million) will go towards replacing our Mobile Workforce Management system with KloudGin Field Service Management. This system not only allows for workforce management but will also add a centralized asset management capability, something that does not exist for ENSTAR management today.

Q. What is the importance of the asset management capability?

A. KloudGin will be the centralized system of record for all assets (pipeline, main, services) from which all field work can be recorded and scheduled. This will increase safety and compliance with improved record keeping on preventative maintenance, making us more efficient and reducing operating costs over time.

C. Inflation

Q. Did the State of Alaska and residents in the ENSTAR service territory experience any challenges with inflation since 2021?

A. Yes, they have experienced significant inflation. In fact, the State of Alaska's Department of Labor and Workforce Development reports the increase in inflation since our last test year in 2021 was 11.8%.[6] The most significant annual increase in inflation occurred in 2022, the year after the test year in Docket U-22-081, and was recorded at over 8%.[7] This was the highest annual price increase since 1990.[8]

Q. What challenges does this increase in prices create?

A. A number of challenges come from inflation. From ENSTAR's perspective, inflation increases the cost of labor and materials, increases the risk of bad debt and ultimately, puts earnings at significant risk.

Q. Do you have any specific examples of price increases for standard equipment that is used routinely in operations?

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[6] CPI Index release by the State of Alaska, Department of Labor and Workforce Development, Urban Alaska, https://live.laborstats.alaska.gov/cpi/table, last accessed April 4, 2025.

[7] *Id*.

[8] January 2023 Alaska Economic Trends, https://labor.alaska.gov/trends/Jan23.pdf,. last accessed April 13, 2025 at 26.

A. Yes. To take a few examples, ENSTAR experienced over 30% price increases in both the locking meter valves and ¾-inch HDPE pipe used in daily operations, a 92% price increase in ¾-inch couplings, and a 118% price increase in ½-inch couplings. These are just some of the increases we are seeing today that are making it more expensive to do business.

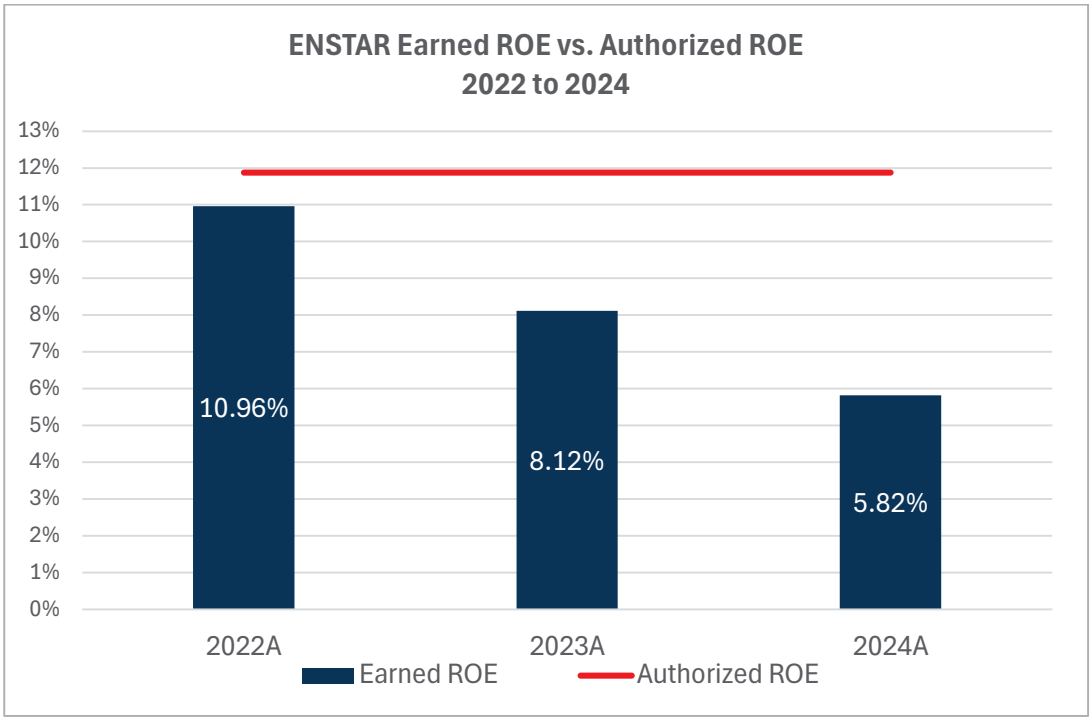
Q. How does inflation put earnings at significant risk?

A. Looking at recent history as the best example, ENSTAR is required to file the 275(a) form utilizing a historic test year as a regulated utility in the State of Alaska. In Docket U-22-081, ENSTAR used a 2021 test year to complete this form. The Company also bases its deficiency (the amount of additional revenues the utility needs to earn its allowed rate of return) off of those numbers from its test year. So, when a company has a significant increase in inflation the year following a test year, like the one that occurred in 2022, it increases the company's cost to serve customers and eliminates the opportunity to earn its allowed return. In the case of Docket U-22-081, inflation was already at 9.6% before an order resolving the revenue requirement was issued in 2024. ENSTAR was unable to capture any of the resultant increases in costs over that period.

Q. Has ENSTAR earned its authorized returns since filing its last rate case?

A. No. As shown in Figure 3, inflation, increased labor costs, the use of a historic test year, and a lack of timely cost recovery mechanisms, result in customer rates that do not reflect actual current costs of providing service to customers. Therefore, ENSTAR significantly underearned compared to our authorized ROE during the last three years.

FIGURE 3



Q. Does the Company have mechanisms to increase revenues to make up for these financial challenges?

A. Currently, the only way for ENSTAR to increase revenues between rate cases is to increase how much gas we transport on our pipelines. This can only come from increased demand from our customers in the form of rises in use per customer, customer growth, or colder temperatures. In 2023 and 2024, we increased our customer count and experienced temperatures colder than normal and still could not reach our regulated rate of return. However, we are planning a filing in the coming days to propose a ratemaking mechanism that will allow the Company to adjust its base rates annually similar to the formula rate mechanism used by CINGSA to address this issue.

Q. Why didn't ENSTAR reduce operating expenses to increase earnings?

A. The single, largest controllable expense we have on an annual basis is labor (our employees). We could reduce our workforce, but we already focus on operating efficiently and minimizing employee headcount to the greatest extent possible, and any further reductions to our workforce would impact our ability to safely and reliably serve our customers. Aside from cutting workforce, other necessary O&M expenses or capital investment could be slashed, but those options are not conducive to operating a safe and reliable gas utility.

Q. How does ENSTAR compare to the other Railbelt utilities in employee count?

A. Similar to my comments above, comparing the Railbelt utilities is very difficult as ENSTAR has a very different operational area and business. However, as depicted in Table 1 below, if you were to compare the utilities based on the number of employees per meter that is reported from each utility's annual operating report, ENSTAR has the highest customer count per employee.

TABLE 1

Utility	Customers	Employees	Customers per Employee
ENSTAR	153,000	224	683
CEA	113,257	448	253
MEA	69,809	228	306
HEA	33,817	231	146

V. ENSTAR'S REQUESTED ROE

Q. What ROE is ENSTAR requesting in this proceeding?

A. ENSTAR is requesting an ROE of 13.00%. Our request is consistent with Ms. Nelson's direct testimony, which provides for a range of ROE between 12.50% and 13.50%. Her recommendation reflects the unique risks to the Company operations. For a variety of reasons, which I will discuss, and which are also discussed in the direct testimony of Ms. Nelson and Ms. Johansen, ENSTAR is a unique transmission and distribution utility operating in an increasingly challenging environment.

Q. What business attributes and risks are presented by ENSTAR's operations?

A. ENSTAR's operations present many challenging business risks to investors. First, ENSTAR has inherent risk because the Company provides not only distribution services but also transmission services. Maintaining and operating transmission assets in Alaska presents unique risks that natural gas distribution utilities simply do not face, and those risks are severe. In general, transmission assets require significant capital to maintain reliability and safety, and these processes are often more complex and more expensive as compared to natural gas distribution companies. ENSTAR must also comply with PHMSA's requirements for both transmission integrity management plans ("TIMP") and distribution integrity management plans ("DIMP"). Complying with TIMP requirements is generally more expensive and requires more comprehensive testing and evaluation than DIMP requirements applicable to distribution utilities.

In addition, the Company faces unique, additional risks primarily due to its remote geographic location and relatively harsh operating environment, its lack of gas supply diversity, and its small size. Other risks to the Company are also presented by volatility in local economic conditions and declining use per customer.

Q. How do ENSTAR's remote geographic location and harsh operating environment increase risk?

A. Utility companies operating in Alaska, including ENSTAR, deal with significantly higher costs than those in the Lower 48, which have all been inflated by recent events. The fact is, goods cost more, goods are harder to procure, and qualified labor is harder to hire and retain due to the remote location of our facilities. In addition, a small company like ENSTAR has difficulty absorbing increases in costs without having a significant impact on our expenses and ultimately our return, all of which have been a particular problem, as described in other portions of my testimony, in an inflationary environment. Furthermore, maintenance of transmission and distribution assets in Alaska's harsh environment and climate, expansive footprint, and its geographical isolation increase the risks and costs associated with providing reliable and safe natural gas to customers. I discuss several of these risks below.

Q. What makes operating in Alaska more difficult than operating in the Lower 48?

A. There are several reasons that make operating in Alaska more difficult than operating in the Lower 48. First of all, we have a shorter construction season as opposed to other utility peers, including those in Ms. Nelson's proxy group, which increases risk to execute projects on a timely and cost-effective basis. The Alaska Department of Transportation & Public Facilities, Municipality of Anchorage, and Matanuska-Susitna Borough close the rights-of-way for utility work, typically between the months of October through May, for any activity that requires hauling heavy equipment on the road system. To operate within those months, a company must apply for a special permit to construct during the winter months or transport equipment to the job

site. Winter emergency response excavation occurs in frozen soil conditions at significant depth, increasing excavation time in duration by two to three times. Planned winter excavation activity will likely include mobilization and operation of ground thaw equipment two days prior to construction, ice road construction, or specific cost-inefficient construction methods. The seasonality of the construction season also relies on seasonal labor and contractor workforce, necessitating additional hiring, training, and operator qualification testing expense. Qualified labor is not readily available from neighboring jurisdictions, as the source for qualified labor is generally located in the Lower 48. Additionally, each individual project is more susceptible to cost increases due to normal supply chain delays or impacts to the schedule.

Second, a significant portion of ENSTAR's service territory consists of federal or Alaska native lands, regulated sensitive environments, and anadromous (salmonid bearing) streams. Special construction methods, such as horizontal directional drilling or United States Army Corps of Engineering-approved methods and restoration, in conjunction with specific land-use or environmental permitting, are regularly employed for a large portion of the Company's construction activities, much more so than the companies in the Lower 48. These requirements increase project timelines and add additional costs to capital projects.

Lastly, another challenge of operating in Alaska is its remote locations, especially when providing maintenance of our transmission assets. An example of this occurred on November 4, 2024, when a dog musher reported a smell of gas just west of the Kenai National Wildlife Refuge in the Kenai Peninsula Borough. ENSTAR dispatched technicians to investigate and determine the source of the gas. Because the

site was in the wetlands with no road access, ENSTAR had to build an ice road. ENSTAR then excavated the pipeline and found the source of the leak to be a crack in the twelve-inch "A" line, one of only two transmission lines used to bring gas to Anchorage from Kenai. The section of pipe was removed and replaced.

Q. Did ENSTAR see an increase in costs to maintain the transmission system?

A. Yes, ENSTAR spent an additional $1.66 million in 2024 when compared to the 2021 test year in Docket U-22-081. This represents a 43% increase. These costs, which were necessary to continue to operate a safe and reliable transmission system, were not included in the revenue requirement approved in ENSTAR's last rate case and are an example of costs that resulted in a direct reduction to earnings.

Q. Can you please describe some of the drivers for the observed increase in costs?

A. Yes, O&M expenses have generally increased due to an increase in staffing and necessary asset maintenance. Over the past three years, ten full-time positions have been added to meet the needs of the growing business. Many of these roles are craft personnel directly working on ENSTAR's assets, performing necessary functions to maintain a reliable service. For example, a valve maintenance technician was added in 2024 to perform our PHMSA required annual valve maintenance, and as industry best practice maintenance standards have expanded, a specialized role is needed to complete this task. The other roles added are a field measurement technician, a drafter, an engineer, two pipeline & compressor operators, two compliance specialists to assist with PHMSA audits, and two supervisors.

Q. Were there any additional cost increases in Transmission and Distribution expenses?

A. Yes. ENSTAR has also been performing increased asset maintenance such as Right-of-Way ("ROW") brushing, facility and fencing repairs, and other ongoing system tasks. The list below provides brief summaries of each:

- Brushing: maintaining access to our pipeline routes for activities like leak surveying and line locating is critical. Brushing is also required for basic access in locations like trailer parks where multi-meter manifolds are hung remotely and serve many residences. In the case of trailer parks, these areas are not typically maintained by the park owners and can quickly become overgrown. Additionally, it is a wildfire mitigation activity to maintain reliable service in an emergency scenario.
- Facilities: maintenance requirements with the age of many of our buildings have increased. Full roof repairs and major HVAC system repairs were required to maintain the functionality of our administrative and operation office buildings.
- Locating: as our damage prevention program and 811 awareness becomes more and more effective and successful, the volume of locates steadily increases. This positive outcome means fewer third-party damages, but it requires additional personnel and expense to complete the locate requests as we are required by law to respond to each and every locate ticket within two business days.
- OT & Communications: ENSTAR has increased our efforts into improving our communication systems to maintain reliable operations. This included the addition of personnel, but also an increase in maintenance to our communication network to ensure our regulator and compressor stations continue to transmit pipeline operations data back to our SCADA system and control room.

- Fencing: ENSTAR has performed necessary security fencing repairs over the last few years, including the installation of an anti-cut fence at its Operations center due to repeated thefts of equipment. ENSTAR also had to repair security fencing around pipeline valve stations required to prevent any malicious isolation or over-pressurization of our system.
- Compressor Stations: Changes to Title 40 Code of Federal Regulations specifically Subpart OOOOb require significant labor hours and contractor costs to quantify and record methane emissions at our compressor stations.

Q. What are some of the reasons that goods cost more for utilities operating in Alaska than those in the Lower 48?

A. First and foremost, the cost to ship goods and materials to Alaska is extremely expensive. Nothing is manufactured or produced anywhere near our service territory, which means that everything we use for serving our customers on a daily basis has to be flown in, shipped into the Port of Alaska, or trucked in through Canada. This fact is unique to Alaska when compared to any other utility in the Lower 48 and adds considerable, and frequently unexpected, expense to our business.

Q. Does ENSTAR have any supply chain or logistical challenges due to its remote location?

A. Yes, supply chain and logistical challenges are one of the leading causes for project cost overruns and delays. ENSTAR relies on long and complex supply chains. Disruptions at any point in these chains, such as natural disasters, geopolitical conflicts, labor disputes, or transportation issues, can lead to significant delays and increased costs that were unexpected.

Q. Can you provide an example of an unexpected cost that would impact only Alaska utilities related to supply chain issues?

A. Yes. Just recently, the province of British Columbia announced that commercial trucks traveling from Washington to Alaska could be subject to new fees in response to the United States' increase in tariffs on imports from Canada.[9] This could directly impact our costs to serve our customers and was not anticipated or expected. While it could change, it highlights the challenges for shipping through Canada. Additionally, the drive from Seattle to Anchorage is 2,266 miles with very limited infrastructure available along the route. Due to the varying weather conditions and geographical barriers, there is a wide array of challenges that could be expected along the way that all other utilities in the Lower 48 don't have to deal with when procuring items.

Q. How does ENSTAR's lack of gas supply diversity increase risk?

A. As has been thoroughly documented and discussed both before the Commission and in the public arena, the State of Alaska faces significant challenges trying to address stranded resources and getting Alaska's gas to market. The challenges when discussing gas supply are really three-fold.

First, since ENSTAR began operating as a transmission and distribution utility, we have never been connected to any large pipeline network similar to those in the Lower 48, which connects most of the country to a variety of different natural gas basins. Today, 100% of the natural gas that our customers consume comes from the Cook Inlet. That fact has not changed, and while there has been recent advancement

[9] https://vancouver.citynews.ca/2025/03/06/bc-eby-new-fees-commercial-vehicles-alaska/, last accessed April 13, 2025.

on a natural gas pipeline bringing gas from the North Slope to Southcentral Alaska, there are still a lot of unknowns related to that project and it faces significant challenges before it can be completed.

Second, as discussed in the direct testimony of witness Ms. Johansen, we continue to see a decline in deliverability and overall gas volumes from Cook Inlet wells. This fact increases the need for additional natural gas storage, and the need to source natural gas from other locations.

Finally, we have been unable to procure firm gas supply contracts to fill the projected requirements for our customers in 2025 and 2026. The gas supply secured under the agreement with Furie for the period 2026 - 2031 that is supposed to cover ENSTAR's remaining gas supply gap comes with a tremendous performance risk. Despite the fact that ENSTAR's current contractual commitment with Hilcorp does not terminate until 2033, ENSTAR is deeply concerned about short-term and long-term energy security for all of the gas consumers in Cook Inlet especially given the fact that the contractual commitments with Hilcorp only cover approximately 85% of ENSTAR's projected demand.

Q. How will ENSTAR meet future gas supply needs?

A. ENSTAR is currently working to secure a path to long-term gas supply for the Railbelt. Over the short-term, we continue to negotiate with every producer willing to provide us additional gas supplies in an effort to procure more gas. At this point, Furie is the only entity willing and able to offer us gas not already under contract. ENSTAR has a gas supply contract with Furie that will supply gas to the market in 2026 through 2031. But, deliveries under that contract are pending a successful drilling campaign.

Regardless of the ultimate solution, we have an ongoing obligation to serve customers with safe and reliable utility service and we must find that solution before it is too late. The risk to ENSTAR and its investors in a situation where there is no gas supply is unquantifiable on its own, but the risk to the Company's customers is potentially catastrophic. Please also see the direct testimony of Ms. Johansen and Ms. Nelson for additional discussion of this risk.

Q. How does ENSTAR's small size increase risk?

A. As discussed in detail in the direct testimony of Ms. Nelson, smaller companies generally are: (1) less able to deal with significant events that affect sales, revenues, and earnings; (2) less able to manage through swings in business cycles and economic conditions; and (3) less able to adjust to changes in customer usage or customer count given the relatively small number of customers served. For these reasons and others, including support Ms. Nelson cites from various industry experts, small size relative to the industry proxy group creates significant risk for an investor.

Q. What do you mean when you say smaller companies are "less able to manage through economic conditions?"

A. Because ENSTAR is a relatively small distribution and transmission utility, increased operating expenses and/or material disallowances in a rate case will have a much greater impact on ENSTAR than they would on a larger natural gas utility. This is true both because of the smaller cost base of ENSTAR and the relatively low level of expenses required to operate ENSTAR as compared to a larger utility.

To illustrate the impact of the smaller cost base of ENSTAR, I will use an example of a $1 million impact on ENSTAR's return, which is less than the

approximate $1.6 million in higher transmission costs I discuss above. Assuming the Commission approves all operating expenses proposed by the Company in this case, if ENSTAR were to incur $1 million in operating expenses more than what is approved, that increase would have a much larger impact on ENSTAR than that same cost increase would have on an entity like Atmos Energy Corporation ("Atmos"). A $1 million annual expense represents approximately 2% of ENSTAR's total O&M (including A&G) expense as proposed. Assuming this $1 million impact flows through to the equity return (as proposed), it would reduce ENSTAR's overall return by almost 50 basis points. For Atmos, this same $1 million annual expense would equate to an approximate one basis point impact to their return. If the experienced increase in operating expenses were to rise to $5 million, ENSTAR's equity return would be reduced by approximately 240 basis points, whereas Atmos' equity return would experience a reduction of only four basis points for the same $5 million expense increase. ENSTAR is at additional financial risk as compared to larger utilities solely due to its size.

A common perception is that when a utility has increased expenses or a disallowance occurs, the utility can recover its approved return by otherwise adjusting its capital spending program or expenses. In reality, making those adjustments is difficult for any utility, and for ENSTAR it is extremely difficult, if not impossible. The Company does not have any significant expenses to cut or significant planned expenditures that it could defer given its focus on minimizing costs, its geographic isolation, and its obligation to provide safe and reliable service at a reasonable cost. ENSTAR simply cannot manage these types of adverse impacts to the extent that larger

utilities can. These facts, coupled with the need to invest significant capital in the foreseeable future as ENSTAR embarks on its RIRP and other capital-intensive initiatives as described in Section VI of my testimony, increases our business risk.

Q. What was the difference in overall operating expense in the test year when compared to the last test year, 2021?

A. ENSTAR has seen an increase in normalized annual operating expense of over $8.8 million when compared to the test year filed in Docket U-22-081.

Q. What significant increases in expense categories has ENSTAR experienced since 2021?

A. As discussed above ENSTAR has seen increases in transmission expense, customer accounting, distribution expense, insurance expense, and medical and dental expense, among others. All of these categories have seen cost increases of over $1.4 million since the Company's last rate case test year in 2021.

Q. Are there other factors that will potentially affect earnings in the near future?

A. Yes. The current and prospective local economic conditions in Alaska have a strong potential to affect ENSTAR's earnings. The State of Alaska is facing an imminent budget deficit of upwards of $1.6 billion in the fiscal year 2026, requiring unprecedented action by Alaska's leaders to increase state revenue and decrease spending. The fiscal situation of the state government is merely indicative of the overall condition of the Alaska economy, particularly in ENSTAR's service territory. Between 2014 and 2024, the Municipality of Anchorage, which represents the largest portion of ENSTAR's service territory, has experienced negative net migration every year—in other words, more people are leaving Anchorage than are arriving.

Furthermore, as attached as Exhibit JDS-5, the Anchorage Economic Development Corporation ("AEDC") is expecting no growth in population for the next five years, and population challenges will continue to have adverse effects on the local economy and labor market.

As the Commission is no doubt aware, this is not the first time that Alaska has faced an economic crisis. In the mid-late 1980s, Alaskans suffered through the worst economic downturn since statehood, when, in 1986, oil prices slid to below $10 per barrel. Much like the current crisis, state revenues and spending plummeted and jobs were lost at an alarming rate, impacting the housing market and causing material increases in bad debt and uncollectible accounts for ENSTAR. The risk to ENSTAR is not limited to bad debt and uncollectible accounts. There is potential for negative impacts on ENSTAR's total customer count as jobs are lost and workers look for other opportunities outside of Alaska. Struggling families and others affected by the economic downturn are likely to shift into conservation mode, which has the potential to reduce consumption of natural gas. Alaska will most likely survive the current economic crisis, much as it did in the 1980s, as State leaders are working hard to address the budget deficit and reform the Alaska economy. But the current challenges are real, and investors will consider them when deciding where to put their money.

Q. Is the Company exposed to risks associated with declining use per customer?

A. Yes, it is. ENSTAR's average use per customer has declined by approximately 5% from 2015 to 2024, and our average use per residential G1 customer has declined by approximately 4.0% over the same time period. Since Docket U-22-081, the average use per residential G1 customer has declined by 2%.

Q. What are the main drivers for reductions in use per customer?

A. There are many. The long-term trend has been driven by energy efficiency and conservation programs, the construction of more energy efficient homes, and increased awareness regarding the importance of energy conservation. More importantly, as ENSTAR has communicated publicly on multiple occasions, energy conservation is going to become more prevalent as the cost of gas increases due to new contracts approved with Furie[10] and anticipated in the near future with LNG imports.[11]

Q. How does a declining use per customer put ENSTAR's earnings at risk?

A. Because ENSTAR rates are established, in part, on test year demand levels, absent some form of revenue stabilization, declining use per customer diminishes revenues and substantially decreases ENSTAR's ability to earn its authorized return. The use per customer decline for residential G1 customers that I discussed above equates to a loss of approximately 0.4 Bcf of usage or $0.7 million in lost margin. As with the other risk factors discussed above, these factors should be considered by the Commission in establishing an ROE for ENSTAR that will allow it to successfully attract new capital.

VI. ENSTAR'S CAPITAL PLAN AND EFFECTS ON FINANCIAL INTEGRITY

Q. Has ENSTAR invested capital since its last rate case?

A. Yes. Since the end of the test year in Docket U-22-081 (December 31, 2021) through the end of the test year in this case (December 31, 2024), ENSTAR invested approximately $127 million in capital in its utility system. These investments included safety and reliability upgrades; regulator station replacements; control system

[10] The first-year price effective April 1, 2026, is set at $12.30 per Mcf.

[11] See BRG and Alaska Utilities Working Group, Phase I Assessment: Cook Inlet Gas Supply Project ("CIGSP") presented at the RCA Public Meeting June 28, 2023: LNG price of $12-$23 per Mcf.

replacements; and strategic distribution system reinforcements among other critical investments for the benefit of our customers. Please see the direct testimony of Mr. Burke for further discussion of the Company's capital investments since the last rate case.

Q. Does ENSTAR have a plan for deploying capital prospectively?

A. Yes. Pursuant to its currently approved capital plan, ENSTAR is projected to invest between $60 to $70 million each year, for the next five years. This capital is designed to address several important issues and must be addressed in the near future. First, as I have already discussed, the Company plans to spend a significant amount of capital to improve technology. These advances will make us more efficient and protect us from external cybersecurity threats. Second, the Company will continue its RIRP to replace aging, high-risk transmission pipelines and distribution mains and services. The RIRP will create a safer, more reliable natural gas distribution system for the Company and its customers. Third, we are planning to replace and improve a number of large meters and valves at some of our regulation stations that regulate system pressures. All of this capital is necessary to provide the safe and reliable service that ENSTAR's customers are accustomed to receiving. Mr. Burke in his direct testimony provides additional details on some future capital projects that the Company plans to complete in the next five years.

Q. Is ENSTAR unique in this challenge when compared to utilities across the country?

A. Yes and no. Currently, utilities across the country are deploying capital at a very rapid rate for various reasons, including safety, reliability, cybersecurity, a need to replace

aging infrastructure, and economic expansion. At the end of the day, without timely recovery of capital, cash flows are greatly reduced, which puts pressure on credit metrics and utilities' ability to borrow funds at reasonable rates. That is the case for ENSTAR.

Q. Has the National Association of Regulated Utility Commissioners ("NARUC") ever adopted resolutions in favor of utilities proactively addressing issues related to this risk?

A. Yes, on July 24, 2013 NARUC Board of Directors adopted a resolution "encouraging natural gas line investment and the expedited replacement of high-risk distribution mains and service lines." I have attached the NARUC resolution to my testimony as Exhibit JDS-6.

Q. Will the level of additional capital investment put pressure on the earnings and financial health of the Company?

A. Yes, without timely capital recovery, the level of investment approved in the capital plan will put extreme pressure on earnings and will essentially negate the Company's ability to earn its authorized return whatever that may be. Given the period of time between the deployment of capital at the level contemplated in the capital plan and the time for recovery given the current regulatory paradigm in Alaska, ENSTAR will not have a reasonable opportunity to realize its authorized return unless it slashes its O&M budget or reduces its capital plan, both of which would run counter to the objective of operating a safe and reliable transmission and distribution system.

In reality, it isn't just the capital program that is causing us to be gravely concerned about future earnings, it's all of the challenges combined together. When

you look at the capital needed to maintain a reliable and safe system, in addition to the declining use per customer, challenging Alaska economy, geographic isolation, supply chain obstacles, inflationary pressures, and gas supply challenges it makes it nearly impossible to achieve the authorized return. Which is why, in TA 353-4 ENSTAR requested Commission's approval to implement a formula rate mechanism ("FRM"). This mechanism has already been established, is tried and true, and utilized by this Commission for years to help mitigate the adverse financial impacts of operating in Alaska for the benefit of the customers and the utility. By adjusting rates annually to ensure that they reflect current costs of providing the service to our customers, the FRM will provide greater stability to the Company and its customers.

Q. Can ENSTAR demonstrate the effects its capital plan will have on earnings?

A. Yes. To demonstrate this dynamic, ENSTAR prepared an earnings analysis assuming various factors to demonstrate that earnings will fall way short of its authorized ROE given its current five-year capital plan.

Q. Please describe the earnings analysis.

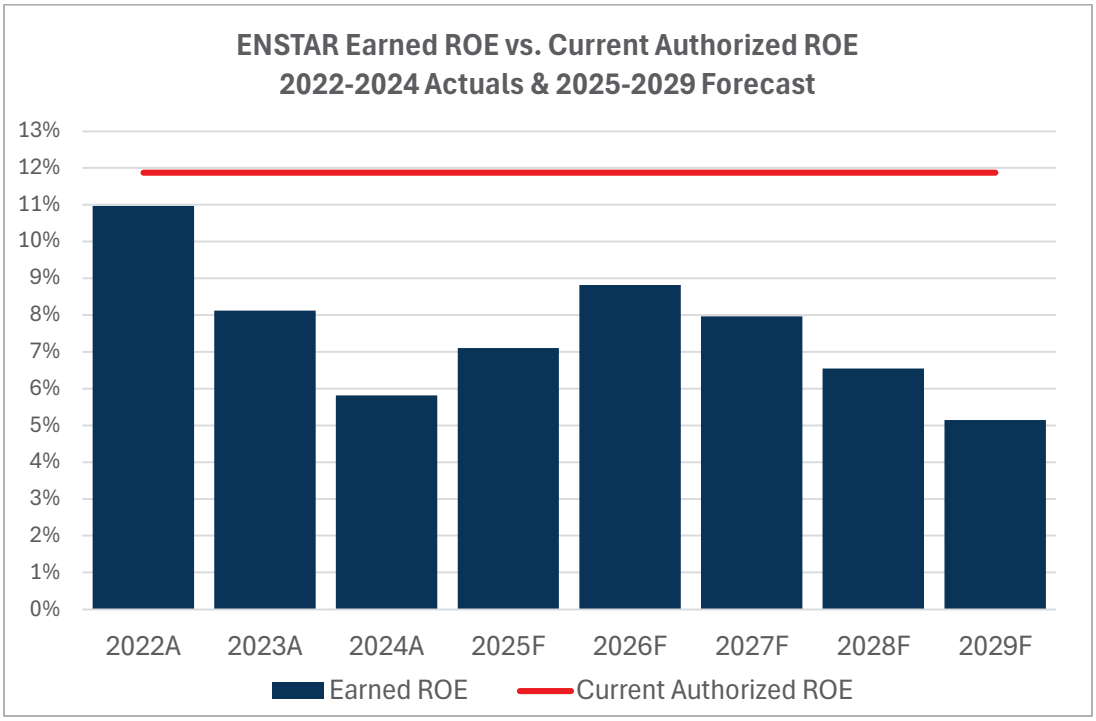
A. ENSTAR's projected earned ROEs for forecasted years 2025 to 2029 demonstrate the effects its future capital spend will have on the Company's ability to earn its authorized ROE. Figure 4 below provides ENSTAR's actual earned ROEs for 2022 to 2024 and forecasted ROEs for 2025 to 2029. To prepare the forecast for future years, ENSTAR assumed that the entire requested rate case filing has been approved by the Commission as filed, including the proposed ROE and overall cost of capital. In addition, ENSTAR used the following assumptions:

- Capital additions: the average annual projected capital investment of $65 million.

- Sales revenues: the historical ten-year average rates for customer growth and normalized use per customer were applied to calculate gas sales future revenue.
- Transport revenues: volumes are projected at the same level as normalized in 2024.
- O&M expenses excluding cost of gas: increased at 3% per year to account for annual inflation and other cost increases.
- Property taxes and depreciation: applied growth rates correlating to plant additions.

The analysis clearly demonstrates, for both historical and future periods, that ENSTAR will continue to fail to earn its currently authorized ROE.

FIGURE 4



As I stated earlier, unless we slash our O&M or cut our capital investment that is required to sustain the safety and reliability of our system, we will not have a reasonable opportunity to earn a reasonable return on our investment.

VII. CORPORATE SERVICES

Q. Does ENSTAR receive support services from TSU?

A. Yes. Support services are sourced from TSU in order to streamline overhead expenses and processes, thereby reducing costs to our customers and maximizing the efficiency of the utility service we provide. Additionally, TSU provides ENSTAR with a significant pool of expertise, skill sets, capital, and other resources to draw upon as needed. ENSTAR's Cost Allocation Manual, attached to the direct testimony of Ms. Riggs, and the Company's Amended and Restated Services Agreement with TSU, attached to the direct testimony of Ms. Jackson, describe the services TSU provides to the Company.

Q. Please describe the relationship between TSU and ENSTAR.

A. ENSTAR was established in Alaska in 1959 and first began providing natural gas service in 1961. It has had various owners over its history. In March 2023, TSU acquired ENSTAR. As a result of that transaction, ENSTAR became an indirect, wholly-owned subsidiary of TSU USA Holdings Inc., which is a direct, wholly-owned subsidiary of TSU.

Q. Are ENSTAR and TSU affiliates pursuant to AS 42.05.990?

A. Yes.

Q. Do the costs associated with the services performed by TSU meet the statutory requirements under Alaska law for inclusion in rates?

A. Yes. Pursuant to AS 42.05.511(c), the utility has the burden to prove that: (1) services provided by the affiliate are necessary and consistent with the public interest; (2) payment made for those services is reasonably based, in part, on the cost incurred by the affiliate to provide those services; and (3) the payment is reasonably based, in part,

on the estimated cost for the utility to perform those services if it were to self-provide those services with its own personnel and capital.

Pursuant to AS 42.05.441(c), the utility also has the burden to prove that: (1) payments made for the services provided by the affiliate were for services that were reasonably necessary for the operation of the utility; and (2) the services were provided to the utility at a cost that is competitive with the price at which the utility could have obtained the services from an unaffiliated third party. Relevant portions of both statutes are attached hereto as Exhibit JDS-7.

As stated in the direct testimony of Ms. Jackson, services are provided to the Company at cost with no additional mark-up. The service-related costs from TSU cover numerous responsibilities associated with Board of Directors; Executive Committee; Accounting, Tax and Finance; and Corporate Resources (including Legal and Compliance), as well as a portion of the office space and equipment required for these employees to provide these services. By sourcing these services from TSU, ENSTAR not only receives the services at cost, but the portion that is allocated to ENSTAR represents a significant savings to self-providing these services given the efficiencies and economies of scale that result from this business practice.

Q. Are the services provided by TSU "reasonably necessary for the operation of the utility" and "necessary and consistent with the public interest"?

A. Yes. As President of ENSTAR, I can attest to the need for these services as well as the efficiencies that the services provide. As a small company with 230 employees, providing these services on a standalone basis would be prohibitively expensive as compared to the current corporate structure.

Further, acquiring these services from TSU is necessary and consistent with the public interest. Safe and reliable service is a core value for ENSTAR and TSU. Collectively, we work to achieve this goal by maximizing our resources to deliver the highest quality service at a reasonable cost to our customers. The services that ENSTAR receives from TSU serve the public interest by allowing ENSTAR to access tremendous resources, which improves the service that ENSTAR provides while requiring the Company to incur only a small portion of the expense.

Q. Can you elaborate on why the services provided by TSU are reasonably necessary for ENSTAR's operation?

A. Yes. As discussed in the direct testimony of Ms. Jackson, the services that TSU provides are imperative for the operation of any publicly-traded, investor-owned utility. The TSU shareholders bear many of the upfront costs for these services. It follows, then, that if the services were not necessary for the operation of this utility, such services would not be procured or performed on ENSTAR's behalf. In addition to the testimony of Ms. Jackson regarding the necessity of these services for ENSTAR, I will briefly address the necessity of the services below.

1. Board of Directors. ENSTAR requires the oversight it receives from the TSU Board of Directors to carry out its business functions in Alaska. Moreover, the fiduciary and governance services that ENSTAR receives through this function, which Ms. Jackson details in her testimony, are critical to providing ENSTAR with access to capital needed to maintain critical investment in ENSTAR's system and come with a cost.

2. Executive Committee. Skilled, expert management is necessary at the executive level to strategically lead ENSTAR to continue to operate, not just in the immediate future, but decades from now. There is one natural gas utility in Southcentral Alaska, and 155,000 customers – or roughly half of the households in this state – rely on that utility for their primary heating source. Poor management at any level of this organization could have significant negative consequences for the region and the State of Alaska. Expert executive management is essential to ensuring the economic stability of ENSTAR now and into the future.

Ms. Jackson's testimony details the many services that this function provides. To replicate these services, ENSTAR would have to attract and pay high level, quality executive officers, with the experience and skillset to provide the oversight and strategic planning ENSTAR receives through TSU.

3. Accounting, Tax and Finance. As Ms. Jackson explains in detail, the Accounting, Tax and Finance function includes numerous services associated with preparation of audited consolidated financial statements; internal audits; securities filings; treasury, cash management, budgeting, and planning; and tax planning, among other things, necessary for a public reporting issuer. All of these services are necessary for ENSTAR to access the capital it requires to maintain its safe and reliable operation.

4. Corporate Resources (including Legal and Compliance). As Ms. Jackson explains in detail, the Corporate Resources function advises on an array of corporate matters, including governance, code of business ethics, risk management, compliance, disclosure, employment, and legal matters. All of these services are necessary for

ENSTAR to operate.

Q. Would it be less costly for ENSTAR to internally provide the services provided by TSU?

A. No. As demonstrated in Exhibit JDS-8, which is a summary of a hypothetical analysis that I co-sponsor with Ms. Jackson, the costs for ENSTAR to provide these services would be higher if the Company provided these support services internally.

Q. What were the costs of the services provided by TSU in 2024 and how were those costs allocated to ENSTAR?

A. TSU allocates the costs to its subsidiaries by utilizing the methodology described in the direct testimony of Ms. Jackson. In 2024, the total amount charged to ENSTAR for the services provided to it by TSU was approximately $2,866,000 as set forth above and in the direct testimony of Ms. Jackson, these costs were all reasonable, necessary, and consistent with the public interest. These services are provided at cost and are less than they would have been had ENSTAR sourced these services independent from its affiliate.

VIII. CONCLUSION

Q. Does ENSTAR's proposed revenue requirement result in just, fair, and reasonable rates?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes.

John D. Sims

EMPLOYMENT

TriSummit Utilities, Inc. 2023 - Present

ENSTAR Natural Gas Company/Alaska Pipeline Company

President, 2023 - Present

SEMCO Energy, Inc. 2005 - 2023

ENSTAR Natural Gas Company/Alaska Pipeline Company

President, 2017 - 2022

Vice President, Corporate Resources and Business Development: 2015 - 2017

Director, Business Development 2013 - 2015

Director, Corporate Communications & Customer Service 2011 - 2013

Manager, Corporate Communications & Customer Service 2009 - 2011

Manager, Credit & Customer Service 2007 - 2009

Business Development & Public Affairs Representative 2005 - 2007

American Family Life Assurance Company

District Manager 2002 - 2005

Sales Representative 2002

EDUCATION

Hillsdale College: Bachelor of Arts, Marketing Management

University of Alaska Anchorage: Masters, Business Administration

OTHER

Board Member, Junior Achievement Alaska

Board Member, Chugiak Eagle River Foundation

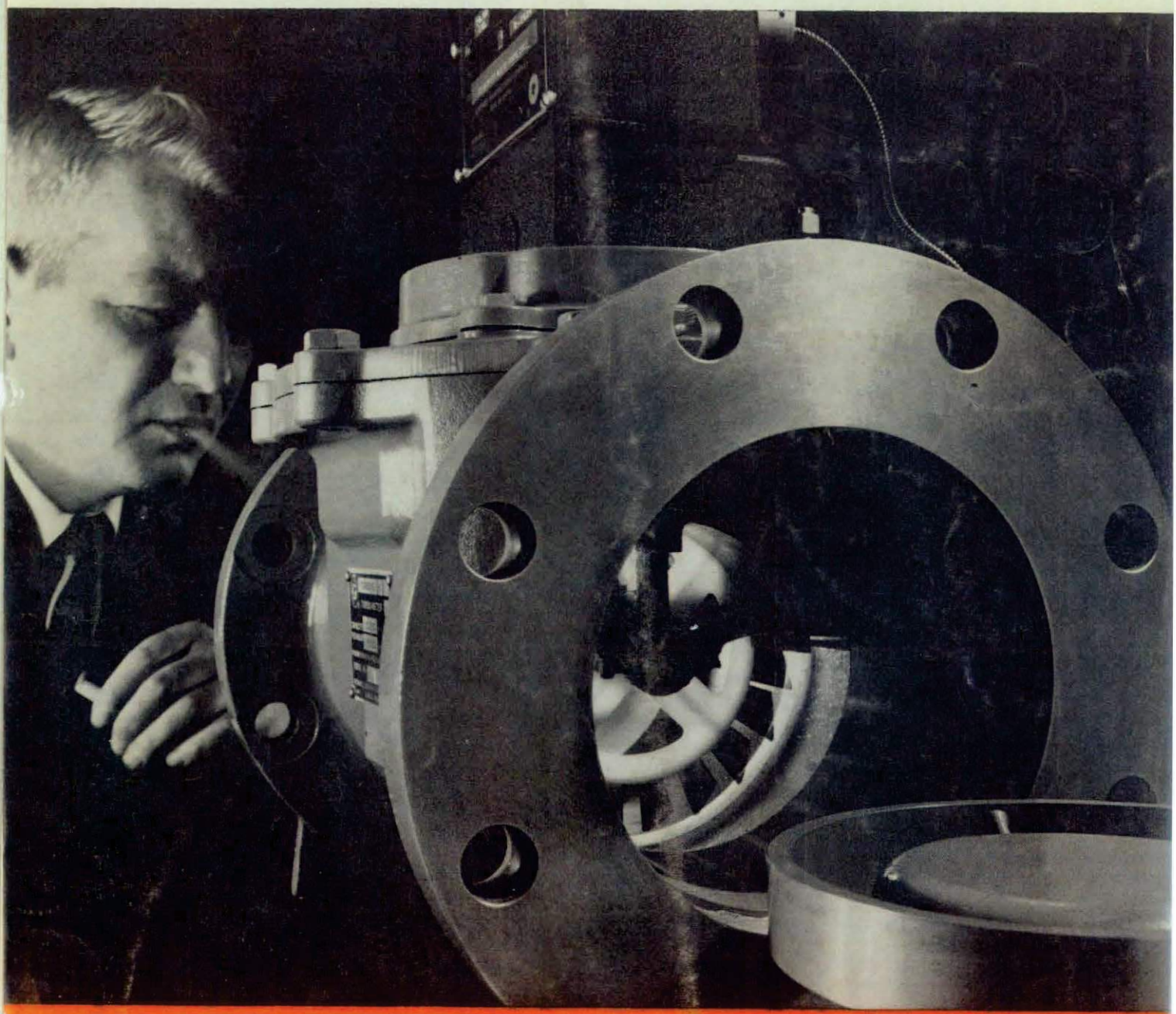
GAS

AUGUST 1964

Stump

The magazine of the natural gas industry

A CHILTON PUBLICATION



Need low flow sensitivity in a high volume gas meter?
Just a breath is enough to operate the Turbo-Meter.

Rockwell
MANUFACTURING COMPANY

See Table of Contents page for details

Docket U-25-___

Exhibit JDS-2
Page 1 of 7

This is what remains of a school in the northern section of Anchorage after an earth slide broke it in two. Portion of school at left and schoolyard in foreground were originally at the same level as corner of school at extreme right.

Typical residential damage caused by earth subsidence.

When the earthquake struck

By Willard J. Stump, Operations Manager
Anchorage Natural Gas Corp., Anchorage, Alaska

"IT'S just another earthquake" was the reaction of Anchorage residents at 5:36 p.m., Good Friday, March 27. But after the movement continued past the normal few seconds, the seriousness became apparent. Our customers saw their yards rise and fall in a wave motion exceeding 4 ft. People saw the wave action in the streets, in sidewalks, in frozen ground. An engineer reported watching a 14-story hotel sway 20 ft. Cars literally bounced off the paving. The violent motion bent the trees toward the ground. A helicopter pilot saw the ground open 4 ft and close to again open in another place close by. People were thrown to the ground and could not stand without help. Chimneys were thrown down, some collapsing on our meter settings located outside of the boiler rooms.

The Knick Arm steam generating plant had many breaks in the pressure piping. Many buildings, especially the tall ones, were damaged within the first 15 ft above the ground. The inertia of mass alone confined damage to the area adjacent to the ground surface. In one case, a 12-in. "I"-beam located in the corner of a building was twisted in two.

An underlying strata of blue clay which occurs at sea level liquefied because of the continued vibration and flowed from under the sand and "glacial till" overburden, permitting the Cook Inlet bluffs to fall away and move into tidal water. Some land did not slump but moved horizontally several feet. Survey ties were displaced as much as 11 ft. One of our engineering crews attempted to survey a line location to restore a 2-in. main. They set up the transit on one hub and backsighted on a reference. When they projected the line forward, it did not parallel the alley line but intersected the corner of a hospital one block away. Bench marks have had to be re-established. Because of general subsidence of the entire area, the tides at our submarine crossing of Turnagain Arm are now rising 3.8 ft higher on the shore.

"Our line must be broken here because a pressure ridge is 8 ft high," came the radio report of a supervisor.

"I still had gas when I left my house," reported an engineer in southeast Anchorage.

It was soon determined that not only was our 84-mile 12-in. transmission line still in operating condition, but we could maintain service to the two largest hospitals and about 1000 customers near our city gate station. But a break in our 12-in. high pressure distribution main dictated that a block valve be closed, isolating 90% of the city.

An engineering aide was dispatched to make a preliminary plot of the fissures. This plot defined the problem and on this was based the decision for various temporary loops. It was observed that most of the land movement occurred in the north and west part of town. The supply enters the distribution system at the southeast corner of the system. It was possible to restore service in a systematic manner from that point toward fractured areas, leaving the most damaged areas until last.

Northwest Natural, Cascade Natural, and Washington Natural were contacted through military communications. They were asked to send a total of 30 men, divided among service and distribution. Within 24 hours, these men began arriving. All skills were present: management, supervision, servicemen, a pressure man, welders, and street fitters. Their experience permitted them to set to work immediately and without direct help from our people. Their ability permitted the use of our own men elsewhere; for example, our pressure and measurement engineer was released to supervise the installation of temporary loops and the repair of the mainline. They brought with them line locators, gas testers, and hand tools. Their cooperation and assistance was reassuring to the tired men of Anchorage Natural who as yet had not had any rest.

An above-ground 3-in. loop was started about 10 Friday night, following the earthquake at 5:36 p.m., to bring gas from the hospital area into the isolated section of Anchorage. Steam thaw rigs were placed in operation at the tie-ins with the mains that were to be fed. The 3-in. pipe was strung on top of the ground and Dresser couplings were used to join the line. By 6 a.m. Saturday, this loop was ready to restore gas to the abbreviated distribution system.

During this time, a temporary above-ground 4-in. line also was strung to serve the two 15-magawatt gas-fired turbines of the Anchorage Municipal Light and Power Department. Since the quake, the city had been without power. The standby fuel oil tank had ruptured and the fuel was lost. Salesmen, customers, and volunteers from the street began stringing 4-in. threaded pipe to tie across the broken 12-in. and 6-in. mains formerly serving the turbines. Plates were welded on the trimmed broken ends, valves were installed, and the 4-in. line was screwed together with 48-in. wrenches and chain tongs.

Within 30 hours after the quake, we had the turbines back on gas. A total of 2000 ft of 4-in. line was laid on a hillside covered with ice, and at the turbine plant through fuel oil 6 in. deep which had

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Exhibit JDS-2
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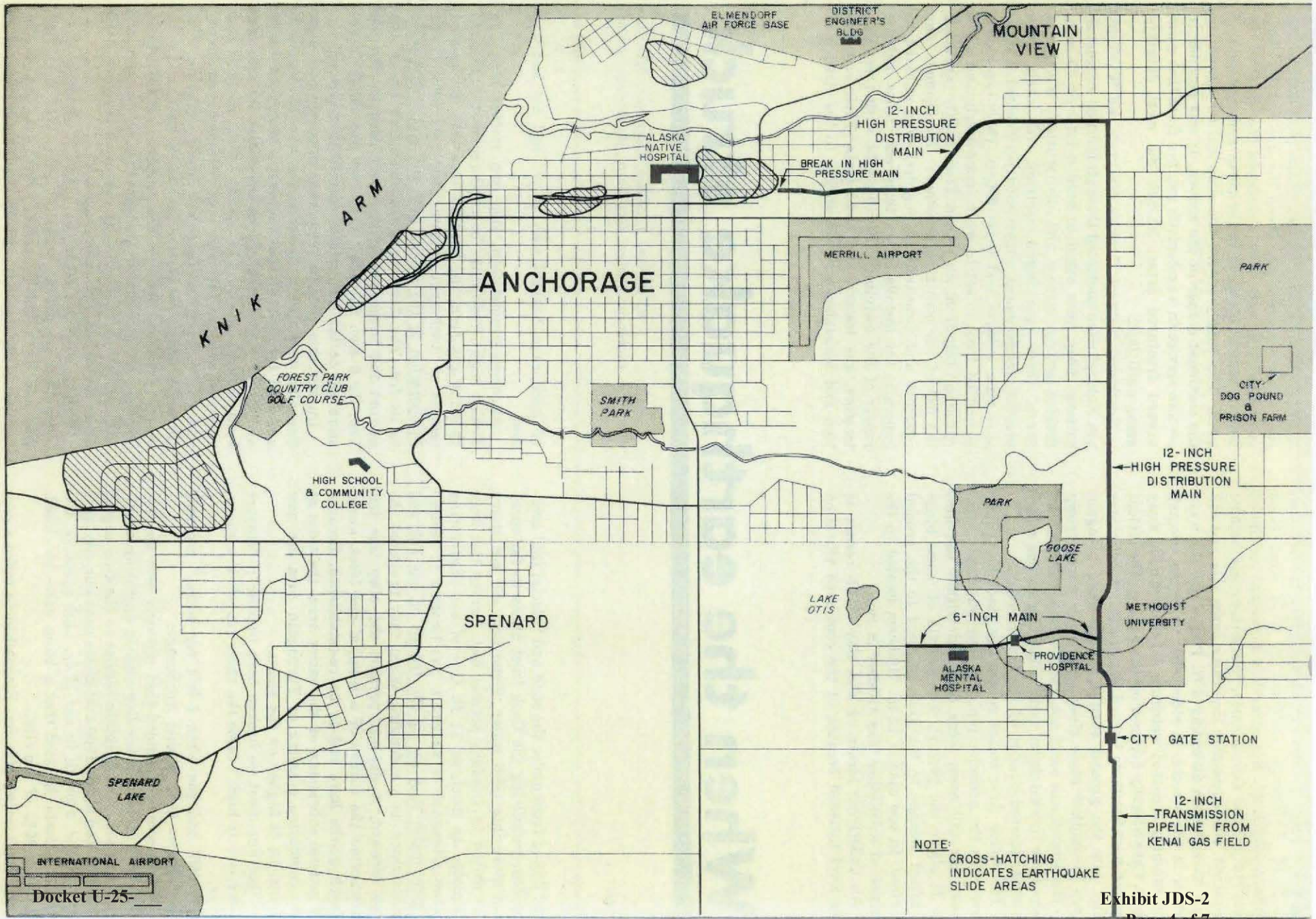
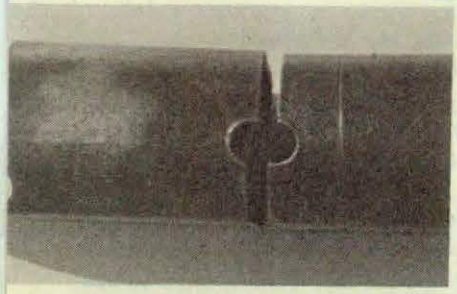
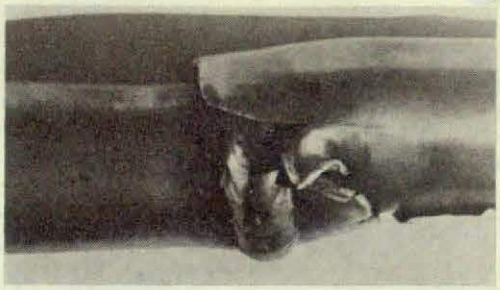
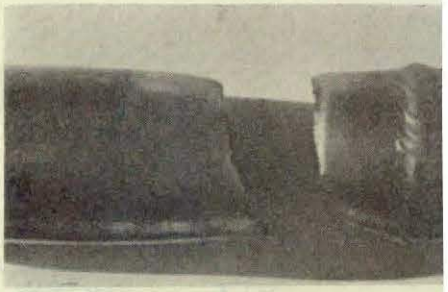

ELMENDORF AIR FORCE BASE
DISTRICT ENGINEER'S BLDG
MOUNTAIN VIEW
12-INCH HIGH PRESSURE DISTRIBUTION MAIN
ALASKA NATIVE HOSPITAL
BREAK IN HIGH PRESSURE MAIN
KNIK ARM
ANCHORAGE
MERRILL AIRPORT
PARK
FOREST PARK COUNTRY CLUB GOLF COURSE
SMITH PARK
CITY DOG POUND & PRISON FARM
HIGH SCHOOL & COMMUNITY COLLEGE
12-INCH HIGH PRESSURE DISTRIBUTION MAIN
PARK
GOOSE LAKE
LAKE OTIS
METHODIST UNIVERSITY
6-INCH MAIN
PROVIDENCE HOSPITAL
ALASKA MENTAL HOSPITAL
SPENARD
CITY GATE STATION
SPENARD LAKE
12-INCH TRANSMISSION PIPELINE FROM KENAI GAS FIELD
INTERNATIONAL AIRPORT
NOTE:
CROSS-HATCHING INDICATES EARTHQUAKE SLIDE AREAS



1¼-in. main sheared at punch hole.



Pipe failure caused by compression. Note tearing of pipe wall.



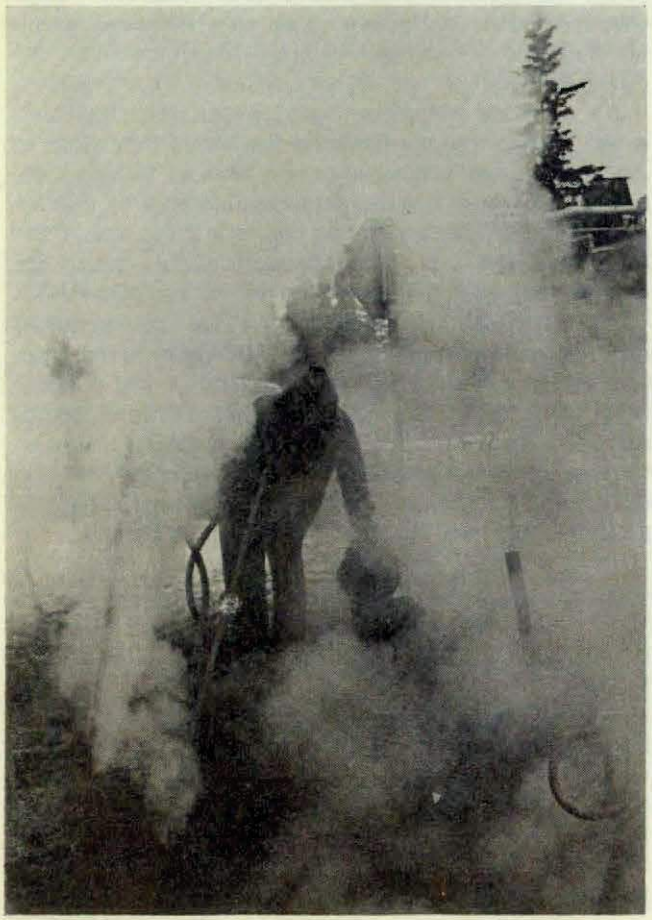
Pipe failure due to tensile strain. Note decreased wall thickness at point of failure.

spread out on top of the ice and frozen ground. Installing 4-in. pipe with only hand labor is most difficult, but add to this oil on top of ice. At times it was almost impossible to stand.

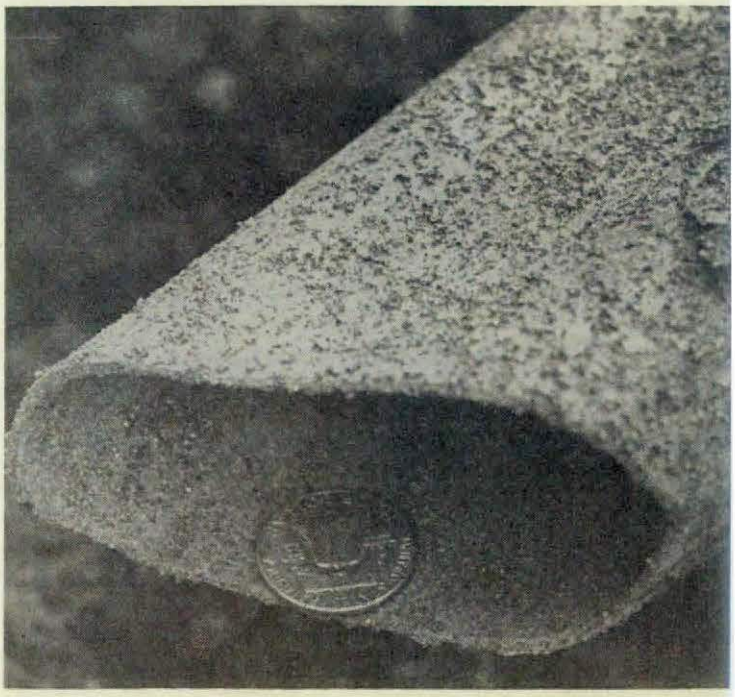
Because the ground was frozen to a depth of about 10 ft, steam thaw rigs were immediately assigned to thawing for excavations at valve boxes. Frozen glacial till must be thawed by steam injection approximately two hours before it can be dug. Temperatures ranged from 0° to +30°F during the outage. All valves and excavations were thawed by portable steam generators before work could be started at a job site.

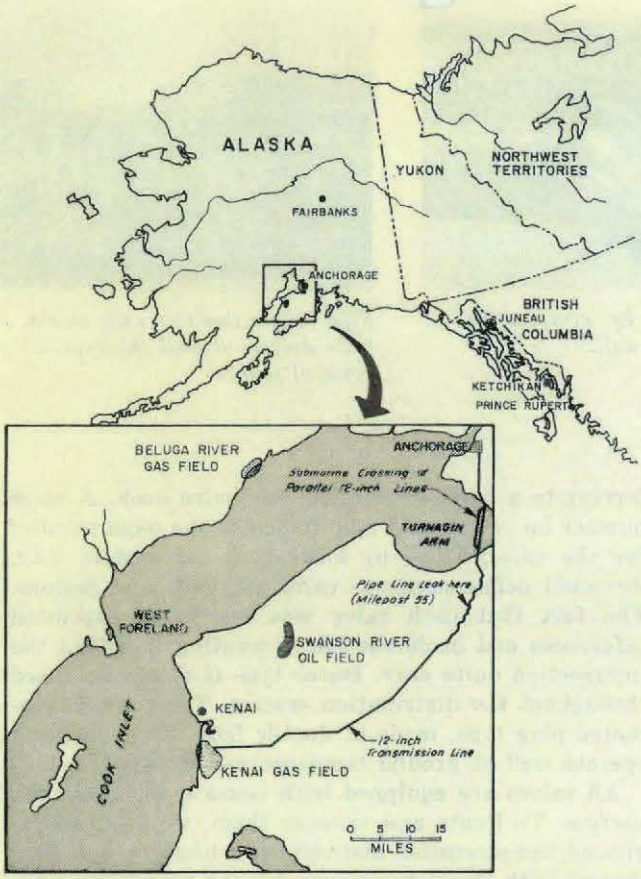
Our 130-mile-long distribution system is equipped with 500 valves, each of which can be located by referring to a tie-down sheet in our valve book. A valve number on our system map indicates the page number for the valve. Thus, by looking at the system map, we could define areas to valve off, test, and restore. The fact that each valve was numbered expedited references and made the job of locating it within the intersection quite easy. Durco type G valves are used throughout the distribution system. They are Teflon-coated plug type, made of ductile iron. They seal and operate well at ground temperatures of +20°F.

All valves are equipped with boxes 6 in. below the surface. To locate and uncover them, we used above-ground measurements and valve box locators, and then thawed with steam to remove ice and frozen gravel.



Left: Steam thawing for a 2-hr period was required before excavations could be made. Ground was frozen to depth of 10 ft, while air temperature ranged from 0°F to +30°F. Below: 4-in. main pulled in two by earth movement. Half dollar shown for size.





Because breaks were found that were not indicated by surface faults, all of the system had to be tested. Sections were valved off and a pressure of 5 psig was used for one-half hour minimum. If that held, an increase in the distribution pressure of 20 to 30 psig was valved off for another half hour for the final test. Several tests were delayed by customers attempting to light their own equipment during the test periods, thereby creating an erroneous pressure drop.

Typical commercial building in damaged business area.

It was known that the bar method of leakage survey was impossible during the frozen winter months, so contact was made with Heath Survey Consultants for a mobile flame ionization detector. One unit was available in Indiana and another in Lubbock, Texas. The one in Lubbock was chosen because of the airfield there. The State Civil Defense office arranged for a MATS plane to depart from its base in South Carolina, pick up the machine, and deliver it to Anchorage. These arrangements required only 15 minutes.

The mobile detector operator returned from his first vacation in four years and was in Anchorage 48 hours later. The field superintendent had arrived from the East Coast 24 hours earlier. The Heath unit was in town only one hour before it started the survey work. A "breadboard" mobile radio (mounted on a plywood base) was placed in the unit, and it was assigned to the area already restored. Whenever a new section under test would not hold, the unit would be summoned to patrol this area. Many breaks were located rapidly in this way, permitting our crews to concentrate their efforts on repair and not on leak survey.

This survey unit was operated on two 12-hr shifts for the first two weeks. After once completing a survey of the entire town, it started a re-survey. By this time, the frost was leaving the ground and additional ground movement was occurring as a result of aftershocks. We decided to continue using the Heath unit until the leaks detected fell to zero. This did not occur until mid-May.

Because the Anchorage system is less than four years old, there were no known leaks other than those caused by the earthquake. The only threaded joints underground are the saddle-punch tee connections. All other connections are either welded or compression.

An airplane patrolling our transmission line that extends from the gas fields on the Kenai Peninsula to Anchorage observed an apparent leak at Milepost 55, in an area where the line is accessible only by tractor and airplane. This point was one mile from one of the three airstrips built along the right-of-way which are of sufficient size to permit the operation of a DC-3.

Investigation by helicopter verified the presence of a leak, and arrangements were made to bring tractors and steam thawing equipment up on the pipeline right-of-way from the wells. Men and additional equipment—including fuel oil, water, anti-freeze, shovels, food, and camping gear—were flown in to the job site from Anchorage. A mobile radio with battery power supply was included for communications.

After thawing and excavation were completed, it was determined that a circumferential leak existed in the pipe adjacent to a weld. A split sleeve was delivered to the job site and installed, effecting a gas-tight repair.

The submarine crossing of Turnagain Arm, consisting of parallel 12-in. lines across the 8-mile span where 35-ft tides occur, was not affected by the earthquake. Previous experience has shown that during vibration the saturated sandy soil converts itself to a form of quicksand; and, if any action took place, it would be one of stress-relieving. Observations since

Faulting that occurred on bluff overlooking Cook Inlet. Street sign in right foreground settled 8 ft.

the quake indicate practically no movement of the lines within the sand. However, the general subsidence of this area, with the resulting tides reaching higher on the shore line, has dictated the elevation of our automatic control system to a point above the new maximum high tide.

Pipe failures occurred in many forms. Some lines failed in compression, others in tension; and some failures indicated a combination of both forces. Other failures indicated excessive shear, and still others were due to continued flexing. Because all our welders are tested and continually spot-checked in the field, we had very few failures in the welds. The pipe is from various manufacturers and all in "new" condition due to excellent coating and high soil resistances. Because the best grade of steel pipe was used with the best welding available, our system damage was held to a minimum.

We have also installed approximately 3000 ⅝-in. OD copper tubing service lines. We have observed that they were subjected to the same forces and reacted in the same manner as the steel lines. There is no indication that copper tubing is not a satisfactory material in this location or under these severe conditions.

All valves are protected by adjacent compression couplings. In many cases these moved, indicating that these couplings prevented additional strain on the valve. Based on this experience, this appears to have been a very good method of valve protection.

All of the domestic regulators and most of the large-capacity regulators on customer services have built-in lockout features. This proved invaluable as it permitted rapid testing in many areas. These regulators proved reliable in their ability to lock out and seal themselves during the pressure-testing operation—and they have the added advantage of keeping uninitiated customers from restoring service to their meters.

This emergency showed us the value of accurate maps, and of having records of all construction details immediately available. It was also very fortunate that we could reproduce these documents right in our own office. This made it a simple matter for us to disseminate the required information to our field units.

Our mobile radio system was indispensable and was in constant use. By the time the quake subsided, our standby generator was running and our radio system was on the air. Probably no other means of communication could have been as successful as this privately owned system.

Anchorage Natural's distribution system and transmission line are constructed in complete accordance with the ASA B-31 code. Without the quality dictated by these specifications, our damage would certainly have been greater. Considering the natural forces that were unleashed on the area, it is amazing that our underground system came through in such good condition. □

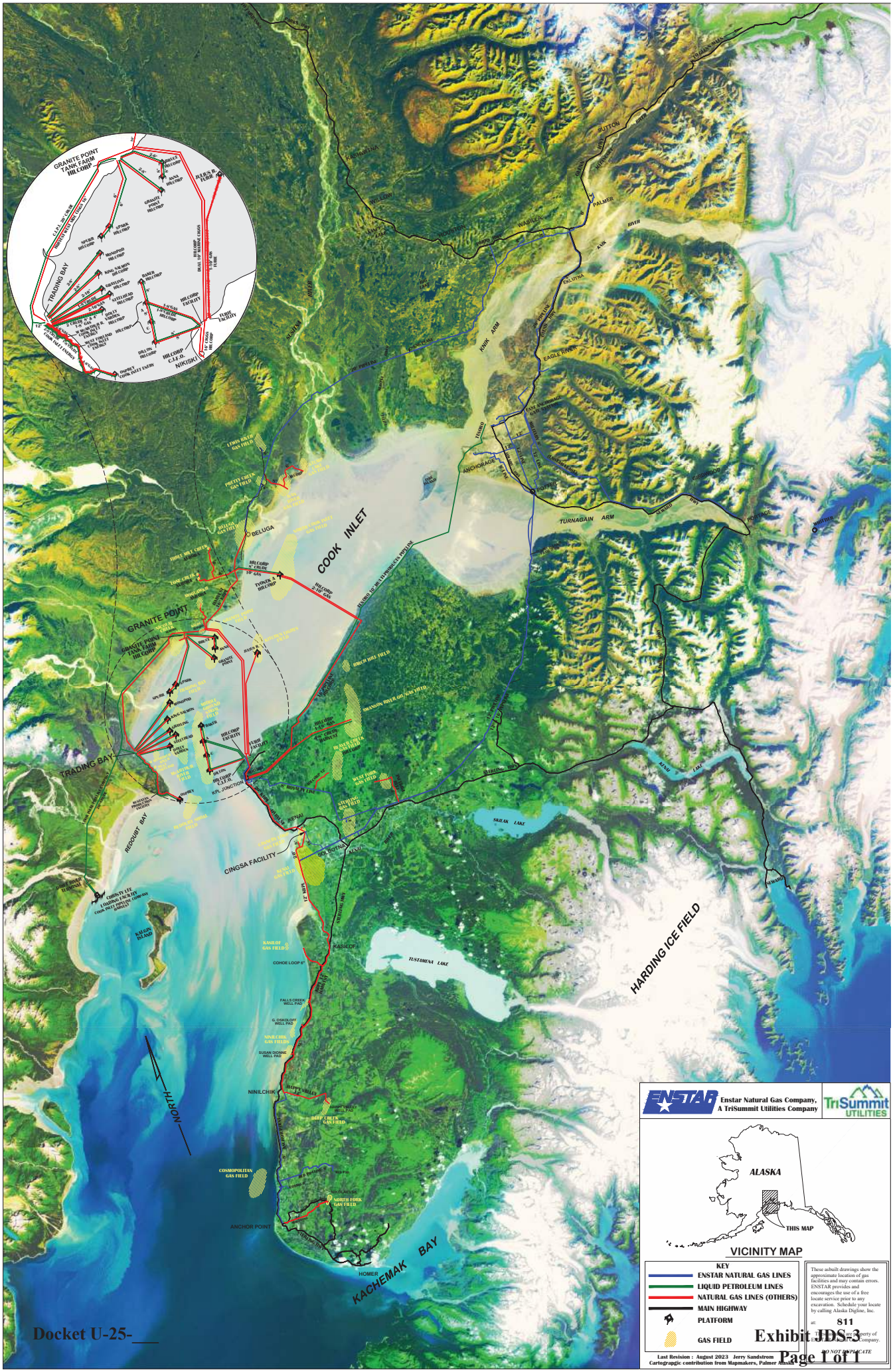


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Exhibit JDS-3

Industry Leader Accident Prevention Award

Presented to

ENSTAR Natural Gas

In recognition of ENSTAR Natural Gas achieving a total DART incidence rate below the industry average for

2019

in the category of

Medium-Small Local Distribution Company

Industry Leader Accident Prevention Award

Presented to

ENSTAR Natural Gas Company

In recognition of ENSTAR Natural Gas Company achieving a total DART incidence rate below the industry average for

2020

in the category of

Medium-Large Local Distribution Company

Industry Leader Accident Prevention Award

Presented to

ENSTAR Natural Gas Company

In recognition of ENSTAR Natural Gas Company achieving a total DART incidence rate below the industry average for

2021

in the category of

Medium-Large Local Distribution Company

Industry Leader Accident Prevention Award

Presented to

ENSTAR Natural Gas Company

In recognition of ENSTAR Natural Gas Company achieving a total DART incidence rate below the industry average for

2022

in the category of

Local Distribution Company

Industry Leader Accident Prevention Award

Presented to

ENSTAR Natural Gas Company

In recognition of ENSTAR Natural Gas Company achieving a total DART incidence rate below the industry average for

2023

in the category of

Local Distribution Company

2025 ANCHORAGE ECONOMIC FORECAST REPORT

AEDC
Anchorage Economic Development Corporation

RESEARCH PROVIDED BY
McKINLEY RESEARCH GROUP, LLC

REPORT SPONSOR
Northrim Bank

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THE BIG PICTURE

In recent years, Anchorage has seen a notable improvement by many measures of the economy. This includes increased cargo traffic at Ted Stevens International and the Port of Alaska, a higher dollar value of construction permits, robust visitor volume, increased employment, and even an increase in real personal income (adjusted for inflation). Several of these measures reflect the strength of the national economy, federal policies and spending, or other macroeconomic factors extending beyond Anchorage. Closer to home, new projects and developments on the North Slope are advancing, with the new Santos building in downtown Anchorage a visible symbol of increased oil and gas activity in Alaska.

Despite these positive economic signs, many households faced rising prices and affordability challenges in the economy of 2023 and 2024, leading to relatively weak consumer confidence in Anchorage and nationwide[1]. While federal interest rate policy has been effective in slowing the rate of inflation, prices remain high. Specifically, housing prices have continued to climb, with the average single-family sales price reaching nearly $514,000 in 2024, a 40% increase over 2019. The relatively slow pace of new housing construction is one contributing factor. New single-family, duplex, triplex, and fourplex construction remained anemic with an estimated 237 units permitted in 2024, well below the 500 units permitted annually between 2012 and 2015. Employers have cited these factors as key challenges in attracting new workers to Anchorage.

Several forces in Anchorage's economy will feature prominently in 2025. New energy from development work on the North Slope will increasingly be felt in Anchorage as the Pikka project moves toward production in late 2025/early 2026 and Willow project development continues toward oil production at decade's end. An influx of federal construction funding statewide has brought a wave of new work to Anchorage's architects, engineers, and construction companies. Through late 2024, Alaska entities have been awarded $8.5 billion in funding through the federal Infrastructure Investments and Jobs Act; these awards will likely increase construction activity through about 2031. Additionally, the demand for goods and travel in the U.S. domestic market is expected to buoy the various measures of economic activity described in this report.

Yet potential changes in federal policy, such as the imposition of new tariffs, any renewed upticks in inflation, and a dearth of residential construction could all impact the strength of Anchorage's economy and resident perceptions of it.

---

[1] *Anchorage Consumer Optimism Index Quarter 3 2024 prepared by Alaska Survey Research; University of Michigan Consumer Sentiment Index*

DEMOGRAPHICS AND EMPLOYMENT

POPULATION

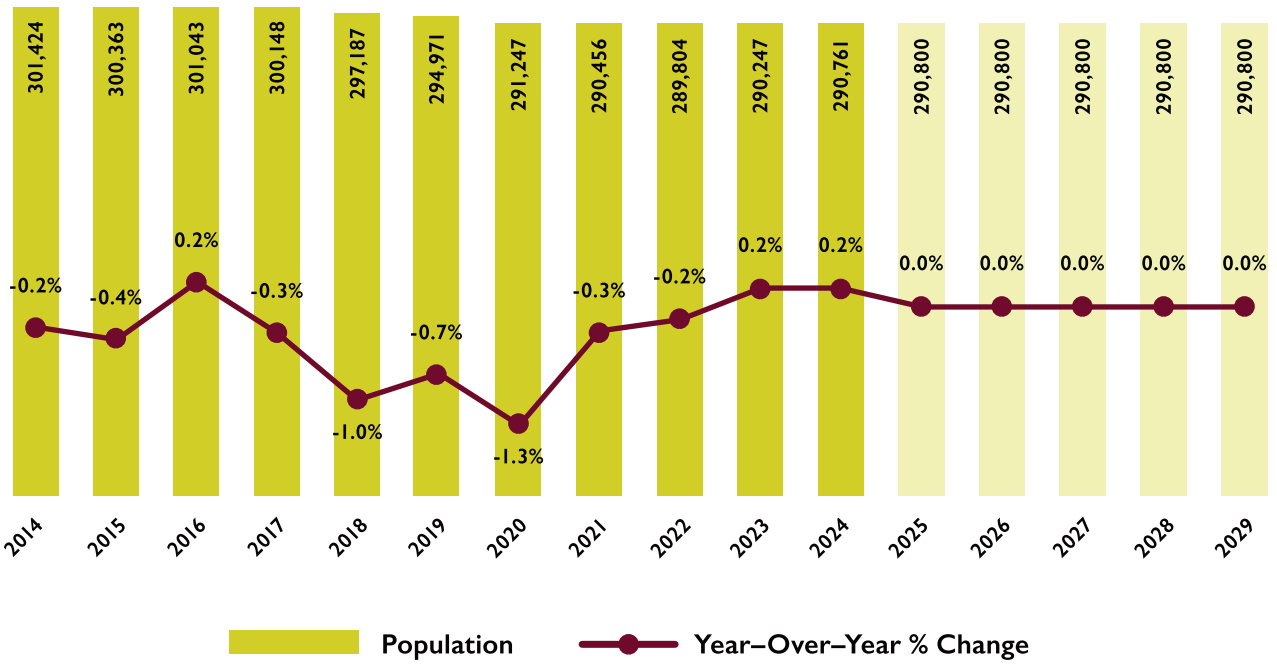
Anchorage's population is expected to remain stable over the next five years following a modest increase in 2024.

FACTORS CONTRIBUTING TO THE FORECAST

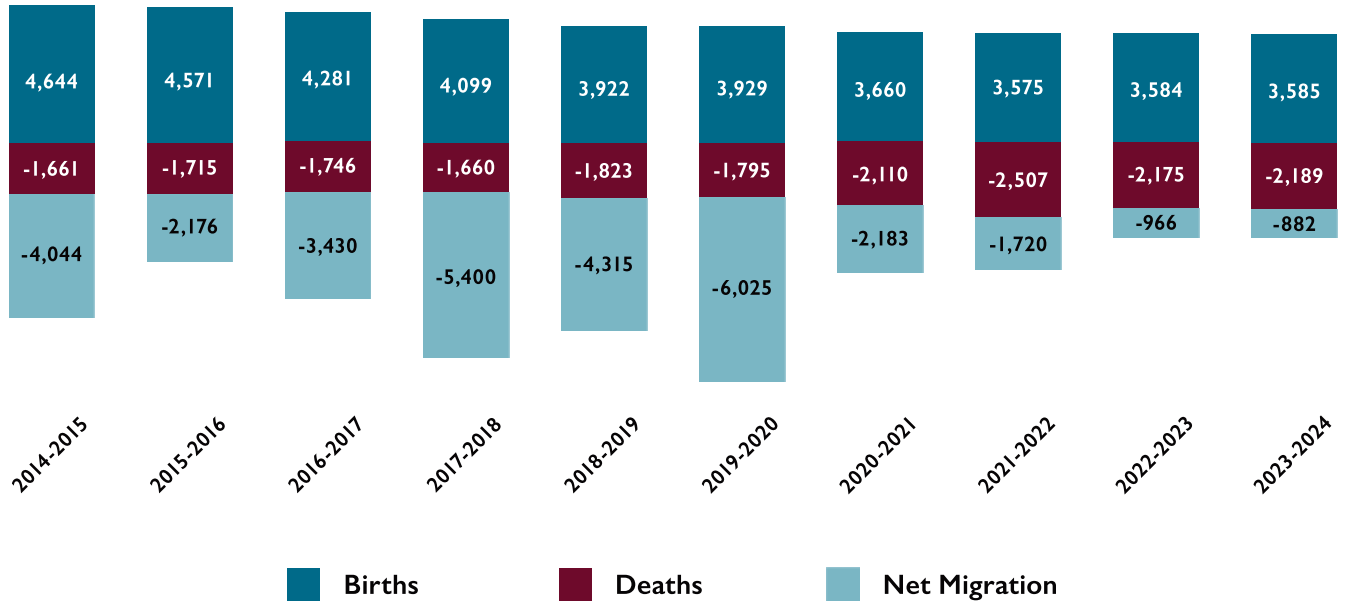
- The number of births in Anchorage continues to decline with a lower working age population. This trend is expected to continue, while annual deaths increase as the population continues to age.
- Net outmigration from Anchorage has slowed considerably compared to the pace of population loss during the Alaska statewide recession (2015-2018).
- Developments on Alaska's North Slope and significant construction investments have drawn workers to Anchorage, and Alaska. However, demographic shifts are likely to counter these population draws in the long term.

Anchorage Population and Annual Growth Rate, 2014–2029

Anchorage's population increased in 2024, marking a change from several years of decline.



Components of Anchorage Population Change, 2014-2024



CURRENT TRENDS		
	2023–2024 CHANGE	**2023–2024 % CHANGE**
TOTAL POPULATION	+514	+0.2%
NET MIGRATION	-882	-9%
NATURAL INCREASE	+1,396	-1%
BIRTHS	+3,585	0%
DEATHS	-2,189	+1%

Source: Alaska Department of Labor and Workforce Development (2014-2024); McKinley Research Group estimates (2025-2029)

WORKING AGE POPULATION

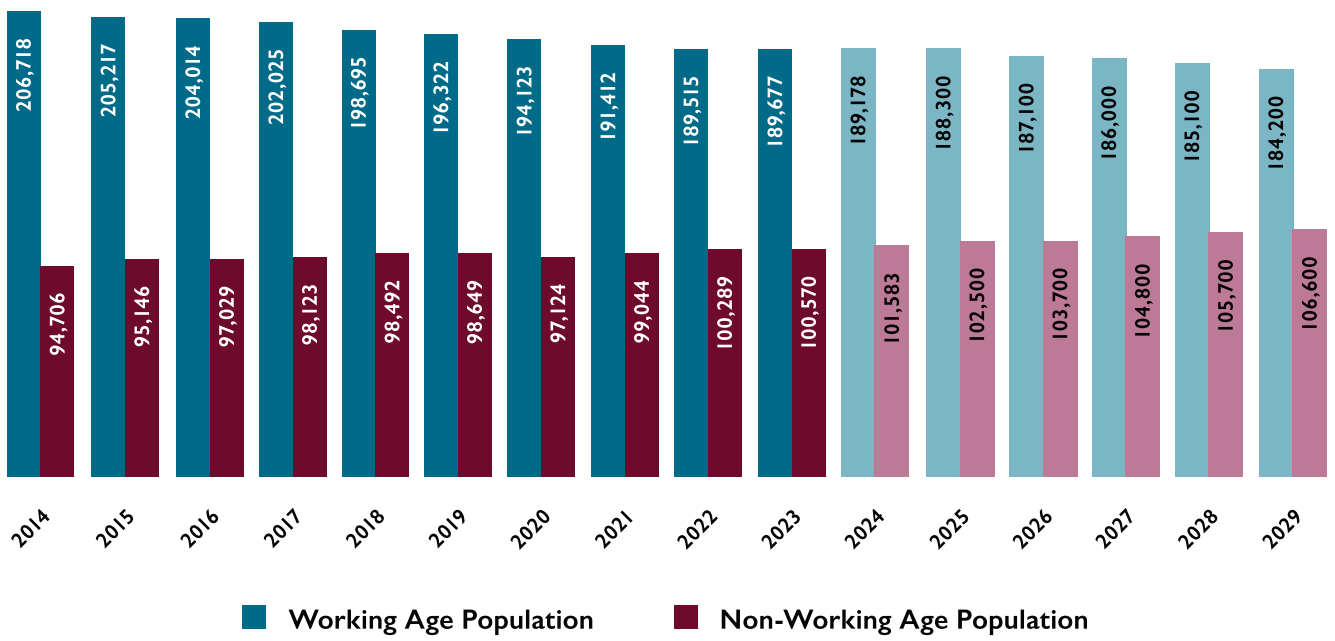
The proportion of Anchorage's population that is working age (between 16 and 64 years old) is expected to decline further as the population ages.

FACTORS CONTRIBUTING TO THE FORECAST

- By 2029, all members of the baby boomer generation will have aged out of the working-age population. While many continue to be active in Anchorage's labor force this will nevertheless reflect a change in the number of residents within the traditional "working age".
- Typically a source of new working-age residents, in-migration to Anchorage has slowed over the last decade.
- New residents moving to Anchorage for jobs in the oil or construction industries are not expected to outpace the rate of baby boomers aging out of the working-age population.
- Working-age residents made up 69% of the Anchorage population in 2014 and have steadily declined to make up only 65% in 2024.

Anchorage Population by Age Category, 2014-2029

Anchorage's working age population declined for the 11TH consecutive year in 2024.



CURRENT TRENDS		
	2023–2024 CHANGE	**2023–2024 % CHANGE**
TOTAL WORKING-AGE POPULATION	-499	-0.3%
		2015-2020
AVERAGE ANNUAL WORKING AGE NET MIGRATION		-2,908
AVERAGE ANNUAL WORKING AGE IN-MIGRATION		+14,999
AVERAGE ANNUAL WORKING AGE OUT-MIGRATION		-17,908

Source: Alaska Department of Labor and Workforce Development (2013-2024); McKinley Research Group estimates (2025-2029)

EMPLOYMENT

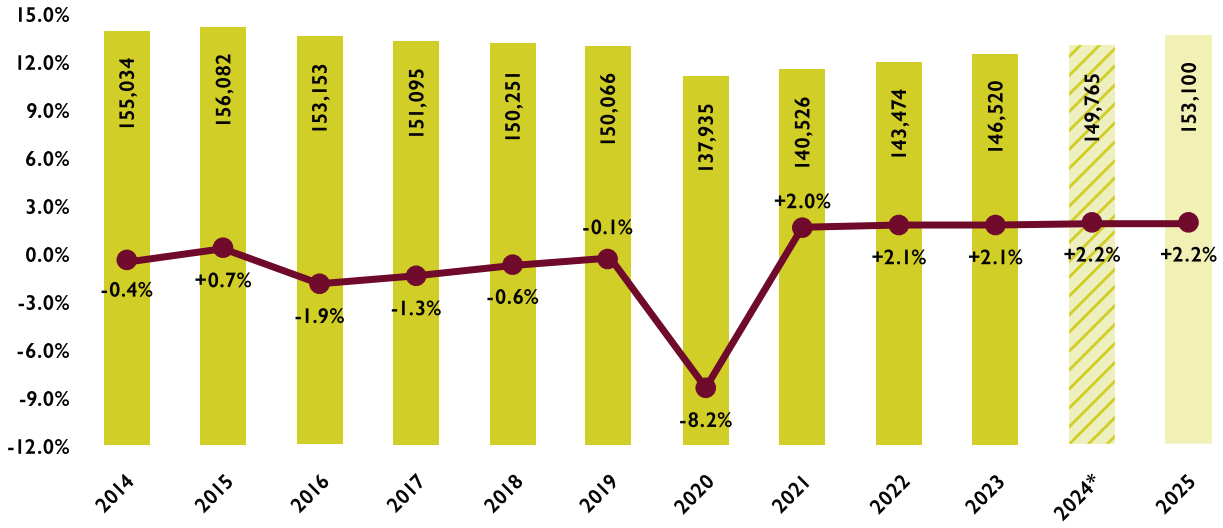
Employment in Anchorage is expected to make a full recovery to pre-pandemic levels in 2025.

FACTORS CONTRIBUTING TO THE FORECAST

- Slow population growth and lower working-age population continue to constrain employment growth. However, the level of job openings statewide has begun to ease from highs in 2022 and 2023, years in which there were about two job openings for every unemployed Alaska resident looking for work.
- Construction employment is expected to further expand as infrastructure funding moves through the grant pipeline, and North Slope development work continues.
- Anchorage's oil and gas industry employment will grow modestly as North Slope developments move toward the production phase.
- The strength of the national economy will continue to support transportation services through, and visitor travel to, Anchorage.

Anchorage Average Employment, 2014-2025

Anchorage employment recovery has been steady over the past four years.



Note: Sole proprietor employment is not included in average annual employment figures.

** Employment estimate is preliminary*

CURRENT TRENDS			
TOP 3 SECTORS (JAN-JUN 2023-2024)	**BOTTOM 3 SECTORS** (JAN-JUN 2023-2024)		
CONSTRUCTION (+912 JOBS, +13%)	RETAIL (-501 JOBS, -3%)		
HEALTHCARE (+912 JOBS, +4%)	FINANCIAL SERVICES (-316 JOBS, -4%)		
GOVERNMENT (+431 JOBS, +2%)	INFORMATION (-129 JOBS, -5%)		
2022 WORKFORCE RESIDENCY	**ALASKA RESIDENTS**		**NON-ALASKA RESIDENTS**
	LIVE WHERE THEY WORK	**DON'T LIVE WHERE THEY WORK**	**WORK HERE, LIVE ELSEWHERE**
WHERE ANCHORAGE WORKERS LIVE	75%	12%	14%
WHERE ALASKA WORKERS LIVE	66%	13%	21%

Source: Alaska Department of Labor and Workforce Development (2013-2023) and McKinley Research Group estimates (2024-2025)

Note: Rows may not add to 100% due to rounding.

PURCHASING POWER

PERSONAL INCOME

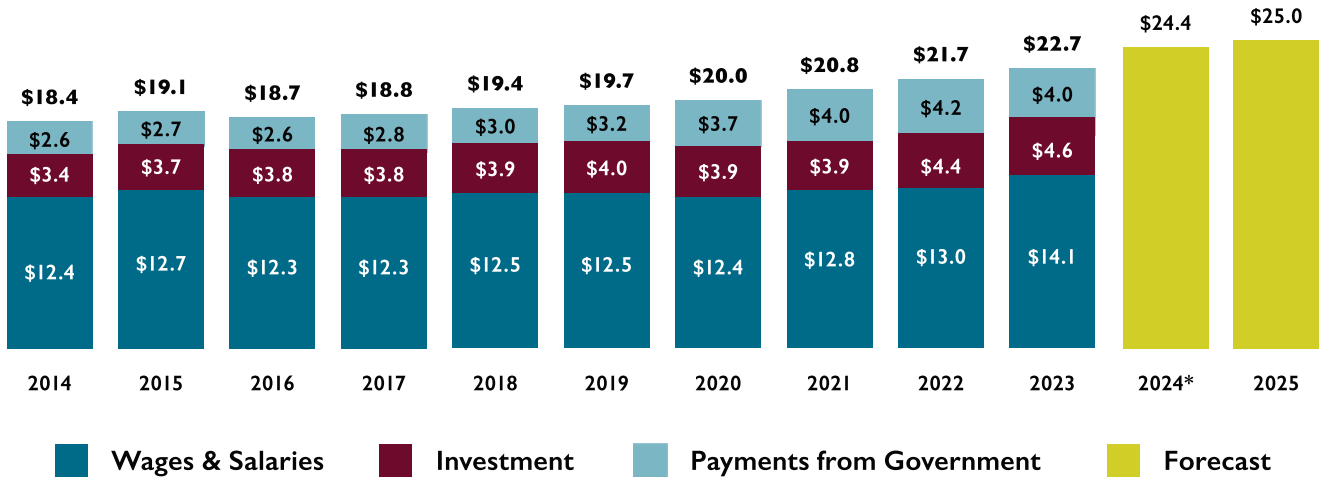
While expected to moderate, wage growth will continue to increase personal income in 2025.

FACTORS CONTRIBUTING TO THE FORECAST

- While still the largest contributor to personal income, work-related income has represented a lower share of total income in Anchorage over the last decade. Work-related income is expected to increase along with steady increases in Anchorage employment in 2025.
- Personal income from investments and government payments include retirement earnings, income from pension plans, and social security payments. As Anchorage's retiree population increases, these retirement – and senior-related sources of personal income are anticipated to expand.

Anchorage Personal Income ($Billions), 2014–2025

COVID-19 related payments to individuals drove up personal income but wage growth has sustained the increase.



CURRENT TRENDS			
	2023 ($BILLON)	% OF 2023 TOTAL	2022-2023 % CHANGE
INCOME FROM WORK	$14.1	62%	+5.9%
INVESTMENT FROM INCOME	$4.6	20%	+10.4%
PAYMENTS FROM THE GOVERNMENT (I.E., COVID RELIEF, SOCIAL SECURITY, PFD)	$3.9	17%	-10.0%

Source: U.S. Bureau of Economic Analysis (2013-2023), McKinley Research Group Estimates (2024 – 2025)

INFLATION

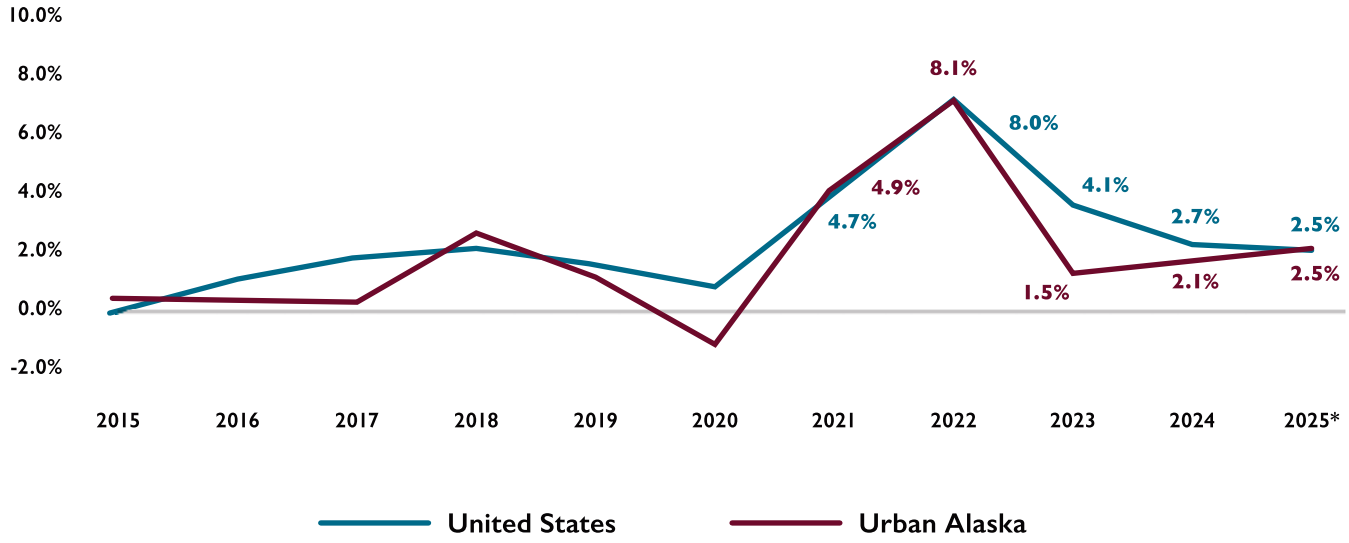
While inflation is expected to continue declining nationally in 2025, an expected gap in Southcentral natural gas supply could impact the overall rate of inflation in Anchorage.

FACTORS CONTRIBUTING TO THE FORECAST

- Annual inflation, the rate at which consumer prices change, dropped significantly in 2024 after several years of rapid increase.
- The Federal Reserve is expected to make two quarter-point interest rate cuts in 2025 as the pace of inflation slows.
- Cook Inlet natural gas plays an important role in providing heat and electricity in Southcentral Alaska. Regional utilities have been seeking alternate sources of natural gas amid notification by Hilcorp in mid-2022 that they would be unable to commit to new contracts as current contracts expire over the next decade. Options include importing natural gas. Replacing Cook Inlet gas supply is likely to increase energy prices in Anchorage in the next several years.
- The tariff charged on all items brought through the Port of Alaska is set to increase in 2025 in an effort to fund the Port Modernization project. The tariff increase is not expected to significantly impact consumer prices in Anchorage.

Consumer Price Index, 2015-2025

Inflation declined significantly in 2023 and 2024.



CURRENT URBAN ALASKA TRENDS			
TOP 3 PRICE INCREASES (2023-2024)		**TOP 3 PRICE DECREASES (2023-2024)**	
MEDICAL CARE	+10.6%	MOTOR FUEL	-18.7%
HOUSEHOLD ENERGY	+9.8%	USED VEHICLES	-5.4%
RENT	+4.5%	FRUITS & VEGETABLES	-0.5%

Source: U.S. Bureau of Economic Analysis (2013-2024), U.S. Federal Reserve and McKinley Research Group Estimates (2024 – 2025)

TRANSPORTATION INDUSTRY

ANCHORAGE AIR CARGO

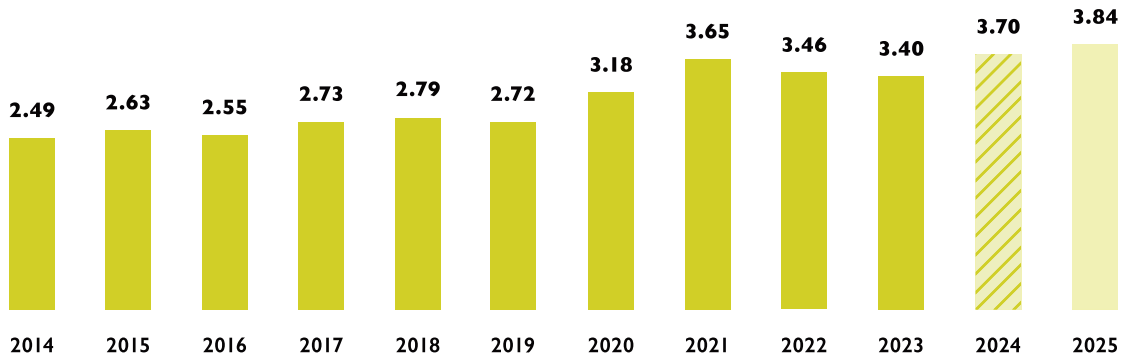
Increased cargo landings, and new carriers, will increase cargo volume at the Anchorage International Airport in 2025.

FACTORS CONTRIBUTING TO THE FORECAST

- Cargo carriers already using Anchorage International are expected to add 2,000 additional cargo landings in 2025.
- Five new cargo carriers have announced plans to land in ANC in 2025, moving cargo along the Asia to North America route.
- International political events have contributed to some re-routing of cargo aircraft to Anchorage International.
- Completion of two new cargo facilities – FedEx and NorthLink - at Anchorage International, including additional hardstands, will increase capacity for cargo landings by the end of 2025.
- Any new federal tariffs on imported goods transiting the Asia to North America route have the potential to negatively impact cargo volume brought through Anchorage International.

Anchorage International Airport Air Cargo (Million Metric Tons) 2014-2025

Air cargo volume has increased significantly since 2020.



CURRENT TRENDS			
	2024 (JAN-NOV)	**2023-2024 CHANGE**	**2023-2024 % CHANGE**
METRIC TONS OF AIR CARGO	3.36M	+257,207	+8%
CARGO LANDINGS	49,624	+2,839	+6.5%
		2024 RANK	
GLOBAL AIRPORT RANK BY CARGO VOLUME		3RD	

Source: State of Alaska Department of Transportation and Public Facilities (2013 – 2023), McKinley Research Group Estimates (2024 – 2025)

PORT OF ALASKA MARINE CARGO

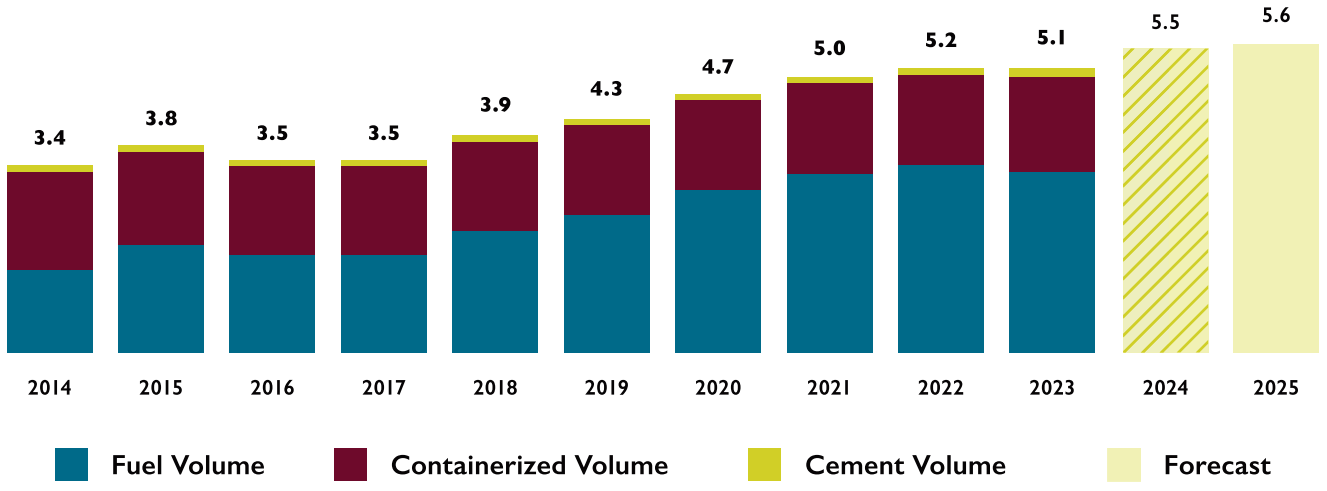
Shipping through the Port of Alaska will continue at historically high volumes through 2025.

FACTORS CONTRIBUTING TO THE FORECAST

- A Port of Alaska tariff increase will go into effect in January 2025. Despite this increase, cargo volume is not expected to be diverted to other modes of transportation (air, highway) or Southcentral ports.
- The volume of petroleum products, including aviation fuel, moving through the Port of Alaska has risen substantially over the last decade. Demand for petroleum products is expected to remain strong in 2025 due to increased cargo traffic at Anchorage International Airport, among other factors.
- Despite a decline in cement volume in 2024, construction activity in Alaska is expected to remain strong in 2025 and cement shipments are anticipated to resume growth.
- Construction projects at the Port in 2025 may increase capacity in future years, but shipping volume will likely remain stable throughout the next year.

Port of Alaska Volume (Million Tons), 2014-2025

Petroleum product shipping has driven increased volume at the Port of Alaska over the last several years.



CURRENT TRENDS			
	2024 TONS (JAN-NOV)	% OF 2024 TOTAL	2023-2024 % CHANGE IN VOLUME
FUEL VOLUME	3.4M	67%	+13%
CONTAINERIZED VOLUME	1.6M	31%	+2%
CEMENT VOLUME	0.1M	2%	-30%

Source: Municipality of Anchorage, Port of Alaska (2013 – 2023), McKinley Research Group Estimates (2024 – 2025)

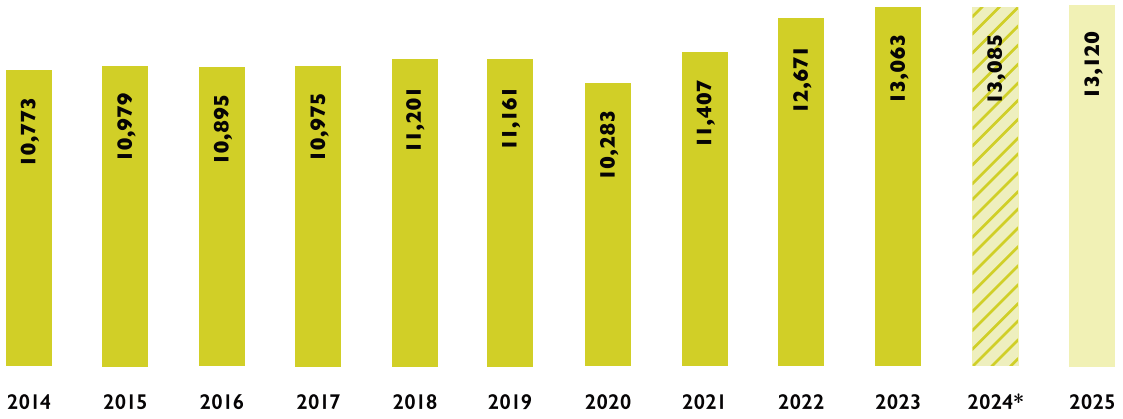
TRANSPORTATION EMPLOYMENT

Transportation employment will expand only slightly in 2025.

FACTORS CONTRIBUTING TO THE FORECAST

- New sorting facilities under construction by FedEx and NorthLink are expected to open later in 2025, increasing demand for employees in the Transportation sector.
- The Alaska Airlines/Hawaiian Airlines merger is not likely to have a significant impact on employment in Anchorage, as no routes are planned to substantially change.

Anchorage Transportation Employment, 2014-2025



Source: Alaska Department of Labor and Workforce Development (2014 – 2023), McKinley Research Group Estimates (2024 – 2025)
**Employment estimate is preliminary*

CONSTRUCTION INDUSTRY

BUILDING PERMIT VALUES

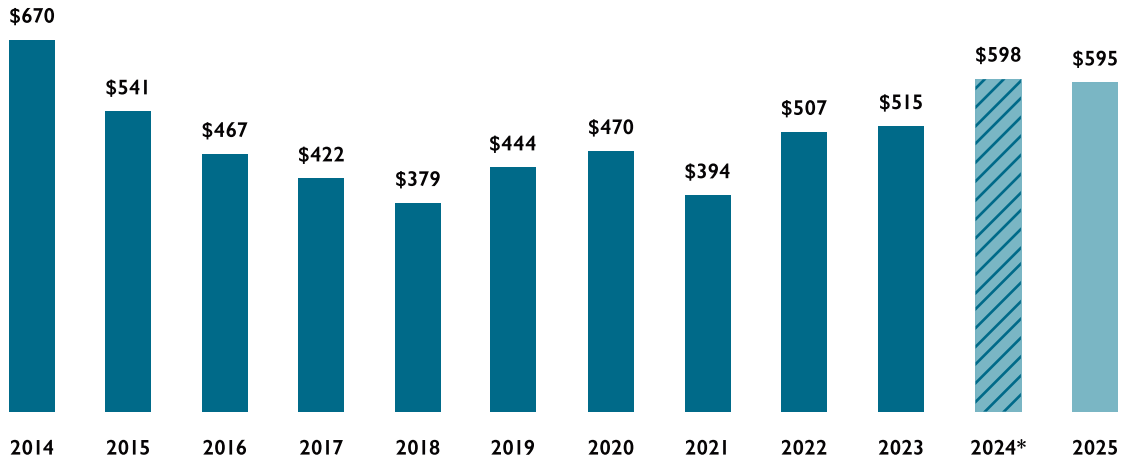
Anchorage construction permits in 2025 are expected to remain elevated compared to the decade average.

FACTORS CONTRIBUTING TO THE FORECAST

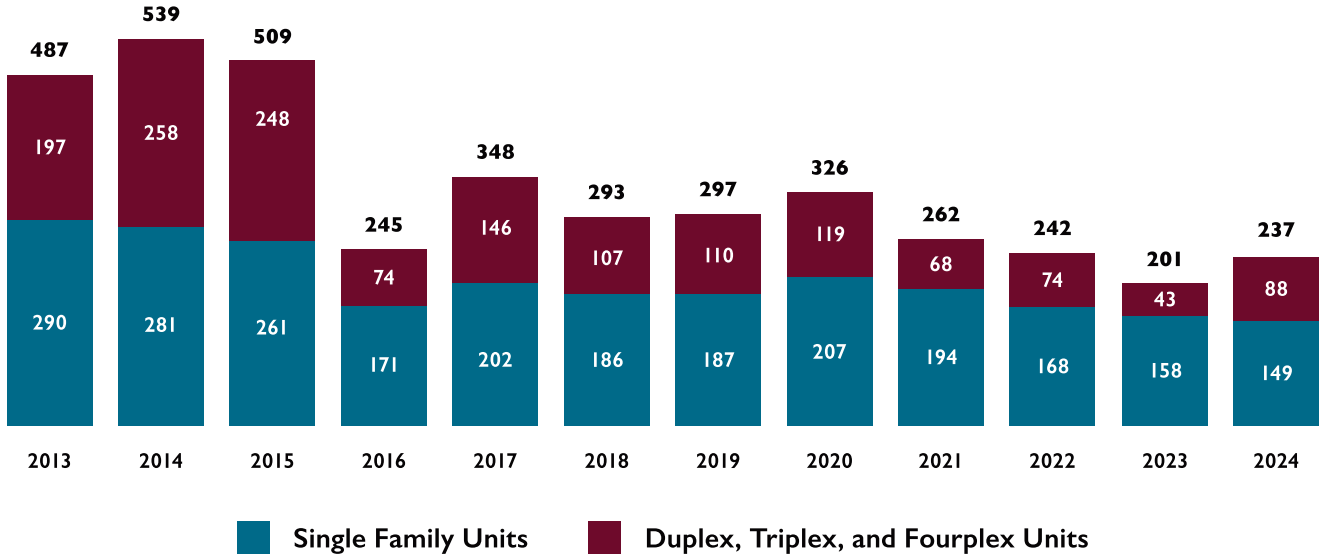
- The Federal Reserve is expected to continue with interest rates cuts. However, rates remain above pre-pandemic levels, exerting downward pressure on residential and private, commercial construction activity. Residential remodeling activity in particular contracted in 2024 amid high project costs.
- Permitting of two large projects – a new skilled nursing facility and a detox center – valued at a combined $100 million, drove up building permit values in 2024. Notable commercial projects which could be permitted in 2025 include the Municipality of Anchorage Emergency Operations Center project and Atlas Air facilities at Anchorage International Airport, among others. However, total permit values in 2025 are expected to be slightly below 2024 due to the two large projects permitted that year.
- While Alaska organizations have received significant federal grant funding through the 2021 Infrastructure Investment and Jobs Act (IIJA), many projects are not in Anchorage, or otherwise do not fall within the Municipality of Anchorage's permitting requirements.

Anchorage Building Permit Values ($Millions), 2014-2025

Two large projects permitted in 2024 drove up total construction permit values.



New Residential Units Permitted in Anchorage by Type, 2013-2024



CURRENT TRENDS		
	2024 PERMIT VALUES	**2023-2024 % CHANGE**
TOTAL ACTIVITY	$598.8 MILLION	+16%
	2024	**2023-2024 % CHANGE**
AVERAGE HOMES SALES PRICE	$513,916	+7%
	2019, YTD THROUGH OCTOBER	**2024, YTD THROUGH OCTOBER**
ANCHORAGE - MAT-SU AVERAGE HOME SALES PRICE DIFFERENCE	$95,661	$102,269

Source: U.S. Bureau of Economic Analysis (2013-2023), McKinley Research Group Estimates (2024 – 2025)

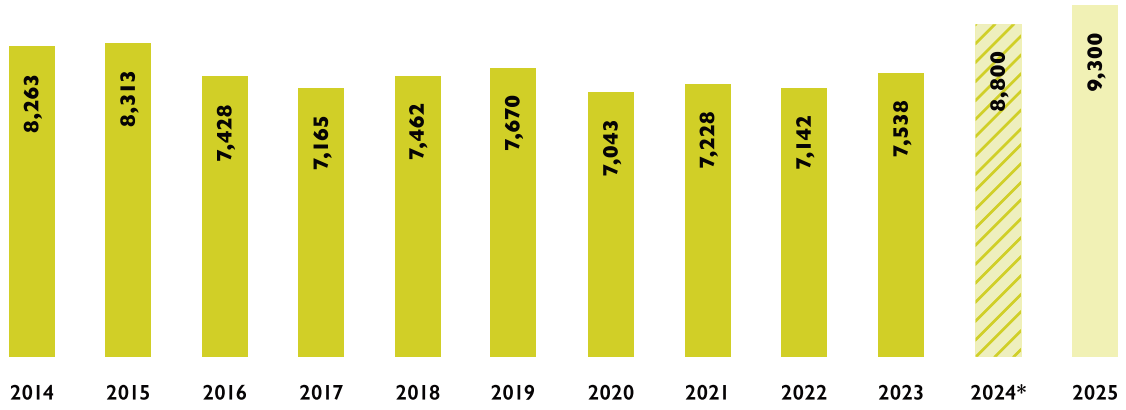
CONSTRUCTION EMPLOYMENT

Heightened construction activity across Alaska continues to drive increased Anchorage construction employment in 2025.

FACTORS CONTRIBUTING TO THE FORECAST

- Over $8 billion in infrastructure funding authorized by the federal Infrastructure Investment and Jobs Act has been awarded to Alaska organizations, supporting demand for construction services statewide.
- Large oil field development projects on Alaska's North Slope are also supporting demand for construction services.
- Anchorage is a hub of the statewide construction industry, and local employers will see increased demand for their services statewide based on these significant sources of demand.

Anchorage Construction Employment, 2014-2025



Source: Alaska Department of Labor and Workforce Development (2014 – 2023), McKinley Research Group Estimates (2024 – 2025)
**Employment estimate is preliminary*

VISITOR INDUSTRY

ANCHORAGE AIR PASSENGERS

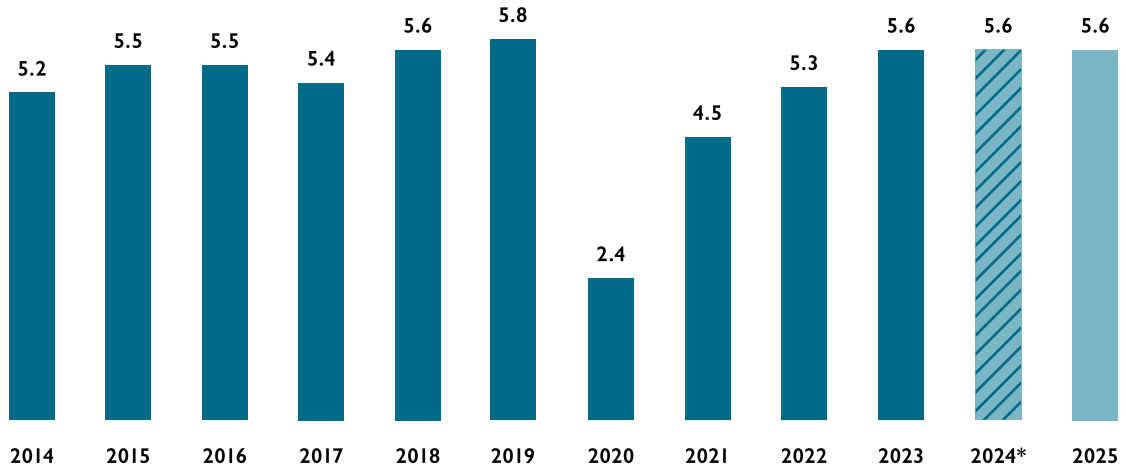
Air passenger volume through Anchorage International Airport is expected to remain consistent at 5.6 million passengers as post-pandemic travel stabilizes.

FACTORS CONTRIBUTING TO THE FORECAST

- Cross-gulf cruise ship passenger volume expanded in 2024 and is expected to remain above pre-pandemic levels in 2025.
- Non-cruise related visitor volumes have shown signs of stabilization to pre-pandemic levels. This trend is likely to continue in 2025.
- Nationally, domestic leisure travel is expected to expand into 2025 despite increasing travel costs over the last several years.
- In 2025, Alberta based WestJet plans to add a twice weekly service between Calgary and Anchorage, while Alaska Airlines adds new nonstop service to Detroit and Sacramento.

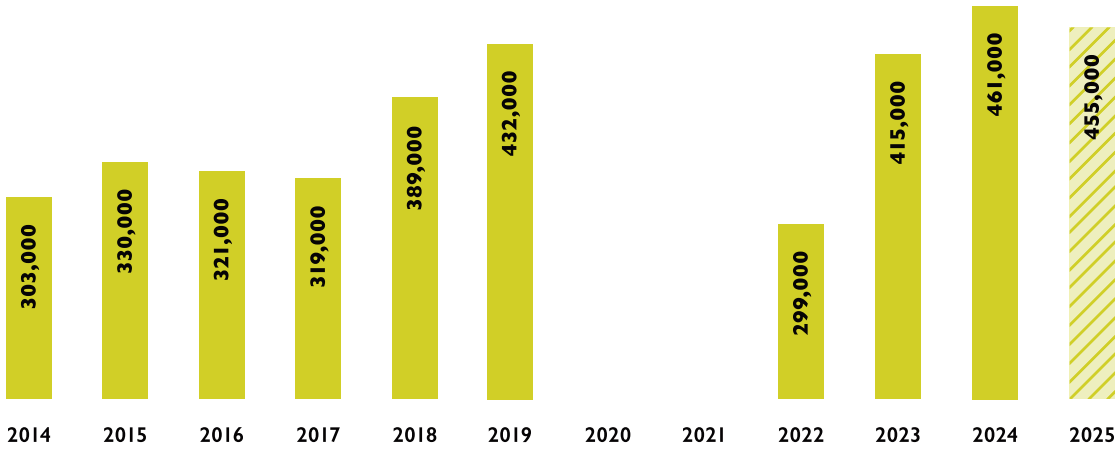
Anchorage International Airport Air Passenger Volume (Million Passengers), 2014-2025

Air passenger volumes were steady between 2023 and 2024.



Cross-Gulf Cruise Ship Passengers 2014-2024, 2025 Capacity

Cross gulf capacity will remain stable in 2025.



CURRENT TRENDS		
MUNICIPAL TAX RECEIPTS	**YTD (JAN-SEPT) 2024**	**YTD (JAN-SEPT) 2023-2024 % CHANGE**
ROOM TAX	$40.5M	+6%
RENTAL VEHICLE TAX	$9.2M	-6%
ANCHORAGE AIR PASSENGERS	**YTD (JAN-OCT) 2024**	**YTD (JAN-OCT) 2023-2024 % CHANGE**
PASSENGER VOLUME	4.8M	<1%
CROSS-GULF CRUISE VOLUME (WHITTIER, SEWARD)	**2024**	**2023-2024 % CHANGE**
PASSENGER VOLUME	461,000	+11%

Source: Municipality of Anchorage; Cruise Line Agencies of Alaska; McKinley Research Group Estimates

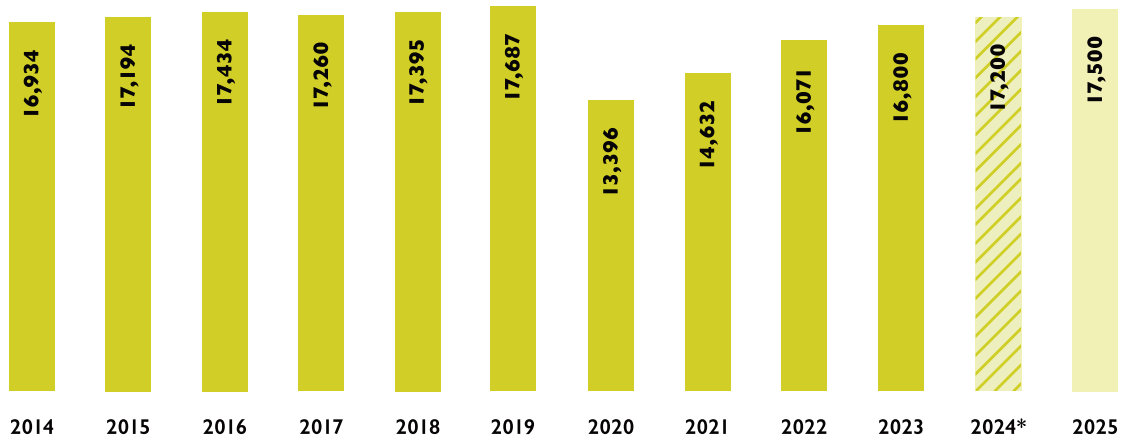
LEISURE AND HOSPITALITY EMPLOYMENT

Leisure and hospitality employment will continue to grow modestly in 2025.

FACTORS CONTRIBUTING TO THE FORECAST

- Across the U.S., the increase in the cost of dining out has outpaced the rise in grocery prices over the last several years, putting downward pressure on restaurant demand.
- In 2024, leisure and hospitality employment growth was largely driven by workers at recreation businesses which benefit from resident and visitor spending.
- Participation in the foreign summer visa program (J-1 exchange worker program) expanded beyond pre-pandemic levels in summer 2023 in Anchorage and statewide.

Leisure and Hospitality Employment, 2014-2025



Source: Alaska Department of Labor and Workforce Development (2014 – 2023), McKinley Research Group Estimates (2024 – 2025)
**Employment estimate is preliminary*

OIL AND GAS INDUSTRY

ALASKA NORTH SLOPE OIL PRICE AND PRODUCTION

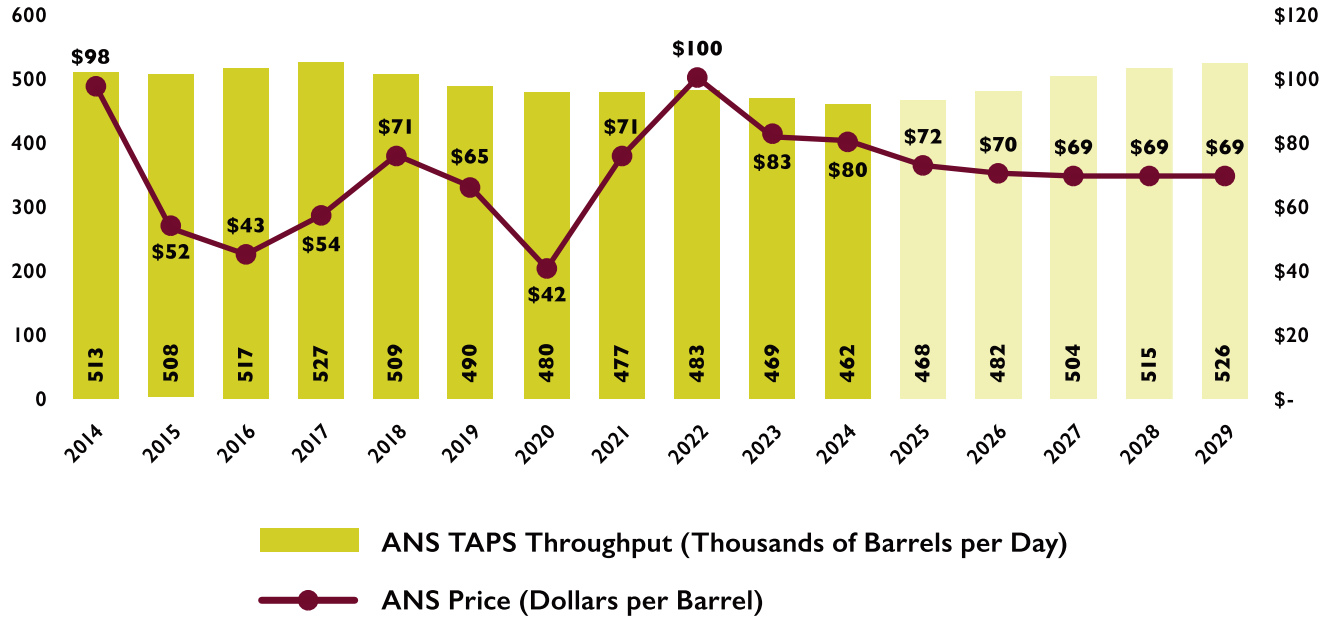
Alaska North Slope (ANS) prices are expected to trend downward, while production is expected to steadily increase as new production comes online in 2026 and beyond.

FACTORS CONTRIBUTING TO THE FORECAST

- Construction is underway on two large new developments on Alaska's North Slope – Santos' Pikka project and ConocoPhillips' Willow project. New production may begin in late 2025/early 2026, with the pace of work accelerated on Santos' Pikka project.
- ConocoPhillips' Nuna project moved into production in late 2024. The development is expected to add 20,000 barrels per day at peak production.
- Global oil supply growth is likely to outpace demand growth in the near term, exerting downward pressure on oil prices.
- Continued geopolitical pressures from conflict in the Middle East and Russia/Ukraine are a significant source of uncertainty in production and price expectations.
- Alaska North Slope oil prices averaged about $80.47 per barrel in 2024, a decrease of 3% compared to 2023.

Alaska North Slope Crude Oil Production and Prices, CY 2014-2029

Production has remained steady through volatile price swings.



CURRENT TRENDS		
	CY 2024 AVERAGE	CY 2023 – CY 2024 % CHANGE
ANS OIL PRICE/BARREL	$82.47	-3%

Sources: Alaska Department of Revenue, Energy Information Administration, CME Group, McKinley Research Group calculations

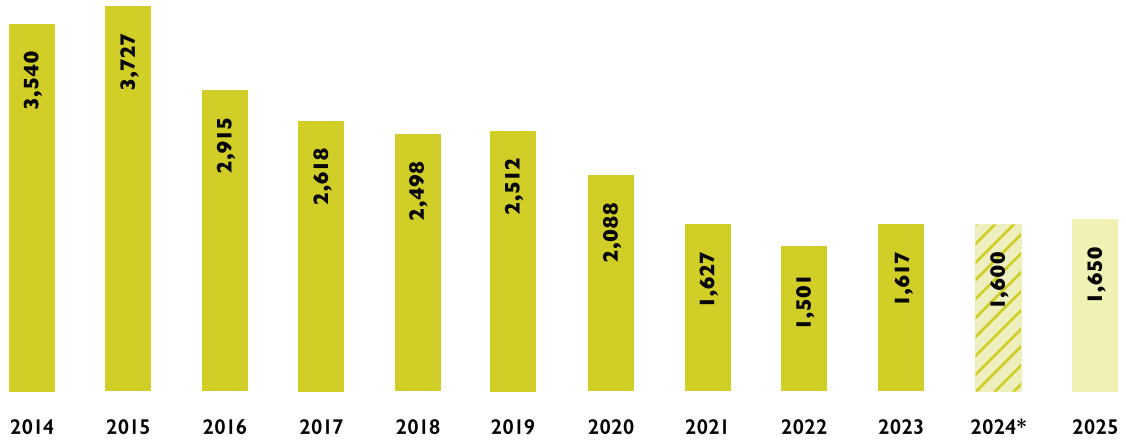
OIL AND GAS EMPLOYMENT

Projects under development on Alaska's North Slope will drive modest Oil & Gas employment growth in Anchorage.

FACTORS CONTRIBUTING TO THE FORECAST

- Santos intends to increase Anchorage employment in 2025 as they work towards first production at Pikka at year end.
- High oil price environments and increased activity on Alaska's North Slope will generate modest additional oil and gas and support services employment in Anchorage in 2025.
- Oil industry employment growth was slow, yet positive through the first half of 2024.

Anchorage Oil & Gas Employment, 2014-2025



Source: Alaska Department of Labor and Workforce Development (2014 – 2023), McKinley Research Group Estimates (2024 – 2025)
**Employment estimate is preliminary*

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510 L STREET, SUITE 603
ANCHORAGE, AK 99501

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Resolution Encouraging Natural Gas Line Investment and the Expedited Replacement of High-Risk Distribution Mains and Service Lines

WHEREAS, NARUC and its members have long focused on pipeline safety, led by the Committee on Gas, established in 1964, the Staff Subcommittee on Pipeline Safety, the Task Force on Pipeline Safety, and the newly created Subcommittee on Pipeline Safety; *and*

WHEREAS, NARUC enjoys a close working relationship with the National Association of Pipeline Safety Representatives (NAPSR), a national organization representing the State pipeline inspection workforce throughout the country; *and*

WHEREAS, NAPSR in November 2011 released an exhaustive compendium of State pipeline safety programs which exceed the minimum federal standards States must meet in order to receive funding from the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA); *and*

WHEREAS, NARUC and the Committee on Gas maintain a strong cooperative partnership with PHMSA, which is essential to ensure State and federal safety regulators work closely on pipeline safety; *and*

WHEREAS, More than two million miles of natural gas distribution pipelines crisscross the United States, connecting homes and businesses with one of America's most important energy resources. These pipelines are the safest, most reliable and cost-effective way to transport this essential fuel across the country; *and*

WHEREAS, The safe and reliable delivery of natural gas to homes and businesses and its use in providing new products and services is vital to the U.S. and of paramount importance to members of NARUC; *and*

WHEREAS, By law, the utilities are charged with knowing the location, material, age and condition of their systems. Developing essential data to evaluate the integrity of the systems is the foundation for any determination over what regulators need to fund in rates, as well as what rate recovery methodology best suits a particular case; *and*

WHEREAS, Many States and distribution utilities are undergoing significant pipeline replacement programs to replace aging pipe; *and*

WHEREAS, Many distribution companies are being proactive about replacing their aging pipelines through a risk-based approach focusing on prioritizing safety, asset replacement, and rate impact; *and*

WHEREAS, Alternative rate-recovery mechanisms may help expedite the replacement and expansion of the pipeline systems by promoting more timely rate recovery for investments in infrastructure, safety and reliability; *and*

WHEREAS, Alternative rate recovery mechanisms may help eliminate near-term financial barriers of traditional ratemaking policies such as "regulatory lag" and promote access to lower-cost capital; *and*

WHEREAS, The adoption of alternative rate policies may be very effective for advancing critical safety and reliability infrastructure upgrades, *and*

WHEREAS, Notwithstanding the positive advances in innovative ratemaking and proactive remediation by many distribution companies, utility management bears ultimate responsibility for their respective systems and should seek to work, in ways permissible under their respective State rules and law, collaboratively with Commissioners and/or Commission staff to prioritize asset replacement based upon asset risk, available technology, public safety risk, rate impact, *and*

WHEREAS, Ensuring pipeline safety is about more than just replacement and cost recovery. It is also about effective communication, enforcement, risk sharing, and establishing a long range strategic plan that ensures a safe and reliable gas pipeline system; *and*

WHEREAS, As evidenced in the NAPSR 2011 Compendium, State commissions and inspectors are best suited to determine how best to finance system improvements because each State is different and the needs and financial circumstances of each utility system are unique; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at the 2013 Summer Committee Meetings, in Denver, Colorado, encourages regulators and industry to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms that reflect the financial realities of the particular utility in question; *and be it further*

RESOLVED, That State commissions should explore, examine, and consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems, *and be it further*

RESOLVED, That NARUC encourages its members to reach out to PHMSA, NAPSR, industry, State and local officials, and the general public about pipeline safety and replacement programs.

Sponsored by the Committee on Gas and the Committee on Critical Infrastructure
Adopted by the NARUC Board of Directors July24, 2013

Alaska Statutes

Sec. 42.05.511. Unreasonable management practices.

(c) In a rate proceeding, the utility involved has the burden of proving that any written or unwritten contract or arrangement it may have with any of its affiliated interests for the furnishing of any services or for the purchase, sale, lease, or exchange of any property is necessary and consistent with the public interest and that the payment made therefor, or consideration given, is reasonably based, in part, on the submission of satisfactory proof as to the cost to the affiliated interest of furnishing the service or property and, in part, on the estimated cost the utility would have incurred if it furnished the service or property with its own personnel and capital.

Sec. 42.05.441. Valuation of property of a public utility.

(c) For rate-making purposes, indebtedness, debt service, and payments by a regulated public utility to a person having an ownership interest of more than 70 percent in the utility shall be considered to be ownership equity, profits, or dividends except to the extent that there is a clear and convincing showing that: (1) the indebtedness was incurred, or the payments made, for goods or services that were reasonably necessary for the operation of the utility; and (2) the goods or services were provided at a cost that was competitive with the price at which they could have been obtained from a person having no ownership interest.

Summary of Costs to ENSTAR to Perform All Corporate Services Activities ($000s)

ENSTAR's Expense for TSU's Corporate Services	
Corporate Services Function	**TOTAL**
Board of directors	$210
Executive Management	$722
Acctg / Tax / Finance	$974
Corporate Resources (incl. Legal & Compliance)	$959
TOTAL Cost to ENSTAR	$2,866

Costs if Corporate Services Moved to ENSTAR		
Function	**FTE REQUIRED**	**TOTAL**
Board of directors		$1,399
Executive Management	2	$5,197
Acctg / Tax / Finance	3	$3,711
Corporate Resources (incl. Legal & Compliance)	3	$876
TOTAL Cost to ENSTAR	**8**	**$11,183**

$8.3 million cost savings for ENSTAR with TSU performing Corporate Services

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chairman
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Consideration of the Revenue Requirement Designated as TA 354-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF CHELSEA N. GUINTU

PREFILED DIRECT TESTIMONY
OF
CHELSEA N. GUINTU

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EXHIBITS

Exhibit CNG-1 Resume of Chelsea N. Guintu
Exhibit CNG-2 Year End Capital Plant Calculation
Exhibit CNG-3 Calculation of Normalized Rate of Return at Current Rates
Exhibit CNG-4 Calculation of Interim Rates

I. POSITION AND QUALIFICATIONS

Q. Please state your name, business address and present position.

A. My name is Chelsea N. Guintu. My business address is 3000 Spenard Road, Anchorage, AK 99503. I am the Manager of Regulatory and Planning for ENSTAR Natural Gas Company, LLC ("ENSTAR") and Alaska Pipeline Company, LLC ("APC"). I will refer to ENSTAR and APC together as "ENSTAR" or "Company."[1]

Q. Briefly describe your professional experience and educational background.

A. I have been employed by ENSTAR since 2015. Before joining ENSTAR, I worked in public accounting for three years while I obtained my Certified Public Accountant license, which I have maintained since. My educational background includes a Master of Business Administration with an emphasis in Business Intelligence and a Bachelor of Business Administration with a major in Accounting, both from the University of Alaska Anchorage. In 2020, I completed a year-long program with the University of Illinois Springfield and received my Graduate Certificate in Public Utility Management and Regulation. My resume is attached as Exhibit CNG-1.

Q. Briefly describe your current responsibilities.

A. As Manager of Regulatory and Planning, I oversee the preparation of financial analyses and reports, as well as the preparation of testimony, tariff revisions, and filings with the Regulatory Commission of Alaska ("Commission" or "RCA") and act as a liaison for ENSTAR and Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA") with

[1] The Commission regulates APC and ENSTAR as a single entity. The use of the name "ENSTAR" or "Company" in this filing is intended to include both APC and ENSTAR, unless the context clearly requires otherwise.

Commission staff. Additionally, I oversee the budget and planning for both ENSTAR and CINGSA.[2]

Q. Have you previously testified before the RCA?

A. Yes, I provided testimony before the RCA on behalf of ENSTAR in Dockets U-19-101, U-22-081 and on behalf of CINGSA in Dockets U-18-024, and U-21-058.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. My testimony has several primary functions. First, I am sponsoring ENSTAR's revenue requirement on a 13-month average (Attachment B) which is in compliance with 3 AAC 48.275(a).[3] Secondly, I will be sponsoring ENSTAR's comparative financial schedules, which are included in Attachment B to TA354-4, and discussed below. Next, I will summarize ENSTAR's rate history including its last rate case (U-22-081). Fourth, I will discuss and sponsor the following pro forma adjustments as well as the corresponding schedules in the 275(a) filing:

- Removal of Disallowed Reg Assets (Schedule A)
- Removal of Misc. Revenues and Expenses (Schedule B)
- Removal of Other Assets (Schedule C)
- Removal of CWIP (Schedule E)
- Rate Case Expense (Schedule J)
- Removal of ROU Lease (Schedule K)

[2] ENSTAR performs management services for CINGSA through an Operation and Maintenance Agreement.

[3] A "275(a)" filing refers to a filing in compliance with the Commission's regulations at 3 AAC 48.275(a), which specifies the information necessary to support a new revenue requirement filing.

- Payroll Adjustment (Schedule M)
- Cash Working Capital (Schedule N)
- Year-End Plant Adjustment (Schedule O)

Finally, I am sponsoring the related tariff sheets that present the proposed interim and permanent rates. Ms. Inna B. Johansen is sponsoring the tariff sheets related to ENSTAR's Very Large Firm Transportation/South Central Power Pool Firm Transportation Peak Reduction Credit.

Q. What comparative financial schedules in ENSTAR's 275(a) filing are you sponsoring?

A. I am sponsoring the following comparative financial schedules of the 275(a) filing (Attachment B), which were prepared by me or under my direction:

- Comparative Statement of Assets, Liabilities and Other Credits;
- Comparative Statement of Income and Operating Expenses;
- Comparative Statement of Changes in Equity;
- Plant in Service and Accumulated Depreciation;
- Depreciation Expense;
- Long-Term Debt Outstanding; and
- Effective Proposed Rate Increase.

These schedules are required by 3 AAC 48.275(a)(1)-(4), and (10).

Q. Describe the information contained on these schedules.

A. These schedules were prepared using historical financial data compiled from ENSTAR's accounting books and records, or are based on such data, for the test year ended December 31, 2024.

III. 3 AAC 48.275(a) FILING DATA

Q. Have you reviewed ENSTAR's books and records in connection with this filing and made any adjustments to the data?

A. Yes. In preparing this filing, I (or ENSTAR employees acting under my direction) reviewed the data contained in ENSTAR's accounting records and identified unusual events, non-recurring expense and revenue items, areas requiring or warranting adjustments for known and measurable changes, and other necessary and/or appropriate revenue, expense, and investment adjustments. This review identified and quantified adjustments needed for a fair and reasonable evaluation of the adequacy of ENSTAR's base rates.

The results of this review are reflected in various adjustments to test year data made to arrive at the "normalized" test year included in this filing. Normalizing test year data is a standard regulatory practice and is intended to give the Commission a reasonable accounting basis for evaluating and establishing ENSTAR's revised base rates.

Q. Please identify the schedules in the filing.

A. ENSTAR's 275(a) filing is contained in Attachment B to TA354-4 and includes the following:

- the computation of the revenue requirement and revenue deficiency or surplus in both absolute dollars and as a percentage of revenues for the normalized test year are presented on page 4;
- the test-year operating revenues and expenses, net pro forma adjustments, and the resulting normalized test-year operating revenues and expenses are

presented on page 1, and a summary of the pro forma adjustments is shown on pages 6-8;

- the computations of and narrative explanations for the pro forma adjustments to the actual test-year figures are shown on Schedules A though Q in Attachment B, while more detailed discussions for many of the pro forma adjustments are contained in my testimony as well as in the testimony of ENSTAR witnesses Ms. Johansen, Dr. Bruce H. Fairchild, Ms. Abigail L. Riggs, and Mr. Harold Walker, III;
- the computation of the pro forma adjustment for state and federal taxes for the normalized test year is shown on Schedule F and contained in the testimony of Dr. Fairchild;
- the computation of rate base using the 13-month average (Attachment B) values of all rate base components, except cash working capital allowance, is shown on page 2;
- the pro forma cash working capital requirement based on the normalized test year is shown on Schedule N and is derived based upon the lead-lag study sponsored by Mr. Walker;
- the computation of ENSTAR's requested weighted cost of capital is shown on page 3 and sponsored by ENSTAR witnesses Ms. Riggs and Ms. Jennifer Nelson;
- the Comparative Statement of Assets, Liabilities and Other Credits for 2023 and 2024 is shown on page 26 of Attachment B;

- the Comparative Statement of Income and Operating Expenses for 2023 and 2024 is shown on page 27 of Attachment B;
- the Comparative Statement of Changes in Equity Position for 2023 and 2024 is shown on page 28 of Attachment B;
- Plant in Service and Accumulated Depreciation balances for 2023 and 2024 are shown on pages 29 and 30 of Attachment B;
- Depreciation Expense for 2023 and 2024 is shown on pages 31 and 32 of Attachment B;
- Long-Term Debt Outstanding for 2023 and 2024 is shown on page 33 of Attachment B; and
- Effective Proposed Rate Increase is shown on page 34 of Attachment B.

Q. Please briefly describe the normalized test year and revenue requirement schedules, which are pages 1-4 of ENSTAR's 275(a) filing (Attachment B).

A. Page 1 summarizes the filing and shows the actual results of ENSTAR's operations for the year ended December 31, 2024 (column 1), followed by a summary of adjustments (column 2) made to convert the historical test year to a normalized test period representative of ENSTAR's ongoing operations (column 3). The adjustments set out on pages 6-8 specify the related supporting schedule and identify the primary sponsoring witness(es), respectively.

Page 2 of the filing develops ENSTAR's rate base, beginning with 13-month average, on Attachment B, followed by a summary of adjustments (column 2) made to reflect the current level of ENSTAR's investment in assets used to provide service to customers, followed by the adjusted test-year rate base (column 3). Like the

adjustments to income and expenses, the adjustments to rate base are set out on pages 6-8 and specify the related supporting schedule and the primary sponsoring witness(es).

Page 3 of the filing includes ENSTAR's proposed capital structure, embedded cost of debt, and requested rate of return on equity; this schedule is sponsored by Ms. Riggs and Ms. Nelson.

Page 4 of the filing reconfigures the information on pages 1, 2, and 3 into a revenue requirement format. Pages 9 through 25 of Attachment B provide supporting schedules that detail the various adjustments made on pages 1 through 4. Pages 26 through 28 on Attachment B provide the required historical comparative information.

Q. What is a "normalized test-year?"

A. 3 AAC 48.820(42) defines "normalized test-year" as a "historical test-year adjusted to reflect the effect of known and measurable changes and to delete or average the effect of unusual or nonrecurring events, for the purpose of determining a test year which is representative of normal operations in the immediate future." In other words, it is used to develop a representative cost of service for the period during which the rates being set will be in effect. This is the traditional cost of service approach that the Commission has routinely followed in rate case orders over the years. For example, in Order U-05-043(15)/U-05-044(15) at page 6, the Commission stated:

> [T]he goal of cost-based ratemaking is not to recover past costs but to predict the rates necessary to yield revenue adequate to cover the utility's costs and provide the opportunity to earn a reasonable return on investment during the future period when the rates are likely to be in effect.[4]

[4] Other examples include Order U-87-084(8), *Order Deciding Revenue Requirement Issues And Requiring Filings.* dated September 7, 1989 at 13-14; Order U-93-058(8), *Order Addressing Issues And Requiring Filing*, dated December 21, 1993 at 7; Order U-00-088(12), *Order Establishing Revenue Requirement, Requiring Filings, Scheduling Prehearing Conference, And Affirming Electronic Rulings,* dated August 8, 2002 at 5; and Order P-97-004(151) et al., dated November 27, 2002 at 6-7.

The fact that the Commission utilizes a historical test year, not a future period test year, makes the adjustments to the historical test year data very important.

Q. Why are adjustments to historical test year data important?

A. A utility filing a rate request before the RCA must base its request on a completed test year. From my experience, it generally takes three to nine months after the test year ends to prepare a rate request. During that time, conditions change, operations and construction (new investment) continue, inflation occurs, labor rates increase, and overall costs almost always increase. Pursuant to AS 42.05.175(c), the statutory timeline for the Commission to rule on a rate case is 450 days. If a final order is issued in a rate case proceeding at the end of this 450-day period, by the time the new rates are put into effect, the costs from the historical test year will be more than two years old. Without taking into account changes that have occurred since the test year, the utility's rates will almost certainly be based on costs that are below those that it is actually incurring.

Q. Is Alaska's 450-day statutory timeline for ruling on a rate case typical when compared to other jurisdictions?

A. No. According to data from Regulatory Research Associates ("RRA"), 85% of the regulatory jurisdictions in the United States are required to rule on a rate case within twelve months of filing.

Q. What is the impact of Alaska's 450-day statutory timeline on ENSTAR's ability to recover its costs?

A. ENSTAR's capital expenditures (net of contribution in aid of construction ("CIAC")) in 2024 were $41.3 million, which were 2.3 times its depreciation expense of $18.0

million. The combination of ENSTAR's significantly greater capital spend relative to its internal cash generation through depreciation expense and the 450-day timeline subjects ENSTAR to an extraordinary delay in recovering its costs, such as capital, and exacerbates the risk that it will not be able to realize its authorized rate of return.

Q. What types of pro forma adjustments are generally made to test years in rate requests?

A. Adjustments to the historical test year are generally of three types. The first are normalization adjustments designed to eliminate unusual or non-recurring items during the test year. The second are adjustments to reflect known and measurable, or pro forma, changes in test-year revenues, expenses, and rate base (or investment). The third are regulatory adjustments intended to account for items in a manner consistent with currently accepted ratemaking principles and objectives. ENSTAR has made various adjustments to revenues, expenses, and rate base.

Q. For an adjustment to be approved, what requirements must be satisfied?

A. Normally, adjustments must be: (1) reasonably known and measurable; (2) synchronized with other expenses, rate base, and revenue; (3) supportable; and (4) disclosed.

Q. Do ENSTAR's proposed pro forma adjustments meet these requirements?

A. Yes, as described below and in the direct testimony of Dr. Fairchild, Ms. Johansen, Ms. Riggs, and Mr. Walker.

Q. Based on the adjustments to the test year and ENSTAR's requested rate of return, what is ENSTAR's total revenue requirement?

A. As shown at the bottom of page 4 on Attachment B, ENSTAR's revenue requirement based on its normalized 13-month average rate base (excluding cost of gas) is $117,811,841.[5] Comparing this with current adjusted normalized revenues (excluding cost of gas) of $92,918,768 developed on page 1 of Attachment B, ENSTAR has a revenue deficiency of $24,893,073 and proposes to increase its rates by 26.79% to alleviate the revenue deficiency.

IV. ENSTAR'S RATE CASE HISTORY

Q. Briefly summarize ENSTAR's history of base rate changes since it began operating.

A. As described by Mr. John D. Sims in his testimony, ENSTAR was first organized in 1959 and gas service began in the summer of 1961. ENSTAR's base rates (i.e., the rates that recover the Company's costs of providing service to customers exclusive of gas costs) remained unchanged between 1961 through 1974, except for a reduction ($1 per customer per month) instituted in 1972. In 1976, ENSTAR filed its first base rate increase with the Commission (Docket U-75-095). At the conclusion of that case, the Company's base rates were increased and ENSTAR was authorized to earn a return on equity of 14.25%. ENSTAR filed its second rate case in 1981 (Docket U-81-101) and was granted another base rate increase on an awarded 16.65% return on equity. In connection with the construction of the Beluga Pipeline in 1984, ENSTAR filed its

[5] Whereas the revenue requirement (including cost of gas) is $456,139,812 compared to the adjusted normalized revenues (including cost of gas) of $431,246,738 for a total increase of 5.77%.

third base rate case (Docket U-84-059) and was granted another base rate increase on a 15.65% return on equity.

ENSTAR's base rates remained the same from 1987 through 2002. As a condition of approval of SEMCO Energy, Inc.'s ("SEMCO") purchase of ENSTAR in 1999, the Company was required to file information regarding the adequacy of its base rates in 2000, using a test year ending December 31, 1999.[6] ENSTAR filed this data, but the Commission later determined that a test year ended December 31, 2000, would be a better basis from which to evaluate rates.[7] ENSTAR then submitted information for the test year ended December 31, 2000, which became the basis for a base rate review in Docket U-00-088.

Phase One of Docket U-00-088 dealt with ENSTAR's revenue requirement. Based on its review, the Commission granted a 12.55% return on equity and ordered a base rate reduction.[8] The Commission also instituted a second phase of the proceeding to focus on rate design.[9] ENSTAR filed the required rate design information in December 2002, and the rate design portion of the proceeding was settled by a stipulation accepted by the Commission.[10]

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[6] Order U-99-093(1)/U-99-094(1), *Order Approving Applications, Subject to Conditions; and Requiring Filings,* dated October 19, 1999.

[7] Order U-00-088(3), *Order Affirming Bench Rulings; Granting Unopposed Motion to Substitute Test Year; Accepting, in Part, Proposed Procedural Schedule; and Scheduling a Hearing for ENSTAR to Show Cause Why its Current Rates Should Not Be Made Interim and Refundable,* dated March 5, 2001.

[8] Orders U-00-088(12), *Order Establishing Revenue Requirement, Requiring Filings, Scheduling Prehearing Conference, and Affirming Electronic Rulings,* dated August 8, 2002; and U-00-088(15), *Order Granting Petition for Reconsideration; Granting in Part, Motion for Across-the-Board Rate Decrease; and Denying Motion to Make Rates Interim and Refundable* dated September 16, 2002.

[9] There was a third phase of this proceeding that related to transportation terms and conditions. That phase was completed and the entire docket was closed effective May 17, 2006 (Order U-00-088(40)).

[10] Order U-00-088(22), *Order Accepting Stipulation, Subject to Condition, and Approving Tariff Sheets,* dated May 21, 2003.

Order U-04-106(5), dated June 16, 2005,[11] required ENSTAR to file, among other things, a revenue requirement and cost-of-service ("COS") study. Order U-04-106(8)/U-08-123(1) revised the filing deadline to June 1, 2009, and established a test year ending on December 31, 2008. Following ENSTAR's filing, the Commission suspended and bifurcated it into two dockets: U-09-069 (revenue requirement) and U-09-070 (rate design). Both dockets were settled by a stipulation accepted by the Commission,[12] which resulted in the four general service rate classes and the rate structure currently in place. The stipulation provided for a total increase of $10,761,729 on a rate base of $199,000,000, with a cost of equity of 12.55%. The stipulation also provided that ENSTAR would file "a base rate case no later than August 1, 2014 based upon a test year ended December 31, 2013."[13] In Order U-09-069/U-09-070(12), dated August 6, 2014, the Commission granted ENSTAR's request to extend the filing deadline to September 5, 2014.

In September 2014, ENSTAR submitted the required revenue requirement filing along with a 275(h) COS study and supporting testimony. The Commission suspended the filing into Docket U-14-111 and granted an interim increase of 3.75% effective November 1, 2014.[14] The docket was settled by a stipulation accepted by the

[11] *In the Matter of the Investigation into the Financing Provided by K-1 GHM, LLP to SEMCO Energy, Inc.* Order No. 5 also granted a motion to withdraw and terminate the proceeding.

[12] Order U-09-069(10)/U-09-070(10), *Order Accepting Stipulation, Vacating Hearing Dates, And Approving Tariff Sheets*, dated August 9, 2010.

[13] *Id*. Appendix at 8. The requirement is reiterated in Ordering Paragraph No. 5 of Order U-09-069(10)/U-09-070(10).

[14] Order U-14-111(1), *Order Suspending TA262-4, Granting Request For Interim And Refundable Rate Increase, Establishing Interest Rate On Refunds, Requiring Filing, Approving Tariff Sheets, Scheduling Prehearing Conference, Addressing Timeline For Decision, Inviting Participation By The Attorney General And Intervention, Designating Commission Panel, And Appointing Administrative Law Judge*, dated October 27, 2014.

Commission, which resulted in a permanent rate increase based upon a revenue requirement of $81,088,932 effective October 1, 2015, and an interim rate increase based upon a revenue requirement of $83,288,932 effective January 1, 2016. The rates would stay interim upon ENSTAR's next rate case filing.

In June 2016, ENSTAR filed a revenue requirement and COS study based upon a 2015 test year as stipulated to in Docket U-14-111. Following a three-week public hearing in June of 2017, the RCA issued Order U-16-066(19) dated September 22, 2017, which resolved revenue requirement and COS issues in the case, including granting ENSTAR a return on equity of 11.875% and return on total capital of 8.59%. ENSTAR was directed to file revised revenue requirement schedules, a revised COS study, and tariff sheets consistent with the Commission's decisions. The Commission also required ENSTAR to file another rate case based upon calendar year 2020 by June 1, 2021. ENSTAR filed the revised revenue requirement schedules, COS study and tariff sheets in compliance with Order 19 and the Commission accepted the filing and approved the tariff sheets effective November 1, 2017, in Order U-16-066(20), dated October 25, 2017.

ENSTAR lowered its rates in 2018 in response to the Tax Cuts and Jobs Act of 2017 ("TCJA") that was enacted on December 22, 2017. ENSTAR filed the rate revision as TA303-4 on April 26, 2018, which represented "a 5.7% reduction of ENSTAR's non-gas revenue requirement." The rates proposed in TA303-4 were approved in Letter Order L1800240 dated May 29, 2018, with an effective date of June 1, 2018.

The Commission granted ENSTAR's motion for relief from the requirement to file a rate case based on a 2020 test year and required ENSTAR to file a rate case, including a lead-lag study, based on a 2021 test year by June 1, 2022 in Order U-16-066(21). In Order U-16-066(22), the Commission extended the time to file a rate case based on a 2021 test year to August 1, 2022.

Q. Briefly summarize ENSTAR's last rate case, U-22-081.

A. ENSTAR's last rate case was filed in compliance with the August 1, 2022 date set by the Commission in Order U-16-066(22). ENSTAR requested a permanent increase of 5.68% to base rates. The issues in the rate case, excluding return on equity, were resolved by stipulation which the Commission accepted in Order U-22-081(11), dated October 11, 2023. After a three-day hearing regarding return on equity, the Commission awarded ENSTAR an 11.875% return on equity in Order U-22-081(14), issued on April 8, 2024. The Commission required ENSTAR to file a revised revenue requirement with supporting schedules and revised tariff sheets consistent with Order U-22-081(14) and the partial stipulation accepted in Order U-22-081(11). ENSTAR filed its revised schedules and tariff sheets, and the Commission accepted the filings on May 8, 2024, in Order U-22-081(15).

V. ADJUSTMENTS TO 275(a) FILING

Q. Which adjustments included in ENSTAR's 275(a) filing do you sponsor?

A. I sponsor the following adjustments to expenses and rate base that are included in the 275(a) filing:

- Removal of Disallowed Reg Assets (Schedule A);
- Removal of Misc. Revenues and Expenses (Schedule B);

- Removal of Other Assets (Schedule C);
- Removal of CWIP (Schedule E);
- Rate Case Expense (Schedule J);
- Removal of ROU Lease (Schedule K);
- Payroll Adjustment (Schedule M);
- Cash Working Capital (Schedule N); and
- Year-End Plant Adjustment (Schedule O).

A. Removal of Disallowed Reg Assets (Schedule A)

Q. Please describe the Removal of Disallowed Regulatory Assets adjustment shown on Schedule A of the 275(a) filing.

A. This pro forma adjustment reduces ENSTAR's rate base and operating expenses. ENSTAR's 2009 rate case was settled by a stipulation that included a provision that ENSTAR would not include its costs incurred on the proposed Bullet Line pipeline from the North Slope in future ENSTAR rate proceedings. The Bullet Line regulatory asset was fully amortized in December 2024. To adjust out these costs, Pro Forma A removes the regulatory asset of $232,893 from rate base and the associated amortization expense of $465,786 from test year expenses.

B. Removal of Misc. Revenues and Expenses (Schedule B)

Q. Please describe the Removal of Miscellaneous Revenues and Expenses adjustment shown on Schedule B of the 275(a) filing.

A. This adjustment reduces ENSTAR's operating expenses and miscellaneous revenues. ENSTAR is removing expenses related to lobbying, charitable contributions, penalties, club dues, and incidental employee benefits. The adjustment reduces test year expenses by $1,748,457.

ENSTAR is also removing the revenues associated with the Homer Surcharge. These amounts are recovered through a separate mechanism that includes a return resolved by stipulation and accepted by the Commission in Order U-19-014(9) and are not included in general system-wide rates. This adjustment reduces revenues by $108,532.

Q. How did ENSTAR arrive at the amount for the adjustment found on Schedule B?

A. My team and I reviewed entries in ENSTAR's general ledger with a focus on operating expenses. When reviewing the general ledger description and underlying support (if necessary), we determined whether each individual expense should remain in ENSTAR's expenses for the test year.

Q. What type of expenses were individually removed resulting from the general ledger review?

A. Some examples of removed items are non-working meals related to items such as birthdays, retirements, and department holiday lunches. Additionally, employee relation items such as gift cards, party decorations, and flowers were also removed.

C. Removal of Other Assets (Schedule C)

Q. Please describe the Removal of Other Assets adjustment shown on Schedule C of the 275(a) filing.

A. This adjustment reduces ENSTAR's rate base by removing various regulatory assets that are included on ENSTAR's books. Additionally, the stipulation settling Docket U-14-111 provided that ENSTAR shall not include the unamortized amounts of the Anchor Point Litigation in rate base, so those amounts have also been removed. The total adjustment reduces rate base by $3,877,497.

D. Removal of CWIP (Schedule E)

Q. Please describe the Removal of CWIP adjustment shown on Schedule E of the 275(a) filing.

A. This adjustment reduces ENSTAR's rate base. In keeping with Commission precedent, ENSTAR has removed construction work-in-progress ("CWIP") from the rate base calculation. The adjustment decreases rate base by $17,270,338.

E. Rate Case Expense (Schedule J)

Q. Please describe the Rate Case Expense adjustment shown on Schedule J in the 275(a) filing.

A. This pro forma is a two-part adjustment to rate case expense. First, I include a pro forma of the anticipated fees and costs associated with prosecuting the instant rate case and amortize the amount over three years. Next, I reduce the amortization amount by the rate case expense in the 2024 test year from Docket U-22-081. This ensures there is no double-recovery of rate case expenses from the previous and the current rate case.

Q. What was the amount of Docket U-22-081 Rate Case Expense on the test year books?

A. ENSTAR's amortized test-year rate case expense was $305,909.

Q. How does this amount compare with the amount agreed to in the partial stipulation between ENSTAR and RAPA, and authorized by the Commission to be included in rates per Order U-22-081(11)?

A. In the partial stipulation accepted in Order U-22-081(11), ENSTAR agreed to reduce its rate case costs associated with U-22-081 to $2,060,433, to be amortized over three years, resulting in annual rate case expense of $686,811.

Q. Is ENSTAR seeking to recover the remaining balance in this regulatory asset?

A. No. In Docket U-16-066, the Commission stated that "[t]he amount of rate case expense that we include in the revenue requirement is an estimate of future rate case cost, not the recovery of past rate case expenditures."[15] As such, Schedule J requests an adjustment to omit this unamortized balance.

Q. What amount is ENSTAR estimating for rate case expenses for this case?

A. ENSTAR estimates it will incur $2.9 million in rate case expenses for this case. This estimate is based on the actual costs ENSTAR incurred three years ago in U-22-081, while also reflecting the professional support services ENSTAR has enlisted to prepare this case, attempting to account for inflation in costs since that case along with preparation and costs for a hearing. This is consistent with the Commission's statement in Order U-16-066(19) at page 92 that "[c]urrent experience is relevant and may indicate trends that costs will differ from past experience."

Q. What is ENSTAR's proposed amortization period for rate case expenses incurred in this case?

A. ENSTAR proposes a three-year amortization period which results in an amortization amount of $966,667 per year. Once this amount is netted against the U-22-081 rate case expense removed from the test year, it creates an increase to operating expenses of $660,758.

Q. Why did ENSTAR select this amortization period?

[15] Order U-16-066(19), *Order Resolving Revenue Requirement And Cost Of Service Issues And Requiring Filings*, dated September 22, 2017 at 92, citing Order U-00-088(12), *Order Establishing Revenue Requirement, Requiring Filings, Scheduling Prehearing Conference, And Affirming Electronic Rulings*, dated August 8, 2022 at 24.

A. As described by Mr. Sims and Mr. Burke, ENSTAR anticipates significant capital investment and gas supply related investment in 2025 and going forward. ENSTAR does not currently have a method to reasonably recover this investment without filing a full rate case. Without such an alternative mechanism, it is highly likely ENSTAR will file another rate case in a short period of time following the conclusion of this rate case. In these circumstances a three-year amortization period is reasonable and is likely conservative.

Mr. Sims explains that ENSTAR has filed a request for a Formula Rate Mechanism in the near future. If this request is approved, a longer five-year amortization period may be reasonable.

F. Removal of ROU Lease (Schedule K)

Please describe the Removal of ROU Lease Contracts adjustment shown on Schedule K of the 275(a) filing.

A. This adjustment reduces rate base by $2,745,856. Additionally, it increases operating expenses by $97,375. To perform this adjustment, I removed ENSTAR's Right of Use ("ROU") finance leases (and the associated accumulated amortization) and the ROU operating leases from rate base (and depreciation and amortization expense). These leases were recorded on the balance sheet in 2019 per Accounting Standards Codification 842. Prior to 2019, these leases were classified as operating leases. The adjustment then includes the lease payments in administrative and general ("A&G") expenses.

Q. Did ENSTAR propose a similar regulatory treatment of operating leases in Docket U-22-081?

A. Yes. In Docket U-22-081, ENSTAR included the lease payments in A&G expenses, as opposed to including the leases in rate base. Also, CINGSA performed the same adjustment in Docket U-21-058.

G. Payroll Adjustment (Schedule M)

Q. Please describe the Payroll adjustment shown on Schedule M of the 275(a) filing.

A. The purpose of the payroll adjustment shown on Schedule M is to account for changes in the compensation of ENSTAR's employees compared to the test-year data, consistent with Commission precedent.

Q. How did ENSTAR develop the adjustment shown on Schedule M?

A. The payroll adjustment was developed by reviewing ENSTAR employee rates charged to operating expenses, fleet, and stores loading on a position-by-position basis. Then, wage rates were adjusted to reflect salary and wage rates for each non-union position in effect on April 1, 2025. For union-represented clerical and operations employees, wage rates were adjusted to reflect scheduled grade changes along with a 5.0% cost of living increase specified by union contract that became effective on April 1, 2025, as discussed in Mr. Sims' testimony. This adjustment increases ENSTAR's revenue requirement by $833,331.

Is there precedent for this type of payroll adjustment?

A. Yes. In Order U-08-157(10)/U-08-158(10), the Commission allowed the Municipality of Anchorage d/b/a Anchorage Water and Wastewater Utility ("AWWU") to use updated wage rates that were known and measurable at the time it filed its rate case. AWWU was required to hold the number of employees constant and then adjust its

wage rates for known and measurable changes. The Commission affirmed this approach in Order U-13-184(22)/U-15-096(1)/U-15-097(1) by allowing Municipal Light & Power to utilize test-year employee levels and adjust for known and measurable pay increases. In Order U-16-066(19), the Commission also allowed ENSTAR to make pro forma wage adjustments to update wage rates for known and measurable changes.

H. Cash Working Capital (Schedule N)

Q. Please describe the Cash Working Capital adjustment shown on Schedule N of the 275(a) filing.

A. In the partial stipulation accepted by the Commission in Order U-22-081(11), ENSTAR agreed to exclude deferred income tax, depreciation, and the common equity return component of net income from its cash working capital calculation. Based on Mr. Walker's testimony and the lead-lag study performed in compliance with that partial stipulation, ENSTAR proposes a cash working capital adjustment of $6,950,657 to rate base.

I. Year-End Plant Adjustment (Schedule O)

Q. Please describe the Year-End Plant adjustment shown on Schedule O of Attachment B.

A. As discussed by Mr. Sims and Mr. Nathan T. Burke, the costs associated with certain capital projects that meet safety and reliability criteria are being adjusted to year-end balances, or as if they were in service throughout the test year. A detailed schedule of these "year-end" capital projects showing the calculation for the adjustment to test-year plant, accumulated depreciation, and depreciation expense is shown on Exhibit CNG-2.

Q. Please describe Exhibit CNG-2 in more detail.

A. The first column of Exhibit CNG-2 ("Jobs") lists each capital project by category. The next column provides the FERC account number associated with the project. The third column provides the depreciation rate used for the asset based on ENSTAR's last depreciation study. The next three columns (under "Gas Utility Plant") show the amount of capital dollars added to the test year, the amount included in the 13-month average rate base, and the adjustment needed to bring the 13-month average amount to a year-end balance. The same calculation is done for depreciation and accumulated depreciation for proper synchronization. The pro forma amounts from this exhibit are included in Schedule O and summarized by FERC account number.

Q. Is the pro forma adjustment to annualize qualifying capital projects appropriate in ENSTAR's current filing?

A. Yes. As I discussed above, ENSTAR had a significant level of capital expenditures in 2024 ($55.2 million excluding CIAC), an amount more than 17% of its 2023 net plant. The majority of these capital expenditures, $41.2 million, were attributable to non-income producing plant. "Non-income producing plant" is investment that does not result in nor is intended to significantly increase customer connections.

In 2024, ENSTAR performed a number of necessary updates and repairs to existing infrastructure that consisted of non-income producing plant and is detailed in the testimony of Mr. Burke. These projects are necessary to ensure ENSTAR's safe, efficient, and reliable service to its customers. Because these projects updated and repaired existing infrastructure, these costs, while critical for ENSTAR's service, did not result in additional demand or a growth in customer base.

Q. What is the Commission's process for calculating a utility's rate base in rate cases?

A. The Commission's regulations require a utility to file its calculation of rate base using a 13-month average.[16] According to the regulation, the 13-month average is "the arithmetic sum of the beginning of each month net balance for the 12-month test period, plus the balance at the end of the twelfth month of the test period, divided by 13."[17] The regulation also states, however, that the utility may propose "any other rate-base theory [that] the utility … considers appropriate and supportable."[18]

The Commission has addressed this issue in several past rate cases, including ENSTAR's 2016 rate case.[19] In that proceeding, the Commission explained that while the 13-month average is the Commission's "preferred method" for calculating rate base, the Commission will approve the use of year-end rate base in certain circumstances.[20]

Q. When a utility has placed new facilities into service during the test year, has the Commission authorized pro forma adjustments to annualize those plant additions?

A. The Commission has allowed this in certain circumstances. In ENSTAR's 2016 rate case (Order U-16-066(19)), the Commission explained as follows: "[w]e have allowed annualizing pro forma adjustments for plant placed in service during the test year that

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16 3 AAC 48.275(a)(9).

17 *Id.*

18 *Id.*

19 Order U-16-066(19), *Order Resolving Revenue Requirement and Cost-of-Service Issues and Requiring Filings*, at 18-24 (Sep. 22, 2017) ("Order U-16-066") (discussing past cases).

20 *Id.* at 23.

provides a benefit to ratepayers, such as a reduction in costs or an increase in safety and reliability."[21]

VI. INTERIM RATES

Q. Is ENSTAR asking for interim rate relief?

A. Yes. ENSTAR's TA354-4 filing includes a request for an interim and refundable base rate increase of 23.21% (approximately 5.00% on total revenues including gas cost), which is expected to generate about $21.6 million more in annual base rate revenues for billings on or after July 1, 2025.

Q. Is ENSTAR currently earning its previously authorized return on equity?

A. No. As shown on Exhibit CNG-3, ENSTAR's current rates result in an effective rate of return on equity ("ROE") of 4.57% on a normalized basis, and therefore, ENSTAR is not earning the approved return on equity of 11.875%. Additionally, Mr. Sims provides a detailed discussion on ENSTAR's historic ROE earnings since its last general rate case. Without Commission approval of interim and refundable rates, the current inadequate rates would remain in effect until the conclusion of these proceedings and the issuance of a final order, because rates cannot be collected retroactively. The rate case process could take up to 450 days, or longer, as provided by Commission statute. Assuming the Commission will later approve some or all of

[21] *Id.* at 26.

ENSTAR's proposed permanent increase, interim rates protect ENSTAR from irreparable harm.

Q. How did ENSTAR calculate the 23.21% interim rate increase?

A. In keeping with Commission policy on interim increases, the interim base rate increase of 23.21% was developed using the requested revenue requirement calculated using the 13-month average rate base (Attachment B to the TA Letter) and using the currently-approved return on equity of 11.875% from Order U-22-081(14).

Q. Is ENSTAR providing a schedule showing how the interim rates were calculated and tariff sheets for the interim rates?

A. Yes. Exhibit CNG-4 is a schedule showing the across-the-board application of the requested interim rate increase. As discussed above, the tariff sheets for the interim rate increase are included as Attachment D to TA354-4.

Q. Why is ENSTAR requesting this interim increase to be effective July 1, 2025?

A. As set out in TA354-4, ENSTAR is requesting that the additional interim increase be effective as of July 1, 2025, which is the beginning of the first month following the statutory 45-day review period.

VII. PERMANENT TARIFF SHEETS

Q. Are you sponsoring the permanent tariff sheets?

A. Yes, I am sponsoring the permanent tariff sheets. The permanent tariff sheets reflect the proposed rate increase. Additionally, as discussed in Ms. Johansen's testimony, ENSTAR developed a VLFT Peak Reduction Credit provision which is presented in Section 2170 of ENSTAR's tariff.

VIII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Chelsea N. Guintu

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, AK: 2015 - Present

Manager of Regulatory and Planning: 2024 - Present

Supervisor of Rates and Regulatory Affairs: 2019 - 2024

Senior Financial Analyst: 2015 - 2019

Aldrich CPAs, Anchorage, AK: 2014 - 2015

Regulatory Consultant

The Brandon Skinner Group, Anchorage, AK: 2013 - 2014

Staff Accountant

Newhouse & Vogler CPAs, Anchorage, AK: 2013

Staff Accountant

Pacific Plumbing Supply Company, Anchorage, AK: 2009 - 2012

Office Administrator

EDUCATION

University of Illinois Springfield: Graduate Certificate in Public Utility Management and Regulation, 2020

University of Alaska Anchorage: Master of Business Administration with emphasis in Business Intelligence, 2016

University of Alaska Anchorage: Bachelor Business Administration with a major in Accounting, 2012

OTHER

Certified Public Accountant, Alaska

American Institute of Certified Public Accountants, member

ENSTAR Natural Gas Company, LLC

Capital Projects for Test Year 2024

Jobs	FERC Account #	Depr. Rate	Gas Utility Plant			Depreciation			Accumulated Depreciation		
			2024 Year End Plant	Amount in 13-Month Average	Adjustment to Plant	Annual Depreciation Expense	Amount in Test Year	Adjustment to Depreciation	2024 Year End Accum Dept	Amount in 13-Month Average	Adjustment
Safety											
Oilwell East Gate PIG Traps (Lines)	367.00	1.76%	10,786	830	9,956	190	16	174	(95)	(1)	(94)
Oilwell East Gate PIG Traps (M&R Sta Structures)	366.00	1.87%	14,445	1,111	13,334	270	23	248	(135)	(2)	(133)
Oilwell East Gate PIG Traps (Meas & Reg Sta Equip)	369.00	2.42%	126,263	9,713	116,550	3,056	255	2,801	(1,528)	(20)	(1,508)
MP39 Odorant Replacement (Office Buildings)	390.00	1.63%	149,606	34,018	115,588	2,439	601	1,838	(1,219)	(46)	(1,173)
MP39 Odorant Replacement (M&R Sta Equipment)	369.00	2.42%	194,980	54,973	140,006	4,719	1,441	3,277	(2,359)	(111)	(2,248)
K6 12TP Replacement (Lines)	367.00	1.76%	5,989,735	460,749	5,528,986	105,419	8,785	96,634	(52,710)	(676)	(52,034)
Dist-Svc SK Steel Replacement 5/8" PL (Services - Plastic)	380.00	3.64%	18,242	13,888	4,354	664	548	116	(332)	(42)	(290)
Dist-Svc SK Steel Replacement 7/8" PL (Services - Plastic)	380.00	3.64%	463,711	357,023	106,689	16,879	14,079	2,801	(8,440)	(1,083)	(7,357)
Dist-Svc SK Steel Replacement 1" PL (Services - Plastic)	380.00	3.64%	68,799	48,432	20,367	2,504	1,910	594	(1,252)	(147)	(1,105)
Dist-Svc SK Steel Replacement 2" PL (Services - Plastic)	380.00	3.64%	6,717	5,519	1,198	245	218	27	(122)	(17)	(106)
Dist-SK Mains Steel Replacement 2" PL (Mains - Plastic)	376.00	2.08%	837,316	428,041	409,275	17,416	9,645	7,771	(8,708)	(742)	(7,966)
Dist-SK Mains Steel Replacement 4" PL (Mains - Plastic)	376.00	2.08%	224,052	114,915	109,136	4,660	2,589	2,071	(2,330)	(199)	(2,131)
Dist-SK Mains Steel Replacement 6" PL (Mains - Plastic)	376.00	2.08%	241,557	123,430	118,127	5,024	2,781	2,243	(2,512)	(214)	(2,298)
Dist-SK Mains Steel Replacement Unall (Mains - Plastic)	376.00	2.08%	216,659	76,689	139,969	4,507	1,728	2,778	(2,253)	(133)	(2,120)
Dist-Svc SK Steel Replacement Unall (Services - Plastic)	380.00	3.64%	66,696	48,875	17,821	2,428	1,927	500	(1,214)	(148)	(1,066)
KUSCO S/L Replacement (7/8" PL) (Services - Plastic)	380.00	3.64%	68,220	5,248	62,973	2,483	207	2,276	(1,242)	(16)	(1,226)
KUSCO S/L Replacement (1" PL) (Services - Plastic)	380.00	3.64%	25,358	1,951	23,408	923	77	846	(462)	(6)	(456)
Robin Drive Steel Replacement (Mains - Plastic)	376.00	2.08%	26,437	4,728	21,709	550	107	443	(275)	(8)	(267)
Togiak Street Steel Replacement (Mains - Plastic)	376.00	2.08%	44,352	25,459	18,893	923	574	349	(461)	(44)	(417)
Swanson River Steel Replacement (Mains - Plastic)	376.00	2.08%	99,348	19,154	80,194	2,066	432	1,635	(1,033)	(33)	(1,000)
Camrose Drive Steel Replacement (Mains - Plastic)	376.00	2.08%	106,376	30,095	76,281	2,213	678	1,534	(1,106)	(52)	(1,054)
Dist-Svc AN Copper Renewal 5/8" PL (Services - Plastic)	380.00	3.64%	513,263	302,245	211,018	18,683	11,919	6,764	(9,341)	(917)	(8,425)
Dist-Svc AN Copper Renewal 7/8" PL (Services - Plastic)	380.00	3.64%	1,011	619	393	37	24	12	(18)	(2)	(17)
Dist-Svc AN Copper Renewal 1" PL (Services - Plastic)	380.00	3.64%	320	226	93	12	9	3	(6)	(1)	(5)
Dist-Svc AN Copper Renewal 1" Stubs (Services - Plastic)	380.00	3.64%	332	277	55	12	11	1	(6)	(1)	(5)
Dist-Svc AN Renewal 5/8" PL (Services - Plastic)	380.00	3.64%	8,873	4,561	4,312	323	180	143	(161)	(14)	(148)
Dist-Svc AN Renewal 7/8" PL (Services - Plastic)	380.00	3.64%	5,345	3,380	1,964	195	133	61	(97)	(10)	(87)
Dist-Svc AN Renewal 1" Stubs (Services - Plastic)	380.00	3.64%	770	351	419	28	14	14	(14)	(1)	(13)
Dist-Svc AN X-trube Renewal 5/8" PL (Services - Plastic)	380.00	3.64%	20,109	13,652	6,457	732	538	194	(366)	(41)	(325)
Dist-Svc AN X-trube Renewal 7/8" PL (Services - Plastic)	380.00	3.64%	47,889	14,011	33,878	1,743	553	1,191	(872)	(43)	(829)
Dist-Svc ER Renewal 7/8" PL (Services - Plastic)	380.00	3.64%	3,607	2,276	1,331	131	90	42	(66)	(7)	(59)
Dist-Svc SK Copper Renewal 5/8" PL (Services - Plastic)	380.00	3.64%	478	2,286	(1,808)	17	90	(73)	(9)	(7)	(2)
Dist-Svc SK Renewal 5/8" PL (Services - Plastic)	380.00	3.64%	300	326	(26)	11	13	(2)	(5)	(1)	(4)
Dist-Svc SK Renewal 7/8" PL (Services - Plastic)	380.00	3.64%	100	83	17	4	3	0	(2)	(0)	(2)
Reliability											
B466 Seldon Reg. Station (M&R Sta Equipment)	369.00	2.42%	521,253	40,096	481,157	12,614	1,051	11,563	(6,307)	(81)	(6,226)
B466 Seldon Reg. Station (Lines)	367.00	1.76%	14,742	1,134	13,608	259	22	238	(130)	(2)	(128)
Water Bath Heater Upgrades - Palmer Airport (M&R Sta Equipment)	369.00	2.42%	286,298	22,023	264,275	6,928	577	6,351	(3,464)	(44)	(3,420)
Seward Meridian Interconnect - Bogard To Seldon (Mains Plastic)	376.00	2.08%	142,024	30,635	111,390	2,954	690	2,264	(1,477)	(53)	(1,424)
Seward Meridian TP Extension (Lines)	367.00	1.76%	1,801,032	138,541	1,662,491	31,698	2,642	29,057	(15,849)	(203)	(15,646)
Seward Meridian TP Extension (M&R Sta Equipment)	366.00	1.87%	3,125	240	2,885	58	5	54	(29)	(0)	(29)
			Total Adjustment		9,928,722			188,835			(122,841)

ENSTAR NATURAL GAS COMPANY, LLC

CALCULATION OF NORMALIZED RATE OF RETURN AT CURRENT RATES
For the Year Ended December 31, 2024

Calculation of Taxes at Current Rates

Normalized Revenues at Current Rates	431,246,738
Normalized Operating Expenses	(406,093,725)
Normalized Taxes Other Than Income	(4,493,232)
Earnings Before Interest and Taxes	20,659,782
Less: Return on Long Term Debt	(8,305,915)
Taxable State Income	12,353,867
State Income Tax Rate	9.4%
State Income Tax	1,161,264
Taxable Federal Income	11,192,604
Federal Income Tax Rate	21.0%
Amount At Tax Rate	2,350,447
Amortization of Excess Deferred Taxes	(831,570)
Federal Income Tax	1,518,877

Calculation of Effective Rate of Return

Normalized Earnings Before Taxes	20,659,782
Net Income Taxes at Current Rates	2,680,141
Net Utility Operating Income	17,979,641
Less: Interest Expense	(8,305,915)
Normalized Net Income Available for Member's Equity	9,673,727
Common Equity Portion of Rate Base	211,466,884
Rate of Return on Equity	**4.57%**

ENSTAR NATURAL GAS COMPANY, LLC

CALCULATION OF INTERIM RATES

	Current Perm Rates	Rates at 23.21%	Rounded for Interim Rates
General Service			
G1			
Monthly Customer Charge	$ 16.25	$ 20.02	$ 20.00
Base Rate (per Ccf)	$ 0.14982	$ 0.18459	$ 0.18459
G2			
Monthly Customer Charge	$ 35.50	$ 43.74	$ 43.75
Base Rate (per Ccf)	$ 0.09602	$ 0.11830	$ 0.11830
G3			
Monthly Customer Charge	$ 112.00	$ 137.99	$ 138.00
Base Rate (per Ccf)	$ 0.09449	$ 0.11642	$ 0.11642
G4			
Monthly Customer Charge	$ 538.00	$ 662.86	$ 662.75
Base Rate (per Ccf)	$ 0.06581	$ 0.08108	$ 0.08108
Mid-Sized Firm Transportation			
Monthly Customer Charge	$ 9,140	$ 11,260	
Base Rate (per Mcf)	$ 0.1629	$ 0.2007	
Very Large Firm Transportation			
Base Rate (per Mcf)	$ 0.1762	$ 0.2171	
Customer Charge per Delivery Point	$ 2,540	$ 3,130	
Demand Charge per Mcf of Contracted Peak Demand per Month	$ 4.26	$ 5.25	
Interruptible Industrial Transportation			
Mcf/Mo.			
< 100,000	$ 17,660	$ 21,760	
Remaining Volumes	$ 0.1770	$ 0.2181	
There is no charge for any month which volumes are not transported.			
Interruptible Storage Transportation			
Mcf/Mo.			
All Volumes	$ 0.1770	$ 0.2181	
Minimum charge for each Year in which gas is transported under this rate schedule.	$ 16,100	$ 19,800	
There is no charge for any month which volumes are not transported.			

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chairman
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Consideration of the Revenue Requirement Designated as TA 354-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF INNA B. JOHANSEN

PREFILED DIRECT TESTIMONY
OF
INNA B. JOHANSEN

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EXHIBITS

Exhibit IBJ-1	Resume of Inna B. Johansen
Exhibit IBJ-2	Calculation of Weather Normalization Adjustments
Exhibit IBJ-3	GL List of Gas Supply Reg Asset Invoices
Exhibit IBJ-4	Phase I Assessment
Exhibit IBJ-5	Phase II Assessment: Summary of Results (Public Issue)

I. POSITION AND QUALIFICATIONS

Q. State your name, business address, and present position.

A. My name is Inna B. Johansen. My business address is 3000 Spenard Road, Anchorage, Alaska 99503. I am the Vice President of Regulatory and Gas Supply for ENSTAR Natural Gas Company, LLC ("ENSTAR") and Alaska Pipeline Company, LLC ("APC"). I am appearing in this proceeding on behalf of ENSTAR and APC. For convenience, I will refer to ENSTAR and APC together as "ENSTAR" or the "Company."[1]

Q. Briefly describe your professional experience and educational background.

A. I was employed by ENSTAR from 2006 to 2012, and I rejoined ENSTAR in 2014. Before my current position, I managed and worked in various departments within ENSTAR, including Finance, Marketing, Operations, Gas Control and Regulatory. From 2013-2014, I held the position of Asset Manager at Southern Power Company ("SPC"), a subsidiary of Southern Company, working with multiple electric utilities and wholesale power buyers across multiple states managing the physical, financial, contractual, and operational activities associated with power purchase agreements. I have been leading the Gas Supply and Budget & Strategic Planning departments since 2015. In 2024, I became VP of Regulatory and Gas Supply. I hold a Bachelor of Arts in Finance from Kazakh State Academy of Business and a Master of Business Administration from Middle Tennessee State University Jennings A. Jones College of Business. My resume is attached as Exhibit IBJ-1.

[1] The Commission regulates APC and ENSTAR as a single entity. The use of the name "ENSTAR" or "Company" in this filing is intended to include both APC and ENSTAR, unless the context clearly requires otherwise.

Q. Briefly describe your current professional responsibilities.

A. I am responsible for all regulatory matters before the Regulatory Commission of Alaska ("RCA" or "Commission"), strategic planning and gas supply for ENSTAR.

Q. Have you previously testified before the Regulatory Commission of Alaska?

A. Yes. I testified before the Commission on behalf of ENSTAR in Dockets U-07-084, U-18-004, U-18-024 and U-22-081.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is three-fold. First, I discuss the significant challenges ENSTAR faces in obtaining gas supply and the operational risks that these circumstances create for the Company. Second, I support certain pro forma adjustments to the Company's revenue requirement, all of which are necessary to reflect known and measurable changes that will occur during the period when new rates are in effect. Finally, I describe ENSTAR's proposed Very Large Firm Transport ("VLFT")/South Central Power Pool Firm Transportation ("SCPPFT") Peak Reduction Credit, which is a new peak demand management program that can help reduce consumption during periods of peak demand.

III. NATURAL GAS SUPPLY RISK

Q. Why is the availability of natural gas supply important to ENSTAR?

A. ENSTAR's core mission is to provide safe and reliable natural gas utility service to its customers, 24 hours a day, 365 days per year. As part of this mission, the vast majority of the Company's customers rely on ENSTAR not only to deliver gas to their premises, but also to procure the gas that is delivered. Quite simply, if ENSTAR is unable to

procure the needed gas, it cannot meet its mandate as a public utility. In addition, ENSTAR must maintain an adequate flow of gas on its pipelines to sustain a certain gas pressure in its transmission pipelines. An adequate pressure is required to deliver gas to its gas sales customers, and just as important to provide service to its transport customers.

Q. Please provide an overview of the Cook Inlet natural gas supply market.

A. ENSTAR, which is wholly dependent on third-party producers for natural gas, has relied on a single basin to supply its gas needs throughout its 64-year history. Not only does ENSTAR operate in a market with increasingly limited gas supply, but we also operate in a closed system. Unlike the Lower 48, where there is an interconnected system of pipelines that can move gas from multiple points in multiple supply basins, ENSTAR's gas system is unconnected to other basins or gas sources.

Currently, Hilcorp Alaska, LLC ("Hilcorp") is the predominant producer in the region, supplying roughly 90% of production in the Cook Inlet, and is the only producer with multiple gas producing fields and storage capabilities. In 2024, Hilcorp provided 85% of ENSTAR's natural gas requirements. As to storage, the only entity that provides third-party storage service in Cook Inlet is Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"), which is currently fully subscribed by local utilities, the largest customer being ENSTAR. On February 20, 2025, Hilcorp, through a newly formed entity, Hilcorp Alaska Gas Storage, LLC, applied for a Certificate of Public Convenience and Necessity to own and operate natural gas storage facilities near the Kenai Gas Field ("KGF") in Alaska. That application is currently pending before the Commission. Hilcorp currently utilizes KGF to provide gas service to ENSTAR and its

other customers during winter months. Based on the application, it is not clear how this newly created third-party storage facility collocated in the same gas field as Hilcorp's private production and storage facility will impact Hilcorp's existing obligations to ENSTAR.

Despite the already limited nature of production and storage in the Cook Inlet, ENSTAR's analysis of the current gas supply market indicates that the availability of gas supply continues to deteriorate. In my testimony in ENSTAR's rate case filed in 2022 (Docket U-22-081), I discussed how projected future demand will begin to exceed the available future supply. Now in 2025, that projected future is here. The Cook Inlet market is not able to meet the requirements of all gas users. Utilities and large industrial gas users are struggling to secure gas supply in the market. While the decline of Alaska's natural gas supply is well documented, in this testimony I will highlight several changes that directly impact ENSTAR and create significant gas supply risk and additional costs for the Company's operations.

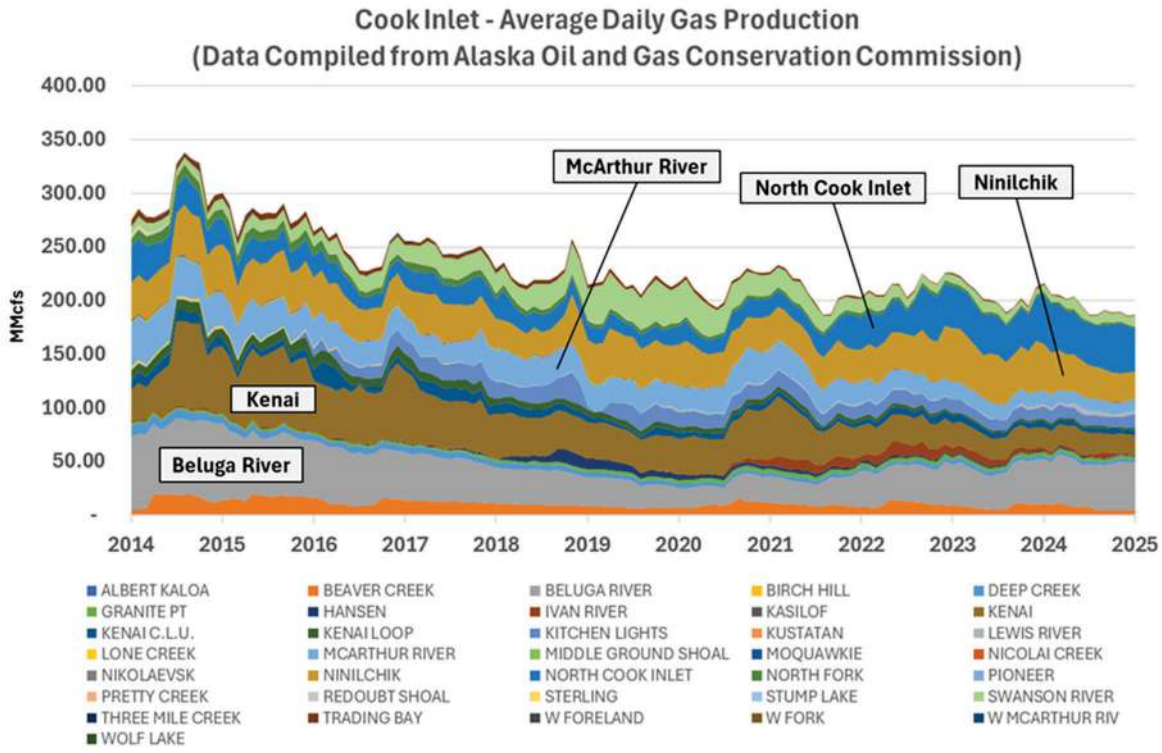
Q. Has Cook Inlet daily production changed over the last 10 years?

A. Yes, in the last ten years, production has decreased by more than one-third. Figure 1 below demonstrates the decline in Cook Inlet daily production deliverability from approximately 300,000 thousand cubic feet ("Mcf") per day in 2015 to approximately 186,000 Mcf per day in 2024. This trend is of particular concern given that despite ENSTAR's intensive efforts, the Company still has not been able to secure 100% of its "Design Day" peak requirements through gas supply agreements.[2] ENSTAR continues

[2] ENSTAR uses the concept of a Design Day to determine its highest gas demand. A design day is an estimate of gas usage that is representative of a utility's highest-demand day. ENSTAR's design day is determined using research conducted by consultants with Marquette Energy Analytics, LLC. To determine its design day, ENSTAR uses the 1-in-30 years wind-adjusted design day temperature of -23.7° F, which yields 88.7

to rely on CINGSA's commercial storage service to help close this gap. In 2023, ENSTAR entered into an Expansion Firm Storage Service Agreement with CINGSA for additional firm storage service, including an anticipated 65,000 Mcf per day in additional deliverability from storage. However, the deliverability from CINGSA is available only when ENSTAR has sufficient volume of gas stored in CINGSA. CINGSA is an important resource, but to fully utilize it, ENSTAR must obtain gas to store in the facility.

Figure 1

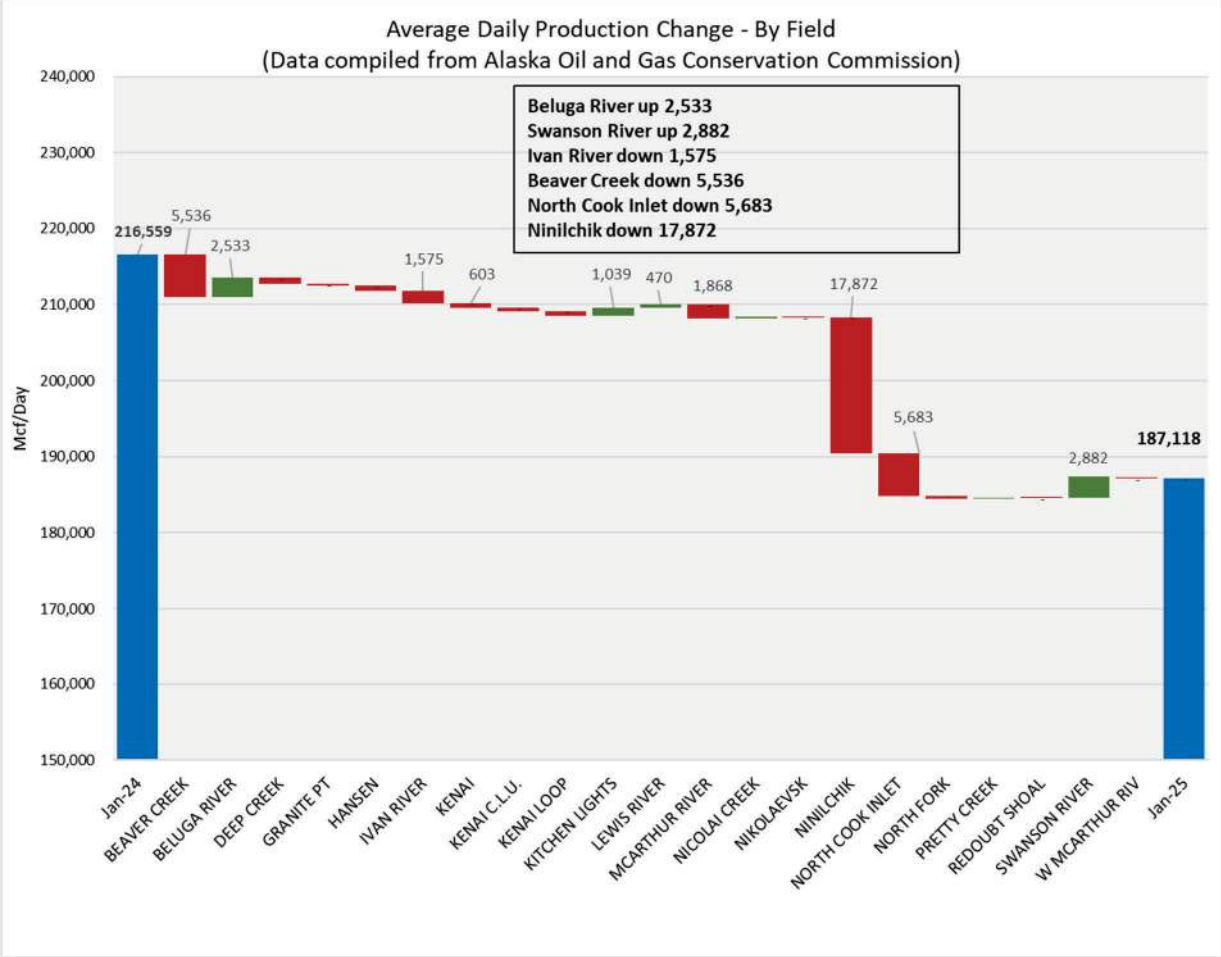


heating degree days. The Design Day estimate for the 2024-2025 season is 319,000 Mcf per day. ENSTAR has experienced temperatures of -22.0° F multiple times over the last 40 years.

Q. Were there any significant changes in gas production observed in 2024?

A. Yes. Cook Inlet gas production saw the largest decline in 2024 compared to the last five years. Figure 2 below shows the production decline of 14% over the course of the last year with major declines observed in the Ninilchik, North Cook Inlet and Beaver Creek fields owned by Hilcorp.

Figure 2



Q. How has annual Cook Inlet gas production changed over the last 10 years?

A. Table 1 below compiles the data collected by Alaska Oil and Conservation Commission ("AOGCC"). It shows that annual gas production declined by 30% over the last 10 years.

Table 1 – Cook Inlet Annual Production 2015-2024

(Data compiled from AOGCC)

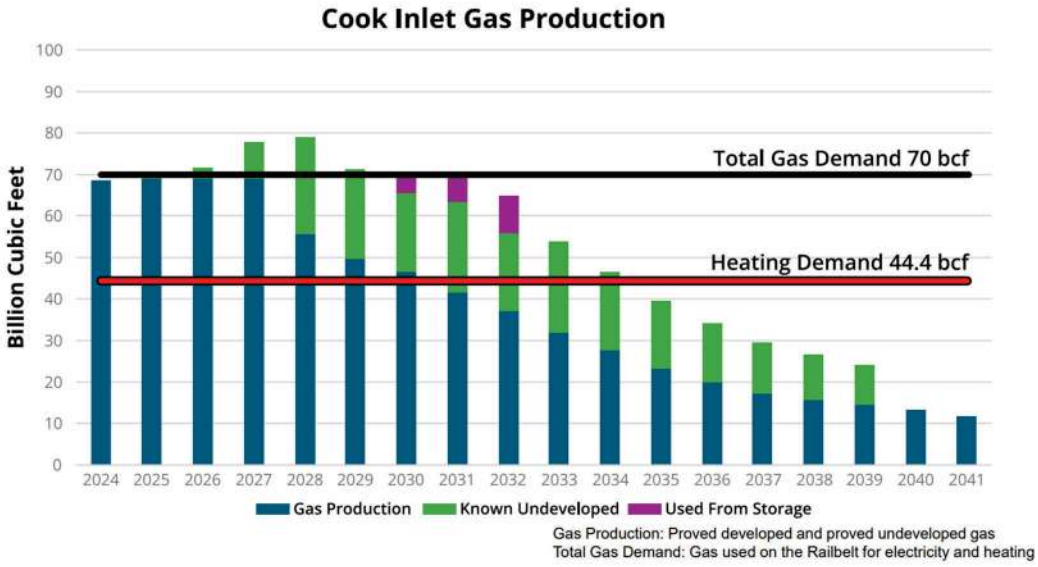
Year	CI Annual Production, Bcf
2015	103.00
2016	90.99
2017	91.15
2018	83.04
2019	79.19
2020	78.46
2021	76.74
2022	77.75
2023	75.16
2024	72.05
Total	**827.54**
10-year change	**-30%**

The Alaska Department of Natural Resources ("DNR") has consistently recognized a shortfall in its forecast issued over the last 10 years. DNR's shortfall is now expected to begin as early as 2027.[3] In its 2024 update to the House Resources Committee, DNR presented a slightly different view by including known undeveloped resources. Figure 3 below shows that under this scenario the shortfall is anticipated to begin in 2032. However, the development of known undeveloped production highlighted by DNR in Figure 3 is highly uncertain and most likely will take significant amount of time and resources to develop.

[3] *See* State of Alaska Department of Natural Resources, Division of Oil & Gas, *Cook Inlet Natural Gas Availability*, March 2018, available at https://dog.dnr.alaska.gov/Documents/ResourceEvaluation/CI_Natural_Gas_Availability_Study_2018.pdf; last accessed on March 20, 2025. *See also* State of Alaska Department of Natural Resources, Division of Oil and Gas, *2022 Cook Inlet Gas Forecast*, January 2023, available at https://dog.dnr.alaska.gov/Documents/ResourceEvaluation/Cook_Inlet_Gas_Forecast_Report_2022.pdf; last accessed on March 20, 2025.

Figure 3

"Runway" of Cook Inlet Gas[4] as Presented by DNR



Over the last three years, DNR, the Commission, the Railbelt utilities, and ENSTAR have all acknowledged the impending natural gas shortfall. Collectively, these entities confirm with increasing urgency that additional gas supply is required to fill the swiftly approaching supply gap.[5]

Q. How is ENSTAR responding to the issue of declining production?

A. Over the last three years, ENSTAR has engaged in continuous negotiations with Cook Inlet producers, Hilcorp, Furie Operating Alaska, LLC ("Furie"), AIX Energy LLC ("AIX"), BlueCrest Energy, Inc., and Vision Resources, LLC, to secure new gas supply for 2024 and beyond. These efforts resulted in ENSTAR and Furie negotiating and signing the parties' Sixth Amendment to the Gas Sales Agreement committing to

[4] *See* Department of Natural Resources, Division of Oil & Gas, *Cook Inlet Oil & Gas Update*, November 19, 2024, https://www.akleg.gov/basis/get_documents.asp?session=33&docid=66259; last accessed April 1, 2025.

[5] *See* Alaska Beacon, *Regulators, advocates warn of utility inaction as Alaska gas shortfall looms*, December 31, 2024, https://alaskabeacon.com/2024/12/31/regulators-advocates-warn-of-utility-inaction-as-alaska-gas-shortfall-looms/; last accessed April 1, 2025.

provide about 32 Bcf of Firm Gas between April 1, 2026 and March 31, 2031 ("Sixth Amendment").[6] However, Furie's commitment to deliver this gas comes with significant execution and performance risk and the delivery of this volume is contingent on the actual drilling and production program. To meet its obligations under the Sixth Amendment, Furie is committing to commence a multi-year development program, drilling several new wells and reworking the existing wells within the Kitchen Lights Unit production field. The gas supply certainty provided by these commitments is vital in a time of growing scarcity. If Furie is not successful in securing the required financing, and all required resources (such as a drilling rig and all required field support services), and if it is not successful in the execution of its drilling program, then ENSTAR will have to develop other more costly alternative solutions very quickly.

Q. What other alternative solutions are available to ENSTAR if Furie fails to deliver gas under the Sixth Amendment?

A. ENSTAR will have to rely on remaining Cook Inlet producers to fill the gap or swiftly develop and build or have built a new gas supply delivery option by bringing gas from outside of Cook Inlet by trucking liquified natural gas ("LNG") from other locations. Not only will this option require significant capital investment to develop in a short period of time, it will also result in a potential gas delivery price of $25-$32 per Mcf.[7] In addition, this option comes with challenging logistical issues and limited scalability. The CIGSP Phase 1 study concluded that this option could only meet approximately

[6] ENSTAR filed the Sixth Amendment on December 31, 2024 as TA 349-4, which was approved on February 26, 2025 in LO# L2500019.

[7] *See* BRG and Alaska Utilities Working Group, *Phase I Assessment: Cook Inlet Gas Supply Project* ("CIGSP"), slide 36. Presented at the RCA Public Meeting June 28, 2023.

13 Bcf per year of total demand, which is only 30% of ENSTAR's requirements. The additional sources of gas will have to be developed quickly after 2029.

Q. What other gas supply options is ENSTAR currently developing?

A. On December 17, 2024, ENSTAR entered into an exclusivity agreement with a global energy infrastructure developer, Glenfarne Infrastructure Holdings OpCo, LLC or designated affiliate ("Glenfarne"), to construct a LNG receiving terminal on the Kenai Peninsula, in close proximity to ENSTAR transmission and storage facilities ("Project"). This potential gas supply option still has to overcome a number of major hurdles during the regulatory reviews, permitting and construction phases that a newly constructed LNG receiving terminal in Cook Inlet will have to go through. The contractual relationships that ENSTAR still has to build with Glenfarne will be a lengthy and complex process aiming to secure long-term gas supply for its customers. The Project faces a tight timeline to complete its development phase and begin construction to ensure that the facility is ready before the projected gas supply shortage arrives.

Q. Does Furie's Sixth Amendment close the gap in ENSTAR's current and near-term gas supply requirements?

A. No. While the Sixth Amendment is expected to provide ENSTAR with gas volumes to partially meet its gas supply requirements during the period of 2026-2031, ENSTAR still has not been able to secure firm gas supply for 11% to 15% of its gas supply requirements in 2025 and 2026. Table 2 below summarizes ENSTAR's annual gas supply requirements through March 2031, including approximately 3-4 Bcf each year

to supply Homer Electric Association, Inc.'s ("HEA") demand. ENSTAR has no firm gas supply secured beyond 2033 for any customers.

Table 2

ENSTAR Projected Gas Requirements									
Volumes (Bcf)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Hilcorp - Amended APL-14	31.19	31.24	30.74	32.24	32.24	32.24	32.24	32.24	12.00
Furie Operating Alaska	0.40								
Furie - 6th Amendment		2.2	7.9	10.5	9.5	7.7	1.8		
Vision Resources	0.5	0.4	0.3	0.0					
Undetermined Supply (+Gap/- To Storage)	5.80	4.02	(1.00)	(4.8)	(3.8)	(1.95)	3.94	5.76	26.02
Total Purchase Requirements	**37.86**	**37.88**	**37.90**	**37.92**	**37.94**	**37.96**	**37.98**	**38.00**	**38.02**
Net Takes for System Supply	**37.9**	**37.9**	**37.9**	**37.9**	**37.9**	**38.0**	**38.0**	**38.0**	**38.0**
Furie Share	1%	6%	21%	28%	25%	20%	5%	0%	0%
Hilcorp Share	82%	82%	81%	85%	85%	85%	85%	85%	32%
Undetermined Supply (+Gap/- To Storage)	**15%**	**11%**	**-3%**	**-13%**	**-10%**	**-5%**	**10%**	**15%**	**68%**

Q. Have ENSTAR's gas requirements changed since ENSTAR's last rate case?

A. Yes. ENSTAR has added approximately 5,000 new customers since 2021. While the overall gas supply requirements for general gas sales customers increased by only 2% or 0.7 Bcf, the addition of HEA as a gas sales customer in 2024 increased ENSTAR's total gas volume requirements by an additional 12%, bringing the total required gas volume to 38 Bcf. In addition to increased volumetric requirements, the latest Design Day study, completed in the fall of 2024, increased ENSTAR's Design Day peak requirements from 295,000 Mcf per day to 305,307 Mcf per day. Transitioning HEA from a transport customer to a gas sales customer further increased ENSTAR's Design Day peak requirements to 322,000 Mcf per day. The declining daily production will continue to increase the gap between daily customer requirements and the availability of gas supply.

Q. Do other Railbelt utilities share your concerns about declining production in Cook Inlet?

A. Yes. In May 2022, ENSTAR, Chugach Electric Association, Inc. ("CEA"), Matanuska Electric Association, Inc. ("MEA"), HEA, Golden Valley Electric Association, Inc. ("GVEA"), and the Interior Gas Utility ("IGU") formed a working group, with participation from the DNR and the Alaska Energy Authority, to assess future gas supply needs and energy security in Cook Inlet. The group was formed in recognition of the expected decline of aging Cook Inlet natural gas-producing assets and after discussions with Hilcorp regarding the uncertainty of Cook Inlet natural gas supplies. In the fourth quarter of 2024, ENSTAR completed a comprehensive market check and assessment of various gas supply solutions presented by industry leaders in the LNG market.

Q. Do the Cook Inlet gas producers share ENSTAR's views about future production in the Cook Inlet?

A. Yes. In April 2022, during the annual customer meeting with Hilcorp, Hilcorp mentioned that it did not have "line of sight" on firm supplies available beyond existing contracts and encouraged utilities to seek other sources.[8] In May 2022, a representative from Hilcorp stated:

> You should buy less of my gas. We should have other supplies of energy in the Cook Inlet basin…What we want to make sure of is that five, six years from now there is no crisis of natural gas. And that means we need to move with urgency as a community to diversify our sources of supply.[9]

[8] *See* Anchorage Daily News, *Hilcorp warns Alaska utilities about uncertain Cook Inlet natural gas supplies*, May 17, 2022, https://www.adn.com/business-economy/energy/2022/05/17/hilcorp-warns-alaska-utilities-about-uncertain-cook-inlet-natural-gas-supplies/; last accessed on April 1, 2025; *see also* HEA, *Monthly Manager's Report*, May 12, 2022, https://www.homerelectric.com/2022/05/monthly-managers-report-5/, last accessed on April 1, 2025.

[9] *See* Alaska Beacon, *Cook Inlet basin energy future lies beyond fossil fuels, conference speakers say*, May 27, 2022, https://alaskabeacon.com/2022/05/27/cook-inlet-teeming-with-renewables/; last accessed on April 1, 2025.

Hilcorp also stated that no new contracts will be signed until it sees the results of that year's drilling season.[10] We are already seeing utilities encounter challenges with securing gas supply beyond current contract terms.[11] And, while ENSTAR might have a longer-term supply under contract in the Cook Inlet basin (through March 31, 2033) that covers the majority of its gas supply, ENSTAR's requirements for firm gas supply far exceed the volumes that electric utilities require in order to provide service. This fact requires ENSTAR to act with urgency in securing additional or alternative gas sources and creates significant operational risk to our utility.

During Hilcorp's presentation to the Senate Resources Committee on January 22, 2025, Luke Saugier, Hilcorp's Senior Vice President, communicated that despite significant investments and an aggressive drilling program by Hilcorp, the outlook for Cook Inlet stays the same. This is the direct quote from Hilcorp's presentation: "There is not sufficient gas under Hilcorp leases to meet the current demands of Southcentral Alaska Utilities and other gas producers must identify new sources of gas supply for Southcentral Alaska."[12]

Moreover, as an incentive for new exploration the DNR included royalty reductions in its 2024 Cook Inlet lease. The results were disappointing attracting only

[10] *See* HEA, *Monthly Manager's Report,* May 12, 2022, https://www.homerelectric.com/2022/05/monthly-managers-report-5/; last accessed on April 1, 2025.

[11] *See* KBBI, *Hilcorp says it may not meet high natural gas needs during the next contract cycle*, May 16, 2022, https://www.kbbi.org/local-news/2022-05-16/natural-gas-from-cook-inlet; last accessed on April 1, 2025.

[12] Luke Saugier to the Alaska Senate Resources Committee, January 22, 2025, slide 5: https://www.akleg.gov/basis/Meeting/Detail?Meeting=SRES%202025-01-22%2015:30:00#tab4_4e; last accessed on April 1, 2025.

three bids from Hilcorp.[13] The message is clear: we need alternate natural gas resources in the near future and currently, there is no definitive solution.

Q. Are there additional factors that are contributing to ENSTAR's gas supply risk?

A. Yes. When ENSTAR negotiated its current contract with Hilcorp in 2015 and the contract amendment in 2020,[14] we were careful to contract for the flexibility to allow ENSTAR to purchase volumes from other producers. ENSTAR has been in constant contact with other producers utilizing its best efforts to enter into agreements with them for additional gas supply. Yet, Hilcorp continues to supply 85% of ENSTAR's annual gas demand and asserts that it does not have line-of-sight on future firm gas beyond existing contracts. Reliance and dependence on one producer for such a large percentage of the Company's gas demand is risky, and when we look at the activity in the Cook Inlet, we do not have confidence that another producer will take over a substantial portion of ENSTAR customers' supply needs any time soon.

In approving APL-14 GSA between ENSTAR and Hilcorp in 2016, the Commission considered the two-pronged analysis called for in AS 42.05.141(d) and stated:

> That statute requires the Commission to (1) recognize the public benefits of allowing the utility to negotiate different pricing mechanisms with different suppliers and to maintain a diversified portfolio of gas supply contracts (thereby protecting consumers from the risks of inadequate supply or excessive cost that may arise from a single pricing mechanism), and (2) consider whether the utility could meet its responsibility to the public in a timely manner

[13] *See* Alaska Beacon, *Royalty-free terms draw only three oil and gas lease bids in Alaska's Cook Inlet,* June 13, 2024, https://alaskabeacon.com/2024/06/13/royalty-free-terms-draw-only-three-oil-and-gas-lease-bids-in-alaskas-cook-inlet/; last accessed April 1, 2025.

[14] The Commission approved the APL-14 GSA between ENSTAR and Hilcorp in LO# L1600163 on April 13, 2016. The Amended and Restated APL-14 was approved in LO# L2000231, dated June 10, 2020.

> and without undue risk to the public if the Commission fails to approve the proposed gas supply contract.[15]

The Commission concluded that approval of the contract was consistent with both prongs of this analysis. As to the first prong, the Commission stated that APL-14 allowed "ENSTAR the option of procuring additional natural gas from other independent suppliers."[16] The Commission further observed that "[t]his option provides ENSTAR with the flexibility to maintain a diversified portfolio of gas supply contracts to protect customers from the risks of inadequate supply or excessive costs that may arise from a single pricing mechanism."[17] The Amended APL-14 remained consistent with the legislature's goal that utilities maintain a diversified portfolio of gas supply contracts. Attempts to diversify its gas supply portfolio resulted in additional risk to ENSTAR.

Q. Has ENSTAR's recent operating experience contributed to its concern with the gas supply situation?

A. Yes. Our operating experience during the 2024 test year was a prime example of how cold weather strains ENSTAR's overall gas supply portfolio and gas delivery system, and demonstrated the current fragility of that system. The cold weather in the Cook Inlet region during January 2024 underscores the declining gas supply available in the market and the need for additional storage. On January 14, 2024, CINGSA notified customers that it had experienced a loss of deliverability in one of its five wells. This resulted in a 19% reduction in the facility's available deliverability. On January 24,

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[15] See LO# L1600163 page 2, dated April 13, 2016.

[16] *Id.*

[17] *Id.*

2024, CINGSA experienced a reduction in another well, reducing facility deliverability by an additional 11%, or 30% total.

In anticipation of significantly colder than normal temperatures forecasted in its service area, on January 26, 2024, ENSTAR initiated daily meetings with all Cook Inlet gas users, including electric utilities, producers, pipeline and storage operators. As temperatures plunged across ENSTAR's service area, on January 27, 2024, ENSTAR continued to closely monitor CINGSA's constrained deliverability and its impact on the system. On the night of January 31, 2024, through the early morning hours of February 3, 2024, ENSTAR maximized all available deliverability under its gas supply agreements and in CINGSA. During that week, ENSTAR requested all power utilities to optimize the most efficient generation and maximize all available hydro-generation in the region. In addition to these steps, electric utilities were prepared to switch to diesel generation or to start importing power from Fairbanks provided by GVEA. The reduced gas demand by electric utilities enabled Hilcorp to bring online an additional 10,000 Mcf per day for ENSTAR's customers to mitigate the need for conversion to diesel. During this extreme cold weather event, ENSTAR's service territory saw record cold temperatures resulting in a daily peak system throughput of 313 million cubic feet per day ("Mmcfd") and gas sales throughput of 245 Mmcfd.

As a result of these events, ENSTAR was extremely close to being unable to deliver gas. To ease the strain on ENSTAR's system, Joint Base Elmendorf-Richardson and the Municipality of Anchorage voluntarily reduced gas usage by turning down thermostats in their buildings. If the cold weather event had extended for

a longer period, or the temperatures had dropped even lower, the demand on ENSTAR's system could have outstripped the gas available to meet that demand with catastrophic results.

Q. How do the challenges described in this section impact ENSTAR's operating environment and ability to serve customers?

A. Since 2021, ENSTAR's operating environment has become increasingly challenging. We have directly experienced the impacts of declining resources and rising demand. As discussed throughout my testimony, HEA was unable to secure needed gas for power generation for the Kenai Peninsula and thus became an ENSTAR gas sales customer. Additionally, our customer base has grown by 5,000 customers, and the cold weather event described above resulted in increased demand variability for natural gas. As the Cook Inlet continues to decline, securing gas to meet customer needs is becoming increasingly difficult each year.

Q. How does the current natural gas supply situation in the Cook Inlet affect ENSTAR's risk?

A. As stated above, ENSTAR's core mission is to provide safe and reliable service to customers, many of whom rely on the Company to procure and supply natural gas to their premises for heating and other personal needs. Operating a closed-loop system with no current access to gas resources outside the Cook Inlet places the Company at a significant risk for gas supply. All options are on the table to ensure customers are not interrupted. In response, ENSTAR will likely have to make substantial investments in developing alternative gas supply solutions and additional storage capacity in the near future to ensure ongoing gas supply. New gas supply solutions that bring gas from

outside of Cook Inlet will also require modifications and upgrades to the existing pipeline infrastructure and gas delivery system.

Any project to bring gas into the Cook Inlet will almost certainly require investment above and beyond ENSTAR's existing costs to provide service to customers. In addition, depending on the type of investment, there is the potential that significant challenges to project development may arise (e.g., cost, procurement of materials, permitting, property acquisition, and cost recovery), which creates additional risk for the Company. Together, these factors place ENSTAR in a challenging paradox of attracting gas supply investment dollars while in a period of increasing gas supply risk.

IV. PRO-FORMA ADJUSTMENTS SPONSORED

A. Normalize Transportation Customer Revenues

Q. Why is ENSTAR adjusting transportation customer revenues?

A. The Transport Sales Agreements ("TSA") and Gas Sale Agreements with IGU, HEA, and GVEA have either been terminated, will terminate in 2025, or require normalization. Base rates should recover the utility's expected costs of providing service to customers in the "rate effective period," or the period in which new rates will be in effect. An element of that process is using historical test year data to estimate the amount of revenues a utility is likely to collect in the rate effective period. Revenue adjustments are necessary to reflect known and measurable changes from the unadjusted test year data.

Q. Please explain the IGU revenue adjustment.

A. IGU's current TSA is used to transport gas from Cook Inlet producers to its Titan facility under ENSTAR's Mid-Sized Firm Transportation Service rate schedule (Tariff

Section 2145, sheet 271). IGU communicated to ENSTAR that it is shifting its gas supply from the Cook Inlet to the North Slope at some point in 2025. After the shift takes place, IGU will no longer require firm transport service from ENSTAR and will transition to a G4 gas sales customer to continue to provide heat to the Titan facility. IGU provided ENSTAR an estimate of 7,000 Mcf per year to keep its facility in a "warm" status. There were $331,681 in revenues from IGU recorded in the test year which are removed and an estimated $74,564 was added to the G4 customer category (Schedule H of Attachment B). The tentative termination date of the TSA is September 1, 2025. While the TSA requires a twelve-month notice period to terminate, ENSTAR agreed to waive the required notice period.

Q. Please explain the GVEA revenue adjustment.

A. On December 9, 2022, ENSTAR filed TA337-4 requesting approval of the Special Contract and Service Agreement for Gas Sales Service between GVEA and ENSTAR. The term for the agreement was for two (2) years (24 consecutive months) following the Effective Date. The contract was approved by the Commission in LO# L2300017 and deemed effective on January 23, 2023. Beginning February 2025, the two years have run their course and the special contract between GVEA and ENSTAR has expired and is no longer in place. ENSTAR therefore removed the $8,830,559 in test year gas sales revenues attributed to GVEA sales (Schedule H of Attachment B). As a result of the termination of the special contract, ENSTAR is also revising the Schedule of Special Contracts (Tariff Section 1900, Sheet 244).

Q. Please explain the HEA revenue adjustment.

A. On February 7, 2024, ENSTAR filed TA342-4 requesting approval of the Special Contract and Service Agreement for Gas Sales Service between HEA and ENSTAR which was approved by the Commission in LO# L2400086 on March 18, 2024. On April 1, 2024, HEA began purchasing gas from ENSTAR resulting in only nine months of revenues to be represented in the test year. To create a representative test year, ENSTAR used HEA's 2024 actual gas usage for January through March 2024 and applied the charges from the Gas Sales Service agreement to estimate January-March revenues of $10,119,545. The estimated revenues were added to ENSTAR's revenue requirement (Schedule H of Attachment B).

Q. Are there any additional adjustments to transport revenues?

A. Yes. The delivery points to HEA's Soldotna, Bernice Lake, and Nikiski plant are now contained within the previously mentioned Special Contract and Service Agreement for Gas Sales Service between HEA and ENSTAR. Because these delivery points no longer fall under separate contracts, the Bernice Lake and Soldotna transport revenues were removed, $10,800 and $27,488 respectively (Schedule H of Attachment B).

Q. Did ENSTAR adjust its cost of gas expense to synchronize with the transportation revenue adjustments?

A. Yes. ENSTAR included an additional $9,754,691 in its cost of gas expense for the increased gas sales to IGU and HEA (Schedule I of Attachment B) and the cost of gas expense attributed to GVEA amounting to $8,648,982 was removed from the test year (Schedule D of Attachment B).

B. Weather Normalization

Q. Why is ENSTAR proposing a weather normalization adjustment to test year gas sales volumes?

A. Weather normalization neutralizes the effect of weather on utility revenues and certain operating costs. It adjusts test year customer gas usage which is used to develop the requested revenue requirement for the test year, allocate costs in the cost-of-service study, and calculate new rates. A "normal weather year" is a year that exhibits an average of the actual observed annual temperatures over the last ten years. ENSTAR measures the impact of weather in heating degree days ("HDD").[18] By adjusting for normalized weather, a test year that experiences more HDD than normal (cold year), will see a downward adjustment to the requested revenue requirement. Conversely, a test year that has fewer HDD than normal (warm year) will see an upward adjustment to the revenue requirement. As temperatures rise and fall, so does the Company's revenue. ENSTAR's Customer Charge includes a volumetric component, meaning, resulting revenues fluctuate depending on how much gas customers use during the test year. A normalization adjustment removes the abnormal weather deviations from expected, or "normal" levels, which is a primary driver of variations in gas volumes sold and outside ENSTAR's control. It allows ENSTAR to set future rates based on the "normal" level of gas sales. For this reason, ENSTAR proposes to weather normalize

[18] Heating degree days ("HDD") are a measure of how cold the temperature was on a given day or during a period of days and is a standard unit of measure in the energy utility industry. A degree day compares the mean (the average of the high and low) outdoor temperatures for a day recorded for a location to 65° Fahrenheit (F) (although some entities may use a different base such as 55°F). For example, on a day where the average of the high and low temperature is 35°F, there would be 30 HDD. The more extreme the outside temperature, the higher the number of HDD. The U.S. Energy Information Administration notes that a high number of HDD generally results in higher levels of energy use for space heating, which has been ENSTAR's experience. ENSTAR tracks the HDD reported by the National Weather Service for the "official" Anchorage recording station (Anchorage International Airport), which uses the 65°F base measurement.

its sales volumes to ensure that the Company's revenue requirement appropriately reflects revenues for weather during the rate-effective period.

Q. Was 2024 a normal weather year?

A. No. The observed temperatures in 2024 were colder than normal during most of the year with the exception of March and December.

Q. Can you provide an example of weather fluctuations that ENSTAR has experienced in its service territory?

A. Yes. Table 3 below shows the actual HDD for the last eleven years, the annual change, the historical ten-year average HDD for the period of 2014 through 2023 ("Normal HDD"), and the difference between actual observed HDD and Normal HDD.

Table 3

HDD in ENSTAR's Service Territory Over the Last Eleven Years[19]

Year	Actual	Annual Change	Normal 10 -year Average	Actual vs. Normal	Actual vs. Normal %
2014	9,092	0%	9,363	(271)	-2.9%
2015	9,111	0%	9,363	(252)	-2.7%
2016	8,531	-6%	9,363	(832)	-8.9%
2017	9,884	16%	9,363	521	5.6%
2018	8,795	-11%	9,363	(568)	-6.1%
2019	8,177	-7%	9,363	(1,186)	-12.7%
2020	10,218	25%	9,363	855	9.1%
2021	10,530	3%	9,363	1,167	12.5%
2022	9,307	-12%	9,363	(56)	-0.6%
2023	9,988	7%	9,363	625	6.7%
2024	**9,870**	**-1%**	**9,363**	**507**	**5.4%**

As the data in the table shows ENSTAR frequently experiences deviations from normal weather in its service territory.

[19] Source: National Weather Service, https://www.weather.gov/wrh/Climate?wfo=afc, last accessed April 1, 2025.

Q. Why is ENSTAR proposing to weather normalize test year gas sales volumes?

A. The 2024 test year weather, as measured in HDD, was colder than average and departed significantly enough from the normal range of temperature fluctuations in a way that was highly correlated with gas usage. Thus, it was not representative of a normal weather year as I defined previously. At 9,870 HDD, 2024 was 5.4% colder than the average for the previous 10 years. Additionally, in ENSTAR's last rate case (Docket U-22-081) intervenors provided testimony stating that ENSTAR needs to include a consistent proforma adjustment to normalize weather in its current and subsequent rate cases.[20]

Q. Based on your understanding of Commission precedent, does this merit an adjustment to ensure that gas sales revenues are more in line with "normal?"

A. Yes.

Q. Is there a strong correlation between HDD and ENSTAR's General Service customer usage?

A. Yes. As Figures 4 through 7 below demonstrate, there is a strong correlation between HDD and ENSTAR's General Service customer usage. These graphs show the average use per customer for each General Service class and the HDD from 2014 through 2024.

[20] *See* Docket U-22-081, the *Prefiled Response Testimony of Kimberly A. Henkel* at 22.

Figure 4

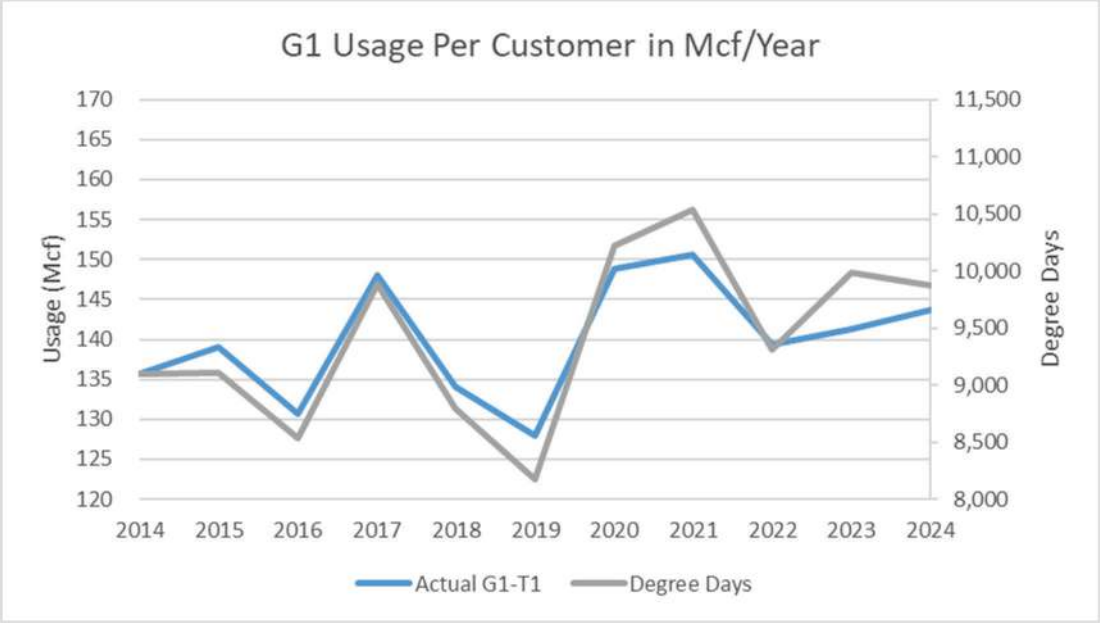


Figure 5

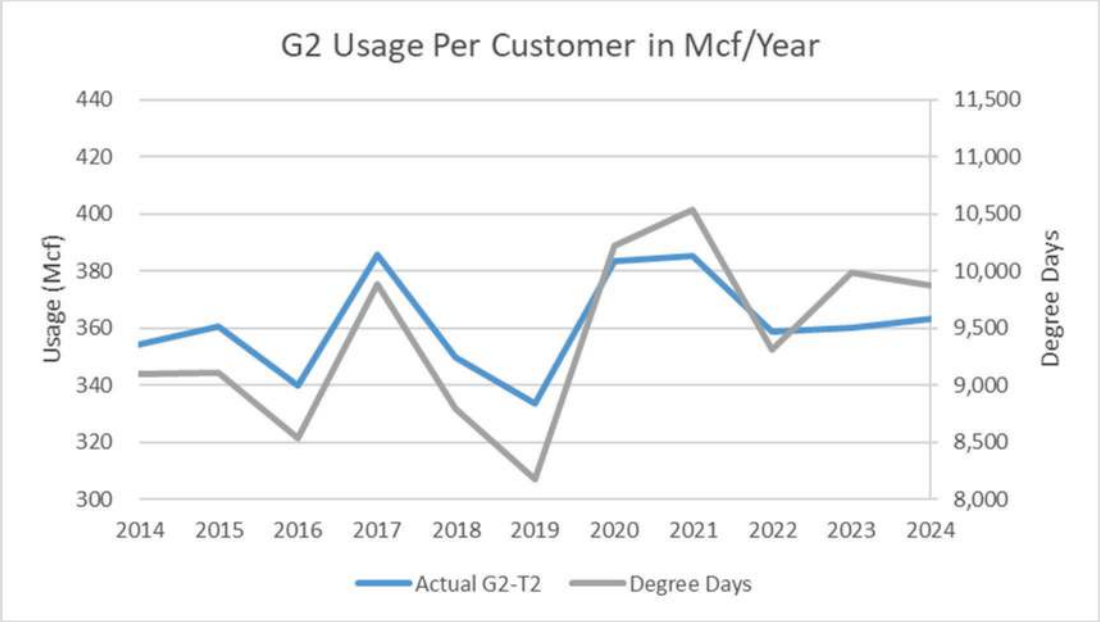


Figure 6

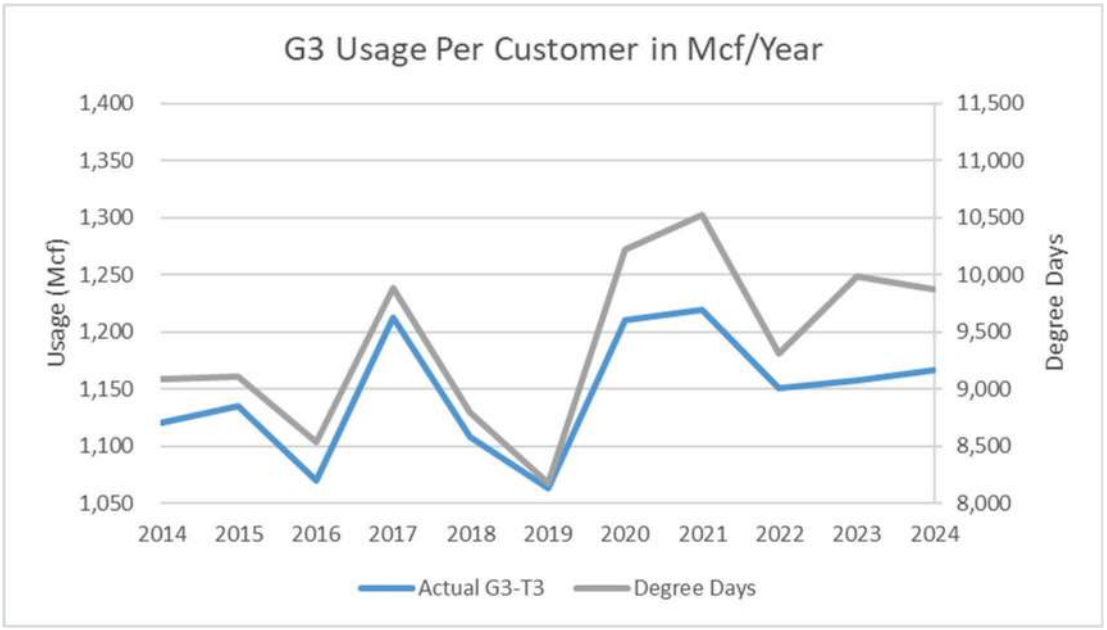
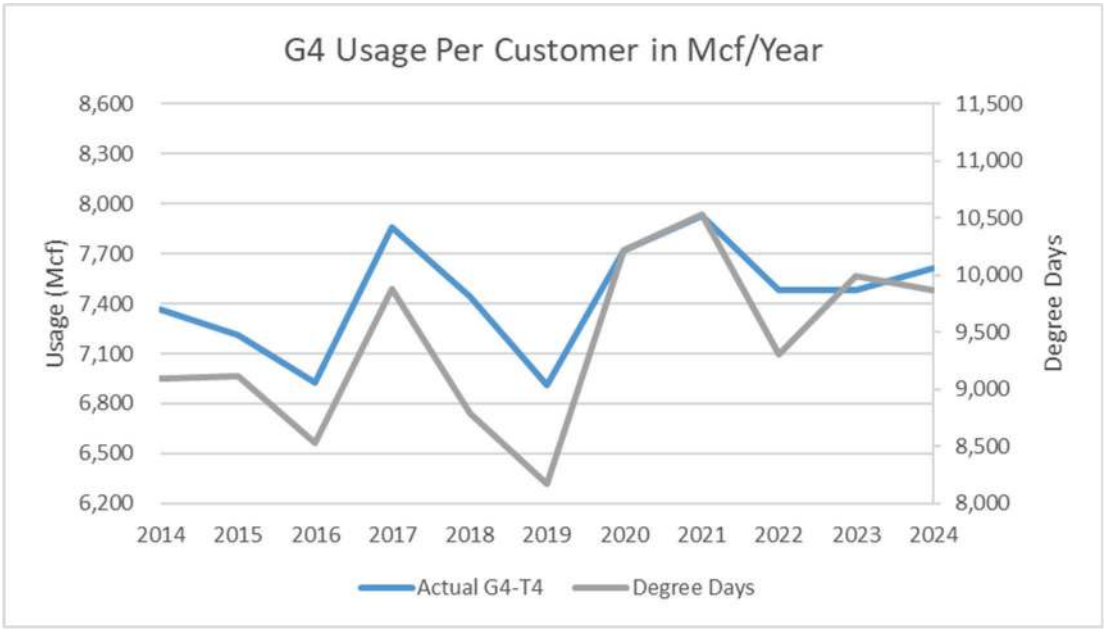


Figure 7



This strong correlation between ENSTAR's General Service customer usage and HDD is consistent throughout ENSTAR's history.

Q. How did ENSTAR calculate its proposed adjustment to normalize customer usage to account for the weather during 2024?

A. The detailed calculation of the adjustment is shown on Exhibit IBJ-2. The methodology used is identical to the methodology ENSTAR used to normalize customer usage for weather in its last rate case (Docket U-22-081) and similar to the adjustment that was made in ENSTAR's approved revenue requirement in its 2000 test year rate case (Docket U-00-088) and the adjustment ENSTAR proposed in its 2009 test year rate case (Docket U-09-069/U-09-070).[21] For each of the General Service customer classes, the test year use per consuming customer is adjusted for the effects of weather (as measured by HDD, using the average HDD from the previous ten years) to arrive at a normalized use per customer. In most Lower-48 jurisdictions, there are normally no HDD in the three summer months and any gas usage in those months is considered non-heating base load. ENSTAR's service area has HDD in every month, so a base amount of degree days and volumes for the summer months have to be computed and figured into the calculation.[22] In his direct testimony, Dr. Fairchild confirms that ENSTAR's weather normalization methodology is reasonable.

Q. Please summarize the results of ENSTAR's weather normalization calculation.

A. ENSTAR's calculation produces the following annual use per customer results:

[21] The U-00-088 revenue requirement was adjudicated by the Commission and set in Order U-00-088(12), dated August 8, 2002. The 2009 and 2021 test year rate cases were settled, and the Commission accepted the stipulations in Order U-09-069(10)/U-09-070(10) and Order U-22-081(11). The weather normalized volumes per customer proposed by ENSTAR were used to derive the tariff rates that were approved in that order.

[22] In both Dockets U-00-088 and U-09-069/U-09-070, only two summer base months were used in the calculation. In Docket U-22-081 and this filing ENSTAR uses three summer months (June-August) as is commonly used elsewhere.

Table 4

Actual and Normalized Annual Usage by Rate Class

Rate Class	Test Year Actual Mcf/Customer	Normalized Mcf/Customer
G1	143.69	136.83
G2	363.32	346.18
G3	1,166.24	1,114.39
G4	7,614.11	7,324.91

The full volume and revenue impacts are shown on Schedule P to Attachment B. The overall impact is a reduction of 1,564,296 Mcf and $1,934,650 in gas sales margins (revenues excluding gas cost).

Figures 8 through 11 below depict the weather-normalized General Service rate class usage for 2014 through 2024 using the same ten-year average HDD (9,363) used in the weather normalization adjustment.

Figure 8

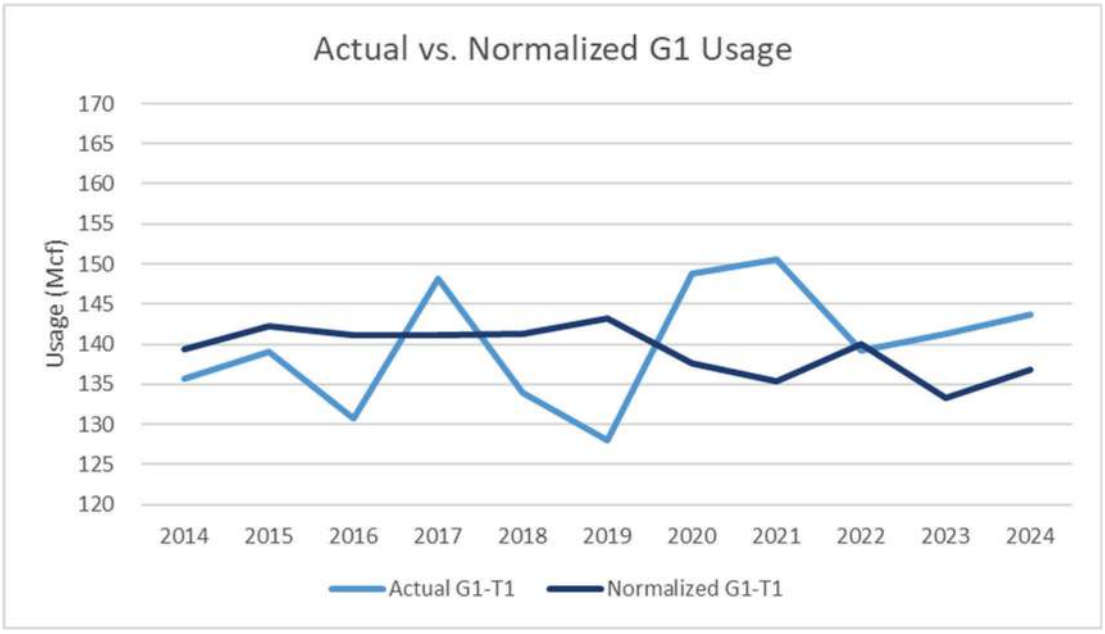


Figure 9

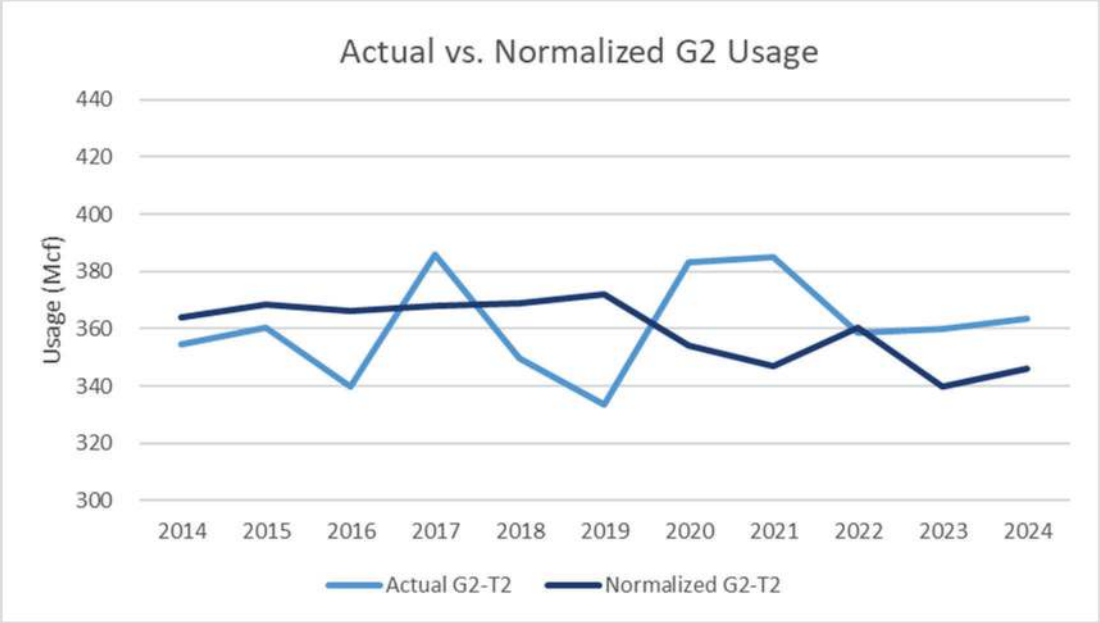


Figure 10

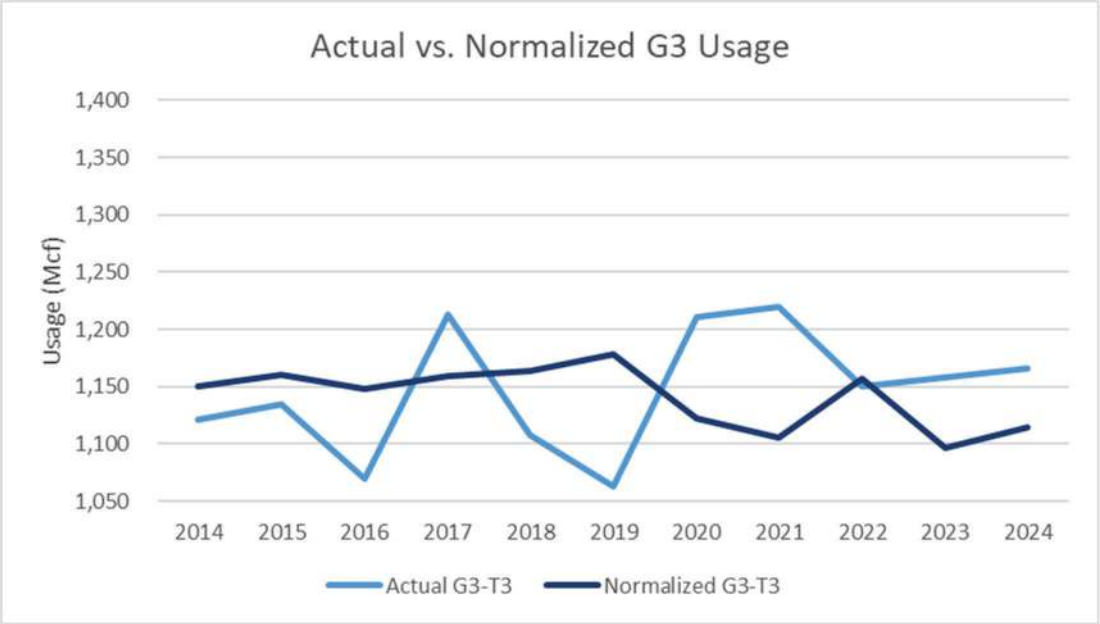
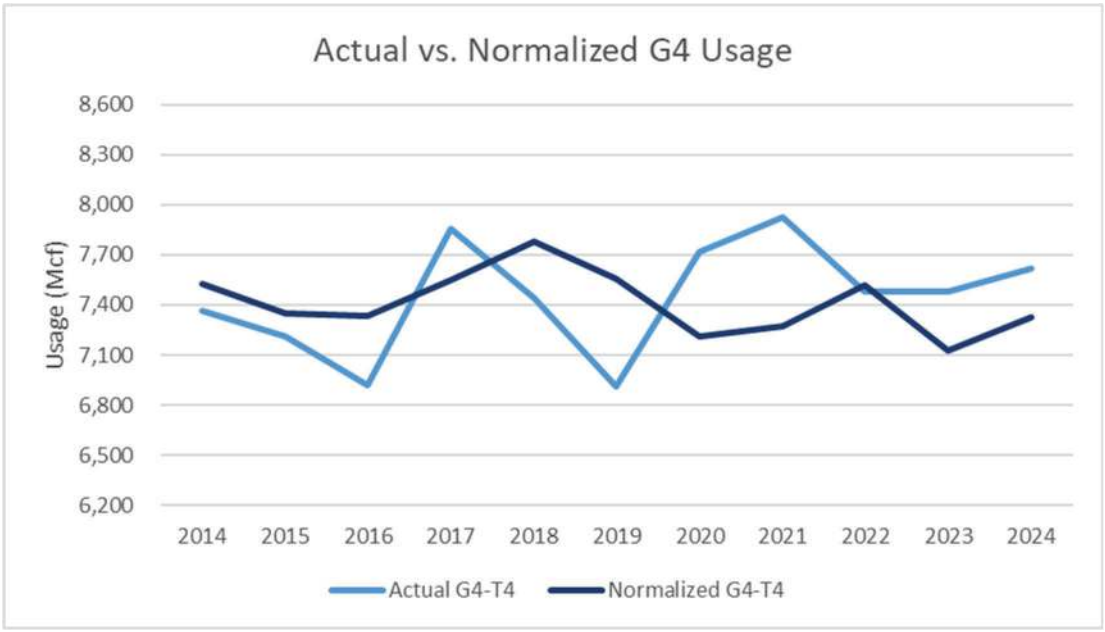


Figure 11



This analysis shows that ENSTAR continues to see erosion in its per-customer usage,[23] particularly in the G1 and G2 rate classes, which make up 97% of its customers and 65% of its gas sales volumes.

Q. Is ENSTAR proposing to weather normalize its medium transportation, large transportation, and power plant customer gas volumes?

A. No. Other than the adjustments to IGU, HEA, and GVEA that I discussed earlier, ENSTAR is not proposing any pro forma adjustments to large transportation customers and power plant volumes and revenues. The gas usage for these customers does not exhibit the same correlation between HDD and their consumption.

[23] As discussed in the Prefiled Direct Testimony of Daniel M. Dieckgraeff in Dockets U-09-069, U-14-111 and U-22-081, ENSTAR has seen a consistent trend of declining average use per customer on a weather-normalized basis.

C. Normalized Gas Cost Revenues

Q. Please discuss the pro forma adjustment to normalize gas cost revenues shown on Schedule D of the 275(a) filing.

A. As ENSTAR witness, Mr. Sims, explains in his direct testimony, ENSTAR recovers its cost of gas through its Gas Cost Adjustment ("GCA"), which is adjusted annually. As a result, the GCA in effect during the test year ending December 31, 2024, is not representative of the updated GCA which will take effect on July 1, 2025. Gas cost revenues in the test year were removed and replaced with the weighted average cost of gas that was effective July 1, 2024, at $9.0716 per Mcf.[24] Additionally, this includes the removal of GVEA volumes from the cost of gas expense, due to their contract expiring as stated above. The new gas cost is then applied to the volumes to calculate the adjusted cost of purchased gas. The adjustment to remove the test year gas cost and add the new gas cost is detailed in Schedule D to Attachment B.

D. Uncollectible Account Pro Forma

Q. Please discuss the uncollectible account pro forma adjustment shown on Schedule G of the 275(a) filing.

A. As shown on Schedule G to Attachment B, ENSTAR is adjusting its test year uncollectible (bad debt) expense to match normalized retail revenues (including the updated gas cost discussed above). The net result of this adjustment decreases uncollectible accounts expense by $30,688.

[24] ENSTAR's annual GCA revision filing, TA345-4, was filed on May 15, 2024, and approved in LO# L2400199, dated June 20, 2024.

E. Long-Term Gas Supply Expense Pro Forma

Q. What is the purpose of the Schedule Q shown on Attachment B?

A. The long-term gas supply expense pro forma is shown on Schedule Q. The schedule adds the regulatory asset amount associated with Orders U-22-090(2) and U-25-004(5) and amortizes the amount over three years. The purpose of Schedule Q is to recover the regulatory asset authorized by the Commission in Order U-22-090(2) in ENSTAR's base rates. In Order U-25-004(5), which was issued on April 22, 2025, the Commission stated that ENSTAR could seek recovery of the asset in base rates in its next rate case. Specifically, on page 51 of Order U-25-004(5) the Commission stated, "[i]n its last rate case, ENSTAR agreed to file a rate case in 2025 or in 2026 based on a 2024 or 2025 test year, respectively. ENSTAR may seek to recover the costs of the $4.6 million regulatory asset in that rate case." This is that rate case.

Q. Please describe the regulatory asset authorized by the Commission in Order U-22-090(2).

A. In Order U-22-090(2), the Commission granted ENSTAR authority to defer all necessary and prudent third-party costs incurred during its participation in the multi-party working group for studying and securing long-term gas supplies in the Cook Inlet. The regulatory asset does not include amounts allocated to future capital projects or amounts reimbursed by third parties. ENSTAR provided the balance of the regulatory asset, and a narrative statement detailing the progress of the working group in securing a gas supply, with its Second and Fourth Quarterly Gas Cost Balance Account Reports since its authorization by the Commission. Those filings were ENSTAR's:

- 2024 Fourth Quarter Gas Cost Balance Account Report and Compliance with U-22-090(2) Reporting Requirements, filed January 15, 2025;

- 2024 Second Quarter Gas Cost Balance Account Report and Compliance with U-22-090(2) Reporting Requirements, filed July 15, 2024
- 2023 Fourth Quarter Gas Cost Balance Account Report and Compliance with U-22-090(2) Reporting Requirements, filed January 12, 2024
- 2023 Second Quarter Gas Cost Balance Account Report and Compliance with U-22-090(2) Reporting Requirements, filed July 17, 2023.

Q. What parameters did the Commission place on recovery of the regulatory asset?

A. In Order U-25-004(5), the Commission found that the regulatory asset closed on December 17, 2024, when ENSTAR signed an exclusivity agreement with Glenfarne, and authorized ENSTAR to address an appropriate amortization period to recover the balance of the regulatory asset as of that date. The Commission also allowed ENSTAR to propose the recovery of carrying costs for the regulatory asset. I address the appropriate amortization period and proposed return on the regulatory asset. My testimony also demonstrates that the costs included in the regulatory asset are reasonable, prudent, and jurisdictional (i.e. they are for studying a gas supply solution and are not for the siting, construction, or operation of an LNG terminal).

Q. What is the balance of the regulatory asset as of December 17, 2024?

A. After reviewing third-party invoices and excluding charges incurred beyond the closing date set by the Commission, the balance of the regulatory asset is $4.55 million. Table 5 below provides a summary of charges for the necessary and prudent third-party costs incurred by ENSTAR to study and secure gas supply. These costs are included in the regulatory asset. The costs do not include amounts allocated to future capital projects or amounts reimbursed by other parties. The costs in Table 5 are broken down into three phases to align with the actual project phases that ENSTAR concluded by

December 17, 2024. In addition, attached as Exhibit IBJ-3 is a summary list of all incurred costs included in the regulatory asset.

Table 5

Phase	Scope Name	Period	Amount
Phase I	Gas Supply Project Planning Assessment	December 2022 - June 2023	$628,229
Phase II	Option Refinement and Feasibility Determination	July 2023 - January 2024	$3,026,689
Phase III	Project Selection and Commercial Due Diligence	February 2024 - December 2024	$896,914

Q. Please describe the activities and tasks that ENSTAR undertook to assess and secure gas supply options?

A. In May 2022, ENSTAR, CEA, IGU, MEA, HEA, and GVEA, along with DNR, and the Alaska Energy Authority ("AEA") formed a working group to assess future gas supply needs and energy security in Cook Inlet ("Working Group"). The Working Group's stated goal was to:

> "[w]ork together for long-term solutions. This requires better understanding of each utility's constraints and needs based on existing contracts and forecasting our collective demand growth into the next decade as well as considering additional options to meet the unique energy needs of our region."

In order to carry out the objectives of the Working Group, utilities undertook their own efforts to forecast long-term demand for natural gas and the unmet need for gas outside of existing contracts or future development of their own gas reserves. Internal utility staff undertook these efforts and these costs are not reflected in the $4.55 million regulatory asset.

In the fall of 2022, the Working Group, facilitated by ENSTAR, reviewed the results of the combined forecast. This initial unmet demand forecast indicated a need

for a major new source of supply of natural gas, which required an assessment of viable and most economic options for the region. No such assessment had been undertaken by the Alaska utilities jointly since 2012, and therefore required additional expertise and efforts to develop and evaluate current marketplace options that would deliver natural gas to Alaska consumers with a sufficiently high degree of reliability at a reasonable cost. The varied needs of all utilities and their customers in the medium and long term had to be considered and balanced in this effort. During this period, DNR was finalizing its assessment of Cook Inlet production. Once completed, the utilities incorporated DNR's Cook Inlet update into their forecast of unmet need.

In furtherance of identifying a suitable natural gas source, the Working Group, through ENSTAR, engaged Berkeley Research Group ("BRG") in November 2022 to conduct a long-term planning assessment. The BRG team brought extensive knowledge and experience in the local Alaska gas and energy market, access to expert knowledge of the LNG market, and an ability to provide coordinated technical project engineering, permitting, and project planning services by local and national specialist providers.

The ENSTAR-led assessment: (1) developed scalable options to fill the anticipated natural gas supply gap, including Alaska-based options; (2) developed and assessed high-level project scope, cost estimates, and time frames to execute for each of the options; (3) for options requiring LNG imports, analyzed the available sources for the required annual volumes of gas, plus potential contract structure and price ranges; (4) combined the analyses in (1)-(3) to estimate and compare the total cost of gas supply to consumers for each of the options; (5) assessed key risks and mitigations

associated with each option; and (6) developed a ranking system identifying and prioritizing project attributes such as reliability, cost, and schedule. Taken together, these actions comprised the utility advisory engagement component of BRG's study titled "Phase I Assessment" ("Phase I"). This phase was concluded in May 2023.

Q. Please describe the engagement of the Working Group.

A. The Working Group met weekly starting on December 6, 2022. During these meetings, BRG provided an overview of the completed tasks and remaining scope of work. The group collaborated to provide guidance and oversight of the project activities. It further proposed, developed, and discussed various potential options and required analysis and research. The Working Group participants collaborated with BRG to develop a prioritization and ranking matrix for evaluating the ten selected options under consideration. Individual utilities also undertook to update their initial demand forecasts, and provided a unified forecast to BRG, which BRG then combined with DNR's updated production and reserves forecast released in January 2023 to estimate unmet gas needs over time. In addition to the Working Group meetings, a group comprised of executive leadership from each of the utilities in the Working Group ("Executive Group") met on a monthly basis to receive updates from ENSTAR and BRG and to provide high-level guidance.

Q. What were the Phase I deliverables?

A. The Working Group presented the Phase I Assessment report prepared by BRG to the Commission on June 28, 2023.[25] The report included a detailed assessment of utilities' gas demand and forecasts of unmet gas supply needs; analysis for ten gas supply project

[25] *See*, ENSTAR presentation to the RCA during the June 28, 2023 Public Meeting: https://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=5B7CF0DC-FAB7-4CA3-BF69-51492B9430D3.

options considered to fill the unmet gas demand; a description of the option selection process; and an LNG market, risk and volatility analysis. The Phase I Assessment report is attached to my testimony as Exhibit IBJ-4. The report also identified the scope for the next phase of the project ("Phase II").

In order to present an estimated cost of supply in the Phase I Assessment and to rank the gas supply options relative to each other, BRG conducted a conceptual engineering cost assessment of any options that required new project construction or modification of existing facilities. In some cases, such as LNG trucking options, this assessment required a combination of reviewing real world projects, developing high-level cost estimates to transport, store, and re-gasify LNG in Southcentral, and evaluating the scalability and upper limits of supply that the project could provide. In Phase I, BRG also developed conceptual schedule estimates based on BRG's and the Working Group's combined experience but without a comprehensive project schedule buildout.

BRG built a flexible economic model that combined these engineering cost estimates and LNG market forecasts to provide ranges of total cost of gas supply for each option in $/Mcf, and total capital costs of each option under several potential price structures (e.g. spot market LNG purchases v. contracted supply). The outcomes of the prioritized ranking of the options as reviewed and agreed upon by the Working Group resulted in a short list of project options to take forward into Phase II for a more detailed evaluation.

Q. What was the Phase II scope?

A. Phase II focused on refining and determining the feasibility of the leading options identified in Phase I. In addition, a new option, an LNG import terminal located at the Alaska LNG site was added and evaluated. BRG recommended completion of the following scope of work over the next four to six months after issuance of the Phase I Assessment:

1. Utilities individually continue to work with Cook Inlet producers and the State to promote and secure additional contracted supply and promote alternative development.
2. As the Working Group, pursue several top-scoring options in order to further define scope, schedule, and commercial viability. Those options included: (1) modification of the existing Kenai LNG facility (via commercial discussions with owner); (2) scope definition and plan for a Floating Storage Regasification Unit ("FSRU") option; (3) conduct a greenfield site selection and feasibility assessment for LNG imports if retrofit options become unavailable; (4) conduct a market survey to further define availability and cost of LNG; and (5) conduct an optimization and feasibility assessment of the in-state pipeline option with AGDC and the State of Alaska in areas of permitting critical path and financing structure.
3. Complete permitting due diligence of all top-scoring options and identify key bottlenecks and showstoppers.
4. For all top-scoring options, develop draft venture model, project finance structure, and plan of engagement with capital markets.

5. Refine cost of supply estimates for the top-scoring options, including a greenfield LNG import project if existing Kenai LNG plant in Nikiski becomes non-feasible or excessively risky.
6. Select one permanent solution or multiple short-term and long-term options to pursue by the end of 2023.

Q. Has the Working Group completed these tasks?

A. Yes. Most of these tasks were completed by January 2024. Once BRG refined project schedules in Phase II, the Working Group recognized a near-term challenge to implement a large-scale option in time for all utilities' projected unmet demand, particularly for electric utilities. In response, the Working Group requested to add small-scale LNG to the options being evaluated for scope, engineering and economic assessment.

The Working Group, facilitated by ENSTAR, collaborated to develop a set of gas specifications that would be acceptable to the Alaska utilities' existing generation and transmission infrastructure. This work product assisted all further engagement with suppliers and project developers to identify necessary equipment needs and optimal sources of LNG.

Phase II also included technical and commercial due diligence of the available import sites. This work included a tabletop site selection study and technical research to identify the best available sites for an LNG terminal. This research assessed key considerations including land ownership, marine conditions, proximity to gas transmission, road and power infrastructure potential risks and necessary investment. To conduct this part of the assessment, BRG and ENSTAR, on behalf of the Working

Group, engaged the appropriate representatives for each potential location to gain additional information, including site visits and document review.

BRG improved the economic model that produced final Phase II cost of gas supply estimates by focusing on the short-listed set of options and adding the significantly more detailed and phased set of development, construction, and operating cost estimates that aligned with probability-based project schedules. BRG also updated the commodity price forecast on the basis of the results of supplier outreach effort.

BRG presented the results of Phase II to the Working and Executive Groups where the team decided not to release the findings of Phase II publicly as planned due to ongoing commercial dealings with several parties. The Phase II Report was completed in March 2024. The permitting and regulatory timelines and requirements identified in the report prepared by BRG were reviewed and confirmed by external regulatory counsel specializing in Federal Energy Regulatory Commission LNG permitting. Due to multiple confidentiality agreements with facility owners and gas suppliers, and the commercial sensitivity of the analysis and work performed during this phase, the team prepared two versions of the reports: a confidential version for the utilities' use only and a public version that excluded all commercially protected data. While the entire report has not been released, the findings of Phase II were shared with the Commission and Legislature in presentations. The public version of the Phase II Assessment: Summary of Results (Public Issue) and presentations are attached as Exhibit IBJ-5.

Q. What other tasks were completed during Phase II?

A. During Phase II the team continued to refine the project cost estimates, conducted engineering, permitting, and commercial diligence, and established a project management strategy. The main scope of work was: (1) to further define and evaluate each of the short-listed options, including site evaluation, design basis, permitting scope, risk analysis, cost model, capital estimates, and schedule integration; (2) to conduct LNG sourcing analyses, including market outreach, executing non-disclosure agreements ("NDAs"), and surveying potential LNG suppliers; (3) to provide a report outlining marine shipping considerations specific to Cook Inlet, and to help formulate a regulatory and commercial strategy for LNG shipping; (4) to update the supply model for the short-listed options and provide an updated estimate of the cost of delivered gas in $/Mcf; (5) to seek feedback from the utilities and recommend commercial structure(s) for LNG acquisition and a financing structure for the project; and (6) to evaluate sourcing and procurement strategies and develop a roadmap for further project development and execution.

During this phase, ENSTAR also conducted a public opinion survey to gauge customer awareness of local gas supply developments and their opinions on potential gas supply options.

Q. Has the Working Group made additional progress?

A. Yes. After the completion of Phase II, the team transitioned into Phase III, which focused on selection of a specific project led by a competent developer that would deliver the lowest-risk schedule, best supply reliability, and lowest costs to all members of the Working Group. Accordingly, ENSTAR assessed multiple projects and

commenced initial negotiations with several third parties during this phase. As a result of Phase II and Phase III work, ENSTAR signed more than 30 NDAs with project developers, LNG industry market leaders, and gas suppliers. These NDAs allowed ENSTAR to conduct necessary commercial due diligence to select a project that is large enough to meet the needs of all members of the Working Group in a timely manner. BRG assisted ENSTAR in designing the process to solicit project proposals that would meet the criteria developed over the previous phases of the work. From there, BRG supported ENSTAR in tabulating, conducting due diligence, and selecting the best option.

The work concluded in Phase I and Phase II provided ENSTAR with the type of information critical in the due diligence process during the selection of a specific project and developer. ENSTAR and the Working Group were well equipped to understand and challenge the issues and risk of each project configuration in regard to permitting, schedule, cost, and ultimately the ability to deliver affordable supplies to their consumers. This resulted in several proposals adjusting their initial schedule and cost estimates.

Q. Why did ENSTAR select the project proposed by Glenfarne?

A. As I stated above, ENSTAR performed due diligence on multiple projects during Phase II and III. In the early stages of the project, in order to objectively assess all options, BRG and the Working Group collaboratively developed a scoring methodology that prioritized certain characteristics of each project option. Table 6 below provides the scoring criteria used by the group.

Table 6

Priority	Scoring Criteria	Weight (1-10)
1	Schedule Risk	**10**
2	Reliability of supply during operations	**9**
3	Delivered cost per Mcf/MMBtu	**8**
4	Flexibility	**7**
5	Project Complexity and Integration	**6**
6	Permitting	**5**
7	Environmental Impact	**4**
8	Size of direct investment required by the utilities (CAPEX)	**3**
9	Local economic impact (jobs and revenues)	**3**
10	Carbon efficiency / Climate change impacts	**2**
	TOTAL WEIGHTED SCORE (Scale 0 to 5)	

The Working Group and ENSTAR continued to apply this scoring methodology to all proposed projects. ENSTAR used the same methodology in the project solicitation, modified for the context of the RFI process. The project presented by Glenfarne scored the highest overall compared to other projects. In addition, the Glenfarne project scored the highest on the technical and economic feasibility evaluation compared to the other projects. The advantageous permitting position of the project and its ability to meet long-term regional needs, along with the unique ability to switch to pipeline gas in the future at a significantly lower cost to LNG, as well as a competent third-party developer, led to the selection of the Glenfarne option.

The Glenfarne project also is uniquely positioned against other considered projects because it minimizes the "Regret Costs" that could be realized. Although not a part of the formal scoring criteria, this was important to ENSTAR. "Regret Costs" are additional costs that utilities might incur by moving forward with a project that

locks them down in decades-long contractual commitments without providing flexibility to switch to alternative resources such as in-state gas or renewable generation. Regret Costs can also be incurred by selecting an undersized project that will not be sufficient to meet all Railbelt gas demand in the future, which would force utilities to develop multiple costly projects.

Q. What return is ENSTAR proposing to apply to the deferred regulatory asset during the amortization period?

A. As with other Commission-approved regulatory assets, ENSTAR is seeking approval to apply its authorized overall rate of return to the deferred asset during the amortization period.[26]

Q. What amortization period does ENSTAR propose for recovery of the regulatory asset?

A. ENSTAR is seeking approval for the recovery of the $4.55 million amortized over three years starting with the effective date for permanent rates approved in this rate case.

Q. Why is ENSTAR using a three-year amortization period for the regulatory asset to study and secure gas supply?

A. In Order U-01-108(14), the Commission stated that a cost may be capitalized and ratably expensed over the period in which the cost is expected to provide benefit. The current regulatory asset contains costs to study options for securing a gas supply that closed with the execution of ENSTAR's exclusivity agreement with Glenfarne. ENSTAR's costs going forward to develop the Project with Glenfarne will be

[26] *See*, e.g. Order U-19-101(5) *Order Granting Petition To Create Regulatory Asset and Closing Docket* dated October 20, 2020 at 9 "…ENSTAR is allowed a return on the regulatory asset and may apply the rate of return determined in its next rate case to the regulatory asset for that intervening time period."

recovered through a separate regulatory asset, also approved by the Commission in Order U-25-004(5). The costs in that regulatory asset will be addressed in a future proceeding. By amortizing the regulatory asset to study gas supply options over a three-year period, ENSTAR seeks to ensure that the recovery of these costs is similar to the period of time in which the costs were incurred. The benefit has already been realized by entering into the exclusivity agreement with Glenfarne.

Q. Are there additional Commission statements in Order U-25-004(5) related to the regulatory asset that you would like to address?

A. Yes. As I mentioned earlier, in Order U-25-004(5) the Commission allowed ENSTAR to create a new regulatory asset to record third-party development costs for the Project and to seek recovery of those costs in a future proceeding. The Commission asserted that the creation of a regulatory asset for development costs is a substantial risk mitigator for ENSTAR, and capped ENSTAR's regulatory asset development costs at $4,758,750. The Commission maintained that ENSTAR's current authorized return on equity ("ROE") of 11.875% provided revenue to address gas supply. However, as Mr. Sims explains in his direct testimony, inflation, increased labor costs, the use of a historic test year, and a lack of timely cost recovery mechanisms, result in customer rates that do not reflect actual current costs of providing service to customers; and as a result, ENSTAR has significantly underearned compared to its authorized ROE during the last three years. Further, with its projected capital plan, ENSTAR will not earn its currently authorized ROE going forward. Under current conditions, ENSTAR does not have a reasonable opportunity to earn its authorized ROE and the revenues referenced by the Commission simply have not and will not be realized.

Q. What customer classes will ENSTAR allocate the regulatory asset costs to?

A. The costs will be allocated to all ENSTAR general service gas sales customers and members of the Working Group who are currently ENSTAR's firm transportation customers based on the annual gas consumption consumed during the 2024 test year. As discussed in ENSTAR's petition in U-22-090, the Working Group was established to assess future gas supply needs and energy security in Cook Inlet. The costs will benefit the customers and residents of the Cook Inlet area as current gas supply agreements expire for all utility members of the Working Group. In Order U-22-090(2), the Commission noted that ENSTAR's costs were part of a multi-party working group and therefore not entirely within ENSTAR's control. By December 17, 2024, as a member of the Working Group, ENSTAR spent $4.55 million after performing a significant amount of work to identify the project that that would deliver the lowest-risk schedule, best supply reliability, and reasonable costs to all members of the Working Group. Dr. Fairchild discusses the cost-of-service allocation in his direct testimony.

VI. VLFT/SCPPFT Peak Reduction Credit

Q. Why is ENSTAR creating a VLFT/SCPPFT Peak Reduction Credit?

A. As I mentioned earlier, ENSTAR has not been able to secure 100% of its "Design Day" peak demand requirements through gas supply agreements but continues to navigate the current energy environment in search of opportunities. While procuring additional gas would be the preferred method of meeting the peak demand requirements, ENSTAR recognizes the alternative is to reduce the peak demand on any given day. By providing an incentive to large gas use customers to divert its gas to ENSTAR, the

Company intends to access additional gas volumes for its remaining gas sales customers during periods of peak demand or other system constraints.

Q. How will the Peak Reduction Credit be applied?

A. ENSTAR is proposing to provide a credit to customers who are willing to divert their gas to ENSTAR during a high gas usage winter period. This credit, set out in a new proposed Section 2170 of ENSTAR's tariff, is specific to customers who currently receive service under the VLFT or SCPPFT Rate Schedule. To qualify for this credit, a customer must: (1) commit to divert a designated gas quantity for a sustained period; (2) demonstrate that it has the capability and sufficient supply for a firm alternative fuel backup; (3) have gas supply agreements in place that allow for volumes to be diverted; and (4) commit to divert designated volumes when called upon by ENSTAR.

Participating customers will receive a 50% credit on the Demand Charges set out in Section 2150b (or Section 2160b, as applicable) of ENSTAR's tariff, for the period in which the designated volumes are subject to diversion at ENSTAR's request (November-February). The total Demand Charge discount will be divided by 12 and credited to participating customers' accounts monthly, regardless of whether gas is actually diverted. The credit is intended to partially offset customers' costs to sustain its alternative fuel capability and to divert gas. Dr. Fairchild explains the calculation further in his direct testimony.

Q. Doesn't ENSTAR's Interruption Cost Sharing provision provide reimbursement if a customer is interrupted as set out in the tariff Section 1205?

A. While Section 1205 provides for reimbursement of the interrupted customer's marginal costs of replacement generation or power purchase, it does not cover any of the capital

costs of having the backup fuel equipment or the costs of maintaining backup fuel capability. It also does not cover any of the carrying costs of having alternative fuel ready for backup generation.

Q. Please detail the requirements to qualify for the Peak Reduction Credit.

A. As set out in proposed Section 2170a, to receive the credit the customer must meet all of the following requirements:

- Customer must elect to divert a gas quantity between 10,000 Mcf/Day to 30,000 Mcf/Day to ENSTAR.
- The customer must have alternative fuel backup available at one of its gas-fired power generation sites and demonstrate the ability to divert gas on a continuous basis for up to 72 consecutive hours.
- Diverted gas must be provided to ENSTAR at the same cost that the diverting customer paid for the gas.
- A transportation customer must have a gas supply arrangement that allows assignment or sale of the diverted gas to ENSTAR at cost either from the customer or the customer's gas supplier. Such agreements must meet all regulatory requirements and approvals.
- The customer must execute a VLFT/SCPPFT Peak Reduction Credit Agreement.

Customers granted the credit will still be eligible for reimbursement of their interruption costs under ENSTAR's tariff Section 1205 as that provision only covers the operating/alternative energy costs incurred when a Customer is interrupted.

Q. How does ENSTAR propose to recover the cost of the credits?

A. ENSTAR is proposing to revise the interruption cost sharing portion of the Gas Cost Balance Account provision (Tariff Section 708c) to include a cost element for the credit. The credits would be included and recovered in ENSTAR's annual GCA filing.

Q. Are you sponsoring the revised Section 708c and Section 2170 VLFT/SCPPFT Peak Reduction Credit tariff sheets?

A. Yes. The tariff sheets for the proposed revision to Section 708c and proposed Section 2170 VLFT/SCPPFT Peak Reduction Credit are included with the revised tariff sheets for the permanent rates in Attachment E.

VII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Inna B. Johansen

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, Alaska: 2014 – Present.

Vice President of Regulatory and Gas Supply: 2024 – Present

Director, Gas Supply Operations: 2019 – 2024

Senior Manager, Gas Supply and Financial Planning: 2016 – 2019

Gas Supply Manager: 2015 – 2016

Manager of Budgeting and Finance: 2014 – 2015

Southern Company, Birmingham, Alabama: 2012 – 2014

Southern Power Company/Asset Manager: 2013 – 2014

Alabama Power Company/ Budget Analyst: 2012 – 2013

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, Alaska: 2006 – 2012

Business Development Manager: 2010 – 2012

Operations Analyst: 2008 – 2010

Financial Analyst: 2006 – 2008

Alaska Pacific Bank, Juneau, Alaska: 2004 – 2006

Accounting Specialist

EDUCATION

Kazakh State Academy of Management, Almaty, Kazakhstan – BA in Finance and Accounting, 1999

Middle Tennessee State University, Murfreesboro, Tennessee: MBA – Emphasis in Finance and Accounting, 2003

OTHER

Commonwealth North, Member

Resource Development Council, Member

Western Energy Institute, Energy Management Team, Member

American Gas Association, Gas Control Committee

Habitat of Humanity, Board Member, 2011 – 2012

WEATHER NORMALIZATION ADJUSTMENTS

Purpose: To adjust for abnormal weather during 2024.

G1 Class:

Test Year Use per Consuming Customer (Mcf)			143.69	143.69
Base Use per Customer				
Jun Use per Customer		4.21		
Jul Use per Customer		3.55		
Aug Use per Customer		4.44		
Total		12.21		
No. of Days - Jun - Aug		92		
Base Use per Day		0.1327		
Annual Days		365		
Base Use per Customer			48.43	
Heating Load per Customer			95.26	
Heating Degree Days				
Actual Degree Days		9,870		
Base Degree Days:				
Jun	245			
Jul	203			
Aug	268			
Total	716			
No. of Days - Jun - Aug	92			
Average Daily	7.78			
Annual Days	365			
Annual Base Degree Days		2,841		
Heating Degree Days			7,029	
Heating Load per Degree Day			0.01355	
Excess Degree Days				
10-Year Normal		9,363		
Actual Degree Days		9,870		
Excess Degree Days			(507)	
Adjustment per Customer (Mcf)				(6.87)
Normalized Use per Customer (Mcf)				136.83
Test Year Customers				141,889
Normalized Volumes (Mcf)				19,414,078
Test Year Volumes (Mcf)				20,388,390
Excess Weather-related Volumes				(974,312)
G1 Volumetric Rate per Mcf				$ 1.4982
G1 Weather Normalization Adjustment				**$ (1,459,714)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G2 Class:

Test Year Use per Consuming Customer (Mcf)			363.32	363.32
Base Use per Customer				
Jun Use per Customer		10.54		
Jul Use per Customer		9.76		
Aug Use per Customer		11.35		
Total		31.65		
No. of Days - Jun - Aug		92		
Base Use per Day		0.3440		
Annual Days		365		
Base Use per Customer			125.57	
Heating Load per Customer			237.75	
Heating Degree Days				
Actual Degree Days		9,870		
Base Degree Days:				
Jun	245			
Jul	203			
Aug	268			
Total	716			
No. of Days - Jun - Aug	92			
Average Daily	7.78			
Annual Days	365			
Annual Base Degree Days		2,841		
Heating Degree Days			7,029	
Heating Load per Degree Day			0.03382	
Excess Degree Days				
10-Year Normal		9,363		
Actual Degree Days		9,870		
Excess Degree Days			(507)	
Adjustment per Customer (Mcf)				(17.14)
Normalized Use per Customer (Mcf)				346.18
Test Year Customers				5,947
Normalized Volumes (Mcf)				2,058,556
Test Year Volumes (Mcf)				2,160,467
Excess Weather-related Volumes				(101,910)
G2 Volumetric Rate per Mcf				$ 0.9602
G2 Weather Normalization Adjustment				**$ (97,854)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G3 Class:

Test Year Use per Consuming Customer (Mcf)			1,166.24	1,166.24
Base Use per Customer				
Jun Use per Customer		35.47		
Jul Use per Customer		37.39		
Aug Use per Customer		39.80		
Total		112.67		
No. of Days - Jun - Aug		92		
Base Use per Day		1.2246		
Annual Days		365		
Base Use per Customer			447.00	
Heating Load per Customer			719.24	
Heating Degree Days				
Actual Degree Days		9,870		
Base Degree Days:				
Jun	245			
Jul	203			
Aug	268			
Total	716			
No. of Days - Jun - Aug	92			
Average Daily	7.78			
Annual Days	365			
Annual Base Degree Days		2,841		
Heating Degree Days			7,029	
Heating Load per Degree Day			0.10232	
Excess Degree Days				
10-Year Normal		9,363		
Actual Degree Days		9,870		
Excess Degree Days			(507)	
Adjustment per Customer (Mcf)				(51.85)
Normalized Use per Customer (Mcf)				1,114.39
Test Year Customers				3,758
Normalized Volumes (Mcf)				4,187,988
Test Year Volumes (Mcf)				4,382,828
Excess Weather-related Volumes				(194,840)
G3 Volumetric Rate per Mcf				$ 0.9449
G3 Weather Normalization Adjustment				**$ (184,105)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G4 Class:

Test Year Use per Consuming Customer (Mcf)			7,609.31	7,609.31
Base Use per Customer				
Jun Use per Customer		275.36		
Jul Use per Customer		320.75		
Aug Use per Customer		311.83		
Total		907.93		
No. of Days - Jun - Aug		92		
Base Use per Day		9.8688		
Annual Days		365		
Base Use per Customer			3,602.12	
Heating Load per Customer			4,007.19	
Heating Degree Days				
Actual Degree Days		9,870		
Base Degree Days:				
Jun	245			
Jul	203			
Aug	268			
Total	716			
No. of Days - Jun - Aug	92			
Average Daily	7.78			
Annual Days	365			
Annual Base Degree Days		2,841		
Heating Degree Days			7,029	
Heating Load per Degree Day			0.57007	
Excess Degree Days				
10-Year Normal		9,363		
Actual Degree Days		9,870		
Excess Degree Days			(507)	
Adjustment per Customer (Mcf)				(288.85)
Normalized Use per Customer (Mcf)				7,320.46
Test Year Customers				1,015
Normalized Volumes (Mcf)				7,431,487
Test Year Volumes (Mcf)				7,724,721
Excess Weather-related Volumes				(293,234)
G4 Volumetric Rate per Mcf				$ 0.6581
G4 Weather Normalization Adjustment				**$ (192,977)**

ENSTAR Natural Gas Company
LT Gas Supply Regulatory Asset Balance as of 12/17/2024
5/2/2025

Doc Co	Co	Do Ty	Doc Number	Bth Ty	Batch Number	G/L Date	Amount	Explanation	Explanation -Remark-	Business Unit	OBJ Acct	Sub- ledger	Invoice Number
4	4	JE	95032306	G	491975	03/31/2023	160,060.53	GL Reclass Long Term Gas Suppl	Reclass from 4.33218	4	33211		
4	4	PV	855397	V	492046	04/04/2023	118,795.32	BERKELEY RESEARCH GROUP LLC	PLANNING ASSESMENT	4	33211		149671
4	4	PV	856340	V	493161	05/09/2023	88,647.09	BERKELEY RESEARCH GROUP LLC	PLANNING ASSESMENT	4	33211		150862
4	4	PV	857245	V	494227	06/07/2023	99,358.35	BERKELEY RESEARCH GROUP LLC	SVC RENDERED APRIL 30 2023	4	33211		152818
4	4	PV	859074	V	496473	08/01/2023	86,539.91	BERKELEY RESEARCH GROUP LLC	SVC RENDERED THROUGH 06/30/23	4	33211		157203
4	4	PL	859271	V	496738	08/08/2023	7,255.20	HUNTON ANDREWS KURTH LLP	Legal advice re gas supply	4	33211	LEGAL	116128299
4	4	PV	861163	V	499140	09/23/2023	173,224.91	BERKELEY RESEARCH GROUP LLC	SERVICES RENDERED THROUGH 7/31	4	33211		158873
4	4	PV	861164	V	499140	09/23/2023	2,664.17	BERKELEY RESEARCH GROUP LLC	SERVICES RENDERED THROUGH 7/31	4	33211		158874
4	4	PL	860598	V	498562	09/27/2023	13,342.95	HUNTON ANDREWS KURTH LLP	REGULATORY COMPLIANCE&COUNSEL	4	33211	LEGAL	116129020
4	4	PV	861659	V	499802	10/05/2023	206,911.85	BERKELEY RESEARCH GROUP LLC	SERVICES RENDERED THROUGH 8/31	4	33211		160675
4	4	PV	861669	V	499869	10/05/2023	72,163.88	BERKELEY RESEARCH GROUP LLC	SERVICES RENDERED THROUGH 5/31	4	33211		154884
4	4	JE	95102301	G	499999	10/09/2023	41,497.50	BU Reclass	BLUEPRINT ALASKA LLC	4	33211		
4	4	JE	95102301	G	499999	10/09/2023	1,202.50	BU Reclass	BLUEPRINT ALASKA LLC	4	33211		
4	4	PL	861712	V	499993	10/16/2023	17,326.40	HUNTON ANDREWS KURTH LLP	DOE import license	4	33211	LEGAL	116129508
4	4	PL	861720	V	499993	10/16/2023	6,896.00	HUNTON ANDREWS KURTH LLP	Kenai LNG advice	4	33211	LEGAL	116129510
4	4	PL	862840	V	501496	11/10/2023	19,584.80	HUNTON ANDREWS KURTH LLP	Gas supply advice	4	33211	LEGAL	116130053
4	4	PV	863409	V	502144	11/28/2023	623,212.74	BERKELEY RESEARCH GROUP LLC	SERVICE RENDERED THOUGH 93023	4	33211		161812
4	4	PL	863570	V	502366	12/11/2023	6,675.00	DILLON & FINDLEY P C	Gas supply consulting	4	33211	LEGAL	12535
4	4	PL	864153	V	502892	12/21/2023	78,824.80	HUNTON ANDREWS KURTH LLP	Gas supply advice	4	33211	LEGAL	116130710
4	4	PV	864350	V	503095	12/27/2023	489,015.22	BERKELEY RESEARCH GROUP LLC	COOK INLET GAS SUPPLY PROJECT	4	33211		164562
4	4	PL	864624	V	503381	01/03/2024	9,931.96	DILLON & FINDLEY P C	Gas supply	4	33211	LEGAL	12549
4	4	PV	864867	V	503700	01/17/2024	38,460.40	HUNTON ANDREWS KURTH LLP	GAS SUPPLY COUNSELING	4	33211	LEGAL	116131243
4	4	PV	864868	V	503700	01/17/2024	44,256.80	HUNTON ANDREWS KURTH LLP	KENAI LNG IMPORT-DUE DILIGENCE	4	33211	LEGAL	116131242
4	4	PV	865191	V	503950	01/19/2024	404,775.29	BERKELEY RESEARCH GROUP LLC	COOK INLET GAS SUPPLY PROJECT	4	33211		166356
4	4	PV	866202	V	504886	03/05/2024	8,578.49	DILLON & FINDLEY P C	REG ASSET/IMPORT/GAS SUPPLY	4	33211		12618
4	4	PV	866219	V	504918	03/05/2024	4,214.80	HUNTON ANDREWS KURTH LLP	GAS SUPPLY COUNSELING	4	33211		116131730
4	4	PV	866220	V	504918	03/05/2024	27,733.60	HUNTON ANDREWS KURTH LLP	KENAI LNG IMPORT	4	33211		116131729
4	4	PV	867097	V	505714	03/12/2024	467,589.07	BERKELEY RESEARCH GROUP LLC	SVC RENDERED THROUGH 12/31/23	4	33211		168435
4	4	PV	867098	V	505714	03/12/2024	336,178.47	BERKELEY RESEARCH GROUP LLC	SVC RENDERED THROUGH 01/31/24	4	33211		169942
4	4	PL	866257	V	504955	03/15/2024	35,961.20	HUNTON ANDREWS KURTH LLP	Gas supply counseling	4	33211	LEGAL	116132406
4	4	PL	866439	V	505091	03/15/2024	4,867.60	HUNTON ANDREWS KURTH LLP	import due diligence	4	33211	LEGAL	116132405
4	4	PV	867861	V	506601	04/23/2024	101,965.29	BERKELEY RESEARCH GROUP LLC		4	33211		173718
4	4	PV	868020	V	506686	04/24/2024	68,774.69	CORNERSTONE ENERGY SERVICES, I		4	33211		0018244
4	4	PL	867382	V	506142	04/25/2024	856.8	HUNTON ANDREWS KURTH LLP	Gas supply counseling	4	33211	LEGAL	116133043
4	4	PL	867585	V	506341	04/25/2024	3,225.00	DILLON FINDLEY & SIMONIAN P.C	Gas supply consulting	4	33211	LEGAL	12698
4	4	PL	867806	V	506534	04/25/2024	1,739.94	DILLON FINDLEY & SIMONIAN P.C	gas supply legal	4	33211	LEGAL	12732
4	4	PL	868307	V	507157	05/07/2024	30,092.40	HUNTON ANDREWS KURTH LLP	Gas supply counseling	4	33211	LEGAL	116133578
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4	4	PV	869236	V	508301	06/04/2024	237,168.69	BERKELEY RESEARCH GROUP LLC	PROFESSIONAL SERVICES	4	33211		171976
4	4	PV	869240	V	508301	06/04/2024	64,214.05	BERKELEY RESEARCH GROUP LLC	PROFESSIONAL SERVICES	4	33211		175246
4	4	PV	870191	V	509486	06/26/2024	27,773.66	BERKELEY RESEARCH GROUP LLC		4	33211		177208
4	4	PV	870192	V	509486	06/26/2024	20,615.00	CORNERSTONE ENERGY SERVICES, I	ENSTAR - ALASKA GAS SUPPLY	4	33211		0018389
4	4	PV	870194	V	509486	06/26/2024	12,994.00	CORNERSTONE ENERGY SERVICES, I	ENSTAR - ALASKA GAS SUPPLY	4	33211		0018572
4	4	PL	869479	V	508471	07/01/2024	5,280.00	HUNTON ANDREWS KURTH LLP	Gas supply counseling	4	33211	LEGAL	116134123
4	4	PL	869754	V	508937	07/01/2024	5,797.40	DILLON FINDLEY & SIMONIAN P.C	Gas supply counseling	4	33211	LEGAL	12883
4	4	PD	871185	V	511021	07/23/2024	-5,459.90	DILLON FINDLEY & SIMONIAN P.C	CREDIT - REG ASSET/IMPORT	4	33211	LEGAL	12949
4	4	PL	870644	V	510163	07/23/2024	2,550.00	HUNTON ANDREWS KURTH LLP	LNG import permitting	4	33211	LEGAL	116134742
4	4	PL	871745	V	511847	09/13/2024	20,151.60	HUNTON ANDREWS KURTH LLP	Gas supply counseling	4	33211	LEGAL	116135330
4	4	PV	873807	V	514413	09/23/2024	45,815.91	BERKELEY RESEARCH GROUP LLC	PLANNING ASSESSMENT	4	33211		10002312
4	4	PV	873808	V	514413	09/23/2024	13,766.45	BERKELEY RESEARCH GROUP LLC	PROFESSIONAL SERVICES	4	33211		178882
4	4	PV	873809	V	514413	09/23/2024	55,303.92	BERKELEY RESEARCH GROUP LLC	PROFESSIONAL SERVICES	4	33211		10003512
4	4	PL	874365	V	515222	10/16/2024	476	HUNTON ANDREWS KURTH LLP	GAS SUPPLY COUNSELING	4	33211		116136463
4	4	PV	877694	V	518755	12/26/2024	35,102.84	BERKELEY RESEARCH GROUP LLC	SERVICES THROUGH SEPT 2024	4	33211		10005356
4	4	PV	877696	V	518755	12/26/2024	37,474.03	BERKELEY RESEARCH GROUP LLC	SERVICES THROUGH DEC 2024 UP TO Dec 13th	4	33211		10010197
4	4	PV	877697	V	518755	12/26/2024	67,295.29	BERKELEY RESEARCH GROUP LLC	SERVICES THROUGH NOV 2024	4	33211		10008720
						Total	**4,551,832.36**						

ALASKA UTILITIES WORKING GROUP

PHASE I ASSESSMENT: COOK INLET GAS SUPPLY PROJECT

June 28, 2023

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LIST OF ABBREVIATIONS

ADNR	State of Alaska Department of Natural Resources
AECO	Alberta Energy Company; Alberta hub natural gas price.
AGDC	Alaska Gasline Development Corporation
AEA	Alaska Energy Authority
BCF	Billion cubic feet
BRG	Berkeley Research Group
BV	Black and Veatch
CEA	Chugach Electric Association
CINGSA	Cook Inlet Natural Gas Storage Alaska
DES	Delivered ex-ship
EV	Electric vehicle
FEED	Front-end engineering design
FID	Final investment decision
FOB	Free on Board (loaded onto vessel)
FSRU	Floating storage and regasification unit
GVEA	Golden Valley Electric Association, Inc
HEA	Homer Electric Association
HH	Henry Hub
IGU	Interior Gas Utility
JBER	Joint Base Elmendorf-Richardson
JCC	Japan Customs Cleared
JKM	Japan Korea Marker

KGFGS	Kenai Gas Field Gas Storage
KBPL	Kenai Beluga Pipeline System
LNGC	LNG carrier
m^3	Cubic meter
MEA	Matanuska Electric Association
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MMgal/d	Millions of gallons per day
Mtpa	Million tonnes per annum
MW	Megawatts
PCGS	Pretty Creek Gas Storage
SRGS	Swanson River Gas Storage
USCG	U.S. Coast Guard
USDOT FHWA	US Department of Transportation Federal Highway Administration
WCSB	Western Canadian Sedimentary Basin

1 EXECUTIVE SUMMARY

1.1 Background and Scope

1. Southcentral Alaska, along with the Interior (the "Railbelt"), comprise the most densely populated areas of the State. These regions have relied on natural gas produced in Cook Inlet to various degrees to supply its heating and power generation needs since the 1950s. Gas production in Cook Inlet field peaked in the mid-2000s at around 200 BCF per year,[1] and has steadily declined to the current annual production of approximately 70 BCF per year.[2] Formerly active export facilities of Agrium Kenai Nitrogen Plant and Kenai LNG stopped operating in 2007[3] and 2015,[4] respectively, due to the shortage and cost of gas produced in the region.

2. Over the last decade, Hilcorp Alaska, LLC ("Hilcorp") has become the largest operator and gas supplier in the state, maintaining and stabilizing Cook Inlet gas production after a period of threatened shortages.[5] Hilcorp has invested over $750 million in Cook Inlet drilling and capital projects since 2012, and plans to continue the investment at around the same pace over the next decade.[6] In April 2022, Hilcorp first warned of uncertainty of future Cook Inlet natural gas supplies, stating that "gas purchasers [were] not to rely on Hilcorp for gas beyond existing contracts."[7]

3. In May 2022, ENSTAR Natural Gas ("ENSTAR"), Chugach Electric Association, Inc. ("CEA"), Interior Gas Utility ("IGU"), Matanuska Electric Association, Inc. ("MEA"), Homer Electric Association, Inc. ("HEA"), and Golden Valley Electric Association, Inc. ("GVEA"), along with the State of Alaska Department of Natural Resources ("ADNR"), and the Alaska Energy Authority ("AEA")[8] formed a working group to assess future gas supply needs and energy security in Cook Inlet ("Working Group"). The Working Group's stated goal is to:

> *"[w]ork together for long-term solutions. This requires better understanding of each utility's constraints and needs based on existing contracts and forecasting our*

[1] State of Alaska Department of Natural Resources, Division of Oil & Gas, *Cook Inlet Natural Gas Availability*, March 2018, p. 19, available at https://dog.dnr.alaska.gov/Documents/ResourceEvaluation/CI_Natural_Gas_Availability_Study_2018.pdf.

[2] State of Alaska Department of Natural Resources, Division of Oil and Gas, *2022 Cook Inlet Gas Forecast*, January 2023, pp. 10 and 17, ("2022 Cook Inlet Gas Supply Study").

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

[4] 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/.

[5] Bradner, Tim. *Study says Inlet gas discoveries won't stop shortage*, Alaska Journal of Commerce, March 22, 2012.

[6] Saugier, Luke, *Presentation to Alaska State Legislature*, House Energy Committee, p. 5, January 2023.

[7] DeMarban, Alex, *Hilcorp Warms Alaska utilities about uncertain Cook Inlet natural gas supplies*, Anchorage Daily News, May 17, 2022.

[8] ADNR and AEA participated in advisory capacity in order to provide information to the utilities, as well as remain aware of the effort. These agencies did not fully participate in the deliberations or scoring of the options.

collective demand growth into the next decade as well as considering additional options to meet the unique energy needs of our region."[9]

4. In furtherance of these goals, the Working Group, through ENSTAR, engaged Berkeley Research Group ("BRG") to conduct a planning assessment to: (i) develop scalable options to fill the natural gas supply gap anticipated to occur as Cook Inlet production declines, including Alaska-based options; (ii) develop and assess high-level project scope, cost estimates, and time to execute for each of the options; (iii) for options requiring LNG imports, analyze the available sources for the required annual volumes of gas, potential contract structure and price ranges; (iv) assess key risk and mitigations associated with each option; and (v) develop a ranking system, ranked assessment of options, and recommendations, all of which comprises the advisory engagement titled "Phase I Assessment."

5. This report summarizes the outcomes and recommendations of the Phase I Assessment.

1.2 BRG Credentials

6. BRG's expert Energy & Climate and Project Development Advisory practices combine gas and LNG market, commercial, contractual, and project financing expertise capabilities in technical project development and project management systems. Our advisory practice experts have deep experience in evaluation and development of LNG terminals and regasification facilities, utility infrastructure and major project management, market analysis and contracting. We also excel in providing strategic, market, commercial, economic, and financial advisory services in the global oil and natural gas industry.

7. The areas of focus for our utility clients are summarized in Figure 1.

Figure 1: Areas of Focus for Utility Clients

[9] Regulatory Commission of Alaska, *Affidavit of John D. Sims*, p. 3, November 9, 2022.

8. Appendix A.1. details BRG's relevant engagements and experience in project analysis, management, and design within the global oil and natural gas industry.

1.2.1 Project Leadership

9. The following key experts from BRG and Cornerstone Energy Services, a subcontractor engaged by BRG, led the Phase I Assessment.

Key Staff	Position	Key Role
Steve Means	Managing Director, Infrastructure Development	Infrastructure Development subject matter expert, technical integration
Lieza Wilcox	Director, Project Manager	Project Management, Commercial Assessment Lead
Steve Sawyer	Engineering Project Management	PM, Pipeline Engineering, Construction Management

10. In addition, the team included BRG and Cornerstone staff with deep experience in LNG systems engineering, siting, and processing, pipeline engineering and materials, worldwide gas and LNG market analysis and contracting, energy macroeconomic, investment analysis, financial modeling, and market research.

1.3 Summary of Conclusions

11. Based on the results of this Phase I Assessment, we make the following conclusions:

12. Cook Inlet gas cannot fully meet demand forecast beyond 2026 with current proved reserves or beyond early/mid 2030s assuming incremental local supply development.[10]

13. While continuing to work on Cook Inlet options, other project(s) must be pursued due to lead time to implement.

14. It is vital for the Alaska utilities to have control of the pace of the option development due to the impending gas shortage. Therefore, options that can be approved and either sourced or executed by the utilities are preferrable.

15. Shifting away from local gas supply will require supply options of either scalable or temporary ("stopgap") nature. Expanded underground gas storage will play a critical role in ensuring deliverability of seasonal gas supply with most alternatives.[11]

[10] Demand projections are based on the utilities Working Group's estimates, as described below in this report.

[11] The cost, design, or potential location(s) of this storage expansion have not been taken into account in Phase I Assessment.

16. In order to meet the expected supply shortfall, one or more options need to be selected to progress to an active engineering effort by the end of 2023. In order to meet the expected gas shortfall in 2027-2028, there is a limited set of options that can deliver, namely LNG imports in various forms, and all of them are still at a stage where uncertainties and risks related to design and feasibility need to be resolved before choosing a specific design configuration. Other options, such as a gas pipeline from the North Slope, can meet long-term demand most economically, but are not expected to be online by 2027-2028 or even reach a construction decision in the timeframe where alternatives would need to be sanctioned.[12] This drives the potential need to make progress on multiple fronts. Several viable options to supplement Cook Inlet gas supply need to be progressed further in the next phase of this project ("Phase II") to enable a sanction decision on at least one option by the end of 2023.

1.4 Recommendations

17. BRG recommend the following scope of work as part of "Phase II", estimated to take 4-6 months:

    a. Utilities individually continue to work with Cook Inlet producers and the State to promote and secure additional contracted supply and promote alternative development.

    b. The Working Group should continue to pursue top-scoring options to further define scope, schedule, and commercial viability; specifically: 1) Modification of existing Kenai LNG facilities (via commercial discussions with owner); 2) Scope definition and planning for FSRU option; 3) Greenfield site selection and feasibility assessment for LNG imports if retrofit options become unavailable; 4) Market survey to further define availability and cost of LNG; and 5) Optimization and feasibility assessment of the In-State Pipeline option with AGDC and State of Alaska in areas of permitting critical path and financing structure.

    c. Complete permitting due diligence of all top-scoring options and identify key bottlenecks and showstoppers.

    d. For all top-scoring options, develop draft venture model, project finance structure and plan of engagement with capital markets.

    e. Refine cost of supply estimates for the top-scoring options, including greenfield LNG import, if existing infrastructure in Nikiski becomes non-feasible or excessively risky.

    f. Select one permanent solution or multiple short and long-term options to pursue by the end of 2023 with target date for first delivery of gas in 2027-2028. Phase II

[12] The timeline of feasible start dates and cost of supply ranges for various options are presented in Appendix D, which was assembled by CEA as a collaborative work product between BRG and BV based on each company's separate analyses, and illustrates a multitude of considered options with their feasible start dates.

refinement of scope and schedule will enable a more accurate estimate of feasible start dates for the options under consideration.

1.5 Structure of the Report

18. The remainder of this report is organized into five primary chapters, as follows:

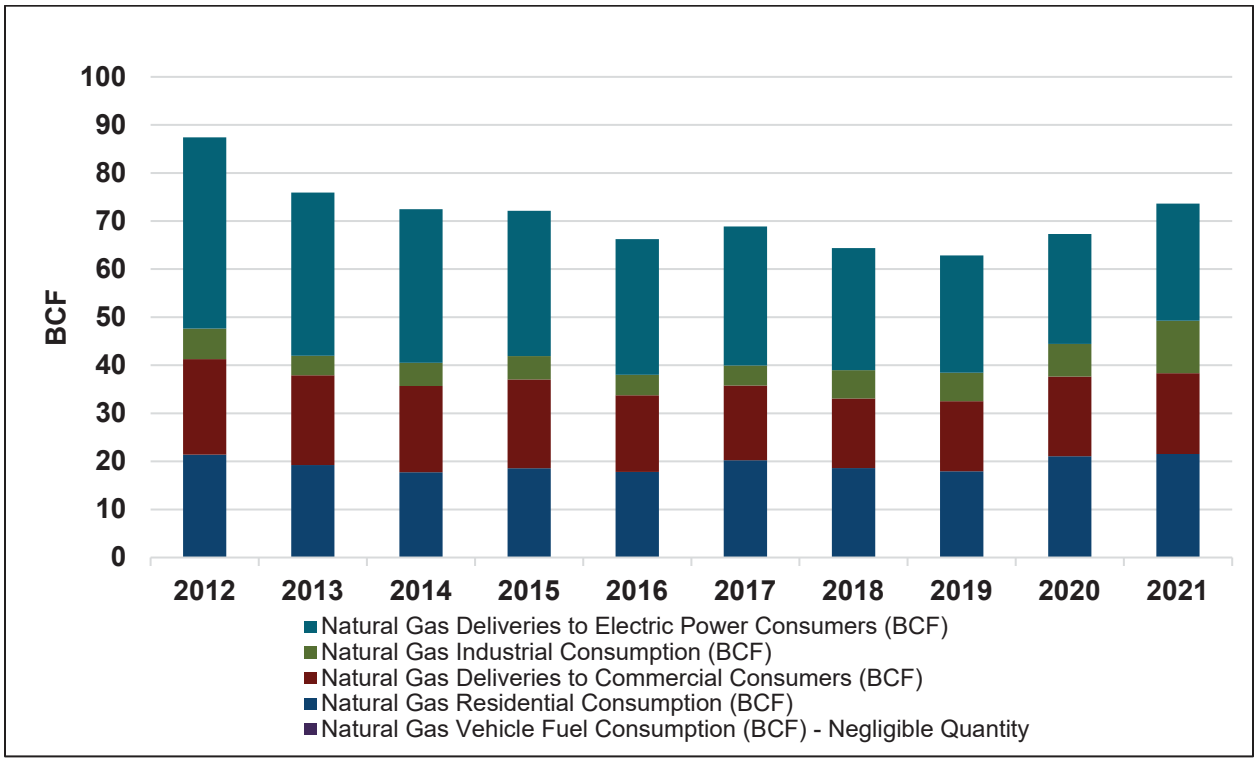
- Chapter 2: Forecast of Unmet Gas Demand Need
- Chapter 3: New Supply Options Considered
- Chapter 4: Option Selection
- Chapter 5: Market, Price Volatility, and Risk Analysis
- Chapter 6: Recommendations and Next Steps

2 FORECAST OF UNMET GAS DEMAND NEED

2.1 Historic and Current Demand for Natural Gas by the Working Group Utilities

19. After the end of fertilizer production and export, Alaska natural gas consumption in the Railbelt area decreased to around 70 billion cubic feet per year ("BCF") over the last decade, divided between residential and commercial heating, power generation, and the rest for small industrial users, such as Kenai Refinery owned by Marathon Petroleum Corporation ("Marathon"). The chart below breaks down the various consumer uses of natural gas.

Figure 2: Alaska Natural Gas Delivered to Consumers



2.2 Incorporation of Renewable Energy Scenarios into Power Generation Utilities' Forecasts

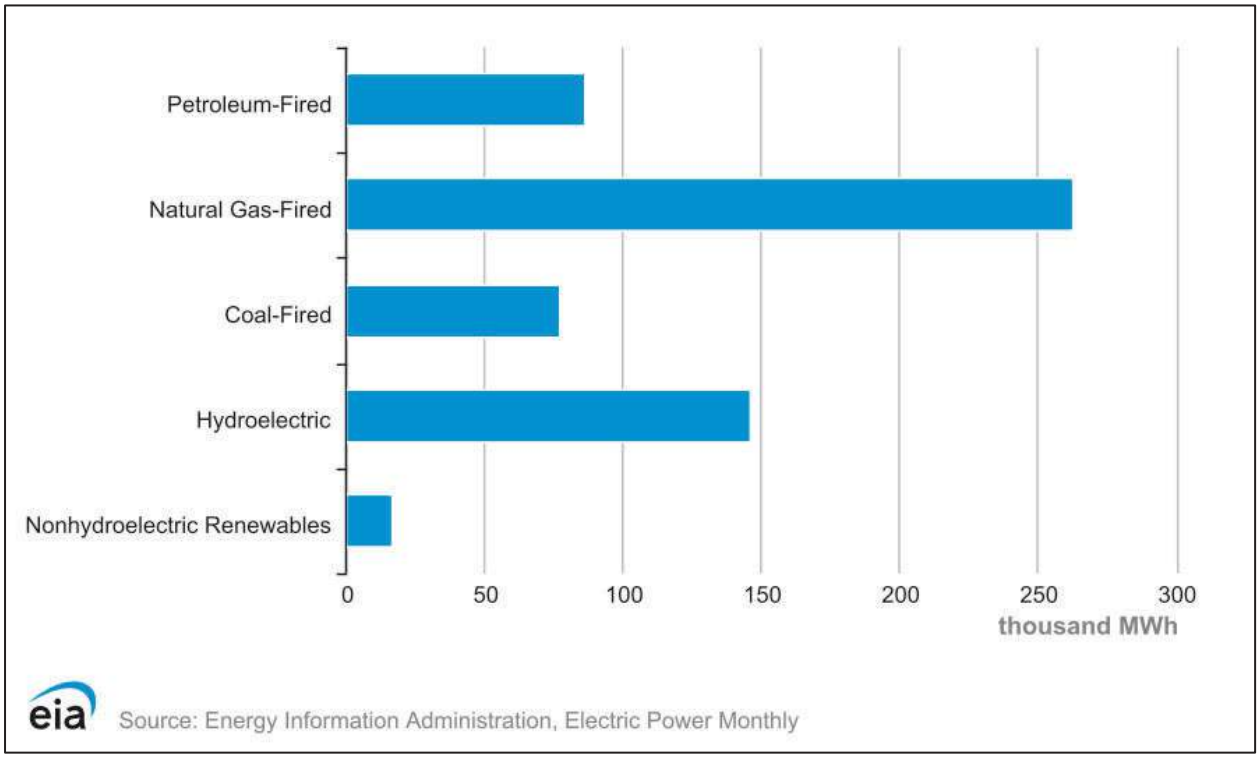
20. Renewable energy has been a part of Alaska's power generation portfolio for decades, with hydropower supplying more than 20 percent of the state's electrical energy in an average year. The integrated Railbelt system is powered by approximately 85% fossil fuels and 15% renewables.[13] The largest renewable energy project supplying the Working Group of utilities is Bradley Lake, at 120 megawatts ("MW") installed capacity. The project supplies about 10% of

[13] Bettina Chastain (CEA Board President) and Arthur Miller (CEA CEO), Opinion: *Anchorage's electric utility is making progress on its clean-energy goals*, Anchorage Daily News (April 13, 2023).

the Railbelt's electricity demand.[14] Several new projects, some of them very large, are in various stages of development.[15]

21. Solar and wind generation has gained footing in the state as well, starting to supply a significant part of electric generation produced in the entire state, as shown in the chart below.

Figure 3: Alaska Net Electricity Generation by Source (December 2022)



22. All electric utilities in the working group have incorporated plans for integration of renewables into their generation portfolio as part of their strategic and near-term plans. For example, CEA is currently evaluating two proposed utility-scale projects (one wind, one solar), that could provide up to 400,000 MWh, or 20% of their annual energy needs, provided that the ongoing feasibility studies can show no negative impact on electricity rates.[16] GVEA's plan to incorporate more natural gas generated electricity into its system would offset the decrease in natural gas demand from using more renewable power generation in the Railbelt. Also, Alaska's currently

[14] Kirong, N., *Alaska utilities plan $200M Railbelt transmission system upgrades*, S&P Global, May 30, 2022.

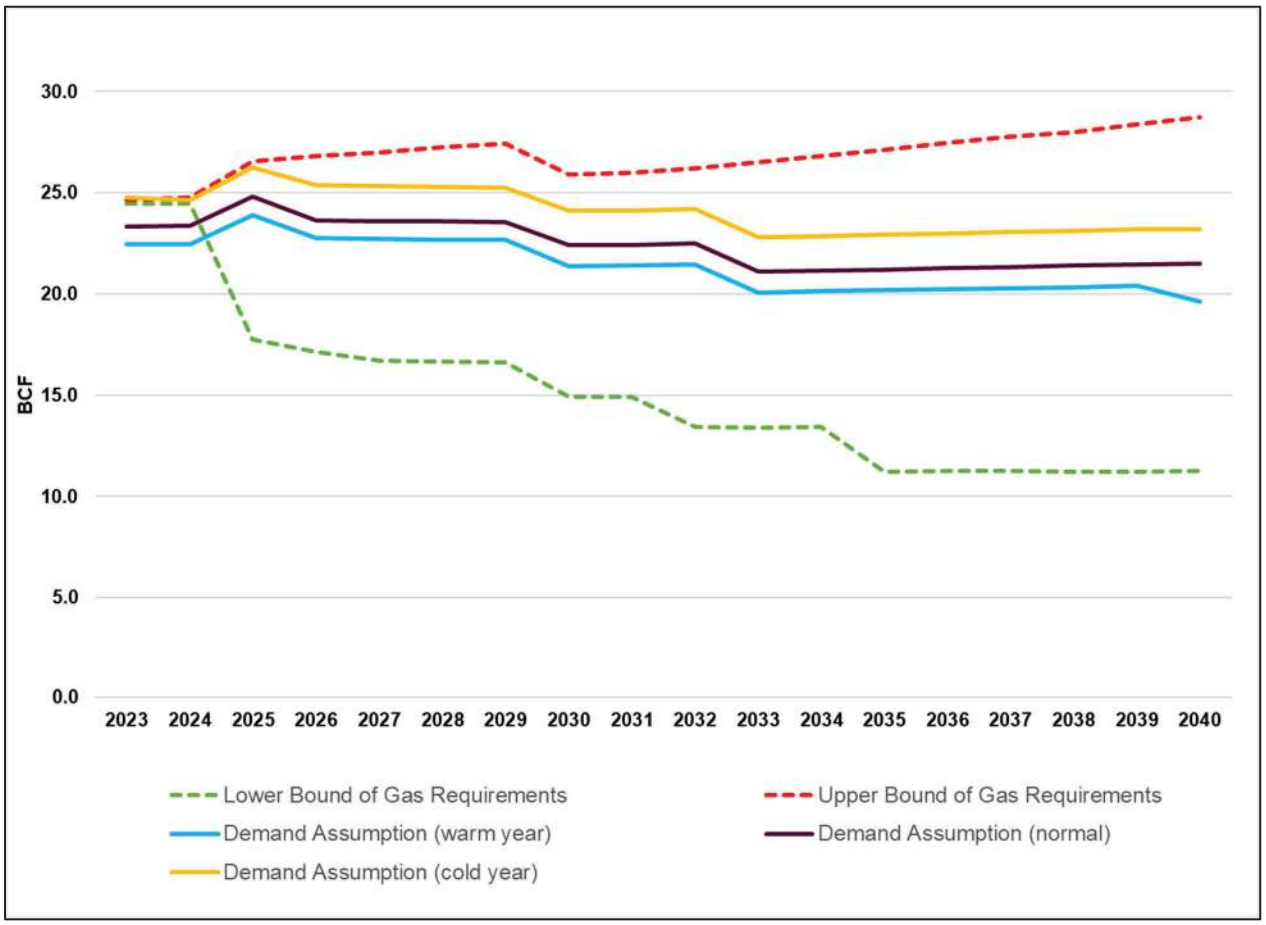
[15] Corri A. Feige (ADNR Commissioner) and Lucinda Mahoney (Alaska Department of Revenue Commissioner), *Investing in Alaska Beyond ESG,* January 2022, available at https://dog.dnr.alaska.gov/Documents/ResourceEvaluation/Alaska_ESG_Jan_2022.pdf.

[16] Bettina Chastain (CEA Board President) and Arthur Miller (CEA CEO), Opinion: *Anchorage's electric utility is making progress on its clean-energy goals*, Anchorage Daily News (April 13, 2023).

relatively low (0.2%) penetration of electric vehicles ("EV"), heat pumps, and induction cooking will likely grow over time and increase combined-cycle natural gas power generation demand overall. [17]

23. Figure 4 below provides a breakout of the projected electric utility[18] natural gas requirements. These requirements (represented by dotted lines) are based on planning scenarios to provide a range for strategic planning. As can be seen, there is a substantial range of projected gas requirements for the electric utilities attributed to potential varying degrees of clean energy uptake along with beneficial electrification such as EVs and heat pumps. For the purposes of project requirements, the three demand lines between the Lower and Upper Bounds of Gas Requirements were utilized since they best represent reasonable expectations and timelines.

Figure 4. Power Generation: Demand Planning Assumptions vs. Potential Bounds of Gas Requirements



[17] Alaska Energy Authority, *State of Alaska Electric Vehicle Infrastructure Implementation Plan* (approved by USDOT FHWA on September 27, 2022), pp. 25-26.

[18] CEA, MEA, HEA, and GVEA.

2.3 2022 Cook Inlet Gas Supply Study by the Department of Natural Resources

24. In the 2022 Cook Inlet Gas Forecast,[19] ADNR evaluates 90 oil and gas pools in the Cook Inlet Basin within 38 different fields and developed probabilistic forecasts for proved developed and proved undeveloped dry and associated natural gas reserves for each pool.[20] The study assesses reserves based on "present conditions and assumptions"[21], and "does not estimate future natural gas prices".[22] Undeveloped reserves are assumed to be developed at a drilling pace of 15 wells per year from 2023 until 2030, with no additional drilling assumed thereafter.[23] ADNR's assumed annual gas demand is 70 BCF; it is a "steady demand profile" assumption[24] and thus does not make judgments regarding any potential changes in future natural gas demand.

25. ADNR truncates forecasts of the technically recoverable gas to account for the economic limit of the various pools. The economic limit ensures that the production forecasts are limited to only economically feasible production. This is typically determined as the difference between revenues and variable costs borne by the producer.[25] Since ADNR does not forecast future prices in this study, it is implied that production for various pools will be truncated based on the economic limits determined under the prevalent price conditions. ADNR estimates that under the mean truncated ("ADNR's 2022 Mean Truncated") production scenario there are currently 803 BCF of dry natural gas and 17 BCF of associated natural gas remaining in Cook Inlet.[26]

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

[20] 2022 Cook Inlet Gas Supply Study, p. 4.

[21] 2022 Cook Inlet Gas Supply Study, p. 3.

[22] 2022 Cook Inlet Gas Supply Study, p. 3.

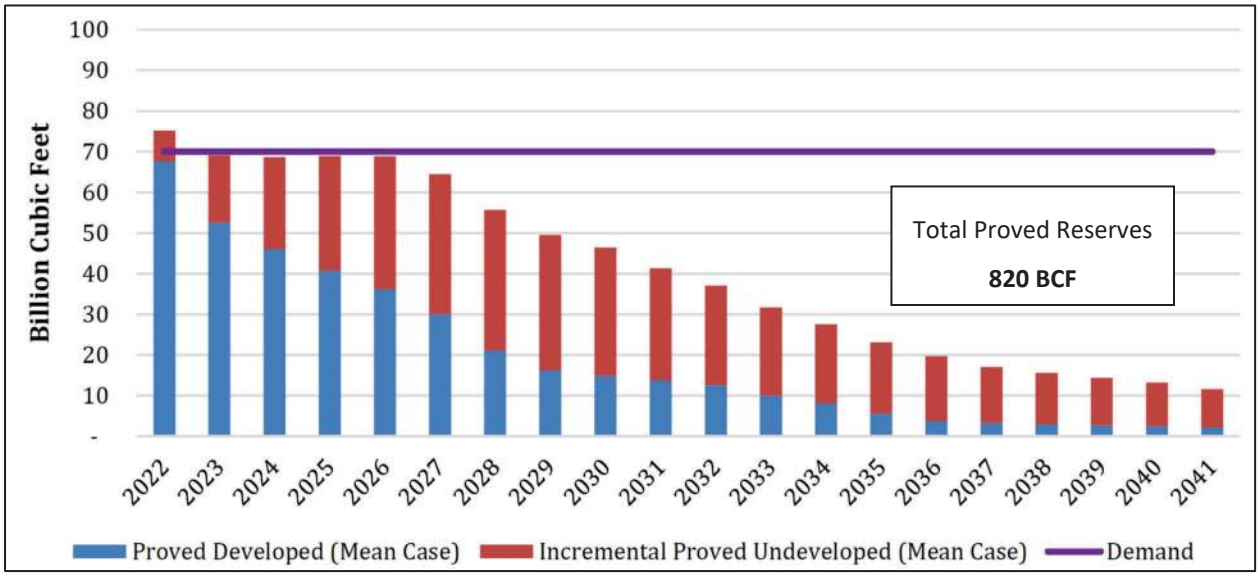
[23] 2022 Cook Inlet Gas Supply Study, p. 4. "The forecast does not assess or assume how many wells may be drilled after 2030."

[24] 2022 Cook Inlet Gas Supply Study, p. 17.

[25] ADNR did not analyze the potential economic limit of the entire basin that would take into account ability to sustain a support industry and interactions between upstream and midstream, such as maintaining pipeline pressures.

[26] 2022 Cook Inlet Gas Supply Study, p. 15.

Figure 5: ADNR's 2022 Mean Truncated Annual Gas Supply Forecast



2.4 Unmet Gas Demand Forecast

26. The main gas consumers in Cook Inlet are ENSTAR and CEA and together account for more than 75% of gas demand in Cook Inlet. ENSTAR is the largest overall consumer of natural gas in the state and does not expect material shifts in its demand over the next 20 years. ENSTAR's 2023 contracted demand is approximately 34 BCF. CEA has contracted approximately 8 BCF with an additional 8 BCF sourced from Chugach's 66.7% working interest ownership in the Beluga River Unit. Other major gas consumers include MEA, HEA, GVEA as purchaser of economy energy sales from Cook Inlet basin, and Marathon as an industrial user for local refinery. In addition, IGU located in Fairbanks, currently supplies Cook Inlet sourced gas to Fairbanks via an LNG trucking operation. IGU has concluded a firm 20-year contract with Harvest Midstream to supply LNG from the North Slope starting approximately in 2024, with two 5-year extension options.[27] IGU's future demand outside of its current Cook Inlet gas contracts is thus excluded from the estimated demand profiles. However, should IGU choose to participate in the selected supply option, its demand could be easily incorporated into the design of the top-ranked options under consideration.

27. Future "Unmet Gas Demand" can be defined in two ways:

[27] IGU Board of Directors Special Board Meeting, January 17, 2023, *IGU Board Memorandum 2023-01*, p. 8. IGU's current gas contract with Hilcorp provides sufficient gas through 2032, however in the event of the gas supply source switching to Harvest, the Cook Inlet contract will end earlier, as shown in Figure 6.

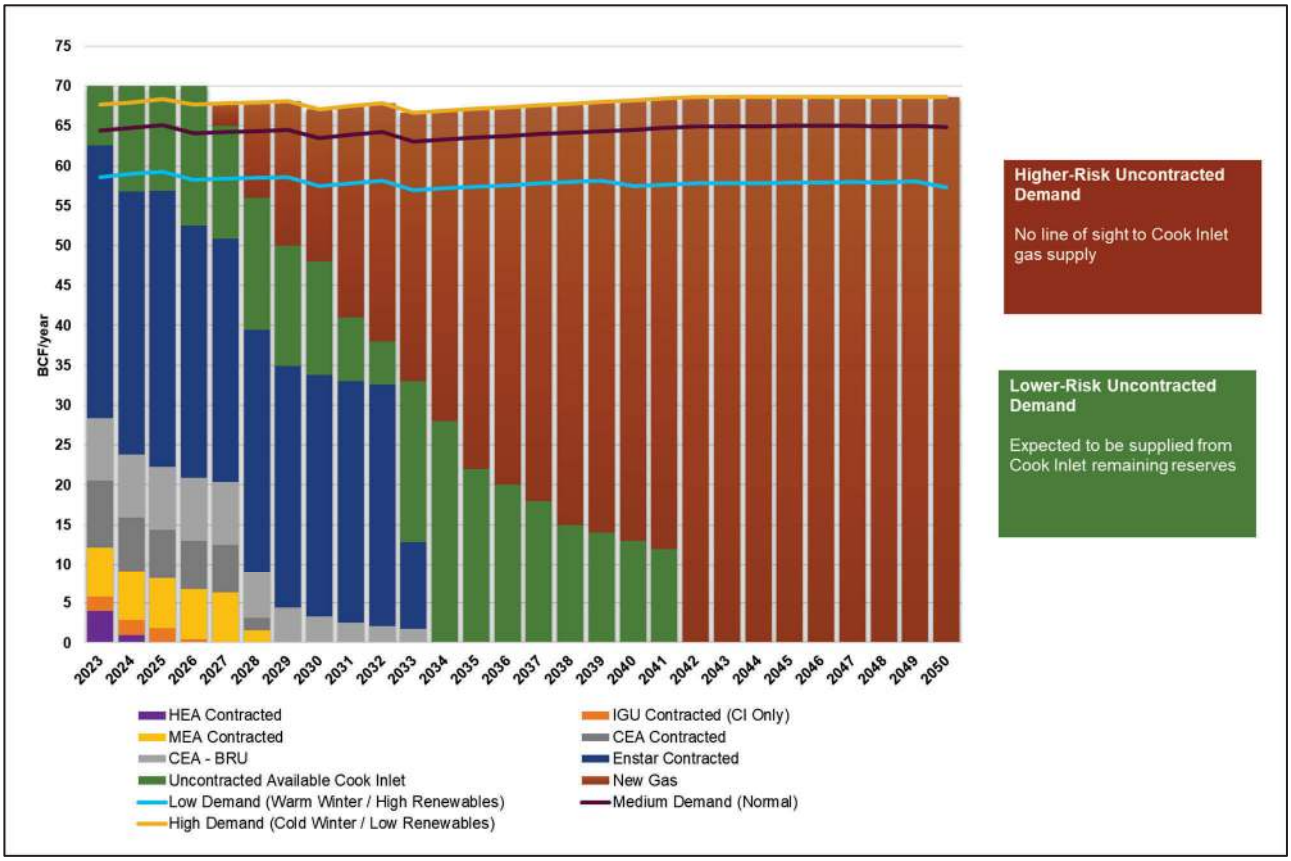
a. Lower-risk uncontracted demand compares consumer demand forecasts to firm contract quantities committed to Alaskan utilities with access to the Cook Inlet gas market; or

b. Higher-risk uncontracted demand compares consumer demand forecasts with ADNR truncated production, which assumes that utilities are able extend or execute new agreements up to the proved reserves production profile provided by ADNR.

28. BRG used the second definition as the planning assumption in this assessment to determine Unmet Gas Demand, since ADNR's 2022 Mean Truncated forecast is based on reserves of high degree of confidence (1P) that can be delivered at current prices. In other words, this assessment assumes that additional Cook Inlet gas will be contracted and re-contracted up to ADNR's 2022 Mean Truncated production profile. ADNR's 2022 Mean Truncated production profile[28] along with demand forecasts provided by utilities are depicted in Figure 6.

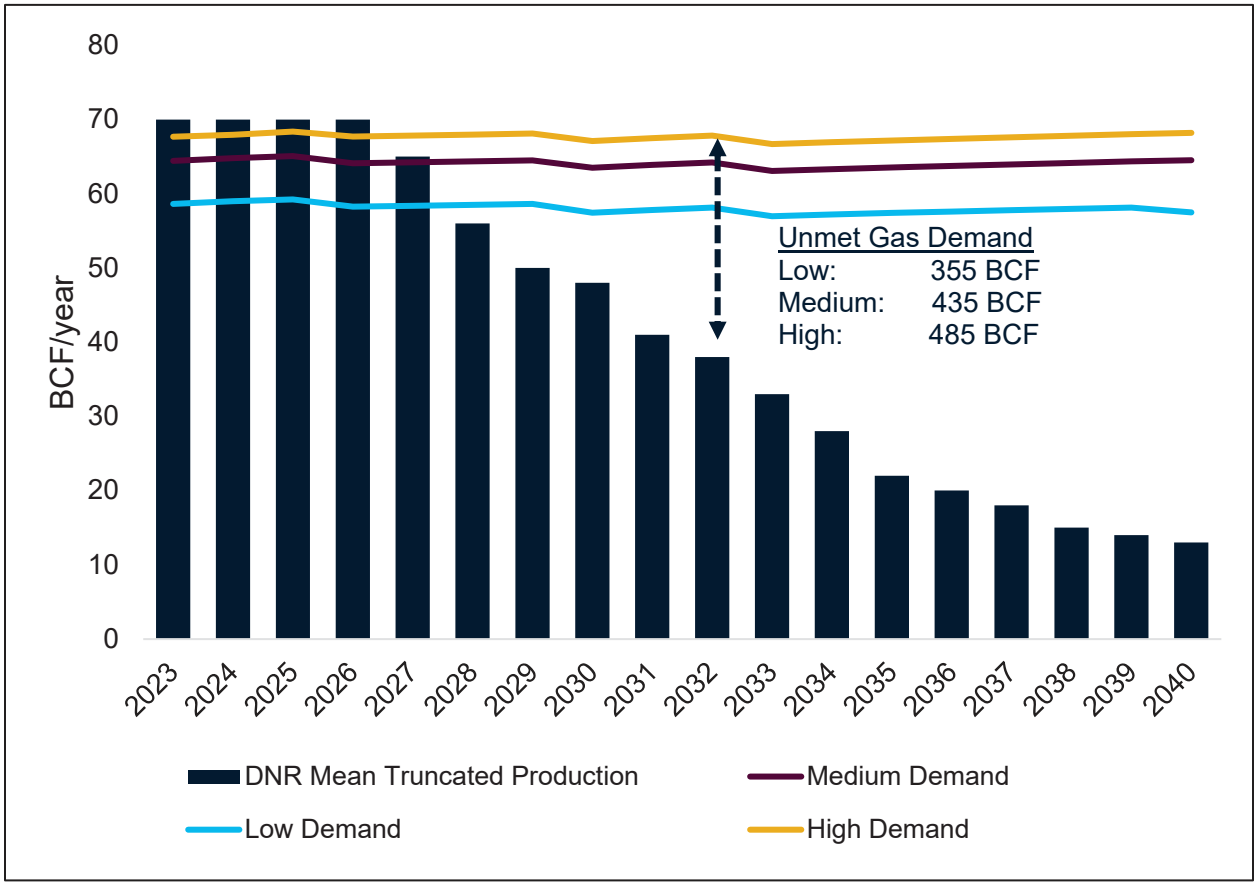
[28] This is the Base Case for the gas supply forecast that is based on ADNR's 2022 Mean Truncated Annual Gas Supply Forecast which BRG digitized with the values rounded and truncated after 2040.

Figure 6. Utilities' Contracted and Uncontracted Demand vs Cook Inlet Supply



29. The difference between these assumed supply and demand forecasts is the Unmet Gas Demand assumed by BRG for the purposes of sizing a potential natural gas replacement project and calculating the costs of supply per Mcf, as depicted in Figure 7. The assumed demand stays relatively flat for each of the High, Medium, and Low scenarios after 2040 as a planning assumption for the purpose of sizing a project that is capable of delivering up to each respective demand assumption and for calculating 20-year levelized costs of supply per Mcf.

Figure 7: ADNR's 2022 Mean Truncated Natural Gas Supply and Utilities' Demand Forecasts



30. Subject to the risks described below in Section 2.5, and in order to evaluate the project options on a comparable basis, the Working Group and BRG adopted the following range of Unmet Gas Demand as part of this assessment, presented graphically in Figure 8 and in Table 1 below.

Figure 8: Unmet Gas Demand for Low, Medium, and High Demand Scenarios

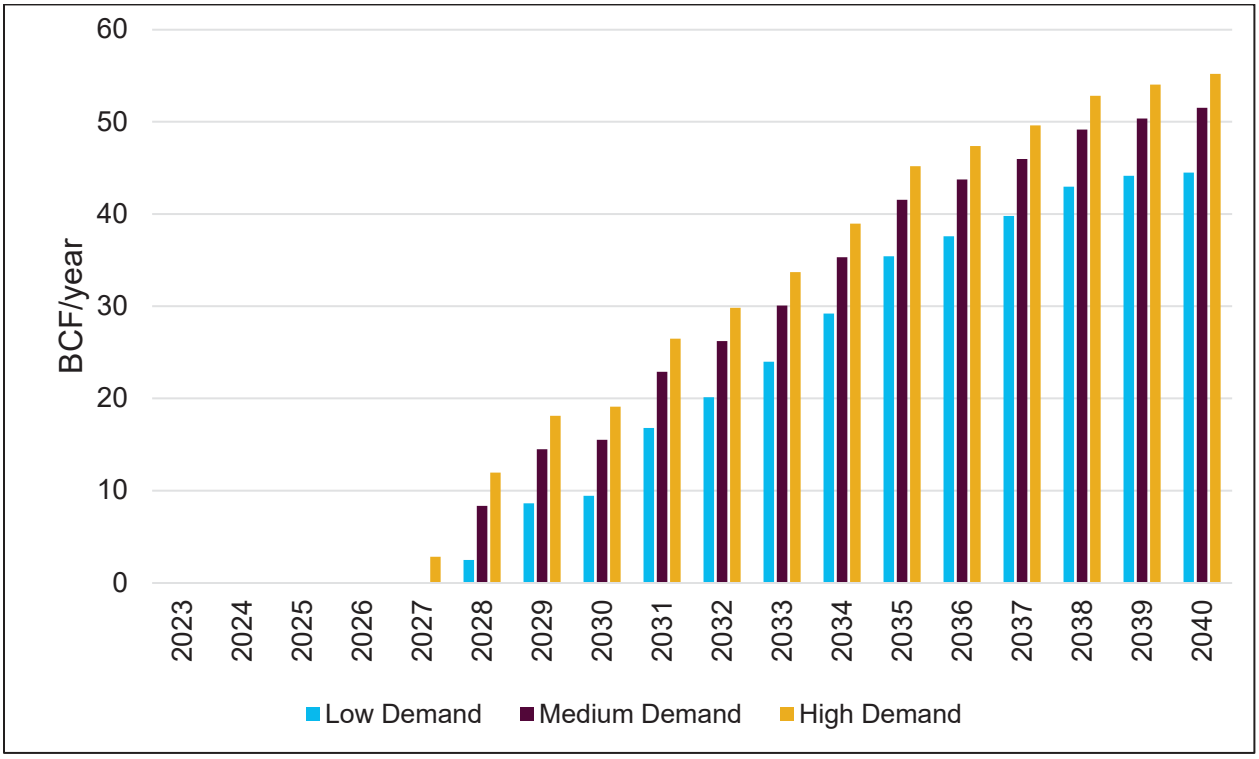


Table 1: Unmet Gas Demand by Year (BCF)

	Low Demand	Medium Demand	High Demand
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	3
2028	2	8	12
2029	9	14	18
2030	9	16	19
2031	17	23	26
2032	20	26	30
2033	24	30	34
2034	29	35	39
2035	35	42	45
2036	38	44	47

	Low Demand	Medium Demand	High Demand
2037	40	46	50
2038	43	49	53
2039	44	50	54
2040	44	52	55

2.5 Uncertainties of the Unmet Gas Demand Forecast.

31. The main uncertainties associated with Unmet Gas Demand include:

    a. The actual quantity of remaining reserves and resources that could be developed to fill a portion of the Unmet Gas Demand. Proved developed and proved undeveloped reserves, used in the ADNR study, are generally considered to be reserves of high confidence and likelihood of commerciality.[29] However, it is possible that the ultimately recoverable reserves will end up materially higher or lower than ADNR's 2022 Mean Truncated estimate resulting in smaller or larger Unmet Gas Demand over the next thirty years.

    b. The pace of Cook Inlet development needs to be sufficient to bring resources online in time to satisfy the demand in a particular year. The ADNR study assumed a drilling rate of 15 development wells based on historic development drilling activity in Cook Inlet. Lower drilling activity would likely result in higher Unmet Gas Demand and a different production profile than what was anticipated by ADNR.

    c. Anticipation of additional supply entering the Cook Inlet market could influence the rate of development activity by Cook Inlet producers (i.e. slowing down drilling programs). This could potentially result in a steeper production decline for proved reserves than currently anticipated over the entire forecast window.

    d. The Unmet Gas Demand contains projections of household, commercial, and industrial consumer gas demand in the future, and thus is inherently uncertain.

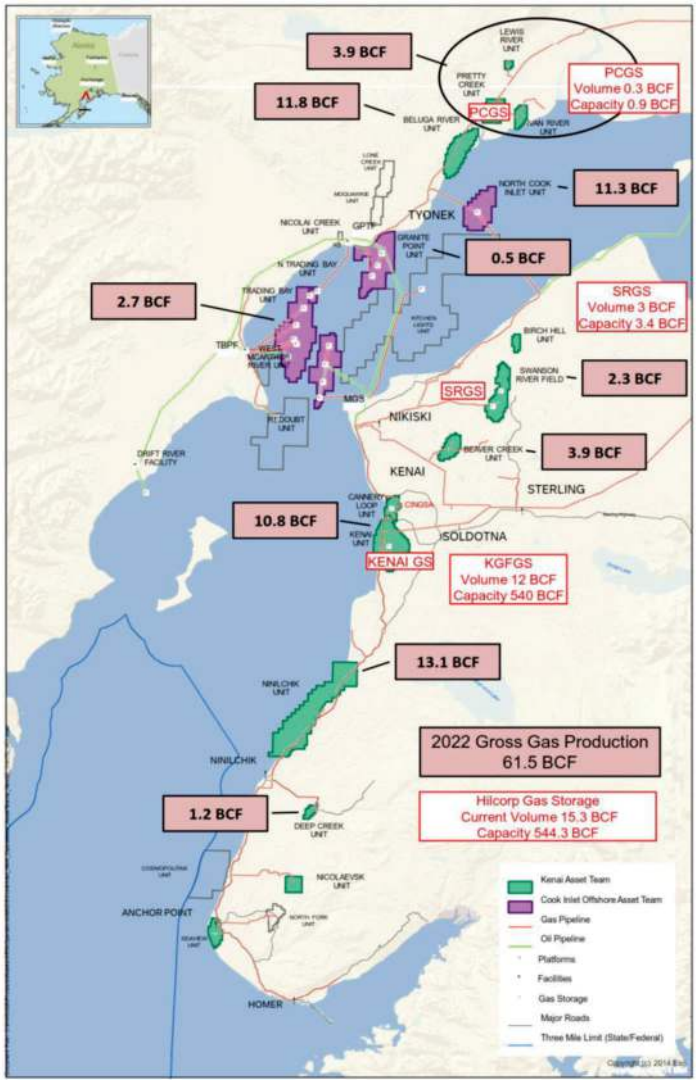
    e. Finally, the adoption rate of renewable power generation by utilities can have significant impacts on the resulting overall demand for natural gas, particularly in the later portion of the demand forecast window of 2023-2050. The upper and lower bounds of potential outcomes in utility gas demand impacted by levels of renewable power penetration are shown above in Figure 4.

32. The Cook Inlet market will have additional storage requirements to meet seasonal, daily, and hourly demand obligations. The Unmet Gas Demand presented in this study is quantified on an

[29] 2022 Cook Inlet Gas Supply Study, p. 7.

annual basis; however, adequate storage capacity and deliverability needs to be in place to ensure the demand is met on the coldest days of the year. The Cook Inlet Natural Gas Storage Alaska ("CINGSA") facility has a current design capacity of 11 BCF. Additionally, Cook Inlet gas storage capacity held by Hilcorp is depicted in Figure 9 below as part of all storage and producing fields. Hilcorp-owned storage fields are Swanson River Gas Storage ("SRGS"), Pretty Creek Gas Storage ("PCGS"), and Kenai Gas Field Gas Storage ("KGFGS").[30]

Figure 9: Hilcorp's Cook Inlet Gas Storage and Production Capacity[31]



33. The timing of when Cook Inlet will first require additional sources of gas and the Unmet Gas Demand profile have significant implications on the schedule and the cost of meeting this

[30] All storage assets are depicted as white boxes with red borders and text on the map below.

[31] Hilcorp Presentation to the House Energy Committee – Luke Saugier, Senior Vice President, Alaska, January 2023.

shortfall. Some of the long lead-time options which are described in subsequent chapters have longer development timeframes than what is necessary to meet the Unmet Gas Demand in 2027 and 2028. Furthermore, the Unmet Gas Demand increases from less than 10 BCF in the medium demand case in 2028 to over 50 BCF in 2040. Large scale developments could be underutilized in early years leading to higher overall cost of supplying the gas.

34. Continued close coordination within the Working Group and with the project management team as project options are developed further is essential to ensure the most efficient timely implementation of solutions to fill the Unmet Gas Demand during this generational energy system transition.

3 NEW SUPPLY OPTIONS CONSIDERED

35. In this chapter, we review the scope of the project options considered by BRG to fill the Unmet Gas Demand need starting at first occurrence and continuing to 2050 and beyond.

3.1 Project Options

36. The main options for supplying Unmet Gas Demand considered in this Phase 1 Assessment are shown in the table below. These options were originally proposed by BRG as the most viable based on previous studies and market knowledge and were expanded and modified in cooperation with the Working Group from original six options to ten. Other options to fill the Unmet Gas Demand were evaluated by CEA and its consultant Black and Veatch ("BV") as part of a separate study; the summary of all options evaluated is presented in Appendix C.

Table 2: Project Options Considered

#	Project Option	Short Title
1	Development of additional regional gas supply	Cook Inlet Gas
2	Alaska in-state pipeline	In-state Pipeline
3	LNG imports using existing Kenai LNG infrastructure	Kenai LNG
4	LNG imports or spot or seasonal contracted cargos via a green-field port and regas facility	Greenfield Port and Regas
5	LNG imports via a Floating Storage and Regasification Unit ("FSRU")	FSRU
6	LNG imports via barge or small vessel	Barge / Small LNG Carrier
7	North Slope natural gas supply via the Alaska LNG project	Alaska LNG
8	North Slope natural gas supply via LNG trucking or combination of trucking and rail/pipe to CI	LNG Truck and/or Rail
9	Options to supplement natural gas supply with renewable natural gas	RNG
10	Hydrogen and hydrogen-derived fuels	Hydrogen

37. While not reflected in the order of the options listed above, the project options fall into several logical groups based on the source of supply that are frequently discussed together, and may include further variations or sub-options that can be refined and developed in the next stage of implementation. They are:

    a. Cook Inlet and Southcentral gas supply (Option 1)

    b. Alaska North Slope gas supply (Options 2, 7, and 8)

    c. LNG imports (Options 3, 4, 5, and 6)

    d. Renewable and low-carbon gas (Options 9 and 10)

3.2 Summary of Option Analysis

38. BRG and Cornerstone analyzed each project option at a sufficiently detailed screening level to enable the prioritization and scoring of the options. The summary of this analysis in the table below highlights the main outcomes of the analysis:

39. **Year Available.** The year that each option is estimated to deliver first gas, assuming that a decision is made in 2023 to progress the option to the next necessary development step. For most project options, the next step is preliminary engineering design, and in some cases Front End Engineering Design ("FEED"), which precedes a Final Investment Decision ("FID").

40. **Max Annual Supply and Demand Met Through [Year].** The Unmet Gas Demand assumed in Phase I Assessment (using High Demand case from the Working Group) begins in 2027 and increases to approximately 20 BCF annually by 2030, and to approximately 55 BCF by 2040. Assuming ADNR's case of mean truncated supply, all Cook Inlet Gas is offline by 2041, necessitating the new supply project to provide up to approximately 70 BCF of gas annually. Some of the options, such as the North Slope gas pipeline projects, have plentiful capacity to meet this demand; LNG Import options are expandable beyond listed initial capacity. All other project options have unique capacity limitations that make them unsuitable for long-term supply reliance, although it is our understanding that utilities with contracts expiring in the short term are considering other short-term options, as detailed in Appendices C and D.

41. **Total CAPEX, $MM.** Total estimated capital investment made by utilities and/or third parties expressed in 2023 prices ("$2023").

42. **Direct Investment, $MM.** Estimated portion of Total CAPEX shouldered by the utilities individually or as part of a joint venture. This figure is subject to change and commercial structure negotiations. The estimate reflects the industry standard or status-quo assumption for each type of project, in $2023.

43. **Indicative Cost of Supply, $2023/Mcf.** For all options, the estimated indicative cost of supply carries an inherent uncertainty at this stage of evaluation, whether or not stated in the table below or further in this report. This is due to the early stage of development of all the options. For some options such as Cook Inlet Gas or North Slope Gas Supply, once in service, costs of supply are likely to stay relatively flat. For projects involving LNG Import, prevailing market will create ongoing volatility in the cost of supply during operations that could be smoothed out with hedging. BRG used the Working Group's high demand case to estimate the cost of supply presented below. This indicative cost of supply compares to the current contract price of Cook Inlet Gas of about $8 per Mcf. Current estimates of the cost of supply do not include potential additional underground storage.

Table 3: Summary of Project Option Analysis

							Indicative Cost of Supply, $2023/Mcf		
#	Title	Year Available	Max Annual In-State Supply, BCF	Demand Met Through	Total CAPEX, $MM	Direct Investment, $MM	Gas	Transport and Processing	TOTAL
1	Cook Inlet Gas	2027	23	2032	$1,500 - $2,000	NA	$9.3 - $25.5	Included	$9.3 - $25.5
2 (a)	In-state Pipeline (Privately owned)	2030	142	After 2050	$8,750	$10	$1.3	$26.8	$28.1
2(b), (c)	In-State Pipeline (Subsidized or State-Owned)	2030	142	After 2050	$8,750	$10	$1.3	$7.8	$9.1
3	Kenai LNG	2028	55	2040	$768	$768	$8.6	$3.4	$12.0
4	Greenfield Port and Regas	2030	55	2040	$877	$877	$8.6	$4.0	$12.6
5	FSRU (Own/Lease)	2027-2029	55	2040	$698	$607 / $201	$8.6	$3.6	$12.2
6	Barge / Small LNG Carrier	2027-2029	25	NA	$563	$158	$8.6	$13.3	$21.9
7	Alaska LNG	2030	182	After 2050	$43,000	$140	$1.3	$3.1	$4.4
8	LNG Truck and/or Rail	2026	10	2028	$796	$346	$2.5	$25.0	$32.0
9	RNG	Unknown	1	NA	NA	NA	$0.0	$25.0	$25.0
10	Hydrogen (green)	2035 or later	Unknown	NA	NA	NA	$0.0	>$32	>$32

3.2.1 Scope Descriptions

44. In this section, we describe the high-level scope of each of the project options considered in Phase I. BRG and Cornerstone provided corresponding supporting cost and high-level project schedules (to be refined in Phase II) to ENSTAR in support of the summary assumptions.

3.2.1.1 Option 1 - Cook Inlet Gas

45. The Cook Inlet Gas option is the estimated quantity of gas that may be available for future contracting in Cook Inlet above and beyond ADNR's 2022 Mean Truncated case.

46. Information on available reserves is generally confidential, and thus we relied on the previous 2018 ADNR Cook Inlet Natural Gas Availability study ("2018 ADNR Study") to estimate the quantifies of gas that may be available beyond the 2022 Cook Inlet Gas Forecast mean truncated supply, and thus also likely above the level of current contract prices. Figure 10 below from the 2018 ADNR study[32] shows total gas supply available at a 15% hurdle rate assumption, including proved reserves. The amount of gas incremental to the rough equivalent of ADNR's 2022 Mean Truncated case is only the portion of the supply above the $8/Mcf price threshold in Figure 10, i.e. around 220 Bcf at the 50th percentile measurement.

Figure 10: 2018 ADNR Cook Inlet Gas Availability Curve

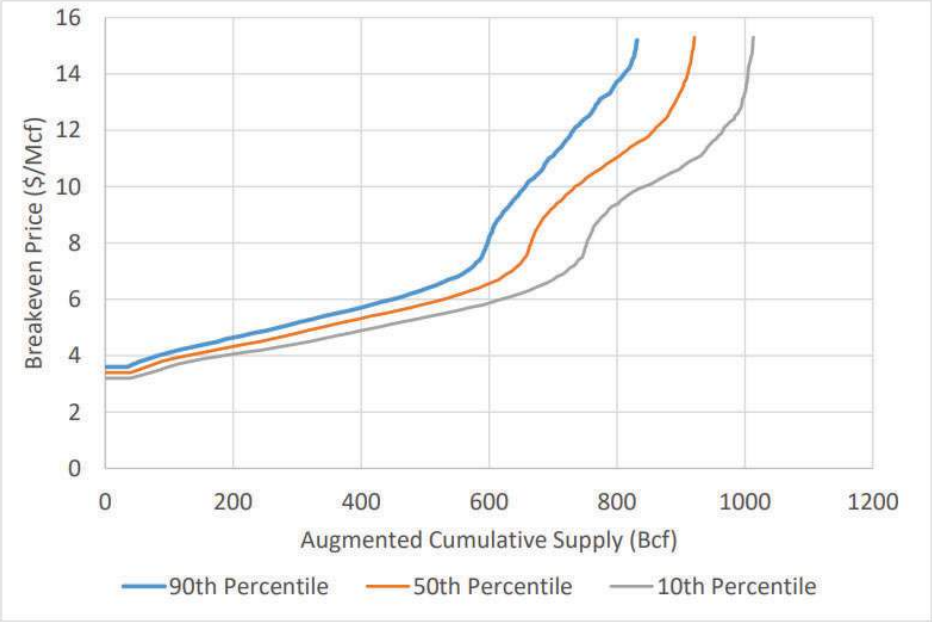


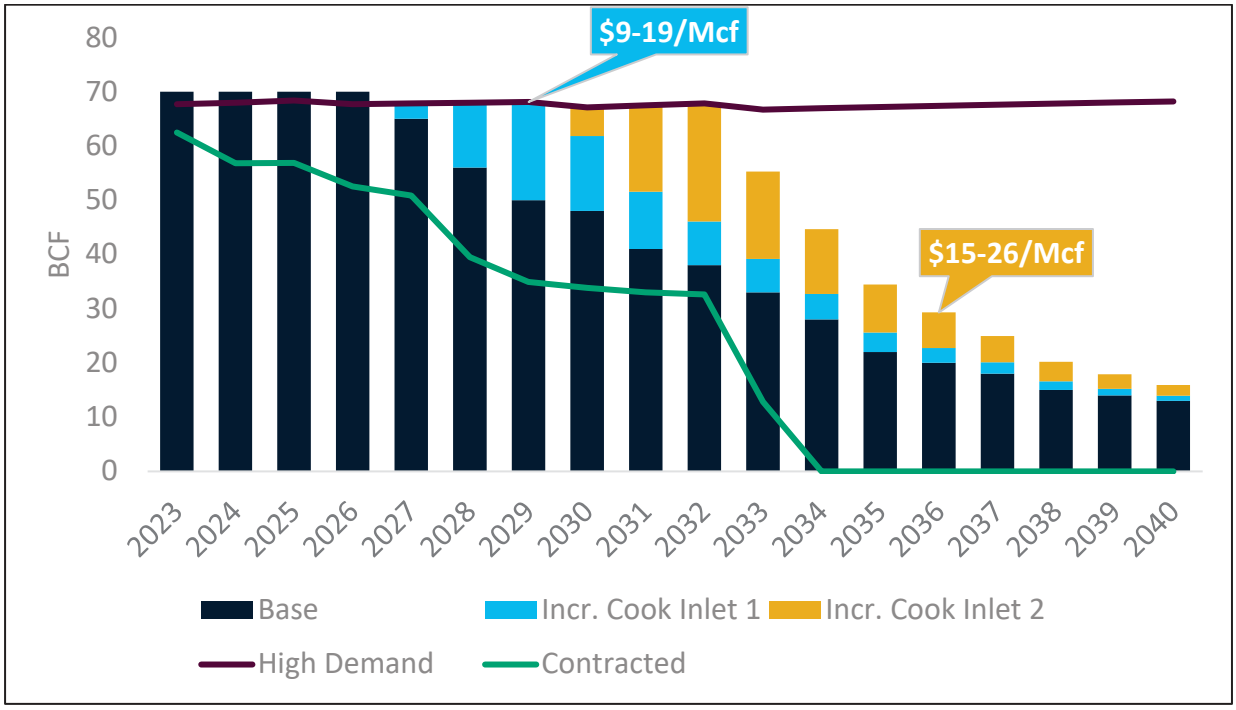
Figure A-1. Cumulative supply from augmented production sources (15% real hurdle rate)

[32] 2018 ADNR Study, p. 34.

47. Due to the vintage of the 2018 ADNR study and the intervening factors such as the stability of remaining proved reserves and prices between the two ADNR assessments, as well as the recent inflationary market signals, we perceive and acknowledge a significant amount of uncertainty in both the quantity of additional gas available, and its potential price. However, after review of the available public information and a consultation with ADNR's technical staff, the estimate of 220 BCF available[33] additional reserves beyond ADNR's 2022 Mean Truncated forecast appears to be a reasonable working assumption using public data.

48. The chart below represents the estimated potential of incremental regional gas supply beyond the ADNR's 2022 Mean Truncated case.

Figure 11: Incremental Regional Gas Supply Estimate[34]



49. The gas supply estimate depicted in Figure 11 consists of reserves and resources with different degrees of commercial and technical confidence. Approximately 466 BCF of already contracted capacity is included as part of the Base profile that represents ADNR's Mean Truncated case.[35] Approximately 287 BCF of uncontracted capacity would also fall within the ADNR's 2022 Mean Truncated case.[36]

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[33] Please see Appendix B.2.

[34] Please see Appendix B.2 for production profile and price assumption methodology.

[35] Sum of Base production below the green line.

[36] Sum of Base production above the green line; equal to Sum of Uncontracted Available Cook Inlet from Figure 6.

50. Approximately 188 BCF of 220 BCF incremental production might be developed by 2040.[37] Depending on location, investments by ENSTAR and Harvest Midstream in new pipeline connections may be necessary.

51. This additional supply could come online in Cook Inlet to fill in Unmet Gas Demand beyond proved reserves, starting around 2027. These reserves could be comprised of a mix of onshore, near-shore developments, including installation of new platforms and longer economic life of existing fields. Regional gas supply is provided in the form of contracted agreements where the utility customers incur minimal direct investment. However, the new capital needed to invest in the development of these new reserves is difficult to secure for Cook Inlet operators for various reasons. Based on the interviews conducted by BRG and on public information presented by certain operators during the 2023 Alaska State Legislative session, these reasons include the high cost of securing an offshore or even a new land rig for only a few prospects, overall high operating costs and low availability of service providers, difficulty securing capital for Alaska oil and gas activities based on climate change concerns as well as past fiscal instability, and the overall concentration of the Alaska market under a large owner and operator in Hilcorp. The relatively small and closed gas market generally leads to the dilemma of operators being unmotivated to take substantial risks without a gas contract, utilities unwilling to sign firm gas contracts for unproven reserves, and both parties finding it difficult to land on mutually agreeable prices for new developments with significant cost uncertainty. Recent federal offshore lease sales attracted no new interested producers to Cook Inlet,[38] accentuating the challenge of securing new capital for the region.

52. Working Group utility customers continue to be best positioned to gauge the availability and pricing of incremental Cook Inlet gas supply, as they have access to confidential producer information that is not available to this Phase I Assessment. However, based on the review of public information and in consultation with the Working Group, it is our opinion that it would be risky and unadvisable under current market conditions to count on sufficient Cook Inlet or other regional gas supply to fill the Unmet Gas Demand beyond 2026 without developing alternative supplies.

3.2.1.2 Option 2 - In-State Pipeline

53. The In-State Pipeline option is a variant of the Alaskan Gasline Development Corporation's (AGDC) proposed Alaska Standalone Pipeline (ASAP). The pipeline would run 733 miles to supply natural gas from Prudhoe Bay to ENSTAR's system in Anchorage. AGDC has previously sized this pipeline with a 36-inch diameter to meet a demand of 500 MMcfd to Anchorage and the

[37] See Appendix B.2 for production profile and price assumption methodology.

[38] Anchorage Daily News, *Hotly debated federal Cook Inlet oil and gas lease sale draws only 1 bid*, Dec. 30, 2022, https://www.adn.com/business-economy/energy/2022/12/30/hotly-debated-federal-cook-inlet-oil-and-gas-lease-sale-draws-only-1-bid/.

surrounding utilities together with an industrial export customer. The design has a ~30 mile, lateral to supply the Fairbanks region.[39]

54. For the purposes of Phase I Assessment, BRG and its sub-contractor, Cornerstone Energy Services, Inc., have assumed that the intent of this In-State Pipeline is to meet *only* local utility and refinery natural gas needs with no initial intent to provide exporting capabilities like that of the Alaska LNG project. Operating under that assumption, BRG has determined that the current 36-inch diameter ASAP pipeline is over-designed and could be optimized to better fit the needs of the state of Alaska. Assumptions made in a preliminary sizing of the ASAP line are outlined in the following section.

Mainline Size

55. The Gas Supply model developed by ENSTAR, in conjunction with the Working Group and Marathon, indicates projected peak-day demand of around 404 MMcfd.

Table 4: Peak Day Demand for Alaska Consumers (MMcfd)[40]

Year	ENSTAR	CEA	MEA	HEA	GVEA	Tesoro	IGU	Total
2023	290.9	43.9	24.4	14.5	2.7	12.1	6.0	**394.5**
2024	290.9	43.7	24.5	13.4	2.7	12.1	6.9	**394.2**
2025	290.9	43.5	24.6	13.9	6.8	12.1	8.0	**399.8**
2026	290.9	40.6	25.0	13.4	6.8	12.1	10.0	**398.8**
2027	290.9	40.3	25.2	13.4	6.8	12.1	11.8	**400.5**
2028	290.9	40.0	25.2	13.4	6.8	12.1	13.6	**402.0**
2029	290.9	39.7	25.4	13.4	6.8	12.1	15.1	**403.4**
2030	290.9	37.5	25.0	14.6	6.8	12.1	16.4	**403.3**
2031	290.9	37.5	25.1	14.6	6.8	12.1	17.4	**404.4**
2032	290.9	37.6	25.3	14.6	6.8	12.1	18.2	**405.5**
2033	290.9	33.5	25.4	14.6	6.8	12.1	18.7	**402.0**
2034	290.9	33.5	25.6	14.6	6.8	12.1	19.0	**402.5**
2035	290.9	33.5	25.8	14.6	6.8	12.1	19.2	**402.9**
2036	290.9	33.5	26.0	14.6	6.8	12.1	19.3	**403.2**
2037	290.9	33.5	26.1	14.6	6.8	12.1	19.3	**403.3**
2038	291.0	33.5	26.2	14.6	6.8	12.1	19.3	**403.5**
2039	291.0	33.5	26.6	14.6	6.8	12.1	19.3	**403.9**
2040	291.0	33.5	26.9	14.6	6.8	12.1	19.3	**404.2**

[39] Davis, Carolyn, Natural Gas Intel, *Alaska Gasline Secures Final EIS for Pipeline Project*, June 22, 2018, https://www.naturalgasintel.com/alaska-gasline-secures-final-eis-for-pipeline-project/.

[40] Working Group input, November 2022.

56. Sized at 36 inches, the 733 miles ASAP pipeline can free-flow 390 MMcfd from Prudhoe Bay to Anchorage while experiencing a pressure drop of < 300 psig. A 36-inch pipeline can handle nearly 100% of Alaska natural gas needs on a peak demand day from first day of operation, and requires no compression or storage to do so. This design is the basis for the project cost estimate used in this report for the In-State Pipeline option. BRG adapted the estimate from the 2014 AGDC FEED results by removing the gas processing plant on the North slope (which also included compression), adding a pipeline from Pt Thomson to Prudhoe Bay, and adjusting for inflation up to $2023.

57. A more economical solution would be to utilize a smaller diameter pipeline and add compression along the mainline as the gas demand increases. Cornerstone has performed some preliminary modeling using GasCalc 5.0[41] that indicates that a 24-inch steel pipeline could accomplish this goal. The 24-inch pipeline provides enough capacity to free-flow gas from Prudhoe Bay to Anchorage at 105 MMcfd, thus supplying average annual Unmet Gas Demand until at least 2034.

Compression

58. Adding compression at key points in the line would provide capacity for the 24-inch ASAP pipeline to flow 390 MMcfd to Anchorage in addition to 60 MMcfd to Fairbanks.[42] This volume, according to the gas supply model, would eliminate the need for any Cook Inlet supply, and thus would likely be subject to a phase-in period of time as Cook Inlet declines.

Infrastructure Requirements

59. The infrastructure requirements and supply sources and strategy are as follows:

- Approx. 800 miles 24-inch steel pipeline from Pt Thomson to Anchorage Beluga Pipeline interconnect
- 30 miles 12-inch steel pipeline to Fairbanks
- ~38 mainline valve sites (for both mainline and Fairbanks lateral)
- Up to 7 mainline compressor stations, as needed

Supply Sources and Strategy

60. Gas to the pipeline would be supplied via a gas purchase agreement with Pt. Thomson gas owners, including potentially State of Alaska as a Royalty-In-Kind gas owner. Placing the pipeline origin at Pt. Thomson, rather than Prudhoe Bay, allows deliver of utility-quality gas with minimal conditioning requirements, [43] thus avoiding a multi-billion expenditure for this In-State Pipeline project.

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[41] Copyright 1993-2023 B3PE LLC Revision: 6.1.35 - March 29,2023.

[42] These volumes represent the scenario modeled to meet peak day demand; however, capacity could be increased further to provide 500 MMcfd and include other industrial customers.

[43] AGDC Board Meeting, February 4, 2021, President's Report, p. 32, available at https://agdc.us/wp-content/uploads/2021/02/02042021_Board-Meeting-Presidents-Report.pdf

Financing and Ownership

61. Even the smaller 24-inch pipeline dedicated solely to filling the Unmet Gas Demand for the Working Group is oversized and expensive compared to other feasible options, such as LNG imports. Current natural gas demand in Alaska simply does not support a pipeline project of about 800 mi in length, if compared strictly on cost to the LNG import option. However, the Working Group recognizes that such a project may still have significant generational benefits due to the ability of the In-State Pipeline project to:

- Supply natural gas to areas of the state currently relying on coal, biomass, or diesel for power generation and heating, and thus experiencing the negative effects of pollution, intense carbon emitting generation, high and volatile costs, or both;
- Generate significant in-state construction and operations jobs;
- Create the ability to supply natural gas to new industrial customers along and nearby the pipeline route, such as mine projects;
- Generate gas royalty revenue to the State of Alaska;
- Aid in extending the life of the North Slope oil and gas production base by creating a new revenue stream in large-scale gas sales; and
- Provide a stable and reliable energy source for many years that will benefit economic development of the region.

62. In recognition of these unique characteristics of an In-State Pipeline option, ENSTAR requested that BRG evaluate alternative ownership and financing structures of this pipeline option. BRG developed three example ownership structures:

a. **Option 2(a).** Traditionally financed, privately owned pipeline.

b. **Option 2(b).** Public-Private Partnership structure, with a private pipeline owner and operator, and a percentage of the project construction costs shouldered by a government sponsor. This is effectively a subsidized structure that can be arranged so that upside economic gains go to the public partner. The level of public investment can vary; BRG modeled an 80% "subsidy" investment.

c. **Option 2(c).** Fully state-owned structure that substitutes a 2% annual return on investment back to the state for State of Alaska and does not carry Ad Valorem tax or a traditional return structure.

3.2.1.3 Option 3 - Kenai LNG

63. Kenai LNG in the context of this study, refers to the concept of retrofitting the Kenai LNG export facility located in Nikiski (owned by Marathon) to be utilized as an LNG import and regasification facility for a broader group of customers than the Kenai refinery as currently proposed by

Marathon.[44] The project would utilize as much of the existing infrastructure as possible, including the pier and the storage tanks, at project initiation. LNG would be imported via an LNG tanker,[45] offloaded, stored in the existing storage tanks, and then vaporized and injected into the Kenai Beluga Pipeline system ("KBPL").

Infrastructure Requirements

64. When the Kenai LNG facility was in active operation, its storage capacity consisted of three tanks with total capacity around 2 BCF. The tanks would be modified as required to fit the new facility arrangement. Since the existing tanks are now more than 50 years old, we suggest that the long-term solution is to site a new storage tank on the facility to replace these aging vessels, with a target date of 2032.

65. Pier upgrades are not expected to be required, however top-side mechanical work on the liquid and vapor lines would be required.

66. New vaporizers (capable of 150 MMcfd sendout capacity) would be installed in the Kenai facility to meet daily send out demands. The design of the plant would allow vaporization scalability. Initial vaporization sendout rates would be discussed and finalized with the Working Group during sequential design phases such that capital deployment is phased responsibly.

67. A custody transfer meter station equipped with gas measurement, and any necessary upgrades to the pipeline connecting the Kenai LNG terminal to KBPL.

68. We note that the infrastructure assumptions are not taking into account the maximum extent of potential investments necessary to bring the facilities to current FERC standards for long-term use, should that be required. These assumptions need to be further examined and developed with participation of the facility owner.

Supply Source and Contracting Strategy

69. Since the current facility owner has filed and gained FERC approval to import LNG for its own gas usage, the contracting strategy for this project has become more complicated than in years past when this project was considered. BRG sees four methods of executing this project:

    a. Joint venture with Marathon for joint investment and LNG sourcing.

    b. Contract with Marathon to provide dry gas supply to utilities.

    c. Purchase the Kenai LNG facility from Marathon with agreement to supply the volumes the Kenai refinery requires.

[44] FERC Docket No. CP19-118-000.

[45] Shipping cost estimates for this and other LNG import options assume average shipping distance equivalent to the distance between Nikiski and Vancouver, and include either seasonal or year-round (depending on annual demand) charter cost assumptions for the requisite number of vessels (up to four ~140,000 cubic meter vessels), associated fuel and incidental expenses, and port fees.

d. Limited use of the facility with floating storage, as suggested by an independent study conducted by CEA and BV, thus only contracting with Marathon for the use of the dock and sufficient land area for regasification.

3.2.1.4 Option 4 -Greenfield Port and Regas

70. A greenfield LNG import terminal is another possible solution to meet the gas needs for the region. This import terminal would contain a pier capable of docking a 3.5-4 BCF LNG tanker which would offload LNG year-round. LNG would be offloaded, stored, and then vaporized when system demand calls for it. Since the Alaska LNG project has been able to site a pier and above ground storage for export purposes, the proposed site for this greenfield import terminal is the same site as that of the Alaska LNG project until further siting search and analysis is performed.

Infrastructure Requirements

71. The proposed pier would be of similar size of the one proposed by the Alaska LNG project, designed to handle LNG cargo ships up to 180,000 m^3 in capacity. The final vessel size will be determined in later phases as scope is narrowed. The chosen vessel will be designed to provide volumes on a year-round basis to the port in the long term. Seasonal deliveries may be appropriate in the near term when shortages between Cook Inlet production and utility demands are not significant.

72. The terminal itself would require approximately 60 acres of land suitable to site a 3.5 BCF storage tank (size to be finalized in further siting and design efforts) along with the necessary spill containment and vaporization equipment.

73. Vaporization capacity for this facility will have capacity finalized in later phases of design efforts but is proposed to scale up to 150 MMcfd at full build out, as currently estimated.

74. A custody transfer meter station equipped with gas measurement, as well as an interconnecting pipeline will be required to deliver volumes from the LNG import terminal to KBPL.

Supply Source and Contracting Strategy

75. The freedom to design the new pier and a new storage tank provides flexibility and opens up additional market possibilities based on acceptable LNG cargo vessel sizes. There are developing projects in British Columbia and Mexico which could provide the contracted LNG volumes for this project. Pricing structure on a $/Mcf basis assumes multi-year contracts using a North American gas index, pipeline toll, liquefaction toll, and marketing premiums.

3.2.1.5 Option 5 – FSRU

76. A Floating Storage and Regasification Unit (FSRU) is a viable LNG import solution to meet gas needs for the region. This option would require the use of a new pier, or an existing dock ("Agrium Pier," currently owned by Nutrien, or other) with modifications to support the year-round docking of large LNG vessels, 140,000 m^3 or larger in size. This solution provides a scalable, but not totally permanent asset to be utilized to supply gas to the region.

Infrastructure Requirements

77. A single large FSRU vessel would be required (3.5 – 4 BCF) for the long-term needs of the region. The vessel would be designed and constructed to be moored permanently at a selected pier that could handle the docking of such a vessel. Onboard the vessel, it is proposed there be enough room to provide a scalable vaporizer arrangement, allowing the flexibility to add necessary equipment to meet increased sendout demands in later years.

78. The pier that is selected for this option must be designed to handle a moored vessel year-round, as even the most efficient seasonal operation can only deliver up to about 37 BCF per year.[46] Seasonal deliveries by an existing FSRU vessel in the market could meet demands in the near term, but would not be a permanent solution as Cook Inlet production continues to decline. Agrium Pier would require substantial work to upgrade the structure to not only handle larger vessels, but reach deeper water at lower risk of freezing. As a result, later stages of analysis should consider siting a new pier for this solution.

79. A high-pressure gas pipeline is required to transport gas from the FSRU vessel, across the pier, and to a custody transfer meter station equipped with gas measurement. Once measured for volume and heat content, an interconnect to KBPL may be required to deliver the volumes to CINGSA or other gas storage. The length of this interconnecting pipeline will be a factor in siting a potential new pier for an FSRU solution.

Supply Source and Contracting Strategy

80. Pending selected or newly installed pier, existing market vessels could be contracted in the near-term and have the potential to be utilized to provide seasonal deliveries, and leave port during the winter months. The new build of an FSRU vessel can be optimized for available supply source and demand profile, and provide the capability to be docked 365-days a year as the demand for LNG volumes grows. British Columbia and Mexico are developing projects that could supply contracted volumes, in addition to spot market volumes. Pricing for this LNG would be based on the NA gas index, pipeline toll, liquefaction toll, and a marketing premium.

3.2.1.6 Option 6 -Barge/Small LNG Carrier

81. Small scale LNG has gained popularity in recent years with companies like Norgas out of Norway[47] supplying single or fleet solutions for LNG transportation and regas needs. A small-scale FSRU would be moored at the end of a pier, take deliveries from vessels smaller than typical LNG carriers ("LNGC"), vaporize the gas on-board, and inject it into a high-pressure gas pipeline where it is transported to a meter station for odorization, gas quality and volume measurement, and then injected into the ENSTAR system. This LNG import option would have sendout scalability as sendout demand grows, but due to smaller on-vessel liquid storage, would also involve increasing the frequency of LNG deliveries to the vessel as the LNG demand grows to cover Cook Inlet shortfalls.

[46] With an LNGC of 145,000 cubic meters in size, delivering and off-loading to a moored FSRU with re-gas capacity of 300 MMcfd, a seasonal operation from Vancouver may supply the Unmet Gas Demand through 2034.

[47] https://norgascarriers.com/

Infrastructure Requirements

82. A single small scale FSRU vessel would be needed to be moored at the selected site to provide the storage and regas. LNG deliveries would be taken onto the FSRU, stored, and vaporized as needed. These deliveries would quickly scale up as the LNG demand is increased to counteract the Cook Inlet decline in production.

83. A pier, Agrium Pier with modifications or otherwise, will be required to permanently moor the small-scale FSRU vessel. Because these vessels are not as large as a typical LNGC, there is more flexibility in selecting, or constructing, a pier to meet this project's needs.

84. A high-pressure gas pipeline is required to transport gas from the FSRU vessel, across the pier, and to a custody transfer meter station equipped with gas measurement. Once measured for volume and heat content, an interconnect to KBPL may be required to deliver the volumes to CINGSA or other gas storage. The length of this interconnecting pipeline will be a factor in siting a potential new pier for an FSRU solution.

Supply Source and Contracting Strategy

85. British Columbia (Kitimat or Tilbury) are the likely source of this LNG supply and would be long-term contracts due to the limited number of suppliers. Spot market options are likely limited, and would involve re-selling LNG delivered to Asia, or shipping long distances such as from an FSRU on the coast of Peru.

3.2.1.7 Option 7 -Alaska LNG

86. AGDC is advancing the 807 miles, 42-inch pipeline project from the North Slope to Nikiski that is designed to transport about 3.5 BCF/D of natural gas, and export LNG from a new terminal sized at 20 Mtpa (together, the "Alaska LNG" project). This strategic project has reserved more than sufficient capacity for local gas demand and has included local offtakes in its design basis, however there is no lateral pipeline connecting the mainline to Fairbanks in its scope.[48] Therefore, BRG has included a provision for this pipeline in the direct investment portion of the estimate (see Table 3).

87. Alaska LNG has been approved by FERC under Section 3 of the Natural Gas Act as an integrated gas processing, pipeline, and LNG export project. The Biden administration recently re-affirmed its LNG export permit to non-Free Trade Agreement nations.[49] While in possession of significant government and local support, this large project nevertheless faces the challenge of marshalling a ~$43 billion investment and debt package that will require long-term firm LNG supply agreements to secure. Currently in 2023, AGDC is working to secure an initial at-risk FEED

[48] Alaska LNG project map and description, available at https://alaska-lng.com/

[49] Casey, Jessica, LNG Industry. *Biden Administration authorizes LNG exports from Alaska LNG project*, April 17, 2023, available at https://www.lngindustry.com/liquid-natural-gas/17042023/biden-administration-authorises-lng-exports-from-alaska-lng-project/.

investment of around $150 million for a FEED study.[50] Despite being the lowest-cost alternative if sanctioned at full capacity, Alaska LNG Alaska LNG does not currently have a target FID date and requires multiple years to construct after FID, requiring progress on other alternatives from the Working Group.

3.2.1.8 Option 8 - LNG Truck and/or Rail

88. As another source of LNG, Trucking and Rail transportation from the North Slope was analyzed. Due the lack of established technology, rules, and regulations, in addition to the added layer of logistical barriers, LNG transport by rail was disregarded early on in the evaluation process, and this option became purely trucking from the North Slope. LNG would be produced in Deadhorse, and then trucked by teams of drivers down to the Matanuska-Susitna Valley area where it would be unloaded, stored, and vaporized as demand required.

Infrastructure Requirements

89. Harvest Midstream, an LNG supplier on the North Slope, could expand its planned facility from 150,000 gal/day to 450,000 gal/day by adding two (2) additional trains of LNG production.[51] This production could meet ~13 BCF/yr of total system demand, meaning there would need to be additional sources of gas to meet volume demands very quickly after 2029. As a result, trucking is best looked at as a bridge or partial solution and not a long-term solution to address the declining Cook Inlet production. Understanding this, a virtual pipeline of LNG between the North Slope would involve the following major investments:

- Expanding Harvest Midstream's LNG production facility from initial 150,000 gal/day to 450,000 gal/day.[52]
- A fleet of LNG trucks/trailers to scale with trucking demand, ultimately requiring between 28 and 35 truck deliveries (depending on size of the trailer) on a daily basis to keep up with 450,000 gal/day production.[53]
- A service garage near Fairbanks to act as both a depot to store and repair trucks, as well as a location to switch truck drivers heading north and south.

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[50] FY2024 Alaska Governor-Amended Operating Budget Summary, p. 2; at https://omb.alaska.gov/ombfiles/24_budget/PDFs/Corrected_FY2024_Operating_Governor_Amend_Bill_Summary_Spreadsheet_4-18-2023.pdf

[51] Interior Gas Utility, IGU Special Board Meeting Packet, January 17, 2023, pp. 14.19, available at https://www.interiorgas.com/wpdm-package/1-17-2023-igu-special-board-meeting-packet/

[52] Further expansion may be possible but has not been publicly scoped out by the supplier.

[53] While there is sufficient gas on the North Slope to provide supply beyond the 450,000 gal/day, the logistics of having more than this number of trucks on the Dalton and Parks highways appear quite challenging. The operational risks and potential for supply interruptions also must be considered. BRG used 450,000 gal/day as the maximum potential due to these considerations, as well as the cost and contracting information available for this specific option from IGU and Harvest Midstream.

- An LNG Trucking Depot with a 1 BCF storage tank, vaporizers, and gas measurement. Storage tank size and vaporization system sizing is to be finalized in later stages of design to accommodate ENSTAR sendout needs and functional capacity of the operation.

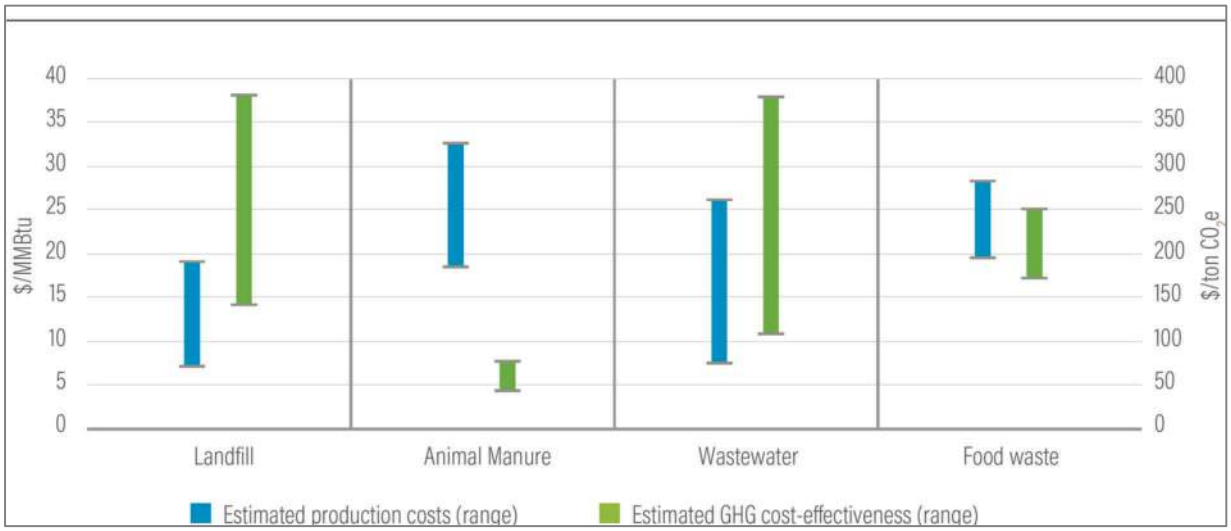
Supply Source and Contracting Strategy

90. Due to the nature of this project requiring extensive investments both on the liquefaction side to produce the LNG, and the LNG trucking depot in Anchorage to store and regas, there would be long-term ~20-year volume commitments on the part of the utilities. Contracts for the volumes would be based on the cost of gas, cost of liquefaction, cost of transportation, and the capital costs associated with the necessary infrastructure investments.

3.2.1.9 Option 9 - RNG

91. Renewable natural gas can be produced by upgrading biogas generated from landfills, wastewater sludge, animal manure, municipal solid waste and other sources. Cost of producing natural gas can vary significantly by source and project as depicted below in Figure 12.[54]

Figure 12: Estimated Project Costs and Greenhouse Gas Emissions



92. BRG identified Landfill and Wastewater biogas as the main potential sources of RNG that could be delivered to the Alaska utilities. The largest landfill[55] in Alaska is the Anchorage Regional Landfill which already collects 4 MMcfd[56] of non-upgraded natural gas, about 2.3 MMcfd[57] flows from Anchorage Landfill Gas to Energy Project that supplies power to Joint Base Elmendorf-

[54] World Resources Institute, *Renewable Natural Gas as a Climate Strategy: Guidance for State Policymakers,* December 17, 2020, https://www.wri.org/research/renewable-natural-gas-climate-strategy-guidance-state-policymakers.

[55] US EPA, *Project and Landfill Data by State- Alaska (March 2023),* https://www.epa.gov/lmop/project-and-landfill-data-state.

[56] US EPA, *Project and Landfill Data by State- Alaska (March 2023),* https://www.epa.gov/lmop/project-and-landfill-data-state.

[57] US EPA, *Project and Landfill Data by State- Alaska (March 2023),* https://www.epa.gov/lmop/project-and-landfill-data-state.

Richardson ("JBER"),[58] and about 2 MMcfd is flared. If the flared gas could be re-used, or if an additional resource in a comparable amount is available at Anchorage Regional Landfill, 2 MMcfd could support production and upgrade to 0.3 BCF/year of pipeline quality natural gas, assuming 50% of the gas is methane and the processing facility runs with 90% efficiency. Palmer Central Landfill currently collects around 0.174 MMcfd[59] of biogas and should also be considered as an additional source but for much smaller quantities.

93. John M. Asplund Wastewater Treatment facility is Alaska's largest wastewater treatment plant with plant capacity of up to 58 million of gallons per day ("MMgal/d"). The process of extracting methane from wastewater requires construction of an anaerobic digestor.[60] Assuming approximately 60 gallons of wastewater per cubic foot of natural gas,[61] John M. Asplund Wastewater Treatment facility could produce up to 0.35 BCF/year of methane. The majority of the remaining treatment facilities in the region treat less than 2.5 MMgal/d of wastewater, making the economics of producing RNG from such facilities unfavorable.

94. It is likely that up to around 1 BCF/year of renewable natural gas could be produced in Alaska from various across Southcentral Alaska and the Railbelt. There is significant heterogeneity in the cost of supply across different projects and sources of renewable natural gas. Further detailed assessment is needed to quantify the cost of producing natural gas from specific source in Alaska. The higher end of the cost ranges provided in Figure 12 for wastewater and landfill derived RNG development are likely in Alaska due to the length of supply chain and generally higher construction costs.

3.2.1.10 Hydrogen

95. Hydrogen can be produced from multiple sources including natural gas, renewable power sources, nuclear power, coal, as well as biomass. Hydrogen produced from renewable power sources is generally referred to as green hydrogen. BRG assessed potential for wind based green hydrogen development in Cook Inlet. BRG did not estimate the cost of supplying hydrogen from natural gas because natural gas can be used directly in the ENSTAR natural gas system. Furthermore, production of natural gas-based hydrogen would require sufficient and inexpensive gas supply which is unlikely to be available in Cook Inlet unless a viable alternative to Cook Inlet sourced gas is found.

96. Cost of power is the main cost input associated with green hydrogen production. On October 10, 2011 RCA approved a 25-year PPA between Chugach Electric Association and CIRI to supply power from Fire Island Wind facility located in Cook Inlet. Under the supply agreement Chugach

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[58] Municipality of Anchorage, *Anchorage Landfill Gas to Energy Project Details,* https://www.muni.org/departments/sws/pages/anchlandfillgastoenergyprj.aspx.

[59] US EPA, *Project and Landfill Data by State- Alaska (March 2023),* https://www.epa.gov/lmop/project-and-landfill-data-state.

[60] Vutai, V., Cissy Ma, and M. Lu, The Role of Anaerobic Digestion in Wastewater Management, EM Magazine, Air and Waste Management Association, Pittsburgh, PA., 2016.

[61] Lacey, Pamela A., *Developments in Renewable Natural Gas: The Promise of RNG*, American Gas Association, October 26, 2017, p. 8, available at https://www.epa.gov/sites/default/files/2017-11/documents/27.lacey_2017aiw.pdf.

electric pays a fixed price of $97 per megawatt hour.[62] In 2023 electric power rates for large customers ranged between $90 to $137 per megawatt.[63] However, future clean power rates for generation of hydrogen are expected to fall, as the costs of technology for both new solar and wind power generation have decreased globally by 88% and 68% respectively in the past decade.[64] In Alaska, this is evidenced by a more recent small (6 MW) solar power contract held by MEA at $67/MWh,[65] although the project is not anywhere near the size necessary for utility-scale hydrogen generation.

97. Other major cost items include capital expenditures to acquire an electrolyzer facility, cost of acquiring or leasing land parcel of sufficient size to accommodate electrolyzer infrastructure, access to and processing costs of fresh water required for hydrogen generation, operating and maintenance costs as well as onsite and offsite costs that include hydrogen distribution and storage costs, and potential upgrades to the ENSTAR system to accommodate hydrogen development.

98. The Inflation Reduction Act of 2022 introduced tax credits for qualified clean hydrogen facilities.[66] Facilities that begin construction before January 1, 2033, produce less than 0.45 kilograms of CO2 equivalent lifecycle emissions, and meet prevailing wage and apprenticeship requirements can qualify for a tax credit of up to $3/kg for a period of 10 years. The tax credit is viewed as a significant subsidy by industry participants.[67]

99. To assess the viability of hydrogen development in Southcentral Alaska, BRG assumed that the tax credit, if efficiently monetized, could be sufficient to cover both capital and operating costs of an electrolyzer facility and all associated infrastructure costs, other than the cost of power. Assuming power price in the range of $70-80/MW, a high efficiency electrolyzer facility that requires 53 kWh[68] per kg of hydrogen, and a lower heating value of 51,585 btu per pound of hydrogen the cost of delivered hydrogen would exceed $32/MMBtu.

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[62] Chugach Electric, *Fire Island Wind- Power Purchase Agreement*, https://www.chugachelectric.com/about-us/regulatory-affairs/fire-island-wind.

[63] Chugach Electric, *South District Rate Information*, April 1, 2023, https://www.chugachelectric.com/member-services/billing-payments/rate-information-south-district; Matanuska Electric Association, *Schedule of Rates for Q2 2023*, https://www.mea.coop/co-op-benefits/current-rates; Golden Valley Electric Assn, *Rates,* March 1, 2023, https://www.gvea.com/services/rates/; Homer Electric Association, *Rate Schedule*, April 1, 2023, https://www.homerelectric.com/member-services/my-bill/rates/.

[64] IRENA, Renewable Power Generation Costs in 2021, p. 15, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jul/IRENA_Power_Generation_Costs_2021.pdf?rev=34c22a4b244d434da0accde7de7c73d8

[65] RCA, TA535-18; summarized at https://aws.state.ak.us/OnlinePublicNotices/Notices/View.aspx?id=205057

[66] 26 U.S. Code §45V – Credit for production of clean hydrogen. *See* White House, Building a clean energy economy: A guidebook to the inflation reduction act's investments in clean energy and climate action, p. 75, available at https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf.

[67] Bloomberg Tax, *The New Clean Hydrogen Production Tax Credit, Explained*, November 23, 2022, https://news.bloombergtax.com/daily-tax-report/the-new-clean-hydrogen-production-tax-credit-explained.

[68] US Department of Energy, HydroGen, *High Efficiency PEM Water Electrolysis Enabled by Advanced Catalysts, Membranes and Processes*, p. 3, April 30, 2019, https://www.hydrogen.energy.gov/pdfs/review19/p155_ayers_2019_o.pdf.

100. It is important to keep in mind that additional clean power generation capacity is more efficiently used first to replace thermal power generation, before expending additional resources to turn it into a gas in a market that is already experiencing a power fuel shortage. However, there may be synergistic systems of hydrogen production during times of low power demand, once sufficient renewable generation capacity exists.

3.2.2 Cost of Supply Assumptions

101. Due to the screening level of this Phase I Assessment, the costs of each project option were evaluated at a very preliminary level, frequently without the ability to examine physical characteristics of existing infrastructure. Where possible, available, and of a higher quality than would be reasonable to estimate for this assessment, third-party estimates were used, such as those developed by specific project sponsors. However, the estimates were evaluated for reasonableness and completeness with similar projects, and brought to the same $2023 basis at a high level.[69] Table 5 below summarizes the sources of each major cost assumption for the evaluated options.

Table 5: Basis of Cost of Supply Assumptions

#	Option	Cost of Gas	CAPEX	OPEX
1	Cook Inlet Gas	BRG, based on 2018 and 2023 ADNR Cook Inlet Reserves studies	BRG / Public Sources	NA
2	In-State Pipeline	AGDC (Fixed w/escalator)	AGDC, inflated at CPI, omitting GTP, adding pipeline from Pt Thomson to Deadhorse	AGDC as % of Capex
3	Kenai LNG	BRG (AECO+Fixed)	Cornerstone/BRG	Cornerstone/BRG
4	Greenfield Port and Regas	BRG (AECO+Fixed)	Cornerstone/BRG	Cornerstone/BRG
5	FSRU	BRG (AECO+Fixed)	Cornerstone/BRG	Cornerstone/BRG
6	Barge / Small LNG Carrier	BRG (AECO+Fixed)	Cornerstone/BRG	Cornerstone/BRG
7	Alaska LNG	AGDC (Fixed w/escalator)	AGDC	NA
8	LNG Truck and/or Rail	IGU (Fixed w/escalator)	Cornerstone/BRG	IGU/Cornerstone/BRG
9	RNG	BRG / Public sources	BRG / Public sources	BRG / Public sources
10	Hydrogen (green)	BRG / Public sources	BRG / Public sources	BRG / Public sources

[69] Without examining component-specific inflation.

102. In order to develop consistent cost of supply assumptions for all options, we assumed that the costs of investing in each project would be amortized over consistent Unmet Gas Demand, levelized using common midstream capital structure and discount rate assumptions for a 20-year period, and then converted back to $2023 values using inflation assumptions.

103. The capital structure assumptions used for all midstream and shipping infrastructure investments were 60% debt, 40% equity, with 4.6% after-tax cost of debt (BBB rating), and 12% cost of equity. We applied inflation using historic 10-year CPI for All Urban Consumers, PPI for Oil and Gas Extraction, and PPI for Oil and Gas Field Machinery and Equipment Manufacturing indices, as appropriate, to adjust historical estimates. For long-term inflation, we assumed 2% average.[70]

104. The resulting cost of supply estimate range, using High and Low Working Group demand forecast as a variable of the range for midstream costs are presented in Table 6 (for private project options) and Table 7 (for government participation options) below.

Table 6: Private Project Options

Option		Timeline from decision YE2023	Capital Investment	Supply Volume	Cost of Supply		
					Gas	Midstream	Total
		years	$ mm	BCF/year	$/Mcf	$/Mcf	$/Mcf
1	Cook Inlet Gas	3 - 4	up to $1500 - $2000	up to ~23	$9.3 - $25.5	Included	$9.3 - $25.5
2 (a)	In-State Pipeline (Private)	6 - 7	~ $8,790	up to 105	$1.3 – $2.6	$26.8 – $34.2	$28.1 - $37.0
3	Kenai LNG	4 - 5	$768	up to 55	$8.6 - $8.9	$3.4 - $4.7	$12.0 - $13.6
4	Greenfield Port and Regas	6 - 7	$876	up to 55	$8.6 - $8.9	$4.0 - $5.3	$12.6 - $14.2
5	FSRU - Own/Lease	4 - 6	$698	up to 55	$8.6 - $8.9	$3.6 - $5.0	$12.2 - $13.9
6	Barge / Small LNG Carrier	4 - 5	$563	up to 25	$8.6 - $8.9	$13 - $14	$21.6 - $23.0
7	Alaska LNG	7 - 8	~$43,000	up to 183	$1.3 – $2.6	$3.1	$4.4 - $5.8
8	LNG Truck and/or Rail	3 - 4	$321	~9	$2.50	$22.5 - $29.5	$25 - $32

[70] Long-term inflation is used to estimate future annual capital and operating costs of each project, as well as for adjusting future expected tariffs and prices to $2023. Since the valuation period of all projects is about 27 years, the use of standard long-term inflation factor is appropriate. All Capex and Cost of Supply estimates are expressed in $2023 for consistency, and actual project metrics such as capital investment at the time of expenditure, or contract gas prices, will be impacted by actual inflation to the extent it differs from this assumption.

Option		Timeline from decision YE2023	Capital Investment	Supply Volume	Cost of Supply		
					Gas	Midstream	Total
		years	$ mm	BCF/year	$/Mcf	$/Mcf	$/Mcf
9	Renewable Natural Gas	Unknown	n/a	~1	~$25	Included	~$25
10	Hydrogen (green)	12+	unknown	n/a	n/a	n/a	$>32

Table 7: State Participation Options

Option		Timeline from decision YE2023	Capital Investment	Supply Volume	Cost of Supply		
					Gas	Midstream	Total
		years	$ mm	BCF/year	$/Mcf	$/Mcf	$/Mcf
2 (b)	In-State Pipeline (Subsidized 80%)	6 - 7	~ $8,790	up to 105	$1.3 – $2.6	$7.8 - $9.9	$9.2 - $12.6
2 (c)	In-State Pipeline (State Owned)	6 - 7	~ $8,790	up to 105	$1.3 – $2.6	$5.9 – $7.4	$7.3 - $10.0
4 (b)	Greenfield Port and Regas (Subsidized 80%)	6 - 7	$876	up to 55	$8.6 - $8.9	$2.3 - $3.3	$10.9 - $12.2
4 (c)	Greenfield Port and Regas (State Owned)	6 - 7	$876	up to 55	$8.6 - $8.9	$2.2 - $3.1	$10.8 - $12.0

3.2.3 LNGC Assumptions

105. Any LNGC or barge entering Alaska waters must obtain approval of the U.S. Coast Guard ("USCG"). USCG regulates LNGCs' structural steel requirements via 46 CFR 154.176(b)(1)(iii), which requires that "longitudinal contiguous hull structure of a vessel having cargo containment systems with secondary barriers must be designed for Alaskan waters the ambient cold condition of -29 °C (-20 °F)."[71] This regulation applies to all Alaska waters from the North Slope to Ketchikan, without regard for local conditions.

[71] 46 CFR 154.176(b)(1)(iii)(A), Longitudinal contiguous hull structure, up to date as of May 19, 2023; 46 CFR 154.172(c), Contiguous steel hull structure, up to date as of May 19, 2023; 46 CFR 154.32(c), Equivalents, up to date as of May 19, 2023; US Department of Energy, *LNG Annual Report 2015*, Office of Fossil Energy; US Department of Energy, *LNG Annual Report 2014*, Office of Fossil Energy.

106. Among other requirements, this design temperature leads to the requirement for "low-temperature" carbon steel for vessels designed to temperature of -25 °C (- 13 °F). In order to comply with 46 CFR 154.172 (b), vessels need to be constructed using "type E" steel. [72] Given that the Coast Guard regulations do not apply in other commonly visited cold-weather LNG ports, most vessel owners do not select to employ this type of steel in the manufacturing of their ships. There are only two bespoke 89,900 m^3 carriers in the market that were built for ConocoPhillips in 1992-1993. [73] These vessels, Seapeak Polar and Seapeak Arctic, are now owned by Seascape, with one of them offered for demolition sale earlier in 2023.[74]

107. A regular LNGC could be considered compliant with the regulation on an "equivalency argument," as per 46 CFR 154.32 "equivalent or greater protection for the purpose of safety."[75] For example, ConocoPhillips brought LNGC Excel to the Kenai LNG plant in the past for summer cargo shipping between April and October.[76]

108. Based on these standards and history, we are making the assumption that a standard LNGC or FSRU in good condition could be approved to operate in Alaska approximately during the summer months, but a newbuild LNGC or FSRU would be required to operate year-round, given the advanced age and scarcity of the two existing tankers that were constructed specifically for Alaska operations.

109. Even though chartering an LNGC or FSRU for seasonal use is a possible option, BRG has not evaluated availability of specific vessels. Based on BRG's research, there are currently 17 active FSRUs which are under 150,000 m^3.[77] Charter rates for FSRUs and LNGCs have experienced significant recent volatility.[78] This option needs to be approached with the FSRU owners and suppliers at the opportune time when the Working Group is ready to commit to this path.

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[72] 46 CFR 154.172(b), up to date as of 5/19/2023.

[73] ConocoPhillips, *The History of Cook Inlet,* https://www.conocophillipsalaska.com/ea/cookinlettimeline/.

[74] Seapeak, Our fleet, https://www.seapeak.com/our-capabilities/our-fleet/. See also TradeWinds, *Thirty-year-old Seapeak LNG carrier offered for demolition sale*, January 11, 2023, https://www.tradewindsnews.com/gas/thirty-year-old-seapeak-lng-carrier-offered-for-demolition-sale/2-1-1385599.

[75] 46 CFR 154.32, up to date as of 5/19/2023.

[76] US Department of Energy, Vessel-Borne Export of Domestically Produced Liquefied Natural Gas, 2014 and 2015.

[77] BRG internal research; Kpler Database.

[78] Dempsey, H., *Europe battles to secure specialized ships to boost LNG imports*, Financial Times, March 27, 2022, https://www.ft.com/content/bc5f79a6-729e-47ff-bf46-cb23c460fa6f; Chambers, S., *LNG carrier rates on a charge*, Splash 247, September 14, 2022, https://splash247.com/lng-carrier-rates-on-a-charge/; Miller, G., *Price of LNG goes stratospheric. Will LNG shipping rates follow?*, Freight Waves, August 24, 2022, https://www.freightwaves.com/news/price-of-natural-gas-goes-stratospheric-will-lng-shipping-rates-be-next.

4 OPTION SELECTION

110. In this chapter we review the process that BRG and Working Group undertook to select the most viable options among the alternatives that should progress through the next phase of the project.

4.1 Option Scoring Methodology

111. BRG and the Working Group collaboratively developed a scoring methodology that prioritized certain characteristics of each project option and assigned a scoring weight between 1 and 10 according to that priority.[79] While not every member of the Working Group applied the same priority to each selection criteria, the overall results had significant consistency. BRG proposed a consistent priority ranking of selection criteria after review and discussion with the Working Group.

112. We converted the scoring weights to multiplier values, according to the Ratio Method.[80] These multipliers are used to multiply the scores for each project option in each criteria, and then the resulting products are summed together to show a project score for each option up to five (5), the highest possible value.

4.2 Option Scoring Process

113. The table below shows the criteria prioritization results and the final Ratio Method score multipliers.

[79] ADNR and AEA did not submit individual priority rankings, as they participated in an advisory and informational capacity and thus did not participate in the ranking or scoring. *See* Roszkowska, E., *Rank Ordering Criteria Weighting Methods – A Comparative Overview,* Optimum. Studia Ekonomiczne, Nr 5 (65), 2013, available at https://pdfs.semanticscholar.org/f983/e8c4eb7d7c30694dd72c5849dd6fee8a5c79.pdf.

[80] Roszkowska, Ewa, *Rank Ordering Criteria Weighting Methods – A Comparative Overview,* Optimum Studia Ekonomiczne, Issue 65, No. 5, p. 7, 2013, section 4.2.

Table 8: Option Scoring Criteria Summary – Working Group Input and Final Results

Priority	Scoring Criteria	ENSTAR	Chugach	MEA	GVEA	HEA	IGU	BRG Recommendation (10 = Highest Weight)	Ratio Method Score Multiplier
1	Schedule Risk	10	9	10	6	10	9	**10**	**0.18**
2	Reliability of supply during operations	9	10	9	10	5	10	**9**	**0.16**
3	Delivered cost per Mcf/MMBtu	8	8	6	9	9	8	**8**	**0.14**
4	Flexibility	7	5	7	7	7	7	**7**	**0.12**
5	Project Complexity and Integration	5	4	8	2	5	5	**6**	**0.11**
6	Permitting	6	3	4	1	6	3	**5**	**0.09**
7	Environmental Impact	4	6	2	3	6	2	**4**	**0.07**
8	Size of direct investment required by the utilities (CAPEX)	3	2	5	8	8	6	**3**	**0.05**
9	Local economic impact (jobs and revenues)	2	1	1	5	4	4	**3**	**0.05**
10	Carbon efficiency / Climate change impacts	1	7	3	4	6	1	**2**	**0.04**

114. For each Scoring Criteria, BRG in consultation with the Working Group developed a scale of one (1) or zero (0) to 5, and a description of what each score represented in valuing the options, to ensure consistent results. The summary of the scores is presented below in Table 9.

Table 9: Project Option Scores - What Each Value Means

Priority	Scoring Criteria	Score
1	Schedule Risk	5 = Meets contract shortfall by 2026 and volume shortfall by 2029 4 = Meets contract shortfall by 2026 but provides no long-term solution 3 = Meets volume shortfall by 2029 with other options to supplement 2 = Meets volume shortfall by 2029 but precludes other options 1 = May not meet volume shortfall by 2029 and precludes other options 0 = Provides immaterial supply, or utility demand has no ability to affect the sanction of this option

Priority	Scoring Criteria	Score
2	Reliability of supply during operations	5 = Project uses proven technology, experienced providers, and is local to the service area 4 = Project uses proven technology but requires investment remote from service area 3 = Project uses mostly proven technology and relies on new market entrants 2 = Project uses novel technology deployed by experienced suppliers local to the area 1 = Project relies on new technology, providers, and geographic challenges
3	Delivered cost per Mcf/MMBtu	5 = < $10.50 per Mcf 4 = $10.50 - $14.00 per Mcf 3 = $14 - $20 per Mcf 2 = $20 - $30 per Mcf 1 = > $30 per Mcf
4	Flexibility	5 = Storage and gas supply can be increased yearly with no cost or efficiency penalties 4 = Storage and gas supply can be increased in multi-year phases 3 = Storage and gas supply can be ramped up according to a plan but requires substantial upfront investment 2 = Project can be implemented in two (2) phases 1 = Firm daily supply commitment, infrequently adjusted.
5	Project Complexity and Integration	5 = Pipeline system impacts only 4 = Pipeline and Utility Group system impacts including storage 3 = Third party participation required (producers or importers) 2 = Multiple third parties involved 1 = New large diameter pipeline
6	Permitting	5 = Municipal permitting only 4 = State agency permits required 3 = State/Federal permits with offshore impact 2 = FERC permit required 1 = FERC permit required with offshore impact
7	Environmental Impact	5 = Project has minimal or insignificant environmental impact and relies on previously developed infrastructure 4 = Project has modest onshore environmental impact that is easily mitigated 3 = Project has significant onshore environmental impact that will require significant expense to mitigate 2 = Project has modest onshore and offshore environmental impact 1 = Project has significant onshore and offshore environmental impact

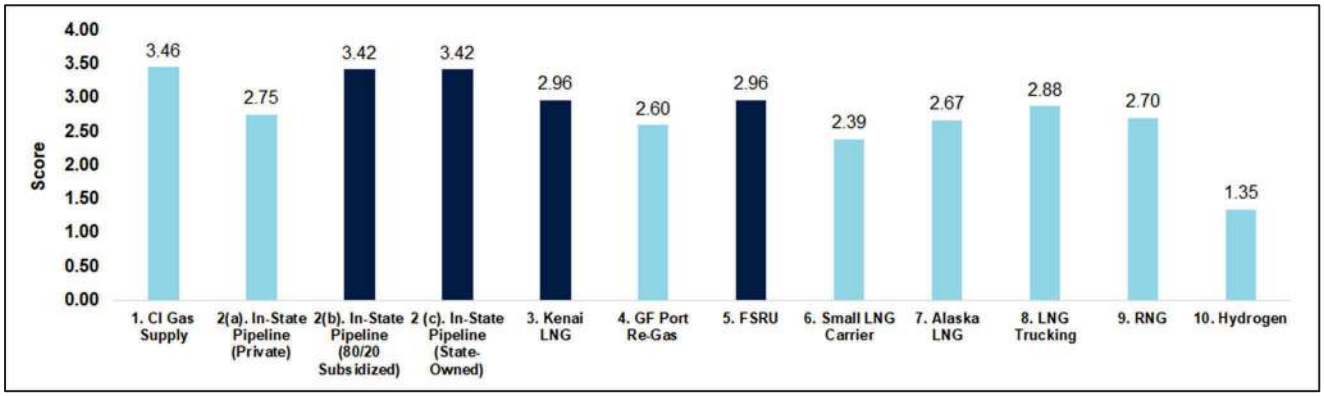
Priority	Scoring Criteria	Score
8	Size of direct investment required by the utilities (CAPEX)	5 =< $300MM 4 = $301 - $600MM 3 = $601-$900MM 4 = $901MM - 1.2B 1 = > $1.2B
9	Local economic impact (jobs and revenues)	5 = > 80% jobs and revenues created are in Alaska 4 = >60 - 80% jobs and revenues created are in Alaska 3 = >40 - 60% jobs and revenues created are in Alaska 2 = >20 - 40% jobs and revenues created are in Alaska 1 = < 20% jobs and revenues created are in Alaska
10	Carbon efficiency / Climate change impacts	5 = Involves a low-carbon fuel or renewable power solution 4 = Local gas production 3 = Gas liquefaction and short-distance transportation 2 = Gas liquefaction and long-distance transportation 1 = Reliance on high-carbon fuels

4.3 Results of Option Scoring Exercise

115. BRG conducted an engineering and commercial evaluation to assign scores to each of the project options. The scores were based on a screening-level evaluation of each option's scope characteristics as described above in this report, including cost, permitting, and schedule constraints. BRG built a cost of supply model in order to evaluate the 20-year levelized equivalent cost of service for each option.

116. The resulting score of all project options and sub-options related to the financing and sponsorship of the In-State Pipeline are presented in Figure 13.

Figure 13: Option Score Summary



117. Based on the scoring results, the Working Group is further evaluating the following options in addition to Cook Inlet Gas Supply[81]:

118. **In-State Pipeline**. In order to achieve the benefits of this option, a decision to subsidize this project needs to be made in an expeditious manner. Given the projected time required to construct a long-distance pipeline across Alaska, it is likely that alternative supply is still necessary to bridge the time to when the pipeline gas becomes available. While an In-State Pipeline project has many benefits, including development of North slope gas with many years of supply security, state royalties, and ability to provide gas to communities along the pipeline route, In-State Pipeline carries prohibitive costs if developed solely for the Working Group utility demand. Reconfiguring the project so that state ownership or an investment decision can be made on the merits of the project for Alaska demand and its economic benefits, rather than depending on large export LNG buyer commitments, would be a change in the strategy of the project and its current owner, Alaska Gasline Development Corporation ("AGDC"). We recognize this as a policy decision outside the scope of this report.

119. **Kenai LNG**. Retrofitting the former Nikiski LNG export facility currently owned by Marathon presents an opportunity to use a brownfield facility with existing pipeline connections to the main ENSTAR system, existing dock, and potentially existing LNG storage tanks. This option provides important advantages of shortening the time to project start-up and potentially lowering costs of LNG import. However, the old age of the facility and the size and condition of the dock and tanks (currently in warm status) present their own risks and challenges related to permitting and potential costs. In addition, Marathon's stated goal to employ the site as a small import facility for Kenai Refinery's own gas needs presents a potential regulatory and operational conflict. This option should not be discounted at this stage due to its timing advantages, provided that good-faith negotiations with the facility owner begin expeditiously.

120. **FSRU**. Importing LNG using an FSRU as storage and regas provides a significant project schedule advantage. To the extent a suitable chartered FSRU vessel can be secured in the short term, this option has the shortest lead time and lowest risk of securing necessary supply of all options reviewed. The key risks to the schedule of this option are availability of cold climate appropriate FSRUs of the right capacity (i.e. small enough to utilize existing docks), and the availability and suitability of either the Agrium Pier (owned by Nutrien) or Marathon dock.

121. These top options, with scores by individual prioritized criteria, are presented in Table 10 below.

[81] See recommendations on Cook Inlet Gas Supply option in Sections 1.3, 16, and 3.2.1.1.

Table 10. Top Scoring Project Options in Phase I

		1 = Low Score, 5 = High Score			
Prior	Scoring Criteria	2(B). In-State Pipeline (80/20 Subsidized)	2 (c). In-State Pipeline (State-Owned)[1]	3. Kenai LNG	5. FSRU
1	Schedule Risk	1	1	3	3
2	Reliability of supply during operations	5	5	4	4
3	Delivered cost per Mcf/MMBtu	5	5	4	4
4	Flexibility	3	3	2	3
5	Project Complexity and Integration	2	2	2	3
6	Permitting	4	4	2	1
7	Environmental Impact	3	3	4	2
8	Size of direct investment required by the utilities (CAPEX)	5	5	3	4
9	Local economic impact (jobs and revenues)	4	4	2	1
10	Carbon efficiency / Climate change impacts	4	4	2	2
	TOTAL WEIGHTED SCORE (Scale 0 to 5)	**3.42**	**3.42**	**2.96**	**2.96**

5 MARKET, PRICE VOLATILITY, AND RISK ANALYSIS

122. In this chapter, we review the current LNG market conditions and outlook, including the global and North American liquefaction capacities. We also analyze the volatility of energy commodity markets to which new LNG supply to Alaska could be indexed.

5.1 LNG Market Environment and Current Outlook

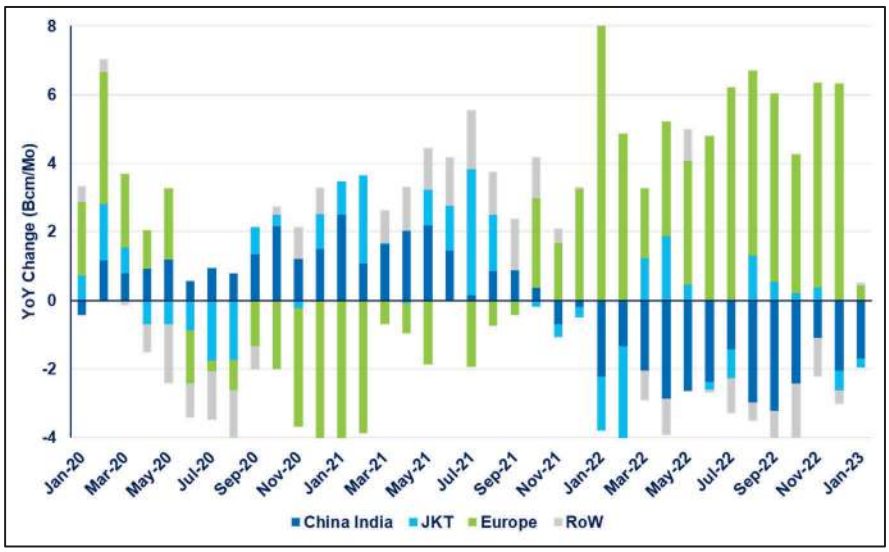
5.1.1 LNG Market Developments

123. LNG market conditions have experienced major changes in the past few years, moving from low prices during the oversupply period in the mid-2020s to extreme high prices in 2021 and 2022.

124. Recent history has indicated a dynamic LNG flow pattern. Global LNG demand dropped sharply in 2020 and as a result, suppliers and importers offloaded their mounting surplus into Europe. Amid economic recovery from the pandemic and demand growth in China, global markets tightened, and LNG supplies shifted towards higher-priced Asian markets starting in mid-2020, as seen in Figure 14.

125. Thereafter, from 2Q 2021, Russia materially reduced its pipeline exports to Europe, and subsequently European nations sought to replace Russian pipeline gas in large part with LNG imports. This resulted in a sharp rise in European demand and correspondingly, higher regional prices pulled LNG supplies away from Asia and into Europe.

Figure 14: Historical LNG Import Movements since January 2020[82]



[82] BRG Analysis of Kpler data.

5.1.2 LNG Market Demand and Supply Outlook

126. The Global LNG market is expected to remain tight in the next few years. Europe is continuing to shift its reliance from Russian gas to LNG following the energy crisis in the second half of 2021 and Russia's invasion of Ukraine. Global LNG demand could reach up to 444 million tonnes[83] in 2026, an increase of 18% from 2021.[84]

127. The favorable market conditions of 2022 did not translate into FIDs on LNG liquefaction projects, with just under 5 trillion cubic feet per year of new capacity globally (excluding North America) that is under construction.

128. Based on BNEF LNG outlook, China, South Asia and Southeast Asia could see LNG imports climb, especially as coal-to-gas switching initiatives continue in China, but growth may be restricted by increased spot LNG prices. Northwest Europe and Italy are slated to see the largest jump in LNG imports, as their LNG demand increases by 36 million tonnes by 2026 compared to 2021. Japan, Korea, Taiwan (JKT) region is the only major market forecast to see a dip in LNG demand due to higher nuclear, renewables and coal generation in Japan and a lower gas demand for power in South Korea.[85]

129. New supply projects are expected to ramp up in the coming years, particularly in the US. Global supply is forecasted to increase to 460 million tonnes in 2026,[86] an almost 20% rise from 2021.[87]

130. With the tight supply expected until 2026, prices are expected to maintain at elevated levels compared to their pre-Covid levels.[88]

5.2 Historic Gas and LNG Price Volatility Analysis

131. Global gas and LNG markets have been characterized by extreme volatility since second half of 2021, largely due to restrained capital expenditure since 2016, buoyant post-pandemic economic conditions, and Russia's invasion of Ukraine in early 2022, which fostered intense global competition for LNG supply to replace Russian pipeline imports. The volatility of energy

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[83] 21.3 trillion cubic feet, using a conversion factor of 1 million tonnes of LNG to 48.028 billion cubic feet of gas from BP Statistical Review of World Energy, Approximate conversion factors, July 2021, p. 2.

[84] Bloomberg, *Global LNG market outlook 2022-26*, June 29, 2022, Global LNG balance- slide 3, https://www.bloomberg.com/professional/blog/global-lng-outlook-overview-tight-supply-expected-until-2026/.

[85] Bloomberg, *Global LNG market outlook 2022-26*, June 29, 2022, Global LNG balance- slides 3-4, https://www.bloomberg.com/professional/blog/global-lng-outlook-overview-tight-supply-expected-until-2026/.

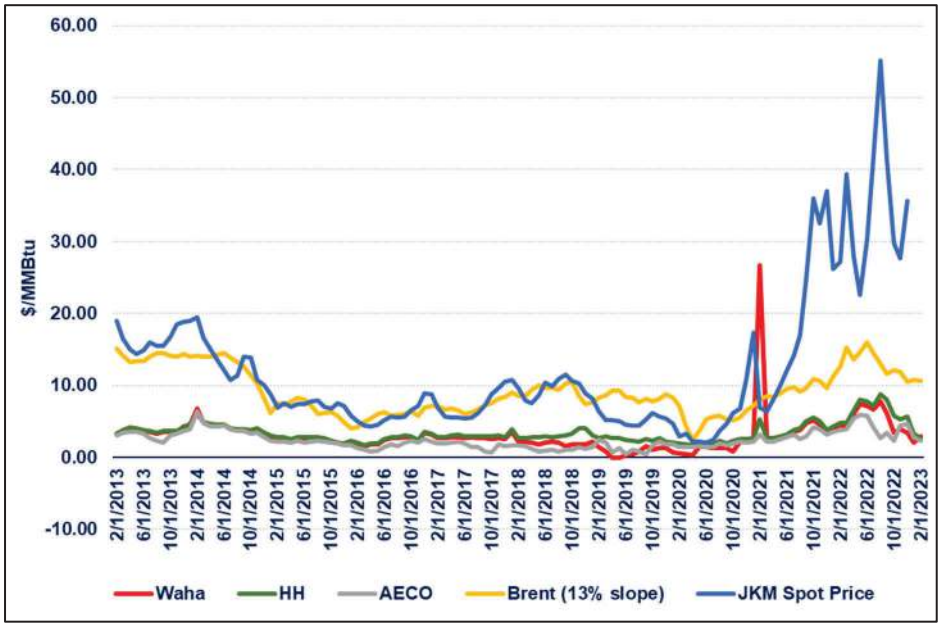
[86] 22.1 trillion cubic feet, using a conversion factor of 1 million tonnes of LNG to 48.028 billion cubic feet of gas from BP Statistical Review of World Energy, Approximate conversion factors, July 2021, p. 2.

[87] Bloomberg, *Global LNG market outlook 2022-26,* June 29, 2022, Outlook overview- slide 1, https://www.bloomberg.com/professional/blog/global-lng-outlook-overview-tight-supply-expected-until-2026/. Note that supply generally exceeds demand due to average utilization of less than 100% of installed capacity.

[88] Bloomberg, *Global LNG market outlook 2022-26*, June 29, 2022, Outlook overview- slide 1, https://www.bloomberg.com/professional/blog/global-lng-outlook-overview-tight-supply-expected-until-2026/.

commodity markets to which LNG supply to the Alaskan project could feasibly be indexed is illustrated in Figure 15 below.[89]

Figure 15: Potential LNG Price Indices: Historical Trends[90]



132. Prices at North American hubs also increased – albeit to a lesser extent – partly due to surging LNG export demand. Average monthly prices at Henry Hub, Waha, and AECO reached their highest levels in over a decade last year. However, prices at North American hubs have since moderated substantially, and there is little to suggest that the multi-year highs of 2022 are likely to recur with any frequency.

133. Nevertheless, LNG and gas price volatility remains elevated by historical standards. This is demonstrated in Table 11, which presents annualized volatility, a measure of how LNG prices fluctuate over a given period, in each of the markets in Figure 15 since 2013. Uncertainty in market conditions or events that affect natural gas supply and demand tend to result in higher price volatility.

[89] Unlike AECO, Henry Hub ("HH"), and Brent crude oil prices, Platts' JKM does not represent a traded market or hub. Rather, it is a price assessment, which is compiled daily on the basis of voluntary reporting of transactions by market participants

[90] Price data from Platts' and S&P Global Capital IQ.

Table 11: Annualized Volatility of Potential LNG Price Indices[91]

Index/Hub	Annualized Volatility 2013-2016	Annualized Volatility 2017-2020	Annualized Volatility 2021-2023
Brent Crude Oil	24%	27%	37%
Henry Hub	50%	58%	106%
Waha Hub	73%	513%	362%
JKM	11%	26%	116%
AECO	62%	473%	277%

134. JKM price volatility has spiked since late 2021 due to disruption to and then full cessation of Russian supply to Europe, prompting intense global competition for spot LNG cargoes. Competition has moderated in recent months, and JKM prices have stabilized, but volatility remains high. In contrast to JKM, volatility at AECO and Waha is in large part a function of low prices in recent years – resulting from constraints on takeaway capacity and local pipeline bottlenecks – rather than demand spikes and reduced global gas availability. The average price of each indexation option since 2013 is presented in Table 12. [92]

Table 12: Average Historical Prices of Potential LNG Price Indices

Index/Hub	Average Price ($/MMBtu) 2013-2016	Average Price ($/MMBtu) 2017-2020	Average Price ($/MMBtu) 2021-2023
Brent Crude Oil	14.55	10.90	14.76
JKM	12.29	7.38	26.14
Henry Hub	3.55	2.88	5.09
Waha Hub	3.43	1.77	5.45
AECO	3.05	1.42	3.51

5.2.1 Potential LNG Price Indices: Price-Volatility Trade-Off

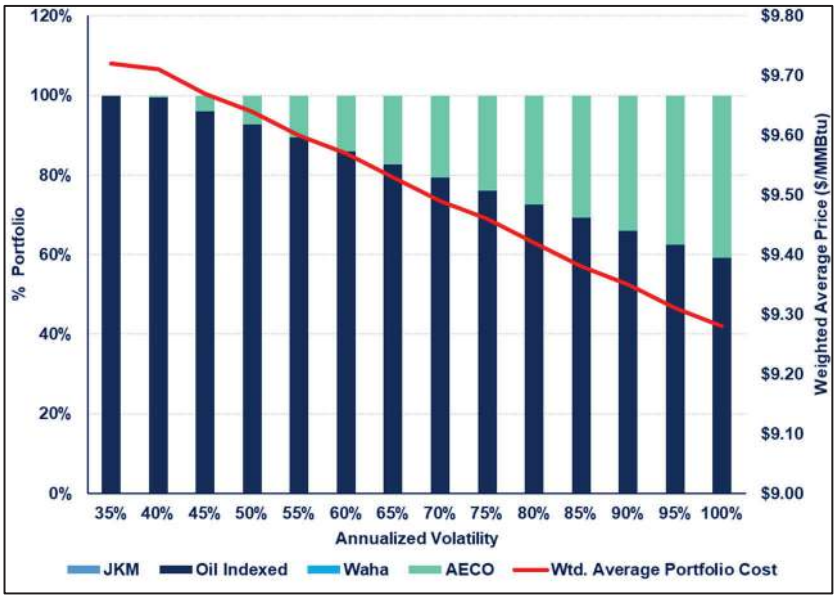
135. Current price projections indicate a modest trade-off between price and volatility with respect to the potential LNG price indices. To evaluate the scale of this trade-off, we use numerical optimization software to solve for the index – or combination of indices – that yields the lowest-cost LNG import portfolio (displayed on the secondary y-axis) available for each 5% increase in

[91] BRG analysis of Platts' and S&P Global Capital IQ price data. Annualized volatility is calculated by taking the standard deviation of the daily price changes over the course of each year and multiplying the result by the square root of the number of trading days in each year.

[92] Note that Waha, HH, and AECO represent only a portion of LNG FOB contract price, as those indices are paired with additional gas transportation and liquefaction fees before shipping, on the order of $4-6 per MMBtu in addition to the index price. JKM Spot Price generally includes full LNG price including shipping to the market hub, and Brent-based LNG prices may or may not include shipping, depending on contract.

annualized volatility (displayed on the x-axis) between 2024–2034. The least volatile potential price index considered is Brent crude oil, with an annualized volatility of 35% since 2013. The results of this analysis are displayed in Figure 16.

Figure 16: Expected Volatility & Average Price (FOB) of Potential Supply Options (2024-34)[93]



136. Assuming a slope of 14% (expressed as a percentage of crude oil prices in $/bbl), an LNG import portfolio fully indexed to Brent crude – the least volatile potential index – is expected to cost just under $9.80/MMBtu over the 2024-2034 time period. This is approximately $1/MMBtu higher than an equivalent portfolio indexed entirely to AECO hub (after accounting for estimated liquefaction costs and marketing fees). Perhaps unsurprisingly, JKM is likely to present the highest potential risks by both metrics, and does not feature in the optimal indexation mix.

5.3 LNG Market Sourcing Strategy

137. The high level of uncertainty that still exists in the design and schedule of any LNG import project makes it too early to engage in LNG contracting other than as part of very early-stage discussions with potential suppliers. Additionally, the annual growth in Unmet Gas Demand and the overall low volumes on the scale of the global LNG market make it a challenge to create the right shape of a multi-year contract. However, ability to plan and use in-ground gas storage can mitigate the issue of instability of demand by allowing to store gas in early low-demand years of shortage.

[93] BRG analysis using price projections developed for the Cook Inlet Gas Supply Project options analysis. Historical annualized volatility calculated based on price data from Platts' and S&P Global Capital IQ. Projected prices include assumed liquefaction & marketing costs.

138. As we reviewed above, Alaska's best matches in the LNG market for suppliers are the projects on West Coast of Mexico and Canada that are currently under construction or in pre-FID stages. Capacity associated with those projects has largely been sold through 2026, however there is some still potentially available in 2026-2028 FID projects. Additionally, spot cargos will likely be available from these projects while in operation in the late 2020s. A global LNG supplier may offer a contract for a number of cargos annually that are supplied from one of the North American West Coast projects or other sources in the Pacific, provided both the vessel and LNG specifications are appropriate for Alaska. Those spot cargos will most likely be priced using JKM indexation. Once this project reaches a stage where an FID commitment is imminent, it would be appropriate to seek a multi-year contract for FOB or DES LNG supply from several of the developing projects and worldwide LNG suppliers, using a structured expression of interest and bidding process.

139. However, even at this early stage, and given the bespoke characteristics of the Alaska regulatory and market environment, we advise conducting an informal outreach to suppliers as early as Phase II of this project, even as non-LNG import options are still under consideration. Confidential discussions with willing suppliers would provide valuable information on the need for this project to procure its own vessels or shipping arrangements, exact LNG chemical composition available from each suppliers, potential indexation and price structures available, and flexibility of seasonal and annual contract volumes. This information would greatly inform technical and commercial planning of the project.

5.4 Statistical Risk Analysis of Recommended Options

5.4.1 Risk Factors of Different Recommended Options

140. The market price risk volatility addressed above is only a part of the potential cost and schedule risk that needs to be evaluated and mitigated for the selected option. For options with large capital investments, additional risk will lie in the ultimate cost of the infrastructure and the date commercial operations can be achieved. The current level of certainty in the cost estimates of the options does not lend itself to a productive risk analysis due to the immaturity of the project scope and estimates; however, in the next phase with fewer options under consideration, it is highly recommended.

5.4.2 Future Risk Analysis Recommendation

141. A Monte Carlo simulation is a common technique used to assess the impact of uncertainty on the economic output such as the NPV of cash flows or the levelized cost of supply. The simulation involves selecting key inputs which typically include capital costs, operating costs, and LNG prices and assigning a probabilistic distribution to those inputs using computer software such as

@Risk[94] or Crystal Ball[95]. These inputs are then used in a cash flow model that combines these inputs by sampling the input distributions to calculate a median economic output and a confidence range indicating the likelihood that the economic parameter would be lower or higher than a certain value. For example, a Monte Carlo could quantify a mean cost of alternative gas supply of $15/mmbtu with a 95% chance that the ultimate cost of supply will not exceed $20/mmbtu and a 5% chance that the ultimate cost of supply will be less than $12/mmbtu.

[94] Palisade, *@Risk Probabilistic Risk Analysis in Excel*, https://www.palisade.com/risk/?gclid=Cj0KCQjwxYOiBhC9ARIsANiEIfbbQoh42P7VupRbwECl9ONAdSoR5is5PmHL08PQFvztrsfDdzod7fAaAuKVEALw_wcB.

[95] Oracle, *Crystal Ball*, https://www.oracle.com/applications/crystalball/.

6 RECOMMENDATIONS AND NEXT STEPS

6.1 Recommended Actions to Confirm Feasibility of Top Scoring Options

142. BRG recommend the following scope of work as part of Phase II, estimated to take 4-6 months:

a. Utilities individually continue to work with Cook Inlet producers and the State to promote and secure additional contracted supply and promote alternative development.

b. The utilities' Working Group should pursue several top-scoring options in order to further define scope, schedule and commercial viability, specifically, 1) Modification of existing Kenai LNG facility (via commercial discussions with owner); 2) Scope definition and planning for FSRU option; 3) Greenfield Port and Regas site selection and feasibility assessment for LNG imports if retrofit options become unavailable; 4) Market survey to further define availability and cost of LNG; and 5) Optimization and feasibility assessment of the In-State Pipeline option with AGDC and State of Alaska in areas of permitting critical path and financing structure.

c. Complete permitting due diligence of all top-scoring options and identify key bottlenecks and showstoppers.

d. For all top-scoring options, develop draft venture model, project finance structure and plan of engagement with capital markets.

e. Refine cost of supply estimates for the top-scoring options, including Greenfield Port and Regas, if existing infrastructure in Nikiski becomes non-feasible or excessively risky.

f. Select one permanent solution or multiple short-term and long-term options to pursue by the end of 2023.

6.2 Project Management Next Steps

143. The following are recommended next steps in Phase II in order to prepare to commence preliminary engineering on a major project, if executed by the Working Group or an affiliated joint venture:

a. Assess Working Group's project delivery capabilities and provide recommendations.

b. Confirm current operating environment, and available resources, processes and enabling technologies.

c. Measure the as-is maturity level of key capability areas required to deliver a large complex project.

d. Define an ideal to-be maturity level based on the complexity of the selected option.

e. Perform a gap analysis and develop recommendations for improvement.

f. Develop an implementation roadmap.

g. Conduct an alternates analysis.

h. Provide a recommendation for contract/procurement strategy.

i. Assist the Working Group in establishing a project management office.

ALASKA NATURAL GAS SUPPLY ASSESSMENT

PHASE II WHITE PAPER: SUMMARY OF RESULTS

April 2024

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LIST OF ABBREVIATIONS

ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADNR	State of Alaska Department of Natural Resources
ADOT&PF	Alaska Department of Transportation and Public Facilities
AGDC	Alaska Gasline Development Corporation
AEA	Alaska Energy Authority
Bbl	Barrels
BCF	Billion cubic feet
BOEM	U.S. Department of the Interior, Bureau of Offshore Energy Management
BOG	Boil-off gas
BRG	Berkeley Research Group
BSEE	Bureau of Safety and Environmental Enforcement
CAA	Clean Air Act
CEA	Chugach Electric Association
CWA	Clean Water Act
DES	Delivered ex-ship
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
DWC	Division of Water Quality
DWP	Deepwater Port
DWPA	Deepwater Port Act of 1974
EIS	Environmental Impact Statement

ENSTAR	ENSTAR Natural Gas
EPA	U.S. Environmental Protection Agency
FECM	Office of Fossil Energy and Carbon Management
FEED	Front-end engineering design
FERC	Federal Energy Regulatory Commission
FID	Final investment decision
FOB	Free on Board (loaded onto vessel)
FSRU	Floating storage and regasification unit
FSU	Floating storage unit
GVEA	Golden Valley Electric Association, Inc
HEA	Homer Electric Association
HH	Henry Hub
IGU	Interior Gas Utility
JKM	Japan Korea Marker
KPB	Kenai Peninsula Borough
LNG	Liquified natural gas
LNGC	LNG carrier
m^3	Cubic meter
MARAD	U.S. Department of Transportation Maritime Administration
MEA	Matanuska Electric Association
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMSCFD	Million standard cubic feet per day
MOA	Municipality of Anchorage

MSB	Matanuska-Susitna Borough
MTPA	Million tonnes per annum
MW	Megawatts
NEPA	National Environmental Policy Act
NFE	New Fortress Energy
NGA	Natural Gas Act
NMFS	National Marine Fisheries Service
NPDES	National Pollutant Discharge Elimination System
NSR	New Source Review
OCS	Outer Continental Shelf
OSV	Offshore Support Vessels
PHMSA	Pipeline Hazardous Materials Safety Administration
PTE	Potential to emit
RFI	Request for Information
RHA	Rivers and Harbors Act
SHPO	Alaska Department of Natural Resources, Office of History and Archaeology
SOA	State of Alaska
USCG	U.S. Coast Guard
USDOT	US Department of Transportation
USFWS	U.S. Fish and Wildlife Service
WSA	Water Suitability Assessment

1 EXECUTIVE SUMMARY

1.1 Background and Scope

1. Southcentral Alaska, along with the Interior (the "Railbelt"), comprise the most densely populated areas of the State. These regions have relied on natural gas produced in Cook Inlet to various degrees to supply its heating and power generation needs since the 1950s. Gas production in Cook Inlet fields peaked in the mid-2000s at around 200 billion cubic feet ("BCF") per year,[1] and has steadily declined to the current annual production of approximately 70 BCF per year.[2] Formerly active export facilities of Agrium Kenai Nitrogen Plant and Kenai LNG stopped operating in 2007[3] and 2015,[4] respectively, due to the shortage and cost of gas produced in the region.

2. Over the last decade, Hilcorp Alaska, LLC ("Hilcorp") has become the largest operator and gas supplier in the state, maintaining and stabilizing Cook Inlet gas production after a period of threatened shortages.[5] Hilcorp has invested over $750 million in Cook Inlet drilling and capital projects since 2012, and plans to continue the investment at around the same pace over the next decade.[6] In April 2022, Hilcorp first warned of uncertainty of future Cook Inlet natural gas supplies, stating that "gas purchasers [were] not to rely on Hilcorp for gas beyond existing contracts."[7]

3. In May 2022, ENSTAR Natural Gas ("ENSTAR"), Chugach Electric Association, Inc. ("CEA"), Interior Gas Utility ("IGU"), Matanuska Electric Association, Inc. ("MEA"), Homer Electric Association, Inc. ("HEA"), and Golden Valley Electric Association, Inc. ("GVEA"), along with the State of Alaska Department of Natural Resources ("ADNR"), and the Alaska Energy Authority ("AEA")[8] formed a working group to assess future gas supply needs and energy security in Cook Inlet ("Working Group"). The Working Group's stated goal is to:

[1] State of Alaska Department of Natural Resources, Division of Oil & Gas, *Cook Inlet Natural Gas Availability*, March 2018, p. 19, available at https://dog.dnr.alaska.gov/Documents/ResourceEvaluation/CI_Natural_Gas_Availability_Study_2018.pdf.

[2] State of Alaska Department of Natural Resources, Division of Oil and Gas, *2022 Cook Inlet Gas Forecast*, January 2023, pp. 10 and 17, ("2022 Cook Inlet Gas Supply Study").

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

[4] 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/.

[5] Bradner, Tim. *Study says Inlet gas discoveries won't stop shortage*, Alaska Journal of Commerce, March 22, 2012.

[6] Saugier, Luke, *Presentation to Alaska State Legislature*, House Energy Committee, p. 5, January 2023.

[7] DeMarban, Alex, *Hilcorp Warms Alaska utilities about uncertain Cook Inlet natural gas supplies*, Anchorage Daily News, May 17, 2022.

[8] ADNR and AEA participated in advisory capacity in order to provide information to the utilities, as well as remain aware of the effort. These agencies did not fully participate in the deliberations or scoring of the options.

> *"[w]ork together for long-term solutions. This requires better understanding of each utility's constraints and needs based on existing contracts and forecasting our collective demand growth into the next decade as well as considering additional options to meet the unique energy needs of our region."*[9]

4. In November 2022, ENSTAR retained BRG to conduct a planning assessment to (i) develop scalable options to fill the anticipated natural gas supply gap; (ii) develop and assess high-level project scope, cost estimates, and time to execute for each of the options; (iii) analyze the available sources for options requiring liquified natural gas ("LNG") imports; (iv) assess key risks and mitigations for each option; and (v) develop a ranked assessment of options and recommendations. This project is referred to as "BRG Phase I Assessment."

5. BRG and the Working Group collaboratively identified ten project options and developed a scoring methodology for various project options proposed and considered. BRG then conducted a screening-level engineering and commercial evaluation, including cost, permitting, and schedule constraints, to assign scores to each of the ten different project options. At the end of the Phase I assessment, based on the scoring results, the top three options were (i) In-State Pipeline – to construct a 24-inch long-distance pipeline across Alaska (if government-subsidized); (ii) Kenai LNG – retrofitting the former Nikiski LNG export facility owned by Marathon to enable LNG imports; and (iii) FSRU – importing LNG using an FSRU as storage and regasification.

6. In the BRG Phase II Assessment, BRG continued to refine the project plans for the top-scoring options, conduct commercial diligence and establish project management strategy. The main scope of work are: (i) to refine each of the shortlisted options, including site evaluation, design basis, risk analysis, cost model, CAPEX and OPEX estimates and integrated schedule; (ii) to conduct LNG sourcing, including market outreach, securing NDAs and surveying potential LNG suppliers; (iii) to provide a report outlining marine shipping consideration specific to Cook Inlet, and to help formulate a regulatory and commercial strategy for LNG shipping; (iv) to update the supply model for the short-listed options and provide an updated estimate of the cost of delivered gas in $/Mcf; (v) to seek feedback from the utilities and recommend commercial structure for LNG acquisition and a financing structure for the project; and (vi) to evaluate sourcing and procurement strategies and develop a roadmap for further project development and execution.

7. This report summarizes the outcomes and recommendations of the BRG Phase II Assessment, or "Phase II."

1.2 BRG Credentials

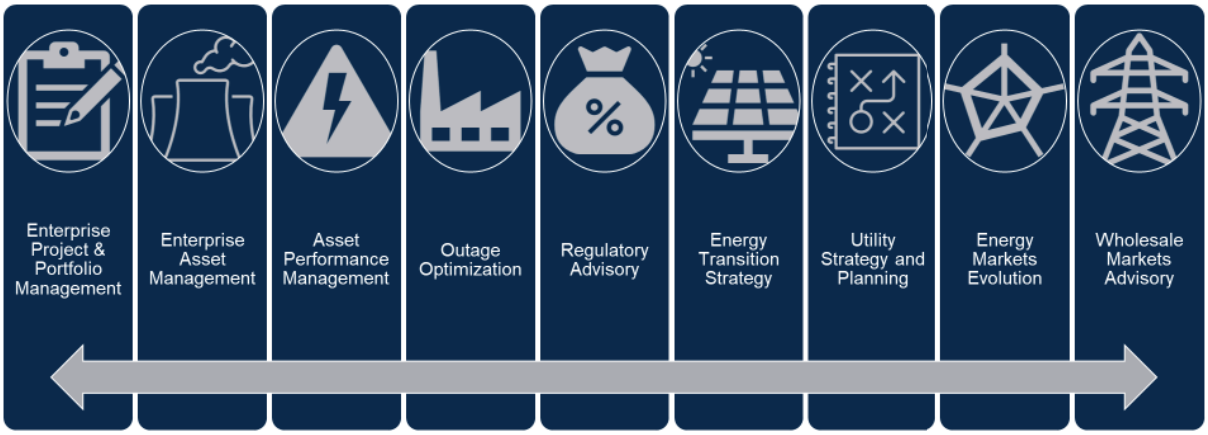
8. BRG's expert Energy & Climate and Project Development Advisory practices combine gas and LNG market, commercial, contractual, and project financing expertise capabilities in technical

[9] Regulatory Commission of Alaska, *Affidavit of John D. Sims*, p. 3, November 9, 2022.

project development and project management systems. Our advisory practice experts have deep experience in evaluation and development of LNG terminals and regasification facilities, utility infrastructure and major project management, market analysis and contracting. We also excel in providing strategic, market, commercial, economic, and financial advisory services in the global oil and natural gas industry.

9. The areas of focus for our utility clients are summarized in Figure 1.

Figure 1: Areas of Focus for Utility Clients



1.2.1 Project Leadership

10. The following key experts from BRG and Cornerstone Energy Services, a subcontractor engaged by BRG, led the BRG Phase II Assessment.

Key Staff	Position	Key Role
Steve Means	Managing Director	Infrastructure Development subject matter expert, technical integration
Lieza Wilcox	Director	Project Manager, Commercial Assessment Lead
Steve Sawyer	Principal, Cornerstone Energy Services	Project Manager, Pipeline Engineering
Pat Convery	Principal, Cornerstone Energy Services	Chief Engineer, LNG Terminal

11. In addition, the team included BRG and Cornerstone staff with deep experience in LNG systems engineering, siting, processing, pipeline engineering and materials, project management and scheduling, worldwide gas and LNG market analysis and contracting, energy macroeconomic, investment analysis, financial modeling, and market research.

12. The group of companies contributing to the project work products in BRG Phase II Assessment was expanded to include other specialty companies with specific expertise in permitting, engineering, and LNG marine transportation. ENSTAR's leadership team, top technical managers, and ENSTAR's legal representatives also provided input and reviewed intermediate work products. BRG's group of subcontractors included:

    - Cornerstone Energy Services
    - Exp.
    - Coffman Engineers
    - Axiom Environmental
    - Cashman Preload
    - Lloyd Engineering
    - Precision LNG

1.3 Executive Summary

1.3.1 Phase II Findings

13. Four distinct project options were shortlisted and reviewed in Phase II: (i) Option 3K, Kenai LNG, modifying Marathon's jetty and installing onshore storage and regasification; (ii) Option 5M, using Marathon's jetty with floating storage and regasification unit ("FSRU"); (iii) Option 5GN, using FSRU Nikiski at Alaska LNG's export dock; and (iv) Option 5GA, development of a greenfield FSRU terminal at a new site.[10]

14. Another option identified as the top-scoring alternative in Phase I, the In-State Pipeline from the North Slope of Alaska, underwent a permitting review, but not a full conceptual engineering effort. This is because more detailed engineering and permitting work has already been completed on a very similar project that served as the basis for the In-State Pipeline Option (AGDC-owned ASAP project). The threshold barrier to developing a large-diameter pipeline from the North slope of Alaska by members of the Working Group is the relatively low level of in-state gas demand that makes the economics of that project challenging, and prevents the Working Group from being able to move the project forward in a meaningful way without government subsidies.

15. As part of BRG Phase II Assessment, BRG and its contractors developed a detailed schedule of activities for the design and development of all four shortlisted options, comprised of up to 170 individual activities per schedule. BRG used a probability analysis for the likely duration of all schedule activities. The key threshold uncertainty in the schedule is the duration of the Federal Energy Regulatory Commission ("FERC")-led LNG import terminal permitting process,

[10] The numbering of the option refers to a system originally stemming from each option's position on a longer Phase I list. It is included here to easily reference these options in detailed design appendices.

and the nature and extent of the connected National Environmental Policy Act ("NEPA") review. The integrated schedules were also reviewed by ENSTAR's legal representatives.

16. The results of this in-depth analysis showed that none of the four shortlisted options could meet the target of delivering first gas or LNG by late 2027 due to likely permitting and construction schedule constraints. The estimated in-service date for the four large-scale options falls between late 2029 and 2033, with the entirely greenfield option having longest schedule duration.

17. These schedule findings prompted a second look at smaller-scale LNG import options that could provide for a more expedited schedule (i.e. earlier first-gas date) and potentially lower "stranded investment" in case of the development of a major gas pipeline project, which would make lower-cost gas available in the long term. The two distinct options that were identified by ENSTAR and BRG were LNG shipments in ISO containers and LNG shipments using smaller cryogenic vessels. Variations of these options have been examined in earlier stages of feasibility studies, including by ENSTAR in 2020, and were dismissed as either high cost and/or not easily scalable for larger imports. In addition, both options have more limited supply sources than those available using standard-size LNGCs. However, due to the schedule priority, BRG returned to these options. BRG used the findings of Phases I and II of this project for a refreshed scoping exercise. The results of this additional study are described in Chapter 5 of this report.

18. The summary of the key characteristics and metrics of all options reviewed by BRG Phase II Assessment is presented in the table below.

Table 1: Summary of Key Characteristics of All Options in BRG Phase II Assessment

		Full Scale Scenarios:					Reduced Scale Options		
#		1	2	3	4		5	6	7
Scenario		3K Ph. 1 & 2 - Kenai LNG	5M - FSRU Marathon	5GN - FSRU Nikiski	5GA - FSRU Greenfield		Small Scale LNG	ISO Anchorage	ISO MacKenzie
Brief Description		LNG delivered to Marathon dock, onshore storage and regassification. In Ph. 2, LNG tanks are replaced with new tank, system expanded.	LNG delivered to moored FSRU at Marathon dock, offshore storage and regassification	LNG delivered to moored FSRU at AlaskaLNG site dock, offshore storage and regassification	LNG delivered to moored FSRU at a new Parcel 68 - site dock, offshore storage and regassification		LNG delivered to FSU, shuttle tankers deliver LNG from FSU to the Marathon dock	ISO containers with LNG delivered to Port of Alaska	ISO containers with LNG delivered to Port MacKenzie
FSRU/FSU		no	FSRU	FSRU	FSRU		FSU	no	no
Start of Commercial Operations		Ph1: Q1 2030 - Q4 2030 Ph2: Q3-2031 - Q2 2032	Q4 2029 - Q1 2031	Q4 2029 - Q1 2032	Q1 2032 - Q3 2033		Q1 2029 - Q3 2029	Q4 2026	Q4 2026 +
Capacity (BCF)		Ph1: < 50 BCFA Ph2: Full Unmet Need	Full unmet need (up to ~ 70 BCFA)	Full unmet need (up to ~ 70 BCFA)	Full unmet need (up to ~ 70 BCFA)		Up to 52 BCF, expandable	6 BCF	6 BCF
Onshore CAPEX	(1)	$ 609	$ 285	$ 552	$ 376	(2)	$ 120	$ 47	$ 61
Offshore CAPEX (Ships)	(3)	$57mm tugs	$269 mil. FSRU, $57mm tugs $4.4 th/hour each + fuel	Same as 5M	Same as 5M	(4)	$217 mil. FSU & chartered shuttle	Four OSV ship charters.	

		Full Scale Scenarios:					Reduced Scale Options		
#		1	2	3	4		5	6	7
LNG DES Basis	(5)	Henry Hub forecast X 115% + $5.8/MMBtu (2023$)					Same as full scale but delivery to FSU	AECO + Fortis B.C. Tariff + Shipping	
LNG Cost (DES)	2034 $ ($/MMBtu)	$11.7	$11.7	$11.7	$11.7	2030 $ ($/MMBtu) (6)	$10.4	$16.9	$16.9
Onshore Cost		$2.2	$1.3	$1.8	$1.3		$1.4	$6.5	$7.0
Offshore Cost		$0.4	$1.2	$1.2	$1.2		$2.4	-	-
Total Delivered Cost		**$14.2**	**$14.2**	**$14.6**	**$14.2**		**$14.3**	**$23.4**	**$23.9**
Total Delivered Cost	2034$ ($/Mcf) (7)	**$14.6**	**$14.6**	**$15.1**	**$14.6**	2030 $ ($/Mcf)	**$14.7**	**$24.1**	**$24.6**

(1) Excludes site acquisition costs.

(2) Including $11 million cost of ISO Containers ($55 th. X 200 containers).

(3) $269mm FSRU is nominal equivalent of $160mm vessel purchase + $80mm vessel conversion. $57mm for tugs is nominal equivalent of 2X $25mm.

(4) $244mm FSU is nominal equivalent of $160mm vessel purchase + $50mm vessel conversion.

(5) Delivery to FSU or Cook Inlet. 3K scenario includes $0.13 uplift to DES price for partial cargoes as a result of limited tank storage through 2032.

(6) $16.9 DES LNG price is $8.7 Canada FOB + ISO $8.3 shipping. Small-scale 10-year levelization shown, levelizing over 20 years reduces delivered cost for small scale LNG by $0.95, ISO onshore facilities levelized over 7 years.

(7) Assumed heat content: 1030 Btu/cubic foot.

19. FSRUs or LNGCs delivering to the FSRU and the FSRU itself should be winterized to operate in severe cold conditions with temperatures down to minus 40 deg C (minus 40 deg F). However, USCG regulations do not require employment of Ice-Classed vessels in Cook Inlet.

20. Based on ENSTAR's specifications for the gas received and delivered, BRG reached out to around 31 potential suppliers with lean LNG in their portfolio to gather information and gauge their interest in the project, of which 17 suppliers expressed interest and eight of them participated in a tailored questionnaire.

21. The range of quality specifications provided by the potential suppliers range between GCV 1,000 to 1,180 Btu/scf. After review of the current utility equipment limitations and requirements, BRG and Cornerstone provided a draft tariff modification for changing the gas quality specifications for interconnected pipelines and customers in Southcentral with input from all utilities. The recommended tariff specifications balance the need for flexibility in supply sources, cost of gas treatment, and avoid dramatic changes in current transmission systems. It is expected that some investments in metering upgrades will still be necessary, and are outside of BRG's scope in this project.

22. To define the various processes required to execute the project, a procurement strategy adapted for ENSTAR comprising six stages has been identified. The strategy consists of (i) Scope – defining and finalizing specification and identifying long lead items; (ii) Risk Assessment – developing a risk management plan, conduct due diligence and having contingency plans; (iii) Supplier / Subcontractors – identifying and evaluating suppliers and subcontractors and evaluating delivery timelines; (iv) Bid – selecting contracting structure, drafting request for proposal and evaluating bids; (v) Order – negotiating contracts and evaluating insurance requirements; and (vi) Order Management – evaluating risks and opportunities, monitoring quality and progress and budget control.

1.4 Structure of the Report

23. The final detailed engineering design, cost, and schedule work products that were referenced in the various options can be found in Appendix A.

2 FORECAST OF UNMET GAS DEMAND NEED

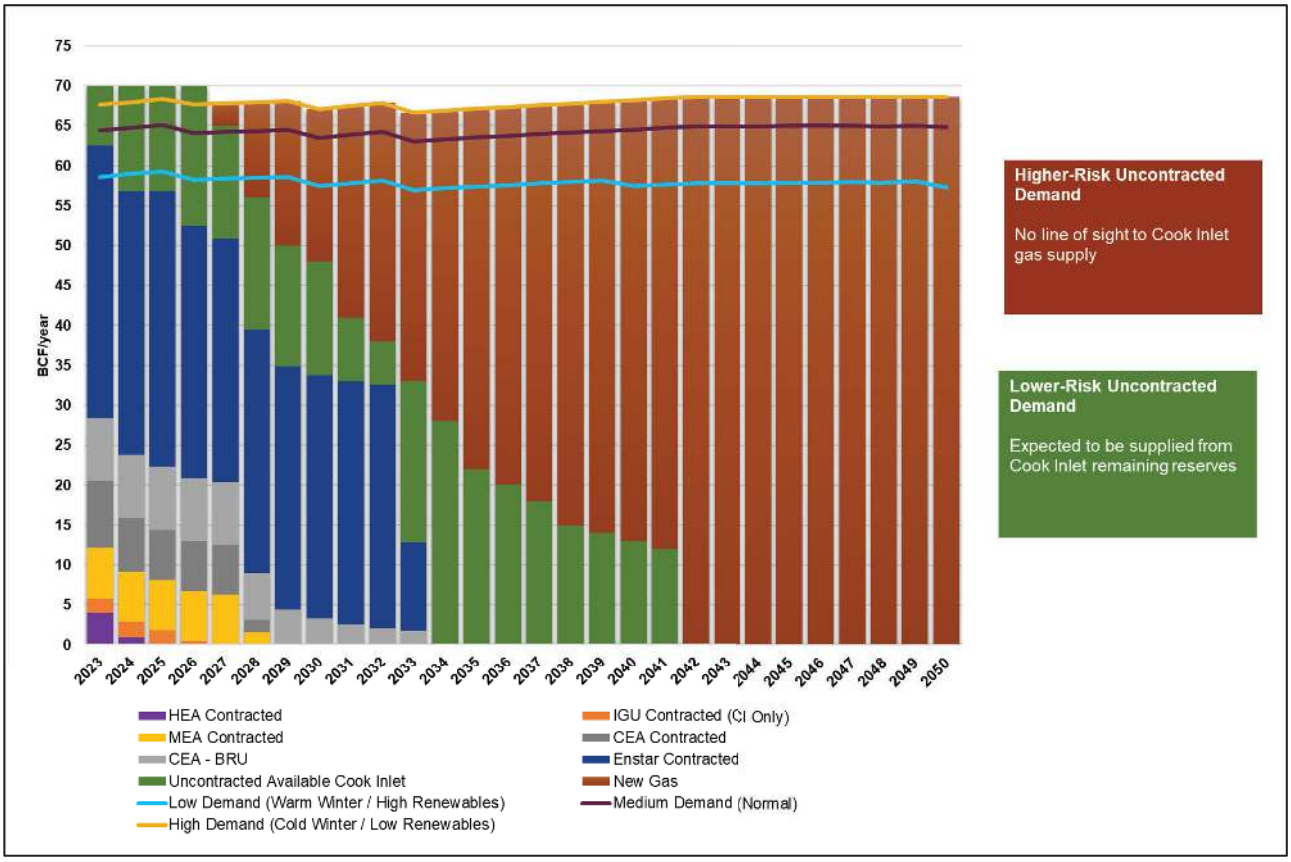
2.1 Historic and Current Demand for Natural Gas by the Working Group

24. In Phase II, BRG estimates the unmet need as the difference between high gas demand scenario as provided by utilities and contracted gas supply. Unmet need is higher in Phase II report because contracted gas supply is a more conservative measure of gas availability to utilities than Cook Inlet production forecasted by DNR that was used to forecast gas supply in BRG's first report. The Working Group prepared a public demand and available supply assessment in the fall of 2022/ early 2023, which signaled additional demand and potentially higher prices for prospective Cook Inlet suppliers, however no significant additional supply arrangements followed over the last year and half.

25. The figure below represents the Working Group's range of demand forecasts (line charts) compared to currently contracted supply by utility, un-contracted reserves (green bars, based on ADNR's "Mean Truncated" case from 2022 Cook Inlet Gas Forecast,[11] and the resulting unmet need for natural gas supplies in the future (orange bars).

[11] State of Alaska Department of Natural Resources, Division of Oil and Gas, 2022 Cook Inlet Gas Forecast, January 2023.

Figure 2: Utilities' Contracted and Uncontracted Demand vs Cook Inlet Supply

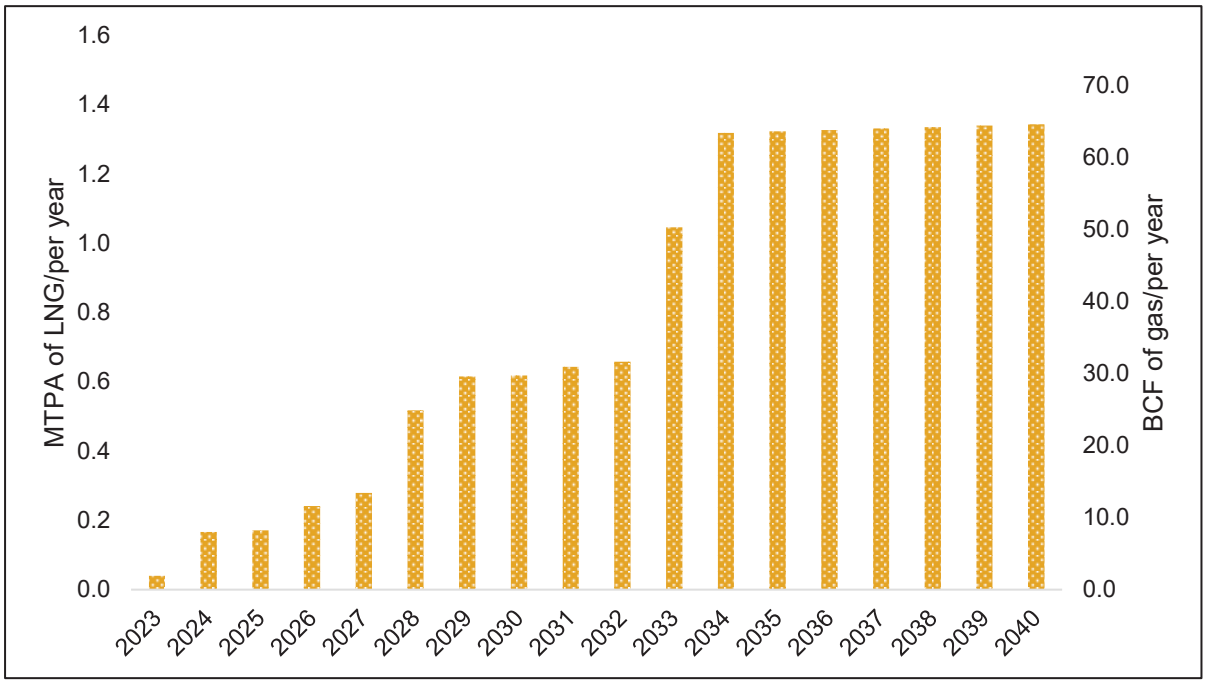


26. It is prudent for a utility to ensure it has sufficient supply to meet its customer demand under high demand requirements. Therefore, to estimate the requirements for gas supply and project requirements for this project, the team used the difference between High Demand and contracted volumes. This "uncontracted gas demand," which excludes IGU demand covered by LNG from the North Slope, more than doubles between 2030 and 2034 from around 30 BCF to almost 64 BCF respectively as Hilcorp contracts roll-over. New Cook Inlet gas supply contracts would lower the uncontracted demand while additional customers on the system would have the opposite effect. Uncontracted demand requirement is also anticipated to vary from year to year in line with annual distribution of heating degree days, affected by temperature. Based on this updated more conservative assumption, BRG Phase II Assessment used the following annual uncontracted gas demand for the determination of project capacity needs. This forecast is presented below in terms of normal/high demand range in BCF/year and as high demand in BCF and million tons per year ("MTPA") of LNG.

Table 2: Uncontracted Gas Demand by Year (BCF)

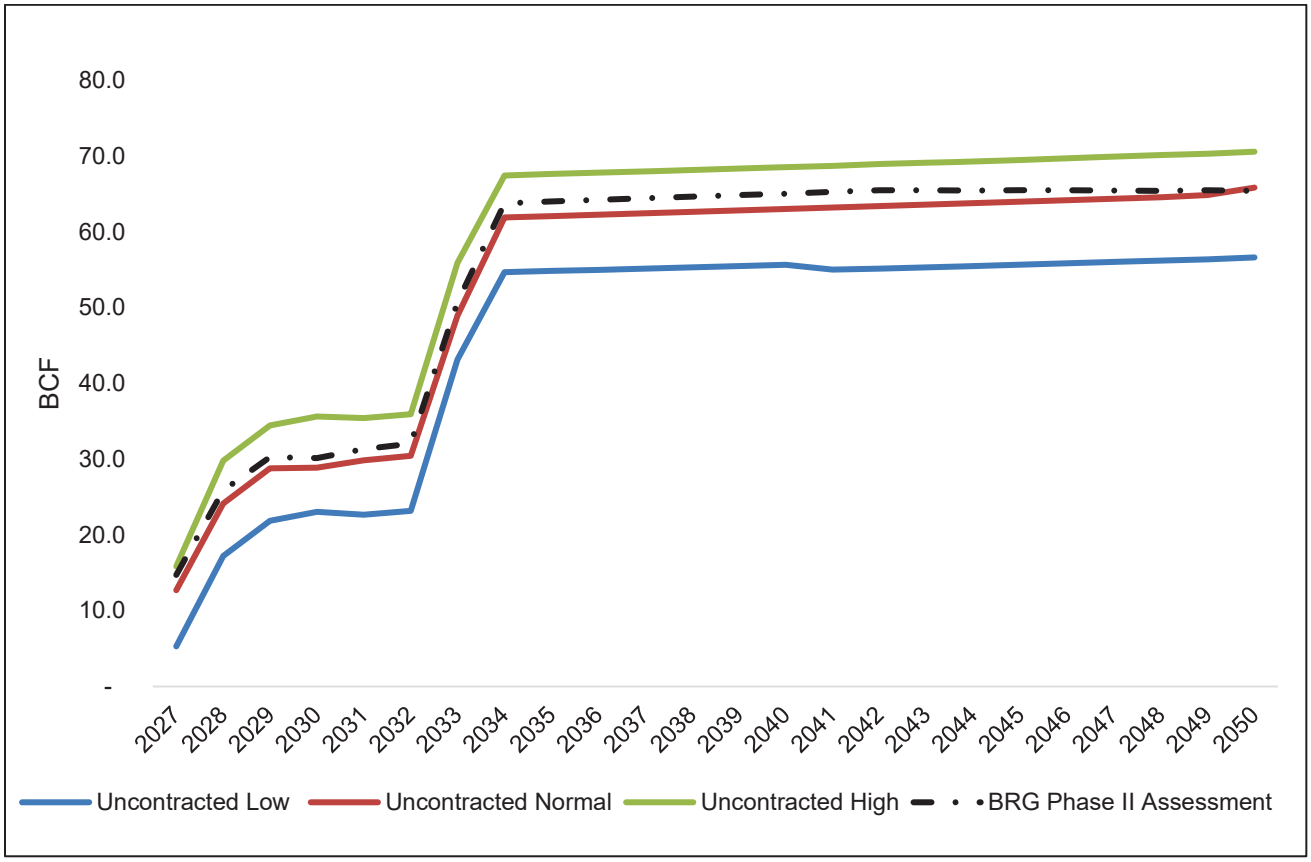
	Normal Demand	High Demand
2027	11.1	14.7
2028	22.3	25.9
2029	26.7	30.3
2030	26.5	30.1
2031	27.7	31.3
2032	28.4	32.1
2033	47.1	50.7
2034	60.2	63.8
2035	60.4	64.0
2036	60.6	64.2
2037	60.8	64.4
2038	61.0	64.7
2039	61.2	64.9
2040	61.4	65.0

Figure 3: Uncontracted Gas Demand as Basis for Project Capacity Assumptions



27. In March 2024, ENSTAR provided another update to the forecasted demand. BRG reviewed this forecast provided by ENSTAR in March 2024, which adjusted for updated fuel gas use in the upstream operations and utilities demand forecast. BRG benchmarked the uncontracted demand used in this study (identified as "BRG Phase II Assessment" in the figure below) against updated "Warm", "Normal" and "Cold" demand net of contracted supply. Uncontracted demand forecasts based on "Warm", "Normal" and "Cold" demand estimates are identified as "Uncontracted Low", "Uncontracted Normal", and "Uncontracted High" and depicted below.

Figure 4: Uncontracted Gas Demand Comparison

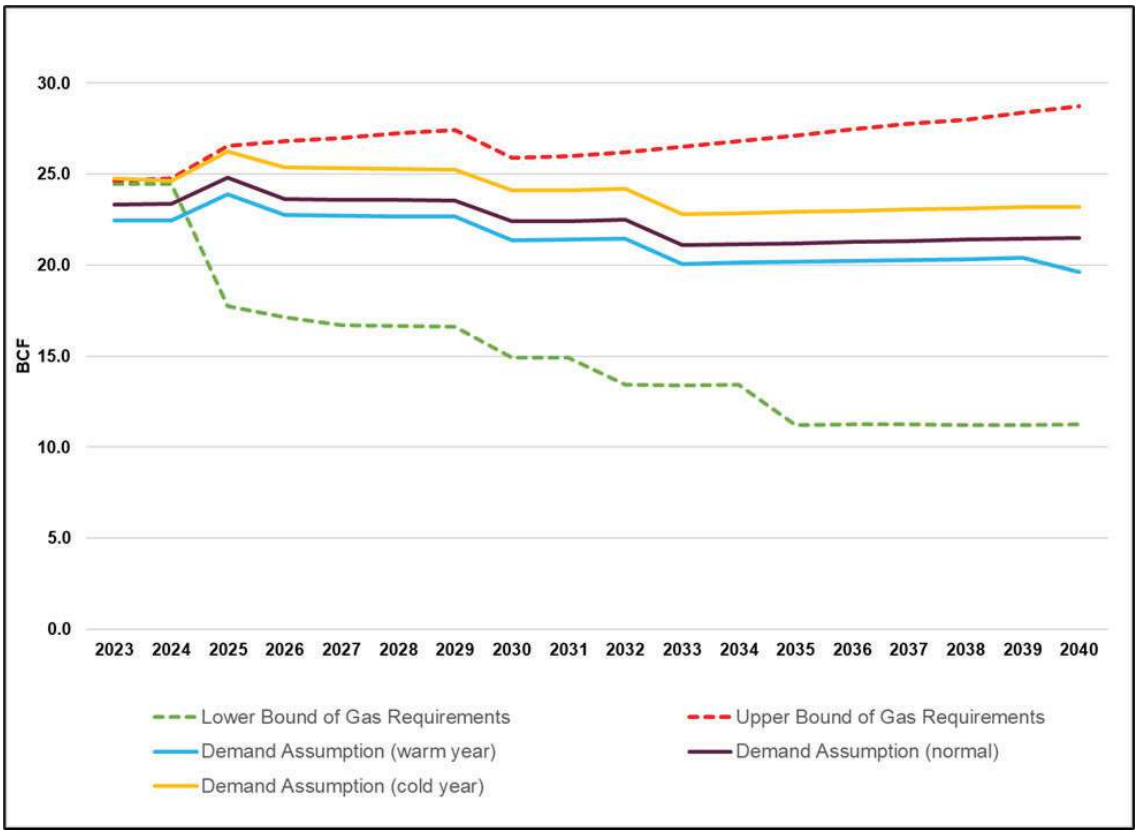


28. The BRG Phase II Assessment uncontracted gas demand falls within the range between the updated "Warm" and "Cold" forecasts of uncontracted demand estimates, net of contracted volumes. BRG understands that the difference between "Warm" and "Cold" is based on a distribution of heating degree days or temperature around Cook Inlet.

29. Due to this similarity of results, BRG staff determined that the uncontracted demand forecast used in this study is a reasonable estimate of uncontracted demand for the purposes of determining levelized cost and within the range of uncertainty associated with the number of residential and industrial customers, weather, and additional supply.

30. There are factors, other than annual temperatures, that can affect future unmet need. On the demand side, additional gas offtakes by industrial customers such as the Donlin Mine, or increased use by existing customers, can increase the unmet need by 12 BCF or more.[12] On the other hand, increased coal power generation, or an expedited pace of renewable power adoption can reduce the unmet need in the power generation sector. The range of outcomes for unmet need for natural gas for the electricity generation sector based on the pace of renewable power adoption is depicted in Figure 5.[13]

Figure 5: Residual Gas Requirements for Power Generation Post Renewable Power Integration



31. On the supply side, additional discoveries and developments in Cook Inlet, or resolution of technical challenges associated with existing Cook Inlet production could reduce unmet need. For example, resolution of technical and commercial issues associated with the Kitchen Lights unit development, or gas development in the Cosmopolitan unit, or additional discoveries

[12] *See* CIGSP Phase 1 Report BRG 28June2023.pdf, Table 1.

[13] Electric utilities' work product from Phase I Assessment, representing a range of gas supply requirements based on several power demand and renewable power integration scenarios.

could all result in additional gas supply and decrease the unmet need at some point in the future.

32. Gradually increasing unmet need would increase the cost of LNG supply, since initial investment and operating costs would have to be amortized over lower volume. BRG considered several phased approaches to better align capital costs and capacity with the growing projections of unmet need requirement.

3 LONG-TERM PROJECT OPTIONS

3.1 Kenai LNG / Onshore Gasification (3K)

3.1.1 Design Description

33. This development concept contemplates construction of an onshore storage and regassification at 48237 Kenai Spur Highway, in Kenai, AK, that would be supplied by winterized LNGC vessels without the need for an FSRU. The site is a former ConocoPhillips LNG export facility, currently owned by Marathon. Site access needs to be secured prior to executing this option. This is a phased development concept that will leverage existing storage tanks in Phase 1 of Kenai LNG, and will add a new 3.7 BCF storage tank to replace existing LNG storage in Phase 2 of Kenai LNG.[14] Project requires numerous federal and state permits, Department of Energy ("DOE") authorization, and likely an Environmental Impact Statement ("EIS"), or another form of NEPA review, coordinated by FERC as part of its authority under the Natural Gas Act ("NGA") Section 3.[15]

3.1.2 Phase 1 of Kenai LNG

34. Phase 1 of Kenai LNG (Option 3K) contemplates both onshore and offshore construction and modifications to existing infrastructure to repurpose existing facilities for LNG exports. Work required includes pier improvements, power distribution improvements and modifications, modification of existing tanks and LNG transfer pumps, boil-off-gas ("BOG") handling modifications and upgrades, installation of three 45 million standard cubic feet per day ("MMSCFD") vaporizers including booster pumps, nitrogen generation and gas treatment plant, gas metering and delivery system to access Harvest transmission and ENSTAR transmission pipeline systems. Because of storage capacity limitations, at Phase 1 the project would be able to accommodate up to 105,000 m^3 of LNG per cargo (2.3 BCF of gas), which could be delivered via a smaller (compared to market standard) or a partially-loaded vessel.[16]

[14] Option 03K Kenai LNG Phase I Scope of Work, §3.

[15] Option 03K Kenai LNG Phase I Scope of Work, §4; Option 03K Kenai LNG Preliminary Permitting Matrix, p. 1.

[16] Option 03K Kenai LNG Design Basis Document, ¶8.1, p. 19.

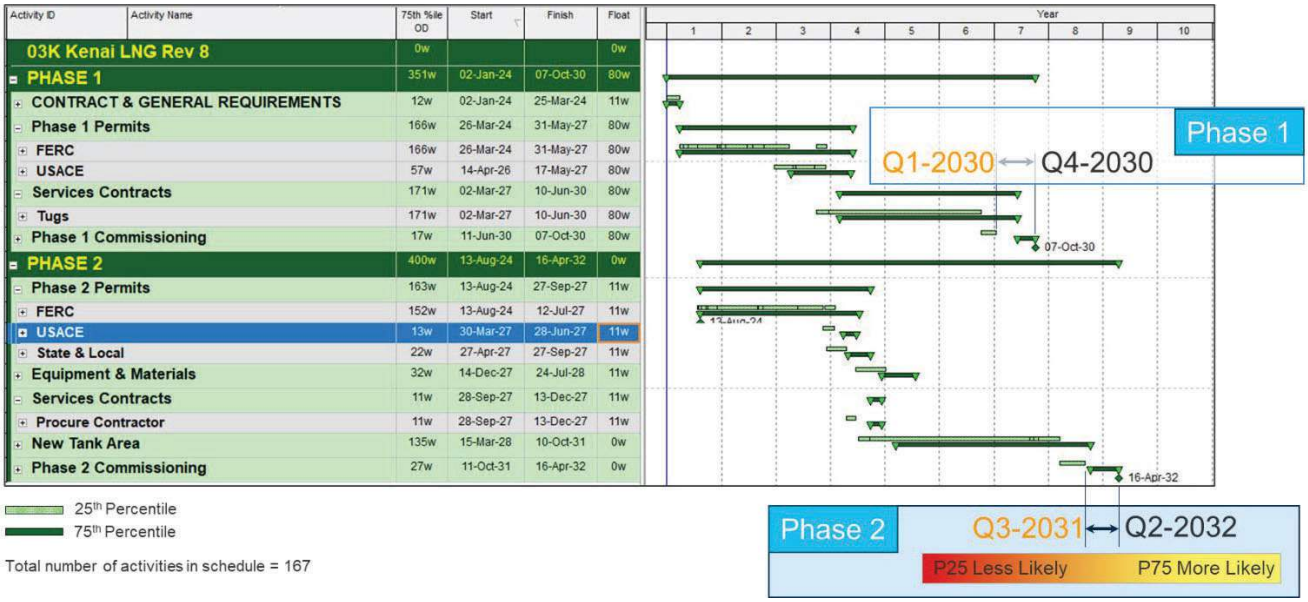
3.1.3 Phase 2 of Kenai LNG

35. Phase 2 of Kenai LNG contemplates only onshore construction including the construction of a ~3.7 BCF storage tank to accommodate fully loaded 170,000 m^3 vessels, and two additional 45 MMSCFD vaporizers. Other modifications would include dike area modifications, installation of new concrete spillway and sump, additional BOG equipment and expansion of the nitrogen generation system.[17]

3.1.4 Project Schedule

36. The project schedules presented below summarizes the P25 (less likely) and P75 (more likely outcomes of major activity categories for Phase 1 and Phase 2 of this option.

Figure 6: Option 3K – Phase 1 of Kenai LNG Project Schedule Summary



37. Critical path items for Phase 1 of Kenai LNG include: [18]

38. Jurisdiction and ratemaking treatment determination;

39. Engineering & Design: Utilities, Hazard, FEED;

40. LNG Supply Negotiations and Contracting;

41. Financing;

42. Construction Contractor Selection;

43. Engineering & Design: Detailed Design;

[17] Option 03K Kenai LNG Phase II Scope of Work, §3.

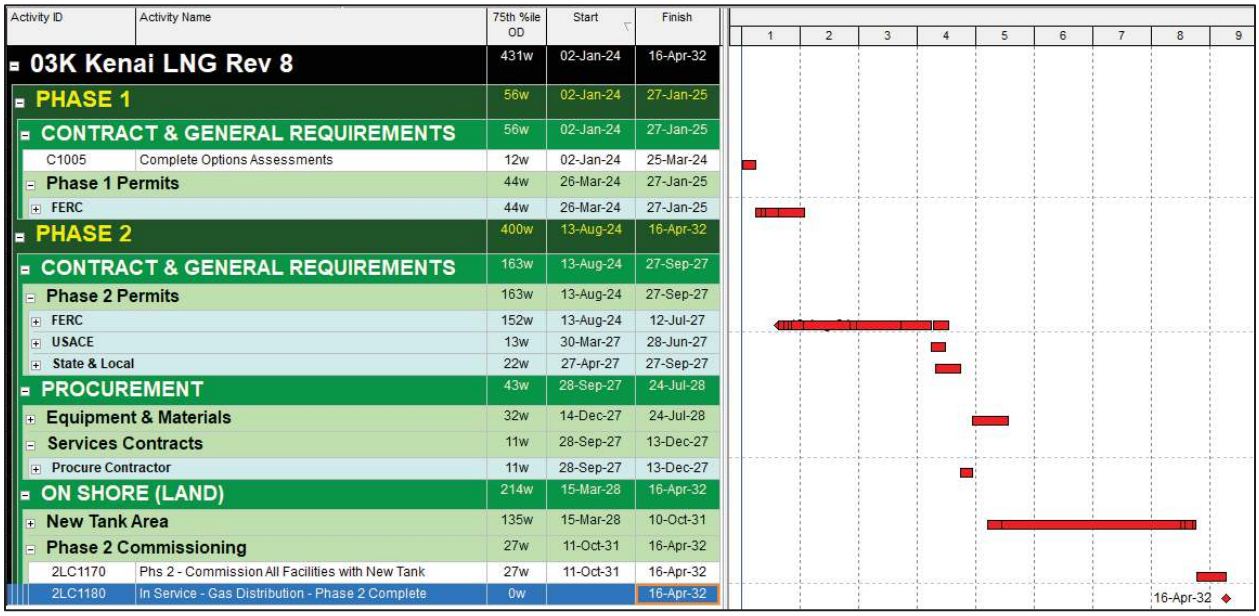
[18] Option 03K Kenai LNG Schedule P75.

44. Offshore Construction: Dredging, Pier/Dock and Mooring Dolphin Upgrades; and
45. Commissioning.
46. The primary assumptions for Phase 1 Kenai LNG project schedule are:
47. Many of the existing federal, state and local permits can be updated rather than start anew; and
48. Offshore work not possible during November to February of each year due to winter/ice conditions.[19]
49. Critical path items for Phase 2 of Kenai LNG include: [20]
    a. Permitting: FERC, USACE and Kenai Peninsula;
    b. Construction Contractor Selection;
    c. Materials Procurement;
    d. Onshore Construction: New Tank, Piping; and
    e. Commissioning
50. The primary assumptions for Phase 2 of Kenai LNG project schedule are:
51. New EIS and permitting will be required for the new tank;
52. Reasonable period to address any intervenor concerns given existing industrial land use;
53. Likely streamlined ROW approval process; availability of additional land necessary for the tank from one existing landowner; and
54. Onshore construction is limited during November to February of each year due to winter conditions.
55. The resulting P75 critical path summary of the combined Kenai LNG Regasification (Option 3K) is presented in the figure below.

[19] These assumptions were made prior to access and review of the Marathon facility permits, and are subject to change and uncertainty based on regulatory determinations.

[20] Option 03K Kenai LNG Schedule P75.

Figure 7: Option 3K – Joint Phase 1 and Phase 2 of Kenai LNG Project Schedule Summary[21]



Activity ID	Activity Name	75th %ile OD	Start	Finish
03K Kenai LNG Rev 8		431w	02-Jan-24	16-Apr-32
PHASE 1		56w	02-Jan-24	27-Jan-25
CONTRACT & GENERAL REQUIREMENTS		56w	02-Jan-24	27-Jan-25
C1005	Complete Options Assessments	12w	02-Jan-24	25-Mar-24
Phase 1 Permits		44w	26-Mar-24	27-Jan-25
FERC		44w	26-Mar-24	27-Jan-25
PHASE 2		400w	13-Aug-24	16-Apr-32
CONTRACT & GENERAL REQUIREMENTS		163w	13-Aug-24	27-Sep-27
Phase 2 Permits		163w	13-Aug-24	27-Sep-27
FERC		152w	13-Aug-24	12-Jul-27
USACE		13w	30-Mar-27	28-Jun-27
State & Local		22w	27-Apr-27	27-Sep-27
PROCUREMENT		43w	28-Sep-27	24-Jul-28
Equipment & Materials		32w	14-Dec-27	24-Jul-28
Services Contracts		11w	28-Sep-27	13-Dec-27
Procure Contractor		11w	28-Sep-27	13-Dec-27
ON SHORE (LAND)		214w	15-Mar-28	16-Apr-32
New Tank Area		135w	15-Mar-28	10-Oct-31
Phase 2 Commissioning		27w	11-Oct-31	16-Apr-32
2LC1170	Phs 2 - Commission All Facilities with New Tank	27w	11-Oct-31	16-Apr-32
2LC1180	In Service - Gas Distribution - Phase 2 Complete	0w		16-Apr-32

3.1.5 Key Considerations and Risks

56. This option requires the use of existing site and facility owned by Marathon. Site acquisition or other commercial arrangement with Marathon is a precursor to construction in this option.

57. One of the key features of Kenai LNG / Onshore Gasification option as contemplated in this assessment is the ability to reuse existing tanks and leverage existing permits to reduce lead time. This option is most complex from an engineering and construction perspective, as it requires construction and improvements at an existing brownfield site, which poses a risk of cost overruns during construction.

58. While not currently on a critical path, scope of in-water construction can have material impact on permitting and schedule, to the extent the work proves to be more extensive than previously anticipated. More detailed information about the state of existing facilities could reduce uncertainty associated with the scope, cost, and schedule of in-water construction.

59. Limited storage in Phase 1 can adversely impact LNG procurement and shipping flexibility and will likely raise the cost of LNG supply. This option does, however, provide a real option to forego Phase 2, if additional supply is not needed beyond aninitial five-year time horizon.

[21] The "Phase 2" activities in this figure, such as "Phase 2 Permits," combine similar activities from both phases of the project that will be happening concurrently.

3.2 Marathon FSRU (5M)

3.2.1 Design Description

60. This development concept contemplates acquisition and refurbishment of an existing LNG carrier into an FSRU vessel of up to 170,000 m^3 (3.7 BCF equivalent) capacity, that would be permanently moored to the Marathon pier located at 48237 Kenai Spur Highway, in Kenai, AK, former ConocoPhillips LNG export facility.[22] LNG would be delivered year-round by LNGC and transferred to the FSRU using shipboard transfer pumps and flexible cryogenic hoses or loading arms.[23] The concept contemplates that the vaporization capacity is installed in stages to provide up to 225 MMSCFD send-out rate (or up to 82 BCF per year) by 2032.[24] Natural gas unloading arms would be connected to a single 16'' high-pressure natural gas pipeline that would operate at about 725 psig.[25]

61. Similar to 3K, this development concept leverages existing infrastructure and permits currently owned by Marathon. Additional facilities would include a high-pressure natural gas feeder line, power supply to both the onshore facility & the FSRU vessel, a nitrogen generation plant that would extract nitrogen form the air and inject it into the natural gas stream to reduce BTU content for the ENSTAR transmission system, and a gas metering building where flow rate, btu content, and impurities would be measured as well as an emergency generator.[26] From the gas metering building, gas flow would be directed to either the 16" line that connects to Harvest Transmission's 20" pipeline, or an 8" line that connects to ENSTAR's existing 8".[27]

3.2.2 Project Schedule

62. The project schedule presented below summarizes the P25 (less likely) and P75 (more likely outcomes of major activity categories for this option.

[22] Option 05M FSRU Marathon Design Basis Document, ¶8.1.

[23] Option 05M FSRU Marathon Design Basis Document, §5.

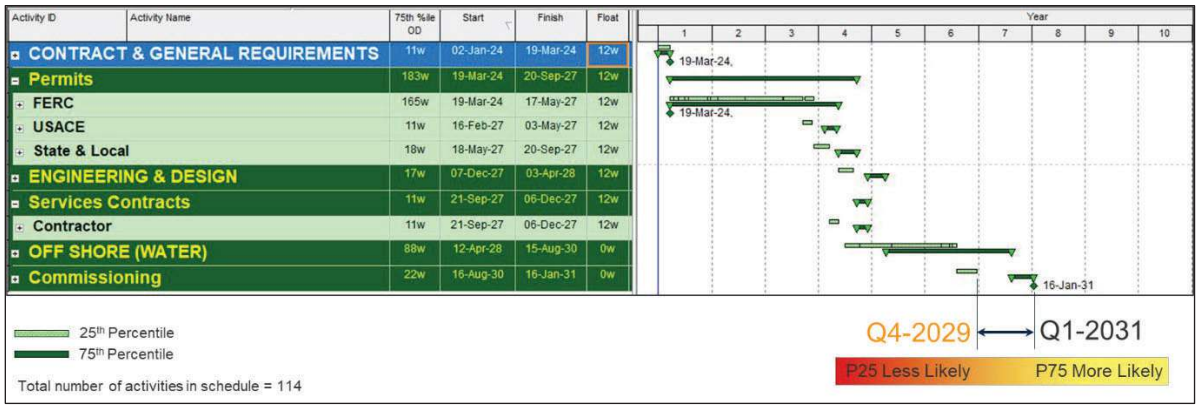
[24] Option 05M FSRU Marathon Design Basis Document, §6.

[25] Option 05M FSRU Marathon Design Basis Document, §6.

[26] Option 05M FSRU Marathon Design Basis Document, §5.

[27] Option 05M FSRU Marathon Design Basis Document, §5.

Figure 8: Option 5M – FSRU Marathon Project Schedule Summary



63. Critical path items include: [28]

    a. Permitting: FERC, USACE and Kenai Peninsula;

    b. Construction Contract Award and Contracting;

    c. Marine Surveys and Engineering;

    d. Offshore Construction: Pier/Dock and Mooring Dolphin Upgrades; and

    e. Commissioning.

64. The primary assumptions for the project schedule are:

    a. New EIS and permitting will be required for FSRU and new tank;

    b. Capital expenditures for FSRU and tugs succeed permit approvals and financing;

    c. Any additional land or ROW will be easily attainable;

    d. Existing or new tug boats can be acquired within 30 months;

    e. Retrofit and Delivery of FSRU within 18 months;

    f. Offshore construction not possible during November to February of each year due to winter/ice conditions; and

    g. Onshore construction limited during November to February of each year due to winter conditions.

3.2.3 Key Considerations and Risks

65. At a minimum, this option requires the use of the existing jetty owned by Marathon, and a portion of the site. Site acquisition or other commercial arrangement with Marathon is a precursor to construction in this option.

[28] Option 05M FSRU Marathon Schedule P75.

66. Similar to the Kenai LNG / Onshore Regasification option, one of the key features as contemplated in this study is the ability to leverage existing permits to reduce lead time. The permitting duration for FSRU Marathon using the Kenai LNG site is expected to take ~ 2.5 years with ~ 30 permits and/or approvals required. Additional permitting requirements could delay construction and impact commissioning timeline.

67. While not currently on a critical path, scope of in-water construction, in particular due to the new use of the jetty for year-round FSRU mooring, can have material impact on permitting and schedule, to the extent the work proves to be more extensive than previously anticipated. More detailed information about the state of existing facilities could reduce uncertainty associated with the scope, cost, and schedule of in-water construction.

3.3 Nikiski FSRU (5GN)

3.3.1 Design Description

68. The Alaska LNG export project ("AlaskaLNG") has completed Pre-FEED and permitted a two-berth dock design near the existing Kenai LNG Marathon dock. The development concept contemplates construction of the dock as designed, and in cooperation with the export project sponsor, Alaska Gasline Development Corp., and acquisition and refurbishment of an existing LNGC into an FSRU vessel of up to 170,000 m^3 (3.7 BCF equivalent) capacity that would be permanently moored to the AlaskaLNG pier. LNG would be delivered year-round by LNGC and transferred to the FSRU using shipboard transfer pumps and flexible cryogenic hoses or loading arms.[29] The concept contemplates that the vaporization capacity is installed in stages to provide up to 225 MMSCFD send-out rate (or up to 82 BCF per year) by 2032.[30]

69. This development concept leverages AlaskaLNG FERC approval that could save permitting-related delays but requires construction of a new jetty based on AlaskaLNG requirements.[31] Additional facilities would include a high-pressure natural gas feeder line, a nitrogen generation plant that would extract nitrogen from the air and inject it into the natural gas stream to reduce BTU requirements for the ENSTAR transmission system, and a gas metering building where flow rate, btu content, and impurities would be measured as well as an emergency generator.[32] From the gas metering building, gas flow would be directed to either the 16" line that connects to Harvest Transmission's 20" pipeline, or an 8" line that connects to ENSTAR's existing 8" transmission line that currently terminates at the Kenai LNG plant from when the liquefaction plant was in operation or both.[33]

[29] Option 05GN FSRU Nikiski Design Basis Document, §6.

[30] Option 05GN FSRU Nikiski Design Basis Document, ¶7.2.

[31] Option 05GN FSRU Nikiski Design Basis Document, §5.

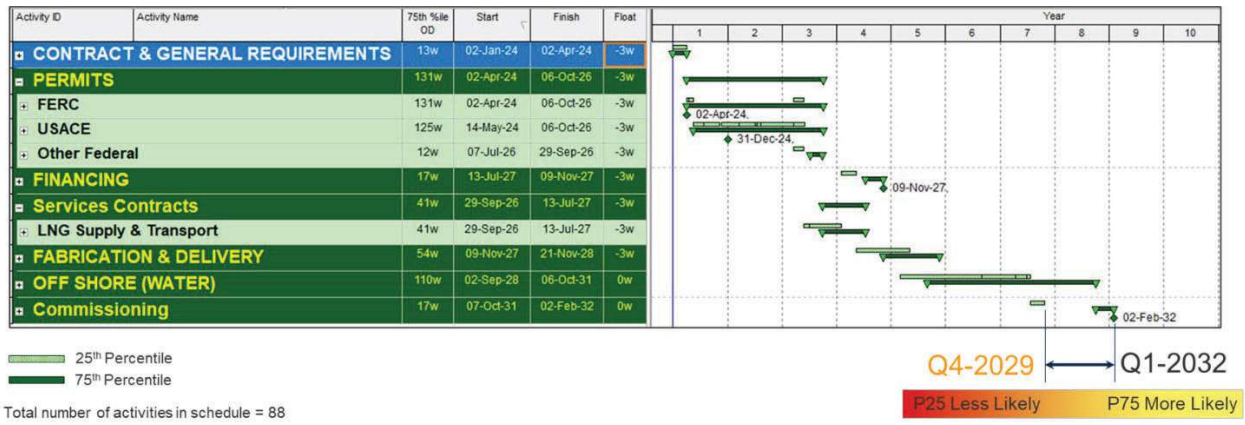
[32] Option 05GN FSRU Nikiski Design Basis Document, ¶11.2.9

[33] Option 05GN FSRU Nikiski Design Basis Document, §6.

3.3.2 Project Schedule

70. The project schedule presented below summarizes the P25 (less likely) and P75 (more likely outcomes of major activity categories for this option.

Figure 9: Option 5GN – FSRU Nikiski Project Schedule Summary



71. Critical path items include: [34]
    a. FEED completion;
    b. Permitting: FERC, USACE and USCG;
    c. LNG Supply Negotiations and Contracting;
    d. Financing;
    e. Steel Fabrication for Dock Construction;
    f. Offshore Construction: Double-Berth Pier, Piping;
    g. Connect FSRU to Dock; and
    h. Commissioning.
72. The primary assumptions for the project schedule are:
    a. Reduced FERC permitting duration for onshore facilities;
    b. Supplemental EIS and permitting will be required for FSRU and acquired within two and a half years;
    c. Capital expenditures for FSRU and tugs succeed permit approvals and financing;
    d. Availability of additional land or ROW if required;

[34] Option 05GN FSRU Nikiski Schedule P75.

e. Existing or new tug boats can be acquired within 30 months;

f. Retrofit and Delivery of FSRU within 18 months;

g. Offshore construction not possible during November to February of each year due to winter/ice conditions; and

h. Onshore construction limited during November to February of each year due to winter conditions.

3.3.3 Key Considerations and Risks

73. The key considerations and risks that may affect Option 5GN's outcome as modeled in this report are:

a. FERC regulatory delay – the advantage of this development concept relative to a greenfield development is in the AlaskaLNG FERC export authorization.. For example, the Waterway Suitability Assessment, which was formerly reviewed as part of initial application for the AlaskaLNG export project, is a key asset that could expedite project development for import. However, the scope of environmental approvals is unclear until Section 3 application is submitted and reviewed by FERC. Since FERC authorization is on a critical path, changes to FERC approval schedule could lead to a project delay.

b. Dual requirement of constructing the LNG import project while preserving the option for possible LNG exports leads to:

c. An increase in the project cost e.g. dock modification would need to satisfy AlaskaLNG requirements;

d. Commercial complexity as at least one additional stakeholder, AGDC, would need to be included in the project development process;

e. Loss of flexibility in choosing between an RCA-regulated and an unregulated project as AGDC anticipates that this project would not be subject to rate regulation ;

f. Potential adverse impacts on the delivered cost of gas due to the necessity to maintain flexibility for the AlaskaLNG dock to be converted into an export dock. This need for flexibility would likely result in shorter-duration agreements that may be needed for the FSRU and LNG supply compared to a dedicated import facility, and thus higher costs.

3.4 Greenfield FSRU (5GA – Parcel 68)

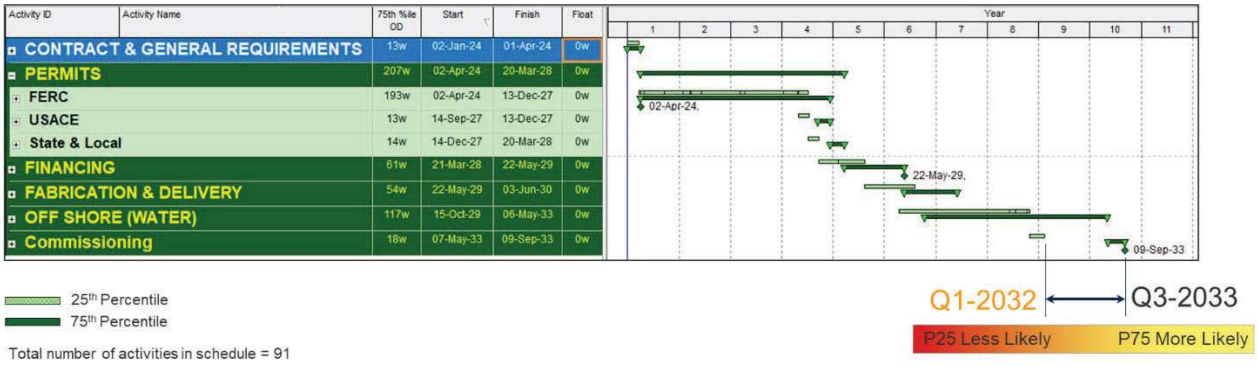
3.4.1 Design Description

74. This option is similar to 5GN, but the pier and onshore facilities would be located on what is referred to as "parcel 68."[35] Furthermore, this greenfield development options contemplates pier design specific to LNG import without the requirement for AGDC input. This development concept contemplates acquisition and refurbishment of an existing LNG carrier into a 170,000 m^3 (3.7 BCF equivalent) FSRU vessel that would be permanently moored to the newly constructed pier and powered from shore. LNG would be delivered year-round by LNGC and transferred to the FSRU using shipboard pumps and flexible cryogenic hoses or loading arms.[36] The concept contemplates that , like other FSRU options, up to 225MMSCFD vaporization would be available by 2032 and involves the same "cold ironing" (FSRU receiving power from onshore source) concept, gas treatment, measurement, and interconnect design to provide volumes to both Harvest and ENSTAR transmission systems.

3.4.2 Project Schedule

75. The project schedule presented below summarizes the P25 (less likely) and P75 (more likely outcomes of major activity categories for this option.

Figure 10: Option 5GA – Greenfield FSRU Project Schedule Summary



76. Critical path items include: [37]

    a. Options Assessment;

    b. Permitting: FERC, USACE and Kenai Peninsula;

    c. Financing;

[35] Option 05GA Parcel 68_Site Search Report_Final.pdf.

[36] Option 05GA FSRU Parcel 68 Design Basis Document, §5.

[37] Option 05G FSRU Parcel 68 Schedule P75.

d. Steel Fabrication for Dock Construction;

e. Offshore Construction: Double-Berth Pier, Piping;

f. Connect FSRU to Dock; and

g. Commissioning.

77. The primary assumptions for the project schedule are:

a. New EIS and permitting will be required for FSRU and acquired within four years;

b. Capital expenditures for FSRU and tugs succeed permit approvals and financing;

c. Any additional land or ROW will be attainable within permitting duration;

d. Existing or new tug boats can be acquired within 30 months;

e. Retrofit and Delivery of FSRU within 18 months;

f. Offshore construction not possible during November to February of each year due to winter/ice conditions; and

g. Onshore construction limited during November to February of each year due to winter conditions.

3.4.3 Key Considerations and Risks

78. The key considerations and risks that may affect Option 5GA's outcome as modeled in this report are:

a. General Greenfield Schedule Uncertainty – Greenfield concept will require schedule allowance for site acquisition, permitting, and construction. Development can experience unanticipated delays and unknown unknowns that are difficult to forecast.

b. Regulatory delay – FERC approval is required to construct LNG facility, including full Environmental Impact Statement. Full authorization is anticipated to require around 4 years but can take longer. Similarly, U.S. Army Corps of Engineers permits especially 404 Clean Water Act permit would be required. Delays in obtaining authorization could extend the schedule and delay first gas deliveries.

c. Time to secure site control – land acquisition would be required for this option. Cost of acquiring the land and the timeline required to obtain any additional easements and rights-of-ways is uncertain at this point.

d. Funding risk - significant capital is required for this development. Difficulty in obtaining the necessary debt and equity financing could delay the project or force the project sponsor to seek more expensive sources of capital.

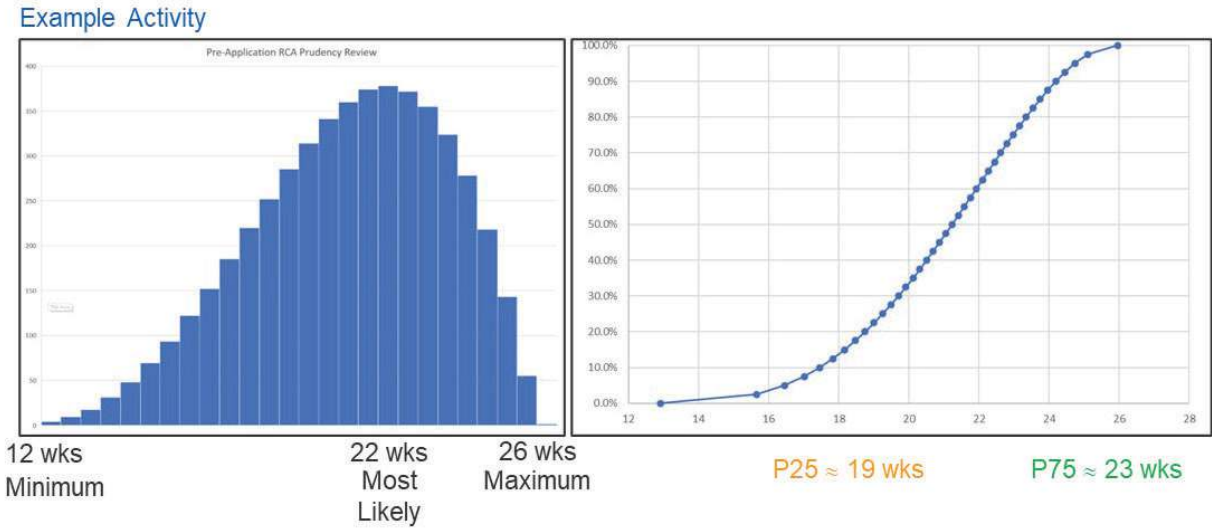
4 COMPARISON OF PHASE II OPTIONS

4.1 Schedule Development Methodology

79. BRG developed detailed schedules for all options, assuming that each of the projects would be ready to begin moving forward with next execution steps by 2Q 2024. The accuracy of the forecasted project schedules is meaningful down to one quarter due to the inherent uncertainty of the permitting and commercial processes, and the level of engineering completed at this stage.

80. The project schedules contain up to 170 activities, with defined probability-based durations for each activity following a Pert distribution. The figure below provides an example of an activity's duration across a range of probabilities.

Figure 11: Probability Distribution of Scheduled Activity (Example)

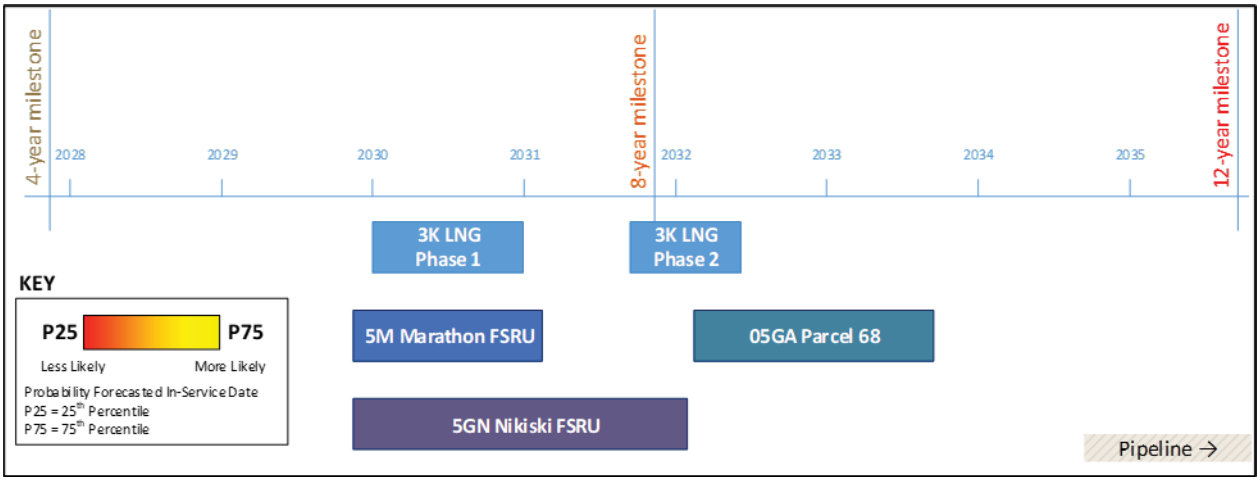


81. Using project schedule and statistical software, we ran 5,000 iterations for each of the activities, thus defining a range of possible schedule outcomes for each option. In presenting results, we used a standard industry approach of showing probability-weighted outcomes in the range of P25 (i.e. more optimistic, with 25% probability of occurrence) to P75 (i.e. more conservative, with 75% probability of occurrence) for project duration.

82. The following summary shows the P25 to P75 range of probabilities for each project option's in-service dates, when the project can start receiving and delivering first gas. None of the options meet the original target in-service date of 4Q 2027, however Kenai LNG Regasification (3K) and Marathon FSRU (5M) options have the best chance of achieving earliest in-service dates of all the options reviewed. The greatest schedule uncertainties are related to FERC and

US Corp of Engineers permitting durations, and time required to modify or construct in-water piers. Certain schedule-driven assumptions have been made for all options, such as the requirement to begin long-lead item procurement and conclude conditional commercial agreements prior to the issuance of major permits. The detailed schedule outputs are included in Appendix A.2.

Figure 12: Summary Schedule Finding for In-Service Dates by Option.



4.2 Cost of Supply

4.2.1 Cost Development Methodology

83. Project development and construction costs were developed by Cornerstone with inputs from specialty subcontractors. Wherever possible, similar line-item costs for projects executed over the last 18 months were used in the estimates.

84. BRG further estimated project management oversight costs using a level-of-effort approach, with benchmarking to standard industry project metrics. The level-of-effort costs were estimated using inputs per month by stage of the project, namely for a) FEED, b) Detailed Design, c) Permitting, d) Construction, and e) Turnover to Operation. The original Cornerstone project cost estimates were also phased using the schedule outcomes, and applying escalation assumptions to create a nominal cost estimate.

85. Cost contingency assumptions were derived using a structured process to assess each option's level of maturity in each category of costs. The cost estimate and contingency assumptions are included in Appendix A.3.

86. Shipping costs including FSRU and new tugs were developed by Precision LNG. To quantify the total cost in $/Mcf, BRG levelized all costs, other than LNG supply, in money-of-the-day terms based on anticipated supply shortfall and weighted average cost of capital allowance

of 8.4%, based on BBB rated U.S. based midstream entities.[38] For LNG supply, BRG used an average of EIA forecasts and forward curves to project Brent and Henry Hub-based LNG price, as discussed in greater detail below.

4.2.2 Project Costs

87. The onshore capital cost estimates developed in BRG Phase II Assessment for the import terminal range between $285 million and $552 million depending on the option selection. These costs do not include site acquisition, FSRU lease that would apply to several of the options as a multi-year charter cost, or costs associated with leasing or acquiring new tugs. However, all of these costs are included in the calculation of the levelized cost of supply per MMBtu.

Table 3: Onshore Project Cost Comparison for Large Scale LNG Options

Onshore Capital Costs $ million	3K-Kenai Phase 1	3K-Kenai Phase 2	5M-Kenai Marathon	5GN - Nikiski FSRU	5GA - Greenfield
FEED Engineering	$ 13	$ 3	$ 9	$ 10	$ 8
Detail Design Engineering	$ 8	$ 2	$ 10	$ 11	$ 9
Permitting	$ 24	$ 2	$ 35	$ 31	$ 68
Land Acquisition	TBD	TBD	TBD	TBD	TBD
Design Development Costs	**$ 46**	**$ 6**	**$ 54**	**$ 53**	**$ 85**
Fabrication, Delivery & Site Work	$ 12	$ -	$ 1	$ 10	$ 5
Offloading, Pier, Construction	$ 27	$ -	$ 39	$ 114	$ 49
Ice Mitigation Structures	$ -	$ -	$ 65	$ 66	$ 67
Transfer Piping	$ 9	$ 1	$ 7	$ 110	$ 19
Buildings / Facilities	$ 119	$ 217	$ 3	$ 7	$ 4
Engineering and Prof. Services	$ 25	$ 16	$ 53	$ 77	$ 56
Construction Costs	**$ 193**	**$ 234**	**$ 168**	**$ 383**	**$ 200**
Contingency	**$ 63**	**$ 67**	**$ 62**	**$ 116**	**$ 91**
Onshore Capital Costs	**$ 302**	**$ 307**	**$ 285**	**$ 552**	**$ 376**

4.2.3 Vessel Capital Costs

88. The cost of acquiring an FSRU is estimated to range from $60 to $160 million depending on availability and the type of vessel used for FSRU conversion. Precision LNG estimates that a used LNG carrier with diesel electric drive would cost approximately $160 million while an LNG carrier with steam turbine drive could be available at a cost as low as $60 million. Another $80 million would be required for conversion. BRG assumed that the higher cost diesel electric LNG carrier would be refurbished, and did not add contingency to the $80 million refurbishment cost as savings associated with finding a cheaper vessel would likely offset

[38] Tugs were assumed to have lower cost of capital of approximately 6%, to account for subsidized MARAD financing and Capital Construction Cost benefits a portion of which would likely be passed on to end users.

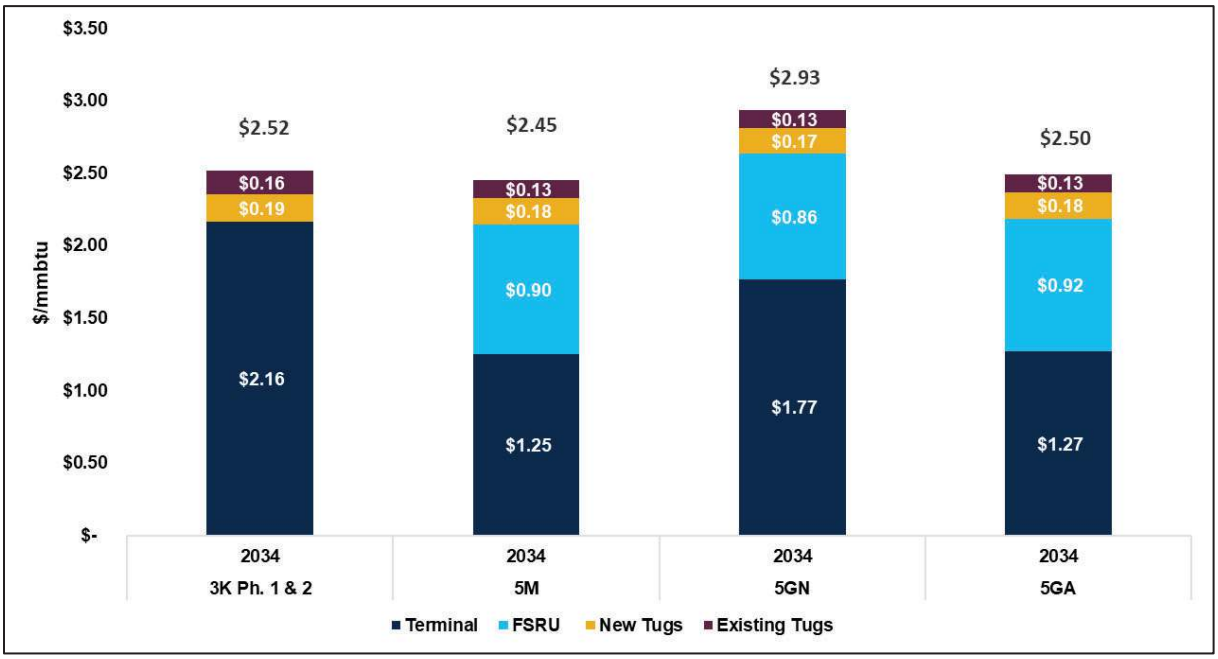
contingency estimate for vessel refurbishment. New Jones Act compliant tugs were assumed to be approximately $25 million each.

89. LNG supply would likely include a transportation cost component, however, BRG estimates that LNG price in the Pacific Rim already reflects the cost of LNG deliveries, and Alaska specific differential would be negligible or potentially negative, for example if the actual cargoes are sourced from Canada and shipped over the shorter distance to Alaska instead of Asia.

4.2.4 Levelized Cost

90. To estimate the cost to final consumers and to compare across scenarios BRG levelized the costs associated with the onshore terminal, FSRU (where applicable), and the two new tugs. The cost of utilizing existing tugs is assumed to remain the same on an inflation adjusted basis. Onshore terminal and FSRU levelized based on WACC of 8.4% for midstream investment grade companies. New tugs assume to require 6% cost of funding, based on MARAD financing and use of Capital Construction Fund benefits. Terminal levelized over a period of 20 years, FSU and Tugs levelized over 15 years. Levelized cost comparison is depicted in Figure 16.

Figure 13: Levelized Infrastructure Costs by Option ($ nominal).



4.2.5 Operating Costs

91. Annual operating costs are depicted below. These costs include operating costs associated with tug and FSRU operations but do not include the capital recovery component associated with acquiring and refurbishing FSRU or the new tugs.

Table 4: Operating Costs Comparison for Large Scale LNG Options

Annual Operating Costs $ million	3K-Kenai Phase 1 & 2	5M-Kenai Marathon	5GN - Nikiski FSRU	5GA - Greenfield
Onshore Terminal	$21.3	$16.1	$15.7	$15.9
FSRU	n/a	$10.2	$10.2	$10.2
2 existing tugs	$6.6	$6.6	$6.6	$6.6
2 new tugs	$3.7	$3.7	$3.7	$3.7
	$31.6	**$36.6**	**$36.2**	**$36.4**

4.2.6 Costs of Supply Forecast

92. BRG considered two primary LNG price scenarios including:

    a. Global Integrated – Gas Basis: Henry Hub X 115% + $5.8/MMBtu adder, 50% of the adder adjusted for inflation; and

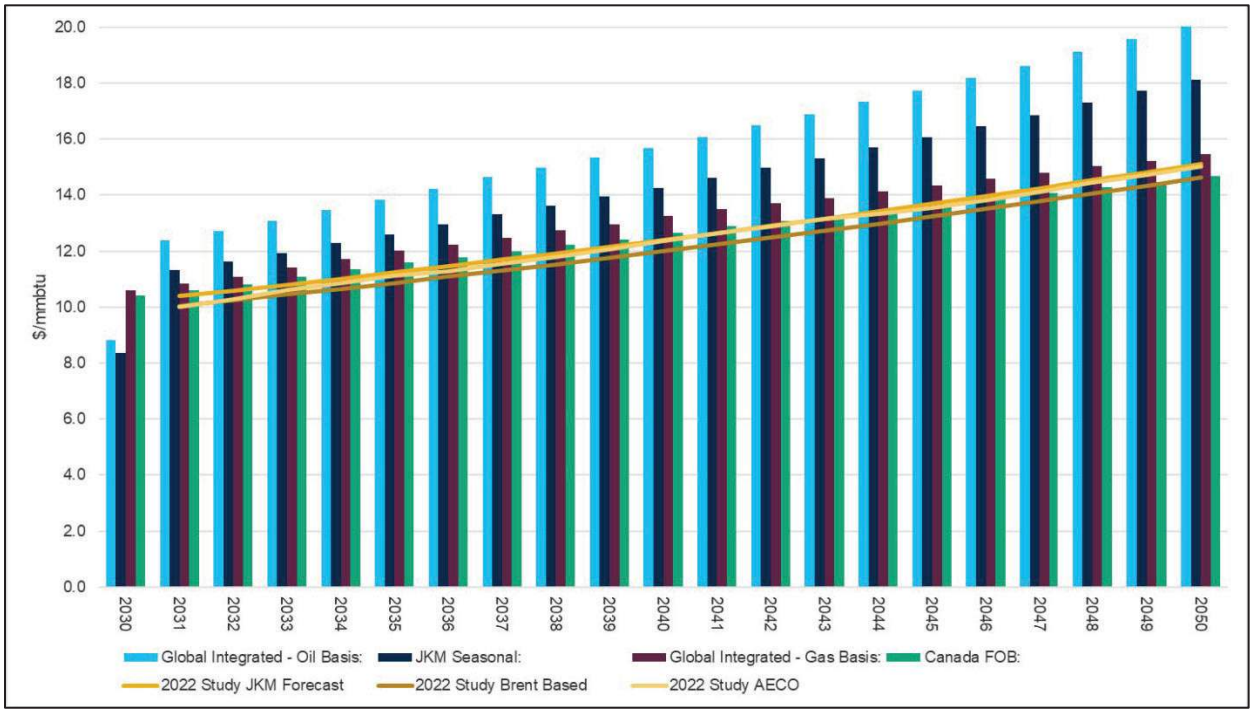
    b. Global Integrated – Oil Basis: Brent-based cost structure with 13% slope.

93. BRG also considered alternative scenarios such as Canada Free on Board ("FOB"), and seasonal Japan Korea Market ("JKM"). However, the reference case used across all full-scale options is Global Integrated – Gas Basis which is the average of EIA 2023 long-term outlook scenarios for Henry Hub and Henry Hub Forward curves from 2nd half of 2023.

94. Ultimately BRG determined that "Global Integrated – Gas Basis" best reflects the cost of the underlying commodity, and at the time of this study exhibits lower differential between forward curves and EIA forecasts when compared to "Global Integrated - Oil Basis" forecast.

95. The figure below represents the resulting delivered LNG (DES) forecasts using different bases (bars), and comparing them to the price forecasts presented in the BRG Phase 1 Assessment (lines). The "Global Integrated – Gas Basis" forecast aligns closely with previous Phase 1 findings.

Figure 14: Long-term LNG price forecast with different scenarios[39]



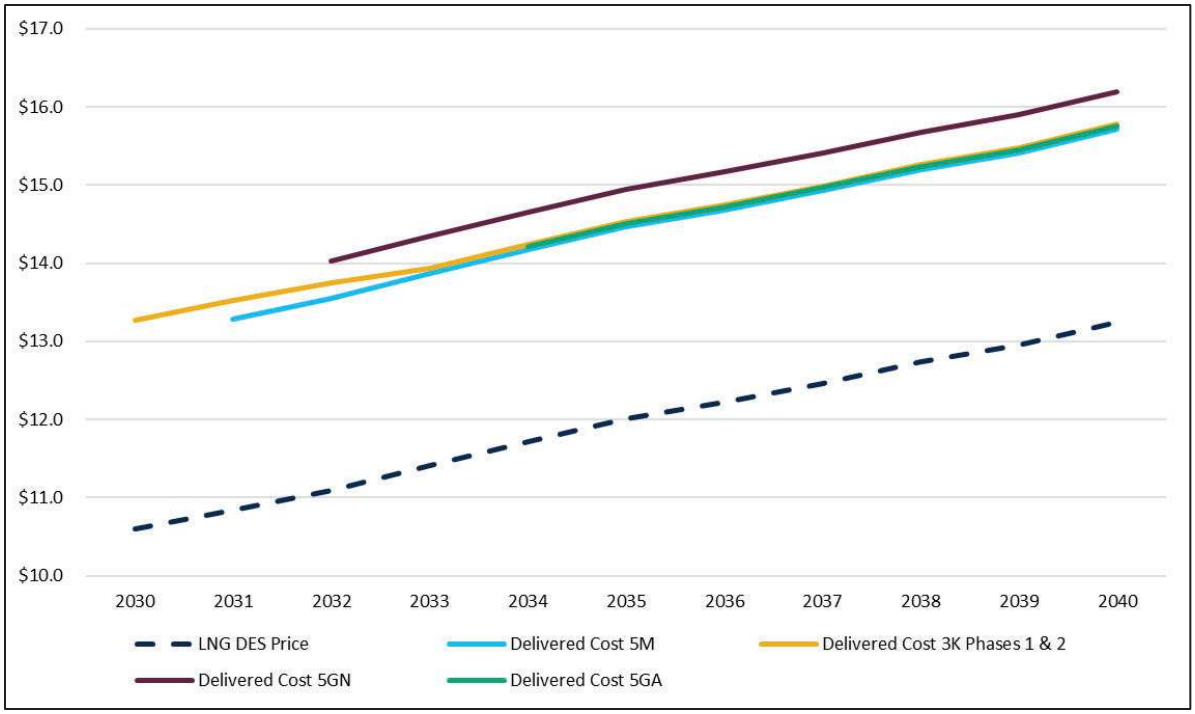
96. The selected LNG pricing assumptions were informed by the results of the LNG supplier Request for Information ("RFI") process described below.

4.2.7 Estimated Delivered Cost

97. Estimated delivered cost is the sum of levelized cost components and DES LNG price, as described above. Forecasted delivered cost is depicted in the figure below:

[39] BRG LNG Tolling Model.xlsm, tab "LNG Prices". Note in this study BRG assumed Henry Hub-based LNG contracts as the reference case. For the purposes of analysis detailed in this report, BRG used five forward strips from July to December 2023. This choice was made to provide for a more robust analysis based on multiple data points. Furthermore, for long-term forecasting BRG averaged these forward curves with EIA long-term Henry Hub forecast. Note in Q1 2024, natural gas prices continued to fall. On March 13, 2024, March 2024 Henry Hub futures were $1.658/MMBtu, on December 15, 2023, March 2024 Henry Hub future were $2.333. However, long term forward curves did not change significantly. Average forward for 2030 delivery changed by less than $0.10 between December 15, 2023 and March 13, 2024. BRG did not include the 2024 strip since impact on the long-term average would have been negligible.

Figure 15: Delivered Cost by Option and LNG Price (DES) in $/MMBtu



4.3 LNG Suppliers' Request for Information Results

98. BRG conducted a request for information ("RFI") process with a group of prominent suppliers of LNG in order to gauge the interest, availability, and potential contract terms for bringing LNG supply to Cook Inlet for the first time.

4.3.1 Initial RFI Results

99. BRG contacted a total of 31 potential suppliers with lean LNG in their portfolio and Pacific basin operations. While the project is at early stage of development to obtain any formal supply commitments, a total of 17 suppliers expressed interest in potentially supplying LNG to Cook Inlet. From these, 8 suppliers participated in the RFI questionnaire, providing non-binding responses about their ability to supply LNG and the preferred contract terms. Overall, 11 suppliers signed NDAs with ENSTAR, indicating their commitment to enter into more detailed LNG procurement discussions once the project concept selection is complete and better defined.

100. Furthermore, 4 suppliers declined to participate in the RFI questionnaire and in the RFP process at this stage. However, BRG believes that these suppliers could still represent potential candidates for LNG supplies, and there could be an opportunity to reach out after the project concept is selected, after the suppliers' respective projects achieve FID, or after

their LNG supply availability in the Pacific basin becomes clearer. BRG will involve them in the subsequent stage of the LNG procurement process.

101. On the other hand, 5 suppliers indicated not to be interested in the project and 5 suppliers did not respond to the RFI solicitation efforts at this stage.

102. The RFI process was helpful in determining the feasibility and potential contract terms of receiving LNG supply in Alaska in the quantities, quality, and within the schedule necessary for the project. Next steps in the LNG procurement process involve a formal solicitation of interest that includes a better-defined scope and schedule of the LNG import terminal project, demand requirements, and a defined buyer entity.

4.3.2 Feedback Received from Suppliers during RFI

103. The LNG suppliers indicated that due to the early stage of the project development they were unable to provide formal commitments for the LNG supply or any firm contract terms. Only after the concept selection is complete and technical specifications of the LNG receiving terminal are known, the suppliers will be able to provide key information including shipping and LNG vessel's compatibility, volumes, duration, and preferred pricing terms. Hence, the information provided by the suppliers during the initial RFI process is only indicative and subject to further discussions.

104. The suppliers indicated that the lean LNG could be sourced from a global portfolio of projects or from specific liquefaction projects located in Canada (LNG Canada), Mexico (Mexico Pacific LNG), Australia (Wheatstone, Darwin and Queensland Curtis LNG projects), and other regions (Peru LNG, Papua LNG, Atlantic LNG, Tangguh LNG). Considering the location of the project within the Cook Inlet, Canada supplies would represent the most logistically convenient location, minimizing the shipping costs. However, careful consideration should be given to all the other supply locations based on offered pricing terms, delivery flexibility and other contractual terms, in order to assess the overall cost benefits for the project.

105. The minimum supply volumes offered by suppliers range between 0.2 MTPA (~10 BCF) to "as large volumes as possible". The minimum SPA term offered is for 5 years, with preference for longer term SPAs which typically encompasses better pricing as compared to short term SPAs. Most of the suppliers also indicated ability to accommodate spot deliveries.

106. The preferred price indexation varies by supplier and the timing of a portfolio which will be driven by the project schedule and the targeted in-service date. While the pricing terms can be determined only once the concept selection is complete, multiple market indexation options are available.

107. Most suppliers are able to accommodate deliveries on delivered ex-ship ("DES") basis. The range of quality specifications for lean LNG provided by suppliers varies between GCV 1,000 to 1,180 Btu/scf. Some suppliers have also provided quality specifications for specific liquefaction projects that could be potential supply candidates to Cook Inlet.

108. The suppliers expressed concerns about the potential requirement for a dedicated Ice-Classed vessels, of which availability in the market is limited. Since the USCG regulations do not require employment of Ice-Classed vessels in Cook Inlet, but only winterized vessels, this should provide greater shipping flexibility to the suppliers for LNG deliveries. However, the vessel's compatibility can only be determined once the project location is selected, and the project configuration is sufficiently defined.

109. Other concerns raised were related to the certainty of the domestic Alaska demand both on short-term and long-term basis, that would underpin the SPAs, as well as the likelihood of the competing Alaska LNG export project materializing. Suppliers also enquired about the entity that will be selected from the group of utilities as the credit-worthy SPA buyer, and the entity that will act as the terminal operator, with previous operational experience of regasification terminals.

110. Other than exclusively supplying LNG to the project, some suppliers offered to provide an "end to end" solution, including procurement of FSRU and LNGC to the project. These proposals will require further discussions.

111. The summary of the RFI responses received by the potential suppliers have been incorporated in Appendix B. These responses are non-binding and subject to further discussions once the project concept selection is complete.

5 SMALL-SCALE LNG IMPORT SOLUTIONS

112. At the conclusion of Phase II, key findings prompted a second look at smaller-scale LNG import options that could provide for a more expedited schedule (i.e. earlier first-gas date) and potentially lower stranded investment in case of a major gas pipeline project going forward, making lower-cost gas available in the long term. The two distinct options that were identified by ENSTAR and BRG were LNG shipments in ISO containers and LNG shipments using smaller cryogenic vessels. Variations of these options have been examined in earlier stages of feasibility studies, including by ENSTAR in 2020, and were dismissed as either high cost and/or not easily scalable for larger imports. In addition, both options have more limited supply sources than those available using standard-size LNGCs. However, due to the schedule priority BRG returned to these options. BRG used the findings of Phases I and II of this project for a refreshed scoping exercise.

113. In order to meet the first gas schedule priority, the design of both options was subject to the following conditions:

a. The solution must use existing facilities in Alaska without extensive modification, especially without in-water works or jetty construction or expansion that would increase permitting time windows;

b. The solution must rely on existing and available vessels that either comply with or are exempt from Jones Act requirements and are functionally appropriate for Alaska waters;

c. The solution must use existing technologies or configurations commonly used in the LNG industry; and

d. The solution must rely on existing or under-construction (i.e. post-FID) facilities for supply of LNG.

114. Onshore Capital Costs for the three options are summarized in Table 5.

Table 5: Onshore Capital Cost Summary for Small-Scale LNG Import Solutions

Onshore Capital Cost ($ thousands)	Small Scale LNG	ISO Anchorage	ISO MacKenzie
Development Phase Costs			
FEED Engineering & Project Management	$ 3.6	$ 0.8	$ 1.6
Detail Design Engineering & Project Management	$ 1.3	$ 1.1	$ 1.1
Permittng (Permits, Engineering Support & Project Management)	$ 5.0	$ 3.7	$ 4.4
Development Phase Costs	**$ 9.9**	**$ 5.6**	**$ 7.1**
Fabrication & Delivery	$ -	$ -	$ -
Sitework	$ 0.8	$ 0.4	$ 0.4
Offloading, Pier, FSRU Construction	$ 1.1	$ -	$ 8.4
Ice Mitigation Structures	$ -	$ -	$ -
Transfer Piping	$ 0.6	$ 0.1	$ 0.3
Buildings / Facilities	$ 72.1	$ 18.6	$ 19.5
Engineering and Project Management Professional Services	$ 9.3	$ 2.8	$ 2.8
Construction Phase Costs	**$ 84.0**	**$ 21.9**	**$ 31.5**
Contingency	**$ 25.8**	**$ 8.3**	**$ 11.8**
Total	**$ 119.8**	**$ 35.8**	**$ 50.3**

5.1 Small-Scale LNG Supply Examples in the US

115. Within the scope of this option, LNG would be shipped to Alaska in intermodal containers manufactured according to the specifications outlined by the International Organization for Standardization ("ISO"). ISO containers can be transported on standard container vessels, by truck, or by rail, and are used widely for LNG distribution around the world. The capacity and mobility of ISO containers lends itself to remote or distributed power generation or transportation fuel solutions, as well as for peaking fuel solutions.[40] ISO containers commonly come in 20-foot or 40-foot length; due to the size of demand, only the larger 40-foot (11,500 gal) containers are considered for Alaska. The capacity of each container is approximately 830 Mcf.[41]

116. Other remote locations in the United States have employed small-scale LNG bulk imports and ISO containers as part of their energy mix, for example Puerto Rico and Hawaii. These operations are reviewed in the section below.

[40] US Energy Information Administration, Natural Gas Weekly Update, October 27, 2016, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2016/10_27/.

[41] US Energy Information Administration, Natural Gas Weekly Update, October 27, 2016, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2016/10_27/.

5.1.1 Puerto Rico Example: San Juan Terminal and Palo Seco Emergency Power Installation

5.1.1.1 LNG Imports

117. Puerto Rico relies largely on a mix of LNG (43%), diesel fuel (37%), and coal (15%) for its power generation mix, supplemented by renewable resources (3%). Puerto Rico's electricity prices are the highest in the nation after Hawaii, at around 25 cents per kW/h. [42] Much of the high costs is attributable to the inefficiency of the power generation system and the reliance on diesel fuel.

118. Puerto Rico imports LNG via two existing terminals, Ponce and San Juan, where other fuels and other goods are also imported. In total, Puerto Rico imported 71 billion cubic feet ("BCF") of gas in 2021. [43] Ponce is able to accept cargoes of around 1.4 BCF in size, still smaller than standard in the current international LNG market. [44] The San Juan terminal is the smaller one of two active LNG import terminals in Puerto Rico, an example of a small-scale import operation using bulk LNG. It has accepted approximately 25 BCF of gas in the form of LNG in the first 9 months of 2023, with 5-10 shipments per month, and between 150 and 600 million cubic feed ("MMcf") in each shipment from Trinidad and Tobago or Nigeria. [45] The LNG is stored on a Floating Storage Unit ("FSU"), designed as a 7-day storage facility, [46] and is vaporized on land to power dual-fuel generators at a neighboring power plant, or loaded into the ISO containers to transport to Palo Seco. [47]

[42] US Energy Information Administration, Puerto Rico Territory Energy Profile, updated on February 15, 2024, https://www.eia.gov/state/print.php?sid=RQ.

[43] US Energy Information Administration, Puerto Rico Territory Energy Profile, "Imports & Exports", updated on February 15, 2024, https://www.eia.gov/state/print.php?sid=RQ.

[44] US Department of Energy, Office of Resource Sustainability, LNG Monthly, November 2023, pp. 52-53, https://www.energy.gov/sites/default/files/2023-11/LNG%20Monthly%20September%202023_3.pdf.

[45] US Department of Energy, Office of Resource Sustainability, LNG Monthly, November 2023, pp. 52-53, https://www.energy.gov/sites/default/files/2023-11/LNG%20Monthly%20September%202023_3.pdf.

[46] While the exact FSU vessel is unclear, it is part of the Anthony Veder small LNG carrier fleet, with capacity of up to 30,000 cubic meters.

[47] YouTube, New Fortress Energy – San Juan Tour, October 24, 2023, https://www.youtube.com/watch?v=1wjnf9hoX-A; New Fortress Energy, "LNG Fuel Supply in the North and Conversion of San Juan Units 5 & 6 to Natural Gas Project", September 25, 2018, p. 66 (PDF), https://ieefa.org/wp-content/uploads/2020/05/NFEnergia-proposal.pdf; US FERC, "New Fortress Energy LLC Order on Show Cause", March 19, 2021, https://www.ferc.gov/sites/default/files/2021-03/C-2-CP20-466-000.pdf.

Figure 16: San Juan, Puerto Rico LNG Terminal

119. In the 2018 original project proposal for the San Juan import terminal, the selected contractor and supplier, New Fortress Energy ("NFE"), offered a five-year LNG supply contract with three optional five-year extensions. NFE offered the price of imported LNG, including supply, transportation, FSU storage, and regasification, to consist of the following components:[48]

120. A fixed annual capacity payment of $10 million for the capacity of 25 TBTU per year (or approximately $0.40 per MMBtu or $0.42 per Mcf); plus

a. Unit Cost $/MMBtu: $7.10/MMBtu Unit Cost for the initial five-year period on average;

b. Year 1 Unit Cost: $8.50/MMBtu;

c. Year 2 Unit Cost: $7.50/MMBtu;

d. Year 3 to 5 Unit Cost: $6.50/MMBtu;

e. Plus Henry Hub ("HH") multiplied by 115%.

[48] New Fortress Energy, "LNG Fuel Supply in the North and Conversion of San Juan Units 5 & 6 to Natural Gas Project", September 25, 2018, Section 3.1, p. 105 (PDF), https://ieefa.org/wp-content/uploads/2020/05/NFEnergia-proposal.pdf.

121. Using this proposal, the cost of LNG imports in 2021 would be approximately $12.40/MMBtu.[49] Other data for Puerto Rico as a whole indicates average actual 2021 LNG import cost of about $9.30/Mcf.[50]

122. NFE did not apply for a FERC Section 3 authorization before adding LNG import capability to the San Juan terminal facility in 2019-2020, but obtained permits from the U.S. Coast Guard ("USCG") and U.S. Army Corps of Engineers ("USACE"). NFE went through a retroactive FERC review process and was declared jurisdictional by FERC, an order later upheld by the DC Circuit Court. The project remains a lingering source of controversy.[51, 52]

5.1.1.2 ISO Container Operations in Puerto Rico

123. Palo Seco Power Plant in Puerto Rico has been in operation since 1959 as a diesel-powered generation source. The disastrous 2017 hurricane season exposed Puerto Rico's aging power grid as vulnerable and incapable of supporting basic human needs in times of extreme weather events. Since then, several other natural disasters have driven continued focus on the renewal of Puerto Rico's power infrastructure. As part of Federal Emergency Management Agency's ("FEMA") mandate to improve the situation, the Palo Seco Power Plant was upgraded in 2023 with 153 megawatts ("MW") of emergency gas-powered generation, supplied with ISO containers trucked from the San Juan terminal.

124. Palo Seco receives up to 52 ISO containers per day by truck (a distance of about 13 miles), and uses five unloading bays to transfer LNG to a 90,000 gal (approx. 340 m^3) storage tank, followed by pressurization and vaporization of LNG for use in gas-powered turbines.[53] This provides the facility with the capacity to accept and process up to 15 BCF annually.

125. The Palo Seco emergency power generation facility was part of a FEMA and U.S. Army Corp of Engineers ("USACE") project, with Weston as the main EPC contractor and New Fortress Energy as the LNG technology and operations subcontractor. The capital cost of the project, including temporary dual-fuel generators, was around $470 million, and the

[49] 2021 monthly average Henry Hub gas price was $3.90/MMBtu, according to EIA. 2021 is assumed to be Year 2 of the contract (terminal was commissioned in April of 2020).

[50] Total value of 2021 LNG imports ($660.3 million) divided by 2021 import volume (71 BCF). *See* Cato Institute, "The Jones Act is Forcing Puerto Rico to Overpay for Energy", July 25, 2022, https://www.cato.org/blog/jones-act-forcing-puerto-rico-overpay-its-energy-needs-0; US Energy Information Administration, Puerto Rico Territory Energy Profile, updated on February 15, 2024, https://www.eia.gov/state/print.php?sid=RQ.

[51] Oil and Gas Watch, "LNG terminal opens in Puerto Rico without required federal approval", January 5, 2024, https://news.oilandgaswatch.org/post/despite-lack-of-permit-federal-authorities-allow-lng-terminal-in-puerto-rico-to-continue-operating; US FERC, "New Fortress Energy LLC Order to Show Cause", June 18, 2020, https://ieefa.org/wp-content/uploads/2020/06/FERC-Order-to-NFE-to-Show-Cause-20200618-305134121036.pdf.

[52] Earth Justice, "Puerto Rico LNG Terminal is a Ticking Time Bomb", May 10, 2022, https://earthjustice.org/experts/jordan-luebkemann/puerto-rico-lng-terminal-is-a-ticking-time-bomb.

[53] New Fortress Energy, "NFE's Palo Seco emergency power is a positively powerful development for Puerto Rico", https://www.newfortressenergy.com/stories/nfes-palo-seco-emergency-power-positively-powerful-development-puerto-rico; YouTube, New Fortress Energy – Palo Seco Power Tour, August 23, 2023, https://www.youtube.com/watch?v=_ML_KjSoLZ4.

emergency power facility was completed in under 4 months from design/build contract award date. [54]

126. Weston completed the Palo Seco project alongside a similar 200 MW emergency power installation at the San Juan terminal, which already has LNG supply from the FSU. The dual San Juan terminal and Palo Seco emergency power project boasted impressive construction completion in under four months at the brownfield sites. Together, the temporary power and fuel supply installations cost around $1.1 billion. [55]

5.1.2 ISO Imports as part of Integrated Resource Planning in Hawaii

127. Hawaii Gas is a public natural gas utility with a majority of its customers located on the island of Oahu [56] and an annual demand of approximately 3.4 BCF. [57] In 2014, Hawaii Gas received an approval from the Hawaii Public Utility Commission to import LNG and received the first ISO container cargo the same year. The natural gas was sourced from Clean Energy's liquefaction plant in Boron, California where it was loaded into ISO containers and delivered to Hawaii Gas via Port of Los Angeles. [58] The Boron, California plant currently has capacity to supply 180,000 LNG gallons per day, [59] approximately 5.45 BCF/year [60]; plant capacity can be expanded to 270,000 LNG gallons per day, 8.18 BCF/year. [61]

128. Hawaii Gas has not been importing LNG since at least 2017 and has primarily relied on synthetic natural gas from Par Hawaii refinery as well as renewable natural gas, and propane

[54] Weston Solutions, "Weston Wins $470M Task Order to Provide Temporary Power Generation at Palo Seco Power Plant in San Juan, PR", March 17, 2023, https://www.westonsolutions.com/news/weston-to-provide-temp-power-generation-at-palo-seco-power-plant-in-pr/#:~:text=(Weston)%20wins%20task%20order%20under,electrical%20grid%20on%20the%20island.

[55] US Army Corps of Engineer, "Omaha District, partners successfully complete temporary power mission in San Juan", November 22, 2023, https://www.nwo.usace.army.mil/Media/News-Stories/Article/3597081/omaha-district-partners-successfully-complete-temporary-power-mission-in-san-ju/. US Army Corps of Engineers, "Omaha District, partners successfully complete temporary power mission in San Juan", November 22, 2023, https://www.nwo.usace.army.mil/Media/News-Stories/Article/3597081/omaha-district-partners-successfully-complete-temporary-power-mission-in-san-ju/.

[56] Hawaii Gas' Final IRP Report and Action Plan, Table 4-1, p. 29, https://assets-global.website-files.com/618c69307382fa36b31ac896/642f89e3171648bf86e7135e_Dkt%202022-0009%20Hawaii%20Gas%20Final%20IRP%20Report%20and%20Action%20Plan%2C%20filed%204-6-2023.pdf.

[57] Hawaii Gas' Final IRP Report and Action Plan, Table 4-1, p. 29, https://assets-global.website-files.com/618c69307382fa36b31ac896/642f89e3171648bf86e7135e_Dkt%202022-0009%20Hawaii%20Gas%20Final%20IRP%20Report%20and%20Action%20Plan%2C%20filed%204-6-2023.pdf. 1 therm ~ 0.1 MMBtu or ~0.1 Mcf. Annual consumption of 33,697,501 therms = 3,369,750 Mcf = 3.4 BCF.

[58] Clean Energy Fuels, Press Release, "Clean Energy Provides First Containerized LNG Shipment to Hawaii", April 10, 2014, https://www.cleanenergyfuels.com/release-archive/clean-energy-provides-first-containerized-lng-shipment-to-hawaii.

[59] Clean Energy Fuels, Bulk LNG Services, https://www.cleanenergyfuels.com/services/bulk-lng-sales.

[60] 180,000 X 0.083 Mcf in one gallon X 365/1,000,000 = 5.453 BCFA. Gallons to mcf conversion sourced from Eagle LNG Calculator, available at https://www.eaglelng.com/lng-calculator.

[61] 5.453 X 270/180 = 8.180.

air.[62] However, additional LNG imports are still being considered as part of future supply options as reflected in the Integrated Resource Plan prepared by Black & Veatch in 2023. Due to limited gas demand, Black & Veatch determined that a full-scale LNG import and regassification terminal would not be a viable option, since a 2 MTPA import and regassification terminal would be only 5% utilized, resulting in delivered cost of more than $30/MMBtu.[63] Instead, Black & Veatch considered the use of existing ISO import capacity and the possibility of investing in vessel unloading, storage and vaporization to expand ISO imports as suitable supply alternatives. Capital costs associated with such investment by capacity are presented in the table below. These costs contain a 20% premium to the lower 48 states, according to the IRP.

Figure 17: ISO Expansion Costs Hawaii Gas IRP[64]

2022 cost estimate

Gas Flow			Flow Rate	LNG Rate			Storage Volume		Equipment Costs (MM$)			TIC + 20% HI Premium
Nm3/h	SCFM	MMSCFD	Therms/Day	mtpa	k gal/d	m3/d	Days	m3	Vessel Unloading	Storage	Vaporization	(MM$)
10	6.2	0.01	89	0.0001	0.11	0.4	3	1	0.9	0.3	0.4	6.8
100	62	0.09	894	0.0007	1.1	4.1	3	12	0.9	0.3	0.4	6.8
500	311	0.45	4,471	0.003	5.4	20	3	61	0.9	0.5	0.4	7.4
1,000	621	0.9	8,943	0.007	11	41	3	122	0.9	1.0	0.5	9.5
2,500	1,553	2.2	22,356	0.016	27	102	3	306	0.9	2.1	0.9	14.0
5,000	3,105	4.5	44,713	0.033	54	204	3	611	0.9	3.5	1.4	19.7
10,000	6,210	8.9	89,425	0.07	108	408	3	1,223	1.5	7.1	2.1	34.4
25,000	15,525	22.4	223,563	0.16	269	1,019	10	10,190	3.0	46.5	3.7	87.9
50,000	31,050	44.7	447,126	0.33	538	2,038	7	14,266	6.0	55.8	5.6	122.5

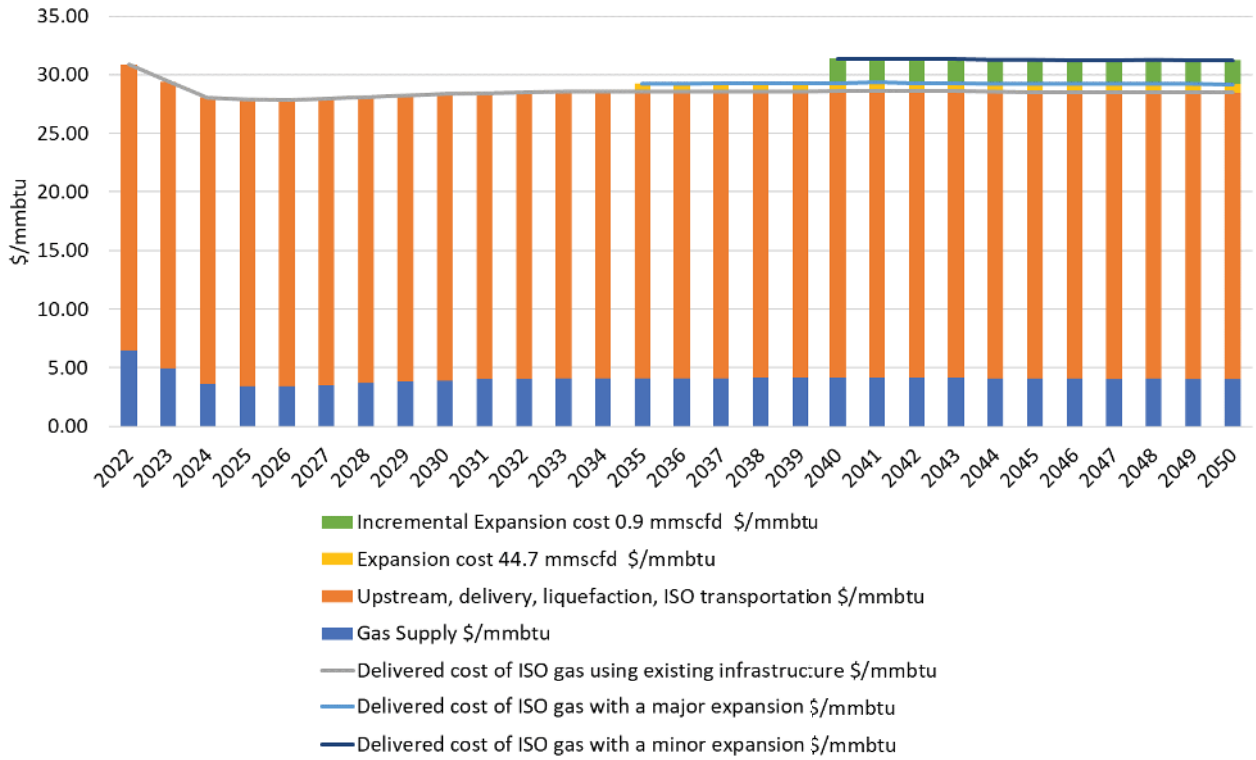
129. Black & Veatch estimated the delivered cost of gas using existing infrastructure to import ISO containers to be the sum of gas cost free on board ("FOB") California plus the midstream expenses associated with gas upstream delivery, liquefaction, and ISO transportation, with total midstream expenses equal to $24.43/MMBtu. For additional gas that would require investment, ISO expansion costs were included in the delivered cost. An illustrative example prepared by BRG, based on the Hawaii IRP model, that depicts the delivered gas costs to Hawaii Gas based on existing ISO container import capacity through 2034, one expansion of 44.7 million standard cubic feet per day ("MMSCFD") in 2035, and one expansion of 0.9 MMSCFD in 2040, is shown below.

[62] Hawaii Gas' Final IRP Report and Action Plan, p. 65, https://assets-global.website-files.com/618c69307382fa36b31ac896/642f89e3171648bf86e7135e_Dkt%202022-0009%20Hawaii%20Gas%20Final%20IRP%20Report%20and%20Action%20Plan%2C%20filed%204-6-2023.pdf.

[63] Hawaii Gas' Final IRP Report and Action Plan, p. 83, https://assets-global.website-files.com/618c69307382fa36b31ac896/642f89e3171648bf86e7135e_Dkt%202022-0009%20Hawaii%20Gas%20Final%20IRP%20Report%20and%20Action%20Plan%2C%20filed%204-6-2023.pdf.

[64] Hawaii Gas IRP Scenario Analysis – Projected HG Model, Issued on March 29, 2023, tab "5. LNG-ISO Expansion", available at https://assets-global.website-files.com/618c69307382fa36b31ac896/642f962061410bf5343742ee_Integrated%20Model%20(Public%20Locked).xlsx (downloaded on February 20, 2024).

Figure 18: Delivered Cost of ISO LNG to Oahu ($2022) based on Hawaii IRP, modified by BRG for illustrative purposes



5.1.3 Alaska ISO Container Supply Sources

130. There are limited options to supply LNG via ISO containers to Alaska independently, i.e. without a pre-existing bulk LNG import project. Supply overland by truck from Canada is impractical for the necessary scale of operation, therefore the assumptions below incorporate the use of existing ports with capabilities to offload ISO containers. [65]

5.1.3.1 Supply from Tacoma, WA

131. The existing Puget Sound LNG facility in Tacoma, WA, provides a convenient supply source, since TOTE Maritime already runs two container ships per week to the Port of Alaska from Tacoma, and fuels these ships with LNG in Tacoma. [66] However, the fuel supply of LNG-fueled vessels draws down most of the capacity of Puget LNG, with some additional LNG intended for cold-weather peak shaving by local utilities. The facility expansion planned previously for Puget LNG by its owner Puget Sound Energy was cancelled in January of 2024

[65] LNG trucking from the North Slope was evaluated as an option in Phase I, and may be feasible for up to 3 BCF, using available capacity of the planned Harvest liquefaction facility. Reduced-size LNG storage in Southcentral Alaska may decrease the costs of supply using this option from Phase I estimates.

[66] The Maritime Executive, "TOTE Completes Delayed LNG Conversion of Orca Class Ships", March 15, 2023, https://maritime-executive.com/article/tote-completes-delayed-lng-conversion-of-orca-class-ships.

in the midst of local opposition to the project.[67] Therefore its current liquefaction capacity of 250,000 gallons per day and the 8-million-gallon storage tank create the ceiling for available supply from this location. This capacity translates to about 7.5 BCF per year, however with LNG bunkering claiming most of the supply, the remaining available capacity is likely significantly lower.[68]

132. Bright Ice Solutions, LLC conducted a scoping assessment for ENSTAR Natural Gas in 2020, which estimated deliveries from this facility using existing TOTE Maritime Alaska container vessels to provide about 2.5 BCF of gas per year, at a cost around $29/Mcf.[69] Given other ISO container cost benchmarks and the cancelled Puget LNG expansion, this still appears to be a reasonable estimate. This option could provide some incremental supply for peaking purposes that could be trucked from the Port of Alaska to suitable locations for meeting deliverability. However, it may not be the most cost-effective alternative if the LNG need is simply for peaking, rather than supplementing a supply shortfall.[70]

5.1.3.2 Supply from FortisBC, British Columbia

133. The Tilbury LNG Plant is a liquefaction, dispensing, and storage site with marine access to Fraser River near Vancouver, BC, owned by FortisBC. After a 2018 expansion, the plant has capacity to liquefy up to 0.24 MTPA, or about 12 BCF of gas per year. Currently, the facility can dispense some of this gas to ISO containers. A discussion with the owners established that the facility could provide as many as 48 ISO containers per day by sometime in 2025, when its marine loading capabilities were further expanded. Tilbury LNG Plant is also going through an environmental assessment and approval process for a new bulk LNG loading marine jetty, and is optimistic about imminent federal and provincial approval of this project. The ISO filling and loading operation does not require any additional regulatory approvals.[71]

134. Tilbury LNG provides an opportunity to purchase LNG at regulated rates, and requires a logistical shipping solution from a competent third-party operator.

[67] The Seattle Times, "Puget Sound Energy cancels liquid natural gas plant expansion in Tacoma", January 24, 2024, https://www.seattletimes.com/seattle-news/environment/puget-sound-energy-cancels-liquid-natural-gas-plant-expansion-in-tacoma/.

[68] Assuming that two 1,100 m^3 LNG fuel tanks supply one week-long round trip for each of the two vessels, TOTE Maritime Alaska's demand is about 5 BCF per year. *See* The Maritime Executive, "TOTE Completes Delayed LNG Conversion of Orca Class Ships", March 15, 2023, https://maritime-executive.com/article/tote-completes-delayed-lng-conversion-of-orca-class-ships.

[69] Data from confidential model that accompanied the study. Similar results listed in ENSTAR LNG Supply Options Overview, Bright Ice Solutions LLC, March 2020, p. 9.

[70] Alternatively, local LNG could be made at the existing Titan LNG plant for peaking purposes, with current capacity of up to 50,000 gallons per day.

[71] Based on discussion with Sarah Smith and Scott Neufeld of FortisBC on January 25, 2024, and associated marketing presentation.

5.1.3.3 Supply of ISO containers from other locations

135. Without an existing supply chain connecting Alaska to other locations in the US, it would be difficult to procure the Jones Act compliant vessels to transport ISO containers. In Canada, we are not aware of another permitted facility that could provide ready supply of LNG in ISO containers on the scale and schedule required for this project. Another relatively close potential alternative for supply is located in La Paz, Mexico, and operated by NFE.[72] NFE also has the experience to be considered as the logistical link between Tilbury LNG and Alaska, along with other similar operators such as Norgas, or smaller but local Canadian companies, such as Cryopeak.[73]

5.2 ISO Supply Options for Southcentral Alaska

136. Based on the industry experience and supply chain issue reviewed above, BRG and its contractor selected two feasible options for supplying LNG to Cook Inlet in material quantities (~6 BCF per year). Those options are described in this section.

5.2.1 Anchorage Port Design concept (6A)

137. This option is a supply of ISO containers by a dedicated set of modified Offshore Supply Vessels, each delivering around 48 ISOs about every other day (12 times per month). Four to five vessels would be required for this operation in order to supply up to 6 BCF per year. The vessels will need to be acquired and modified for this operation by a ship owner via a chartering arrangement or a full-service transportation contract.

138. ISO containers will be unloaded at the Don Young Port of Alaska ("Anchorage Port"), where an efficient gantry crane is available for unloading this quantity of ISO containers five days a week.[74] On regularly scheduled days twice a week when TOTE Maritime or Matson container ships visit the port, the cranes are not available, and those container vessels will always receive priority due to crane ownership.

139. The ISO containers will be loaded onto tractor trailers and trucked to a location near a pipeline interconnect where the LNG can be re-gasified using mobile vaporization facilities, and injected into the pipeline system. Due to the planned dock upgrade at the Anchorage Port, very little laydown area will be available until about 2030, therefore ISO containers will need to be moved efficiently to a re-gasification site. The current design suggests a location near ENSTAR's East Gate station off Glenn Highway, near one of Chugach Electric Association's ("CEA") power generation facilities. The exact siting of the regasification facilities needs to be reviewed and approved by the relevant landowners.

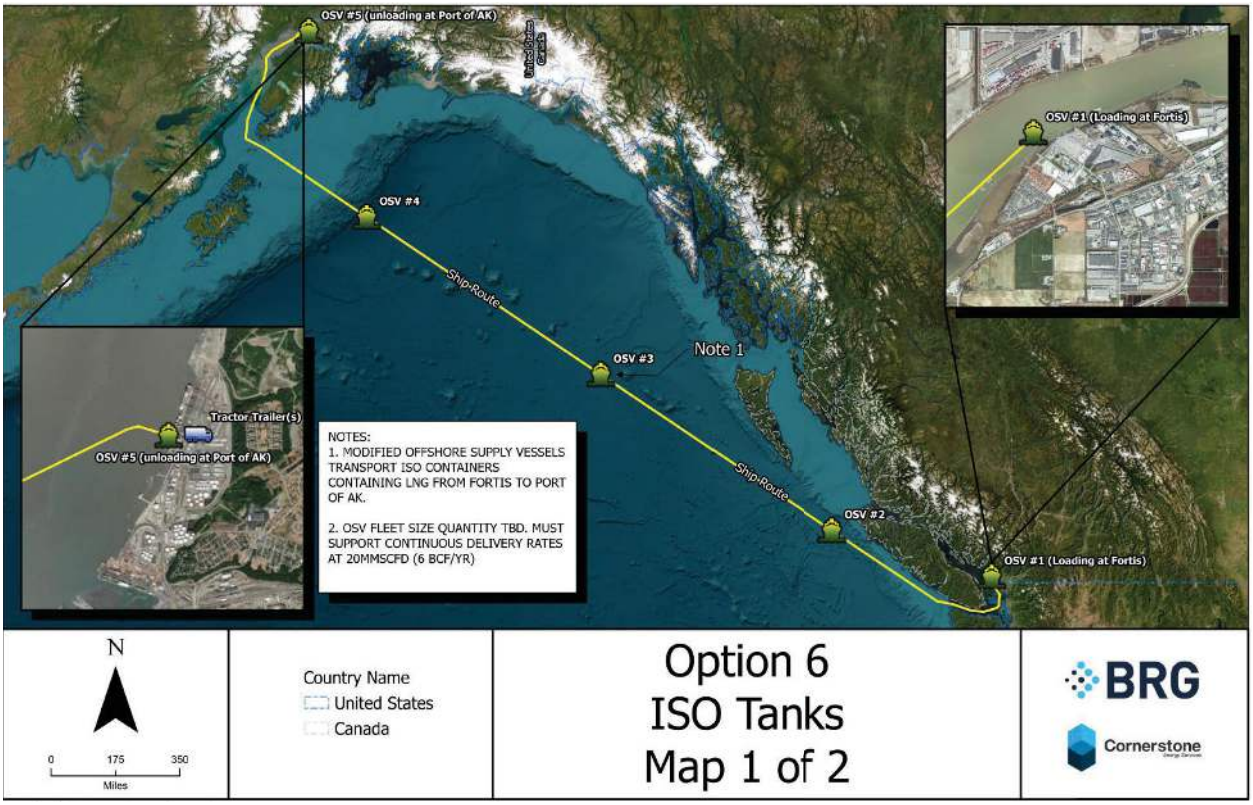
[72] New Fortress Energy, La Paz Mexico LNG Facility, https://www.newfortressenergy.com/operations/La-Paz-Mexico-LNG-Facility.

[73] Cryopeak, https://cryopeak.com/.

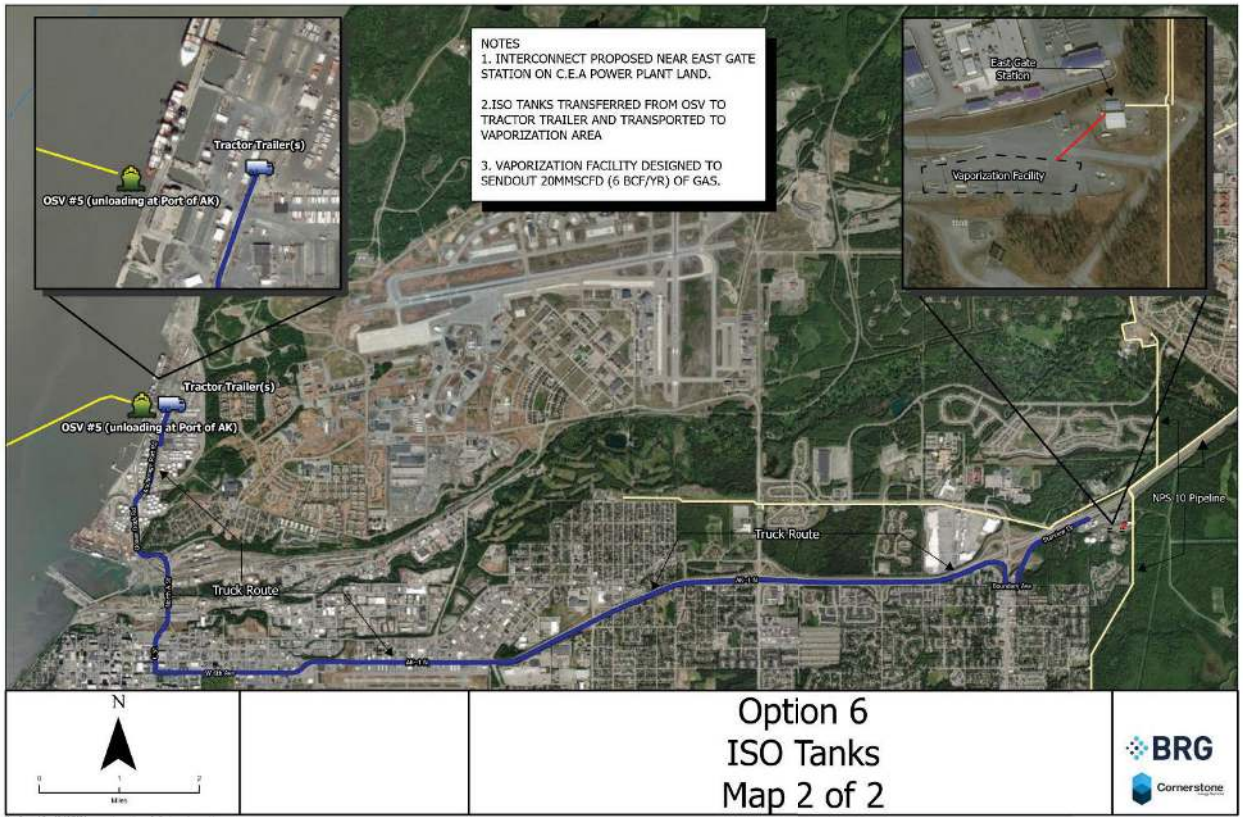
[74] Initial review of compatibility of the vessels with the Port's draft requirements and speed of unloading did not turn up any insurmountable issues.

140. The concept maps of this LNG shipping, offloading, and re-gasification design are presented below.

Figure 19: Concept Maps of ISO Tanks Shipping, Offloading and Re-gasification (Option 6A, Anchorage Port)[75]



[75] OSV refers to Offshore Support Vessel.



5.2.2 Anchorage Port Permitting Requirements (6A)

141. This project requires a Department of Energy ("DOE") license for the importation of LNG. Since the ISO containers are simply offloaded and trucked to a vaporization site away from the port, this project does not represent a new LNG import terminal, which in turn likely removes the need for a Federal Energy Regulatory Commission ("FERC") Natural Gas Act ("NGA") Section 3 authorization and full National Environment Policy Act ("NEPA") review.[76] This significantly simplifies the permitting process in comparison to the large-scale import options. The draft permitting matrix includes permit requirements from DOE (LNG import), Alaska Department of Environmental Conservation ("ADEC") (air and water), and Municipality of Anchorage (conditional land use). It is attached as Appendix C.1 to this report. The overall permitting duration is approximately 24 months, although the major permits would be received within about 15 months, allowing the project to reach Final Investment Decision ("FID") by the second quarter of 2025. Securing the site necessary for the mobile vaporization

[76] General Requirements of Title 10, Chapter X, Part 1021, Subpart C, § 1021.300 suggest discretion with respect to the degree of environmental review process. Port of Anchorage anticipates NEPA compliance as part of port modernization, see Environment – POA Modernization (portofalaska.com). LNG imports using ISO would have relatively small environmental footprint.

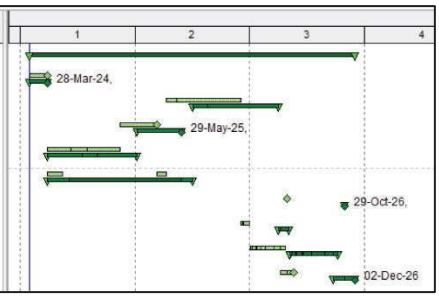
and any potential issues with permitting this facility next to an active power plant carries a potential risk to the project schedule.

5.2.3 Anchorage Port Project Schedule (6A)

142. Current project schedule allows for the first gas deliveries by the fourth quarter of 2026. The figure below represents the critical path activities on the schedule. Supply contractual arrangements with the LNG supplier, as well as RCA contract approvals, are not on the critical path of the project but are also critical to its success.

Figure 20: Schedule of Small-Scale LNG Import Using ISO Containers (Option 6A, Anchorage Port)

#	Activity ID	Activity Name	75th %ile OD	P75 Start	P75 Finish	Float	P25 Start	P25 Finish
1		ISO Containers @ Chugach Rev 5 P75	146w	01-Feb-24	02-Dec-26	0w	01-Feb-24	20-May-26
2		CONTRACT & GENERAL REQUIREMENTS	8w	01-Feb-24	28-Mar-24	0w	01-Feb-24	28-Mar-24
3		Municipality of Anchorage	39w	03-Jul-25	01-Apr-26	0w	10-Apr-25	03-Dec-25
4		Financing	20w	09-Jan-25	29-May-25	0w	14-Nov-24	13-Mar-25
5		LNG Supply	41w	28-Mar-24	08-Jan-25	0w	28-Mar-24	13-Nov-24
6		ENGINEERING & DESIGN	66w	28-Mar-24	02-Jul-25	0w	28-Mar-24	09-Apr-25
7		OFF SHORE (WATER)	0w	29-Oct-26	29-Oct-26	0w	30-Apr-26	30-Apr-26
8		ON SHORE (LAND)	5w	02-Apr-26	06-May-26	0w	04-Dec-25	31-Dec-25
9		New Vaporization Facility	22w	07-May-26	07-Oct-26	0w	01-Jan-26	22-Apr-26
10		Commissioning	10w	24-Sep-26	02-Dec-26	0w	09-Apr-26	20-May-26



5.2.4 Port MacKenzie ISO Design Concept (6M)

143. The design concept for LNG supply via ISO containers using Port MacKenzie is similar to the equivalent project using Anchorage Port.[77] Port MacKenzie offers certain advantages, such as a less congested port and road arrangement and an unused site owned by ENSTAR in close proximity to a pipeline interconnect. In addition, injection of gas into the pipeline system near Port MacKenzie puts the gas much closer to future potential storage sites, such as Pretty Creek or Ivan River.[79]

144. Due to Port MacKenzie being a less developed port, the project scope also carries more uncertainties. For example, in order to unload ISOs from an Offshore Support Vessel ("OSV"), a crane will need to be installed on Port MacKenzie's dock. The full feasibility and cost of this addition, as well as the ability to regularly drive away around 50 LNG containers in a day has not been fully evaluated with the owners of the port. Based on the information in BRG's possession, such as aerial photos of the Port MacKenzie dock, informational discussions with port management, and history of unloading heavy bulk material from large vessels, the ISO unloading operation appears feasible.

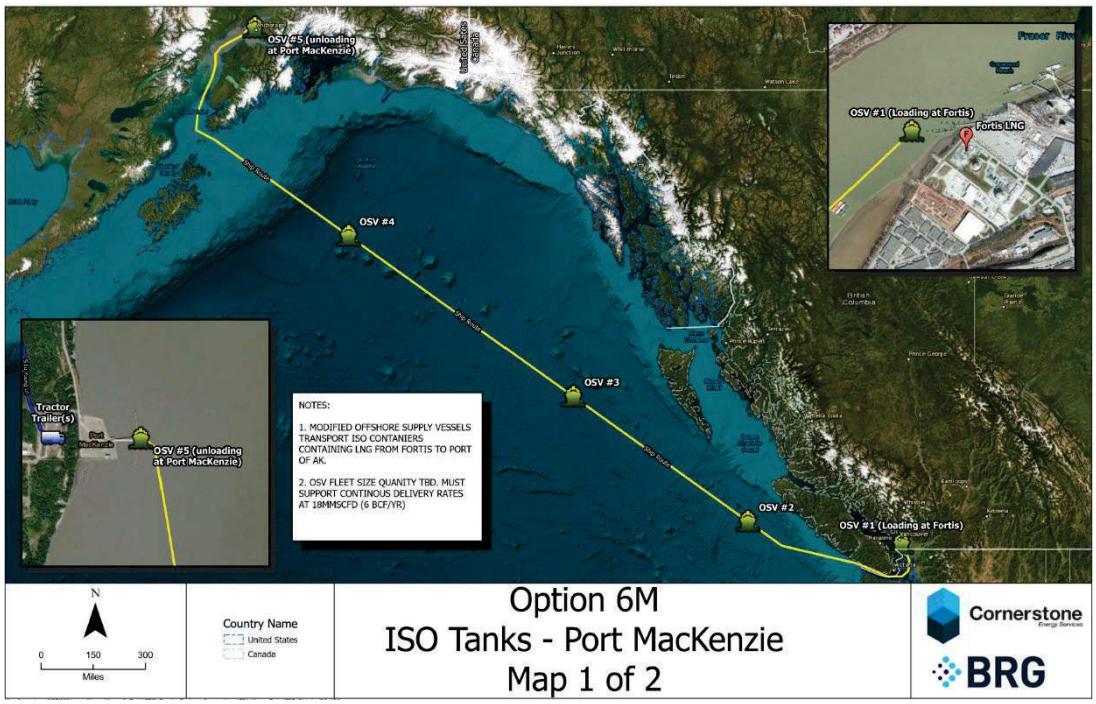
[77] See Section 5.2.1.

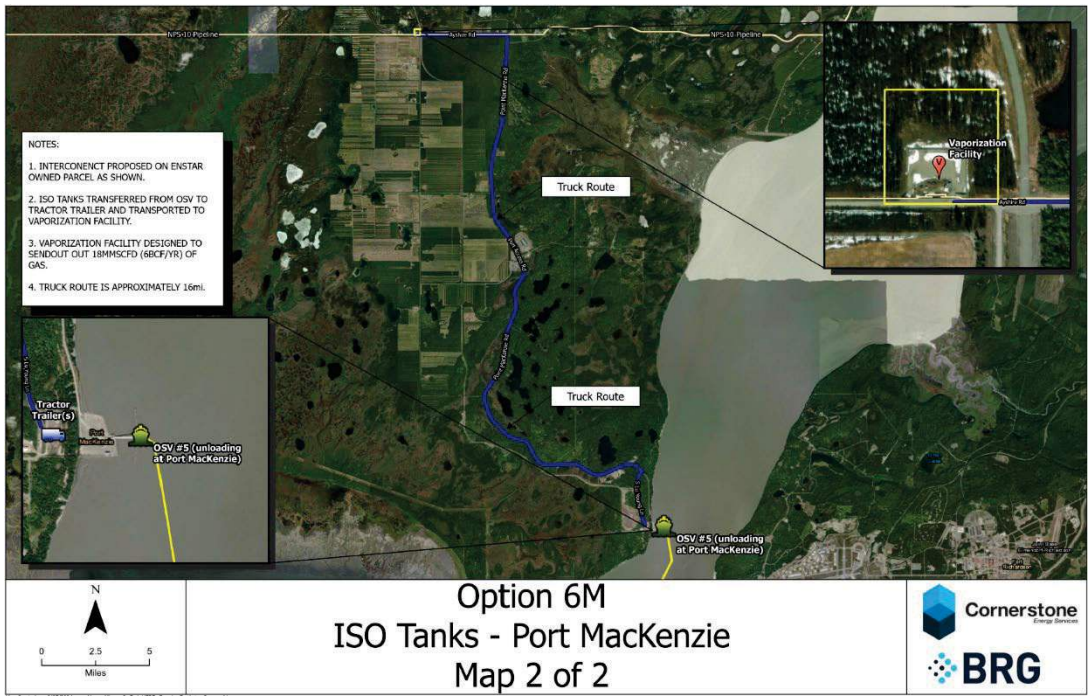
[78] General Requirements of Title 10, Chapter X, Part 1021, Subpart C, § 1021.300 suggest discretion with respect to the degree of environmental review process. LNG imports using ISO would have relatively small environmental footprint.

[79] Alaska State Legislature, "HB280 Gas Storage Map", available at https://www.akleg.gov/basis/get_documents.asp?session=26&docid=5121.

145. Below is a representation of the concept map of this ISO import project unloading at Port MacKenzie (Option 6M).

Figure 21: Concept Maps of ISO Tanks Shipping, Offloading and Re-gasification (Option 6M)





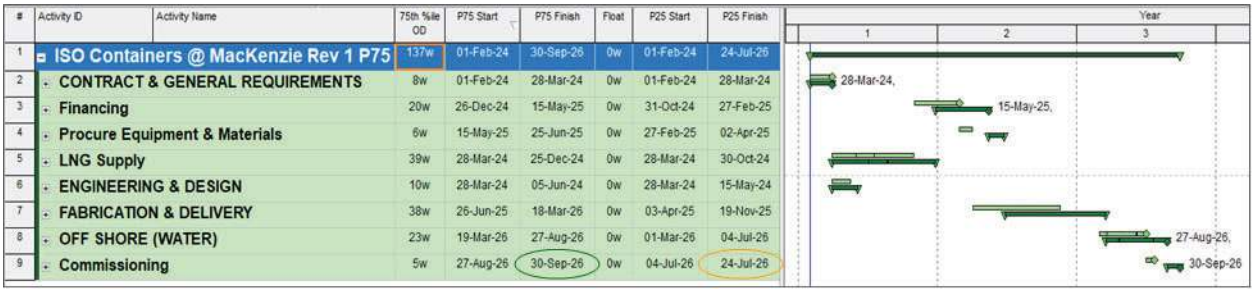
5.2.5 Port MacKenzie Permitting Requirements (6M)

146. This project has similar permitting requirements to the Anchorage Port option, with differences due to location and land ownership. [80] The draft permitting matrix includes permit requirements from DOE (LNG import), Alaska Department of Environmental Conservation ("ADEC") (air and water), and Matanuska-Susitna Borough ("MSB") (construction). It is attached as Appendix C.2 to this report. The overall permitting duration is approximately 24 months, although the major permits would be received within about 15 months, allowing the project to reach FID by the second quarter of 2025.

5.2.6 Port MacKenzie Project Schedule (6M)

147. Project schedule for this option is similar to the Anchorage Port ISO option, delivering first gas by the fourth quarter of 2026. The schedule carries similar risks in the ability to acquire sufficient shipping capacity for the ISO containers, which the vaporization site ownership is already established (by ENSTAR) and should present fewer issues. Due to the less active status of Port MacKenzie and the lack of current crane offloading capacity as described above, the time necessary to fully prepare and proceed with this option may be longer due to the necessary discussions and agreements with the Port MacKenzie owner (MSB).

Figure 22: Schedule of Small-Scale LNG Import Using ISO Containers (Option 6M, Port MacKenzie)



#	Activity ID	Activity Name	75th %ile OD	P75 Start	P75 Finish	Float	P25 Start	P25 Finish
1		ISO Containers @ MacKenzie Rev 1 P75	137w	01-Feb-24	30-Sep-26	0w	01-Feb-24	24-Jul-26
2		CONTRACT & GENERAL REQUIREMENTS	8w	01-Feb-24	28-Mar-24	0w	01-Feb-24	28-Mar-24
3		Financing	20w	26-Dec-24	15-May-25	0w	31-Oct-24	27-Feb-25
4		Procure Equipment & Materials	6w	15-May-25	25-Jun-25	0w	27-Feb-25	02-Apr-25
5		LNG Supply	39w	28-Mar-24	25-Dec-24	0w	28-Mar-24	30-Oct-24
6		ENGINEERING & DESIGN	10w	28-Mar-24	05-Jun-24	0w	28-Mar-24	15-May-24
7		FABRICATION & DELIVERY	38w	26-Jun-25	18-Mar-26	0w	03-Apr-25	19-Nov-25
8		OFF SHORE (WATER)	23w	19-Mar-26	27-Aug-26	0w	01-Mar-26	04-Jul-26
9		Commissioning	5w	27-Aug-26	30-Sep-26	0w	04-Jul-26	24-Jul-26

148. While conceptually feasible, engineering in setting a new crane on the existing dock has not been completed. Load limits and spatial considerations with an existing conveyor belt structure on the dock must be addressed. The schedule in Figure 18 presumes that the existing dock will not require any significant modifications to accommodate an offloading crane or increased truck traffic such as that shown in Figure 25. [81]

[80] See 5.2.2.

[81] Norgas Carriers, "Micro Liquefied Gas – ISO Container Solutions", https://norgascarriers.com/our-services/iso-services/.

Figure 23: Offloading Concept of ISO Containers (Option 6M, Port MacKenzie)

5.2.7 ISO Supply Delivered Cost of Gas

149. The total direct capital investment of the Option 6A, ISO Supply via Anchorage Port, is estimated at $35.8 million for the onshore vaporization facility and $11 million for the purchase of the necessary ISO containers. ISOs can also be structured as a lease. Other costs are likely to take the form of a pass-through charter and other expenses payable to third parties. The capital cost estimate for the onshore portion contains a 30% contingency assumption, and all capital investments, including those made by third parties, are recovered using the project gas supply volume between 4Q2026 and 4Q2033. The largest cost uncertainty is in the substantial costs of shipping that will require further engagement with a shipping agent, scoping, and vessel negotiations.

150. The direct capital investment associated with Option 6M, ISO Supply via Port MacKenzie is higher at $50.3 million for the onshore vaporization facility, primarily due to the need to inspect and conduct maintenance on the Port MacKenzie dock, as indicated in a report provided by the Port. While this cost may be avoided by the project, it was assumed as a potential additional burden for the first major regular customer of Port MacKenzie. This higher cost drives the higher levelized Storage and Re-gasification cost of service calculation, shown below, for the "ISO MacKenzie" columns. Capital cost contingency for this option is similar to the Anchorage Port, estimated at 30.5%.

151. Both options have onshore operating costs estimated to be around $6 million per year. The resulting delivered cost of gas range using ISO containers is represented in the table below.

Table 6: Delivered Cost of Gas – Port MacKenzie ($2028)

	ISO Anchorage		ISO MacKenzie		
	$/mmbtu	$/mcf	$/mmbtu	$/mcf	Estimate Source
LNG FOB (Fortis BC)	$ 8.67	$ 8.93	same	same	Fortis BC Tariff + Commodity Forecast
Shipping	$ 8.27	$ 8.52	same	same	BRG / Precision LNG
ISO Leasing	$ 0.39	$ 0.40	same	same	BRG based on public data
Offloading	$ 1.91	$ 1.97	same	same	BRG based on 2020 TOTE info
Trucking	$ 0.59	$ 0.60	same	same	BRG / Cornerstone estimate
Storage and Re-gasification	$ 3.56	$ 3.67	$ 4.14	$ 4.26	BRG / Cornerstone, 7 year lease
Total:	**$ 23.38**	**$ 24.09**	**$ 23.96**	**$ 24.68**	

5.2.8 ISO Supply Project Advantages and Opportunities

152. Options 6A and 6M have the simplest and likely shortest permitting path of all LNG import options, and the lowest upfront capital investment. They also create the ability to maintain the supply chain into the future for peaking needs. The LNG supply is readily available and price-regulated from an established facility in British Columbia. This option provides access to some of the most plentiful and cost-advantaged gas commodity supply in the world.

5.2.9 ISO Supply Project Risks and Uncertainties

153. One key project uncertainty is the availability of a sufficient number of OSVs that can be modified and chartered at the estimated cost. Other risks include the ability to contract and reliably deliver 6 BCF per year from a single source supplier; this volume is significantly larger than a typical ISO-enabled delivery model.[82] The option is also not very scalable, as 6 BCF would take around half of the current liquefaction capacity of the FortisBC LNG facility. This level of capacity would likely need to be reserved on a firm basis. However, trucked LNG, such as sources on the North Slope, could also be added to an existing storage and vaporization site set-up. The delivered costs of gas are substantially higher when compared to larger-scale options.

154. Given the lack of scalability, the relatively high price of ISO imports may create a Cook Inlet gas price signal that could have a broader market effect, without substantially increasing the available supply. Therefore, BRG's recommendation is to combine any implementation of this option with a larger-scale solution.

5.3 LNG Supply via Smaller Cryogenic Vessels (Option 3SB)

155. The small vessel imports version of the Kenai LNG option aims to meet all or a portion of ENSTAR and other Alaska utilities' gas demand earlier than the large-scale LNG import options, with a lower upfront investment. This option has been developed in an effort to minimize permitting durations, avoid in-water construction and pier improvements, and utilize both existing infrastructure and marine vessels. This option is designed to meet natural

[82] The project requires delivery of about 6,600 ISO containers per year. FortisBC, in a marketing discussion, did not recommend this option due to reliability of supply risk (weather-related shipping delays, etc.)

gas demand of up to 52 BCF per year. The costs of the upfront investment in this scope are assumed to be recovered using the projected gas demand volumes from BRG Phase II Assessment over a 10-year period.

5.3.1 LNG Supply

156. LNG supply is sourced from a supplier able to deliver LNG to a semi-permanently moored FSU via a compatible LNGC approved for operations within Cook Inlet by the USCG.

5.3.2 Design Concept

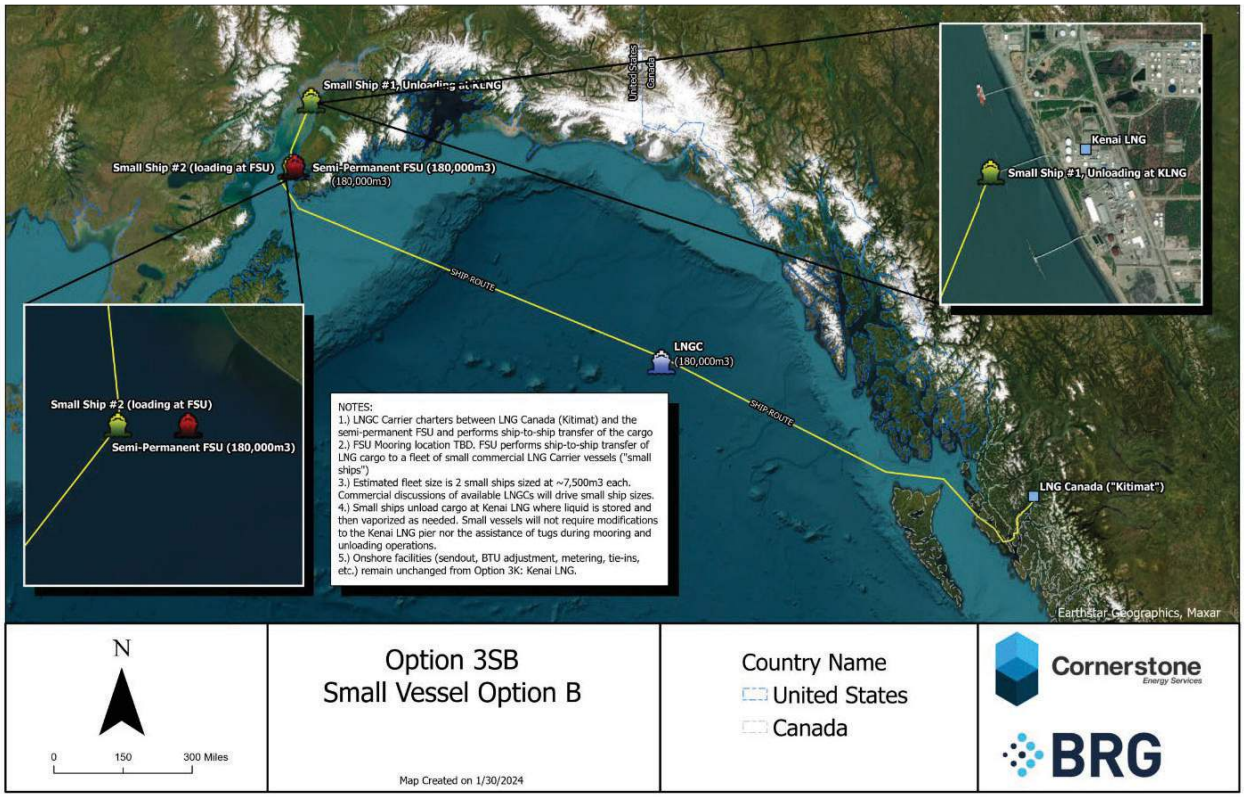
157. A semi-permanent FSU would be moored offshore Cook Inlet, which would take deliveries of LNG by standard Cook Inlet-capable LNGCs, transferred by ship-to-ship operation, and store them. The location of the FSU is yet to be determined and will be done so in further phases, evaluating each potential location from a permitting concern, and physical operations and logistics point of view.

158. While LNG is stored in the FSU, a fleet of one or two small-scale LNGCs would transport volumes from the FSU to the Kenai LNG facility.

159. From there, the project scope is similar to Phase 1 of Kenai LNG. Onshore improvements and modifications also include pumping system modifications, BOG system upgrades, vaporization, metering, flow control, OPP, interconnects, etc.

160. Option 3SB Concept Map has been provided in the figure below for visual aid of the supply chain for this option.

Figure 24: Concept Map of Small Vessels Shipping, Unloading



5.3.3 Scope Modifications from Phase 1 of Kenai LNG

161. The following scope changes differentiate this Option 3SB from Kenai LNG Phase I (Option 3K), as summarized in the table below.

Table 7: Scope Modifications Required for Small Vessels

Scope	Kenai LNG Phase I	Small Vessel
Floating Storage Unit (FSU)	No FSU required.	Purchase or lease of a 180,000 m^3 FSU. Due to the relatively large, fixed cost of the FSU, this scope is designed to maximize its utilization by providing up to 52 BCF/year.
Pier / Jetty Modifications	Modifications and dredging to accommodate a 170,000 m^3 vessel.	No modifications or dredging required.

		Dock maintenance will be required to ensure it is in working condition as originally designed.
Tug Boats	Four (4) tug boats required for berthing and mooring operations.	Same tug boat requirements assumed for the Small Vessels.
LNG Transfer Pumps	Replace P-704, P-705, P-706 with 378gpm 150psi differential pressure pumps.	Same LNG Transfer Pumps modification required for Small Vessels. [83]
Vaporization Capacity	3 x 45 MMSCFD trains (booster pumps and vaporizers).	Same Vaporizationi Capacity required for Small Vessels. [84]
Gas Treatment / Btu Adjustment	5 x Nitrogen Generation Modules.	Same Gas Treatment/Btu Adjustment modification for Small Vessels. [85]

162. Additional reductions in scope are to be evaluated with ENSTAR technical team to determine the potential phasing of this project into Option 3K Kenai LNG Phase 2. Other components such as process piping, control valves and metering will also need to be designed accordingly.

5.3.4 Permitting Requirements

163. We anticipate the permitting process to take approximately 2.5 years from initiation to completion. The draft permitting matrix for this option is included in Appendix C.3. The U.S. Federal permits are typical authorizations and consultations required under Section 3 of the NGA. Thus, this listing may be subject to change, depending on project environmental survey and agency consultations. No permits for activities in Canadian waters or jurisdictions are anticipated under current design.

[83] This can be scaled down for smaller demand such as electing to install only two transfer pumps capable of meeting a sendout rate of 20 MMSCFD for the system, for demand level of 6 BCF (ENSTAR + HEA only through 2032).

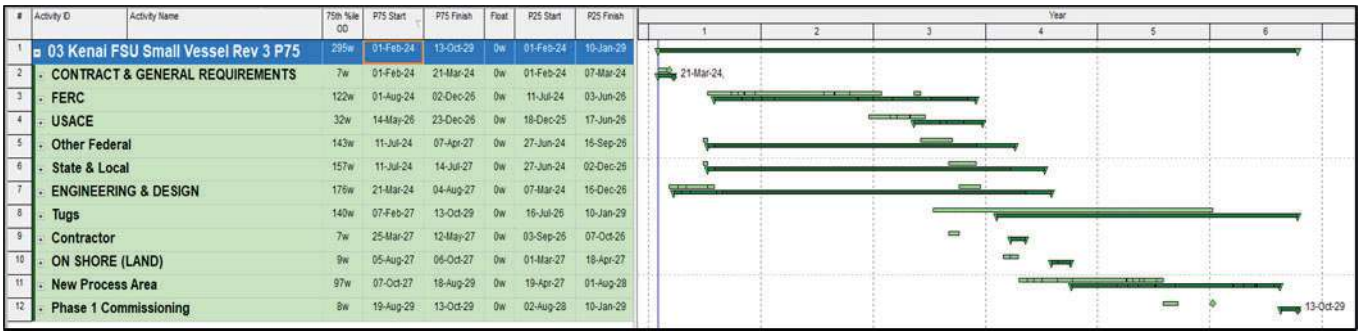
[84] This can be scaled down for smaller demand, such as installing two sets of booster pumps and vaporizers with capacity of 20 MMSCFD each for demand level of 6 BCF (ENSTAR + HEA only through 2032).

[85] This can be scaled down for smaller demand, such as installing 2 nitrogen generation modules for demand level of 6 BCF (ENSTAR + HEA only through 2032).

5.3.5 Project Schedule

164. We anticipate that first gas deliveries can start between 1Q and 3Q of 2029. The project scope around the jetty is substantially simplified compared to the large-scale option Kenai LNG (3K), reducing the amount of time required for onshore permitting, procurement, design, and construction. However, we anticipate that tug procurement, shuttle tanker leasing, and FSU acquisition and refurbishment will still require substantial time and effort due to the relative complexity of the offshore delivery value chain.

Figure 25: Project Schedule Summary for Small-Scale Bulk LNG Imports (3SB)



#	Activity ID	Activity Name	75th %ile OD	P75 Start	P75 Finish	Float	P25 Start	P25 Finish
1		03 Kenai FSU Small Vessel Rev 3 P75	295w	01-Feb-24	13-Oct-29	0w	01-Feb-24	10-Jan-29
2		CONTRACT & GENERAL REQUIREMENTS	7w	01-Feb-24	21-Mar-24	0w	01-Feb-24	07-Mar-24
3		FERC	122w	01-Aug-24	02-Dec-26	0w	11-Jul-24	03-Jun-26
4		USACE	32w	14-May-26	23-Dec-26	0w	18-Dec-25	17-Jun-26
5		Other Federal	143w	11-Jul-24	07-Apr-27	0w	27-Jun-24	16-Sep-26
6		State & Local	157w	11-Jul-24	14-Jul-27	0w	27-Jun-24	02-Dec-26
7		ENGINEERING & DESIGN	176w	21-Mar-24	04-Aug-27	0w	07-Mar-24	16-Dec-26
8		Tugs	140w	07-Feb-27	13-Oct-29	0w	16-Jul-26	10-Jan-29
9		Contractor	7w	25-Mar-27	12-May-27	0w	03-Sep-26	07-Oct-26
10		ON SHORE (LAND)	9w	05-Aug-27	06-Oct-27	0w	01-Mar-27	18-Apr-27
11		New Process Area	97w	07-Oct-27	18-Aug-29	0w	19-Apr-27	01-Aug-28
12		Phase 1 Commissioning	8w	19-Aug-29	13-Oct-29	0w	02-Aug-28	10-Jan-29

5.3.6 Delivered Cost of Gas

165. The total direct onshore capital investment is estimated at $119.8 million with development costs that include onshore vaporization, transfer pumps, and gas treatment. This capital cost estimate is inclusive of 27.5% contingency. The onshore portion of this development is comparable in scale to Phase 1 of Kenai LNG. Unlike Kenai LNG Option 3K, this development does not require extensive pier modifications because of the use of lighter and more frequent shuttle tankers for LNG deliveries. This option does contemplate additional lease related expenses from the use of a FSRU, a refurbished LNG carrier with acquisition price of $60 to $160 million and conversion cost of about $50 million, and one shuttle tanker that can be leased for approximately $30,000/day. Tugs would still be required for FSU and Mooring operations. FSU lease and onshore upgrades are levelized over 10 and 20 years to estimate the impact of this development being treated as a bridge solution or a longer-term solution, respectively.

Figure 26: Delivered Cost of Gas ($2028) [86]

Levelization:	10 year $/mmbtu	20 year $/mmbtu	10 year $/mcf	20 year $/mcf	Estimate Source
Global Integrated Gas Basis	$ 10.43	$ 10.43	$ 10.74	$ 10.74	Average of Henry Hub EIA and Forwards Curves with a $5.8/mmbtu adder
FSU Lease	$ 1.18	$ 0.79	$ 1.21	$ 0.81	Precision LNG inputs, BRG calculations
Tugs- new and existing	$ 0.38	$ 0.38	$ 0.39	$ 0.39	BRG based on public data & Precision LNG
Small LNG Carriers	$ 0.83	$ 0.83	$ 0.86	$ 0.86	Precision LNG inputs, BRG calculations
Kenai LNG Upgrades	$ 1.44	$ 0.88	$ 1.48	$ 0.91	BRG and Cornerstone
Total:	**$ 14.27**	**$ 13.31**	**$ 14.69**	**$ 13.71**	

5.3.7 Project Advantages and Opportunities

166. The following list represents key advantages of this project compared to other options evaluated in Phase II BRG Assessment:

a. Scalability – this option contemplates scaled down onshore infrastructure while potentially satisfying the unmet need beyond the first ten years of shortfall.

b. Greater Flexibility – this option can be used as a bridge to other alternatives with reduced onshore investment exit strategy, for this option shifts to contractual provisions associated with FSU, shuttle tanker, and tug leases and away from owned and operated onshore infrastructure.

167. Smaller onshore storage requirement – this option can trade some of the onshore storage capacity for storage onboard FSU with smaller but more frequent shuttle tanker deliveries.

5.3.8 Project Risks and Uncertainties

168. Jones Act considerations need to be validated with respect to the use of FSU in US waters in combination with foreign-made shuttle tankers (only kind available in the market). BRG previously considered positioning FSU in Canadian water but cross-jurisdictional regulations could extend project timeline and increase the ultimate cost.

169. This option poses logistical challenges associated with fleet management.

170. This option will likely entail greater contractual complexity associated with more extensive offshore logistics.

171. This option requires efficient fleet management that includes timely LNG deliveries to the FSU, FSU capacity management, and logistics associated with LNG deliveries to the port using a shuttle tanker, and thus may be operationally challenging.

172. The operational and permitting difficulties would be greatly reduced if the smaller shuttle tankers were able to load LNG directly at a marine jetty, such as the one currently undergoing final permitting steps by FortisBC (Tilbury LNG marine jetty). This option was not considered due to the current uncertain state of permitting of the jetty.

[86] Inclusive of land acquisition and contingency.

Appendix A –Work Products

A.1 Conceptual Engineering Design

173. The conceptual engineering design for all the options can be found in the attached documents:

Option	File Name
Kenai LNG / Onshore Gasification (3K)	Option 03K Kenai LNG_Design Basis Document_Final.pdf
	Option 03K Kenai LNG_Site Plan_Final.pdf
	Option 03K Kenai LNG_General Arrangement_Final.pdf
	Option 03K Kenai LNG_Electric Load List_Final.pdf
	Option 03K Kenai LNG_Equipment List Phase I_Final.pdf
	Option 03K Kenai LNG_Equipment List Phase II_Final.pdf
	Option 03K Kenai LNG_Process Flow Diagram_Final.pdf
	Option 03K Kenai LNG_One Line Diagram_Final.pdf
Marathon FSRU (5M)	Option 05M FSRU Marathon_Design Basis Document_Final.pdf
	Option 05M FSRU Marathon_Site Plan_Final.pdf
	Option 05M FSRU Marathon_General Arrangement_Final.pdf
	Option 05M FSRU Marathon_Electric Load List_Final.pdf
	Option 05M FSRU Marathon_Equipment List_Final.pdf
	Option 05M FSRU Marathon_Process Flow Diagram_Final.pdf
	Option 05M FSRU Marathon_One Line Diagram_Final.pdf
	Option 05M FSRU Marathon_Concept Map_Final.pdf
Nikiski FSRU (5GN)	Option 05GN FSRU Nikiski_Design Basis Document_Final.pdf
	Option 05GN FSRU Nikiski_Site Plan_Final.pdf
	Option 05GN FSRU Nikiski_General Arrangement_Final.pdf

	Option 05GN FSRU Nikiski_Electric Load List_Final.pdf
	Option 05GN FSRU Nikiski_Equipment List_Final.pdf
	Option 05GN FSRU Nikiski_Process Flow Diagram_Final.pdf
	Option 05GN FSRU Nikiski_One Line Diagram_Final.pdf
	Option 05GN FSRU Nikiski_Concept Map_Final.pdf
Greenfield FSRU (5GA – Parcel 68)	Option 05GA Parcel 68_Design Basis Document_Final.pdf
	Option 05GA Parcel 68_Site Plan_Final.pdf
	Option 05GA Parcel 68_General Arrangement_Final.pdf
	Option 05GA Parcel 68_Electric Load List_Final.pdf
	Option 05GA Parcel 68_Equipment List_Final.pdf
	Option 05GA Parcel 68_Process Flow Diagram_Final.pdf
	Option 05GA Parcel 68_One Line Diagram_Final.pdf
	Option 05GA Parcel 68_Site Search Report_Final.pdf
ISO Containers (Port of Alaska)	Option 06A_ISO Containers_Port of Alaska_Concept Map_Final.pdf
ISO Containers (Port MacKenzie)	Option 06M_ISO Containers_Port MacKenzie_Concept Map_Final.pdf

A.2 Project Schedule

174. The project schedule for all the options can be found in the attached documents:

Option	File Name
Kenai LNG / Onshore Gasification (3K)	Option 03K Kenai LNG_Schedule P75_Final.pdf
Marathon FSRU (5M)	Option 05M FSRU Marathon_Schedule P75_Final.pdf
Nikiski FSRU (5GN)	Option 05GN FSRU Nikiski_Schedule P75_Final.pdf
Greenfield FSRU (5GA – Parcel 68)	Option 05GA Parcel 68_Schedule P75_Final.pdf
ISO Containers (Port of Alaska)	Option 06A_ISO Containers_Port of Alaska_Schedule P75_Final.pdf
ISO Containers (Port MacKenzie)	Option 06M_ISO Containers_Port Mackenzie_Schedule P75_Final.pdf

A.3 Summary of Cost

175. The cost for all the options can be found in the attached documents:

Option	File Name
Kenai LNG / Onshore Gasification (3K)	Option 03K Kenai LNG_Phase 1 Cost_Final.xlsx
	Option 03K Kenai LNG_Phase 2 Cost_Final.xlsx
Marathon FSRU (5M)	Option 05M FSRU Marathon_Cost_Final.xlsx
Nikiski FSRU (5GN)	Option 05GN FSRU Nikiski_Cost_Final.xlsx
Greenfield FSRU (5GA – Parcel 68)	Option 05GA Parcel 68_Cost_Final.xlsx
All Options (Contingency Assumptions)	Enstar Contingency Worksheets - KNLG - PM - PA_Final.xlsx

A.4 Other Work Products

Work Product	File Name
Marine and Shipping Report	Alaska LNG Marine Requirements Report 2023.12.20 Final – Confidential.pdf

Appendix C – Permitting Matrix

C.1 Preliminary Permitting Matrix – ISO Containers (Anchorage Port)

PRELIMINARY U.S. REGULATORY APPROVALS MATRIX FOR ISO TANKS OPTION - PORT OF ALASKA (RE-GAS AT INLAND SITE)						
Jurisdiction	**Type**	**Permit/ Authorization**	**Responsible Party**	**Estimated Duration**	**Notes[1]**	**Level of Detail[2]**
FEDERAL						
U.S. Department of Energy (DOE), Office of Fossil Energy and Carbon Management ("FECM")	Authorization to Import	Authorization to import LNG under the NGA	DOE	At least 90-days	Applications are required to be filed at least 90 days in advance of the proposed import (10 CFR Part 290.201)	Pre-FEED; FEED
USCG	Operations	Letter of Intent (LOI) and Operational Risk Assessment (ORA)	USCG	Up to 1 year	33 CFR Part 127.08 allows for an owner or operator to submit an LOI and ORA in lieu of a Waterway Suitability Assessment. The LOI and ORA must be submitted at least one year prior to the start of LNG transfer operations.	Concept Selection; Pre-FEED and FEED
STATE[3]						
ADEC, Division of Water Quality ("DWC")	Construction	Construction General Permit for Storm Water Discharges for Large and Small Construction Activities (CGP, AKR100000)	ADEC	90-days prior to construction and/or required fieldwork/surveys	Short Lead Time Permits	FEED; EPC
ADEC, Division of Air Quality	Construction	Air Quality Control Construction Permit and	ADEC	60-days after complete application is determined	Additional Project design information regarding emission sources is needed to evaluate the level of permitting required (e.g., Minor Source Construction vs. Major	FEED; EPC

		Operating Permit Applications (likely requires modification to existing Title V Operating Permit)		(likely 6-12 month permitting process)	Title V Permit). Potential to Emit (PTE) inventory is required for all stationary sources, non-road engines (i.e., construction equipment, mobile/marine sources, generators, etc.)	
MUNICIPALITY OF ANCHORAGE						
Municipality of Anchorage ("MOA")	Construction	Conditional Use Approval; Building and Construction Permits	MOA	6-9 Months for Conditional Land Use Approval Variable for Construction and Building Permits (1-3 months)	Conditional Use Approval is a Public Process, subject to Public Notice and Public Hearing.	Pre-FEED; FEED; EPC

Notes:

1) The listed permits are typical authorizations and consultations required. Contingent on project environmental surveys and agency consultations, the above list is subject to change. Matrix does not include potential approvals required for improvements at the Port.

2) Level of Detail categories are generally based on the following criteria:
   - Concept Selection: Range of technically viable options for major project components, business structure, in-state gas/import LNG demand, environmental activities and technical data collection, assure the ability to secure regulatory approvals, permits, land use, stakeholder engagement, and file DOE import license.
   - Pre-Front End Engineering & Design (Pre-FEED): Defines the project scope, develops the project concept, and creates a preliminary design of the required facilities (e.g., Process Flow Diagrams / Preliminary Piping and Instrumentation Diagrams).
   - Front-end Engineering & Design (FEED) is conducted after completion of Conceptual Design and Feasibility Studies. FEED leads to a final investment decision (FID).
   - Engineering, Procurement, and Construction (EPC): EPC occurs after FID and includes material purchase, construction, and commissioning.

3) State approvals matrix does not include Regulatory Commission of Alaska Certificates of Public Convenience and Necessity (CPCN), rate case approvals, and other reviews/approvals that may be required by the RCA.

C.2 Preliminary Permitting Matrix – ISO Containers (Port MacKenzie)

PRELIMINARY U.S. REGULATORY APPROVALS MATRIX FOR ISO TANKS OPTION - PORT MACKENZIE (RE-GAS AT INLAND SITE)						
Jurisdiction	**Type**	**Permit/ Authorization**	**Responsible Party**	**Estimated Duration**	**Notes[1]**	**Level of Detail[2]**
FEDERAL						
DOE, FECM	Authorization to Import	Authorization to import LNG under the NGA	DOE	At least 90-days	Applications are required to be filed at least 90 days in advance of the proposed import (10 CFR Part 290.201)	Pre-FEED; FEED
STATE[3]						
ADEC, DWC	Construction	Construction General Permit for Storm Water Discharges for Large and Small Construction Activities (CGP, AKR100000)	ADEC	90-days prior to construction	Short Lead Time Permit (only required if land disturbance is equal to or greater than one acre)	FEED; EPC
ADEC, DWC	Construction	Hydrostatic General Permit (AKG003000)	ADEC	30-days prior to construction	To be obtained if and/or when hydrostatic testing is required for pipeline(s) tie-ins	FEED; EPC
ADEC, Division of Air Quality	Construction	Air Quality Control Construction Permit and Operating Permit Applications	ADEC	60-days after complete application is determined (likely 6-12 month permitting process)	Additional Project design information regarding emission sources is needed to evaluate the level of permitting required (e.g., Title I Minor Source Construction Permit vs. Title V Major Permit). Potential to Emit ("PTE") inventory is required for all stationary sources, non-road engines (i.e., construction equipment, mobile sources, generators, etc.)	FEED; EPC
BOROUGH						
MSB[4]	Construction	Driveway / Encroachment Permits	MSB	Work in a public easement or right-of-way (30-days)	Required for any modifications to road approaches or driveways within MSB easements/road service areas managed by MSB	Pre-FEED; FEED; EPC

Notes:

1) The listed U.S. Federal permits are typical authorizations and consultations required. Contingent on project environmental surveys and agency consultations, the above list is subject to change and provided as preliminary regulatory requirements.
2) Level of Detail categories are generally based on the following criteria:
   - Concept Selection: Range of technically viable options for major project components, business structure, in-state gas/import LNG demand, environmental activities and technical data collection, assure the ability to secure regulatory approvals, permits, land use, stakeholder engagement, and file DOE import license.
   - Pre-Front End Engineering & Design (Pre-FEED): Defines the project scope, develops the project concept, and creates a preliminary design of the required facilities (e.g., Process Flow Diagrams / Preliminary Piping and Instrumentation Diagrams).
   - Front-end Engineering & Design ("FEED"): Conducted after completion of Conceptual Design and Feasibility Studies. FEED leads to a FID.
   - Engineering, Procurement, and Construction (EPC): EPC occurs after FID and includes material purchase, construction, and commissioning.
3) State approvals matrix does not include Regulatory Commission of Alaska Certificates of Public Convenience and Necessity (CPCN), rate case approvals, and other reviews/approvals that may be required by the RCA.
4) MSB matrix does not include potential approvals required for improvements at the Port.

C.3 Permitting Matrix – Small-Scale Bulk Option

DRAFT - PRELIMINARY U.S. REGULATORY APPROVALS MATRIX FOR SMALL VESSELS (FSU IN COOK INLET >3NM LINE, RE-GAS AT KENAI LNG)

Jurisdiction	Type	Permit/ Authorization	Responsible Party	Estimated Duration	Notes[1]	Level of Detail[2]
FEDERAL						
U.S. Department of Transportation Maritime Administration ("MARAD")	Authorization required to Site and Operate FSU	Deepwater Port Act of 1974 ("DWPA")	MARAD and USCG	Environmental Impact Statement ("EIS"): Up to two years Co-lead agency for Deepwater Port ("DWP") NEPA review	MARAD and USCG would be co-lead agencies for the NEPA review of the FSU and likely require an EIS. Per DWPA at Section 5(f), there is one EIS that covers all DWP license and permitting actions for each project, therefore, the onshore improvements would need to be included in the MARAD/USCG NEPA review. The MARAD DWP/NEPA process is managed under a 356-day "clock" which starts when an applicant submits a licensing application and stops when MARAD issues a Record of Decision (ROD). The "clock" also stops anytime if/when applicants do not provide sufficient information, etc. The MARAD licensing process includes a pre-application phase where applicants confer with MARAD and the USCG; during pre-application phase, applicants should similarly engage state and local regulatory agencies. Furthermore, MARAD is responsible for certifying the applicant's financial and U.S. citizenship requirements have been met and defining the legal scope of DWPA license.	Concept Selection; Pre-FEED and FEED
U.S. Department of Homeland Security, USCG	Authorization required to Site and Operate FSU	DWPA	USCG	Co-lead agency for DWP NEPA review	USCG is responsible for DWPA License application processing, along with post-licensing design, construction, operations approval, and oversight. In addition, USCG certifies that navigational aids for the DWP meet the applicable requirements. Per the DWPA, the USCG is authorized to establish	Concept Selection; Pre-FEED and FEED

Jurisdiction	Type	Permit/ Authorization	Responsible Party	Estimated Duration	Notes[1]	Level of Detail[2]
					federally regulated safety zones around all DWPs to promote marine environmental protection, maintain safety, and reduce risks to navigation.	
USCG	Operations	Waterway Suitability Assessment ("WSA") Review	USCG	Concurrent with NEPA review	For increased frequency of LNG marine traffic to Kenai LNG, the project sponsor must submit a Letter of Intent to the USCG Captain of the Port. USCG would review the existing Port of Nikiski Kenai LNG WSA for conformance of planned activities. Amendments may be required to the existing WSA to cover planned, new activities.	Concept Selection; Pre-FEED and FEED
DOE, Office of Fossil Energy and Carbon Management	Authorization to Import	Authorization to import LNG under the NGA	DOE	Concurrent with Lead Agency NEPA review	U.S. DOE authorization to import based on public interest determinations.	Concept Selection; Pre-FEED and FEED
U.S. Department of Defense ("DoD")	Authorization required to Site and Operate FSU	Consultation (review of license application adequacy and views on effects to departmental programs)	DoD	Concurrent with DWPA application processing	Notable elements of the regulatory framework for a DWPA application include consultations with the Secretaries of the Army, State, and Defense.	Concept Selection; Pre-FEED and FEED
USACE	Authorization required to Site and Operate FSU	Section 404 Clean Water Act ("CWA") – Nationwide Permit (NWP) 8 Section 10 of the Rivers and Harbors Act ("RHA")	USACE	Pre-construction notification (PCN) to the district engineer prior to commencing the activity (45-day review period for PCNs)	NWP 8 covers structures used for the exploration, production, and transportation of oil, gas, and minerals on the Outer Continental Shelf ("OCS"). Structures must not be placed within the limits of any designated shipping safety fairway or traffic separation scheme, except for temporary anchors that comply with fairway regulations. USACE review under NWP 8 will be limited to the effects on navigation and national security. Section 10 of the RHA prohibits the unauthorized obstruction or alteration of any navigable water of the U.S. Section 10 authorization is given for all structures and work located within U.S. waters, including	Concept Selection; Pre-FEED and FEED

Jurisdiction	Type	Permit/ Authorization	Responsible Party	Estimated Duration	Notes[1]	Level of Detail[2]
					infrastructure located on the seabed of the seaward limit of the OCS, through Section 4(f) of the Outer Continental Shelf Lands Act (OCSLA).	
U.S. Department of Transportation ("USDOT"), Pipeline Hazardous Material Safety Administration ("PHMSA")	Operations	Safety Analysis to Establish Siting for LNG Facilities Under 49 CFR Part 601 and 49 CRR Parts 190-193.[4]	PHMSA	Concurrent with DWPA application processing	Administer national regulatory program to ensure the safe transportation of natural gas subject to 49 CFR 193 and review Project's compliance with the siting requirements in 49 CFR 193 Subpart B and issue LOD per 2018 MOU. Assists as a cooperating agency to review the safety and security of waterfront import/export. PHMSA would be involved in plan review and approval for modifications required to support the AKGSP Project under its jurisdiction.	Concept Selection; Pre-FEED
U.S. Department of the Interior, Bureau of Offshore Energy Management ("BOEM")	Authorization required to Site and Operate FSU	Consultation	BOEM	Concurrent with DWPA application processing	BOEM is responsible for issuing and enforcing regulations to promote the safe operation, environmental protection, and resource conservation for all explorations, development, and production activities located on the OCS. The OCSLA defines the OCS as all submerged lands lying seaward of state coastal waters (three nautical miles offshore) which are under U.S. jurisdiction.	Concept Selection; Pre-FEED
Bureau of Safety and Environmental Enforcement ("BSEE")	Operations	Oil Pollution Act of 1990 liability adjustment	BSEE	Concurrent with DWPA application processing	Under the DWPA and subsequent MOU's with the USCG and other Federal Agencies, BSEE would have certain responsibilities for safety and environmental protection if the FSU is located within the OCS. Advise USCG and MARAD concerning the potential impacts of DWPA terminals on OCS lease blocks.	Concept Selection; Pre-FEED; FEED
U.S. Fish and Wildlife Service ("USFWS")	Authorization required prior to Construction	Section 7 Consultation under Endangered	USFWS	Concurrent with DWPA application processing	Consider Lead Agencies' finding of impact on federally listed and proposed threatened and endangered species and their critical habitat and provide a Biological Opinion if the action is likely	Concept Selection; Pre-FEED

Jurisdiction	Type	Permit/ Authorization	Responsible Party	Estimated Duration	Notes[1]	Level of Detail[2]
		Species Act Migratory Bird Treaty Act, Bald and Golden Eagle Protection Act Coordination			to adversely affect federally listed or proposed species or their critical habitat. No application form. However, informal and formal consultation are triggered by requests from a federal agency. Informal consultation can be initiated by an agency request for a species list to USFWS or agency preparation of a species list. Formal consultation and conference is initiated by a written request from a federal agency and must include a biological assessment. A draft biological assessment can be submitted to USFWS.	
U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service ("NMFS")	Authorization required prior to Construction	Marine Mammal Act Consultation (16 USC § 1382) Endangered Species Act Section 7 Consultation (16 USC § 1856 et seq.) Magnuson-Stevens Fishery Conservation and Management Act Consultation Essential Fish Habitat Consultation (50 CFR Part 600) Fish and Wildlife Coordination Act Consultation (16	NMFS	Concurrent with DWPA application processing	The NMFS Essential Fish Habitat (EFH) Response will be provided within 60 days of NMFS determination that all information necessary to initiate EFH consultation has been provided. The final completion date is contingent upon when NMFS receives what it concludes is a complete EFH assessment. Field studies/survey on impact from seawater use (requires 16 to 24 months of ichthyoplankton data to assess impacts under the NMFS EFH requirements) A portion of Cook Inlet is critical habitat for the Cook Inlet Beluga Whale, and areas of the Gulf of Alaska potentially crossed by LNG vessels have been designated as Critical Habitat for the North Pacific and Mexico Distinct Population Segment (DPS) of humpback whale.	Concept Selection; Pre-FEED

Jurisdiction	Type	Permit/ Authorization	Responsible Party	Estimated Duration	Notes[1]	Level of Detail[2]
		USC §§ 661 et seq.)				
U.S. Environmental Protection Agency ("EPA")	Authorization required prior to Construction	CWA National Pollutant Discharge Elimination System ("NPDES") Permit Section 316(b) of the CWA	EPA	Concurrent with DWPA/NPDES application and review (NPDES process is approximately 6 months)	NPDES permit is required for point-source discharge of used water into surface waters of the U.S. Section 316(b) Regulations for cooling water intake structures at offshore facilities for NPDES permitting process when federally-listed threatened and endangered species and/or designated critical habitat are or may be present.	Concept Selection; Pre-FEED
EPA	Authorization required prior to Construction	Clean Air Act ("CAA") New Source Review ("NSR") and/or Prevention of Significant Deterioration Permit CAA General Conformity Determination	EPA	Concurrent with DWPA/NSR permit application and review (NSR process is approximately 18 months)	Section 328 of the CAA, requires the EPA to establish requirements to control air pollution from OCS sources in order to attain and maintain Federal and State ambient air quality standards. OCS new source means any equipment, activity, or facility that emits or has the potential to emit any air pollutant and is regulated or authorized under the OCSLA and is located on the OCS or in or on waters above the OCS. Proposed new or modified air pollutant emission sources must undergo a NSR prior to construction or operation.	Concept Selection; Pre-FEED
FERC	Authorization Required to Construct and Operate Re-Gas Facility at Kenai LNG	Order Granting Authorization to Construct, Operate, or Modify Facilities Used for the Export or Import of Natural Gas Under Section 3 of the NGA	FERC	Environmental Assessment or Categorical Exclusion	While FERC may join as a Cooperating Agency for completion of its NEPA obligations associated with improvements to the Kenai LNG facility, FERC may instead elect to complete its own NEPA review for onshore improvements at the Kenai LNG facility.	Concept Selection; Pre-FEED and FEED

Jurisdiction	Type	Permit/ Authorization	Responsible Party	Estimated Duration	Notes[1]	Level of Detail[2]
Advisory Council on Historic Preservation	Authorization required prior to Construction	National Historic Preservation Act ("NHPA") Section 106 consultation	MARAD/USCG	Concurrent with DWPA application processing	Require to delineate the area of potential effects for historic properties on the OCS that may include historic shipwrecks, sunken aircraft, and pre-contact archaeological sites that have become inundated.	Concept Selection; Pre-FEED
STATE						
State of Alaska ("SOA"), Office of the Governor	Authorization required prior to Construction	DWPA Section 1508	SOA	Concurrent with DWPA application processing	The Governor of the Adjacent Coastal State (SOA) must approve the issuance of a DWP license. If such approval is not provided to the Maritime Administrator within 45 days of the final public hearing, approval shall be conclusively presumed.	Concept Selection; Pre-FEED
ADEC, DWC	Construction	Construction General Permit for Storm Water Discharges for Large and Small Construction Activities (CGP, AKR100000)	ADEC, DWC	90-days prior to construction and/or required fieldwork/ surveys	To be obtained for discharges under State jurisdiction.	FEED
ADEC, Division of Water Quality	Construction	Hydrostatic General Permit (AKG003000)	ADEC, DWC	30-days prior to construction	To be obtained if and/or when hydrostatic testing is required for pipeline(s) under State jurisdiction.	FEED
ADEC, Division of Air Quality	Construction	Air Quality Control Construction Permit and Operating Permit Applications	ADEC	60-days after complete application is determined	For new emission sources at Kenai LNG, additional Project design information regarding emission sources is needed to evaluate the level of permitting required (e.g., Minor Source Construction vs. Major Title V Permit). PTE inventory is required for all stationary sources, non-road engines (i.e., construction equipment, mobile/marine sources, generators, etc.)	Pre-FEED; FEED
Alaska Department of Fish and Game ("ADF&G")	Authorization required prior to Construction	Threatened and Endangered Species Consultation	ADF&G	Concurrent with NMFS/USFWS review	State-level consultation for T&E species of concern.	FEED

Jurisdiction	Type	Permit/ Authorization	Responsible Party	Estimated Duration	Notes[1]	Level of Detail[2]
		State Species of Concern				
Alaska Department of Natural Resources, Office of History and Archaeology ("SHPO")	Authorization required prior to Construction	National Historic Preservation Act Section 106 Consultation	SHPO	Concurrent with NEPA review	New in-water work and onshore facilities would trigger additional consultation requirements.	FEED
Alaska Department of Transportation and Public Facilities ("ADOT&PF")	Construction	Utility Permits Right-of-Way	ADOT&PF	60-days prior to construction	Short Lead Time Permit - to be obtained during FEED or after FID	FEED/EPC
ADOT&PF	Construction	Driveway/ Approach Road Permit	ADOT&PF	60-days prior to construction	Short Lead Time Permit - to be obtained during FEED or after FID	FEED/EPC
ADOT&PF	Construction	Lane Closure Permit	ADOT&PF	60-days prior to construction	Short Lead Time Permit - to be obtained during FEED or after FID	FEED/EPC
ALASKA NATIVE TRIBES						
Alaska Native Tribes	Authorization required prior to Construction	Section 106 Consultation FERC to Consult with the following tribes: Chickaloon Native Village Eklutna Native Village Kenaitze Indian Tribe Knik Tribe	MARAD/ USCG/ FERC	Concurrent with NEPA review	Lead NEPA Agency is responsible for Government-to-Government consultation during NEPA review.	Concept Selection; Pre-FEED

Jurisdiction	Type	Permit/ Authorization	Responsible Party	Estimated Duration	Notes[1]	Level of Detail[2]
		Ninilchik Village Village of Salamatof Seldovia Native Village Native Village of Tyonek Cook Inlet Region, Incorporated Cook Inlet Tribal Council Tyonek Native Corporation Native Village of Nanwalek Chugachmiut, Inc. Native Village of Port Graham Montana Creek Native Association				
BOROUGH						
Kenai Peninsula Borough ("KPB") Government	Construction	Zoning Changes; Letter of No Objection; Building and Construction Permit	KPB	180-days	Short Lead Time Permit - to be obtained during FEED or after FID	FEED

Notes:

5) The listed U.S. Federal permits are typical authorizations and consultations required under Section 3 of the Natural Gas Act (NGA). Contingent on project environmental surveys and agency consultations, the above list is subject to change and provided as preliminary regulatory requirements. Permits and approvals for Authorities having jurisdiction in Canadian waters (e.g. Canadian Federal or Provincial) are not included in this matrix.

6) Level of Detail categories are generally based on the following criteria:

Jurisdiction	Type	Permit/ Authorization	Responsible Party	Estimated Duration	Notes[1]	Level of Detail[2]

- Concept Selection: Range of technically viable options for major project components, business structure, in-state gas/import LNG demand, environmental activities and technical data collection, assure the ability to secure regulatory approvals, permits, land use, stakeholder engagement, and file DOE import license.
- Pre-Front End Engineering & Design (Pre-FEED): Defines the project scope, develops the project concept, and creates a preliminary design of the required facilities (e.g., Process Flow Diagrams / Preliminary Piping and Instrumentation Diagrams).
- Front-end Engineering & Design (FEED): Conducted after completion of Conceptual Design and Feasibility Studies. FEED leads to a final investment decision (FID).
- Engineering, Procurement, and Construction (EPC): EPC occurs after FID and includes material purchase, construction, and commissioning.

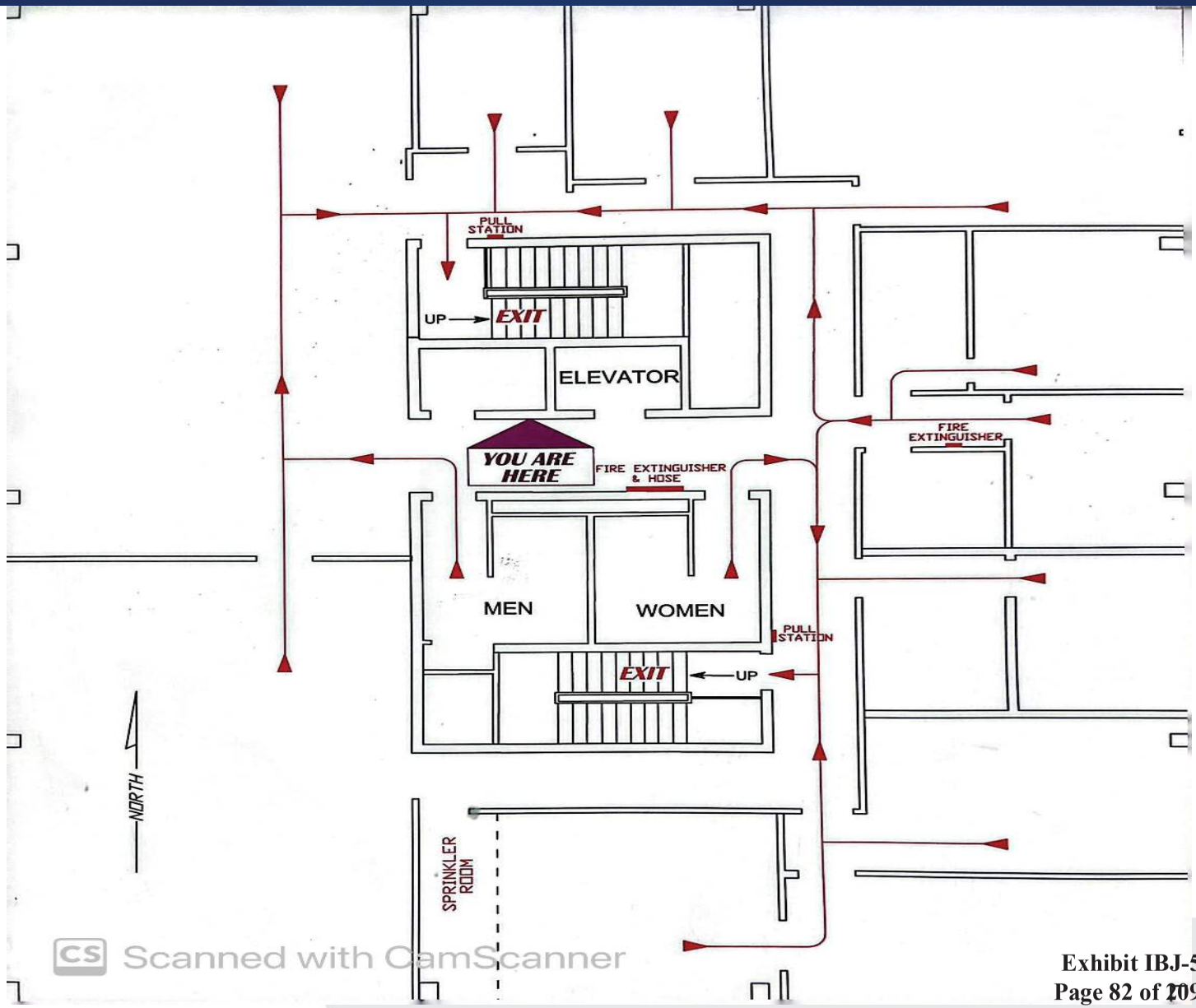
7) The role and jurisdiction of PHMSA will be updated as additional design information becomes available. It is anticipated that PHMSA will weigh in with pipeline safety reviews and findings through coordination with FERC.

Legislative Update

September 21, 2023

ENSTAR Natural Gas Company

Basement Evacuation Route



Scanned with CamScanner

About ENSTAR

- Established in 1959
- 230 employees
- 152,000 customers
- 25 communities served
- 3,560 miles of pipeline
- January average daily throughput: 230 MMcf/d

Agenda

- Background
- Utility Working Group
- Berkeley Research Group (BRG) – Phase I
- BRG – Phase II
- Communications Plan
- Legislative Actions

Background: Role of Natural Gas

- ENSTAR – 34 Bcf
- Electric Utilities – approximately 26 BCF (Chugach, MEA, GVEA, HEA)
- Interior Gas Utility – 1 BCF

Background: Gas Contracts

Hilcorp Contracts 2019-2020:

- Chugach terms 3/31/2028
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Utility Working Group

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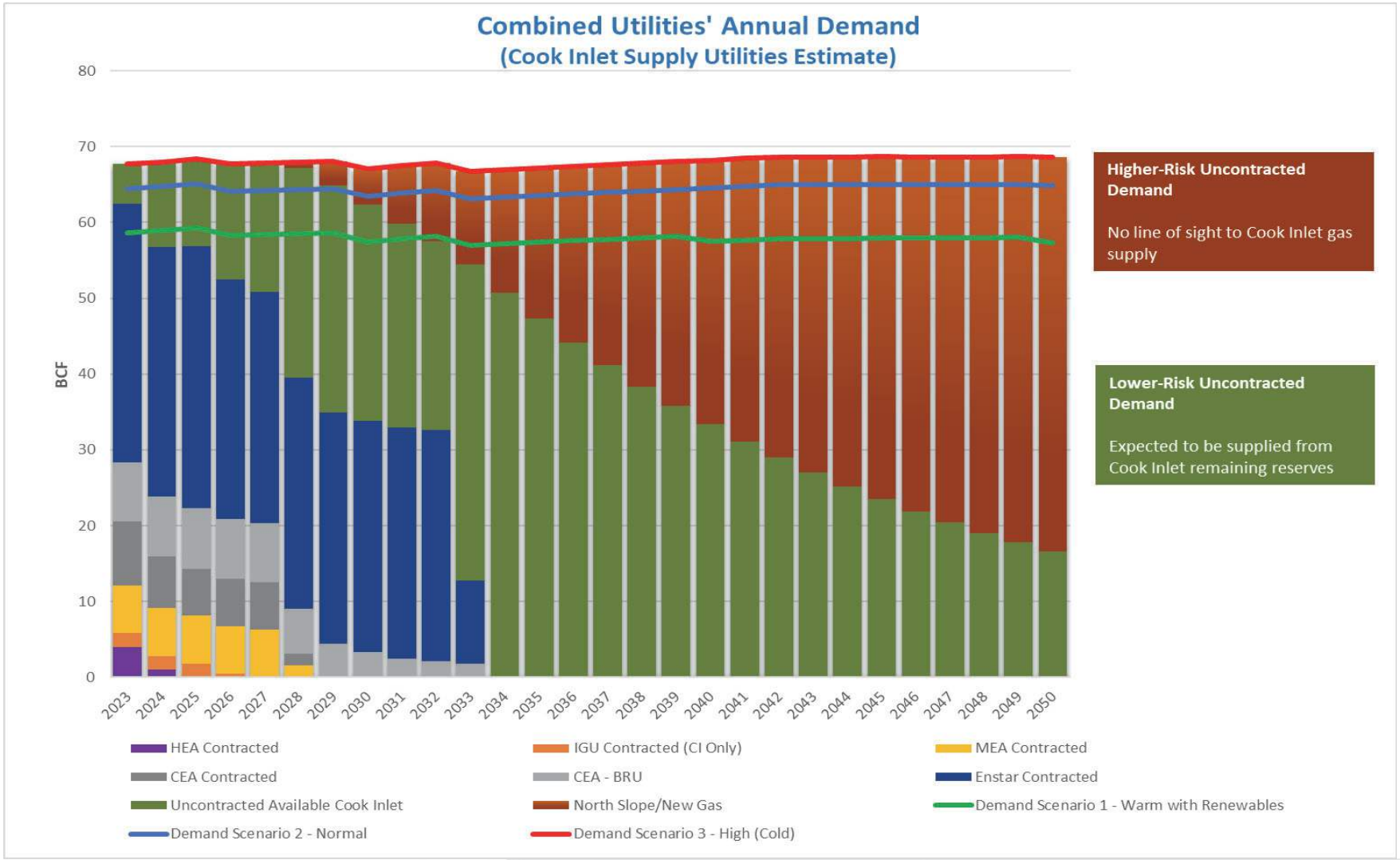
Berkeley Research Group - Phase I

BRG Phase I Effort



BRG Phase I Effort (cont.)

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1. Schedule Risk
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6. Permitting
7. Environmental impact
8. Size of direct investment by utilities
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10. Carbon efficiency

BRG Phase I Effort (cont.)

INTELLIGENCE THAT WORKS

BRG

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Berkeley Research Group - Phase II

Phase II Work

Options for Meeting Future Demand

Phase II assessment is going forward with a prioritized list of options and keen focus on LNG imports

The top scoring options (from Phase I assessment) are:

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Gas Supply Options – Phase II

Option		Timeline from decision	Year Available	Capital Investment	Supply Volume
		years		$USD millions	Bcf/year
1	Cook Inlet Gas	3 - 4	2027	up to $1,500 - $2,000	up to ~23
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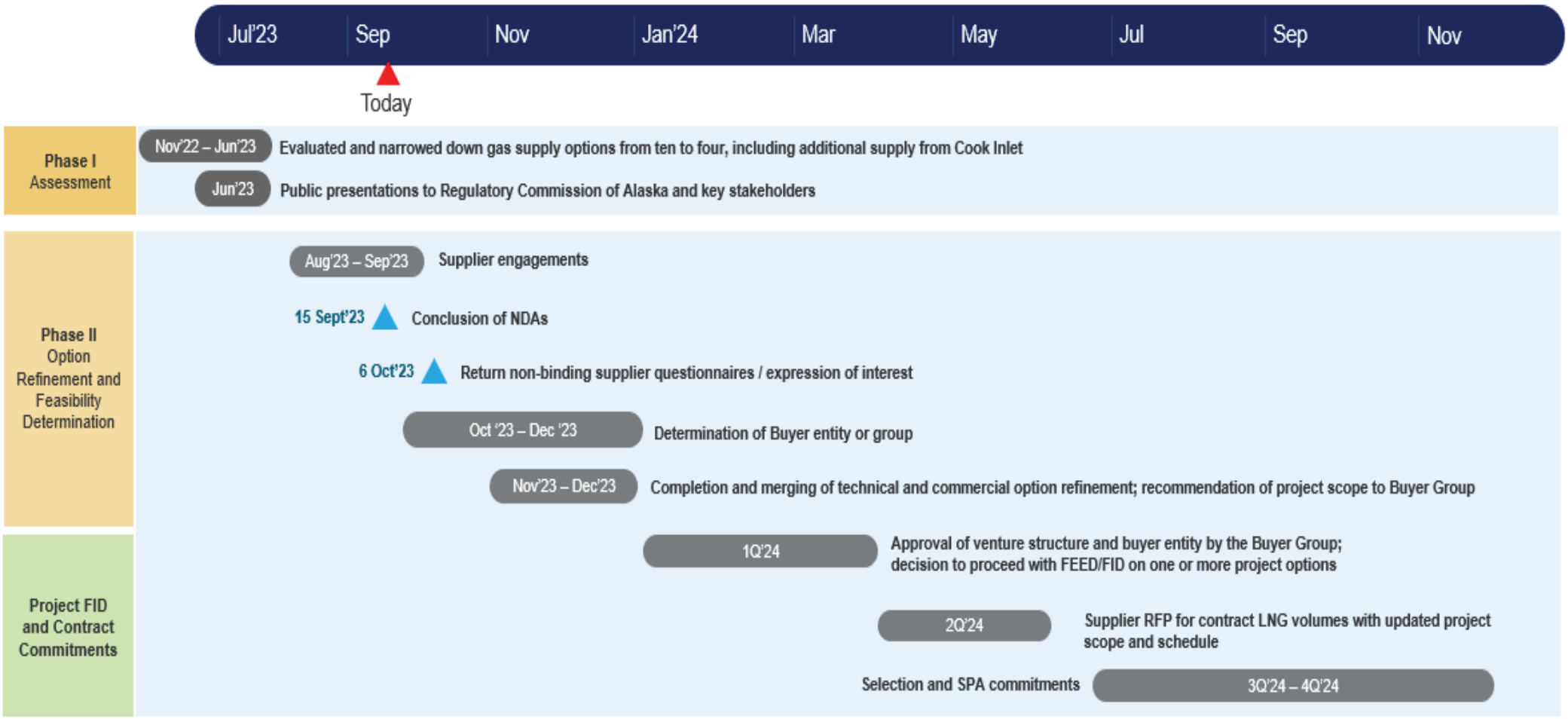
3	Kenai LNG	4 - 5	2028	$768	55 or higher
4	In-State Pipeline (80% subsidized)	6 - 7	2030	~ $8,790	up to 105

Phase II Work

Project Decision Making Timeline



Communications Plan 2023/2024

ENSTAR Natural Gas Company

Southcentral Alaska Public Opinion Survey Results

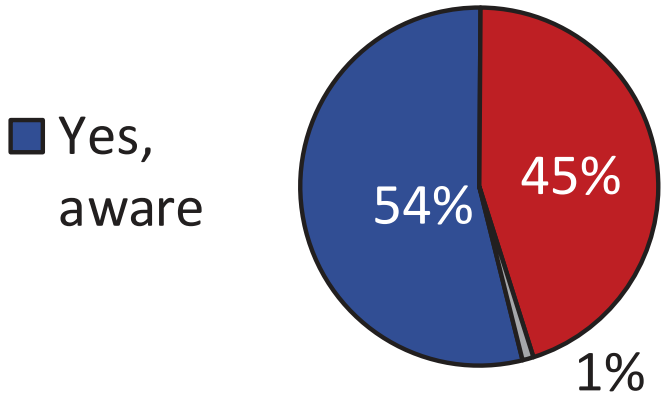
Survey conducted by:

DITTMAN

ENSTAR Natural Gas Company

Awareness of impending shortage

Were you aware of the impending natural gas shortage in Southcentral Alaska, or is this new information?

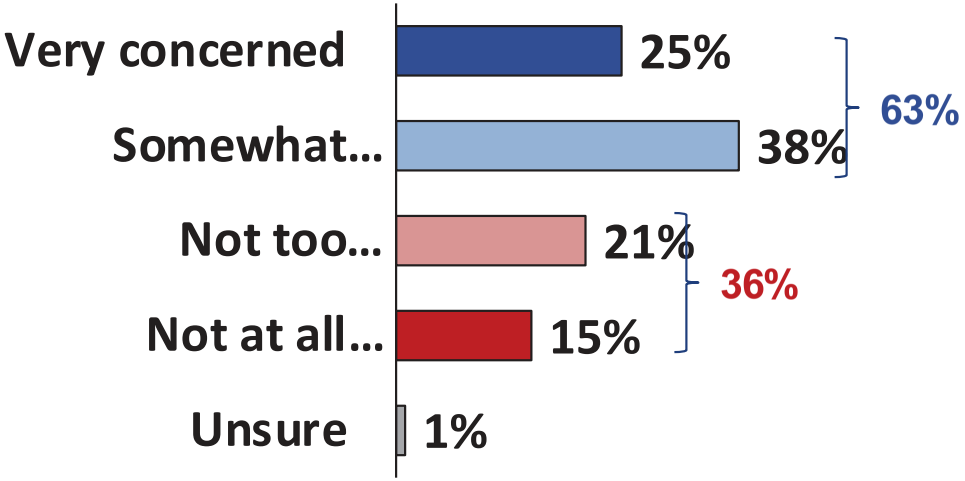


Borough	Aware	Not aware
Anchorage	58%	42%
Mat-Su	46%	51%
Kenai Pen.	56%	43%
Gender		
Male	60%	39%
Female	49%	50%

Age	Aware	Not aware
18-34 yrs old	45%	55%
35-44 yrs old	35%	62%
45-54 yrs old	58%	42%
55-64 yrs old	70%	30%
65+ yrs old	69%	29%
Party		
Democrat	56%	44%
Republican	47%	52%
Non-Partisan	62%	38%
Undeclared	58%	41%
Home heating		
Natural gas	57%	42%
Electric	42%	52%
Heating fuel	58%	42%
Wood	47%	53%
Primary local power		
Natural gas	67%	32%
Hydropower	41%	59%
Other	48%	52%
Unsure	42%	55%

Concern About Shortage

How concerned are you that Southcentral utility companies are preparing for natural gas shortages beginning as early as 2028?

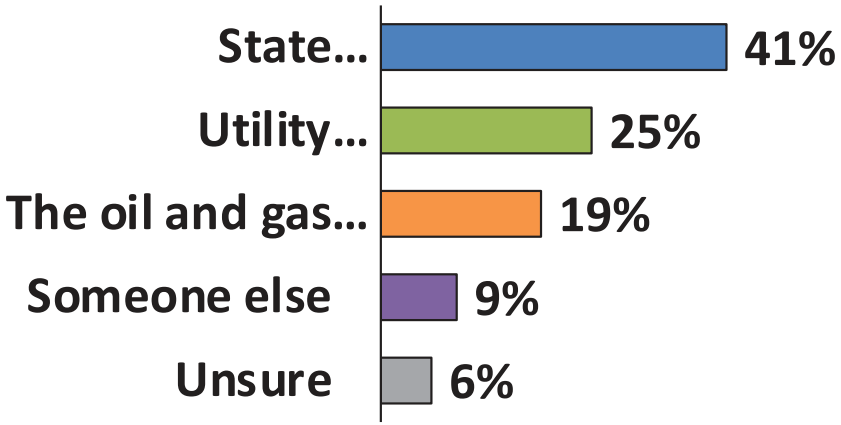


Borough	Very concerned	Total Concerned	Total Not concerned	Net Concerned
Anchorage	24%	66%	33%	+33%
Mat-Su	30%	59%	39%	+20%
Kenai Pen.	19%	55%	45%	+10%
Gender				
Male	21%	52%	48%	+4%
Female	28%	73%	24%	+49%

Age	Very concerned	Total Concerned	Total Not concerned	Net Concerned
18-34 yrs old	20%	72%	28%	+44%
35-44 yrs old	21%	55%	42%	+13%
45-54 yrs old	31%	60%	38%	+22%
55-64 yrs old	27%	58%	42%	+16%
65+ yrs old	26%	67%	31%	+36%
Party				
Democrat	20%	72%	28%	+44%
Republican	30%	62%	38%	+24%
Non-Partisan	17%	59%	39%	+20%
Undeclared	26%	63%	35%	+28%
Follow local news				
Very closely	37%	72%	27%	+45%
Somewhat closely	22%	58%	41%	+17%
Not closely	15%	61%	37%	+24%
Primary local power				
Natural gas	26%	70%	28%	+42%
Hydropower	33%	65%	35%	+30%
Other	23%	49%	50%	-1%
Unsure	20%	55%	44%	+11%

Responsibility for Uninterrupted Supply

In your opinion, who should be primarily responsible for ensuring an uninterrupted natural gas supply?



Borough	State	Utilities	Oil & Gas
Anchorage	43%	25%	17%
Mat-Su	36%	23%	25%
Kenai Pen.	40%	29%	15%
Gender			
Male	36%	25%	19%
Female	45%	25%	18%

Age	State	Utilities	Oil & Gas
18-34 yrs old	52%	9%	26%
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Party			
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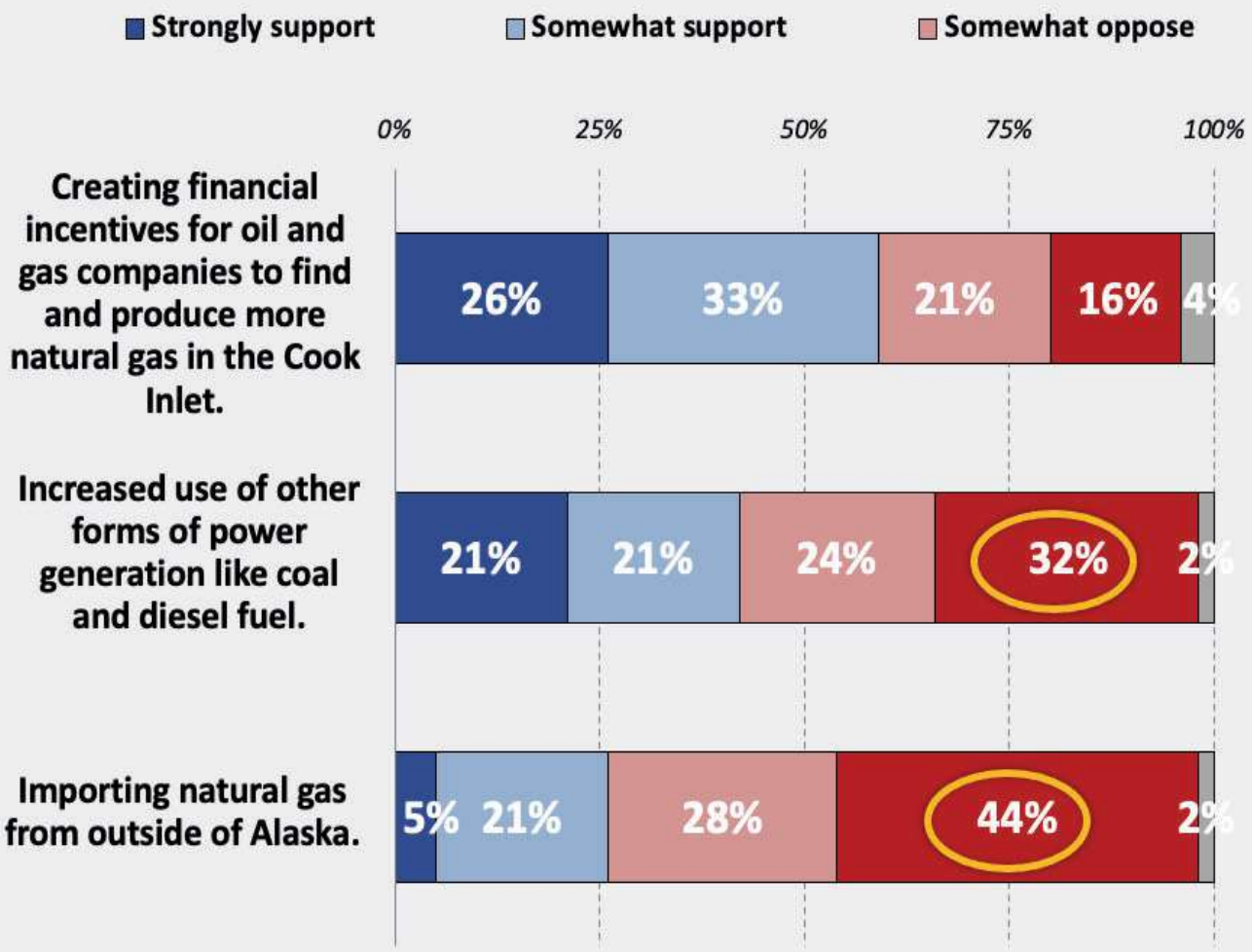
Very liberal	53%	23%	17%
Concerned about shortage			
Very concerned	50%	21%	19%
Somewhat concerned	47%	28%	15%
Not too concerned	33%	27%	22%
Not at all concerned	24%	20%	23%

Short-Term Solutions to Shortage

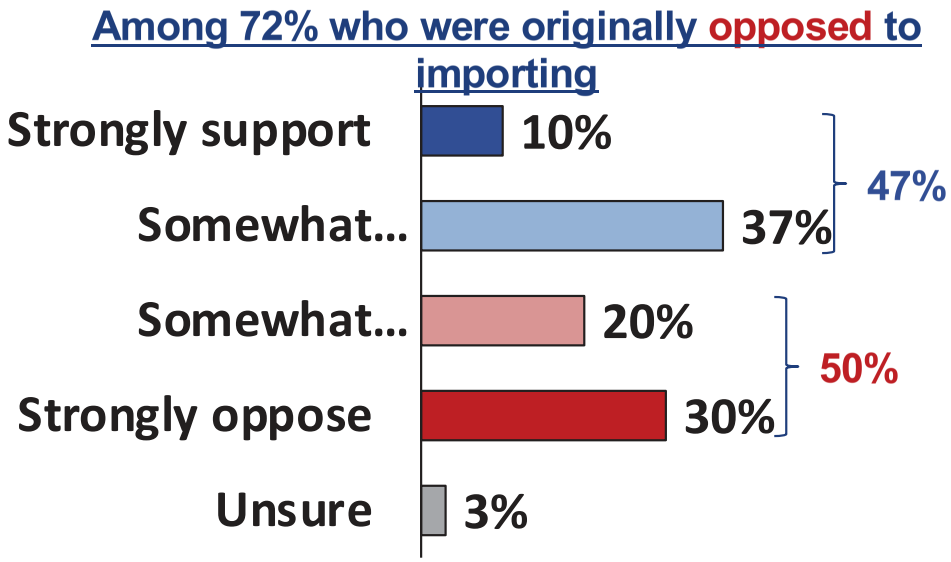
Next I'm going to read several potential short-term solutions to the impending natural gas shortage. For each, please tell me if you would support or oppose it.

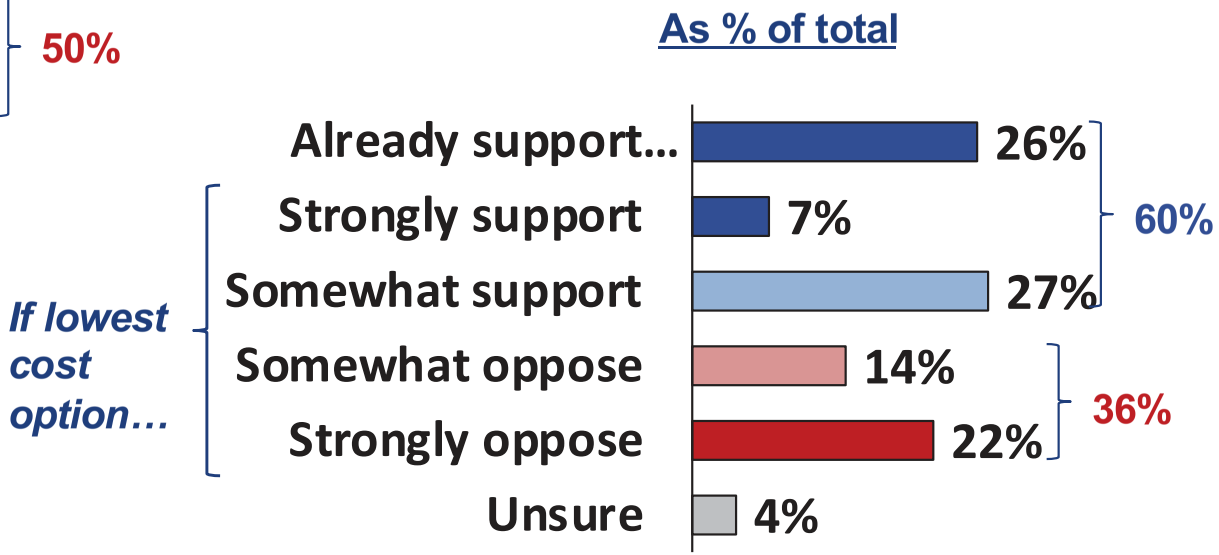


	Total Support	Total Oppose	Net Support	Ratio Supporting
Creating financial incentives for oil and gas companies to find and produce more natural gas in the Cook Inlet.	59%	37%	+22%	1.6-to-1
Increased use of other forms of power generation like coal and diesel fuel.	42%	56%	-14%	1-to-1.3
Importing natural gas from outside of Alaska.	26%	72%	-46%	1-to-2.8

Importing as Lowest Cost Option

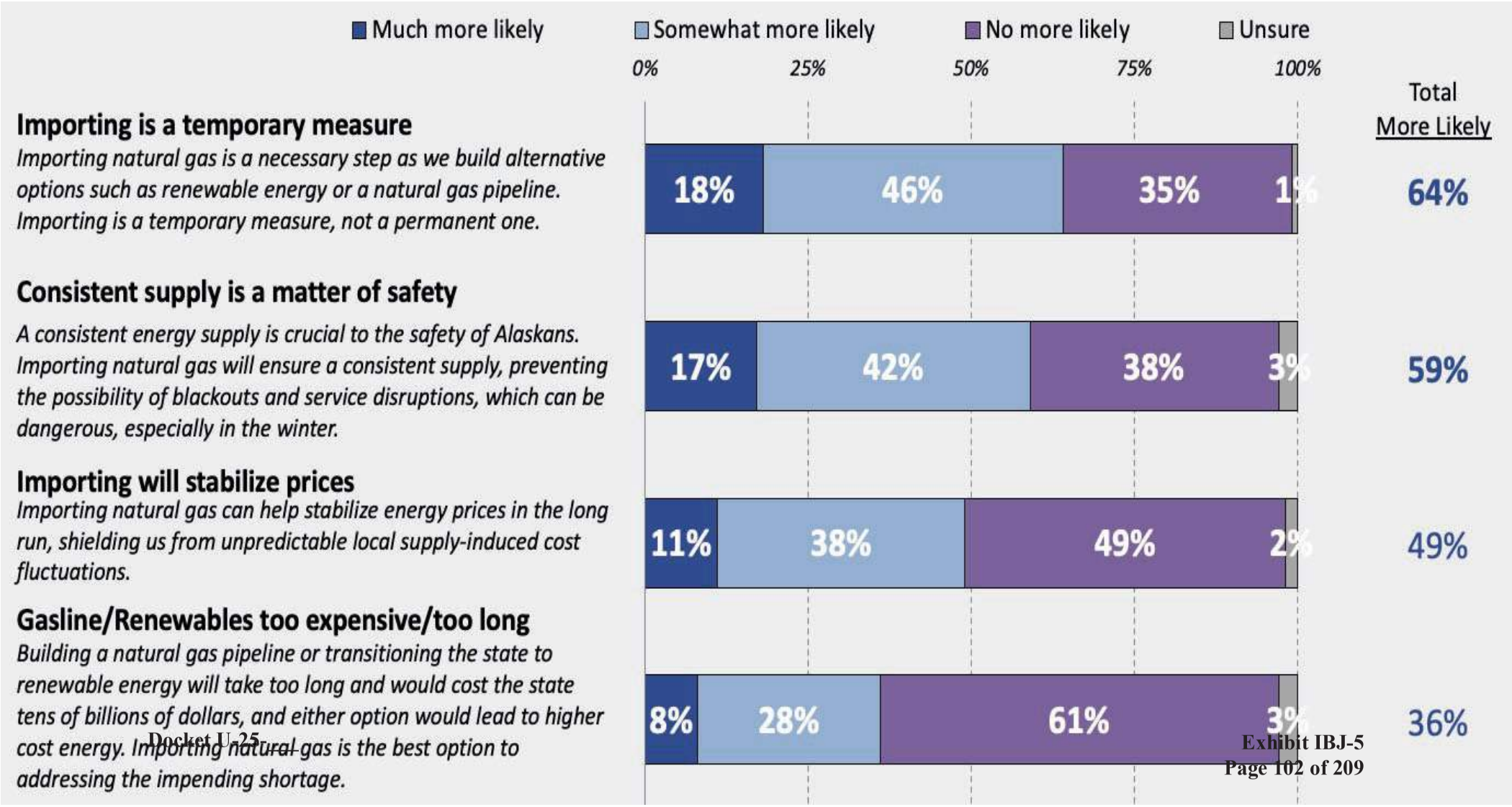
If the lowest cost option for residents is importing natural gas from outside of Alaska, is importing something you would support or oppose?





Messaging in Support of Importing

Next I'm going to read a series of statements about importing natural gas. For each, please tell me if it makes you much more likely, somewhat more likely, or no more likely to support importing natural gas to address the impending shortage.



Legislative Actions

Governor's Energy Security Task Force

Railbelt Subcommittee

- Long-term goal – "Diversification of power generation with an emphasis on local, reliable and affordable."
- Mid-term goal – "Invest in infrastructure improvements to advance us towards our long term goal."
- Near-term goal – "Minimize regret cost while providing reliable service."

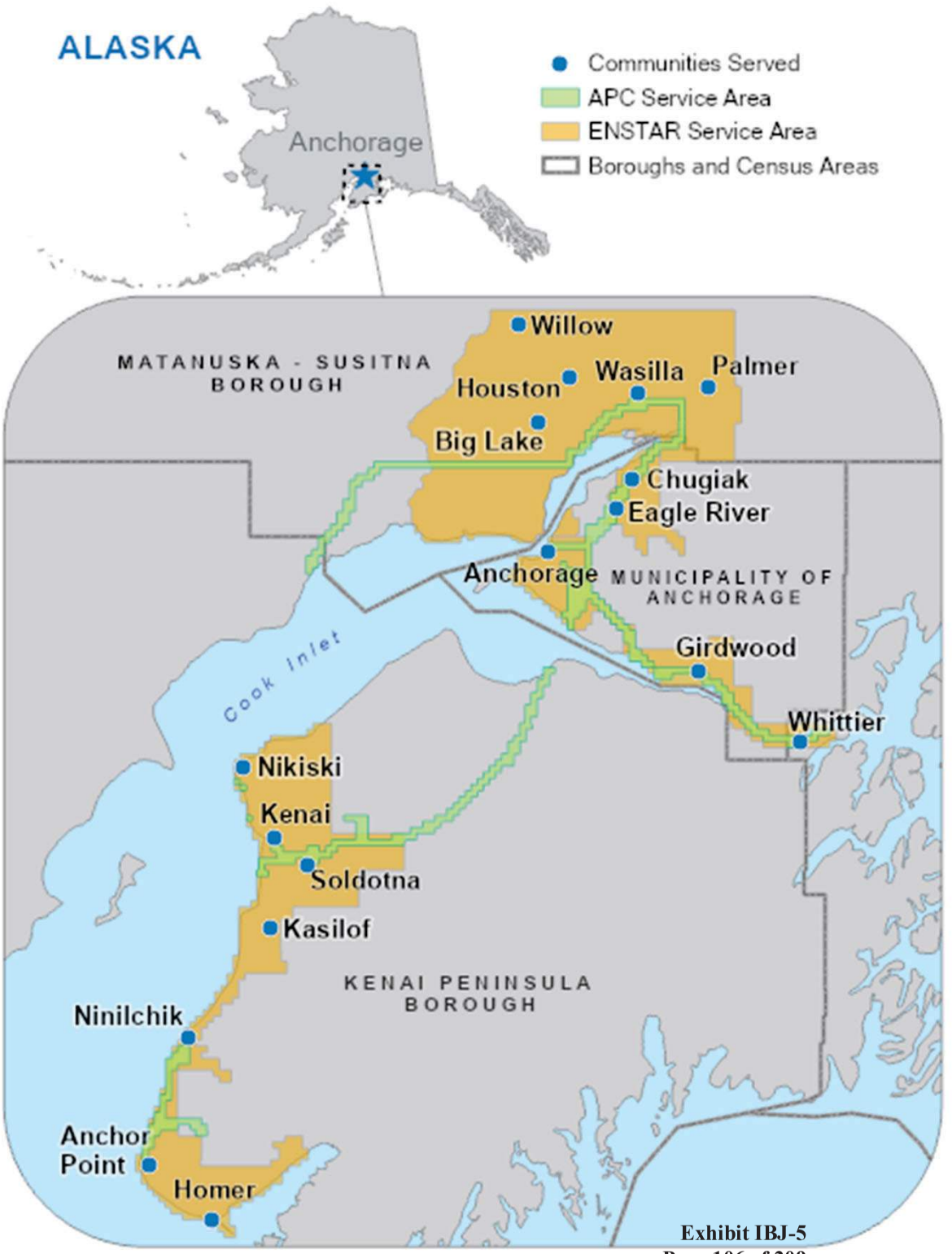
Alaska Chamber Fall Forum

September 27, 2023

ENSTAR Natural Gas Company

About ENSTAR

- Established in 1959
- 230 employees
- 152,000 customers
- 25 communities served
- 3,560 miles of pipeline
- January average daily throughput: 230 MMcf/d



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Utility Working Group

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- April 12, 2022

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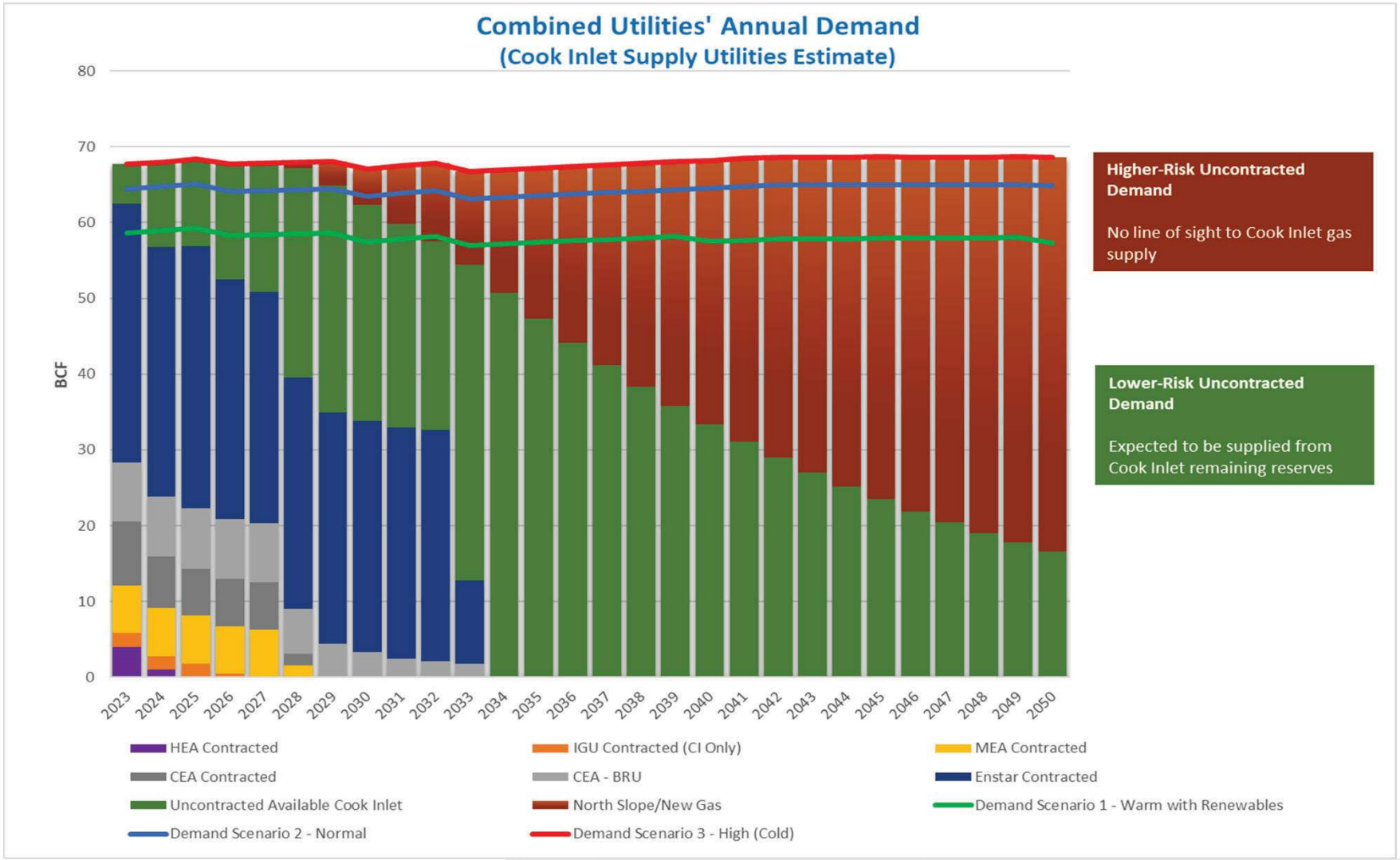
Berkeley Research Group - Phase I

ENSTAR Natural Gas Company

BRG Phase I Effort



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Berkeley Research Group - Phase II

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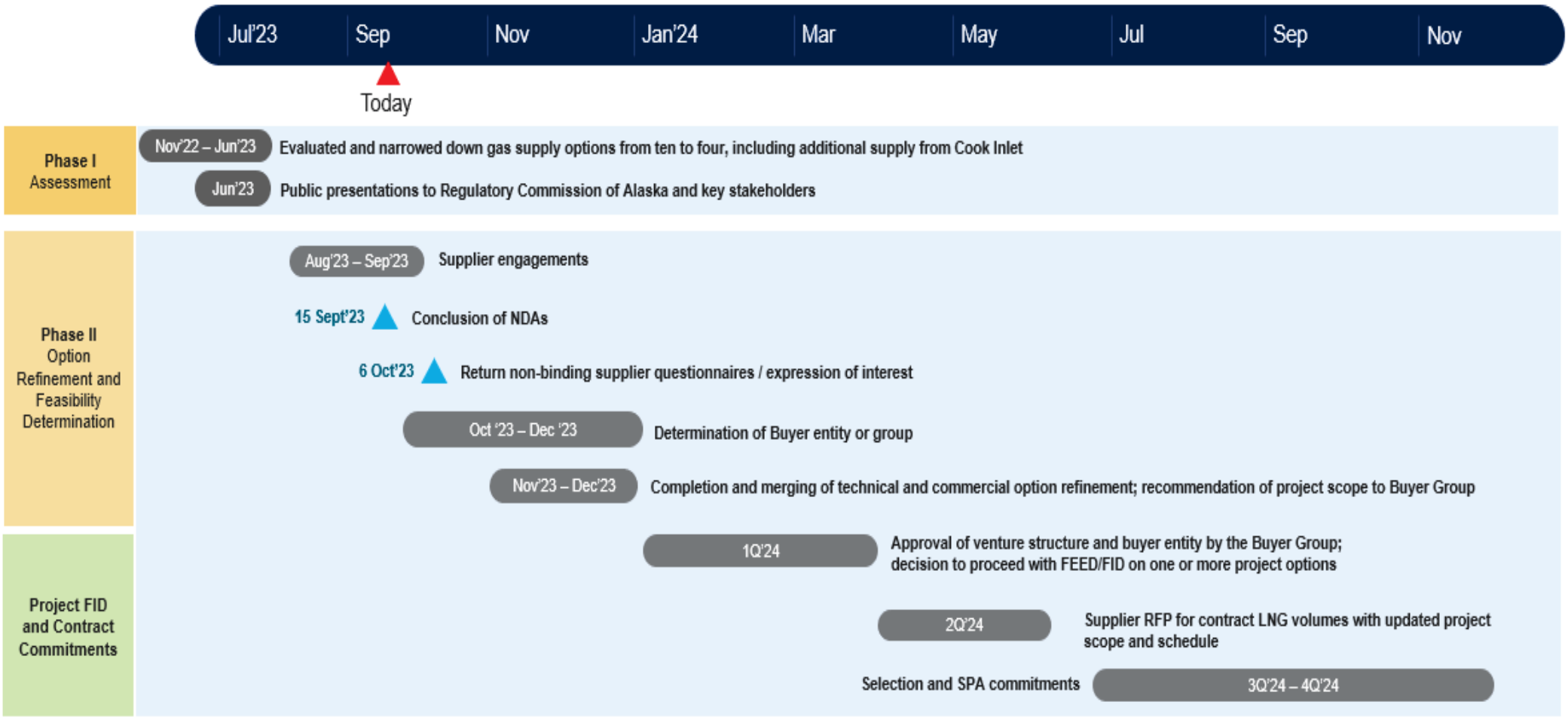

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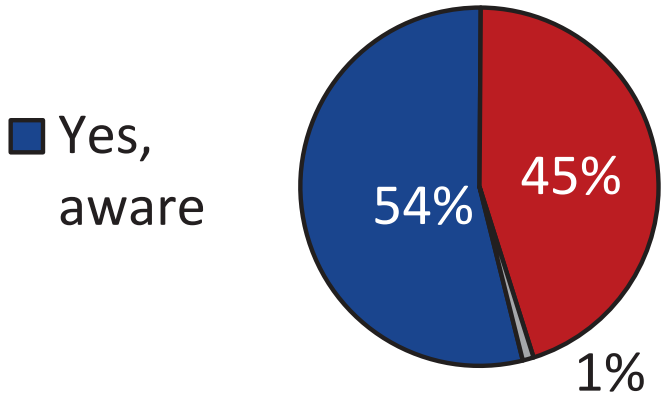

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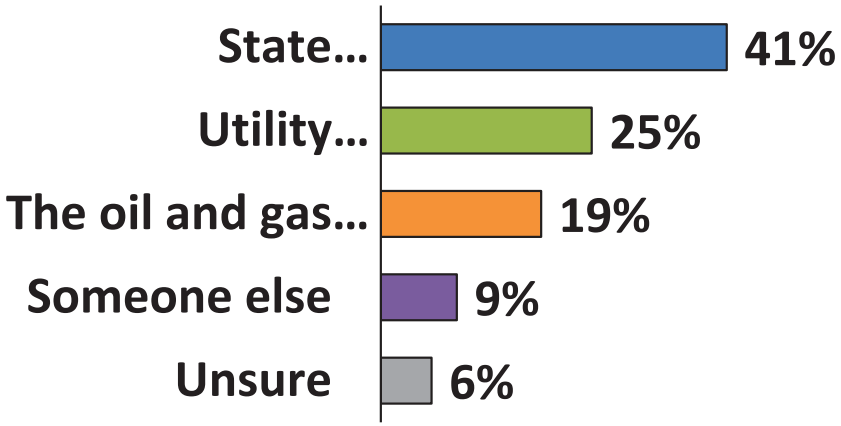

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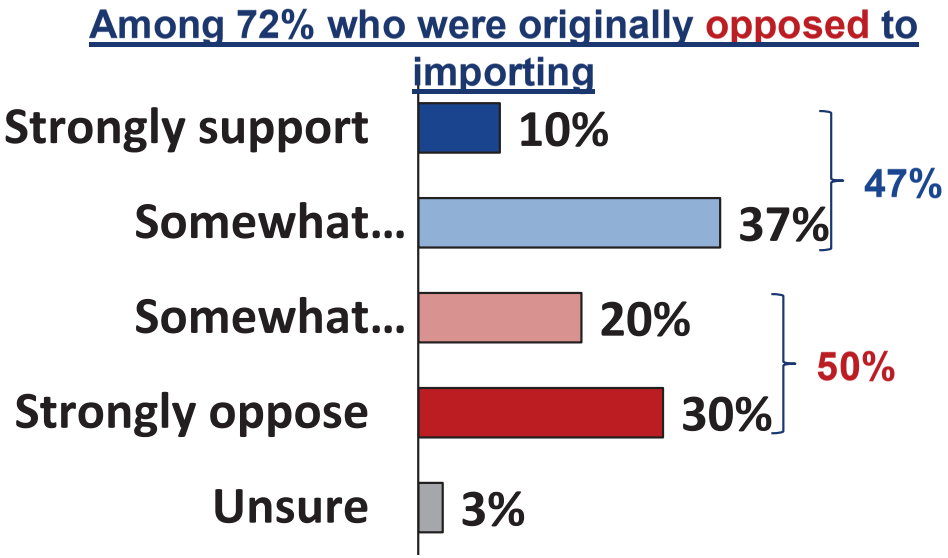

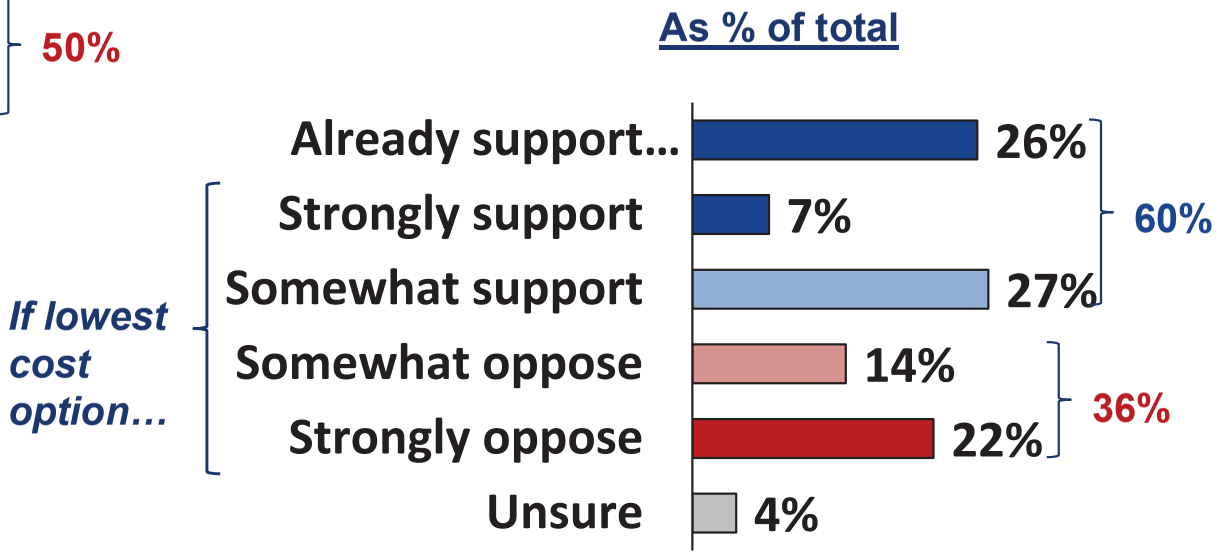

Next Steps

- Governor's Energy Security Task Force
- Legislative Outreach and Education
- Business Community Support
  - No stranger to challenges of operating in Alaska – make best decision given available resources
  - Understand how energy prices impact our economy
  - Be informed on the options for Cook Inlet
- Public Awareness and Support
  - Consequence of doing nothing
  - Bridge to a permanent solution

Cook Inlet Update

February 7, 2024

ENSTAR Natural Gas Company

About ENSTAR

- Established in 1959
- 230 employees
- 152,000 customers
- 25 communities served
- 3,560 miles of pipeline

About CINGSA

- Constructed in 2012 in response to significant concerns about Cook Inlet gas supply
- 11 Bcf storage capacity
- 150 Mmcf max injection/withdrawal
- 3 Firm Customers
- 3 Interruptible Customers
- Provides deliverability for more than 40% of ENSTAR demand on a cold day.

Utility Working Group

- Hilcorp/Utilities Annual Update meeting
  - April 12, 2022
  - Stated they would not extend existing contracts
- Creation of the Utility Working Group
  - April 15, 2022
    - ENSTAR, Chugach, MEA, GVEA, HEA, IGU
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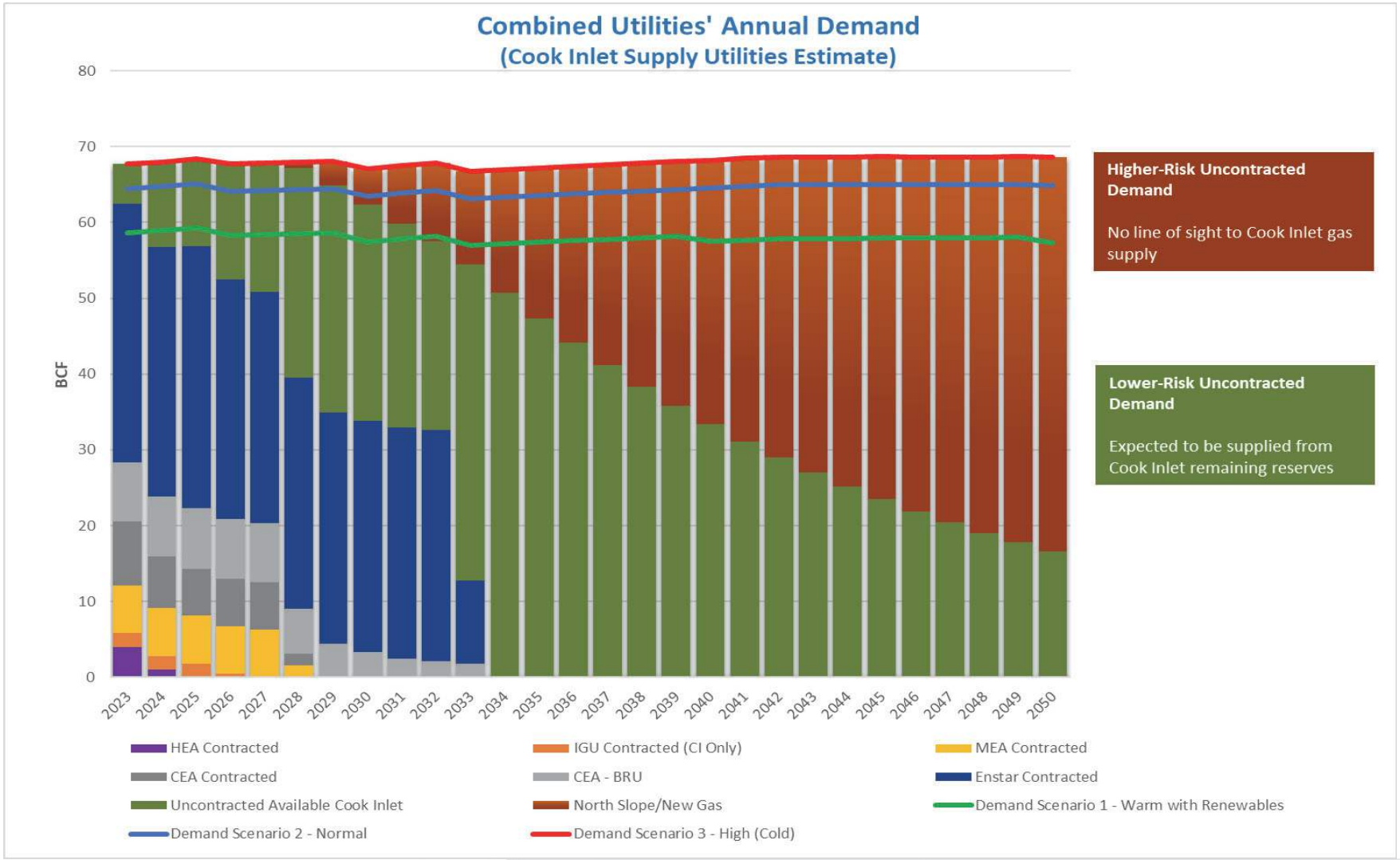
Utilities' Market View Fall '22



Gas Supply Opportunities – Phase I Assessment

	Option	Timeline	CAPEX	Throughput	Gas	Midstream	Cost of Supply
		Years	$ mm	Bcf/year	$/Mcf	$/Mcf	$/Mcf
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2 (a)	In-State Pipeline (Private)	6 - 7	~ $8,790	Up to 105	$1.3 - $2.6	$26.9 - $34.4	$28.2 - $37.0
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9	RNG	Unknown	N/A	~ 1	~ $25	Included	~ $25
10	Hydrogen (green)	2035 +	Unknown	N/A	N/A	N/A	$ > 40

Phase II Project Team

Cornerstone Energy Services | BRG | ENERGY & CLIMATE

Integrated Project Team Roles

ENSTAR and Utility Group
Strategic direction
Commercial, legal, regulatory leadership
Pipeline system, storage, existing supply integration
Public communications strategy and oversight

BRG
Project strategy advisor, local coordination
Planning of deliverables and Phase 2 project management
Gas supply project development and execution planning
LNG supply expertise and market interface
Financial and economic analysis
Project interface with Enstar, utilities, and public forums as directed by client

Cornerstone
Engineering and project cost estimates
Permitting plan
Project option technical viability and risk assessment

Additional Resources Engaged

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Coffman Engineers (Alaska)

Axiom Environmental (Alaska)

Cashman Preload
LNG tank experts, Alaska experience

Lloyd Engineering
Marine engineering, Alaska experience

Precision LNG
Worldwide LNG shipping expertise

Hunton Andrews Kurth LLP
Regulatory / Permitting legal experts

Summary Findings for Schedules – Phase II

- None of the Options meet the LNG demands for the 4-year milestone (first gas 4Q2027)
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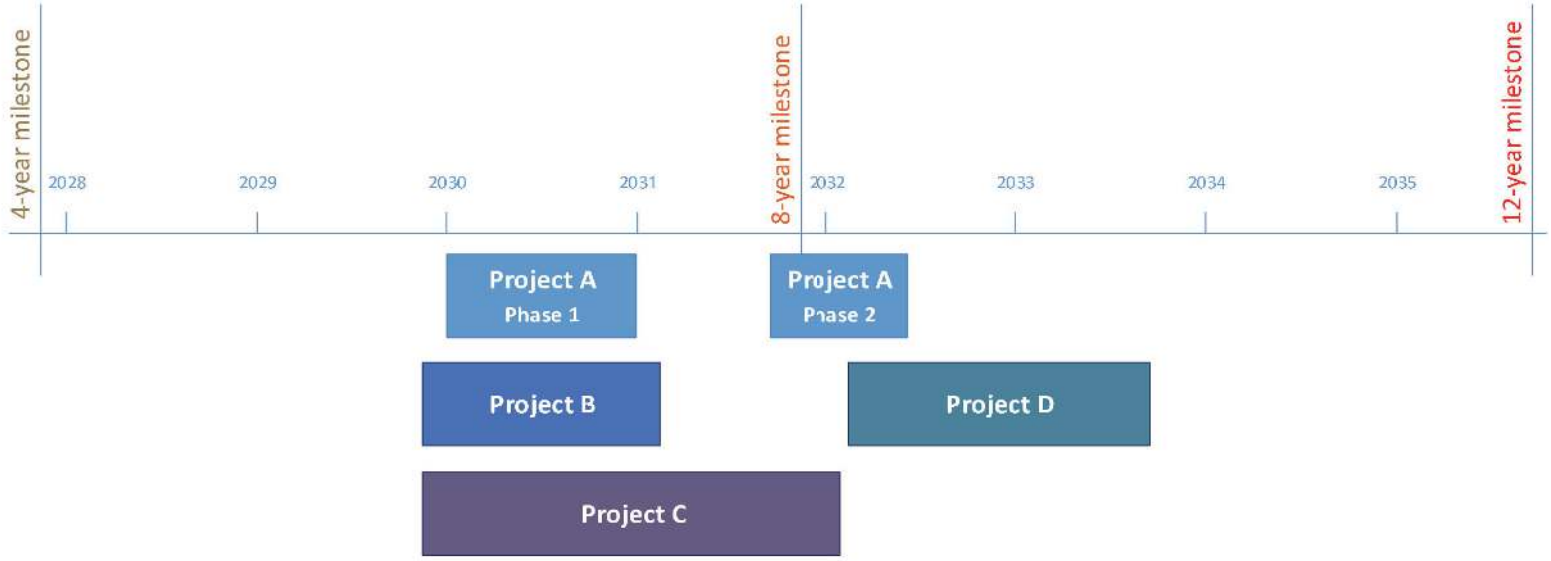
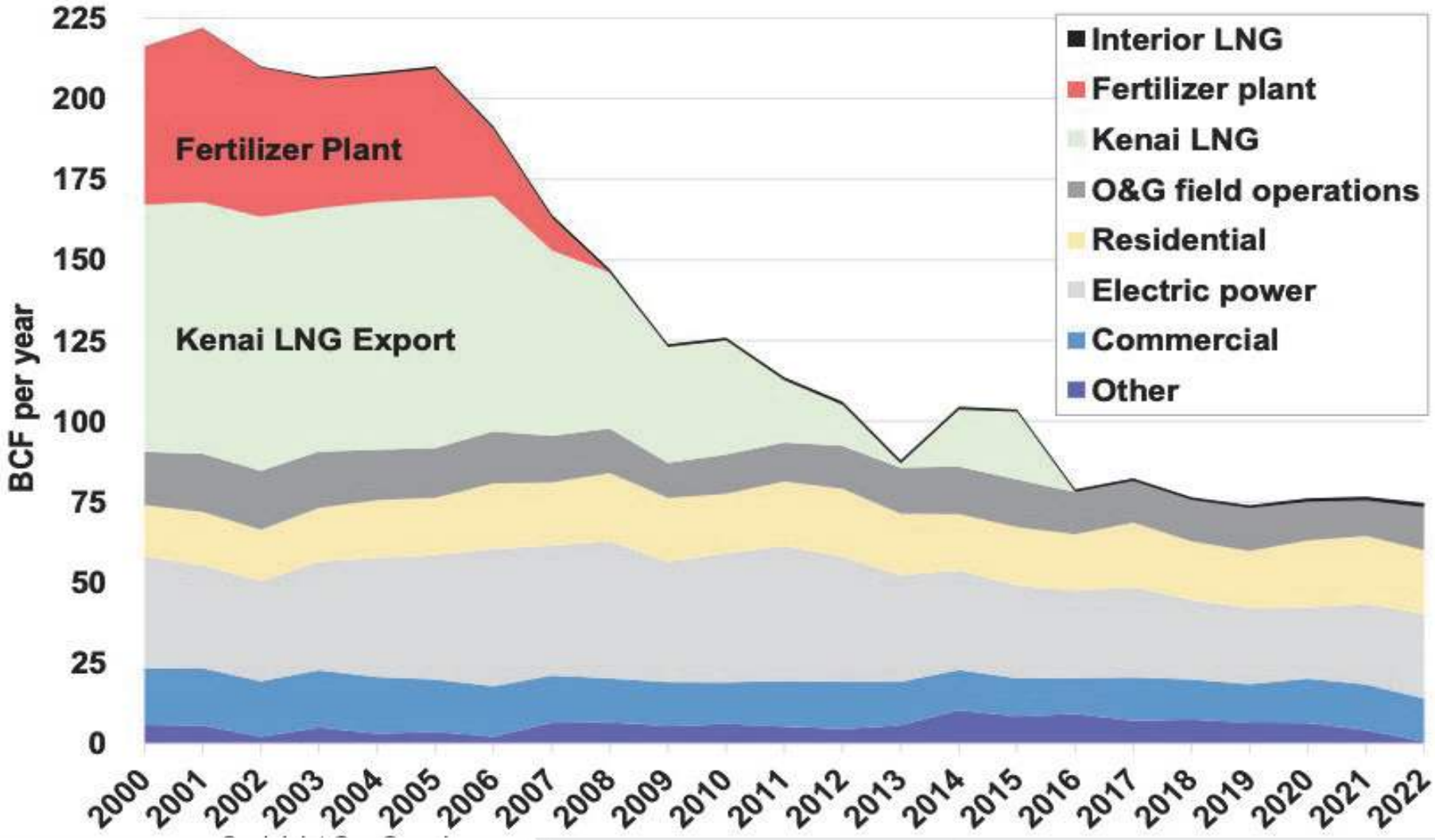
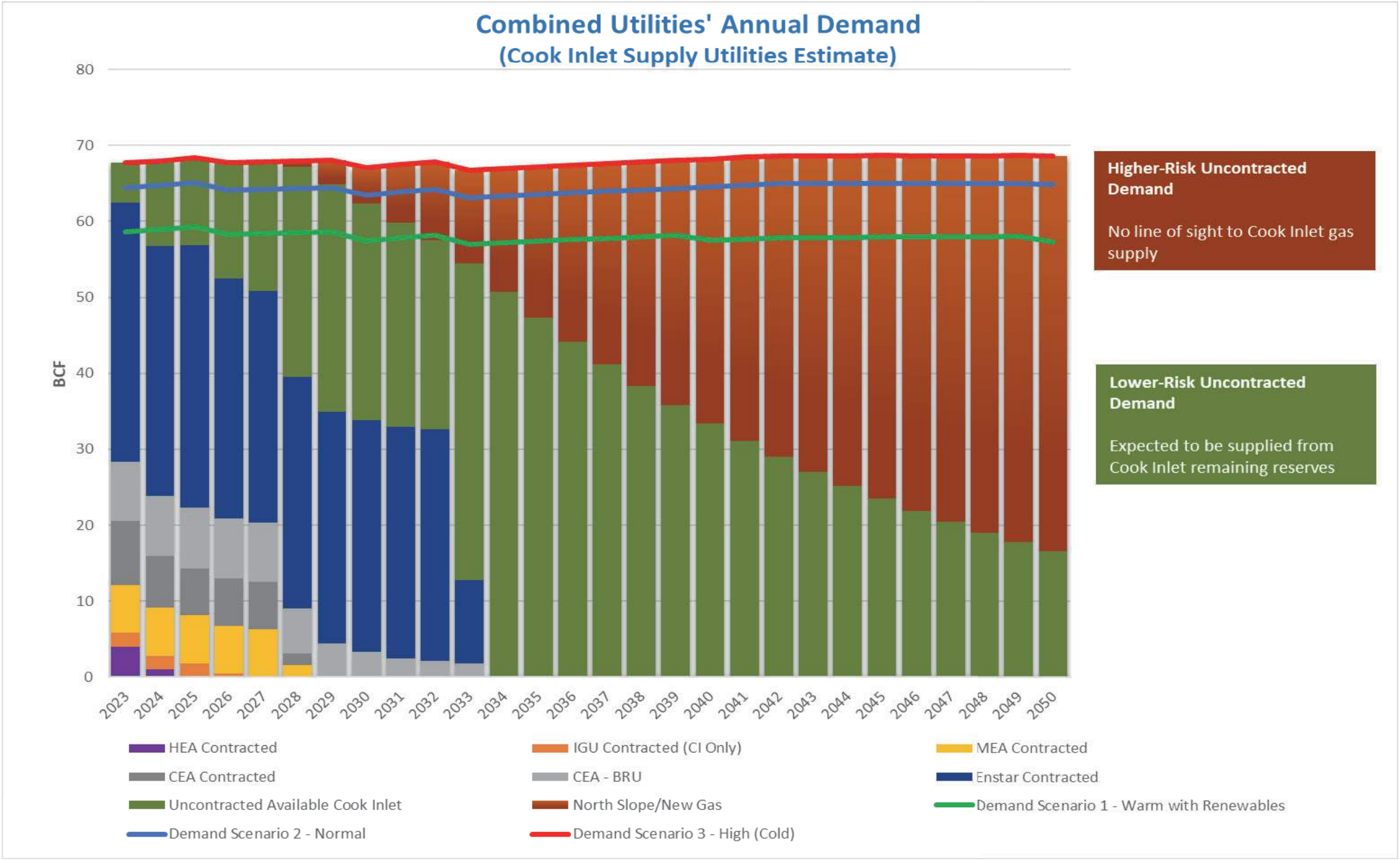


2010 vs. 2024

- In 2010, Cook Inlet utilities faced similar concerns under different circumstances.
- CINGSA is proof that legislative support for energy security matters.
- Today, quick, bold action is required to serve this region in the short and long-term.
- Additional storage is required under any scenario and should be regulated for price transparency.

Cook Inlet Demand (Source: DNR 2024)




Combined Utilities' Annual Demand
(Cook Inlet Supply Utilities Estimate)
BCF
80
70
60
50
40
30
20
10
0
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
2046
2047
2048
2049
2050
Higher-Risk Uncontracted Demand
No line of sight to Cook Inlet gas supply
Lower-Risk Uncontracted Demand
Expected to be supplied from Cook Inlet remaining reserves
HEA Contracted
IGU Contracted (CI Only)
MEA Contracted
CEA Contracted
CEA - BRU
Enstar Contracted
Uncontracted Available Cook Inlet
North Slope/New Gas
Demand Scenario 1 - Warm with Renewables
Demand Scenario 2 - Normal
Demand Scenario 3 - High (Cold)

Gas Supply Contract Terms

Contract Terms	All Requirements	Firm	Interruptible	Spot
Meets 100% deliverability?	✓	✗	✗	✗
Provided under contract?	✓	✓	✓	✗
Penalty for non-delivery? (Cover)	✓	✓	✗	✗
Allows for multi-year gas supply planning?	✓	✓	✗	✗
Set price?	✓	✓	✗	✗
Set quantity?	✓	✓	✗	✗
Set terms?	✓	✓	✗	✗
Not subject to changing market or operating conditions?	✓	✓	✗	✗

Utility Duty to Serve

- This duty is not shared by producers, IPPs, or anyone else in this state. It is our obligation alone.

Sec. 42.05.291. Standards of service and facilities.

(a) Each public utility shall furnish and maintain adequate, efficient, and safe service and facilities. This service shall be reasonably continuous and without unreasonable interruption or delay.

What now?

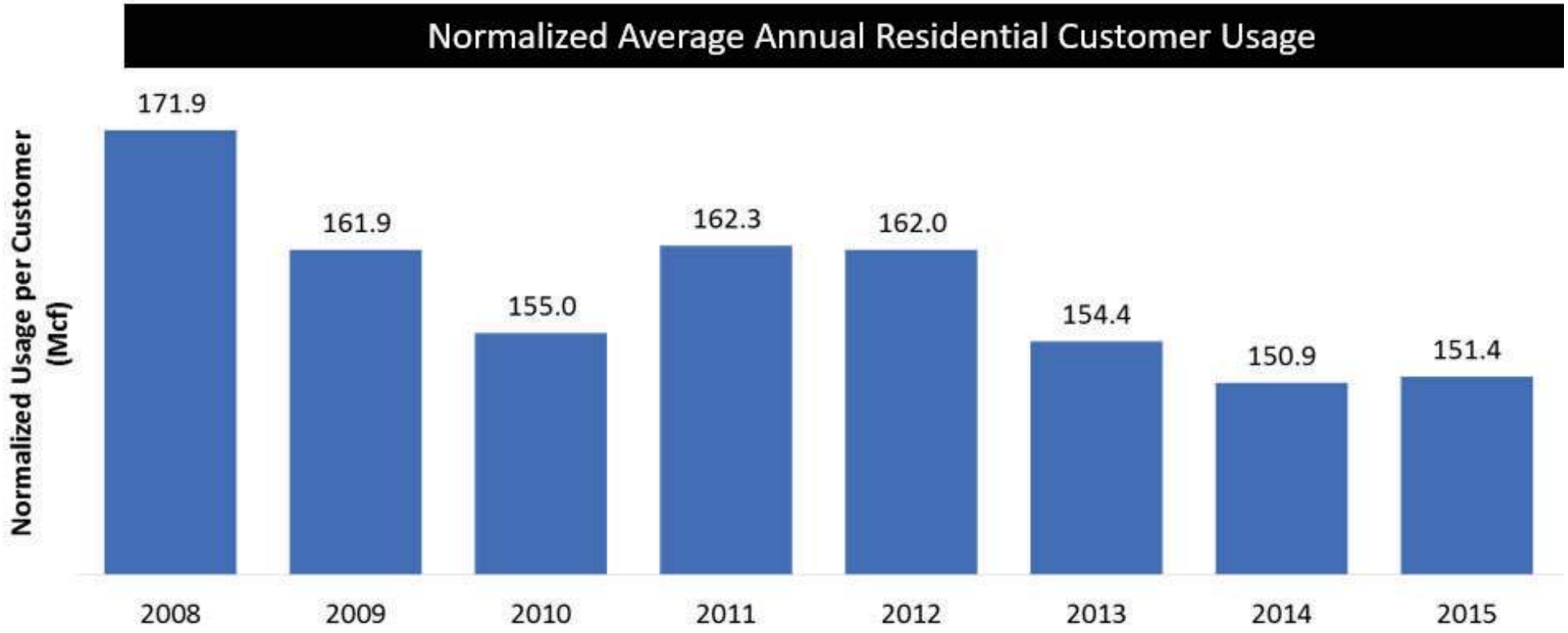
- Timely actions is required to avoid a gap in supply.
  - Short-term: Need strong support for Cook Inlet exploration and production activities.
  - Long-term: Decisive action on a large natural gas supply project.
- Ultimately, customers - Alaska residents and businesses - are on the hook for cost impacts.
- Working to minimize impact, but longer we wait, the fewer options available and at higher rates.

“What can the State do?”

Additional storage is key

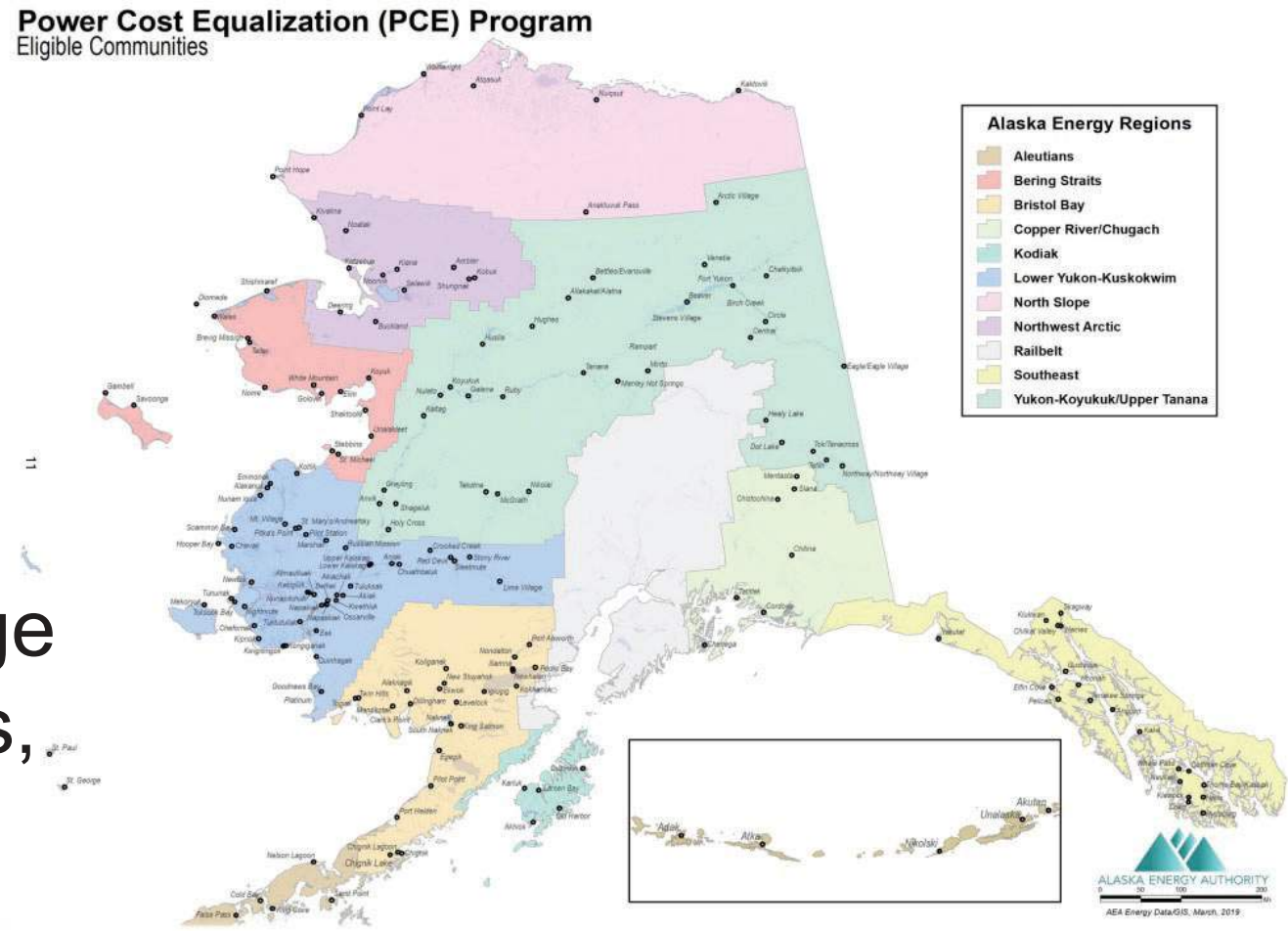
- Under every scenario, additional natural gas storage is required:
  - Added Cook Inlet deliverability
  - Support new projects coming online
- In November, CINGSA filed with the RCA to expand its facility to provide additional service

Home Energy Rebate Program



Cook Inlet Energy: An Alaska issue

- Energy costs in Rural Alaska.
- Local businesses support communities beyond Anchorage with cargo, goods, and services.



Key Considerations

- There is no unsubsidized energy solution that will reduce the cost of power or space heating in the next 10 years.
- Any incentive or tax relief must be linked to firm contracts for Cook Inlet utilities.
- The second worst thing for Alaska is to import LNG. The worst thing is to do nothing.

Questions

ENSTAR Natural Gas Company

Cook Inlet Gas Supply: An Alaska Issue

February 21, 2024

ENSTAR Natural Gas Company

About ENSTAR

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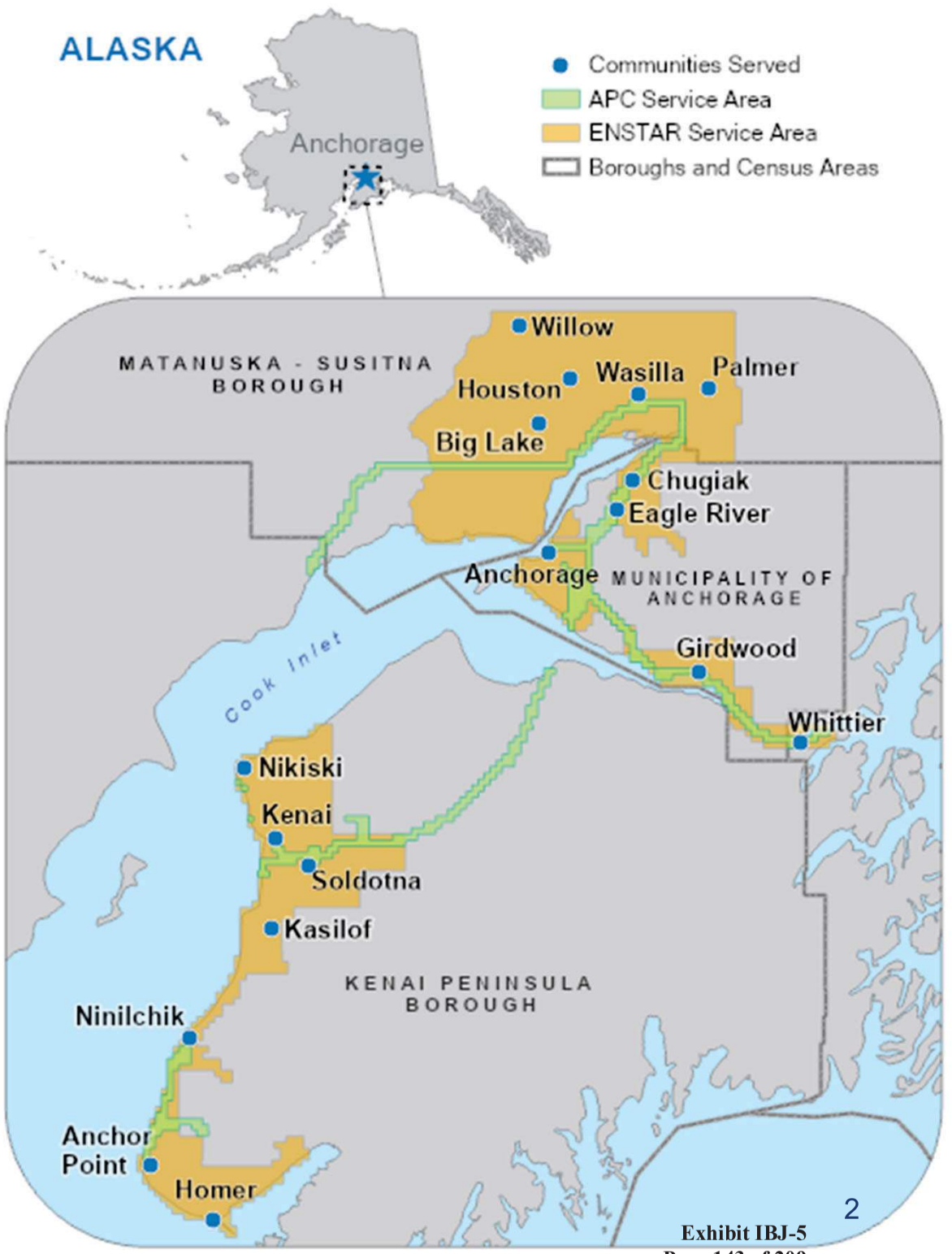
- 230 employees
- 152,000 customers
- 25 communities served
- 3,560 miles of pipeline



History of Cook Inlet Natural Gas

- Swanson River – 1957
  - Launchpad for Statehood
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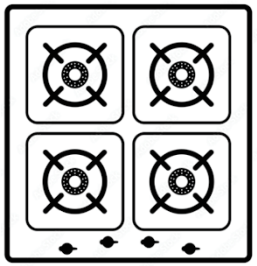
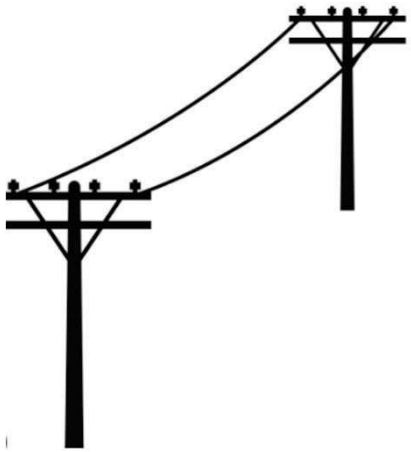
- ENSTAR's first gas delivery – 1961

- All gas used by ENSTAR customers and electrics in Mat-Su, Anchorage, and Kenai Peninsula has been sourced from the Cook Inlet Basin.

Natural Gas 101

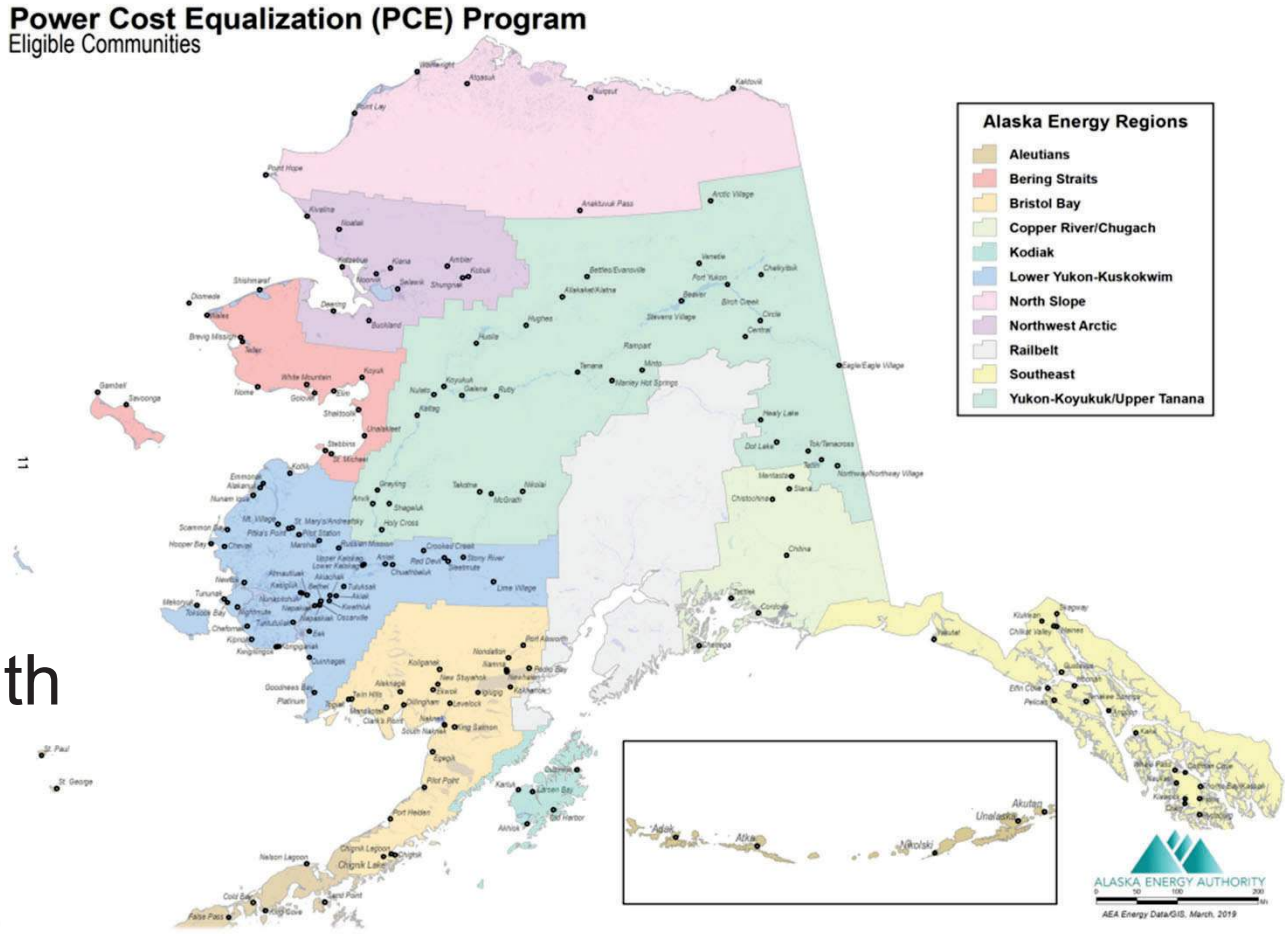
- Home heating for more than half of the state's population.
- Other common gas appliances: hot water heaters, stoves, clothes dryers.
- Efficient energy source: cleaner burning and more affordable compared to alternatives.
- Used to generate more than 80% of regional power.





Cook Inlet's Ripple Effect

- Southcentral: Anchorage, Mat-Su, Kenai Peninsula.
- Energy costs in Rural Alaska.
- Local businesses support communities beyond Anchorage with cargo, goods, and services.



Utility Working Group

- Hilcorp/Utilities Annual Update meeting
  - April 12, 2022
  - Stated they would not extend existing contracts
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  - April 15, 2022
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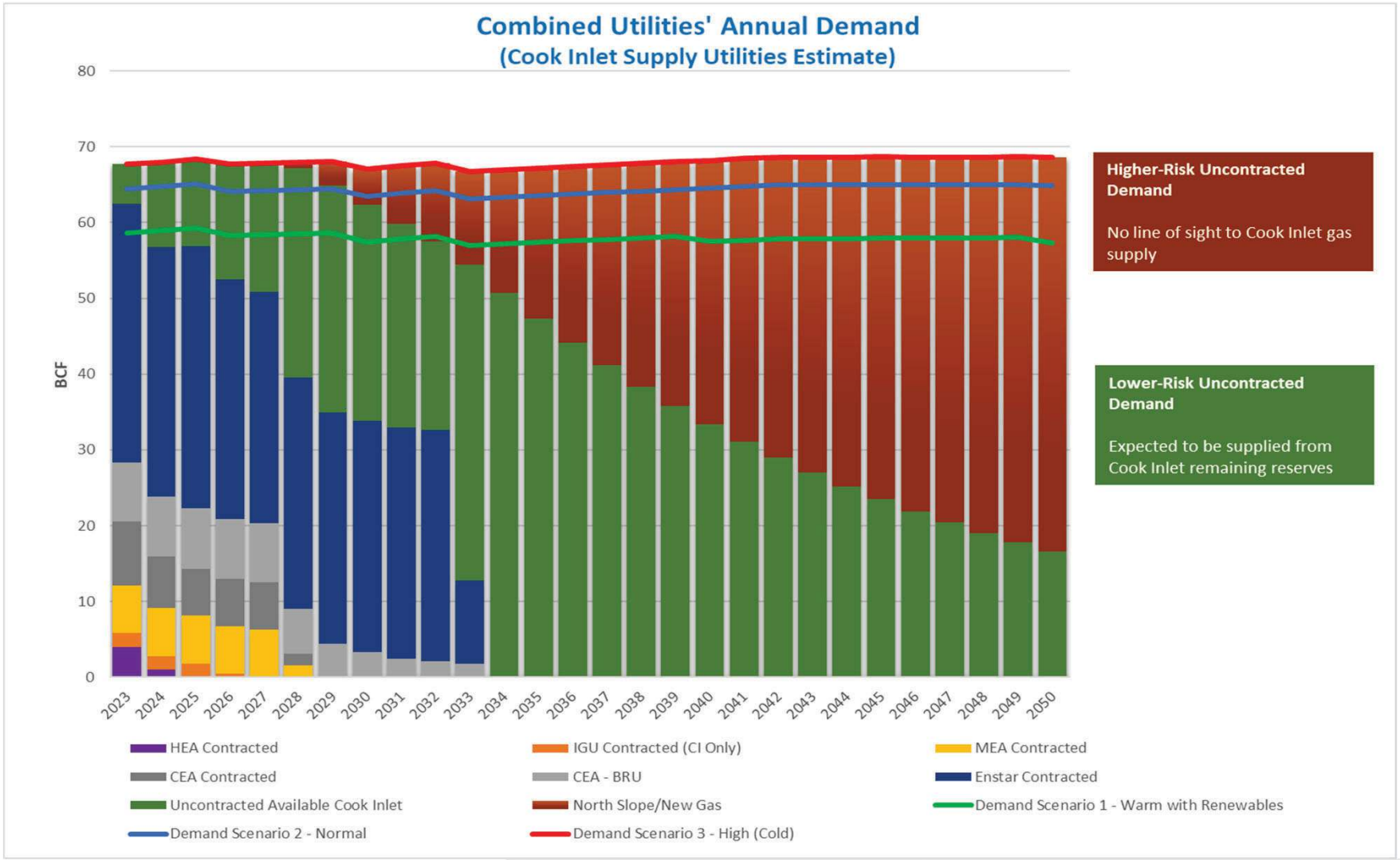
Utilities' Market View Fall '22



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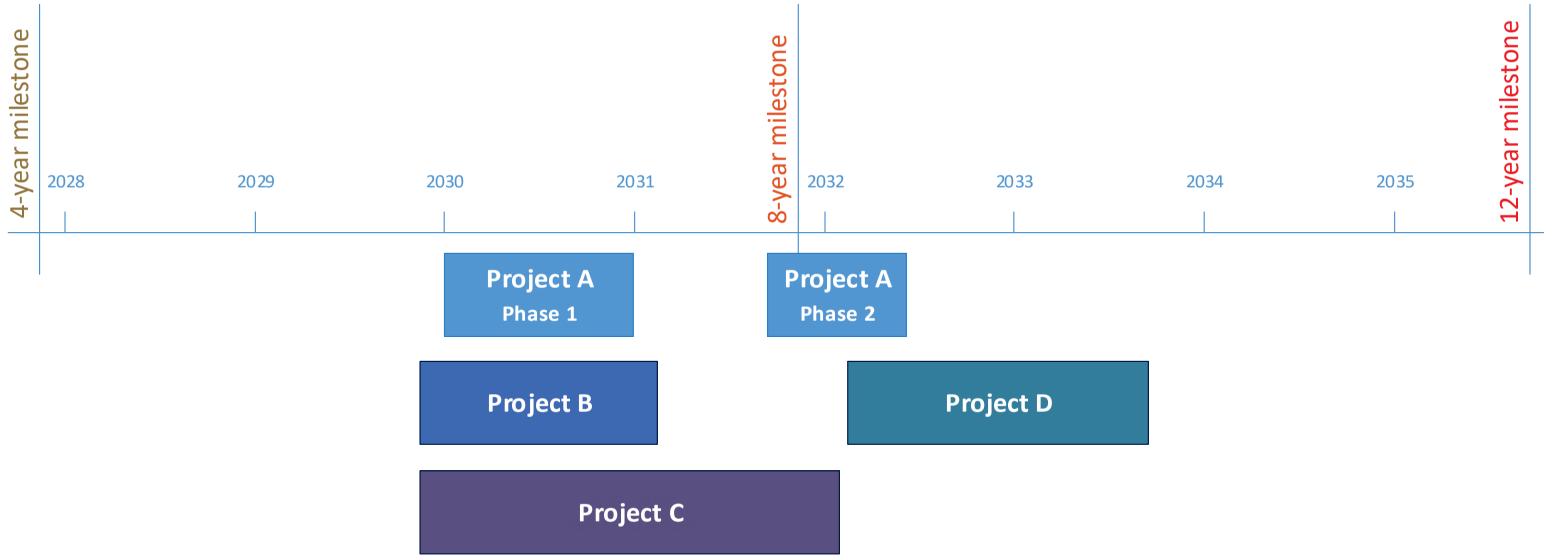

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- Today, quick, bold action is required to serve this region in the short and long-term.
- Similar to 2010, we know natural gas storage is required under any scenario and should be regulated for price transparency.

Early Impacts: Gas Supply Contract Terms

Contract Terms	All Requirements	Firm	Interruptible	Spot
Meets 100% deliverability?	✓	✗	✗	✗
Provided under contract?	✓	✓	✓	✗
Penalty for non-delivery? (Cover)	✓	✓	✗	✗
Allows for multi-year gas supply planning?	✓	✓	✗	✗
Set price?	✓	✓	✗	✗
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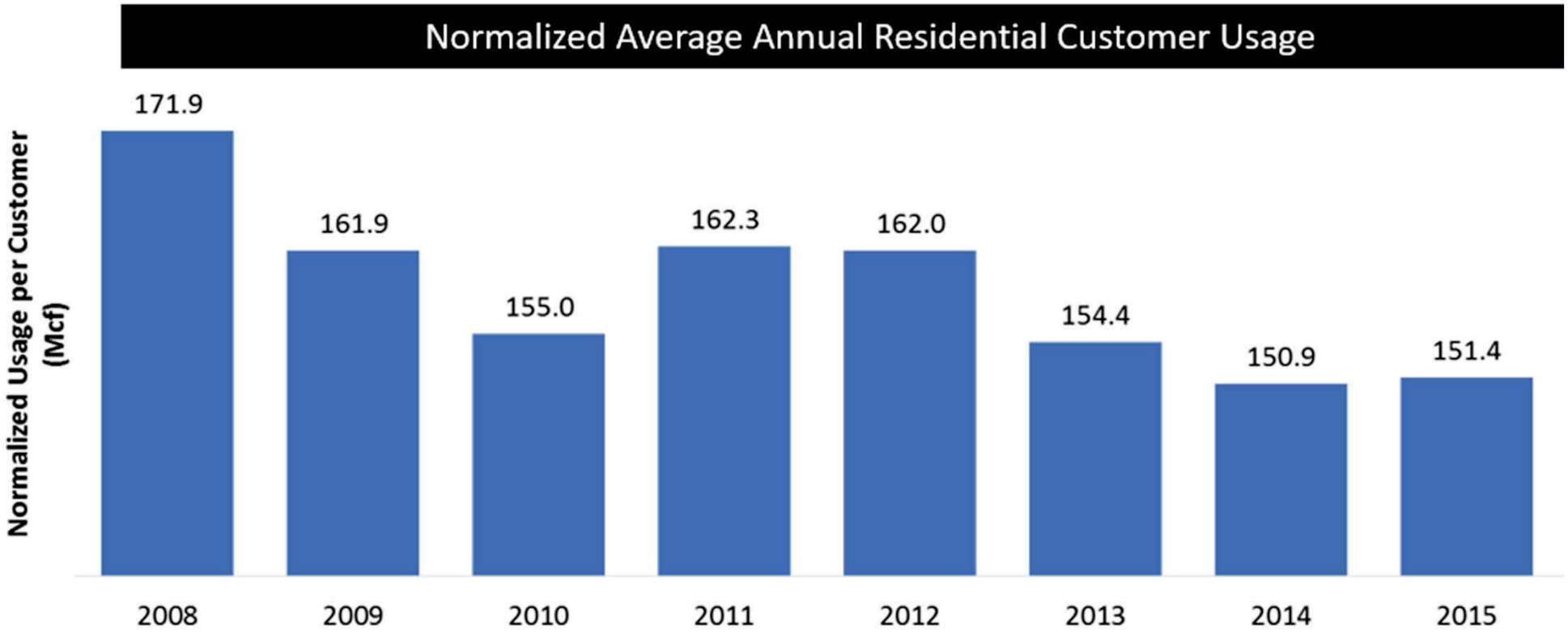
What about communities outside the Railbelt?

- Power Cost Equalization program
  - More than 80% Southcentral electric generation = natural gas, increasing energy parity with PCE communities.
- Economic impacts
  - Higher energy costs in Anchorage = higher cost of goods and services originating from the region.
- Stay informed, talk with legislators, help residents and businesses prepare for impacts.

Home Energy Rebate Program



Key Considerations

- There is no unsubsidized energy solution that will reduce the cost of power or space heating in the next 10 years.
- The second worst thing for Alaska is to import LNG. The worst thing is to do nothing.

Rolling up our sleeves

- We have some time to prepare, plan, and work toward a solution.
- Resourcefulness and ingenuity are the backbone of this State, threaded through each community, especially rural Alaska.
- We will learn from each other, work together, and find the best solution for Alaska's unique needs.

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Kenai Support Industry Alliance

March 8, 2024

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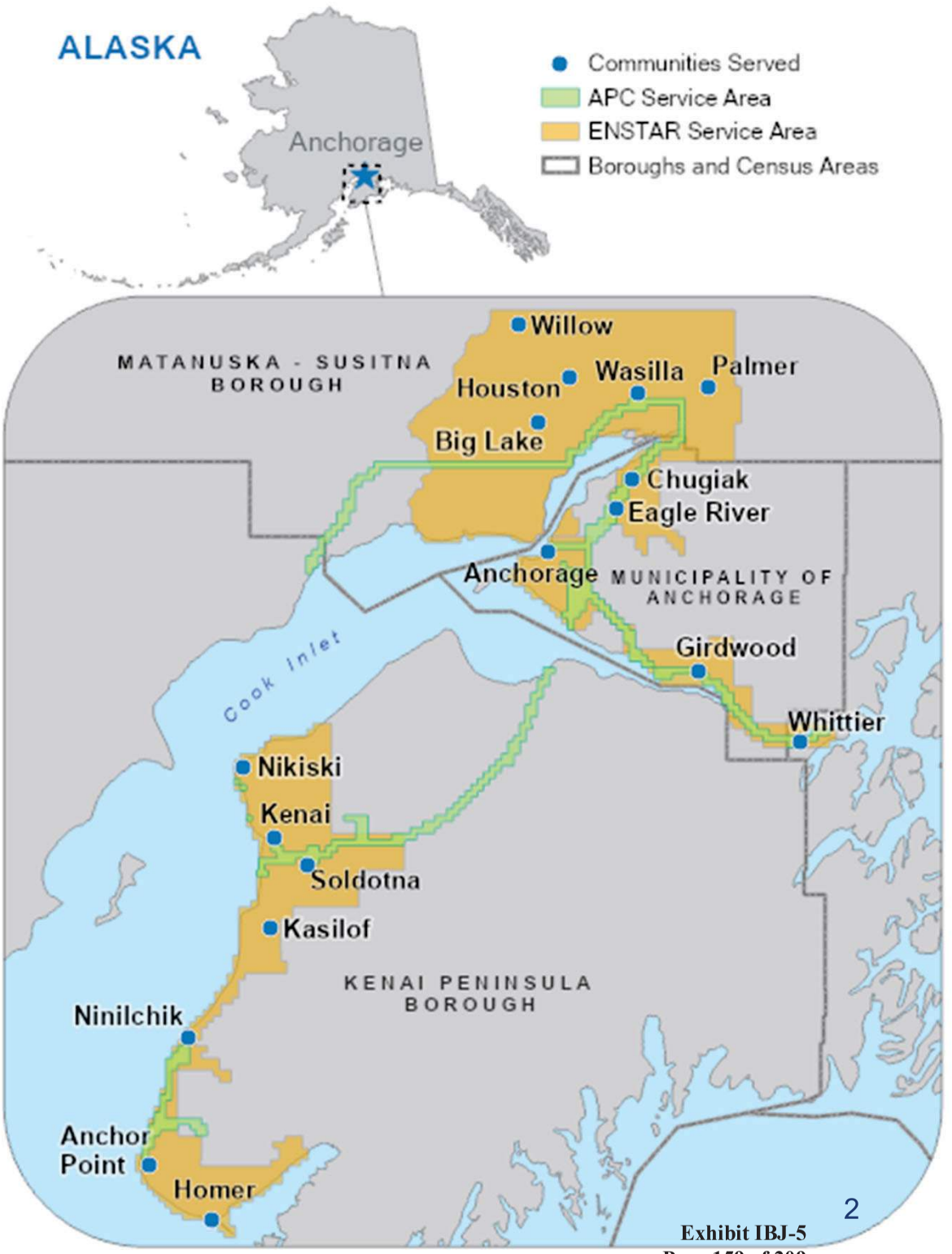

About CINGSA

- Constructed in 2012 in response to significant concerns about Cook Inlet gas supply
- 11 Bcf storage capacity
- 150 Mmcf max injection/withdrawal
- 3 Firm Customers
- 3 Interruptible Customers
- Provides deliverability for more than 40% of ENSTAR demand on a cold day.

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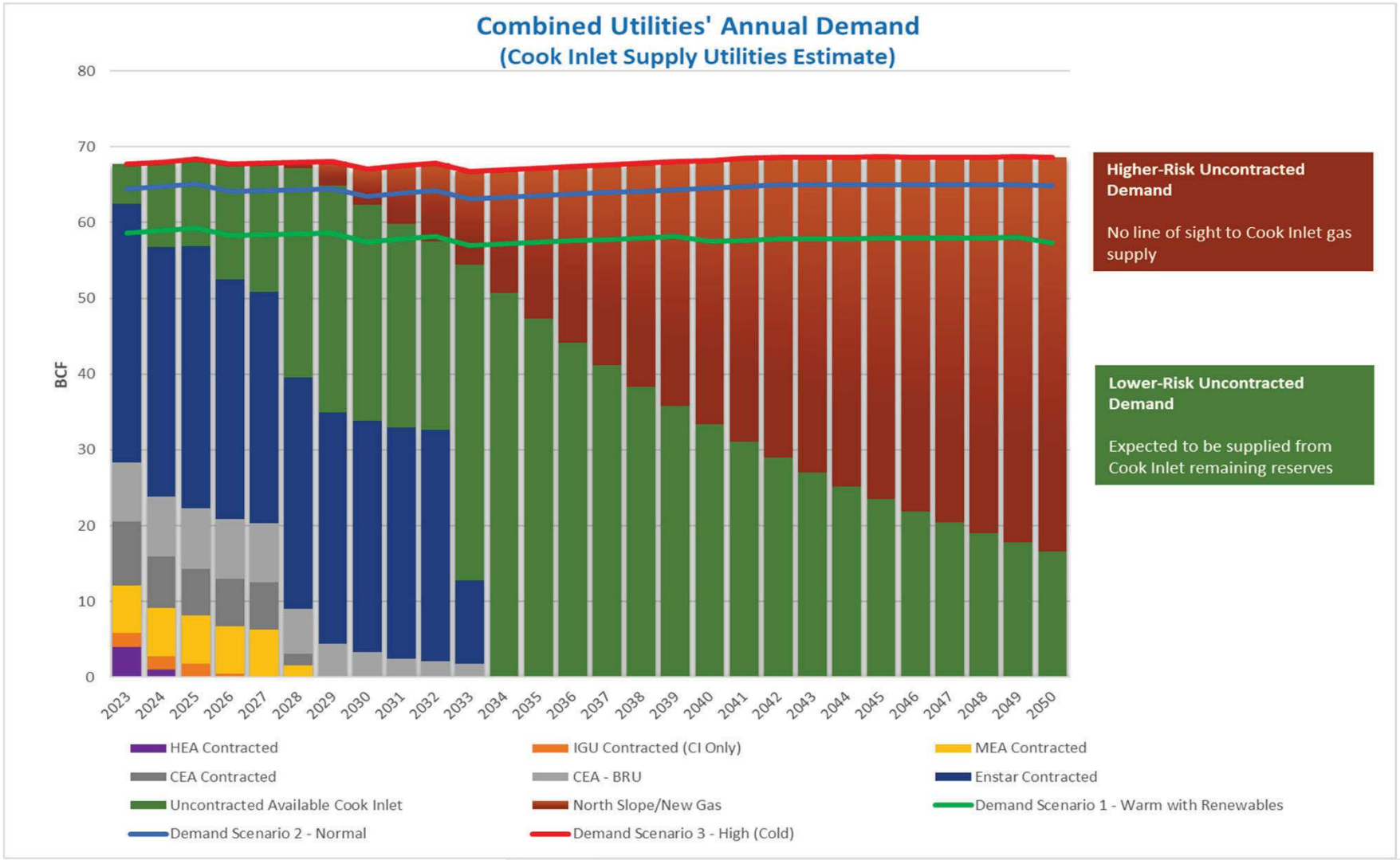

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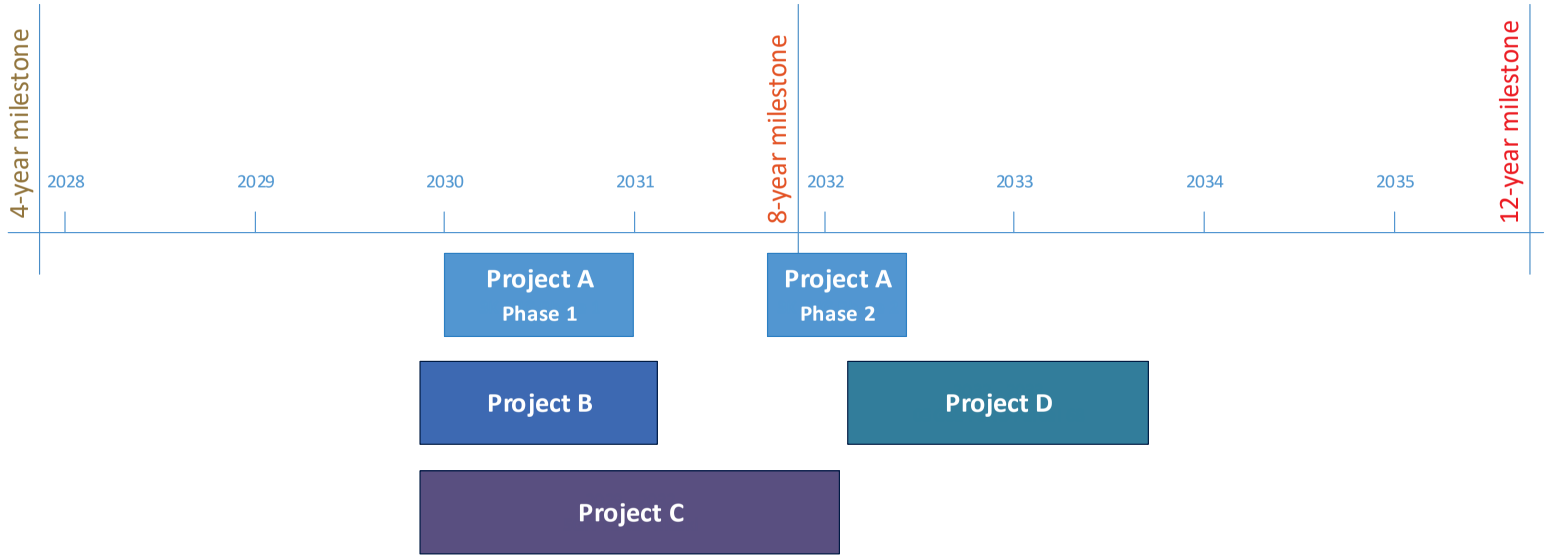
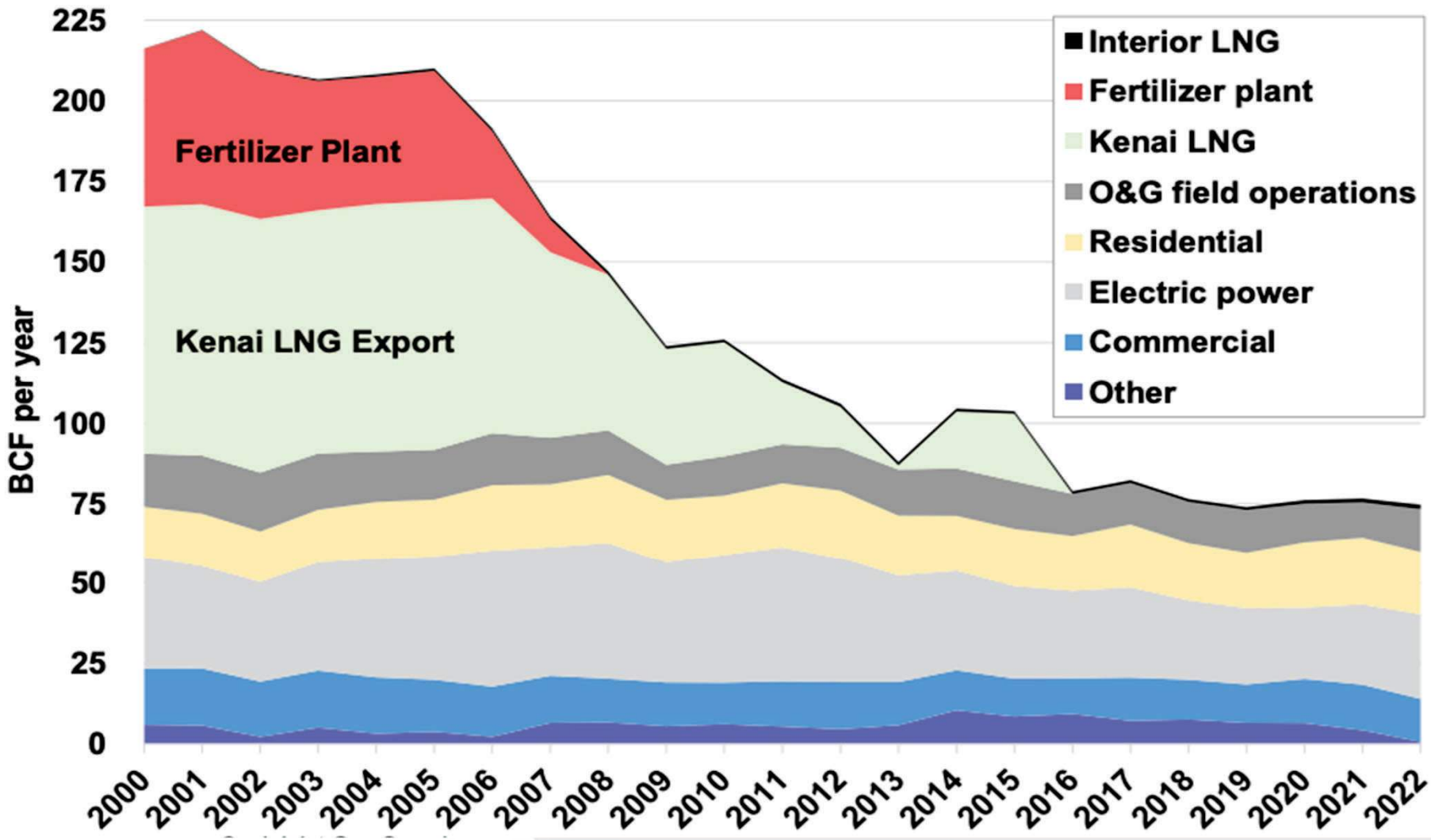


Cook Inlet Demand (Source: DNR 2024)



ENSTAR
NATURAL GAS COMPANY

Cook Inlet Update

March 21, 2024

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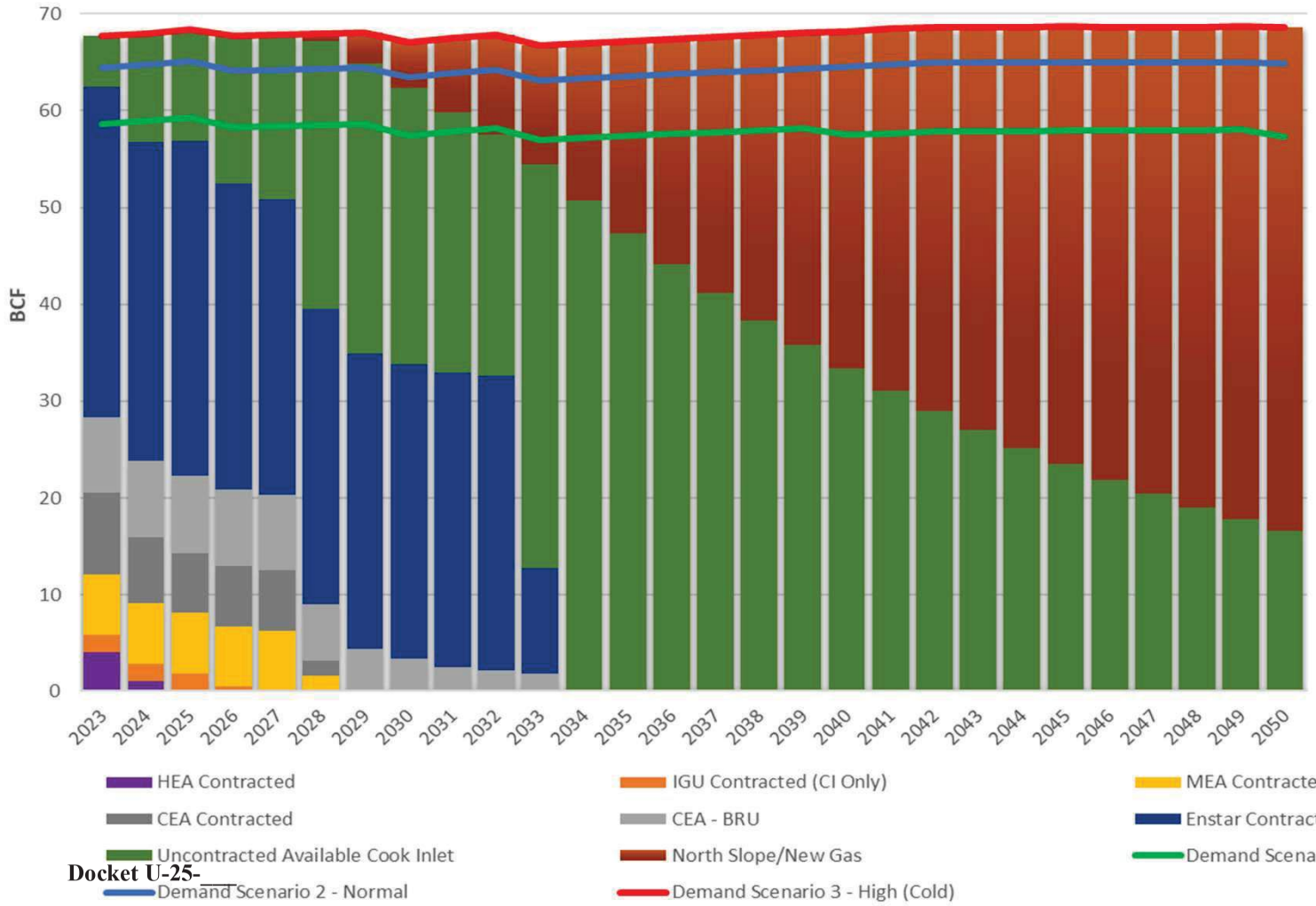

Higher-Risk Uncontracted Demand

No line of sight to Cook Inlet gas supply

Lower-Risk Uncontracted Demand

Expected to be supplied from Cook Inlet remaining reserves.

New contracts, the true cost…

5. **Special Cover Provision**

a. This Special Cover Provision applies in the following amounts for the applicable tranches ("Special Cover Tranches") and for the time periods set forth below ("Special Cover Terms" and collectively the "Special Cover Term"), unless Buyer provides notice otherwise as set forth herein:

Special Cover Tranches and Terms	
April 1, 2024-March 31, 2025	1.0 Bcf
April 1, 2025-March 31, 2026	1.0 Bcf
April 1, 2026-March 31, 2027	1.5 Bcf

b. Buyer and Seller agree that due to delivery of the New Demand Gas, Seller has an enhanced risk of a Delivery Shortfall during the Special Cover Term. If the Delivery Shortfall occurs during the Special Cover Term, Buyer agrees to waive any Cover remedies contemplated in Section 2.4(C)(3) of the Agreement up to the amount of the then-applicable Special Cover Tranche. For the avoidance of doubt, the amount of Cover remedy under this Section 5(b) is not cumulative, and the Cover amount provided by each Special Cover Tranche for New Demand Gas expires on the last day of the applicable Special Cover Term.

Contract Terms Overview

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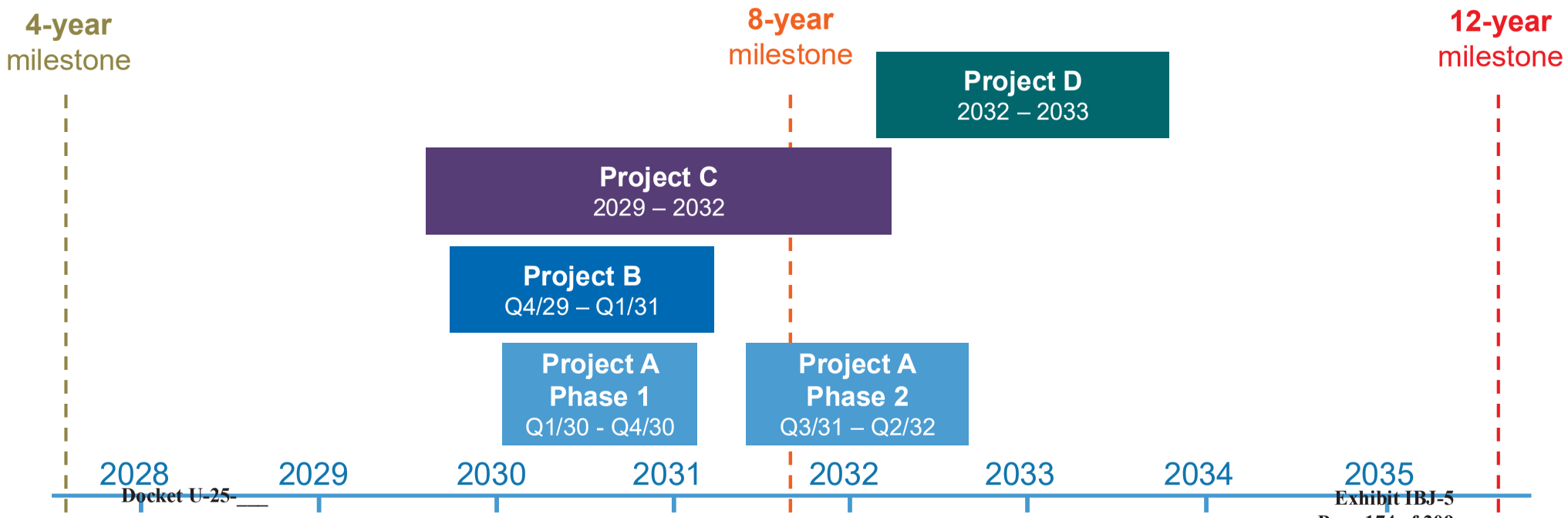

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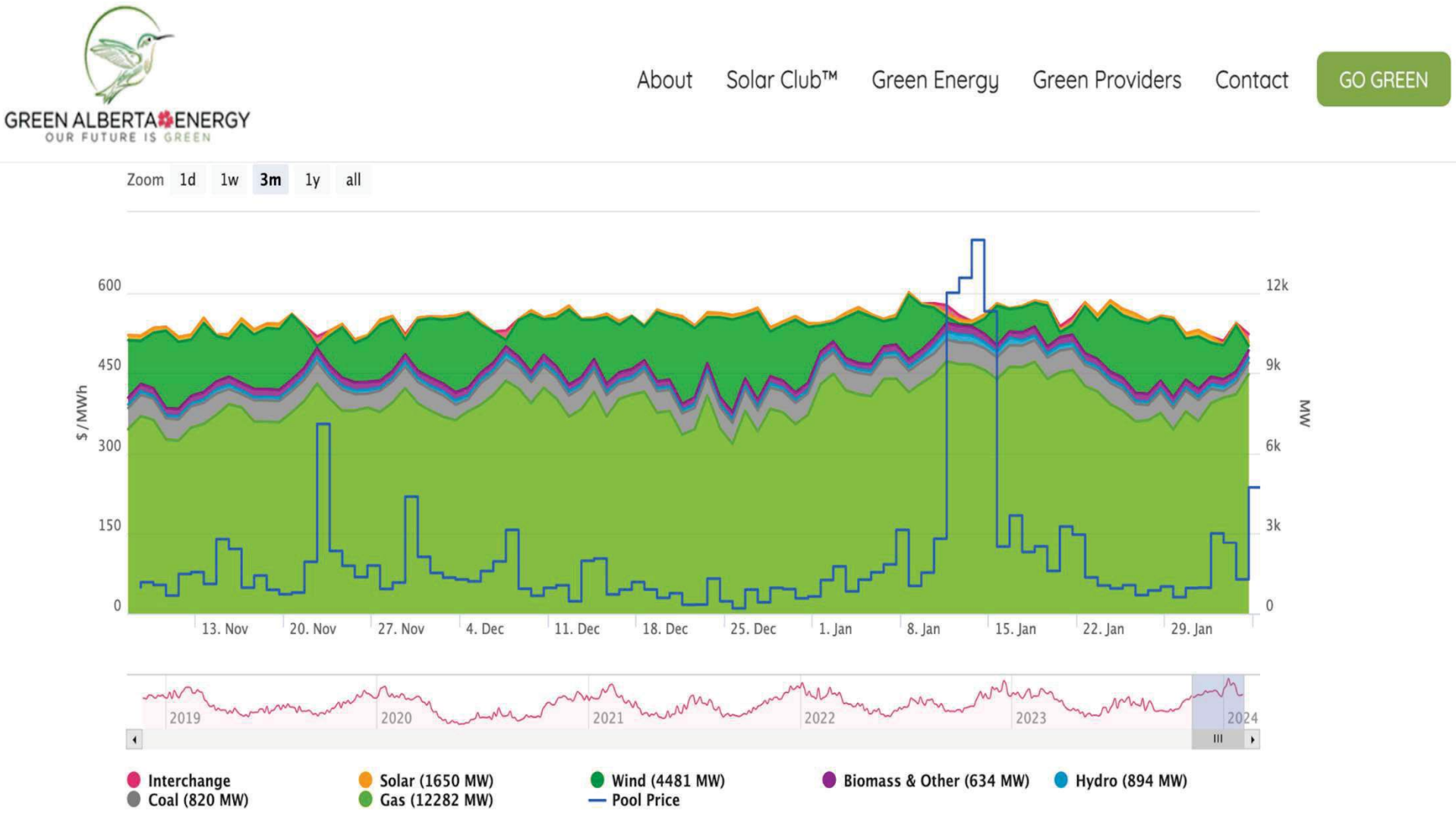
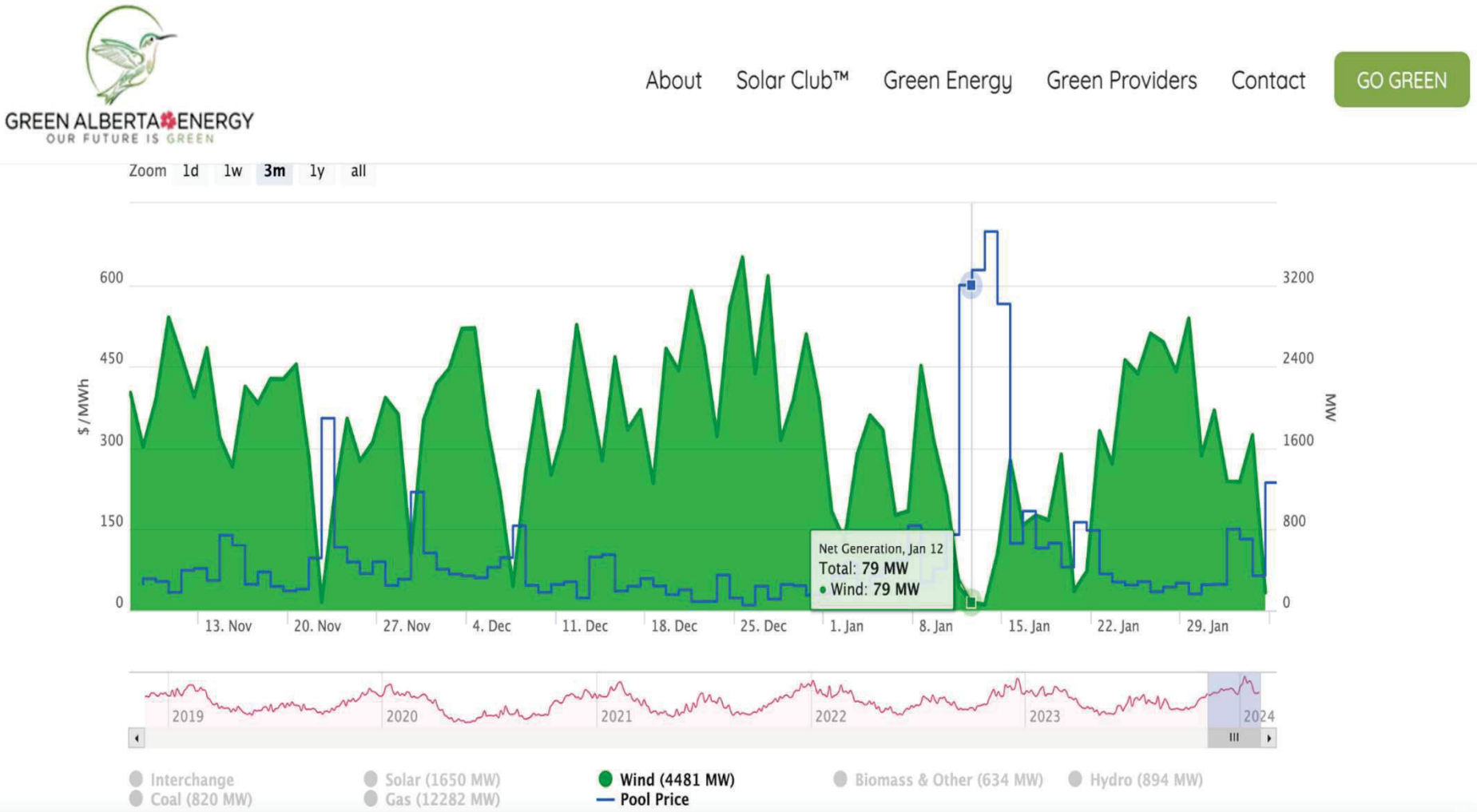
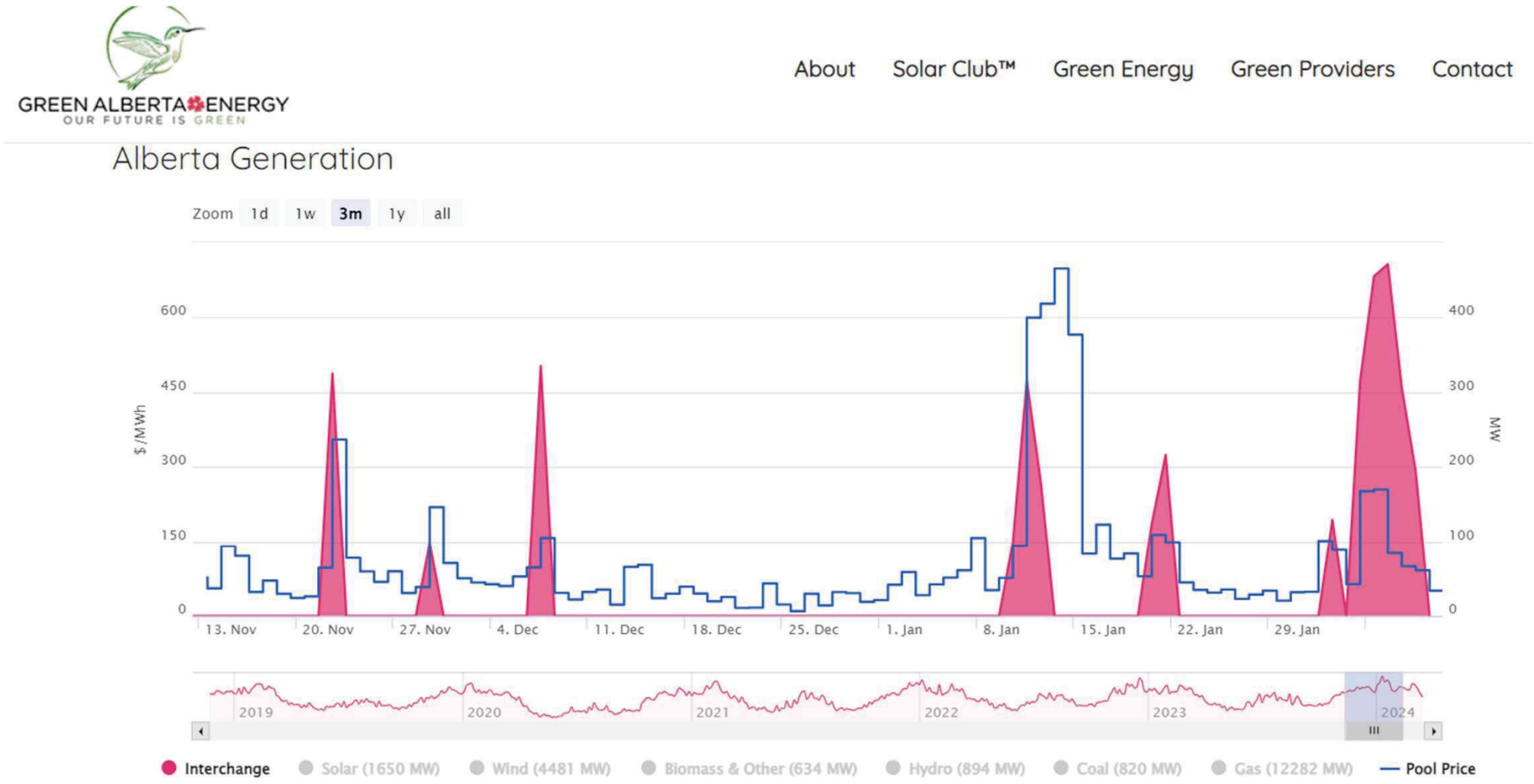
Meeting Peak Demand



Meeting Peak Demand (Cont.)



Meeting Peak Demand (Cont.)



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- There is no unsubsidized energy solution that will reduce the cost of power or space heating in the next 10 years.
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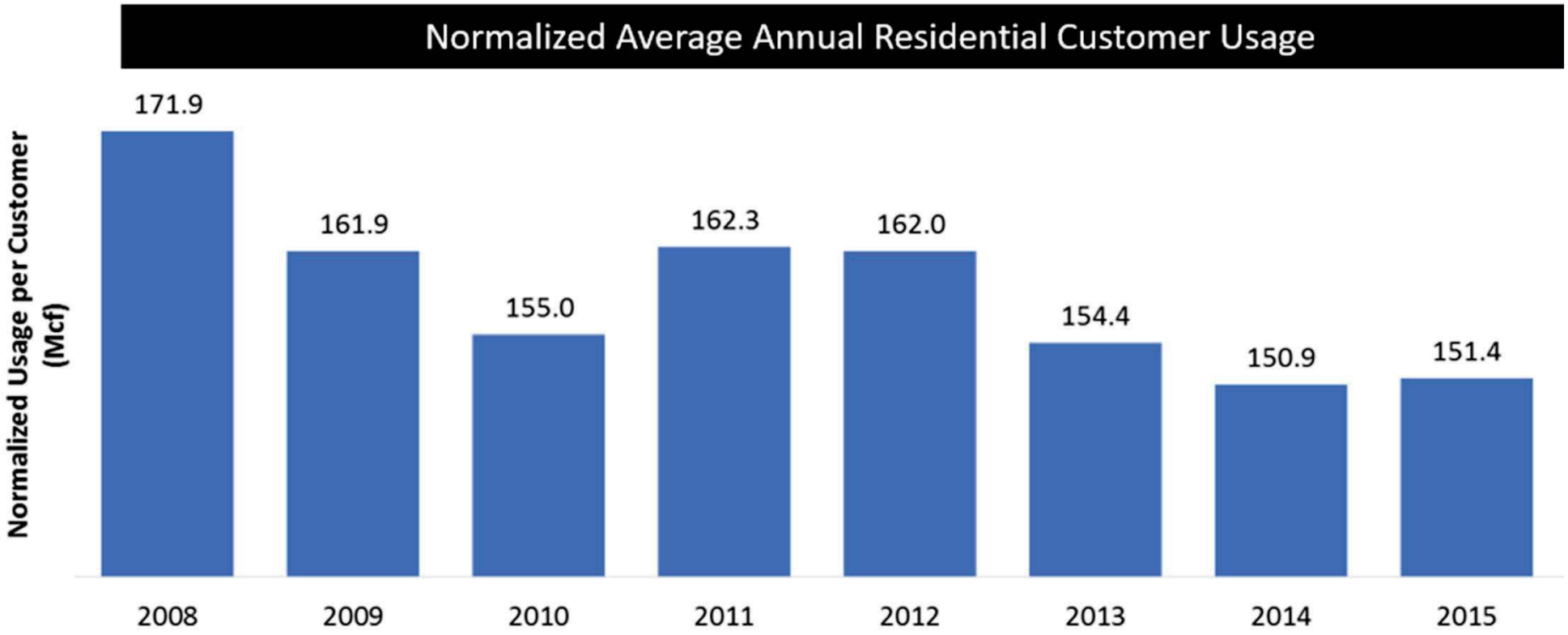
ENSTAR Natural Gas Company

“What can the State do?”

ENSTAR Natural Gas Company

Home Energy Rebate Program



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- Energy costs in Rural Alaska.
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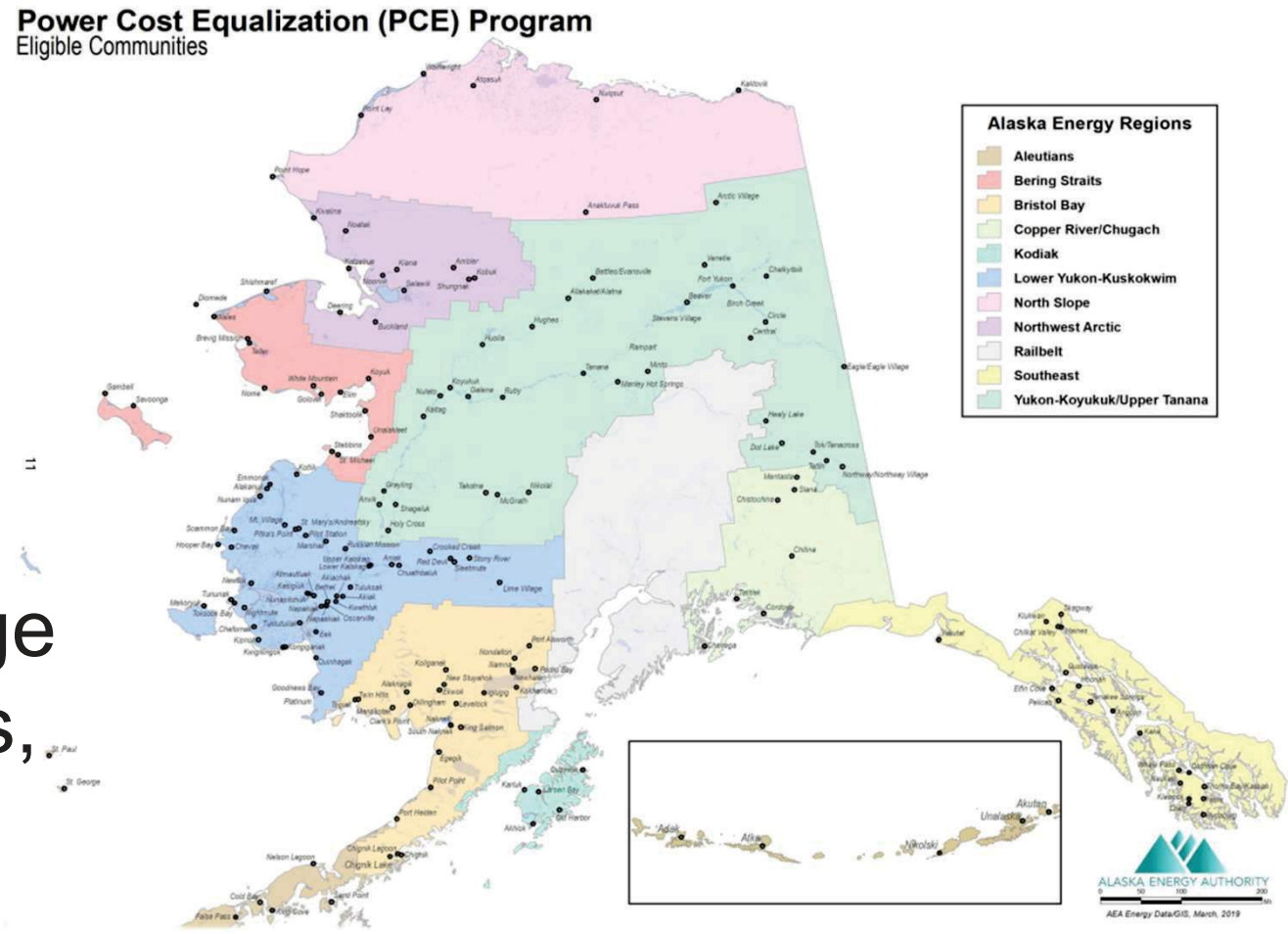

Gas Supply Opportunities – Phase I Assessment

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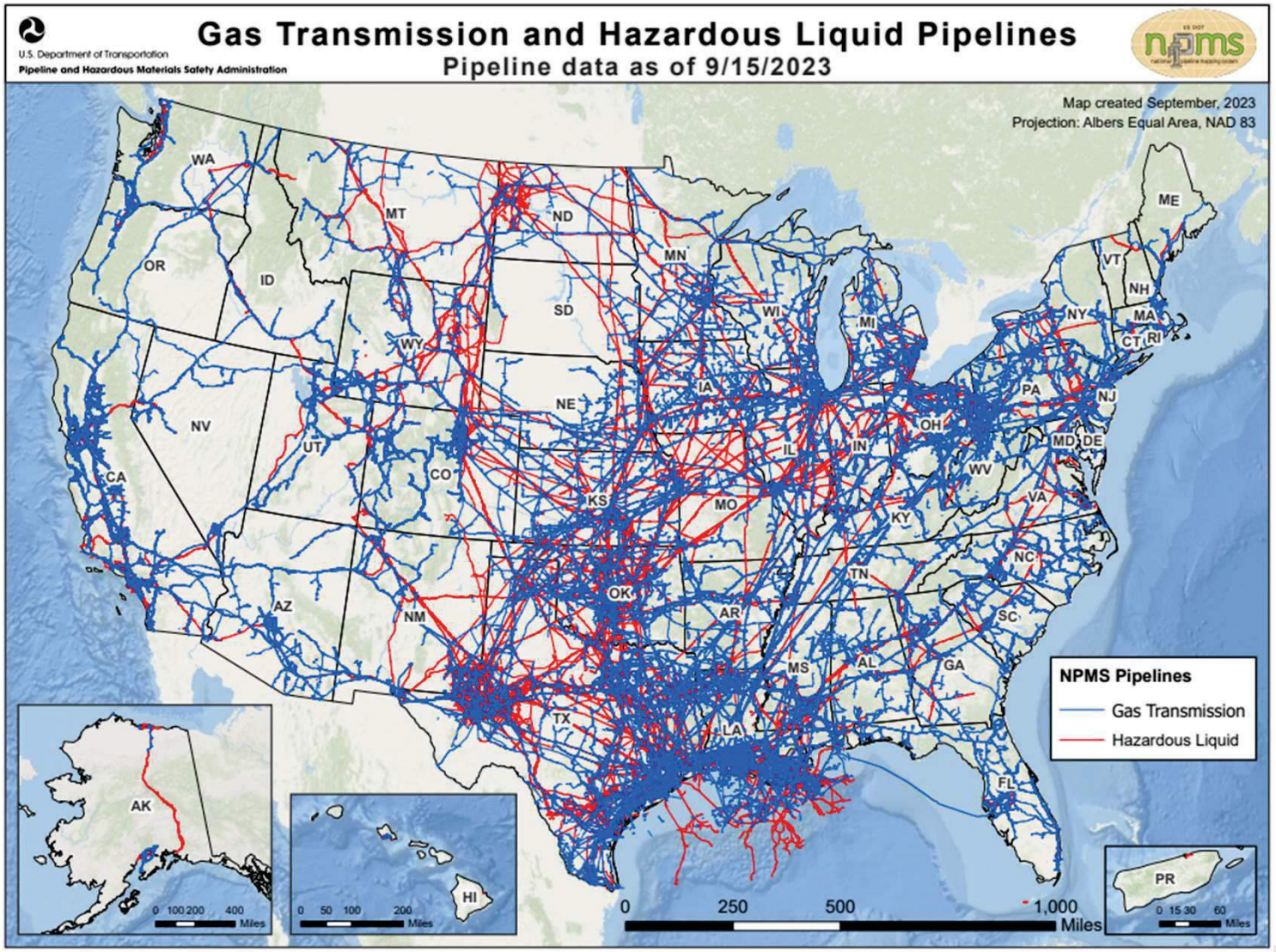
9	RNG	Unknown	N/A	~ 1	~ $25	Included	~ $25
10	Hydrogen (green)	2035 +	Unknown	N/A	N/A	N/A	$ > 40


Gas Transmission and Hazardous Liquid Pipelines
Pipeline data as of 9/15/2023
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Map created September, 2023
Projection: Albers Equal Area, NAD 83
NPMS Pipelines
Gas Transmission
Hazardous Liquid
0 250 500 1,000 Miles
WA
OR
CA
NV
ID
MT
WY
UT
AZ
CO
NM
ND
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NE
KS
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GA
FL
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VA
PA
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Business

ConocoPhillips plans huge Alaska-Chicago natural gas pipeline

Originally published November 30, 2007 at 12:00 am | *Updated November 30, 2007 at 3:32 pm*

Murkowski Lays Out Terms for Alaska Pipeline, Wants Producer Response This Week

NGI BY NGI STAFF REPORTS
September 19, 2005

Share on:

Alaska Gov. Frank Murkowski has told the North Slope producers — BP, ExxonMobil and ConocoPhillips — that he wants a response this week to his contract terms for an agreement on the proposed construction of a gas pipeline from the North Slope to the Lower 48 states.

Cook Inlet Update

April 16, 2024

ENSTAR Natural Gas Company

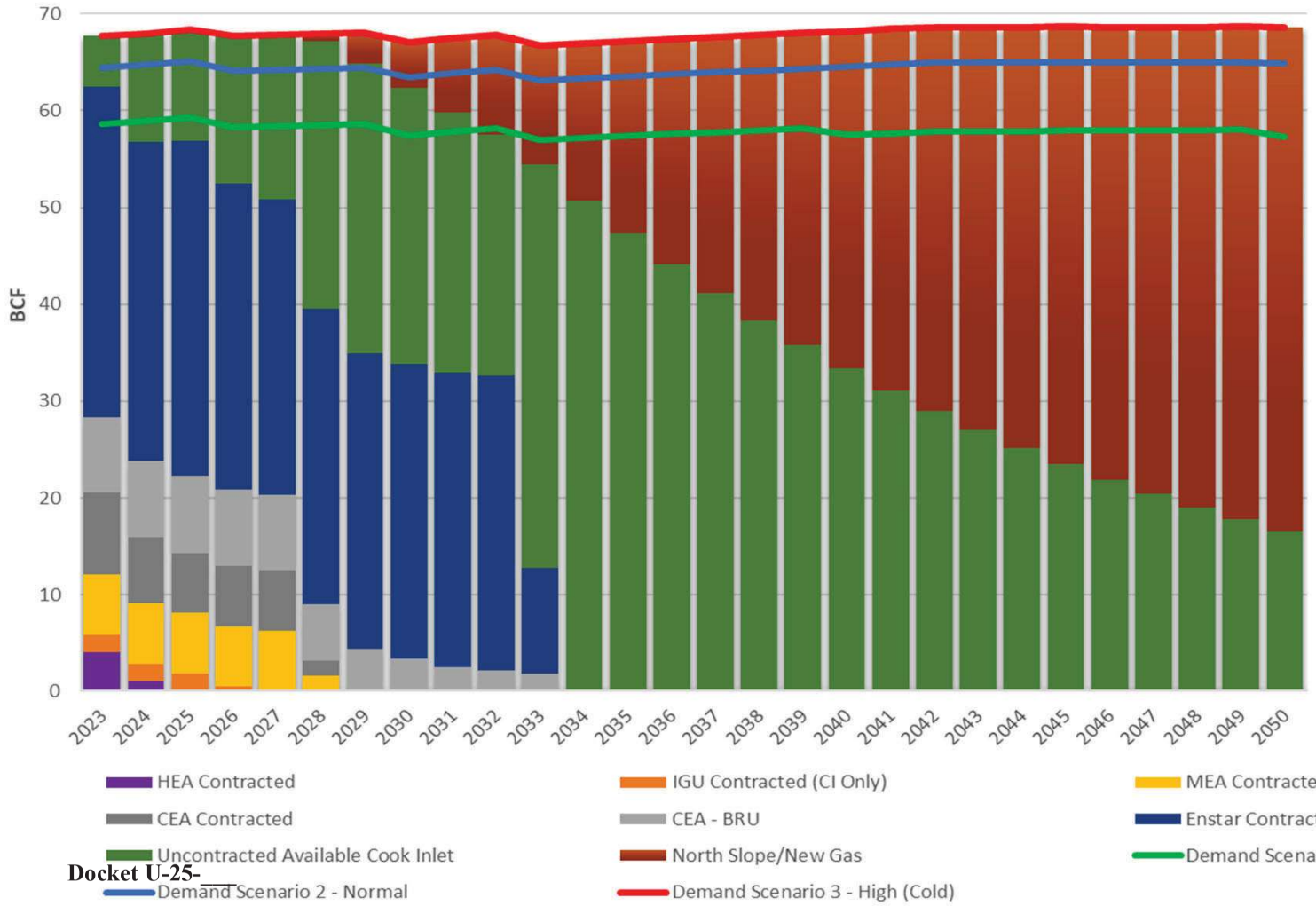
Utility Duty to Serve

- This duty is not shared by producers, IPPs, or anyone else in this state. It is our obligation alone.

Sec. 42.05.291. Standards of service and facilities.
(a) Each public utility shall furnish and maintain adequate, efficient, and safe service and facilities. This service shall be reasonably continuous and without unreasonable interruption or delay.

Utilities' Market View Fall '22

Combined Utilities' Annual Demand
(Cook Inlet Supply Utilities Estimate)



Higher-Risk Uncontracted Demand

No line of sight to Cook Inlet gas supply

Lower-Risk Uncontracted Demand

Expected to be supplied from Cook Inlet remaining reserves.

New contracts, the true cost…

5. **Special Cover Provision**

a. This Special Cover Provision applies in the following amounts for the applicable tranches ("Special Cover Tranches") and for the time periods set forth below ("Special Cover Terms" and collectively the "Special Cover Term"), unless Buyer provides notice otherwise as set forth herein:

Special Cover Tranches and Terms	
April 1, 2024-March 31, 2025	1.0 Bcf
April 1, 2025-March 31, 2026	1.0 Bcf
April 1, 2026-March 31, 2027	1.5 Bcf

b. Buyer and Seller agree that due to delivery of the New Demand Gas, Seller has an enhanced risk of a Delivery Shortfall during the Special Cover Term. If the Delivery Shortfall occurs during the Special Cover Term, Buyer agrees to waive any Cover remedies contemplated in Section 2.4(C)(3) of the Agreement up to the amount of the then-applicable Special Cover Tranche. For the avoidance of doubt, the amount of Cover remedy under this Section 5(b) is not cumulative, and the Cover amount provided by each Special Cover Tranche for New Demand Gas expires on the last day of the applicable Special Cover Term.

Contract Terms Overview

Contract Terms	All Requirements	Firm	Interruptible	Spot
Meets 100% deliverability?	✓	✗	✗	✗
Provided under contract?	✓	✓	✓	✗
Penalty for non-delivery? (Cover)	✓	✓	✗	✗
Allows for multi-year gas supply planning?	✓	✓	✗	✗
Set price?	✓	✓	✗	✗
Set quantity?	✓	✓	✗	✗
Set terms?	✓	✓	✗	✗
Not subject to changing market or operating conditions?	✓	✓	✗	✗

Phase II Project Team

Cornerstone Energy Services | BRG | ENERGY & CLIMATE

Integrated Project Team Roles

ENSTAR and Utility Group
Strategic direction
Commercial, legal, regulatory leadership
Pipeline system, storage, existing supply integration
Public communications strategy and oversight

BRG
Project strategy advisor, local coordination
Planning of deliverables and Phase 2 project management
Gas supply project development and execution planning
LNG supply expertise and market interface
Financial and economic analysis
Project interface with Enstar, utilities, and public forums as directed by client

Cornerstone
Engineering and project cost estimates
Permitting plan
Project option technical viability and risk assessment

Additional Resources Engaged

Exp. (Alaska)

Coffman Engineers (Alaska)

Axiom Environmental (Alaska)

Cashman Preload
LNG tank experts, Alaska experience

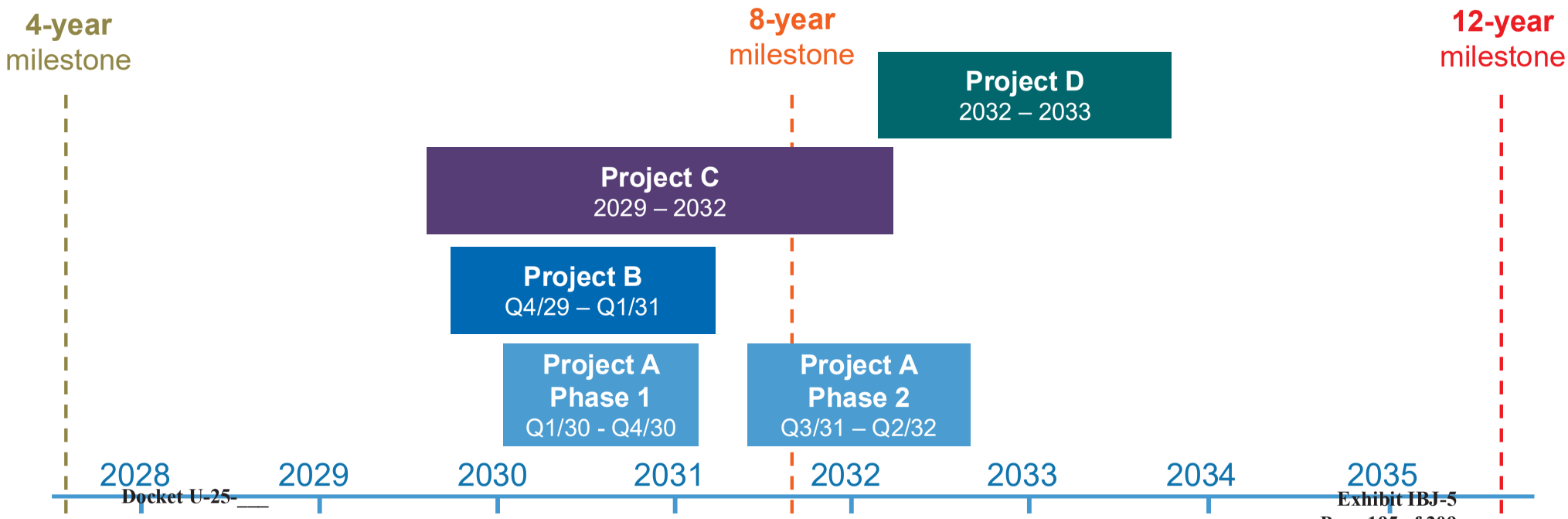
Lloyd Engineering
Marine engineering, Alaska experience

Precision LNG
Worldwide LNG shipping expertise

Hunton Andrews Kurth LLP
Regulatory / Permitting legal experts

Summary Findings for Schedules – Phase II

- None of the options meet the LNG demands for the 4-year milestone (first gas 4Q2027)
- Greatest time unknowns are related to FERC and US Corps of Engineers permitting durations, time to modify or construct in-water piers
- Risks are high for FSRU Options due to tides and winter effects at Cook Inlet
- Long-lead procurement items must be started, and commercial agreements concluded before permits are issued



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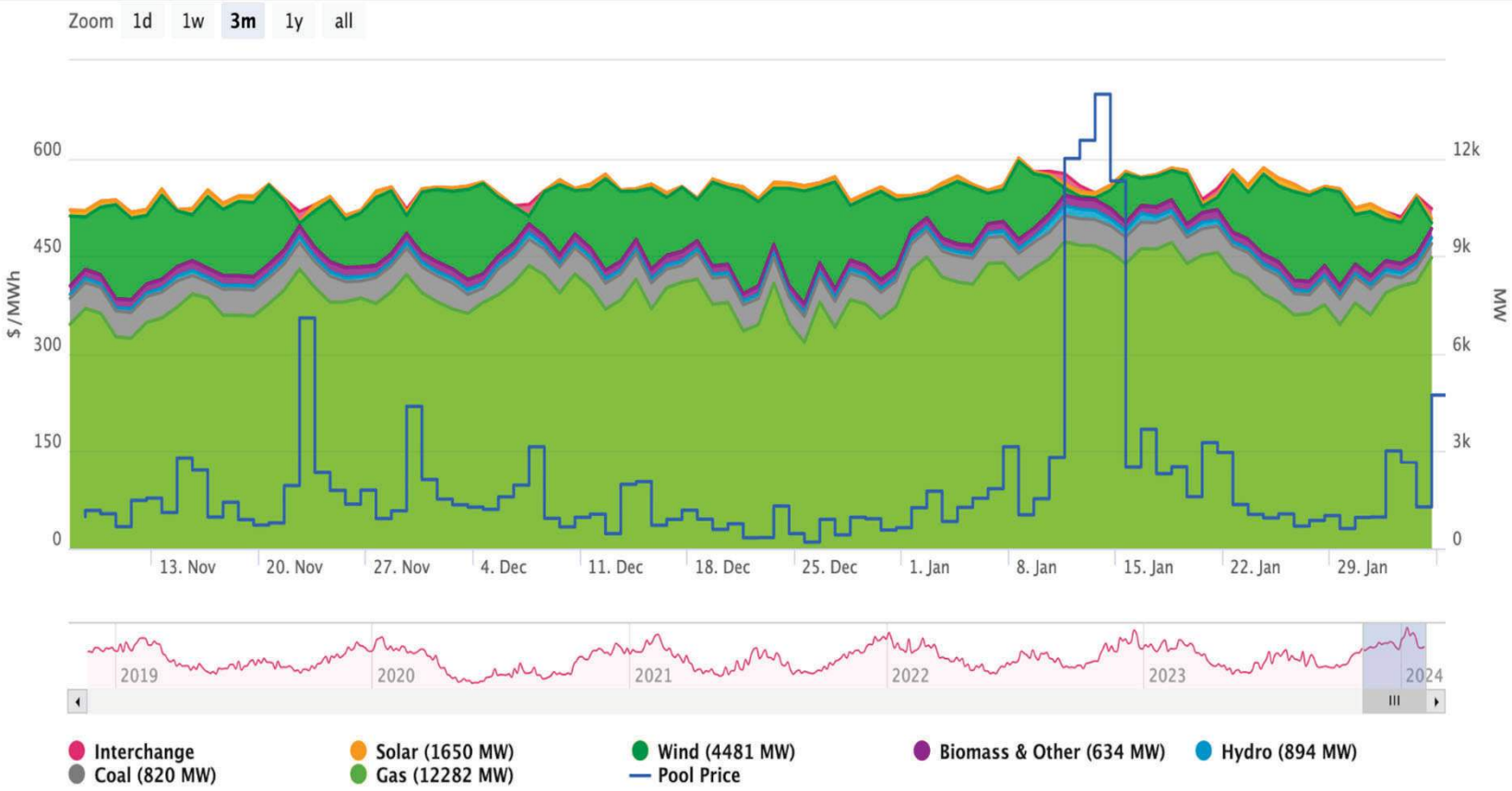
Meeting Peak Demand

GREEN ALBERTA ENERGY
OUR FUTURE IS GREEN

About | Solar Club™ | Green Energy | Green Providers | Contact | GO GREEN



Meeting Peak Demand (Cont.)

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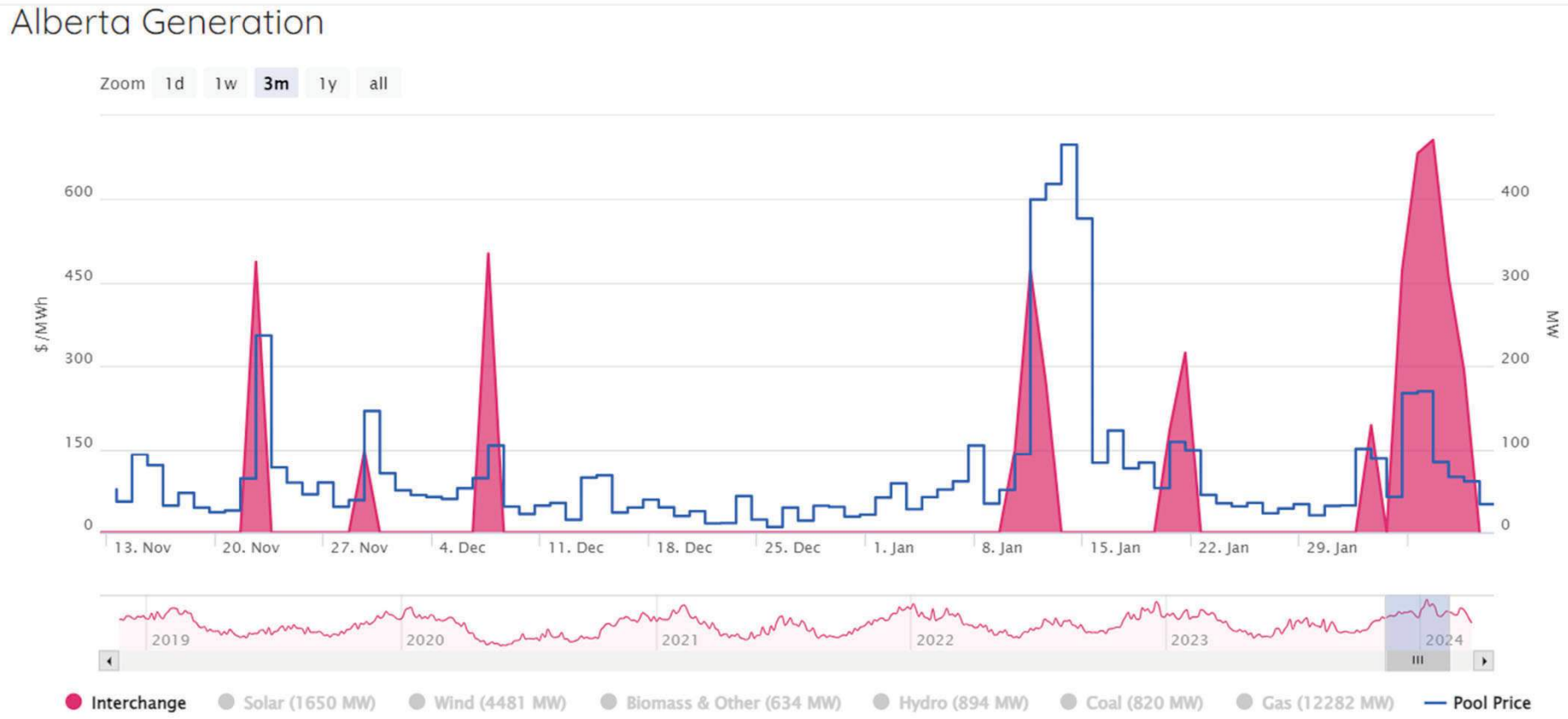

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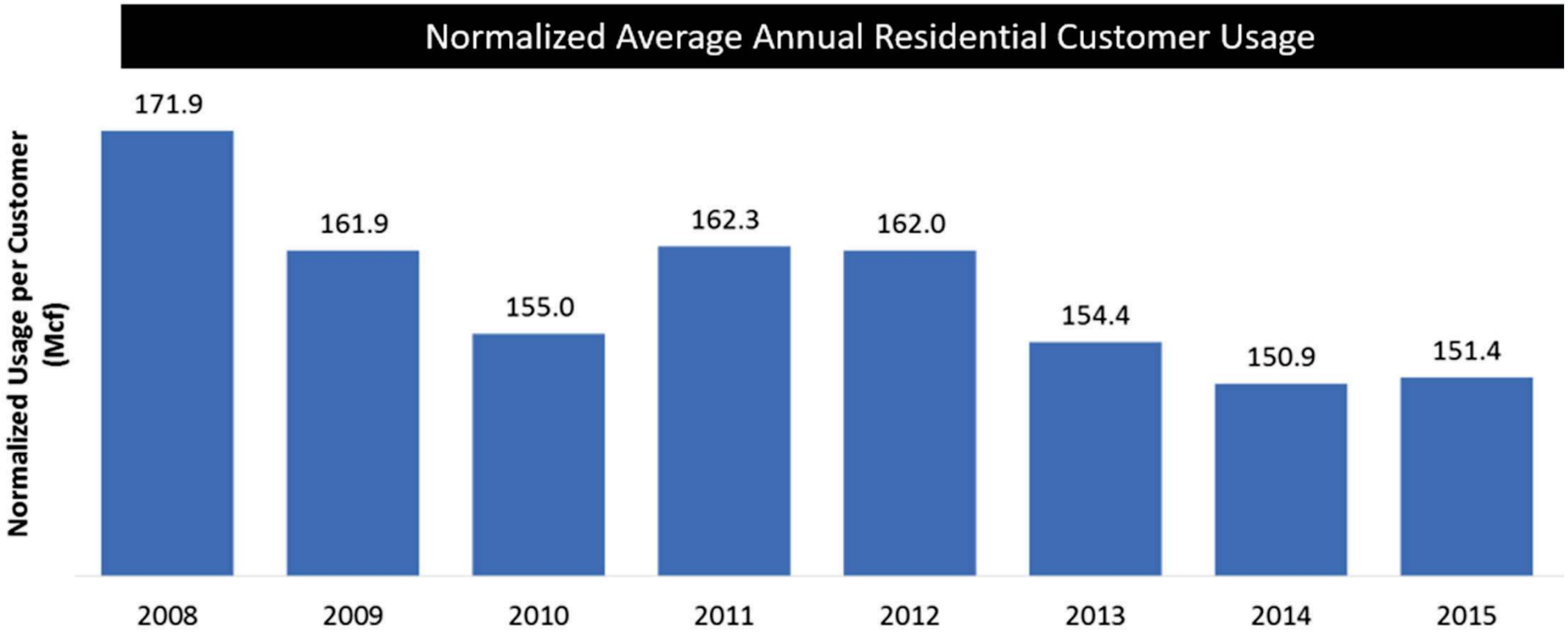

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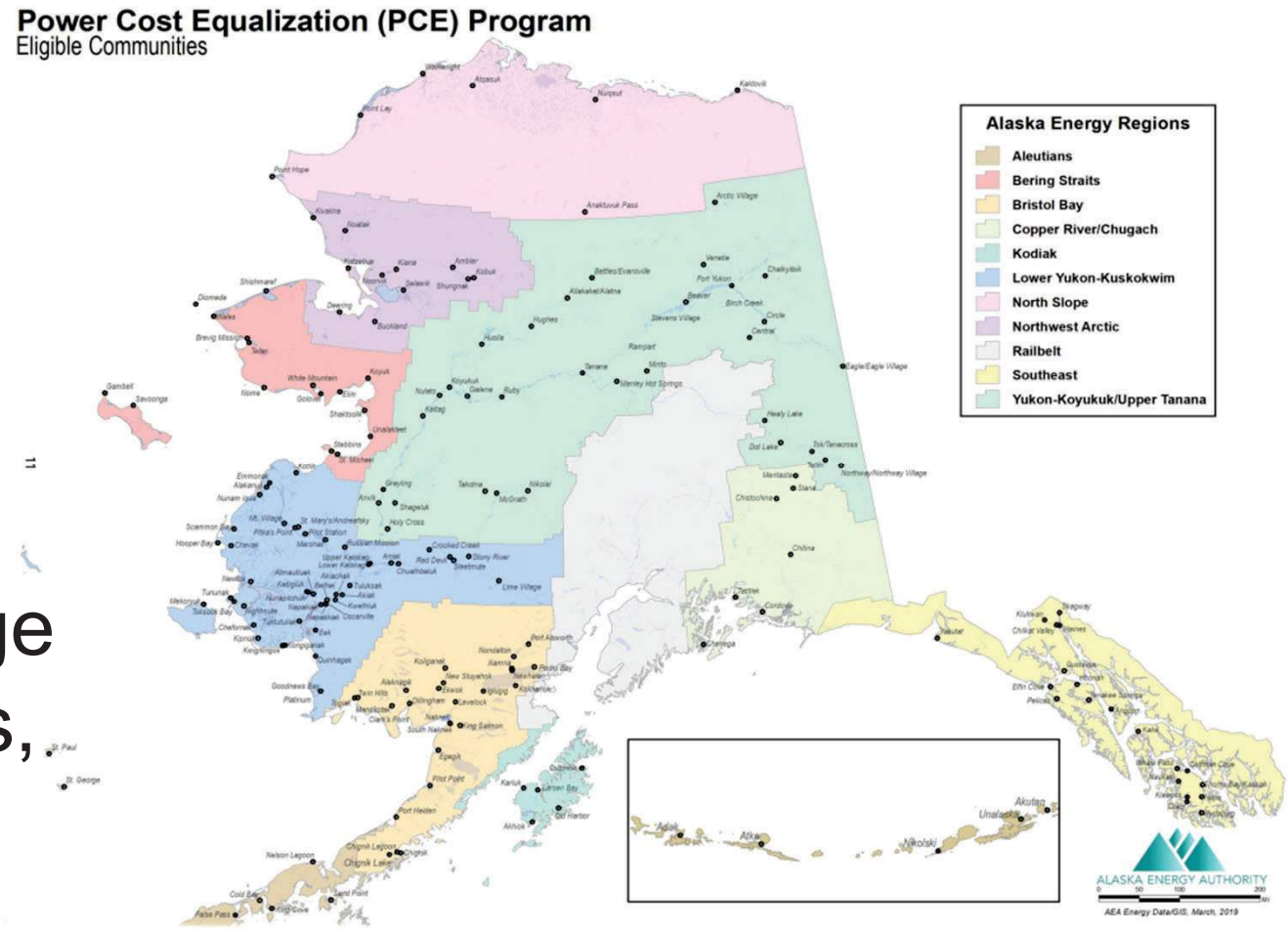

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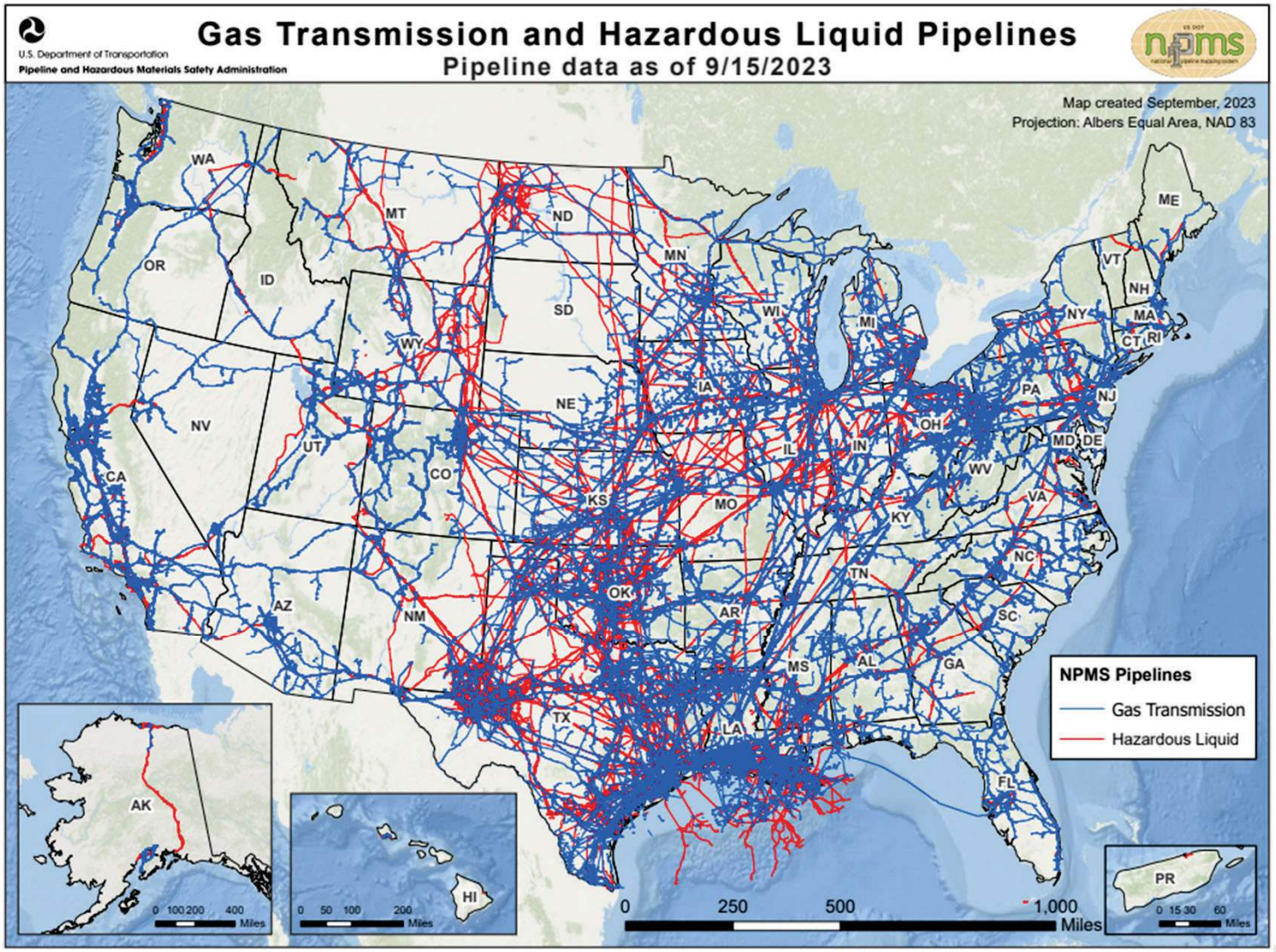
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npms
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WA
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MD
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AK
HI
PR
NPMS Pipelines
Gas Transmission
Hazardous Liquid
0 250 500 1,000 Miles
0 100 200 400 Miles
0 50 100 200 Miles
0 15 30 60 Miles

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STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chairman
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Consideration of the Revenue Requirement Designated as TA 354-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF NATHAN T. BURKE

PREFILED DIRECT TESTIMONY
OF
NATHAN T. BURKE

TABLE OF CONTENTS

I. POSITION AND QUALIFICATIONS 3
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VI. CONCLUSION 34

EXHIBITS

Exhibit NTB-1 Resume of Nathan T. Burke

I. POSITION AND QUALIFICATIONS

Q. Please state your name, business address, and present position.

A. My name is Nathan T. Burke. My business address is 3000 Spenard Road, Anchorage, AK 99503. I am the Manager of Infrastructure and Planning for ENSTAR Natural Gas Company, LLC ("ENSTAR") and Alaska Pipeline Company, LLC ("APC"). ENSTAR and APC are regulated as a single entity and will collectively be referred to in my testimony as "ENSTAR" or the "Company."[1]

Q. Briefly describe your professional experience and educational background.

A. I have served as ENSTAR's Manager of Infrastructure and Planning since 2023. I originally joined ENSTAR in 2012 as an Engineer, and was promoted to Supervisor of Construction and Maintenance in 2015. In my roles as an Engineer and Supervisor, I was involved in project design and management and had first-hand oversight of construction and maintenance crews working on our natural gas pipelines, ensuring safe and reliable operation of our system. In 2021, I left ENSTAR briefly to serve as the General Manager of Mechanical Builders, Inc., a local industrial mechanical company focused on the construction and maintenance of rural Alaska utility power plants, before returning to ENSTAR in 2023. I hold a Bachelor of Science in Mechanical Engineering from the University of Alaska Fairbanks and a Master of Business Administration from the University of Washington. My resume is attached as Exhibit NTB-1.

Q. Briefly describe your current professional responsibilities with ENSTAR.

[1] The Commission regulates APC and ENSTAR as a single entity. The use of the name "ENSTAR" or "Company" in this filing is intended to include both APC and ENSTAR, unless the context clearly requires otherwise.

A. As the Manager of Infrastructure and Planning, my work focuses on the development, design, and execution of larger programs and projects to maintain the Company's safe and reliable operation and continued compliance with pipeline safety regulations. These programs include required pipeline repairs, renewals, and improvements. I also oversee the coordination of annual and future plans for other engineering and operations departments within the Company.

Q. Have you previously testified before the Regulatory Commission of Alaska ("RCA" or "Commission")?

A. No, I have not.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to address three topics. First, I discuss the level of capital investments ENSTAR has made since its last rate case, and demonstrate that these projects are used and useful in providing gas utility service and that the costs are reasonable and prudent. Second, in addition to ENSTAR witness Ms. Chelsea N. Guintu, I support ENSTAR's request for year-end rate base treatment for certain new investments the Company has made to ensure the safe and reliable transportation and distribution of natural gas. Finally, I discuss ENSTAR's Reliability Infrastructure Replacement Program ("RIRP"), which will accelerate the replacement of higher-risk, aging facilities and enhance the safety and reliability of the Company's distribution system in Alaska.

III. CAPITAL INVESTMENT

Q. Since the Company's last rate case, has ENSTAR made any capital investments?

A. Yes. From the end of the test year in ENSTAR's last rate case (December 31, 2021) to the end of the test year in this case (December 31, 2024), the Company invested approximately $127 million in capital to maintain and improve its natural gas transportation and distribution system in Alaska. These investments included a variety of different types of projects, various safety and reliability upgrades; regulator station replacements; control system replacements; and strategic distribution system reinforcements.

Q. Please describe the general process by which ENSTAR executes significant capital projects.

A. ENSTAR leadership, operations teams, and engineers submit projects throughout the year for future capital consideration. Typically, ENSTAR identifies the projects through its integrity management plans, the performance of the overall transmission and distribution systems, and the age and maintenance requirements of the Company's assets. The Company then evaluates the projects, ranks them based on their justification and need, and schedules them for execution.

Q. Can you provide examples of capital projects that have been placed into service since the end of the test year in the last rate case?

A. Yes. The following projects are examples of significant capital investments ENSTAR has undertaken since its last rate case:

- **Kenai A&B Pipeline MP30.9 Valve Replacement (2022)**: For this project, ENSTAR replaced and relocated the buried isolation and crossover valves at milepost 30.9 along the Kenai to Anchorage "A" and "B" Pipelines that transport gas from Kenai to Anchorage, which were originally installed in 1961 and 1974,

respectively. The new valves were installed above ground to enhance the reliability and safety of operating these valves and connected pipelines. For example, bringing the valves above ground allows for better access and ease of operation during an emergency isolation event, improved maintainability by bringing the maintenance ports above ground within eyesight, and elimination of cathodic protection and corrosion issues related to facilities buried underground. Project cost: $541,264.

- **Welaka Lake and Holt Lamplight Regulator Station Replacements (2022)**: For this project, ENSTAR replaced pressure-regulating stations in Nikiski that posed reliability risks due to aged equipment and the stations' under-performance. These stations were originally installed in 1978 and were considered "farm tap" stations meant to serve a small distribution system in the immediate area. As ENSTAR's distribution system grew, these stations operated near their maximum capacity. ENSTAR has many regulator stations along its transmission system of this vintage that are in need of replacement, many of which are extremely difficult to service due to lack of available parts and outdated designs. Components at these stations require annual replacements and are increasingly more difficult to source, as the manufacturer has stopped production on these units. Further, the design of the regulator and station requires higher risk maintenance procedures involving splitting the regulator in half. This procedure increases lateral stresses and strain on the neighboring piping. Modern regulator station designs contain top entry regulators or flanged connections that allow for simple disassembly for maintenance. Project cost: $427,386.

- **Oilwell Pipeline Valve Upgrades and Launching Facility Installation (2023)**: This project included rebuilding a valve station at a junction on the "Oilwell Lateral" pipeline in Anchorage so that an internal inspection device could be used to inspect and monitor the line for system integrity. The federally-mandated transmission integrity management plan ("TIMP") requires ENSTAR to inspect its pipelines at certain time intervals, and the intervals depend on the method ENSTAR uses to conduct the inspection and the data the Company obtains in its inspections. The Oilwell pipeline, installed in 1968, has previously been inspected using an external corrosion direct assessment method. Although that method is acceptable to the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), in-line inspections are considered industry best practices due to the quality of data produced. ENSTAR performed an in-line inspection for the first time in 2024 and found anomalies that had previously not been found using the other inspection methods. Project cost: $576,510.
- **Moose River Horizontal Directional Drill (2023)**: For this project, ENSTAR installed approximately 1,000 feet of new 12-inch steel pipe on the Kenai to Anchorage B Pipeline ("B-Line") to replace a section of the pipeline that had become exposed at the bottom of the Moose River in Sterling and was considered to be a potential public safety hazard. Project cost: $2,051,718. A link to the video describing this project and its benefits can be accessed here: Moose River Project Video.
- **Nikiski Microwave Tower Project (2023)**: ENSTAR installed a new tower in the Nikiski area that is required to create an additional microwave communication loop

for pipeline operations, enabling critical system reinforcement. The new tower bridges a gap and helps provide an alternate communication path for the Company's Supervisory Control and Data Acquisition ("SCADA") system to control and monitor data, including pipeline pressures, compressor stations status, ENSTAR IT communications between divisions, and ENSTAR's mobile radio system used for emergency communication. Absent these investments, our employees would have to perform manual readings of pipeline pressures if the single communication path went down. Project cost: $809,787.

- **Various Distribution System Reinforcements (2022 and 2023):** ENSTAR completed various strategic distribution pipeline installations to increase system pressures in Kenai Peninsula and Matanuska-Susitna Boroughs. ENSTAR's distribution system design pressure is 60 pounds per square inch gauge ("psig"), but in the cold winter months, the system pressures can fall to as low as single digit pressure ranges, which could result in an outage scenario. These pressures are frequently found at the outer edges of the system or in areas that are heavily bottlenecked due to years of expansion and local growth. ENSTAR maintains pressure-recording devices throughout its distribution system to identify these areas and any new system connections that the Company needs to construct to prevent any reliability issues in the future. Combined project cost: $2,044,694.
- **SCADA Replacement (2023 and 2024)**: Due to increased federal requirements for pipeline control room management and ongoing support problems with an old SCADA system, ENSTAR needed to replace its SCADA control system. The Company uses the SCADA system for 24/7 monitoring and control of its pipeline

system to ensure the safe operation of the system and to satisfy the rigid federal regulations applicable to pipeline control rooms. The SCADA system collects and displays data from across the pipeline system (regulator stations, compressor plants) in such a way that pipeline operators can respond appropriately to abnormal operating conditions such as pressure limitations and equipment failure. Controllers use this data to respond to alarms and operate the pipeline system within tolerable limits while meeting customer demand. Project cost: $2,108,016.

Q. Are the projects described above used and useful in providing utility service to ENSTAR's customers?

A. Yes. All of these projects are used and useful in providing gas utility service to ENSTAR customers, and all of the costs associated with the projects are reasonable and prudent.

IV. CRITICAL PROJECTS THAT QUALIFY FOR YEAR-END RATE BASE TREATMENT

Q. Are you familiar with the Commission's process for calculating a utility's rate base in rate cases?

A. Yes, generally. My understanding is that the Commission's regulations require a utility to file its calculation of rate base using a 13-month average, but allows utilities to propose other rate-base theories that are appropriate and supportable.[2] It is also my understanding that the Commission has explained that while the 13-month average is the Commission's "preferred method" for calculating rate base, the Commission will approve the use of year-end rate base in circumstances where capital projects benefit

[2] 3 AAC 48.275(a)(9).

customers in the form of a reduction in costs or an increase in safety and reliability.[3] Ms. Guintu discusses the Commission's analysis regarding year-end rate base in further detail in her direct testimony.

Q. Did ENSTAR make any investments during the test year that qualified for year-end rate base treatment?

A. Yes. ENSTAR invested approximately $12.4 million of its 2024 capital expenditures in facilities that were critical to increasing safety and reliability. These investments include the following:

- **MP39 Odorant System Replacement**: For this project, ENSTAR replaced the existing odorizing system at the MP39 filtration facility, which was originally installed in 1984. The facility is located on the 20-inch Beluga to Anchorage Pipeline on the west side of Cook Inlet and it odorizes natural gas with mercaptan, which gives the gas the "rotten egg" smell to make it easily identifiable in the case of a leak. In its native state, natural gas is odorless, making leaks undetectable without specialized equipment. Adding odorant is therefore required for safe pipeline operations and federal pipeline regulations. Additionally, this facility filters all of the gas supplied to customers in the Mat-Su Valley and to Matanuska Electric Association's electric generating plant in Eklutna, and approximately one-third of the gas supplied to customers in the Anchorage Bowl. This project went into service on August 28, 2024. Project cost: $344,585.
- **Palmer Municipal Airport Water Bath Heater Replacement**: ENSTAR replaced the water bath gas heater at its regulator station located near Palmer

[3] Order U-16-066(19) at 23

Municipal Airport. A water bath heater preheats the gas stream prior to entering a regulator station so that as the gas expands and depressurizes, the gas stream stays above the freezing point of water to prevent ice buildup on the pipe and the equipment and controls. This critical regulator station supplies gas to the Butte community and subdivisions located off Palmer Fishhook Road. The previous water bath was installed in 2010 and was undersized for the gas flows now experienced in the area after 14 years of marked population growth. This created reliability concerns requiring frequent technician dispatches to ensure reliable operation and needed to be replaced to mitigate the concerns. The new unit was installed and placed in service on October 15, 2024 and the old unit was returned to ENSTAR's operation center for refurbishment in preparation for reinstallation in a 2025 project at another site. Project cost: $286,298.

- **Oilwell East Gate "Pig" Traps**: This project, which was the final phase of the 2023 Oilwell Lateral Pipeline Valve and Launching Facility Project, installed the pipeline fixtures necessary to complete a hydrostatic pressure test and in-line inspections required by PHMSA. The launching and receiving traps were completed and placed in service on May 22, 2024. This project served immediate benefits, because when ENSTAR internally inspected the pipeline on June 18, 2024, the Company found anomalies that had not previously been discovered using external corrosion direct assessment methods, such as a dent near an unrelated

sewer or water main. Pipeline repairs are scheduled for 2025. Project cost: $151,493.

- **Kenai B-Line Segment K6 Replacement**: For this project, ENSTAR replaced approximately 2,600 feet of one of the only two pipelines that brings gas to Anchorage from Kenai (the 16-inch Kenai to Anchorage B-Line). Recent in-line inspections had revealed that the line contained significant amounts of corrosion.[4] This substantial replacement project, which ENSTAR completed with a horizontal directional drill, was necessary to improve safety and reliability on a major line that is critical to ensuring deliverability of gas to Anchorage. Project cost: $5,989,735.
- **Camrose Drive Steel Main Replacement**: This project replaced approximately 1,150 feet of 1-1/4" steel main necessitated by a storm drain project undertaken by the Municipality of Anchorage. If ENSTAR had not replaced this main, the municipality's storm drain project would have left sections of the main isolated (or cathodically protected with wires), which severely limits the Company's ability to protect the pipe and mitigate any threat of corrosion (as required by the Company's federally-mandated distribution integrity management plan). Replacing this section of main also reduces the likelihood of leaks, eliminates any preexisting corrosion issues, and reduces customer costs through the elimination of cathodic

[4] An "in-line inspection" or ILI, is an evaluation of the pipeline using tools known as "pigs" or "smart pigs." These tools gather data from inside the pipeline to identify corrosion or other issues affecting the pipeline's integrity.

protection system monitoring and reductions in leak response. The project was completed and placed in service August 15, 2024. Project cost: $106,376.

- **Southern Division Isolated Steel Main Replacements**: For these projects, ENSTAR replaced isolated sections of steel main (*i.e.*, shorter sections of steel main that are surrounded by plastic main) around Soldotna along Robin Drive, Togiak Street, and Swanson River Road. As compared to pipelines made from plastic, steel mains have a higher frequency of leaks and are susceptible to corrosion. Additionally, as mentioned above, isolated sections severely limit the Company's ability to protect the pipe and mitigate any threat of corrosion (as the Company's federally-mandated distribution integrity management plan requires). These replacements were completed in 2024. Project cost: $170,137.
- **Copper and X-TRUBE Service Line Replacement**: Installed in the 1960s, 1970s, and 1980s, these lines are joined by mechanical fittings and are prone to corrosion, and are at risk of failure during a seismic event or as a result of frost heaving. The costs associated with ENSTAR's ongoing efforts to replace these lines totaled $676,503 during the test year.
- **RIRP Project**: As I discuss later in my testimony, in 2024, ENSTAR started implementation of a large-scale program to replace steel mains and services (and other metallic pipes) across the Company's system, beginning in Kenai. As part of the program, ENSTAR replaced more than 26,000 feet of steel mains and 130 service lines installed primarily in the 1960s, on a portion of ENSTAR's system that the Company acquired from Kenai Utility Service Corporation ("KUSCO") in 1985. These improvements will significantly enhance safety and reliability across

a major portion of ENSTAR's Alaska distribution system. Project cost: $2,143,149.

- **Seward Meridian Parkway Reinforcements, Transmission Extension, and Regulator Station (2024)**: ENSTAR completed this group of projects in coordination with Phase II of the Alaska Department of Transportation's federally-funded Seward Meridian Parkway Road Improvements Project. The Company installed a new 8-inch distribution system feed from the Palmer-Wasilla Highway to the Seldon Road area, extended a new 4-inch transmission line approximately 12,600 feet north from the Parks Highway to the Seldon Road area, and installed a new regulator station near Seldon Road to improve pressures in the northern areas of the Mat-Su Valley. The combination of these projects greatly increased the pressure in the northern parts of the valley, thereby improving the stability of the distribution system and delivery pressures in the area. These projects were completed and placed in service in the 2024 construction season. Combined project cost: $2,482,177.

Q. Are the investments listed above in service and used and useful to serve ENSTAR customers?

A. Yes. All of the investments that I have just described were in service during the test year and are currently used and useful in providing natural gas transmission and distribution services to our customers. Further, each of these projects were critical for system safety and reliability.

V. RELIABILITY INFRASTRUCTURE REPLACEMENT PROGRAM

Q. Please provide an overview of ENSTAR's RIRP.

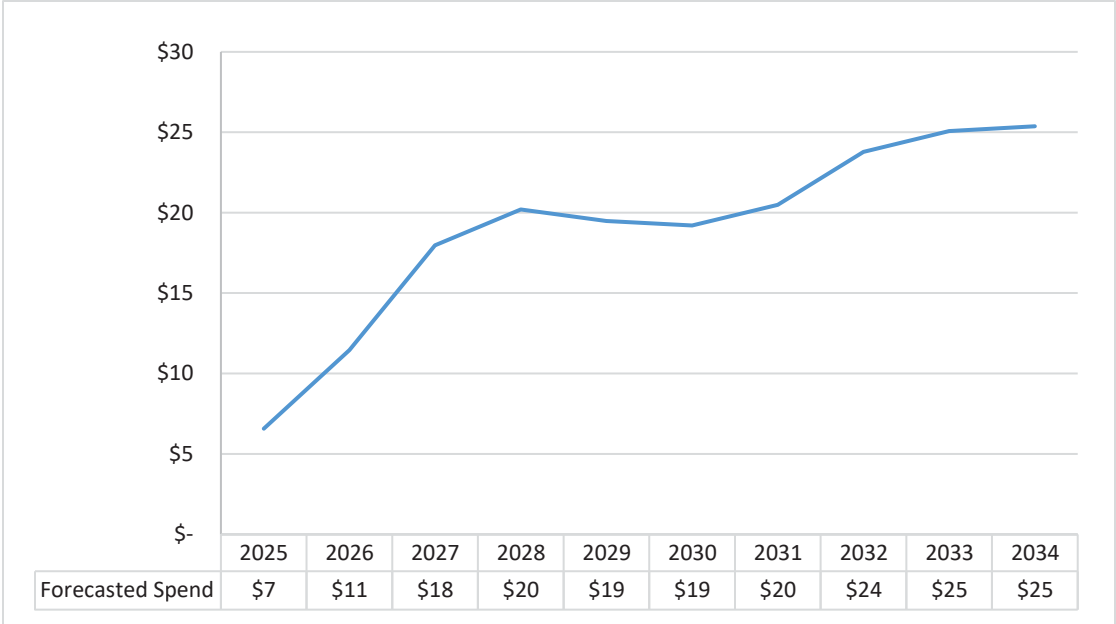
A. ENSTAR has a long history of proactively replacing aging infrastructure to improve the safety and reliability of its natural gas transmission and distribution systems. Consistent with that tradition, in 2024, ENSTAR began a large-scale program to reduce system integrity risks and enhance the safety and reliability of its distribution system by replacing mains as well as service lines ("services") comprised of steel and other metallic materials. The Company undertook this program in connection with its federally-mandated Distribution Integrity Management Program ("DIMP"), which requires the Company to identify existing and potential threats to its system and take appropriate mitigation actions. The proposed mitigation actions under DIMP, and similar actions required under the Company's TIMP, have led ENSTAR to determine that large portions of its distribution and transmission systems should be replaced to maintain safe and reliable service. My testimony will refer to the distribution component of this initiative as the "steel mains" program, but the full RIRP program targets more than steel mains – it also focuses on service lines made from steel and other metallic materials as well as certain transmission pipeline projects with higher failure likelihoods.

Initially, ENSTAR began the distribution component of the RIRP as a project in Kenai, within the boundaries of the former KUSCO service territory. The former KUSCO service territory was an ideal location for the project due to the age of the system and integrity issues attributable to another operator installing and maintaining these pipelines. ENSTAR is expanding the program in 2025, nearly doubling the planned pipeline replacement footage, and will continue growing the program in future years to extend throughout the Company's system.

Over the next ten years, as Figure 1 demonstrates below, ENSTAR anticipates it will spend approximately $10-25 million per year to replace aging, higher-risk transmission lines and distribution mains and services as part of this program:

Figure 1

RIRP Forecasted Spend ($MM)



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Forecasted Spend	$7	$11	$18	$20	$19	$19	$20	$24	$25	$25

Based on ENSTAR's evaluation of risks across its system, the Company believes this program must be a top priority.

Q. What are the benefits of the RIRP?

A. The RIRP will accelerate the replacement of ENSTAR's higher-risk facilities, as identified through the Company's DIMP and TIMP, engineering studies, industry standards, and PHMSA requirements, to create a safer, more reliable natural gas transmission and distribution system. The RIRP will:

- eliminate steel mains and services and other metallic services that ENSTAR's DIMP has identified as having the highest leakage rates;

- address large-scale transmission system risks identified as priorities to maintain the integrity of the system;
- enhance overall safety by eliminating segments in the Company's transmission and distribution systems with higher failure likelihoods;
- reduce operating expense while creating a more reliable transmission and distribution system by reducing system integrity risks attributable to corrosion, equipment failures, material failures, and the impact of natural forces;
- reduce leakage on ENSTAR's system, which conserves critical volumes of natural gas and, in turn, will reduce emissions of greenhouse gases; and
- reduce operating expense by reducing the need to respond to corrosion issues, material failures, and leak response.

Q. Please describe ENSTAR's distribution system.

A. ENSTAR provides natural gas distribution service to approximately 155,000 customers across its service territory, which stretches from Willow to Homer. The Company provides this service through approximately 3,300 miles of mains and 140,000 service lines that the Company owns, operates, and maintains. ENSTAR's distribution system consists primarily of high-density polyethylene ("HDPE") pipes, which is widely considered to be the safest and most reliable material in the natural gas industry. ENSTAR began installing HDPE in 1972, and at that time, the Company also generally stopped installing steel and other metallic piping. But the Company's system continues to include significant sections of coated steel, bare steel, copper tubing, and a steel tubing material called X-TRUBE ("XT"), which is a product that Republic Steel manufactured in the 1960s as an alternative to welded steel pipe. ENSTAR proposes

to replace these aging, higher-risk facilities to create a safer, more reliable distribution system in Alaska.

Q. Please provide a general overview of ENSTAR's DIMP and the requirements it imposes upon the Company.

A. 49 CFR 192 Subpart P requires ENSTAR to develop and implement an integrity management program (including a written integrity management plan) that outlines the Company's overall approach to ensuring the integrity of its gas distribution system. As part of its plan, ENSTAR must: (1) demonstrate an understanding of its gas distribution system; (2) identify threats; (3) evaluate and rank the risks associated with those threats; (4) identify and implement measures to address those risks; and (5) evaluate the effectiveness of the program.

ENSTAR tracks the threats listed below through leak investigation reports for annual review and reporting. The Company then uses this information to adjust its ranking of risks and develop implementation measures. The bullets below represent the categories of threats and examples of conditions giving rise to each threat.

- **Corrosion**: Atmospheric or external corrosion on metallic pipe.
- **Equipment Malfunction**: Failures of couplings, caps and seals, regulators and relief valves, threaded connections, and valves.
- **Incorrect Operations**: Incorrect construction or operations.
- **Material, Weld & Joint Failure**: Welds, dents, gouges, excessive stress, and manufacturing defects that result in system failures.
- **Excavation Damage**: Blasting damage, excavator error, locator error, no locate scenarios, and poor records scenarios.

- **Natural Forces**: Earthquakes, washouts, ice and snow, ground movement, and other natural forces.
- **Other Outside Forces**: This category includes build overs, vehicular damage, and other similar examples (such as a lawn mower running over a line, a dog digging up a damaged line, house fires, and other non-excavation damages).
- **Other**: XT Replacement, Other. Both categories indicate we did not determine the specific cause of the failure and moved straight to replacement. These are common when we suspect failures under driven roadways.

Q. Why does ENSTAR propose to accelerate the replacement of metallic types of facilities?

A. As compared to the HDPE pipes that ENSTAR installs today, steel and other metallic materials carry a greater risk due to their higher leak rates. Without question, the consensus in the natural gas industry and regulatory community is that steel and other metallic materials have a substantially greater risk of failure. Congress, state legislatures, and regulatory agencies have taken steps to encourage natural gas distribution companies to accelerate the replacement of these aging, high-risk facilities. Across the industry, companies are replacing these facilities on an accelerated basis.

Q. As compared to plastic mains and services, are metallic pipes more likely to fail?

A. Yes, undoubtedly. Using five-year average failure rates for non-external interference threats, steel service lines are six times more likely to fail than plastic service lines; copper service lines are 36 times more likely to fail; and XT service lines are 15 times more likely to fail. For distribution mains over the same five-year period, steel mains are 14 times more likely to fail than plastic mains.

Q. What are some of the unique risks associated with steel and other metallic pipes?

A. Metallic compounds have several unique risks that simply are not present in HDPE pipes. First, all metallic compounds in our distribution system are subject to some form of corrosion. Steel and XT (a type of coated steel) can corrode whenever they are not adequately coated and cathodically protected. Historically, ENSTAR primarily installed coated steel, however the long-term effectiveness of the different coating types varies greatly. The coatings in ENSTAR's distribution system are primarily tape-wrap, extruded polyethylene jacketing, and fusion bonded epoxy. ENSTAR has found through our TIMP that tape-wrap coatings perform extremely poorly in our service area and has confirmed this on our distribution system when short sections are exposed. Given the age of ENSTAR's steel system and the generic information previously required on installation records, it is impossible for us to pinpoint the location and full extent of each coating type. Additionally, although copper is widely considered corrosion-resistant, in ENSTAR's experience, the brass fittings that connect sections of copper tubing experience galvanic corrosion over time due to dissimilar metals or external corrosion from a lack of coating. These brass fittings were industry standard at the time of installation.

Second, the use of mechanical fittings in steel, XT, and copper piping also poses a unique risk. Mechanical fittings typically require a rubber O-ring or ferrule followed by a threaded connection that compresses the exterior of the pipe to hold it in place. Originally, mechanical fittings were seen as a way to reduce installation costs by not requiring welding or fusion, but years of ground movement and external disturbance can cause the fittings to deteriorate or come apart, creating leaks. Mechanical fittings

also present issues of product obsolescence and lack of availability. XT has long been out of production and ENSTAR has found only one reliable manufacturer of XT-compatible fittings. Recent design changes to that manufacturer's product line have reduced the useability of the fittings, leading ENSTAR to adopt a practice of replacing nearly all XT lines that experience failures.

Third, steel and XT risers pose multiple issues, including atmospheric corrosion that cannot be mitigated cathodically; the lack of S-bends prevent resilience against ground movement; and encasement of risers in asphalt and concrete, which can cause extreme lateral forces on the riser due to ground movement. Steel and XT must be coated above ground to prevent any external corrosion, and years of direct ultraviolet exposure, weathering, and abuse is causing cracking and chipping in many coating types. This coating damage allows water in, which can lead to external corrosion and, in the worst cases, pinhole leaks above ground immediately adjacent to homes and other structures. Steel and XT are also more rigid materials, and although ENSTAR installed S-bends wherever possible to allow for ground movement and frost jacking, this was not possible in all locations. This leads to tremendous forces in all directions during any ground movement event, and the forces are amplified if the riser has been encased in concrete or asphalt because it is confined to move with the surrounding material.

Q. Can you provide examples of leak incidents that have occurred on the Company's system?

A. Yes. The following examples highlight the serious safety and reliability risks that occur as a result of leaks in metallic mains and services.

- On December 20, 2019, a resident of the Green Acres Trailer Court in Anchorage called to report a strong odor of gas. Responding to the call, an ENSTAR service technician discovered gas (20% lower explosive limit) coming from the skirting under a trailer and from the trailer's interior through a cracked window. The technician immediately ordered the trailer's residents to evacuate. The explosive limits of methane, the main component of natural gas, is between 4.5% and 14.5% methane in air concentration. If a vapor concentration is found within this range, it means that the methane could ignite with any source of ignition such as a spark from a non-intrinsically safe light switch or the lighting of a stove. Vapor concentrations above 14.5% are especially dangerous because as the methane dissipates in air, it has to pass through the explosive range in order to become fully inert. Expanding his investigation, the technician discovered 100% gas-in-ground vapor concentrations at the foundations of three more neighboring trailers, prompting further evacuations. Over the next several hours, ENSTAR construction crews, technicians, and supervisors dug through frozen ground and abandoned a section of main and two services that failed a pressure test.

As a result of these extremely dangerous conditions, customers had to leave their homes and stay with friends, family, or in local hotels until they could safely return. After ENSTAR stopped the leak, crews manned a vapor-extraction unit 24 hours a day for the next seven days, including over the Christmas holiday, to reduce the concentration of gas in the ground. After seven days, residents were able to return to their trailers, and ENSTAR technicians continued taking readings for two more days before determining that the hazardous conditions had subsided. Based

on its post-incident investigation, ENSTAR concluded that the leak likely resulted from one or more failures of mechanical pipe couplings. ENSTAR ultimately replaced the relevant section of main and three service lines with HDPE in the summer of 2020.

- On December 18, 2021, ENSTAR received a report of gas odors near Spenard Road at 26th Avenue in Anchorage. The responding service technician found no measurable concentration of gas in nearby structures, and established a plume perimeter to monitor for any further gas in ground migration. After excavating frozen ground in mid-winter, ENSTAR personnel exposed the area of highest concentrations near the junction of two mains, which triggered a complete closure of 26th Avenue and a partial closure of Spenard Road. Still searching for the leak, the crew continued to expose the main over the course of a day. They found a valve and dresser coupling where only one-half inch of the pipe remained in the coupling—it had almost completely separated. The crew replaced the leaking section with new steel pipe to maintain cathodic protection in the area, and ENSTAR had to maintain the road surfaces along 26th Avenue and Spenard Road throughout the winter and spring months with crews repeatedly bringing in gravel and smoothing out the road surface until the roads could be repaved in the summer.
- On May 24, 2023, ENSTAR received a report of smelled gas in the area east of North Bragaw Street at Thompson Avenue in Anchorage. The responding service technician discovered 100% gas in ground vapor concentrations at a nearby utility pole, 36% at the foundation of a nearby residence, 26% inside of the residence's garage, and 2.5% inside the kitchen. The technician ordered an immediate

evacuation of the building. After discovering high gas concentrations at three more residences, ENSTAR ordered more evacuations, displacing ten families in total. After excavating and exposing the steel distribution main, ENSTAR crews found an approximately 1-inch crack across the top of the main immediately adjacent to a buried valve. The crew noted the main was bowed upwards as if it had excessive downward pressure on either side of the valve. The crew replaced the section of main with a new piece of steel pipe to maintain cathodic protection in the area, and replaced one steel service line with HDPE.

These three examples highlight the importance of maintaining system integrity and ensuring that the Company's mains and services remain safe and reliable. In the first and third examples, gas leaks caused dangerously high concentrations of natural gas in customers' homes. Any source of ignition – a match, a fireplace, a stove, a light switch, even the camera flash on a phone – could have ignited the gas and caused a devastating explosion. Additionally, all of these incidents are an increase to operating expenses. Reducing these types of incidents, lowers operating costs and reduces the costs to our customers.

Q. Are there similar examples from HDPE piping?

A. No. HDPE fares much better than other materials. HDPE piping is not subject to corrosion, and in ENSTAR's experience, is less likely to fail due to natural forces. HDPE leaks are also more benign. Failure modes for HDPE are most frequently due to minor fuzz leaks at the service tee caps, outdated stab-style coupling seals, and threaded connections above ground. These are miniscule leaks that are generally found by highly sensitive methane detection equipment and fixed by tightening loose caps or

valves. Additionally, as the industry evolves and HDPE components improve, the risk of this style of leaks diminishes. For example, the new HDPE service tees utilize larger threads to prevent cross threading and a double O-ring to increase the sealing interface area.

Q. Why did the Company choose to start the program in Kenai?

A. For various reasons, ENSTAR determined that replacing steel mains (and other metallic facilities) in the former KUSCO service territory should be a priority. First, since it acquired the former KUSCO assets in 1985, the Company has had extremely limited access to installation records. The Company did not install these assets, and installation records are vitally important when the Company needs to determine the facilities' location. Except for the size of pipe, ENSTAR has found that much of the installation information for the KUSCO facilities simply does not exist.

Second, KUSCO had different construction and engineering standards than ENSTAR, and these different standards led to inefficiencies. Unlike ENSTAR, KUSCO did not use a set of standardized pipe sizes, and instead used an array of sizes throughout its system, which required ENSTAR to purchase tooling and equipment unique to the KUSCO system. Additionally, KUSCO electrically isolated its service lines from its distribution mains, which prevented adequate cathodic protection on the service lines. ENSTAR installed single-anode cathodic protection for many of these services in 1994, but it was impossible for ENSTAR to know the condition of the lines when the anodes were installed. Unprotected metal services carry a higher risk of corrosion-related failures. ENSTAR has conducted several surveys to try to establish where this isolation problem continues to exist, but without knowing how long the

services went unprotected, it cannot estimate the remaining serviceability of the pipe. The small anodes ENSTAR installed are also nearing the end of their design life and will soon require replacement, or replacement of the service will be required. Finally, the 2016 earthquake outside of Kenai caused a gas main weld to separate, which in turn caused gas to migrate to nearby residences, resulting in four explosions. Fortunately, there were no serious injuries or casualties, but this event demonstrates that aging infrastructure in this operating environment requires diligent surveillance and maintenance until replacement is feasible.

Q. How does ENSTAR assure the safe operation of these higher risk distribution mains until they are replaced?

A. As set out in ENSTAR's DIMP, we leak survey every copper service line each year and make immediate repairs as leaks are discovered. Additionally, ENSTAR also annually leak surveys all steel mains around freeze-up to identify any leaks that may occur due to frost jacking and ground movement. This leak survey is also conducted after every major earthquake event. Per federal code, ENSTAR is required to leak survey only 20% of its distribution system annually. Due to ENSTAR's harsh operating environment, ENSTAR leak surveys at least 25% per year to support reliability. The above leakage surveys on steel and copper pipes are in addition to our accelerated surveys.

Q. Why has ENSTAR waited to replace these mains until now?

A. ENSTAR prides itself on exceeding safety and reliability standards in operating its system. We are also careful to make prudent investments in our system. Surveys are conducted year-round whether on foot, by plane, vehicle, snowmachine, or ATV.

Unlike utilities in the Lower 48, ENSTAR does not grade or log leaks, but rather makes necessary repairs as they are discovered. Our practice of immediate leak repair was commended in a 2024 American Gas Association Peer Review. When it becomes evident that surveys and intermediate repairs are no longer sufficient either from an integrity or resource standpoint, ENSTAR elevates a project for replacement to a top priority. The issues identified in the RIRP have been monitored and mitigated over the years. We have now reached the point where large-scale actions are required to continue to maintain a safe and reliable system.

Q. After it replaces the KUSCO system, how will the Company prioritize distribution replacements under the RIRP?

A. In general, ENSTAR will follow the same basic process that it uses with other types of projects: the Company will review multiple factors and sources of data to determine the priority of replacements within the system. First, as part of its DIMP, federal regulations require ENSTAR to perform risk analyses to identify the greatest threats to safety and reliability across the Company's distribution system, and to implement appropriate measures to address those risks. In addition to these analyses, the Company will consider various other factors, including: history and severity of leaks; known and suspected cathodic protection issues; availability of installation records; concentrations of mechanical fittings and rigid or encased risers; ability to access mains and services; and local improvement projects for roads and other infrastructure. A team of subject matter experts within ENSTAR will meet at least once per year to evaluate these factors and sources of data and identify the most pressing, high-priority replacement projects.

To be clear, at this time ENSTAR is not proposing to replace every single main and service line made from steel, copper, or XT. Instead, the purpose of this program is to target the specific mains and services that the Company has determined to carry the greatest risk and pose the greatest threat on its system. ENSTAR will continually analyze the risks to its distribution and transmission systems to guide the full scope of this program.

Q. Please describe the transmission system ENSTAR operates.

A. ENSTAR operates an approximately 389-mile natural gas transmission system and 55-mile natural gas high pressure distribution system. The fundamental difference between the high-pressure distribution and transmission systems is the allowable stress level in the pipe, but they perform the same basic functions: transport large volumes of high-pressure natural gas to a high-pressure end user or a distribution regulator station. Therefore, they will be referred to collectively as the "transmission system" throughout my testimony. The transmission system generally routes from Beluga across the Susitna basin around the Knik Arm to Anchorage, then south under the Turnagain Arm and through the Moose Range to Sterling, then west towards Kalifornsky and ending near the eastern shores of the Cook Inlet. There are several other segments and laterals to the pipeline network, such as the Anchor Point Pipeline serving Anchor Point and Homer and the Military Lease Pipeline serving Turnagain Arm communities.

ENSTAR's transmission system consists of cathodically protected coated steel pipe and operates at pressures ranging from 271 pounds per square inch ("psi") to above 1,000 psi. ENSTAR installed the Kenai to Anchorage "A" pipeline, City Gate Pipeline,

and Bragaw Pipeline in 1961, bringing gas to the first customers. The pipeline system then grew significantly through the 1960s, 1970s, and 1980s, with 375 pipeline miles installed during that era that are still in service today. While the newest transmission pipeline is the CINGSA Lateral, installed in 2015, the mileage weighted-average pipeline age is approximately 35 years.

Q. Please provide a general overview of ENSTAR's TIMP and the requirements it places on the Company.

A. 49 CFR 192 Subpart O requires ENSTAR to develop and implement an integrity management program (including a written integrity management plan) that outlines the Company's overall approach to ensuring the integrity of its gas transmission system. This plan must follow the requirements of the listed subpart, as well as ASME B31.8S, in identifying high- and moderate-consequence areas, base-line assessments and re-assessment intervals, threats, preventative and mitigation measures, quality assurance measures, performance measures and continual improvement, record keeping and management, communication plans, and employee training plans. PHMSA frequently audits this plan, including most recently in 2023 during the Beluga Pipeline System Audit.

Q. Why does ENSTAR propose to accelerate the replacement of transmission facilities?

A. Since the addition of Subpart O in 2003, ENSTAR collects and evaluates data related to the transmission system and creates action plans to address system risks as required by ENSTAR's TIMP. Originally, the TIMP focused specifically on high-consequence areas, but as the pipeline industry's and PHMSA's knowledge of pipeline systems has

evolved, pipeline operators have expanded their programs to evaluate the full length of their pipelines. As ENSTAR's TIMP matures alongside developments in the pipeline industry, the Company designates additional pipeline segments for replacement that were previously not identified at the appropriate priority or risk level that we now know are necessary to maintain a reliable system.

The transmission system is the backbone of ENSTAR's gas delivery system. If any portion of it were to fail, the effects would be catastrophic to our customers. ENSTAR's transmission system delivers natural gas to all gas-fired power plants in southcentral Alaska, as well as to all of ENSTAR's pressure regulator stations that ultimately deliver gas to our Gas Sales customers. A failure in the transmission system could lead to large-scale gas outages for ENSTAR's customers and power outages due to loss of power plant generation fuel.

Considering the consequences of a transmission line failure, ENSTAR has identified higher threat projects required to continue operating a reliable transmission system. To collect data for its TIMP plan ENSTAR completes certain maintenance tasks such as: (1) periodic direct assessment or internal tool survey (pigging); (2) annual high consequence area (HCA) and moderate consequence area (MCA) monitoring; and (3) annual transmission system leak surveys. As a result of TIMP findings, the following key projects were proposed to support pipeline integrity and address risks related to corrosion, river erosion, and system capacity.

Q. Please highlight key transmission projects in the program.

A. Examples of projects within the program are:

- **Beluga Pipeline Directional Drills in the Theodore River and Susitna River East Channel**: The Beluga pipeline was installed in 1984 and serves the Matanuska Valley. It carries approximately one-third of the gas supplied to Anchorage. These two directional drill projects—one in the Theodore River and the other in the Susitna River East Channel—are similar to a directional drill project the Company completed in the Beluga River in 2015, in which river erosion had caused pipeline exposure along the bottom of the river. In the Theodore River, the 20-inch pipeline has become extremely shallow and sometimes even exposed depending on the flow of sediment at any given time during the year. This poses tremendous risk to the pipeline because of the potential that it could be struck by debris or ice in the river, which could compromise the integrity of the line. ENSTAR proposes directionally drilling a new crossing of the river to re-establish adequate depth under the riverbed and locate the tie-ins far enough away to prevent future exposures.

For the Susitna East Channel directional drill, ENSTAR has been monitoring river bank erosion since the 2006 installation of a new river crossing, and has determined that actions are required to maintain pipeline safety under the river. At the time of the 2006 relocation, the riverbank was approximately 1,850 feet away and the project successfully completed the longest 20-inch directional drill to date in the state of Alaska. Today, there are approximately 1,000 feet between the tie-in location and the current riverbank. Because erosion is not a linear function and is impossible to predict, ENSTAR proposes to complete a

directional drill to relocate the pipeline to a more stable location that is far enough back to eliminate this threat of continued erosion.

- **Westside Feeder Tidelands Relocation**: The Westside Feeder pipeline was installed in 1976 and feeds regulator stations serving southwest Anchorage west of Old Seward and C street and terminates at Chugach Electric's Southcentral Power Plant. The pipeline currently runs through the Turnagain Arm tide flats, which is an area that is difficult to cathodically protect—which means that the possibility of corrosion-related anomalies is high. A 2018 in-line inspection revealed 37 metal loss corrosion indications and a dent. Although these indications do not trigger immediate repairs, they increase the risk of failure, as they lead to points of higher stress and lower overall pipe strength. The pipeline is also tape-wrap coated, which can create a shielding effect to our cathodic protection methods. This can prohibit the electrical current from reaching ground and completing the flow of electricity, which is a key component to cathodic protection. When these factors are combined with the environmental sensitivity and extreme measures required to complete any construction in the area, ENSTAR has identified this pipeline segment as a strong candidate for relocation.
- **Bragaw Line Replacement**: Originally installed in the 1960s, the Bragaw Pipeline provides critical supply to the Providence and Alaska Native Medical Hospital systems, the University of Alaska Anchorage, downtown Anchorage, and neighborhoods in northern and northeast Anchorage. The pipeline was originally installed directly under the driven roadway through Mountain View and for much of Bragaw Street, then through the University of Alaska Anchorage greenbelt and

along Elmore Road to Tudor Road. Similar to the Westside Feeder, the pipe is tape-wrap coated and susceptible to cathodic protection shielding. Additionally, its installation location under the driven roadway has made the pipe and coating susceptible to years of excavation damage. ENSTAR has remediated this as much as possible by recoating exposed sections when the opportunity presents itself, but if excavators did not report any coating damage, ENSTAR could not repair it. ENSTAR has already replaced a 3,000-foot section of this pipeline through the University greenbelt due to a leak and numerous large anomalies that were detected along the pipe. It is also difficult to monitor the pipeline's condition because it is unable to be in-line inspected due to the fittings and original construction materials used. This project would allow ENSTAR to bring this critical pipeline up to modern standards, allow for better monitoring and more reliable operation, and potentially increase the operating pressure to allow for a greater throughput as ENSTAR's system grows.

Q. What other types of projects are planned for the RIRP?

A. The projects identified under the RIRP are generally for pipeline segments that previously had not been given appropriate weight in the Company's TIMP. For example, the Westside Feeder and Beluga Pipeline projects listed above are in Class 1 areas and would not have been identified as segments requiring action under the original version of our TIMP plan, even though they have near-equal outage consequences to other areas that are defined as high-consequence. Other projects generally are also located in areas that federal TIMP requirements define as lower-

consequence, but would require immediate action if they were given equal weight as the higher priority sections.

Q. How will the Company prioritize transmission replacement projects under the RIRP?

A. In general, ENSTAR will follow the same basic process that it uses with other types of projects: the Company will review multiple factors and sources of data to determine the priority of replacements within the system. Primarily, ENSTAR will follow its continuously improving TIMP and identify projects in alignment with the actions required to maintain a reliable system. Additionally, the Company will consider various other factors, including: changing pipeline conditions; environmental conditions; and customer growth and demands impacting system performance. A team of subject matter experts within ENSTAR will meet at least once per year to evaluate these factors and sources of data and identify the most pressing, high-priority replacement projects.

Q. Are the infrastructure replacements proposed under the RIRP reasonable and prudent?

A. Yes. ENSTAR's RIRP is a reasonable, prudent, and necessary plan to reduce the risks associated with this aging, higher-risk infrastructure and enhance the safety and reliability of the Company's system.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Nathan T. Burke

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, AK: 2023 – Present

Manager of Infrastructure and Planning

Mechanical Builders Inc., Anchorage, AK: 2021 – 2023

General Manager

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, AK: 2012 – 2021

Supervisor Construction and Maintenance: 2015 – 2021

Engineer: 2012 – 2015

EDUCATION

University of Washington: Master of Business Administration, 2021

University of Alaska Fairbanks: Bachelor of Science, Mechanical Engineering, 2012

OTHER

Registered Professional Mechanical Engineer (AK), 2016 - Present

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chairman
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Consideration of the Revenue Requirement Designated as TA 354-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF ABIGAIL L. RIGGS

PREFILED DIRECT TESTIMONY
OF
ABIGAIL L. RIGGS

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EXHIBITS

Exhibit ALR-1 Resume of Abigail L. Riggs
Exhibit ALR-2 Cost Allocation Manual

I. POSITION AND QUALIFICATIONS

Q. Please state your name, business address and present position.

A. My name is Abigail L. Riggs. My business address is 3000 Spenard Road, Anchorage, AK 99503. I am the Vice President of Finance for ENSTAR Natural Gas Company, LLC ("ENSTAR") and Alaska Pipeline Company, LLC ("APC"). I am appearing in this proceeding on behalf of ENSTAR and APC. ENSTAR and APC are wholly owned subsidiaries of TriSummit Utilities Inc. ("TSU"). For convenience, I will refer to ENSTAR and APC together as "ENSTAR" or the "Company." [1]

Q. Briefly describe your professional experience and educational background.

A. I have been employed by ENSTAR since 2023. Before joining ENSTAR, I worked for two Alaska Native Regional Corporations as a Controller, Director of Finance, and Senior Tax Accountant. Prior to my work in industry, I worked in public accounting for five years while obtaining my Certified Public Accountant license, which I have maintained. My educational background includes a Master of Business Administration with an emphasis in Capital Markets and a Bachelor of Business Administration with a major in Accounting, both from the University of Alaska Fairbanks. My resume is attached as Exhibit ALR-1.

Q. Have you previously testified before the Regulatory Commission of Alaska ("RCA" or "Commission") or any other regulatory commission?

A. No, I have not.

[1] The Commission regulates APC and ENSTAR as a single entity. The use of the name "ENSTAR" or "Company" in this filing is intended to include both APC and ENSTAR, unless the context clearly requires otherwise.

II. PURPOSE OF DIRECT TESTIMONY AND BACKGROUND

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to address five topics. First, I describe ENSTAR's accounting procedures and Cost Allocation Manual ("CAM"), which establishes the procedures the Company uses to assign and allocate costs to certain affiliates, and I present the costs the Company allocated to these projects and entities during the test year. Second, I discuss the manner in which ENSTAR receives debt financing. Third, I explain ENSTAR's method for calculating its cost of debt. Fourth, I support ENSTAR's accumulated deferred income taxes ("ADIT") on the books. Finally, I support ENSTAR's proposed adjustment for pension costs on Schedule L of Attachment B to TA354-4.

III. ACCOUNTING POLICIES AND PROCEDURES

Q. Please describe ENSTAR's accounting procedures.

A. ENSTAR's accounting books and records are maintained in accordance with the Uniform System of Accounts ("USOA") prescribed by the Federal Energy Regulatory Commission ("FERC") and required by this Commission pursuant to 3 AAC 48.277(a)(5). Internal controls are in place to assure compliance with the applicable accounting instructions, including internal and external audit functions that are performed by two public accounting firms. For internal reporting purposes, ENSTAR uses a more detailed chart of accounts than is prescribed by the USOA, but the Company's accounting system summarizes the accounts into categories that match the USOA. These accounting records are consistent with prior presentations of similar data to the Commission.

Q. Does ENSTAR have in place accounting procedures that address the assignment and allocation of costs between the Company and its affiliates?

A. Yes. In my testimony, I will focus on the CAM, which applies to ENSTAR and Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA") and includes policies and procedures for allocating costs between the companies, among other things. The CAM is attached to my testimony as Exhibit ALR-2.

ENSTAR witness Ms. Andrea D. Jackson discusses the allocation of costs between TSU and ENSTAR for the corporate services TSU provides to the Company.

Q. Please describe the CAM applicable to CINGSA and ENSTAR.

A. The CAM was developed to specify the procedures that ENSTAR uses to assign and allocate costs among the projects and entities for which ENSTAR provides services. It describes the allocation methodology for internal work orders and reimbursable construction projects. For accounting purposes in relation to cost allocations, ENSTAR treats CINGSA like a reimbursable construction project.

The CAM was originally written to address internal accounting policies and procedures. The CAM is updated on an as-needed basis to reflect changes to accounting policies and procedures. It was most recently updated in 2025 primarily to reflect changes as to which entity performs certain accounting functions.

The CAM has been presented to support affiliate costs in past cases (Docket Nos. U-16-066 and U-22-081) where the Commission has not ordered disallowances of such costs.

Q. Please describe the eligible cost allocations transferred to CINGSA during ENSTAR's test year.

A. ENSTAR incurred a total of $36,794,501 of administrative and general ("A&G") expenses during the test year, which is the twelve-month period ending December 31, 2024. Of this amount, $13,572,677 was allocated to ENSTAR (including APC) construction, CINGSA, and reimbursable construction (referred to below as "RC jobs"). Therefore, a total of approximately $13.6 million of test year A&G expenses are not included in ENSTAR's operating expenses. Table 1 below details the A&G costs allocated during the test year.

Table 1

Total A&G Expense (Gross)	$ 36,794,501
A&G Allocated:	
To ENSTAR Construction	$ (8,485,497)
To APC Construction	$ (1,961,635)
Allocated to CINGSA	$ (1,985,054)
Allocated to RC Jobs	$ (1,140,492)
Net A&G	**$23,221,824**

Q. Were the allocations described above performed consistent with the CAM?

A. Yes, the allocations during the test year were performed consistent with the CAM.

IV. LONG-TERM DEBT FINANCING

Q. How does ENSTAR finance its long-term debt?

A. ENSTAR does not issue third-party debt. It obtains long-term debt through intercompany financing. TSU, which is ENSTAR's ultimate indirect parent, is a reporting issuer and accesses the debt capital market to fulfil the funding needs for its investments. ENSTAR's long-term debt is determined in light of its capital expenditure

requirements and capital structure. The expense incurred related to the debt financed was recorded on ENSTAR's books as capitalized debt expense costs and amortized over the term of the loan.

Q. Has ENSTAR's debt changed since the last rate case?

A. Yes. In March 2023, in conjunction with the close of the transaction where TSU became ENSTAR's ultimate indirect parent, ENSTAR entered into intercompany loan agreements for new debt holdings.

Q. How much debt was on ENSTAR's books at the end of the test year?

A. As of December 31, 2024, ENSTAR had $163,683,558 in long-term debt on its books.

V. COST OF DEBT

Q. What is the cost of long-term debt that ENSTAR is proposing in this proceeding?

A. ENSTAR follows the same method it has used to calculate its cost of debt in prior proceedings, which the Commission has routinely approved. Using this method to calculate the cost of long-term debt, ENSTAR performs the following steps:

- First, the Company calculates its outstanding debt costs. This calculation nets the December 31, 2024 balance of outstanding notes and unamortized debt expense on required debt to arrive at a balance of $163,683,558.
- Second, ENSTAR calculates the interest expense for all tranches of its debt for the test year by taking the debt interest rates of 5.34%, 5.38%, and 5.41%, respectively, and applying them to the December 31, 2024 outstanding balance of the tranches, $50,000,000, $25,000,000, and $90,000,000, respectively. Next, ENSTAR adds the test-year amortization cost of the debt expense to the interest expense of the various tranches to arrive at an annual interest expense of $9,088,882.

- Finally, the total interest expense $9,088,882 is divided by the December 31, 2024 outstanding debt $163,683,558, which results in an overall embedded cost of debt of 5.55%.

VI. ACCUMULATED DEFERRED INCOME TAXES

Q. What is ADIT?

A. ADIT is the amount of income taxes the utility has accrued on past and current earnings but has not yet had to pay to the government. ADIT arises from differences in the methods of computing taxable income versus the earnings on the financial statement. Depreciation is typically the main component of ADIT. ADIT associated with depreciation results because of differences due to the amount of depreciation expense recovered in a utility's rates versus the amount of depreciation deductions that the utility can claim for tax purposes.

Q. What ADIT are included in this rate case filing?

A. The treatment of ADIT for ratemaking depends on whether it is a deferred tax liability or a deferred tax asset. Deferred tax liabilities normally reduce rate base so that customers receive the benefit of the utility receiving earlier tax depreciation deductions than book depreciation deductions. Deferred tax assets, where taxes are paid prior to being recorded on the books, normally increase rate base. All of the ADIT recorded on ENSTAR's books during the test year was treated this way, with there being no adjustments on ENSTAR's 275(a) filing.

Q. How was the ADIT included in this rate filing computed?

A. When TSU acquired the assets of ENSTAR in 2023, the ADIT liability then on ENSTAR's books was eliminated because the sale of assets required the seller to pay the taxes that had been deferred. Under TSU's ownership, the acquired assets are again

being depreciated by ENSTAR using accelerated methods for tax purposes and straight-line for book purposes, which has resulted in new ADIT being created and recorded on ENSTAR's books. This accounting treatment of ADIT is consistent with both the FERC Uniform System of Accounts and Generally Accepted Accounting Principles ("GAAP"). The ADIT that has been included in this rate filing has been computed to: (1) include regulatory accounting versus tax differences that have occurred since TSU's acquisition; and (2) ensure the ADIT represents no more income taxes than ENSTAR has deferred due to accelerated tax depreciation (the interest-free loan from the government).

VII. PENSION EXPENSES

Q. Please describe ENSTAR's proposed adjustment for pension expenses.

A. ENSTAR proposes an adjustment for costs associated with pension expenses allocated to the Company, which appears on Schedule L of ENSTAR's 275(a) filing. ENSTAR has pension plans that cover approximately one third of its employees. Given the volatility in the assumptions underlying the pension expense (the discount rate and asset return), test year expenses are not representative of costs going forward. Instead, it is more appropriate to look at the five-year average of pension expenses as opposed to the 2024 expense. Therefore, based on the five-year average of pension expense, I am proposing an adjustment in the pension expense of $78,181, of which $29,274 would be allocated to reimbursable construction and $48,907 would be allocated to administrative and general. This adjustment is set forth in Schedule L to the 275(a) filing.

VIII. CONCLUSION

Q. Is ENSTAR's allocation of costs to CINGSA and other projects and entities reasonable and consistent with the CAM?

A. Yes. ENSTAR's allocations of costs to CINGSA and other projects and entities for which the Company provides services are reasonable and consistent with the policies and procedures set forth in the CAM.

Q. Is the manner in which ENSTAR receives debt financing reasonable?

A. Yes. It is reasonable for ENSTAR, which obtains debt financings through intercompany borrowings.

Q. Is ENSTAR's method for calculating its cost of debt reasonable?

A. Yes. The Company's method for calculating the cost of debt is reasonable, and is the same method that the Company has used and the Commission has approved in prior proceedings.

Q. Is ENSTAR's ratemaking for deferred taxes reasonable?

A. Yes. ENSTAR's ADIT recorded on its financial statement and included in the 275(a) filing are accurate.

Q. Is ENSTAR's proposed adjustment for pension expenses reasonable?

A. Yes. The Company's proposed adjustment for pension expenses is reasonable. Due to the volatility in the assumptions underlying ENSTAR's pension expense, test year expenses are not representative of the costs the Company will likely incur going forward. A five-year average of pension expenses is more appropriate in this proceeding.

Q. Does this conclude your direct testimony?

A. Yes.

Abigail L. Riggs

EMPLOYMENT

ENSTAR Natural Gas Company, LLC/Alaska Pipeline Company, LLC:

Vice President of Finance, March 2023 – Present

Brice, Inc.

Construction Controller, August 2020 – March 2023

Doyon, Limited

Finance Director, May 2018 – August 2020

Senior Corporate Tax Accountant, November 2015 – May 2018

RJG, A Professional Corporation, Certified Public Accountants

Senior Accountant, September 2010 – November 2015

EDUCATION

University of Alaska Fairbanks

Master's in Business Administration w/ an emphasis in Capital Markets, December 2011

Bachelor of Business Administration in Accounting, May 2010

OTHER

Certified Public Accountant, Alaska

American Institute of Certified Public Accountants, member

COST ALLOCATION MANUAL

Guidelines for Cost Allocations to/from ENSTAR Natural Gas Company, LLC. to Construction Projects and Related Companies

Updated: 12/19/2024

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Introduction

This Cost Allocation Manual (CAM) was developed to specify the procedures that ENSTAR Natural Gas Company, LLC (ENSTAR) uses in assigning and allocating costs among the projects and entities for which ENSTAR provides services. This includes Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA).

CINGSA is a regulated underground gas storage utility located in Kenai, Alaska. CINGSA provides working gas storage to both Firm Storage Service (FSS) and Interruptible Storage Service (ISS) customers, including ENSTAR. CINGSA is 100% owned by Alaska Storage Holding Company LLC, of which TSU-CINGSA Storage Company is a 65% member. TSU-CINGSA Storage Company is an indirect wholly-owned subsidiary of TriSummit Utilities Inc. (TSU) while ENSTAR is an indirect wholly-owned subsidiary of TSU, thus ENSTAR and CINGSA are affiliates.

CINGSA has an operating agreement with ENSTAR. The agreement allows ENSTAR to perform all activities necessary to operate and maintain CINGSA. The agreement specifies that CINGSA will provide reimbursement for all authorized, reasonable and necessary expenses incurred by ENSTAR in the performance of its duties. Such reimbursement shall include only the actual costs of the services provided, including reasonable overhead, benefits and tax loading, without any additional fees or charges.

ENSTAR uses a work order accounting system, which is capable of identifying, segregating and accumulating costs to specific work orders. ENSTAR allocates indirect expenses (administrative & general and construction overhead) to construction activities on a monthly basis. For allocation purposes, CINGSA is treated as a reimbursable construction project.

The allocation methodology for reimbursable construction projects is audited by the State of Alaska Department of Transportation and Public Facilities (AK-DOT) each year, and rates are set for each year based on prior year actual financial results. The State of Alaska uses the criteria in 23 CFR 1-645, Highways and 48 CFR 31, Federal Acquisition Regulations (FAR) to determine the acceptability of ENSTAR's accounting system and allowable costs.

The allocation methodology for internal construction projects is based on actual financial results for the current year. The methodology uses the same formulas as the allocation methodology for reimbursable construction and CINGSA, only without the one-year lag in rates that is inherent in the State's auditing and rate-setting program.

Per the National Association of Regulatory Utility Commissioners (NARUC) Guidelines for Cost Allocations and Affiliate Transactions, the purpose of a Cost Allocation Manual (CAM) is to:

- Describe the organizational structure of the entity and its affiliates, stating whether the organization is regulated or non-regulated,
- Describe the assets, services and products provided to and from the entity and each of its affiliates,
- Describe the assets, services and products provided by the entity to non-affiliates, and
- Describe the cost allocations and methods used by the entity and its affiliates.

The following sections describe the organization structure, services provided to/from ENSTAR, CINGSA and affiliates, and the allocation methodology for specific types of costs. In each case the costs are allocated to internal projects based on current year rates, and to reimbursable construction and CINGSA based on prior year rates.

Corporate Organization

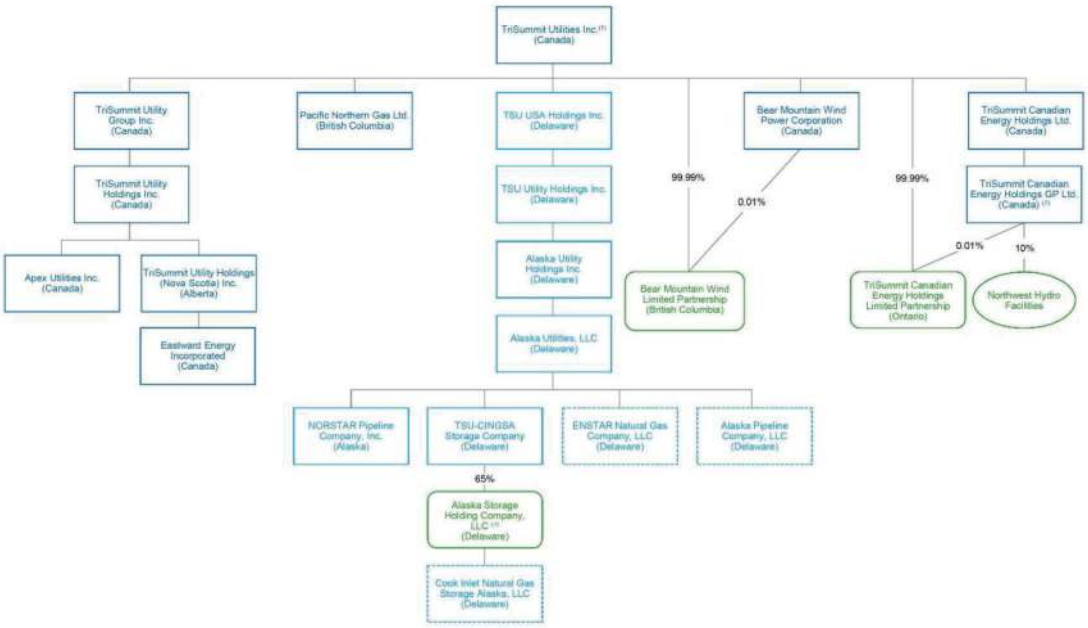
The following is a brief description of the pertinent organizational structure in relation to ENSTAR and CINGSA. An organizational chart is shown on the following page.

TSU, a Canadian corporation located in Calgary, AB, owns and operates rate-regulated distribution and transmission assets and long-term contracted renewable power generation assets. TSU indirectly owns 100% of Alaska Utilities, LLC (AUL) which owns 100% of ENSTAR, Alaska Pipeline Company, LLC (APC) and TSU-CINGSA Storage Company.

ENSTAR is a natural gas distribution utility that supplies purchased gas to its residential and commercial customers in the Cook Inlet area. ENSTAR also delivers gas owned by other commercial, industrial and utility customers that is received on the APC transmission system. ENSTAR and APC are regulated by the Regulatory Commission of Alaska as a single entity.

Norstar Pipeline Company, Inc. (Norstar), located in Anchorage, AK, is a wholly-owned subsidiary of AUL. Norstar provides utility-related contractual services in the Cook Inlet area. Norstar is a non-regulated company.

TSU-CINGSA Storage Company, headquartered in Anchorage, AK, is a wholly-owned subsidiary of Alaska Utilities, LLC. TSU-CINGSA Storage Company holds a 65% ownership in Alaska Storage Holding Company LLC, which in turn owns 100% of Cook Inlet Natural Gas Storage Alaska LLC. The other members of ASHC are Alaska Gas Transmission Company, LLC, a subsidiary of Berkshire Hathaway Energy, (26.5%), and CIRI-CINGSA Holding (8.5%). ASHC financed the construction and owns Cook Inlet Natural Gas Storage Alaska, LLC. TSU-CINGSA and ASHC are non-regulated companies, while CINGSA is regulated by the Regulatory Commission of Alaska.


TriSummit Utilities Inc.
(Canada)
TriSummit Utility Group Inc.
(Canada)
Pacific Northern Gas Ltd.
(British Columbia)
TSU USA Holdings Inc.
(Delaware)
Bear Mountain Wind Power Corporation
(Canada)
TriSummit Canadian Energy Holdings Ltd.
(Canada)
TriSummit Utility Holdings Inc.
(Canada)
TSU Utility Holdings Inc.
(Delaware)
99.99%
0.01%
99.99%
TriSummit Canadian Energy Holdings GP Ltd.
(Canada)
0.01%
10%
Alaska Utility Holdings Inc.
(Delaware)
Apex Utilities Inc.
(Canada)
TriSummit Utility Holdings (Nova Scotia) Inc.
(Alberta)
Bear Mountain Wind Limited Partnership
(British Columbia)
TriSummit Canadian Energy Holdings Limited Partnership
(Ontario)
Northwest Hydro Facilities
Alaska Utilities, LLC
(Delaware)
Eastward Energy Incorporated
(Canada)
NORSTAR Pipeline Company, Inc.
(Alaska)
TSU-CINGSA Storage Company
(Delaware)
ENSTAR Natural Gas Company, LLC
(Delaware)
Alaska Pipeline Company, LLC
(Delaware)
65%
Alaska Storage Holding Company, LLC
(Delaware)
Cook Inlet Natural Gas Storage Alaska, LLC
(Delaware)

Description of Services

The following section provides a description of the regulated services provided by ENSTAR, APC and CINGSA. Each description identifies the types of costs associated with each service or business activity, and identifies the business area or department which offers the service.

GAS UTILITY

Gas – Residential, Commercial & Industrial

This represents the provision of natural gas service to customers within ENSTAR's service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M, A&G costs and depreciation costs. These costs reside within the ENSTAR/APC regulated utility.

Gas – Large Firm Transportation

Large firm gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby ENSTAR/APC transports gas owned by others over ENSTAR/APC's gas pipeline system. Costs associated with this service primarily include facilities O&M, depreciation, and A&G costs. These costs reside within the ENSTAR/APC regulated utility.

Gas – Storage

Gas storage service represents the injection, storage and withdrawal of customer-owned natural gas in the CINGSA storage facility. Costs associated with this service primarily include facilities O&M, depreciation, and A&G costs. These costs reside within the CINGSA regulated utility.

Transactions with Affiliates

OVERVIEW

The sections below separately detail the nature and terms of transactions for services and asset transfers provided by ENSTAR to its affiliates, including CINGSA, as well as services and asset transfers provided to ENSTAR by each of its affiliates.

ENSTAR receives corporate governance, business oversight, financing, planning, administrative, legal, accounting, regulatory and other support services from TSU. ENSTAR is not billed directly for these shared corporate services, but is charged a shared services allocation. The allocations are calculated using the Modified Massachusetts Formula (MMF), which has been approved by the regulatory commission in Alaska.

ENSTAR provides administrative, management, accounting, regulatory, and other support services to CINGSA. ENSTAR employees also manage the direct operations of CINGSA. ENSTAR employees who perform direct operations and maintenance services charge their time directly to CINGSA accounts in the J.D. Edwards accounting system (JDE), and the actual labor costs are billed to CINGSA on a monthly basis. An additional charge for A&G overhead is added to the direct labor costs in order to cover administrative and other support services. The A&G rate is based on the overhead rate determined by the State of Alaska each year for reimbursable construction projects (as detailed in later sections of this CAM). The operating agreement between CINGSA and ENSTAR does not allow for management fees other than actual costs plus reasonable overhead.

SERVICES PROVIDED BY ENSTAR/APC TO AFFILIATES:

CINGSA

Operations and Maintenance: All activities related to operation and maintenance of the storage facility in accordance with the terms of the operating agreement.

Materials and Supplies: Materials and supplies that are not otherwise procured directly by CINGSA. These materials do not normally go through the ENSTAR warehouse, and thus do not include stores loading. In the rare event that inventory is issued to CINGSA from ENSTAR's warehouse, it would include stores loading.

Executive Management Services: Executive management and services, including, but not limited to, officers of ENSTAR.

Legal: Legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other legal matters.

Risk Management Services: Claims services related to casualty, public and company claims.

Corporate Communications: Provides corporate communications and coordinates media services. Provides advertising and branding development. Manages and tracks all contributions made on behalf of ENSTAR and CINGSA.

Employee Communications: Develops and distributes communications to employees.

Corporate Strategy & Business Development: Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements.

Government Affairs: Monitors, reviews and researches government legislation.

Human Resources: Establishes and administers policies related to employment, compensation and benefits. Maintains HR computer system, the tuition reimbursement plan and other employee programs. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.

Finance & Treasury: Coordinates activities related to cash management and financial analysis.

Accounting: Maintains the books and records. Prepares financial and statistical reports and ensures compliance with the applicable laws and regulations. Maintains accounting systems.

Budgeting: Provides financial analysis and budgeting support.

Receipts Processing: Processes payments received from customers and related reporting.

Rates & Regulatory: Determines the regulatory strategy, revenue requirements and rates for storage customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.

Business Systems: Provides basic information technology services such as: application management, voice and data network operations and management, and systems management.

Miscellaneous: Miscellaneous other charges as needed.

ALASKA PIPELINE COMPANY

ENSTAR is regulated together with APC as a single entity. ENSTAR provides all labor and materials required for APC's operation. ENSTAR charges APC for labor, materials and other charges through intercompany transactions using JDE.

NORSTAR

ENSTAR provides all labor and materials required for Norstar's operation. ENSTAR charges Norstar for labor, materials and other charges through intercompany transactions using JDE.

SERVICES PROVIDED BY AFFILIATES TO ENSTAR/APC AND CINGSA:

TriSummit Utilities Inc.

Board of Directors: Provides strategic direction and ensures compliance with all disclosure and corporate governance requirements.

Executive Committee: Provides strategic management oversight and direction on various matters including regulatory, safety, stakeholder relationships, environmental, social and corporate governance, financial planning, equity and debt capital access, investment strategy, business and capital risk management,

organizational structure, establishes effective company-wide governance models and internal controls standards and procedures to drive efficiencies and cost effectiveness

Accounting, Tax and Finance: Prepares consolidated financial statements and coordinates with external auditors for the annual audit and quarterly reviews of TSU's consolidated financial statements, which is needed for access to capital. Also provides services associated with treasury and cash management, rating agencies management, planning and budgeting, insurance, tax, internal audit, enterprise risk management, and stakeholder relations and communications.

Corporate Resources (including legal and compliance): Provides legal and corporate secretarial services, regulatory and other advice and expertise to its subsidiaries by maintaining regular communications with all business functions to ensure effective management of legal matters. Also develops guidelines and policies regarding the code of business ethics and related core policies and maintain compliance of such matters across the organization. Develops employee outreach communications, learning and development and talent management; maintains corporate office space. TSU staff also provides support for executives and employees compensation plan design, retirement savings and benefits management.

CINGSA

Gas Storage Service: CINGSA provides both firm and interruptible natural gas storage services to ENSTAR.

COST ASSIGNMENT AND ALLOCATION PROCESS

OVERVIEW

This section of the CAM provides an overview of the cost assignment and allocation principles of ENSTAR and the accounting processes within the monthly accounting close and within the JD Edwards (JDE) general ledger system, including both system-generated processes and manual processes, used to assign and allocate costs between the business activities of ENSTAR, APC and CINGSA. Each major step is identified in the following pages and explained in conjunction with the flowchart on page 11. Each major step results in costs being either directly assigned or allocated to business units within the affiliated companies.

CINGSA has its own set of books that are maintained on JDE. While ENSTAR does directly charge some items to CINGSA (as explained later in this manual), ENSTAR provides administrative, management, accounting, regulatory and other support services to CINGSA in order to fulfill its commitment to operate and maintain the facility. ENSTAR employees who perform direct operations and maintenance services charge their time directly to CINGSA accounts in JDE, and the actual labor costs are billed to CINGSA on a monthly basis. ENSTAR allocates payroll burden to CINGSA each month using a calculated rate involving total burden and total gross payroll. An additional charge for A&G overhead is added to the direct labor costs in order to cover administrative and other support services. ENSTAR also allocates a portion of construction overhead to CINGSA construction projects (based on direct labor charged to projects) when applicable. In rare situations ENSTAR may allocate stores and transportation loading to CINGSA as well.

The A&G and construction overhead rates that ENSTAR uses in the allocations described above are based on the overhead rate for reimbursable construction projects audited by the State of Alaska Department of Transportation and Public Facilities (AK-DOT) each year. Rates are set for each year based on prior year actual financial results. The State of Alaska uses the criteria in 23 CFR 1-645, Highways and 48 CFR 31, Federal Acquisition Regulations (FAR) to determine the acceptability of ENSTAR's accounting system and allowable costs. The most recent audit report from AK-DOT is included in Appendix A.

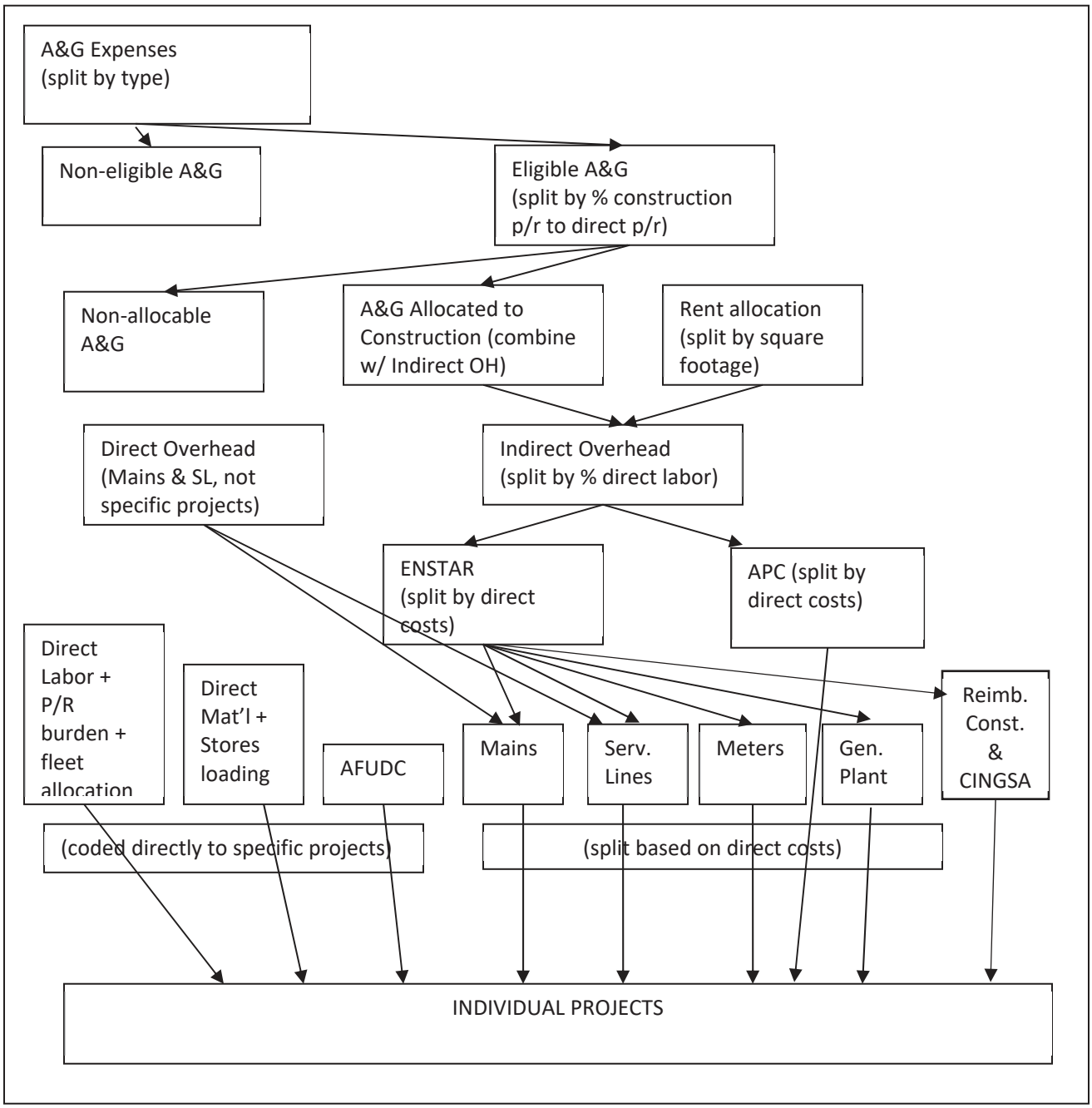
COST ASSIGNMENT AND ALLOCATION PRINCIPLES

ENSTAR applies the following hierarchical cost assignment and allocation principles:

1. Tariffed rate shall be used to value tariffed services provided.
2. Costs shall be directly assigned to the specific business unit whenever possible.
3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost-causation.
4. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

COST ALLOCATION PROCESS

The following flowchart summarizes the flow of project costs through ENSTAR's accounting systems. Details regarding the methodology for each step of the flowchart are in subsequent sections.



Allocation of Administrative & General Expenses

Eligible administrative & general ("A&G") expenses are based on Regulatory Commission of Alaska (RCA), Federal Energy Regulatory Commission (FERC), FAR, and AK-DOT guidelines, rules and regulations. The basis for selecting the eligible accounts is their relationship to the normal operating functions of the utility. Some accounts are analyzed and split into eligible and non-eligible expenses based on the nature of the specific charges to the account. Accounts that are currently analyzed and split, and the determination of which expenses are eligible, include but are not limited to:

Object Account / Description	**Determination of eligibility**
Employee Other Benefits	Wellness program, CDL expenses are eligible; holiday party, coffee supplies are not eligible.
Office supplies	Supplies related to regular business activity are eligible.
Office – contract labor	Charges for office temporary labor are eligible.
Legal	Charges related to general business, such as human resources or rate case issues are eligible. Charges related to litigation are not eligible.
Insurance	Charges for general liability. Charges for Directors & Officers policy and other policies are not eligible.
Advertising	Charges for educational and safety materials, such as statement inserts and 811 promotion are eligible. Charges for company promotion are not eligible.

The following is a partial list of A&G accounts and their eligibility:

JDE Object Account	Description	Eligibility
76100	Salaries	Eligible - Labor
76110	Commissions & Bonuses	Eligible - Labor
76136	Bonuses - LTIP	Eligible - Labor
76215	Benefit Admin Fees	Eligible - Benefits
76220	Medical & Dental - Salary	Eligible - Benefits
76221	Medical & Dental - Union	Eligible - Benefits
76250	Employer 401K Match	Eligible - Benefits
76251	Union 2% Profit Sharing	Eligible - Benefits
76260	Retiree Medical	Eligible - Benefits
76270	Life, AD&D, LTD	Eligible - Benefits
76280	Pension - Defined Benefit	Eligible - Benefits
76310	Employee Relations	Not eligible
76320	Employee Awards	Not eligible
76330	Relocation	Not eligible
76380	Community Relations	Not eligible
76390	Employee Other Benefits	Split
76410	Office Supplies	Eligible - Expense
76420	Telephone	Eligible - Expense
76430	Postage & Shipping	Eligible - Expense
76440	Computer Expenses	Eligible - Data Processing
76445	Licensees & Maint. Agreements	Eligible - Data Processing
76447	Office Expenses - SaaS	Eligible - Data Processing
76490	Building Maintenance	Eligible - Expense
76510	Ground Travel	Eligible - Expense
76520	Air Travel	Eligible - Expense
76530	Lodging	Eligible - Expense
76540	Meals & Ent-Out of Town	Eligible - Expense
76550	Meals & Ent-Other	Not eligible
76570	Training	Eligible - Expense
76580	Conferences	Eligible - Expense
76600	Dues & Subscriptions	Eligible - Expense
76620	Membership Dues - Other	Not eligible
76710	Parent Allocations	Eligible - Expense
76712	Reg Support Parent Allocation	Eligible - Expense
76720	Consulting	Split
76730	Legal	Split
76740	Accounting	Eligible - Audit
76750	Other Professional Services	Split
76810	General Liability Insurance	Eligible - Gen Liability Insurance
76811	General Liability Self Insured	Split
76821	Property Insurance	Eligible - Property Insurance

76840	Bonds	Not eligible
76870	Other Insurance	Not eligible
76910	Regulatory Expenses	Eligible - Expense
76930	Advertising	Split
76935	Job Recruit	Eligible - Expense
76950	Rent	Eligible - Expense
76965	Safety Expenses	Eligible - Expense
76985	Discounts Taken/Lost	Not eligible

Once the eligible A&G is determined, the A&G allocable to ENSTAR/APC construction and CINGSA is calculated. The ratio of total construction payroll (including Norstar) plus CINGSA direct labor, to total direct payroll determines the percentage of eligible A&G that can be allocated.

To determine total direct payroll, A&G salaries are subtracted from total gross payroll. Salaries for Directors in Operations and Engineering that were charged to indirect payroll are added back. Finally, payroll accruals are removed.

Total construction and CINGSA payroll is calculated by adding the payroll charged directly to CWIP (Construction Work-in-Process) projects, RWIP (Retirement Work-in-Process) projects, Reimbursable Construction, Damage Claims, payroll charged to Stores Expense Undistributed (Warehouse), Transportation (Vehicle Shop) allocated to CWIP, and payroll charged to CINGSA.

A&G is multiplied by the percentage of construction payroll (as calculated above) divided by total direct payroll. The following is an example of the A&G allocation and rate calculations:

ELIGIBLE A&G EXPENSES	
A&G Salaries, Burden, Benefits	14,308,497
Less Director's Payroll & Benefits	(4,820)
Eligible Expenses, Various Accounts	2,621,145
Total Eligible A&G Expenses	**16,924,822**

CALCULATION OF A&G ALLOCATION AND A&G RATE	
Gross Payroll	23,708,999
Charges To 76XXX (A&G salaries)	(5,320,338)
Exclude Ops Mgmt Gross Wage	2,505
Less Payroll Accruals	(2,852,479)
Total Direct Payroll	**15,538,687**

Activity Description	Direct Wages by Activity	% of Total Direct P/R[1]	A&G Expenses to Allocate[2]	A&G Rate[3]
ENSTAR CWIP	3,160,815	20.34%	3,442,776	108.92%
Damage Claims	92,156	0.59%	100,376	108.92%
Reimbursable Construction	635,594	4.09%	692,293	108.92%
APC CWIP	839,462	5.40%	914,346	108.92%
CINGSA	841,011	5.41%	916,034	108.92%
Norstar	46,367	0.30%	50,503	108.92%
Total Construction, CINGSA & Norstar	**5,615,404**	**36.14%**	**6,116,328**	**108.92%**
Total Indirect Payroll Charges	**773,282**	**4.98%**	**842,264**	**108.92%**
Total Gross Wages and Eligible A&G	**6,388,686**	**41.11%**	**6,958,592**	**108.92%**

[1]Direct Wages by Activity/Total Direct Payroll

[2](Total Eligible A&G Expenses) x (% of Total Direct P/R)

[3]Included in the AK-DOT audited rate referred to earlier in this CAM.

The A&G allocated to Enstar and APC internal construction projects is split between ENSTAR and APC based on the direct labor charges to each company, and added to Indirect Construction Overhead. It is then

allocated to specific activities via the Indirect Overhead Allocation methodology (see Allocation of Indirect Overhead in next section).

Allocation of Indirect Construction Overhead

ENSTAR allocates indirect construction overhead to internal construction projects and reimbursable construction projects.

Indirect construction overhead consists of costs related to ENSTAR and APC construction projects, but not to one particular project. Examples of indirect overhead costs include salaries, materials and supplies. These costs are accumulated in the following project accounts:

Project Number*	Description
4YY199000500	Enstar Engineering OH – Anchorage
4YY199000xxx	Enstar Distribution OH – Anchorage
4YY399000500	Enstar Engineering OH – Kenai
4YY399000xxx	Enstar Distribution OH – Kenai
4YY499000500	Enstar Engineering OH – Mat. Valley
4YY499000xxx	Enstar Distribution OH – Mat. Valley
5YY999000100	APC Engineering OH
5YY999000200	APC Distribution OH

*Project Number Key:

- First digit indicates Company (4=ENSTAR, 5=APC)
- Second and third digits indicate year
- Fourth digit indicates geographic area (1=Anchorage, 2=ER, 3=Kenai, 4=Mat Valley)
- Fifth and sixth digits indicate FERC type of job (76=Mains, 80=Serv. Lines, 99=Overhead)
- Seventh through tenth digits indicate specific project
- Last two digits indicate type and size of pipe, if applicable.

Charges to these projects (and all CWIP projects) are recorded in the general ledger in the following object accounts:

Object Account	**Description**
26100 – 26170	Labor
26410	Subcontract
26300	Materials / Supplies
26301	Other Costs (Rent & A&G Allocation)
26600	Permits
26210	Fleet
26220	Other clearing (Payroll Burden)

26610	AFUDC
26700	Other Capital Charges (Purchase-cards)

The allocation methodology for indirect overhead uses a ratio of CWIP direct costs by activity to total CWIP direct costs. This ratio is applied to the total of indirect overhead plus allocated A&G expenses (see A&G allocation section), and the result is allocated to the appropriate construction activities.

For example, the calculation of the amount of indirect overhead and A&G to allocate to internal construction projects is shown in the following example. The A&G Indirect Overhead portion is split between ENSTAR and APC based on direct labor dollars.

Project #	Description	Amount
416199000X00	Engineering OH-AN	240,755
416399000X00	Engineering OH-SK	6,756
416499000X00	Engineering OH-MV	21,275
416199000X00	Distribution OH-AN	698,417
416399000X00	Distribution OH-SK	232,728
416499000X00	Distribution OH-MV	180,186
516999000X00	Engineering OH-AN	430,619
		1,810,736
416999000100	A&G Allocation to Constr-ENSTAR	665,514
516999000300	A&G Allocation to Constr-APC	176,750
	A&G related to Indirect Constr OH*	842,264
	Total Indirect and A&G OH for Allocation	**2,653,000**

Calculation of Breakdown of A&G Related to Indirect Constr OH*:	Direct Wages	% to Total	Allocated Amount
APC Direct Wages	839,462	20.99%	176,750
Total ENSTAR Direct Wages	3,160,815	79.01%	665,514
Totals	**4,000,276**	**100.00%**	**842,264**

These amounts are allocated based on the ratio of direct costs by activity to total direct costs:

Activity Description	Total Direct Costs	% of Total Direct Costs	Indirect OH
Mains CWIP	2,679,981	40.76%	833,859
Services CWIP	2,203,356	33.51%	685,560
Meter Loop Assembly CWIP	1,506,837	22.92%	468,842
Other Eligible CWIP	184,385	2.80%	57,370
Total ENSTAR	6,574,559	100.00%	2,045,631
APC CWIP	1,442,464	100.00%	607,369
Total	8,017,022		2,653,000

This overhead allocation is added to the direct overhead allocation (see Allocation of Direct Overhead in next section) for total overhead, which is used to calculate the effective overhead rate. Note that the construction overhead rate used for damage claims, reimbursable construction and CINGSA is the AK-DOT audited rate, which is based on prior year amounts.

Activity Description	Total Direct Costs	ENSTAR/APC Eligible A&G	Indirect OH	Direct OH	Total OH	OH Rate*
Mains CWIP	2,679,981	1,403,376	833,859	1,095,691	3,332,925	124.36%
Services CWIP	2,203,356	1,153,790	685,560	660,425	2,499,775	113.45%
Meter Loop Assembly CWIP	1,506,837	789,057	468,842		1,257,900	83.48%
Other Eligible CWIP	184,385	96,553	57,370		153,923	83.48%
Total ENSTAR	6,574,559	3,442,776	2,045,631	1,756,116	7,244,523	110.19%
APC CWIP	1,442,464	914,346	607,369		1,521,715	105.49%
Total	**8,017,022**	**4,357,123**	**2,653,000**	**1,756,116**	**8,766,239**	**215.68%**

Activity Description	Direct Wages by Activity	Constr OH Rate Used for RC & CINGSA*	Indirect Overhead
Damage Claims	92,156	47.25%	43,539
Reimbursable Construction	635,594	47.25%	300,287
CINGSA	841,011	47.25%	397,336
Totals	1,568,761	47.25%	741,162

***The Construction Overhead Rate used for Damage Claims, Reimbursable Construction and CINGSA is 47.25%, which is based on prior year's amounts. This is the AK-DOT audited rate referred to earlier in this CAM. The actual OH rates for the current year are used for all other overhead allocations.**

Allocation of Direct Construction Overhead

Direct construction overhead is not charged to reimbursable construction projects or to CINGSA. Direct construction overhead is for costs related to Mains and Service lines, but not related to a specific main or service line. These costs are accumulated in the following project accounts:

Project Number*	Description
4YY176990100	Direct Dist. – Mains – Anchorage
4YY176990200	Direct Eng. – Mains – Anchorage
4YY176990300	Direct Mktg. – Mains - Anchorage
4YY376990100	Direct Dist. – Mains – Kenai
4YY376990200	Direct Eng. – Mains – Kenai
4YY376990300	Direct Mktg. – Mains - Kenai
4YY476990100	Direct Dist. – Mains – Mat. Valley
4YY476990200	Direct Eng. – Mains – Mat. Valley
4YY476990300	Direct Mktg. – Mains – Mat. Valley
4YY180990100	Direct Dist. – Serv. Lines – Anchorage
4YY180990200	Direct Eng. – Serv. Lines – Anchorage
4YY180990300	Direct Mktg. – Serv. Lines - Anchorage
4YY380990100	Direct Dist. – Serv. Lines – Kenai
4YY380990200	Direct Eng. – Serv. Lines – Kenai
4YY380990300	Direct Mktg. – Serv. Lines - Kenai
4YY480990100	Direct Dist. – Serv. Lines – Mat. Valley
4YY480990200	Direct Eng. – Serv. Lines – Mat. Valley
4YY480990300	Direct Mktg. – Serv. Lines – Mat. Valley

*Project Number Key:

- First digit indicates Company (4=ENSTAR, 5=APC)
- Second and third digits indicate year
- Fourth digit indicates geographic area (1=Anchorage, 2=ER, 3=Kenai, 4=Mat Valley)
- Fifth and sixth digits indicate FERC type of job (76=Mains, 80=Serv. Lines, 99=Overhead)
- Seventh through tenth digits indicate specific project
- Last two digits indicate type and size of pipe, if applicable.

Charges to these projects (and all CWIP projects) are recorded in the general ledger in the following object accounts:

Object Account	Description
26100 – 26170	Labor
26410	Subcontract
26300	Materials / Supplies
26301	Other Costs
26600	Permits
26210	Fleet
26220	Other clearing
26610	AFUDC
26700	Other Capital Charges (P-cards)

Direct overhead costs are made up of supervisor time directly related to mains/service lines activities, materials used on multiple projects, and other direct costs that are not specific to one project.

Direct overhead is allocated to the related CWIP jobs based on direct costs. For example, 415176990100 (Direct Dist. – Mains – Anchorage) would be allocated to CWIP projects for Mains in the Anchorage area.

An example of the allocation for direct overhead related to Anchorage service lines:

Project #	Direct OH to be Allocated
416180990100.26XXX	250,000
416180990200.26XXX	300,000
416180990300.26XXX	110,425
Total Direct OH-Service Lines AN	660,425

Project #	Direct CWIP Costs	% to Total
4161800001.26XXX	985,000	60.43%
4161800002.26XXX	245,000	15.03%
4161800003.26XXX	400,000	24.54%
Total Direct Costs-Service Lines AN	1,630,000.00	100.00%

Project #	Allocated Direct OH	Entry on Enstar's Books
4161800001XX.26570	399,091	Debit
4161800002XX.26570	99,266	Debit
4161800003XX.26570	162,067	Debit
416999000200.26570	660,425	Credit

Stores Expense Allocation

The Stores Expense Undistributed account consists of the following: payroll and benefits, accounts payable vouchers, fleet allocations, insurance, building services and data processing charges. All charges relating to the warehousing function are accumulated in this account. The stores expense is allocated based on a percentage of the value of items leaving ENSTAR's inventory.

The inventory object accounts are:

Object Account	Description
4.15100	Pipe, Fittings & General Inventory
4.15130	Pipe, Fittings – Shop Trucks
4.15220	Gas Meas. & Reg. Material
4.15230	Gas Meters
4.15235	Gas ERTs
4.15280	Non Stock Inventory

The percentages used to allocate stores expense are determined by comparing the inventory balances to the balance in the Stores Expense Undistributed account. The Stores Expense Undistributed account needs to maintain a balance that can be applied to future inventory issues related to inventory being carried in the inventory object accounts listed above.
The stores loading rate is applied to the total dollar value of inventory issues charged to each project.

For reimbursable construction projects, the stores loading rate is based on prior year actual stores costs and inventory issued.

Fleet Allocation

Several accounts are used to accumulate vehicles' maintenance costs associated with ENSTAR transportation shop: labor, materials, supplies, etc. These costs are recorded under accounts 4.18710 – 4.18716 and 4.18718.

At month end, vehicles' maintenance costs are allocated from the account 4.18717 to accounts 4XXXX.18951, where 4XXXX are appropriate business units (XXXX - home business units). The vehicles' maintenance allocation is based on a standard shop rate that is calculated using a number of vehicles assigned to each business unit.

In addition, separate accounts accumulate costs directly associated with a vehicle (4XXXX.18952 – 4XXXX.18956, where 4XXXX – various business units). In order to allocate the costs from these accounts, the charges are first sorted by business units (4XXXX) based on where the vehicles are assigned.

For example: The balance in the direct vehicle charge accounts is $2,100.

Business Unit	Direct Charges
4400	$500
4271	600
72200 (CINGSA)	1,000
Total	$2,100

Then, the gross wages are analyzed by labor distribution accounts within home business units of the employees with the assigned vehicles. For example, for employees under Home Business Unit 4410:

Employee	Hours Worked	Labor Distribution Accounts	Percentage of Time, %	Fleet Charges Allocated, $
X	45	CWIP	36%	180
Y	80	O&M	64%	320
	125		100%	500

Charges to the CINGSA business unit are likewise separated based on labor charges within CINGSA. If labor is charged to CINGSA capital projects, the related fleet allocation will go to CINGSA capital. If labor is charged to CINGSA O&M, the fleet allocation will go to CINGSA O&M.

The CWIP and Reimbursable Construction allocations are broken down one step further and allocated to specific job numbers.

Payroll Burden Allocation

Payroll burden costs are accumulated in a balance sheet account (4.18960) and allocated each month. These costs include employer's payroll taxes, workers' compensation costs, sick leave, accrued vacation and accrued holidays. Payroll burden does not include pension, 401(k) matching, or healthcare costs, as these are included in A&G and allocated through a separate process (as described above).

The allocation begins with payroll (worked hours only), which is sorted based on the accounts to which labor has been charged within each Business Unit. Labor charged to CINGSA is tracked in a unique set of business units (72xxx). Payroll burden related to CINGSA labor charges is added to the direct labor charged to CINGSA. Reimbursable construction labor is charged to specific object accounts (18931, 18932, 18934), and payroll burden is added accordingly.

Example: The applicable Gross Wages for the month are $50,725. The balance to be allocated is $15,000. Payroll burden is calculated as $15,000/50,725 = average of 29.57% to be loaded to the applicable business units.

Object	Description	Gross Wages (Adjusted)	Burden to Allocate	Burden %
415xxxxxxxxx.26110	CWIP	$10,000	$2,957	29.57%
4xxxx.18932	Reimbursable Construction	10,000	2,957	29.57%
72200.xxxxx	CINGSA	2,000	591	29.57%
xxxx.76100	A&G	3,000	887	29.57%
xxxx.75200.9021	Meter Reading O&M	10,725	3,172	29.57%
xxxx.74320	Service Calls O&M	7,000	2,070	29.57%
xxxx.74872	Mains Expense O&M	8,000	2,366	29.57%
	TOTAL	$50,725	$15,000	

Building Maintenance Allocation

ENSTAR distributes 45% of building maintenance to various balance sheet accounts and O&M accounts. This percentage was derived based on square footage for each of ENSTAR's building facilities. CINGSA has separate facilities and does not receive a building maintenance allocation.

Direct charges (electricity, snow removal, lawn care, etc.) are accumulated in object account 76490. Sub-accounts are used to track costs by location:

76490.1	Admin Building
76490.3	Soldotna Office
76490.4	Wasilla Office
76490.11	Operations Building
76490.14	Palmer
76490.50	Allocation

Year-to-date charges are totaled for all 76490 sub-accounts except 76590.50. The amount to be allocated is calculated as 45% of this total. The allocation is distributed by business unit and object account. The percentage charged to each facility is fixed based upon the facilities' footage.

The accounts that are charged are as follows:

Account number	**Description**
415199000200.26301	CWIP Overhead – Anchorage
415399000200.26301	CWIP Overhead – Kenai
415499000200.26301	CWIP Overhead – Mat. Valley
4001.74790	Distribution Operations
5001.73140	Transport Operations
4.15900	Stores Expense Undistributed
4.18718	Fleet

Reimbursable Construction

Costs are accumulated in specific project accounts. Timesheets, materials, accounts payable, and manual journal vouchers are coded to the applicable business unit (job number) and object code. ENSTAR then manually prepares job charge summaries of payroll, materials, subcontract costs and overheads. These job charges are then summarized on an ENSTAR billing to the State of Alaska or other customer.

For example:

Business Unit*	**Description**
41550	Old Glenn Hwy relocation
41551	Girdwood Drainage relocation
41552	Huffman and Pintail relocation
41553	France Road relocation

*Key: 1st digit equals Company number (4=ENSTAR, 5=APC)
2nd and 3rd digits equal year
4th and 5th digits equal sequential job number.

Charges to these business units are accumulated in the following object codes:

Object Code	**Description**
18931-18934	Labor
18935	Sub-contract
18936	Materials
18937	Permits
18938	Overhead
18939	Clearing

A&G and construction overheads are applied to the billing based on rates audited and approved by the State of Alaska Department of Transportation each year, based on prior year actual numbers. The methodology for determining these rates is the same as the methodology previously described. Payroll burden is not included in the scope of the State of Alaska DOT audit.

Construction overhead, A&G overhead, payroll burden and fleet loading are applied to reimbursable projects based on direct labor charged to the project. Stores loading is applied based on inventory issued to the project.

A copy of the most recent audit report from AK-DOT is attached as Appendix A.

Allowance for Funds Used During Construction (AFUDC) Allocation to Construction Work In Progress

An AFUDC rate is calculated based on guidance provided by FERC. The formula takes into account the company's debt rates and allowed return on equity (as determined by the most recently adjudicated rate case). Rates are computed at the beginning of each year based on prior year actual financial data.

A CWIP job that is eligible for AFUDC receives half of the monthly AFUDC percentage for all current month activity, including CWIP overhead allocation for that job, and a full percentage for all prior months' activity. Each job has an AFUDC code attached to it indicating whether it will receive AFUDC allocation. When the job is completed, it no longer receives AFUDC, so the code is changed in the job master file.

CINGSA capital projects are similarly coded to indicate whether they should receive an AFUDC charge. The interest rate for CINGSA AFUDC is based on CINGSA's debt rates and allowed equity rate.

After all direct cost activity for the month is posted to the job system and the allocation of overhead is posted to the job system, the AFUDC allocation is run. The allocation first totals all activity for the current month (direct costs plus overhead), then determines the AFUDC amount based on the half-month percentage. Next, the system totals all prior activity and determines the AFUDC allocation based on the full-month percentage. The half-month and full-month amounts are combined and posted to the job.

Appendix A

Utility Systems Audit

of

ENSTAR Natural Gas Company

Audit Number 24-UA-08

January 2, 2025

The Internal Review Section has no objection to the release of this report, at the discretion of the Contracting Officer, to duly authorized representatives of the Contractor. However, release to the public of any Contractor information contained in this report should only be made in accordance with Department of Transportation and Public Facilities Policy and Procedure No. 01.04.010 (9/05).

Department of Transportation
and Public Facilities
Office of Internal Review
Issued by:
Deb Stockburger
Chief of Internal Review

INTRODUCTION

A utility systems audit has been conducted on ENSTAR Natural Gas Company (ENSTAR), a Division of SEMCO Energy, Inc. (SEI) and parent company is TSU. Under the systems audit concept, the Department will perform annual reviews of ENSTAR's accounting system and overhead rates if work is anticipated with the company during the current year.

PURPOSE AND SCOPE

The purpose of the audit was to review ENSTAR's indirect cost allocation procedures and work order accounting system. In addition, overhead rates were established based on 2023 actual financial data.

The scope of the audit was limited to the company's calendar year 2023 financial data, cost allocation procedures and work order accounting system.

Our examination was performed in accordance with generally accepted governmental auditing standards, and accordingly, included such tests of the financial records and such other auditing procedures as we considered necessary in the circumstances.

In planning and performing our audit, we conducted a limited review and considered the company's internal control structure in order to determine the nature and extent of the auditing procedures necessary for this audit.

The criteria used to determine the acceptability of ENSTAR's accounting system and allowable costs were 23 CFR 1-645, Subpart B for Utilities and 48 CFR 31, Federal Acquisition Regulations.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on the statement based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in the Government Auditing Standards (GAGAS), issued by the Comptroller General of the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the statement is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the statement. The procedures selected depend upon the auditor's judgement, including the assessment of the risks of material misstatement of the statement, whether due to fraud or error. In making those risk assessments, the auditor considers internal controls relevant to the entity's preparation and fair preparation of the statement in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal controls. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting polices used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the statement.

We believe the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

RESULTS OF AUDIT

1. Work Order Accounting System

   ENSTAR has an acceptable work order accounting system, which is capable of identifying, segregating and accumulating costs to specific work orders.

2. Indirect Cost Allocation System

   - Overhead Rate 138.95% (as a percentage of direct gross wages)
   - Construction Rate 64.81% (as a percentage of direct gross wages)
   - Materials Handling Rate 19.42% (as a percentage of materials issued)
   - Transportation Rate 17.28% (as a percentage of direct gross wages)

   ENSTAR distributes its indirect expenses (administrative & general and construction overhead) to the construction activities on a monthly basis. The allocation methodology utilizes a base of reimbursable construction direct labor. ENSTAR uses a monthly allocation procedure; their allocation methodology is not in conformance with 23 CFR 1-645. Internal Review has annualized the allowable indirect expenses and reimbursable construction direct labor base to establish an audited overhead rate. The methodology used to establish the audited overhead rate is in conformance with 23 CFR 1-645.

3. Materials Handling Rate

   The methodology utilized by ENSTAR to develop their materials handling rate is based on the relationship of the stores expense loaded out divided by total inventory issues. Because ENSTAR uses a monthly allocation procedure, their allocation methodology is not in conformance with 23 CFR 1-645. Internal Review has annualized the allowable stores expense loaded out and inventory issues base to establish an audited rate. The methodology used to establish the audited materials handling rate is in conformance with 23 CFR 1-645.

4. Transportation Rate

   The methodology ENSTAR uses to develop their transportation rate is based on the relationship of indirect transportation expense to direct labor by accounting unit. This allocation process is done on a monthly basis. Therefore, it is not in conformance with 23 CFR 1-645. Internal Review has established an annualized audited rate based on the relationship of reimbursable construction transportation charges divided by reimbursable construction unloaded labor. This methodology is in conformance with 23 CFR 1-645.

5. 2024 Rates

Internal Review recommends that the following rates be utilized for reimbursement of overhead costs of ENSTAR in utility relocation agreements with the Department for calendar year 2024:

- Overhead Rate 138.95% (as a percentage of direct gross wages)
- Construction Rate 64.81% (as a percentage of direct gross wages)
- Materials Handling Rate 19.42% (as a percentage of materials issued)
- Transportation Rate 17.28% (as a percentage of direct gross wages)

6. Findings

No findings

7. Discussion of Audit Results

The results of the audit were discussed with the utility section and ENSTAR officials.

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chairman
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Consideration of the Revenue Requirement Designated as TA 354-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF ANDREA D. JACKSON

PREFILED DIRECT TESTIMONY
OF
ANDREA D. JACKSON

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EXHIBITS

Exhibit ADJ-1	Resume of Andrea D. Jackson
Exhibit ADJ-2	Organizational Chart of TriSummit Utilities Inc. Showing Ownership of ENSTAR
Exhibit ADJ-3	Select Alaska Statutes
Exhibit ADJ-4	Amended and Restated Services Agreement between TriSummit Utilities Inc. and ENSTAR Natural Gas Company, LLC
Exhibit ADJ-5	Summary of Costs to ENSTAR to Perform All Corporate and Shared Services Activities

I. POSITION AND QUALIFICATIONS

Q. Please state your name, business address and present position.

A. My name is Andrea D. Jackson. My business address is 3100, 300 5th Avenue SW, Calgary, Alberta, T2P 3C4, Canada. I am the Treasurer for TriSummit Utilities Inc. ("TSU"). I am appearing in this proceeding on behalf of ENSTAR Natural Gas Company, LLC ("ENSTAR") and Alaska Pipeline Company, LLC ("APC"). ENSTAR and APC are wholly owned subsidiaries of TSU. I will refer to ENSTAR and APC together as "ENSTAR" or the "Company."[1]

Q. Briefly describe your professional experience and educational background.

A. I have been employed with TSU since 2019. I hold a Bachelor of Arts (English) and Bachelor of Management (Finance) from the University of Lethbridge as well as a Master of Business Administration from Emory University in Atlanta, Georgia. I have nearly 20 years of experience in the energy industry, including 12 years in treasury roles. My resume is attached as Exhibit ADJ-1.

Q. Have you previously testified before the Regulatory Commission of Alaska ("RCA" or "Commission") or any other regulatory commission?

A. No.

II. PURPOSE OF DIRECT TESTIMONY AND BACKGROUND

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe the relationship of TSU to ENSTAR, describe the nature of certain corporate support services that TSU provides to

[1] The Commission regulates APC and ENSTAR as a single entity. The use of the name "ENSTAR" or "Company" in this filing is intended to include both APC and ENSTAR, unless the context clearly requires otherwise.

ENSTAR, and support the associated costs of those services to ENSTAR to satisfy the applicable statutes under which the RCA reviews such expenses. I also explain how TSU allocates these costs to ENSTAR.

Q. Please describe TSU and its relationship to ENSTAR.

A. TSU is a Canadian corporation located in Calgary, Alberta, with diversified rate-regulated natural gas distribution utilities in Alaska, British Columbia, Alberta, and Nova Scotia, and long-term contracted renewable power generation assets. TSU's mission is to make its communities a better place to live, by connecting them to the energy they want, when they need it, now and into the future. In 2023, TSU acquired a 100% ownership interest in ENSTAR and APC from SEMCO Energy, Inc., a subsidiary of AltaGas Ltd. ("AltaGas"). A simplified version of the TSU corporate organization is depicted in Exhibit ADJ-2.

Q. Are TSU and ENSTAR "affiliates" under Alaska statutes?

A. Yes, TSU and ENSTAR are affiliates. Pursuant to AS 42.05.990(1), "affiliated interest" includes a person owning or holding directly or indirectly five percent or more of the voting securities of a public utility engaged in intrastate business in this state. Because TSU indirectly owns 100 percent of the voting securities of ENSTAR, TSU and ENSTAR are affiliates under the statutory definition. True and correct copies of the statutes regarding affiliate transactions relevant to this case are attached as Exhibit ADJ-3.

Q. During the test year, did ENSTAR receive services from TSU?

A. Yes, during the test year, which consists of the twelve-month period ending December 31, 2024, ENSTAR relied on TSU to provide support for ENSTAR's overall

operations. These corporate support services ("Corporate Services") are provided pursuant to a written services agreement between TSU and ENSTAR, which is attached as Exhibit ADJ-4. These Corporate Services, as described further below, ranged from board oversight to accounting to legal and compliance services.

Q. Why are these activities performed by TSU instead of by ENSTAR?

A. By centralizing these Corporate Services, TSU is able to share overhead costs and specific expertise across its businesses and achieve economies of scale and other efficiencies that its business units or subsidiaries could not achieve on a stand-alone basis. In many cases, TSU employees have worked for, or served, utility and energy sector companies for decades and are highly knowledgeable and experienced in industry processes. ENSTAR and its customers benefit from not only deep experience, but a broader industry perspective at a lower cost. In addition, consolidation of Corporate Services allows TSU to optimize the performance of its business units and subsidiaries because they can avoid redundant services. Furthermore, as described in more depth below, some of these Corporate Services are services that ENSTAR simply could not reasonably outsource to third parties, such as services provided by TSU's Board of Directors and its executive management team and officers.

Q. Does ENSTAR incur costs associated with the Corporate Services it receives from TSU?

A. Yes. Pursuant to the service agreement mentioned above, TSU periodically invoices ENSTAR for ENSTAR's allocated portion of the costs TSU incurs to perform the various Corporate Services.

Q. What are the statutory requirements governing affiliate transactions in Alaska that are applicable to the Corporate Services provided by TSU to ENSTAR?

A. To include costs associated with affiliate transactions in rates, ENSTAR must show that the costs satisfy two statutory requirements: AS 42.05.511(c) and 42.05.441(c). True and correct copies of these statutes are attached as Exhibit ADJ-3.

Pursuant to AS 42.05.511(c), ENSTAR has the burden to prove that: (1) the services that TSU provides to ENSTAR are necessary and consistent with the public interest; (2) the payment made for those services is reasonably based, in part, on the cost TSU incurs to provide those services; and (3) the payment is reasonably based, in part, on the estimated cost for ENSTAR to perform those services if the Company were to self-provide those services with its own personnel and capital.

Pursuant to AS 42.05.441(c), ENSTAR also has the burden to prove that: (1) ENSTAR's payments to TSU were for services that were reasonably necessary for the operation of ENSTAR; and (2) TSU provided the services to ENSTAR at a cost that is competitive with the price at which ENSTAR could have obtained the services from an unaffiliated third party.

III. CORPORATE SERVICES PROVIDED BY TSU TO ENSTAR

A. Description of Corporate Services

Q. What categories of Corporate Services does TSU provide to ENSTAR?

A. As stated above, TSU provides various Corporate Services to ENSTAR. In general, the services are strategic in nature and focus on business oversight, development and exercise of corporate governance, and ensuring ENSTAR has appropriate access to capital. Specifically, TSU engages in activities in the following broad categories:

- Board of Directors;

- Executive Committee;
- Accounting, Tax and Finance; and
- Corporate Resources (including Legal and Compliance).

Below, I describe each category of service that TSU provides to ENSTAR.

Q. Please describe the Corporate Services that TSU's Board of Directors provides for the benefit of ENSTAR.

A. TSU's Board of Directors (the "Board") is ultimately responsible for the stewardship of TSU and all of its business units and subsidiaries, including ENSTAR. The Board oversees the business affairs of TSU, and ensures compliance with all disclosure and corporate governance requirements. Through periodic review of the strategic environment with management, the Board is responsible for developing TSU's strategic direction. The Board develops standards and procedures to support effective governance of TSU and its businesses. It reviews and approves TSU's consolidated annual budget, which includes key objectives and operational and financial targets. It also reviews and approves TSU's consolidated financial statements and quarterly and annual securities disclosure submissions. Additionally, the Board appoints the chief executive officer ("CEO") and other senior officers of TSU, and engages in succession planning, training, and performance monitoring. The Board provides oversight of principal business risks and adopts policies and practices to promote ethical business conduct of TSU and its businesses.

Q. Please describe the Executive Committee services that TSU provides for ENSTAR.

A. The TSU Executive Committee provides strategic management oversight to all TSU

business units. The Executive Committee provides strategic direction on various matters, including regulatory; safety; stakeholder relationships; environmental; social and corporate governance; company-wide financial planning; capital access; investment strategy; business and capital risk management; and organization structure. It establishes company-wide governance models and internal control standards and procedures, and formulates strategy and provides guidance to operational leadership. Members of the Executive Committee also serve as the principal representatives of TSU.

Q. Please describe the Accounting, Tax and Finance services that TSU provides to ENSTAR.

A. As a public reporting issuer, TSU prepares consolidated financial statements, notes to the financial statements, and related management discussion and analysis as well as other documents required for TSU's securities filings, such as the Annual Information Form. It engages external auditors to perform the annual audit and quarterly reviews of TSU's consolidated financial statements and performs research on current and emerging accounting policies and securities rules. It manages the annual consolidated budgeting and planning cycle, assists and advises TSU's businesses to incorporate their respective forecasts in TSU's consolidated budget, and prepares regular internal reporting and forecasts for executive management to exercise strategic financial oversight of the consolidated company. It develops and maintains the enterprise risk management framework for TSU and its businesses (including procurement of corporate liability insurance policies), and coordinates corporate tax audits and advises on tax planning to ensure overall tax compliance.

In addition, TSU prepares investor presentations and manages communication with shareholders and the capital markets. TSU is responsible for maintaining the capital structure of the consolidated company through equity and debt financing for TSU and its subsidiaries, which includes managing credit rating agency relationships; managing relationships with investors, shareholders, and banks; monitoring market intelligence; consolidated cash flow forecasting; and liquidity management for the entire organization. The Accounting, Tax and Finance function ensures the funding plans of TSU address the operational and capital needs of its businesses.

Q. Please describe the Corporate Resources (including Legal and Compliance) services that TSU provides to ENSTAR.

A. TSU's Corporate Resources function advises on an array of corporate matters, including governance, compliance, disclosure, securities registration requirements, banking and finance, employment, and tax matters. In addition, it provides legal services and advice to TSU's operating businesses and subsidiaries, and maintains regular communications with each business to ensure effective management of legal matters, including management of external legal counsel where appropriate. This group provides corporate secretarial services to TSU and its subsidiaries, and coordinates all communications with, and the meetings of, the boards of directors of TSU and its affiliates, and oversees disclosure and compliance matters related to TSU's status as a reporting issuer. It also develops guidelines and policies regarding TSU's code of business ethics and other core policies, including human rights, environment, and health and safety, and oversees compliance of such matters across the organization. It also develops and coordinates the annual internal audit plan examining governance,

risk management and compliance with internal controls and procedures. In addition, it develops and oversees employee outreach and communication, learning and development, and talent management programs across the organization. It also provides support in the design of executive and employee compensation plans, retirement savings, and benefits management, and maintains corporate office space with necessary facilities to enable performance of corporate functions.

Q. Does TSU provide these services specifically for, or directly to, ENSTAR?

A. No. TSU performs these services for the benefit of all its business units, and not just ENSTAR. It does not perform any of these services specifically for or directly to any particular business unit, and the costs that TSU incurs to perform the services are allocated to other business units in the same manner.[2] These are common services that TSU performs as a parent company for, and on behalf of, all of its business units. If TSU did not perform these services, each business unit would need to perform or procure these services on their own.

Q. Does ENSTAR also self-provide administrative services?

A. Yes. Following TSU's acquisition of ENSTAR in 2023, ENSTAR hired certain employees to provide certain administrative services internally for the Company, which it previously received from affiliates. The administrative services include cash management, payroll, accounting and tax, payment processing, procurement, risk

[2] Rather than receiving an allocation from TSU, Cook Inlet Natural Gas Storage Alaska, LLC receives services and cost allocation from ENSTAR pursuant to the Operation and Maintenance Agreement, as discussed in ENSTAR's cost allocation manual. Inuvik Gas, of which TSU has a one-third (1/3) ownership interest, does not receive an allocation from TSU; it makes up less than 1% of TSU's total consolidated assets and it contributes less than 1% of TSU's consolidated EBITDA.

management (including the acquisition of certain insurance policies for ENSTAR), IT, and HR services.

Q. Is there any duplication of the Corporate Services that TSU provides and the services that ENSTAR's employees provide?

A. No. The services and activities that TSU provides and the services and activities that ENSTAR's internal employees provide are not duplicative. As a result, there is no duplication in costs associated with services performed by TSU. TSU provides corporate and strategic oversight and governance to its businesses. On the other hand, ENSTAR's local management and employees are responsible for the day-to-day safe and reliable operation of the utility business. The services that TSU provides to ENSTAR are complementary to the services that ENSTAR performs in-house.

B. Necessity and Public Interest

Q. Are the Corporate Services that TSU provides to ENSTAR necessary?

A. Yes. The services are common activities that are required as part of the ongoing management of a diversified corporate parent company. Many of these services are focused directly on corporate governance, legal mandates, regulatory compliance, and reducing financial, operational, and other types of risk. The remaining services are focused on management control, strategic planning, and operational execution. The fiduciary and governance functions provided by TSU's Board of Directors, the strategic leadership of TSU's executive management, and the various accounting/tax/finance and legal and compliance activities undertaken by TSU are necessary for TSU to maintain its reporting-issuer status to fund the capital and operational needs of its business units, including ENSTAR, in a timely and efficient manner.

Q. In addition to being necessary, how do the Corporate Services benefit customers?

A. The Corporate Services benefit customers in several ways. First, the TSU executive management team and Board have extensive utility management experience. They provide strategic input, oversight, and governance support to ENSTAR's management, assisting in areas in which their industry experience and expertise can enhance near-term and long-term decisions for the ultimate benefit of ENSTAR and its customers, such as risk management development, enhancing governance, and ensuring best practices in ENSTAR's operations.

Second, the various Corporate Services that TSU performs are necessary to maintain TSU's reporting-issuer status, which provides continued access to capital markets. TSU has well-established track records in capital market issuances and access to bank credit facilities. To illustrate, TSU manages communications with rating agencies' analysts and investors, including relationships with credit rating agencies. Those outreach efforts facilitate capital issuance activities undertaken by TSU, which are essential to providing ENSTAR with access to capital to meet its capital and operational needs.

Third, by consolidating the performance of Corporate Services at TSU, ENSTAR is able to enjoy the benefits of cost efficiencies and economies of scale that ENSTAR could not achieve if it were to source the Corporate Services from third parties or replicate them on its own. Consolidating these services at TSU allows TSU's business units to share in the costs, so that each business unit bears only a portion of the costs.

Q. Can you provide examples of how TSU's provision of Corporate Services to ENSTAR reduces costs for customers?

A. Yes. While not exhaustive, the following are examples that illustrate how TSU's provision of services to ENSTAR reduces costs for customers.

First, if TSU did not perform the Corporate Services needed to maintain its reporting-issuer status, ENSTAR would need to satisfy its legal mandates, compliance requirements, and capital requirements with its own personnel and resources. At a minimum, ENSTAR would need to recruit its own independent board of directors, hire an executive management team, set up its own treasury and corporate communications function, and expand its accounting function to satisfy securities disclosure requirements. Furthermore, to issue its own securities, ENSTAR would need to perform numerous essential functions, such as arranging its own external audit; preparing its own quarterly and annual reports in compliance with securities disclosure requirements; maintaining communications with debt and equity investors; maintaining its own credit rating; engaging in securities registration and stock exchange listing; and procuring directors and officers (also known as "D&O") liability insurance, to name just a few. To support these incremental functions, ENSTAR would need an expanded staff and additional overhead, including office space and related set-up. While some of those activities may be procured from third parties (such as external audit and D&O insurance), it would not be reasonable for ENSTAR to outsource its board, executive management, and associated governance functions, because a market for these services simply does not exist.

To take another example, the total costs of Corporate Services included in TSU's Corporate Cost pool in 2024 were approximately $8.4 million. ENSTAR's allocated portion of these costs was only $2.9 million, yet it received the benefit of the

entire suite of such services. As demonstrated in Section IV of my direct testimony, it would have cost ENSTAR significantly more than $2.9 million if it were to source these services for itself. Furthermore, ENSTAR would need to employ additional personnel and incur more overhead costs to manage these additional functions. Thus, the prudent and practical approach is for TSU to perform these Corporate Services on ENSTAR's behalf.

Q. Are the Corporate Services that TSU provides to ENSTAR in the public interest?

A. Yes. The Corporate Services described above are not only necessary to the operation of ENSTAR, but also are beneficial to customers. TSU's provision of Corporate Services creates economies of scale that directly result in lower costs for ENSTAR's customers. For the reasons discussed above, this arrangement is in the public interest.

IV. COST ALLOCATION AND COMPETITIVENESS OF COSTS

Q. How does TSU charge the costs of the Corporate Services to its divisions and subsidiaries?

A. TSU allocates costs for Corporate Services to ENSTAR based on the Modified Massachusetts Formula ("MMF"). The MMF is an industry-standard methodology for allocating fixed and common costs among business units.

First, TSU combines all of the costs for Corporate Services into one common cost pool. TSU then allocates this cost pool to ENSTAR and TSU's other business units using the TSU Modified Massachusetts Formula ("TSU MMF"). The TSU MMF uses a simple average of three different cost-allocation bases (the "TSU MMF Allocator") to allocate costs to ENSTAR and the other TSU business units. Using ENSTAR as an example, the three cost-allocation bases are as follows: (1) ENSTAR's

total property (property, plant, and equipment, including construction work in progress, plus materials, supplies, and gas inventories) divided by TSU's total property for all business units; (2) ENSTAR's payroll divided by TSU's total payroll for all business units; and (3) ENSTAR's normalized earnings before interest, tax, depreciation, and amortization ("EBITDA") divided by TSU's normalized EBITDA for all business units. Table 1 below illustrates the 2024 TSU MMF Allocator used to allocate costs of Corporate Services to ENSTAR:

Table 1

2024 TSU MMF Allocator Percentage Calculation
C$000's

	ENSTAR	TSU Total
Property Factor		
PP&E (Net of Amortization)	478,420	1,879,945
Inventory	87,136	90,133
Capital supplies	-	4,672
	565,555	1,974,751
% of TSU	28.64%	**100.00%**
Payroll Factor	43,880	99,149
% of TSU	44.26%	**100.00%**
EBITDA Factor	61,528	210,507
% of TSU	29.23%	**100.00%**
% of TSU	**34.04%**	**100.00%**

Note: ENSTAR's numbers are converted to CAD using the 2023 year-end CAD:USD exchange rate (for the Property Factor) and the 2023 average CAD:USD (for the Payroll and EBITDA factors).

Q. Why does TSU choose to use the MMF to allocate the Corporate Services?

A. The MMF is a reasonable way to allocate necessary costs of Corporate Services. The MMF is commonly used in the utility industry to allocate such shared costs that benefit

multiple subsidiaries or business units. Additionally, the MMF is not only commonly used, but is routinely accepted by utility regulators.

In fact, the MMF has been used to allocate costs to ENSTAR for many years. Even before TSU acquired ENSTAR in 2023, the Company's previous corporate owners used the MMF to allocate the costs of shared services between ENSTAR and its affiliates since 1999. This Commission has consistently deemed the MMF acceptable since that time. The shared services agreement between TSU and ENSTAR, which is attached to my testimony as Exhibit ADJ-4, describes the TSU MMF in more detail.

Q. Does TSU charge a mark-up or profit of any kind on the costs it incurs to provide the Corporate Services?

A. No. TSU provides the Corporate Services at cost. In other words, TSU allocates the costs associated with these services to its business units without any mark-up or profit of any kind.

Q. What amount of costs for Corporate Services did TSU allocate to ENSTAR in 2024?

A. In 2024, the total amount of costs for Corporate Services that TSU allocated to ENSTAR was $2.9 million. Table 2 below depicts the various service functions and allocations of costs to ENSTAR in 2024.

Table 2– Summary of Costs to ENSTAR to Perform all Corporate Service Activities ($000s)	
Corporate Services Functions	**2024 Total ENSTAR Allocation ($000s)**
Board of Directors	210
Executive Committee	722
Accounting, Tax and Finance	974
Corporate Resources (incl. Legal and Compliance)	959
Total Cost to ENSTAR	**2,866**[3]

Q. Has TSU incurred any costs for services that are not allocated to ENSTAR?

A. Yes. Costs incurred by TSU for corporate and business development, corporate donation and promotion, supplemental executive retirement plan expense, long-term incentive compensation expenses, employee recognition and social events, meals, and certain travel expenses are not allocated to ENSTAR. For example, during 2024, $5.3 million in costs incurred by corporate were not allocated to TSU's businesses and remained with the corporate segment.

Q. How does TSU manage the costs incurred in providing the Corporate Services?

A. The actual costs incurred in providing the Corporate Services are tracked against budget. TSU's Accounting and Finance leaders review the performance of its businesses and collaborate with the accounting and finance counterparts in the businesses to review variances. These reviews and discussions allow management to engage meaningfully in cost control as business conditions evolve.

[3] The variance between the total cost allocated to ENSTAR for 2024 as shown in the table and the accrued amount recorded in ENSTAR's general ledger as of December 31, 2024 of approximately $8,000 is a timing difference.

Q. How does TSU ensure the costs it incurred in providing Corporate Services are competitive with the costs ENSTAR would incur to obtain the services from an unaffiliated third party?

A. TSU ensures that these costs are competitive in several ways. First, the labor component of the Corporate Services costs allocated by TSU excludes long-term incentive payment and supplemental retirement plan costs, which amounted to $3.1 million in 2024. TSU promotes an integrated view of total compensation that includes compensation, benefits and working conditions to attract and retain TSU's workforce. TSU's compensation practices are designed to provide competitive compensation to employees that align with the market.

Second, the costs associated with services performed by third parties are competitive by definition. TSU's third-party services are procured using standard and customary procurement practices. Because they are the result of arm's-length transactions between unrelated parties, these costs represent market prices. For example, in 2024, TSU retained Ernst & Young ("EY") for auditing and other consulting work, and the fees it paid to EY were approximately $300,000. EY provides these types of services in a very competitive market, and TSU retained EY at arm's length.

Third, any services that ENSTAR might obtain from third parties will likely contain profit margins, whereas the costs TSU incurs to perform Corporate Services are allocated to ENSTAR with no mark-up or profit margins of any kind.

Fourth, ENSTAR receives only a fraction of the costs that TSU incurs for the Corporate Services. While the total amount of costs may be less for an organization of

ENSTAR's size as compared to an organization the size of TSU, a large portion of the costs would be necessary regardless of ENSTAR's size. For example, TSU, as a public-reporting issuer, incurred close to $500,000 in third-party costs during 2024 for securities listing registration, annual report preparation, annual general meetings, other forms of shareholder communications, and corporate insurance (including D&O, crime and fiduciary insurance). ENSTAR's allocation of these costs was less than $160,000. If ENSTAR were to self-provide these services, ENSTAR would expect to pay more than $800,000. The main driver for the spike in ENSTAR's stand-alone cost is the significant corporate insurance premium associated with a U.S. reporting issuer; and some of the other costs have no direct correlation to company size. In addition, ENSTAR currently enjoys more favorable terms in securing general liability insurance for its operations due to economies of scale resulting from grouping coverages with other TSU utilities. If it were to procure its own separate liability insurance with the same coverage, ENSTAR's general liability insurance premium is expected to increase by as much as $1.4 million.

To take another example, the fiduciary, governance, and strategic management services that TSU performs are not even available from third parties. To replace those services, ENSTAR would need its own board of directors, a CEO, and a chief financial officer ("CFO"). The average bundled cost of a board of directors, CEO, and CFO of five Alaska Native corporations and four listed public utilities in the Northwestern part of the U.S.[4] is approximately $6.6 million. In contrast, ENSTAR was only allocated

[4] The five Alaska Native corporations are: (i) Bristol Bay Native Corporation; (ii) Doyon, Ltd.; (iii) Cook Inlet Region, Inc.; (iv) Calista Corporation; and (v) NANA Regional Corporation. The four public utilities in the Northwestern part of the U.S. are: (i) ATN International, the parent company of Alaska

approximately $0.9 million of total costs (including both compensation and third-party costs) associated with TSU's Board and Executive Committee in 2024.

For these reasons, the costs ENSTAR pays to obtain the Corporate Services from TSU are competitive with (and less than) the costs the Company would incur to obtain the services from third parties, assuming the services were even available.

Q. Has ENSTAR analyzed what it would cost to perform the Corporate Services with its own personnel and funding?

A. Yes. To address AS 42.05.511(c), ENSTAR has undertaken an analysis to determine what it would cost to self-provide the Corporate Services, assuming ENSTAR was a stand-alone entity with no parent company. This hypothetical analysis, also discussed in Company witness Mr. John D. Sims' testimony, demonstrates that the cost to self-provide the suite of services is much higher than the costs ENSTAR incurs to obtain the services from TSU. In the analysis, ENSTAR included some of the known third-party costs necessary to perform the services and additional employee compensation costs. Attached to my testimony as Exhibit ADJ-5 is a summary of the analysis that I co-sponsor with Mr. Sims, which depicts a hypothetical workforce and some of the associated third-party costs ENSTAR would incur if the Company were to self-provide the services provided by TSU.

Taking into consideration market data, as well as TSU's practices with regard to employee benefits and compensation, ENSTAR estimates that it would cost approximately $11.2 million to perform the services that TSU currently performs, in

Communications Systems Group, Inc.; (ii) Avista Corporation, the parent company of Alaska Electric Light & Power; (iii) Northwest Natural Gas Company; and (iv) Puget Sound Energy, Inc.

comparison to the $2.9 million ENSTAR received as an allocation of performed Corporate Services.

The Company's analysis does not take into consideration the significant years of management experience or the industry knowledge that ENSTAR benefits from as part of a diversified energy company. While it may be hard to put a price on those advantages, ENSTAR would unquestionably lose the advantages if it were a stand-alone company.

V. CONCLUSION

Q. Are the Corporate Services that TSU provides to ENSTAR, and the costs associated with those services, reasonable and necessary?

A. Yes. The Corporate Services that TSU provides to ENSTAR are necessary and in the public interest, and they are complementary to—and not duplicative of—other services that the Company's own employees perform internally. The allocation method TSU uses to allocate Corporate Services costs to ENSTAR and its other business units is widely accepted, and TSU uses an established, effective process to develop and manage the costs it incurs to provide Corporate Services. TSU's provision of these services benefits ENSTAR's customers in numerous ways, including through reduced costs. The costs associated with the Corporate Services are less than they would be if ENSTAR performed the services for itself, and they are competitive with the costs ENSTAR would incur to obtain the services from an unaffiliated third party, assuming

it could do so. For these reasons, the Corporate Services and associated costs are reasonable and necessary.

Q. Does this conclude your direct testimony?

A. Yes.

Andrea D. Jackson

EMPLOYMENT

TriSummit Utilities Inc. Calgary, Alberta, Canada: 2019 – Present

Treasurer: 2025 – Present

Assistant Treasurer: 2021 – 2025

Manager Treasury & Planning: 2019 – 2021

AltaGas Ltd. Calgary, Alberta, Canada: 2006 – 2019

Manager – Treasury: 2013 – 2019

Manager – Budgeting & Planning: 2011 – 2013

Sr. Procurement Business Analyst: 2010 – 2011

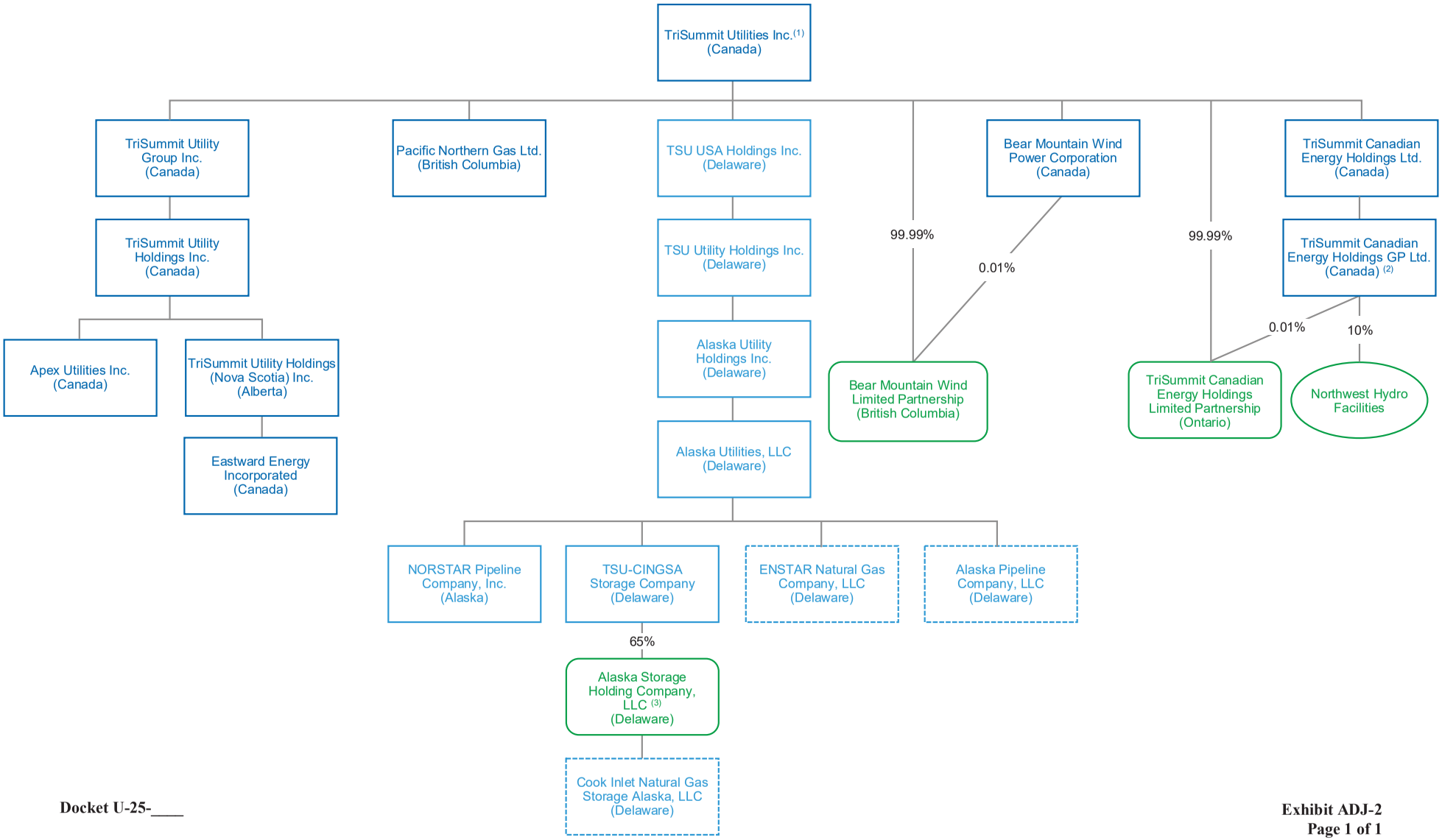
Senior Business Advisor – Enterprise Planning: 2009 – 2009

Financial Analyst – Budgeting, Planning and Forecasting: 2006 – 2008

EDUCATION

Emory University, Goizueta Business School: Master of Business Administration, 2010

University of Lethbridge: Bachelor of Management, Finance/BA English, 2005


TriSummit Utilities Inc.(1)
(Canada)
TriSummit Utility Group Inc.
(Canada)
Pacific Northern Gas Ltd.
(British Columbia)
TSU USA Holdings Inc.
(Delaware)
Bear Mountain Wind Power Corporation
(Canada)
TriSummit Canadian Energy Holdings Ltd.
(Canada)
TriSummit Utility Holdings Inc.
(Canada)
TSU Utility Holdings Inc.
(Delaware)
99.99%
0.01%
99.99%
TriSummit Canadian Energy Holdings GP Ltd.
(Canada) (2)
0.01%
10%
Apex Utilities Inc.
(Canada)
TriSummit Utility Holdings (Nova Scotia) Inc.
(Alberta)
Alaska Utility Holdings Inc.
(Delaware)
Bear Mountain Wind Limited Partnership
(British Columbia)
TriSummit Canadian Energy Holdings Limited Partnership
(Ontario)
Northwest Hydro Facilities
Eastward Energy Incorporated
(Canada)
Alaska Utilities, LLC
(Delaware)
NORSTAR Pipeline Company, Inc.
(Alaska)
TSU-CINGSA Storage Company
(Delaware)
ENSTAR Natural Gas Company, LLC
(Delaware)
Alaska Pipeline Company, LLC
(Delaware)
65%
Alaska Storage Holding Company, LLC (3)
(Delaware)
Cook Inlet Natural Gas Storage Alaska, LLC
(Delaware)

Alaska Statutes

Sec. 42.05.511. Unreasonable management practices.
(c) In a rate proceeding, the utility involved has the burden of proving that any written or unwritten contract or arrangement it may have with any of its affiliated interests for the furnishing of any services or for the purchase, sale, lease, or exchange of any property is necessary and consistent with the public interest and that the payment made therefor, or consideration given, is reasonably based, in part, on the submission of satisfactory proof as to the cost to the affiliated interest of furnishing the service or property and, in part, on the estimated cost the utility would have incurred if it furnished the service or property with its own personnel and capital.

Sec. 42.05.441. Valuation of property of a public utility.
(c) For rate-making purposes, indebtedness, debt service, and payments by a regulated public utility to a person having an ownership interest of more than 70 percent in the utility shall be considered to be ownership equity, profits, or dividends except to the extent that there is a clear and convincing showing that: (1) the indebtedness was incurred, or the payments made, for goods or services that were reasonably necessary for the operation of the utility; and (2) the goods or services were provided at a cost that was competitive with the price at which they could have been obtained from a person having no ownership interest.

AS 42.05.990(1). Affiliated interest includes

(A) a person owning or holding directly or indirectly five percent or more of the voting securities of a public utility engaged in intrastate business in this state;
(B) a person, other than those specified in (A) of this paragraph, in a chain of successive ownership of five percent or more voting securities, the chain beginning with the holder of the voting securities of such public utility;
(C) a corporation five percent or more of whose voting securities are owned by a person owning five percent or more of the voting securities of the public utility or by a person in such a chain of successive ownership of five percent or more of the voting securities;
(D) a corporation which has one or more officers or directors in common with a public utility;
(E) a person with whom the public utility has a management or service contract;
(F) a person who is an officer of such a public utility or of a corporation in a chain of successive ownership of five percent or more voting securities
(G) a corporation which has one or more officers or directors in common with a public utility;
(H) a person or corporation who or which the commission determines as a matter of fact, after investigation and hearing, actually is exercising such substantial influence over the policies and actions of a utility in conjunction with one or more other corporations or persons with whom they are related by ownership or blood, or by action in concert, that together they are affiliated with the utility within the meaning of this section even though none of them alone is so affiliated; or
(I) a person or corporation who or which the commission determines as a matter of fact after investigation and hearing actually is exercising substantial influence over the policies and actions of a utility even though such influence is not based upon stockholdings, stockholders, officers or directors to the extent specified in this section.

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AMENDED AND RESTATED SERVICES AGREEMENT

THIS AGREEMENT is made effective November 17, 2023 (the "**Effective Date**").

BETWEEN:

TRISUMMIT UTILITIES INC., a corporation incorporated pursuant to the laws of Canada having an office in Calgary, Alberta, Canada ("**TSU**")

AND

ENSTAR NATURAL GAS COMPANY, LLC a limited liability company pursuant to the laws of Delaware having an office in Anchorage, Alaska, United States of America and **ALASKA PIPELINE COMPANY, LLC** a limited liability company pursuant to the laws of Delaware having an office in Anchorage, Alaska, United States of America (collectively referred to as "**ENSTAR**")

WHEREAS

A. Each Party wishes to retain the other Party to provide certain Services on the terms and conditions set forth in this Agreement; and

B. The Parties are willing to render such Services under those terms and conditions.

NOW THEREFORE in consideration of the premises and the mutual covenants and agreements contained herein, the sufficiency of which is hereby acknowledged by each of ENSTAR and TSU (individually, each being a "**Party**" and, collectively, the "**Parties**") agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement:

"**Affiliate**" when used to indicate a relationship with a person or company has the same meaning as set forth in the Alaska Public Utilities Regulatory Act;

"**Agreement**" means this Amended and Restated Services Agreement;

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"**Applicable Law**" means any applicable law including any statute, regulation, by-law, treaty, guideline, directive, rule, standard, requirement, policy, order, judgment, decision, injunction, award, decree or resolution of any Governmental Authority, whether or not having the force of law, binding on the Parties;

"**Business Day**" means a day, other than a Saturday, Sunday or statutory holiday, when banks are generally open in Calgary, Alberta, Anchorage, Alaska, and New York City, New York, for the transaction of banking business;

"**Expenses**" means all reasonable out-of-pocket expenses incurred by a Provider in connection with carrying out its duties and obligations under this Agreement;

"**Fee**" means a fee payable to a Provider by a Recipient as consideration for the provision of the Services;

"**Force Majeure**" means for the purposes hereof, an event, condition or circumstance (and the effect thereof) which is not within the reasonable control of the party claiming Force Majeure and which, by the exercise of due diligence the party claiming Force Majeure is unable to prevent or overcome, including acts of god, fire, explosion, civil disturbance, war, riot, insurrection, military or guerrilla action, terrorist activity, economic sanction, blockade or embargo, sabotage, flooding, earthquake, drought and action or restraint by the order of any governmental authority (so long as the party claiming Force Majeure has not applied for or assisted in the application for, and has opposed where and to the extent commercially reasonable, such action or restraint by such governmental authority); provided, however, that a party's own lack of funds shall not constitute "Force Majeure" in respect of such party;

"**Governmental Authority**" includes any court (including a court of equity); any multinational, federal, provincial, state, regional, municipal or other government or governmental department, ministry, commission, board, bureau, agency or instrumentality; any securities commission, stock exchange or other regulatory or self-regulatory body; any arbitrator or arbitration authority; or any other governmental authority;

"**Insolvent**" means, in relation to any person, being insolvent, bankrupt, making a proposal under the *Bankruptcy and Insolvency Act* (Canada) RSC 1985, c B-3 or the U.S. Bankruptcy Code, or having a trustee or receiver or manager appointed in respect of its assets;

"**Normalized EBITDA**" means, for ENSTAR, total earnings before interest, depreciation and amortization as calculated using figures from ENSTAR's annual audited financial statements prepared in accordance with the accounting principles set out in Section 1.7 for the period ending December 31 adjusted for any normalization adjustments as determined in the preparation of TSU's management discussion and analysis for the period ending December 31; for TSU, total earnings before interest, deprecation and amortization of TSU's operating businesses for the period ending December 31 adjusted for any normalization adjustments as determined in the preparation

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of TSU's management discussion and analysis for the period ending December 31 plus the pro-rata share of normalized EBITDA from its equity investments;

"**Payroll**" means, for ENSTAR, total salaries and wages including bonuses, if any, for any given calendar year; for TSU, total salaries and wages including incentive compensation if any, of TSU's operating businesses for any given calendar year;

"**Person**" includes any individual, body corporate, partnership, association, joint venture, trust, other organization or entity (whether or not a legal entity) or Governmental Authority;

"**Provider**" means a Party providing Services under this Agreement;

"**Recipient**" means a Party receiving Services under this Agreement;

"**Representatives**" means, with respect to any Party, any of such Party's directors, officers, employees, consultants, advisers and agents;

"**Services**" means the services to be provided to a Recipient by a Provider as more particularly described in Schedule "A"; and

"**Total Property**" means, for ENSTAR, property, plant and equipment, including construction work-in-progress, plus materials, supplies and gas inventories, as shown in ENSTAR's annual audited financial statements prepared in accordance with the accounting principles set out in Section 1.7 as at December 31; for TSU, the total property, plant and equipment plus materials, supplies and gas inventories of TSU's operating businesses as at December 31 plus the pro-rata share of property, plant and equipment from its equity investments.

1.2 Schedules

Schedule "A" and Schedule "B" are attached to, and are incorporated by reference into, this Agreement.

1.3 Interpretation

In and for the purpose of this Agreement:

(a) This "Agreement" means this Agreement as the same may, from time to time, be modified, supplemented or amended in effect;

(b) Any reference in this Agreement to a designated "Article", "section" or other subdivision is to the designated Article, section or other subdivision of this Agreement;

(c) The words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section or other subdivision;

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(d) The headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement; and

(e) The singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto).

1.4 Currency

Unless otherwise indicated, all sums of money referred to in this Agreement are expressed in lawful currency of Canada.

1.5 Date for Any Action

If, under this Agreement, one or both of the Parties are required to undertake some action and the date when the action is required is not a Business Day, such action shall be required to be taken on the next Business Day.

1.6 Entire Agreement

This Agreement and any documents attached to this Agreement constitute the entire agreement between the Parties with respect to the Services set forth herein and supersede all other prior agreements, understandings, negotiations and discussions, whether oral or written, between the Parties with respect thereto.

1.7 Accounting Principles

For purposes of this Agreement, reference to generally accepted accounting principles ("**GAAP**") will mean a reference to the GAAP as adopted by TSU. In the event TSU changes the GAAP it adopts, it shall provide prompt written notice to ENSTAR describing the change and the effective date of the change.

1.8 Governing Law

Interpretation of this Agreement and the rights and remedies of the Parties will be determined in accordance with the laws of the Province of Alberta and the laws of Canada.

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ARTICLE 2
SERVICES

2.1 Services

A Provider hereby agrees to provide to a Recipient the Services, assistance, and advice as further described in Schedule "A", which are of benefit to the Recipient.

2.2 Affiliates

TSU and ENSTAR agree that ENSTAR may request Services from other Affiliates of TSU, and Affiliates of TSU other than ENSTAR may request Services from ENSTAR, as if such Affiliates were original parties hereto. To the extent Services are provided to ENSTAR by other Affiliates of TSU under this Agreement, or to other Affiliates of TSU by ENSTAR, references to a Party or the Parties (including, for clarity, references to ENSTAR, TSU, Recipient, and Provider) shall be read to mean such other Affiliates, as applicable, and the terms and conditions of this Agreement shall apply *mutatis mutandis*.

Fees and Expenses incurred for Services provided to or by other Affiliates of TSU in accordance with this Section may be invoiced directly by a Provider to the Recipient. Without limiting the liability of TSU hereunder, an Affiliate of TSU receiving or providing Services under this Agreement shall not be jointly or jointly and severally liable for the obligations of TSU or any other Affiliates of TSU under this Agreement.

When either Party receives Services from another Party and the costs associated with those Services are not allocated using the methodology set forth in Schedule "B", but instead are directly charged to the other Party, the relevant charges will be based on the lesser of fair market value or the cost to the Party of providing the Services, with cost inclusive of reasonable overhead if appropriate.

2.3 No Obligation to Provide Additional Services

Neither Party shall have an obligation to perform any services on behalf of the other Party except as set out in this Agreement.

2.4 Consultation with ENSTAR

Each Party will consult with the other Party, as required, concerning the performance of the Services.

2.5 No Partnership, Joint Venture, Agency or Trust

The Parties are not and shall not be deemed to be partners or joint venturers with one another and nothing herein shall be construed so as to impose any liability as such on any of them. The Parties

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agree that a Provider shall perform its obligations under this Agreement as an independent contractor and shall not be, and shall not be deemed to be, a trustee for any person, whether or not a party, in connection with the discharge by the Provider of such obligations. A Provider's employees, contractors or agents shall not be construed as employees of a Recipient for any purpose.

2.6 Standard of Care

In exercising its powers and discharging its duties under this Agreement, a Provider shall exercise the powers and discharge the duties conferred hereunder honestly, in good faith and in the best interests of the Recipient and in connection therewith shall exercise that degree of care, diligence and skill that a reasonably prudent professional administrator and service provider having responsibilities of a similar nature would exercise in comparable circumstances.

2.7 Confidentiality of Information

Each Party hereby agrees that, unless the written consent of the other Party is obtained, a Party (the "**Informed Party**") will not at any time use, disclose or make available, to any Person, any information (herein "**Confidential Information**") concerning the business carried on by the other Party which is acquired in connection with conducting the activities contemplated herein, provided that notwithstanding the foregoing, the Informed Party may make use of, reveal or disclose Confidential Information:

(a) as may be expressly permitted by this Agreement;

(b) where it is already in the public domain when disclosed to the Informed Party or becomes, after having been disclosed to the Informed Party, generally available to the public through publication or otherwise unless the publication or other disclosure was made directly or indirectly by the Informed Party in breach of this Agreement;

(c) as required in order to comply with Applicable Laws, the orders or directions of any Governmental Authority, or the requirements of any other Governmental Authority having jurisdiction;

(d) where it was made available to the Informed Party on a non-confidential basis from a third party source, or where such information can be demonstrated by the Informed Party to have come into its possession independently of anything done by the Informed Party under or pursuant to this Agreement;

(e) where required for the purposes of performing its obligations under this Agreement, to Affiliates of the Informed Party and the Representatives of the Informed Party and its Affiliates, provided such Persons have agreed to maintain such Confidential Information in confidence on terms substantially similar to those in this Section 2.7; and

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(f) as necessary in connection with any dispute resolution or any litigation commenced in respect of this Agreement.

Confidential Information provided to a Provider to enable the Provider to carry out its responsibilities under this Agreement shall be used by the Provider only to the extent necessary to fulfill its responsibilities under this Agreement and with respect to corporate governance, policy and strategic direction of businesses affiliated with TSU.

A Recipient will not release to a Provider confidential information relating to a utility customer or prospective utility customer of the Recipient, without receiving the prior written consent of the utility customer or prospective utility customer of the Recipient, unless such confidential information is required:

(a) for the purpose of a court proceeding or a proceeding before a quasi-judicial body to which the utility customer of the Recipient is a party;

(b) for the purpose of complying with a subpoena, warrant, or order issued or made by a court, person or body having jurisdiction to compel the production of information or with a rule of court that relates to the production of information;

(c) to a municipal or provincial police service for the purpose of investigating an offence involving the utility customer of the Recipient, if the disclosure is not contrary to the express request of the utility customer of the Recipient;

(d) by Applicable Law or by an order of a government or agency having jurisdiction over the Recipient; or

(e) by the Provider for the purpose of performing the Services, provided appropriate measures are first put in place by the Provider to protect the confidential information and the confidential information is used by the Provider only for the purpose of performing the Service.

ARTICLE 3
COMPENSATION

3.1 Compensation for Services and Shared Costs

Except as otherwise specified in this Agreement, a Recipient agrees to pay to the Provider a Fee for the Services as set out in Schedule “B”.

3.2 Amendment to Costs

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The amounts set out in Schedule "B" may be amended annually by agreement between the Parties to reflect the forecast cost expected to be incurred in performing the Services.

In the event services to be provided by a Provider to a Recipient are not contemplated under this Agreement, they will be subject to additional compensation as agreed between the Parties and will require an amendment to this Agreement in accordance with Section 10.3.

To the extent such additional services are provided specifically by a Provider to a Recipient ("**Direct Services**"), the cost for such Direct Services will be determined based on the actual time spent by the Provider to perform such Direct Services multiplied by the direct labor cost, plus Expenses, if any, incurred by the Provider or its Affiliate, in performing such Direct Services. Expenses which can be directly assignable to a Recipient maybe identified and assigned. It is expected that such expenses will be of two types, specific and allocated.

(a) Specific expenses are those which are received by a Provider or its Affiliate and which identify specifically the cost responsibility of a Recipient. Examples include certain outside accounting services; and

(b) Allocated direct billings are those which are received by a Provider or its Affiliate and which are attributable to a Recipient on the basis of an allocation factor which relates to the incurring of the expense. Examples of such included incurred expenses related to property and employee benefits related to numbers of employees.

3.3 Invoicing

A Provider will invoice the Recipient for Services performed no later than the 25th day following the end of the month or in such other manner as the Parties may agree.

3.4 Payment

Within thirty (30) days of receipt of an invoice from a Provider, the Recipient will pay to the Provider or any Person specified by the Provider the amount specified in such invoice. In the event a Recipient disputes the invoiced amount, it shall send written notice to the Provider no later than 15 days after receipt of the invoice to describe the nature of the dispute. Both Parties shall resolve the dispute through good faith negotiation, failing which the matter shall be resolved in accordance with Section 8.1. The Provider shall re-issue the invoice to the Recipient after resolution of the disputed invoice amount, and the Recipient shall pay to the Provider the amount specified on the re-issued invoice within thirty (30) days of receipt.

Any amount to be remitted by a Recipient to a Provider and not remitted on or before the date when it is due shall thereafter bear interest. Any amounts unpaid thirty (30) days after the date of invoice will be subject to a late charge of 1.5% per month (18% per annum) payable to the Provider.

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3.5 Taxes

Notwithstanding any other provision of this Agreement, amounts paid or payable by one Party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are currently or may, during the term of this Agreement, become applicable to the provision of the Services. A Recipient shall pay to a Provider any value added taxes or sales tax the Provider is obligated to collect from the Recipient in relation to amounts paid or payable under this Agreement within thirty (30) days of receipt of an invoice requesting such payment.

ARTICLE 4
INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by Recipient

Subject to Section 4.4, a Recipient will indemnify, defend and hold the Provider and its directors, officers, employees, agents and contractors, harmless from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgment or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur, directly or indirectly, in whole or in part, in connection with the Provider's provision of the Services, except and to the extent, if any, the same results from, or arises out of, the willful misconduct or gross negligence of the Provider.

4.2 Limitation of Liability of Provider

Neither a Provider nor any of its directors, officers, employees, agents or contractors will be liable to the Recipient for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgment or award, or cost or expense (including reasonable legal fees and disbursements) which the Recipient may suffer or incur, directly or indirectly, in whole or in part, in connection with the Provider's provision of the Services, except and to the extent, if any, the same results from or arises out of the willful misconduct or gross negligence of the Provider.

4.3 Indemnity by Provider

Subject to Section 4.4, a Provider will indemnify, defend and hold the Recipient and its directors, officers, employees, agents and contractors harmless from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgment or award and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur as a result of any act or omission or error of judgment as a result of which the Provider is adjudged to have been guilty of willful misconduct or gross negligence.

4.4 Consequential Losses

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Neither Party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

ARTICLE 5
COVENANTS

5.1 Covenants by Recipient

A Recipient covenants and agrees to:

(a) fully co-operate with the Provider in respect of all matters contemplated by or within the scope of this Agreement; and

(b) Subject to Section 3.4, pay on or before the due date specified on any invoice, all amounts payable by the Recipient to the Provider or any other Person pursuant to, or as contemplated by, this Agreement.

5.2 Covenants by Provider

A Provider covenants and agrees to:

(a) comply with all Applicable Laws in performing the Services; and

(b) provide, upon request, data necessary to support the Fee.

ARTICLE 6
REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of Provider

Throughout the duration of this Agreement, a Provider represents and warrants to the Recipient:

(a) the Provider has been duly organized or created, is validly existing under the laws of its jurisdiction of formation or creation, is in good standing (or the equivalent) in its jurisdiction of formation, and has full power and authority to perform its obligations under this Agreement;

(b) This Agreement constitutes a valid and binding obligation of the Provider enforceable in accordance with its terms and conditions. Notwithstanding this, (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now

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or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defenses and to the discretion of the court before which any proceeding may be brought; and

(c) the Provider possesses all of the skills and personnel required to provide the Services.

Other than the warranties and representations expressly set forth herein, a Provider makes no other representations or warranties of any kind, whether statutory, oral, written expressed or implied, including any relating to merchantability or fitness for any particular purpose of the Services or any of them, which representations and warranties are hereby expressly disclaimed.

6.2 Representations and Warranties of Recipient

Throughout the term duration of this Agreement, a Recipient represents and warrants to the Provider:

(a) the Recipient has been duly organized or created, is validly existing under the laws of its jurisdiction of formation or creation, is in good standing (or the equivalent) in its jurisdiction of formation, and has full power and authority to perform its obligations under this Agreement; and

(b) This Agreement constitutes a valid and binding obligation of the Recipient enforceable in accordance with its terms and conditions. Notwithstanding this, (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defenses and to the discretion of the court before which any proceeding may be brought.

Other than the warranties and representations expressly set forth herein, a Recipient makes no other representations or warranties of any kind, whether statutory, oral, written expressed or implied, which representations and warranties are hereby expressly disclaimed.

ARTICLE 7
DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective from the Effective Date and unless earlier terminated pursuant to Section 7.2, shall automatically be renewed for further one-year terms.

7.2 Termination

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This Agreement may be terminated at any time in the following ways:

(a) by TSU giving ENSTAR six (6) months' written notice of such termination; or

(b) immediately by TSU giving written notice to ENSTAR if ENSTAR:

(i) Becomes insolvent, admits in writing its inability to pay its debts as they become due, commits or threatens to commit, an act of bankruptcy or makes a general assignment for the benefit of creditors;

(ii) Becomes subject to any proceeding instituted by, or against ENSTAR, adjudicating ENSTAR as bankrupt, Insolvent, seeking the dissolution, winding-up, liquidation, reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors, seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or ENSTAR consents by answer, acquiescence or otherwise to the institution of any such proceeding(s) against it; or

(iii) In the event ENSTAR breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by ENSTAR of written notice of such breach from TSU or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence, in good faith, the curing of such breach forthwith upon receipt of written notice thereof from TSU and to continue to diligently pursue the curing of such breach thereafter until cured;

(c) by ENSTAR giving TSU six (6) months' written notice of such termination; or

(d) immediately by ENSTAR giving written notice to TSU if TSU:

(i) Becomes insolvent, admits in writing its inability to pay its debts as they become due, commits or threatens to commit, an act of bankruptcy or TSU makes a general assignment for the benefit of creditors;

(ii) Becomes subject to any proceeding instituted by, or against TSU, adjudicating TSU as bankrupt, Insolvent, seeking the dissolution, winding-up, liquidation, reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors, seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official, or TSU consents by answer, acquiescence or otherwise to the institution of any such proceeding(s) against it; or

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(iii) In the event TSU breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TSU of written notice of such breach from ENSTAR or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence, in good faith, the curing of such breach forthwith upon receipt of written notice thereof from ENSTAR and to continue to diligently pursue the curing of such breach thereafter until cured;

(e) by either TSU or ENSTAR by giving the other Party 30-days' written notice of termination, in the event that TSU or its Affiliates collectively, directly or indirectly, own less than 20% of the total issued and outstanding common stock (or equivalent) of ENSTAR.

7.3 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, a Provider will have no further obligations under Article 2 and, upon receipt of payment in accordance with Section 7.4 and written request of the Recipient, will promptly deliver to the Recipient any material documentation, software or materials in the possession of the Provider pertaining to the business of the Recipient obtained through the provision of the Services. A Recipient will be entitled to retain a copy of any and all documents as required by law or as otherwise agreed upon by the Parties.

Upon expiry or termination of this Agreement for any reason, a Recipient will cease to receive or have access to the Services, and, upon written request of the Provider, the Recipient will forthwith deliver to the Provider any material documentation, software or materials in the possession of the Recipient pertaining to the business of the Provider obtained through the provision of the Services.

7.4 Compensation of Provider on Expiry or Termination

In the event of the expiration or termination of this Agreement for any reason, a Recipient will remain responsible to the Provider for payments of all Fees earned to which the Provider was entitled pursuant to, and in accordance with the terms and conditions of this Agreement, up to and including the date of expiration or termination. Within one (1) month after the termination of this Agreement, a Recipient will pay to the Provider all amounts owing to the Provider hereunder (including any amount owing on account of the Fee provided for in Article 3 calculated up to the date of termination). For the purposes of this Section, the Fee set forth in Article 3, which is payable to the Provider on a monthly, annual or other periodic basis, will be deemed to accrue due and be payable on a daily basis.

ARTICLE 8
ARBITRATION

8.1 Arbitration

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Any dispute between a Provider and a Recipient regarding an alleged breach of this Agreement may be submitted to, and settled by, arbitration. Arbitration proceedings may be commenced by the Party desiring arbitration giving notice to the other Party, specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator in accordance with the National Arbitration Rules of the ADR Institute of Canada Inc., in force from time to time. If the Parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either Party may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed. Such appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section will be final and binding upon the Parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both Parties, provided each Party will bear its own witness and counsel fees. The Parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgment on the award of the arbitrator may be entered in any court having jurisdiction over the Party against which enforcement of the award is being sought. Each Party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgment of any such award.

ARTICLE 9
FORCE MAJEURE

9.1 Consequence of Force Majeure

During the occurrence of an event of Force Majeure, the obligations of the Party affected by such event of Force Majeure, to the extent and for the period that such obligations are not performed as a result of such event of Force Majeure, shall be suspended. Such party shall not be considered to be in breach or default under this Agreement for the period of such occurrence, except that the occurrence of an event of Force Majeure (a) affecting a Recipient, but not affecting the performance of the Provider's obligations hereunder, shall not relieve the Recipient of its obligation to make payments of the Expenses of the Provider or the Fee to the Provider or (b) affecting a Provider, but not affecting the performance of the obligations of the Recipient hereunder, shall not relieve the Recipient of its obligation to make payments of the Expenses of the Provider incurred before the event of Force Majeure in respect of services performed by the Provider prior to such event of Force Majeure or the Fee attributable to the period prior to such event of Force Majeure. The suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure. Any obligation of a Party arising prior to the event of Force Majeure causing the suspension of performance shall not be excused as a result of the event of Force Majeure.

9.2 Performance Prevented by Force Majeure

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Any Party prevented from carrying out any obligation by Force Majeure shall promptly give notice to the other Party of the Force Majeure, including reasonably full particulars of the relevant circumstances and/or event.

9.3 Remedy of Force Majeure

A Party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such Party is reasonably able to do so. The terms of settlement of any strike, lockout or other industrial disturbance shall be wholly at the discretion of the Party claiming suspension of its obligations hereunder by reason thereof and such Party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to promptly remedy such Force Majeure.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money otherwise due under this Agreement.

ARTICLE 10
MISCELLANEOUS

10.1 Notice

Any notice, consent, waiver, direction or other communication required or permitted to be given under this Agreement by a Party to the other Party shall be in writing and shall be delivered by personal delivery, registered mail (provided that the mailing Party does not know, and should not reasonably have known, of any disruption or anticipated disruption of postal service which might affect delivery of the mail), or electronic means of communication, addressed to the Party to whom the notice is to be given, at its specified address herein. Any notice, consent, waiver, direction or other communication aforesaid shall, if hand delivered or delivered by electronic means, be deemed to have been given and received on the date on which it was hand delivered or delivered by electronic means of communication (if prior to 4:30 pm (local time at the place of receipt) on a Business Day and, if not, the next succeeding Business Day). If sent by registered mail, notice will be deemed to have been given and received on the fourth Business Day at the point of delivery following the date on which it was sent. For purposes of this Agreement any notice or other communication should be addressed to:

In the case of TSU:

TriSummit Utilities Inc.
3100, 300 – 5th Avenue SW

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Calgary, AB T2P 3C4
Canada

Attention: Executive Vice President, General Counsel and Corporate Secretary
Tel: (587) 955 3652
Email: legal@trisummit.ca

In the case of ENSTAR:

ENSTAR Natural Gas Company, LLC &
Alaska Pipeline Company, LLC
3000 Spenard Road
Anchorage, AK 99503
USA

Attention: Vice President and General Counsel
Tel: (907) 334-7662
Email: legal@enstarnaturalgas.com

or such other address as may be designated by either Party by notice to the other Party given in accordance with this Section.

10.2 Assignment

Neither Party may assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the other Party, such consent not to be unreasonably withheld. A Provider may subcontract to any person the performance of any of the Services, but any such subcontract will not release or relieve the Provider of the due and proper performance of such Services unless the Recipient relieves the Provider of any or all such obligations in writing.

10.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the Parties.

10.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

10.5 Further Assurances

Each Party shall, from time to time, and at all times hereafter, at the request of the other Party, but without further consideration, do all such further acts and execute and deliver all such further

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documents and instruments as shall be reasonably required in order to fully perform and carry out the terms and intent of this Agreement.

10.6 Waiver

No waiver by either Party shall be effective unless such waiver is in writing. Any waiver shall affect only the matter and shall not extend to any other matter or occurrence.

10.7 Amendment and Restatement

This Agreement amends and restates the services agreement between the Parties dated March 1, 2023 (the "**Original Agreement**") and is not a novation of the Original Agreement. All obligations under the Original Agreement shall continue as obligations under this Agreement, and this Agreement shall not evidence or result in the extinguishment of such obligations.

10.8 Counterparts

This Agreement may be executed in one or more counterparts, which, taken together, will constitute the execution page.

ENSTAR NATURAL GAS COMPANY, LLC

Per: _____
Name: John Sims
Title: President

ALASKA PIPELINE COMPANY, LLC

Per: _____
Name: Moira K. Smith
Title: Vice President & General Counsel

TRISUMMIT UTILITIES INC.

Per: DocuSigned by: Shaun Toivanen 0C4AB76D6F0247A...
Name: Shaun Toivanen
Title: EVP & CFO

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SCHEDULE "A"
DESCRIPTION OF SERVICES

TSU Services

ENSTAR receives the benefit of the expert advice and experience of TSU's Board of Directors, officers and employees.

TSU shall provide services and support to ENSTAR that are generally strategic in nature and focus on business oversight, development of and exercise of corporate governance, and ensuring ENSTAR has appropriate access to capital. These services include management, financing, planning, and financial advisory services; and any other services that ENSTAR may request and TSU agrees to provide. Such services and support may include services performed by, the offices of TSU's executive leadership, legal and corporate secretary, treasury, finance, investor relations, insurance, corporate and external reporting, general accounting, tax, corporate resources, internal audit and compliance, planning, human resources and any other services as may be required by ENSTAR to be performed by, and agreed upon by, TSU from time to time including as necessary for TSU to maintain access to capital to provide financing to ENSTAR as required.

Other Services

A Provider may provide certain support to a Recipient. This may include certain technical, advisory, and administrative support services, and any other technical, advisory, and administrative support services that the Recipient may request and the Provider agrees to provide.

The Services that may be performed are:

(a) financial reporting, treasury, tax, audit, and accounting services; and

(b) execution of debt financings, including rating agency reviews, investor reporting and marketing, liquidity management and legal reviews with respect to such financing matters.

In addition, upon request from a Recipient, a Provider may agree to provide certain other services to the Recipient, including information technology, regulatory, legal, engineering, construction, environmental, health and safety, and operations support, where the Provider determines, in its sole discretion, that it is prudent to do so. Unless the parties agree otherwise, those services will be provided in accordance with the terms of this Agreement.

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SCHEDULE "B"
PRICING

Calculation of the Fee for Services

(a) The Fee shall be calculated through the application of an allocator (the "**Allocator**").

(b) The Allocator is the simple average of three quotients that are calculated as:

(i) ENSTAR's Total Property in Canadian dollars divided by TSU's Total Property in Canadian dollars;

(ii) ENSTAR's Payroll in Canadian dollars divided by TSU's Payroll in Canadian dollars; and

(iii) ENSTAR's Normalized EBITDA in Canadian dollars divided by TSU's Normalized EBITDA in Canadian dollars.

(c) The Total Property, Payroll and Normalized EBITDA used in the calculation of the Allocator will be based on the most recent calendar year's data available after books are officially closed. As an illustration, 2021 year-end values are used to establish the Allocator for calculation of Fee in 2023, until such time when 2022 actual results are available, the Allocator will be re-calculated and the Fee in 2023 will be updated using the Allocator with 2022 inputs.

(d) In the event of material transactions such as acquisition or disposition of assets or investments, the Allocator will be determined as if the material transaction had occurred at the beginning of the period to establish the Allocator. The new Allocator will be applied effective transaction completion.

(e) The Fee is determined based on corporate general and administrative ("**G&A**") costs incurred by TSU's Calgary head office for the year in which the Fee is applicable, excluding:

(i) business development expenses;

(ii) compensation costs tied to share performance;

(iii) general corporate donations, promotion and advertising;

(iv) vehicle expenses; and

(v) social event costs.

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(f) The Fee is payable in twelve (12) equal monthly payments, or in such other manner as the Parties may agree.

(g) The Fee is computed in Canadian dollars but converted to United States dollars for invoicing. All currency conversions will use the average exchange rates for the last period obtained from Bank of Canada.

(h) Within 90 days of the end of the calendar quarter, the budgeted G&A costs used to determine the Fee will be trued up to reflect actual expenses. The Fee will be re-calculated based on the actual G&A costs incurred (the "**Trued-up Fee**"). Any variance between the Fee and the Trued-up Fee will be reconciled and collected or repaid, as the case may be, as part of the Fee for the subsequent year.

Summary of Costs to ENSTAR to Perform All Corporate Services Activities ($000s)

ENSTAR's Expense for TSU's Corporate Services			Costs if Corporate Services Moved to ENSTAR		
Corporate Services Function	**TOTAL**		**Function**	**FTE REQUIRED**	**TOTAL**
Board of directors	$210		Board of directors		$1,399
Executive Management	$722		Executive Management	2	$5,197
Acctg / Tax / Finance	$974		Acctg / Tax / Finance	3	$3,711
Corporate Resources (incl. Legal & Compliance)	$959		Corporate Resources (incl. Legal & Compliance)	3	$876
TOTAL Cost to ENSTAR	$2,866		**TOTAL Cost to ENSTAR**	**8**	**$11,183**
$8.3 million cost savings for ENSTAR with TSU performing Corporate Services					

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chairman
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Consideration of the Revenue Requirement Designated as TA 354-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF JENNIFER E. NELSON

PREFILED DIRECT TESTIMONY
OF
JENNIFER E. NELSON

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EXHIBITS

Exhibit JEN-1	Résumé and Testimony Listing of Jennifer E. Nelson
Exhibit JEN-2	Constant Growth DCF Results
Exhibit JEN-3	Quarterly Growth DCF Results
Exhibit JEN-4	Expected Market Return Calculations
Exhibit JEN-5	CAPM and Empirical CAPM Results
Exhibit JEN-6	Bond Yield Plus Risk Premium Analysis
Exhibit JEN-7	Small Size Premium Analysis
Exhibit JEN-8	Regulatory Risk
Exhibit JEN-9	LDC Proxy Group Capital Structure Analysis
Exhibit JEN-10	LDC Proxy Group Authorized Equity Ratio Analysis
Exhibit JEN-11	Map of U.S. Shale Gas Basins and Proxy Group Natural Gas Distribution Companies

I. POSITION AND QUALIFICATIONS

Q. Please state your name, business address, and present position.

A. My name is Jennifer E. Nelson. I am a Vice President at Concentric Energy Advisors. Concentric is a management consulting and economic advisory firm that specializes in the North American energy and water industries. Based in Marlborough, Massachusetts and Washington, D.C., Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts, 01752.

Q. Briefly describe your professional experience and educational background.

A. I have more than 15 years of experience in the energy industry, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to clients on a range of financial and regulatory issues including cost of capital, ratemaking policy, and regulatory strategy issues. Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities, and a petroleum economist at the Tax Division of the Alaska Department of Revenue. As a petroleum economist at the Tax Division, I managed the publication of the Revenue Sources Book and developed the oil and gas production forecast for both the North Slope and Cook Inlet. I completed utility regulatory training offered by New Mexico State University's Center for Public Utilities and have earned the Certified Rate of Return Analyst designation from the Society of Utility and Regulatory Financial Analysts based on my experience and successful completion of

an examination. I earned a Bachelor's degree in Business Economics from Bentley University and a Master's degree in Resource and Applied Economics from the University of Alaska Fairbanks. A summary of my professional and educational background, including a list of my testimony filed before regulatory commissions, is included as Exhibit JEN-1.

Q. Have you previously testified before the Regulatory Commission of Alaska ("RCA") or any other regulatory commission?

A. While I have not testified before the RCA, I have previously filed testimony before regulatory commissions in Arkansas, California, Delaware, Florida, Kentucky, Maine, Montana, New Hampshire, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, Virginia, West Virginia, and Wyoming. During my time as a consultant, I have supported the development of expert witness testimony and analyses regarding return on equity ("ROE") and capital structure in more than 100 proceedings filed before numerous U.S. state regulatory commissions and the Federal Energy Regulatory Commission.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide the RCA with a recommendation regarding ENSTAR Natural Gas Company, LLC's and Alaska Pipeline Company, LLC's (collectively, "ENSTAR" or "Company") ROE[1] and to

[1] Throughout my Direct Testimony, I use the terms "ROE" and "cost of equity" interchangeably.

assess the reasonableness of the Company's requested capital structure. My analyses and conclusions are supported by the data presented in Exhibits JEN-2 through JEN-11.

Q. Were your testimony and exhibits prepared by you or under your direct supervision and control?

A. Yes.

III. SUMMARY AND OVERVIEW OF TESTIMONY

Q. What are your conclusions regarding the appropriate cost of equity and capital structure for ENSTAR?

A. Based on my analyses of three widely used market-based financial models, the Company's risk profile, and the current capital market environment, I conclude that a range of 12.50 percent to 13.50 percent reflects investors' required return for an equity investment in ENSTAR. Within that range, I recommend a ROE at the midpoint, or 13.00 percent. As to the Company's capital structure, I conclude that its requested capital structure, consisting of 58.57 percent equity and 41.43 percent debt, is reasonable and within industry standards and should be used for ratemaking purposes. ENSTAR's requested weighted average cost of capital ("WACC") is shown in Figure 1 below.

Figure 1: Weighted Average Cost of Capital

	% of Capital	Cost (%)	Weighted Cost
Long-Term Debt	41.43%	5.55%	2.30%
Common Equity	58.57%	13.00%	7.61%
Total	100.00%		9.91%

Q. Please provide a brief overview of the analysis that led to your ROE recommendation.

A. My recommendation is developed using three widely accepted financial modeling approaches applied to a proxy group of 14 natural gas distribution utilities and pipeline utilities: (1) the constant growth and quarterly growth forms of the Discounted Cash Flow ("DCF") model; (2) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. The results of those analytical approaches are summarized in Figure 2 below.

Figure 2: Summary of Results[2]

Constant Growth DCF	Low	Mean	High
30-Day Average	10.48%	11.55%	13.10%
90-Day Average	10.69%	11.61%	13.15%
180-Day Average	11.04%	11.90%	13.38%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	10.73%	11.81%	13.40%
90-Day Average	10.95%	11.86%	13.46%
180-Day Average	11.30%	12.21%	13.71%
CAPM and Empirical CAPM		**Current 30-Year Treasury Yield (4.82%)**	**Projected 30-Year Treasury Yield (4.46%)**
CAPM (Forward Market Return)		14.33%	14.29%
Empirical CAPM (Forward Market Return)		14.57%	14.54%
CAPM (Blended Market Return)		12.91%	12.87%
Empirical CAPM (Blended Market Return)		13.11%	13.09%
Bond Yield Plus Risk Premium			
Current 30-Year Treasury Yield (4.82%)		10.30%	
Projected 30-Year Treasury Yield (4.46%)		10.13%	
Average		10.21%	
Alaska ROE Risk Adjustment		2.22%	
Average Risk Premium with Alaska Risk Adjustment		12.43%	

In addition to the methodologies noted above, my recommendation is supported by the Company's especially unique business risks that distinguish it from its Lower 48 peers as discussed in my testimony and the testimonies of ENSTAR witnesses Mr. John D. Sims and Ms. Inna B. Johansen. In particular, those risks include: (1) the

[2] *See* Exhibits JEN-2 through Exhibit JEN-6. DCF and CAPM results reflect the average of the proxy group mean and median ROE estimates. Data as of January 31, 2025.

Company's substantial transmission assets; (2) the Company's relative geographical isolation, harsh climate, and dependance on a less diversified economy; (3) its natural gas supply risk; (4) its significantly smaller size; and (5) the regulatory environment and the Company's need to access the capital necessary to maintain its assets and operations. I also consider the current capital market and macroeconomic environment in which utilities such as ENSTAR operate. Although those factors are relevant to investors, their effect on the Company's cost of equity cannot be precisely quantified.

Q. How do you determine your recommended range from the methods and results summarized above?

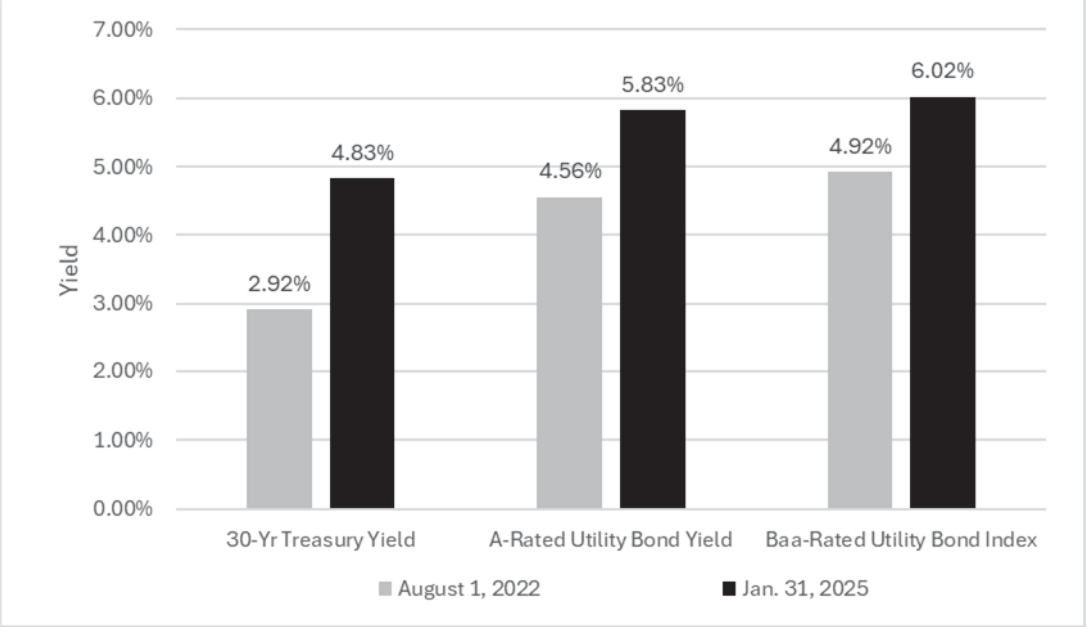
A. The cost of equity is an opportunity cost that cannot be precisely quantified. Therefore, it must be estimated using various financial models. Each of the ROE-estimation models is subject to limiting assumptions and each provides a different perspective on investors' return requirements under varying market conditions. The use of multiple financial models, therefore, enables a more robust and comprehensive assessment of the cost of equity instead of relying on one specific estimation model.

The low end of my range, 12.50 percent, is within the range of the DCF and the Risk Premium results. The high end of my recommended range, 13.50 percent, is within the range of the high DCF and CAPM results. Based on those considerations, it is my opinion that an ROE at the midpoint of the range, or 13.00 percent, is a just and reasonable estimate of ENSTAR's cost of equity.

Q. How has the capital cost environment changed since the Company filed its last rate case in August 2022?

A. By several measures, the capital cost environment has increased significantly since that proceeding. When ENSTAR filed its last rate case on August 1, 2022, the 30-year Treasury yield stood at approximately 2.92 percent and the A-rated and Baa-rated utility bond indices stood at approximately 4.56 percent and 4.92 percent, respectively. As of January 31, 2025, the 30-year Treasury bond yield was 4.83 percent, an *increase of more than 190 basis points,* as depicted in Figure 3 below. Utility bond yields have *increased by 110 to 127 basis points* over the same period, which is a direct indication of the increase in utility capital costs.

Figure 3: 30-Year Treasury Yield and Utility Bond Yield
(August 2022 vs. January 2025)

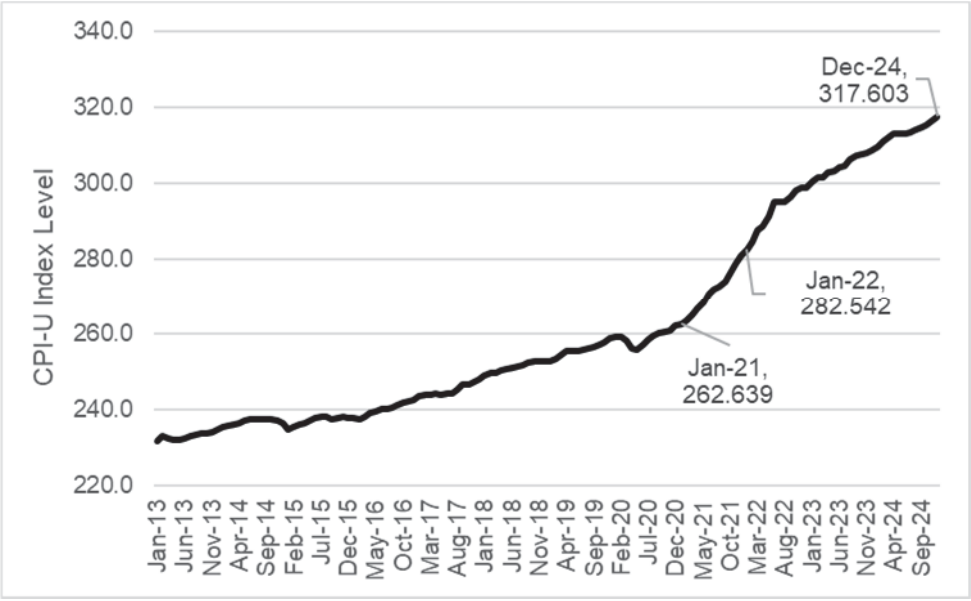


Prevailing long-term bond yields have a significant effect on utilities' cost of capital, as well as investors' return requirements. Rising Treasury yields signal to investors that they can earn a higher return investing in risk-free government bonds.

Because investors expect higher returns when investing in assets riskier than government-issued bonds such as utility equities, the cost of equity for utilities has increased along with the rise in interest rates, though not on a one-to-one basis.

Inflation has also increased dramatically since the last rate case. Nationally, inflation has increased by 12.4 percent on a cumulative basis between January 2022 and December 2024. As a comparison, inflation increased nationally by 20.9 percent between January 2021 and December 2024. Inflation data from prior periods is important because the actual impact of inflation is often delayed until months after inflation figures are published. Figure 4 below is the Consumer Price Index from 2013 through 2024.

Figure 4: Consumer Price Index (2013-2024)



Mr. Sims discusses the effects of Alaska's inflation in his direct testimony.

Bonds become less attractive (and therefore, their prices fall) when inflation is rising because inflation erodes the value (*i.e.*, price) of bonds. Since the yield on a bond moves inversely with the price, as prices fall, the yield increases. Therefore,

rising inflation contributes to higher capital costs. As explained in Section V, capital costs are part of the cost of service and reflect the cost that the Company must pay its debt and equity investors to compensate them for the use of their financial capital. An ROE that does not sufficiently allow ENSTAR to recover its higher capital costs ultimately reduces the Company's relative attractiveness to investors and further increases the cost of debt and equity.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

- Section IV – Discusses the specific business and regulatory risks that have a direct bearing on the Company's access to capital and cost of equity;
- Section V – Provides a summary of issues regarding the cost of equity estimation in regulatory proceedings, describes the regulatory guidelines pertinent to the development of the cost of capital, explains my selection of the proxy group used to develop my analytical results, and describes my analyses on which my ROE determination is based;
- Section VI – Assesses the Company's requested capital structure;
- Section VII – Reviews the current capital market conditions and the effect on the cost of equity; and
- Section VIII – Summarizes my conclusions and recommendations.

IV. ENSTAR'S BUSINESS RISK PROFILE

Q. Please provide a summary profile of ENSTAR.

A. ENSTAR is a wholly owned subsidiary of Alaska Utility Holdings, Inc., which in turn is a subsidiary of TriSummit Utilities, Inc. ("TSU"). The Company is an integrated, hybrid system composed of both natural gas transmission and distribution assets and serves approximately 155,000 residential, commercial, and industrial customers in the Southcentral Alaskan region. ENSTAR's service territory extends from Willow to the north of Anchorage, to Whittier to the southeast, and south to Homer, a distance

covering approximately 300 road miles. While ENSTAR does not have standalone credit ratings, Morningstar DBRS rates its direct parent Alaska Utility Holdings, Inc. as "BBB (high)." This rating is equivalent to a rating of BBB+ from Standard and Poor's ("S&P") and Fitch Ratings ("Fitch"), and a rating of Baa1 from Moody's Investor Service ("Moody's").

Q. Please provide a description of ENSTAR's system.

A. ENSTAR's transmission system consists of two high-pressure natural gas pipeline systems that extend from natural gas production fields on either side of the Cook Inlet and transport gas to the Anchorage area. The Kenai pipeline system transports natural gas from the East side of the Cook Inlet and the Beluga pipeline system transports gas from the West side. The transmission system also consists of two compressor stations that include a total of eight compressors. ENSTAR's distribution system consists of approximately 3,300 miles of distribution service mains that deliver natural gas to 140,000 service lines serving approximately 155,000 customers. As of December 31, 2024, ENSTAR's transmission system represented approximately 40 percent of its total transmission and distribution plant. Please see the direct testimony of Mr. Sims for additional description of the ENSTAR system.

Q. Are there factors specific to ENSTAR's operating environment that you considered in your ROE recommendation?

A. Yes, there are several additional factors that have a direct bearing on ENSTAR's ability to earn a fair return and on the Company's riskiness relative to a typical natural gas distribution utility[3] operating in the Lower 48, including its: (1) operation and

[3] Also known as a Local Distribution Company or "LDC."

maintenance of substantial transmission infrastructure; (2) geographic isolation, harsh climate, and dependence on a less diversified economy; (3) natural gas supply risk; (4) significantly smaller size; and (5) regulatory risk and the need to maintain access to capital.

Q. Has the RCA previously acknowledged the additional unique risks associated with operating a utility business in the state of Alaska?

A. Yes, the RCA has acknowledged that utilities operating in Alaska face relatively higher risk compared to those operating in the Lower 48. For example, in Docket U-16-066, the RCA noted the increased relative risks that ENSTAR faces due to factors such as less diverse natural gas supply sources, geographic isolation resulting in a relatively higher cost environment, and challenging economic conditions.[4]

A. Transmission and Distribution Utility Operations

Q. Please describe ENSTAR's transmission and distribution utility operations and how ENSTAR's transmission operations compare to the proxy group.

A. As described earlier, and in the direct testimony of Mr. Sims, ENSTAR functions as a natural gas transmission utility and a natural gas local distribution company. When compared to the natural gas LDCs in the proxy group described in Section V, ENSTAR has more than three times the average natural gas transmission plant in service as the gas utilities in the proxy group, as shown in Figure 5 below. As described in Section V below, I account for ENSTAR's greater proportion of riskier transmission operations

[4] Order U-16-066(19) *Order Resolving Revenue Requirement and Cost-of-Service Issues and Requiring Filings*, September 22, 2017, at 52. The RCA reiterated its acknowledgement of ENSTAR's diminishing natural gas supply in its last rate case. Order U-22-081(14), *Order Resolving Return of Equity Issue, Requiring Filings, and Redesignating Commission Panel*, April 8, 2024, at 32.

by including seven pipeline companies that have regulated natural gas pipeline operations in the proxy group.

Figure 5: 2023 Regulated Natural Gas Transmission Plant (%)[5]

Company	Transmission Plant in Service (%)
Atmos Energy Corp.	25.02%
New Jersey Resources	18.79%
NiSource, Inc.	6.01%
Northwest Natural Holdings	14.47%
ONE Gas, Inc.	9.35%
Southwest Gas Holdings	4.53%
Spire, Inc.	5.90%
Average	**12.01%**
ENSTAR Natural Gas	**37.94%**

Q. How do transmission assets increase ENSTAR's risk relative to companies that are primarily LDCs?

A. Maintaining and operating transmission assets in Alaska presents unique risks that are more severe than those faced by natural gas distribution companies. Generally, transmission assets require significant capital expenditures to maintain reliability and safety for customers. These processes are often more complex, more specialized, and costlier when compared to those for natural gas distribution companies. Furthermore, maintenance of transmission assets in Alaska's harsh environment and climate,

[5] Source: S&P Capital IQ; Annual Report of ENSTAR Natural Gas Company/Alaska Pipeline Company for the Year Ended December 31, 2023. Transmission plant in service as a percentage of distribution and transmission plant in service. 2024 data was not available at the time of original submission.

expansive footprint, and its geographical isolation increase the risks and costs associated with providing reliable and safe natural gas to customers.

ENSTAR must also design, maintain, and operate in compliance with the transmission-related requirements set by the Pipeline Hazardous Material Safety Administration ("PHMSA"). As a result, ENSTAR must regularly conduct leak surveys, in-line inspections, right-of-way inspections, and other requirements on a cycle as per code requirements. Code requirements continue to evolve as more technologies become available and materials improve, and this requires continued vigilance and investment. In his direct testimony, Mr. Sims explains how maintaining natural gas transmission assets is more complex and expensive than distribution assets. These tasks are even more challenging for ENSTAR given its harsh climate, vulnerability to natural disasters, and the large geographic area it serves.

B. Geographic Concentration and Isolation

Q. Please describe the primary location of ENSTAR's operations.

A. As described by Mr. Sims in his direct testimony, ENSTAR's overall transmission pipeline system is comprised of two separate pipeline systems that extend from production fields located on either side of Cook Inlet and transport gas into the Anchorage area. The transmission assets move gas from the Cook Inlet to large consumers (*i.e.*, power generation facilities) and to the Company's distribution system. The distribution assets deliver natural gas to smaller end-users such as homes, schools, and hospitals in communities solely in Southcentral Alaska.

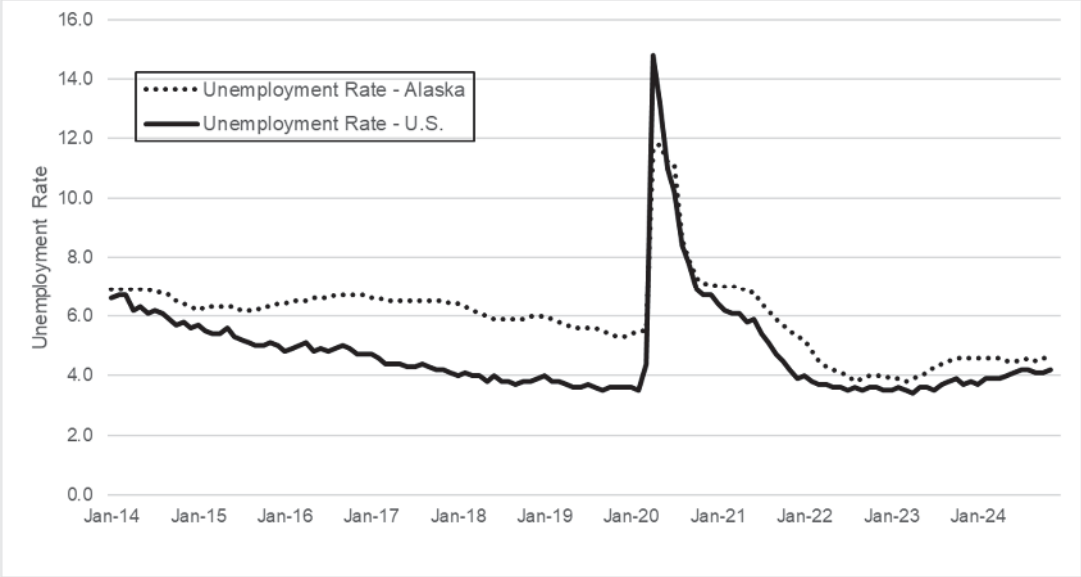
Q. Do ENSTAR's operations in Alaska increase its risk profile relative to natural gas distribution utilities operating in the Lower 48?

A. Yes, ENSTAR's operations outside of the contiguous United States create heightened risks for the Company's operations. First, operating in a single region concentrates the Company's risks on the geographic, demographic, economic, and regulatory risks inherent in its service territory. While this is true for any utility that operates in a single state, the risks associated with ENSTAR's operations in Alaska are especially unique from any of the companies in the proxy group and other industry peers. Alaska's harsh climate and exposure to natural disasters, its isolation and lack of transportation connectivity to other basins, and its economic dependence on an industry known for booms and busts, taken together, are unique from any other LDC.

While all but one proxy company (New Jersey Resources Corporation ("NJR"))[6] operate in at least two or more states in the Lower 48, ENSTAR's operations are concentrated in a single area of a single state with higher rates of unemployment than those experienced nationally. ENSTAR's commitment to serving the communities of Southcentral Alaska creates a reliance on the economy of a single state, and does not provide the economic and regulatory diversification offered by operating in other states that do not have Alaska's unique risks. As shown in Figure 6, the unemployment rate in Alaska has generally been above the national rate.

[6] As explained below, New Jersey's economy is highly interconnected to the economies of New York (particularly, New York City metro area) and Pennsylvania (particularly, Philadelphia), thus diversifying its economic, geographic, and demographic risks. Further, NJR is a more diversified holding company with FERC-regulated natural gas operations in addition to its distribution operations regulated by the New Jersey Board of Public Utilities.

Figure 6: Unemployment Rate in Alaska vs. U.S. (2014-2024)[7]



Operating solely in Alaska also exposes ENSTAR to increased risks associated with the relative lack of economic diversity in the remote region. In particular, Alaska's economy is reliant on the oil and gas industry, which is prone to booms and busts. Since 2014, the oil and gas industry has contributed an average of 19.26 percent to Alaska's total private industry GDP.[8] By contrast, oil and gas exploration has contributed on average only 1.68 percent to the overall U.S. GDP over this period.[9] According to Alaska's Revenue Sources Book,[10] in the 2024 fiscal year, petroleum comprised 37 percent of the state's unrestricted revenue, and approximately 19 percent

[7] Source: Federal Reserve Bank of St. Louis FRED Database. Not Seasonally Adjusted. Data as of January 31, 2025.

[8] Source: Bureau of Economic Analysis.

[9] *Id.*

[10] Alaska Department of Revenue, Tax Division. (2024). *Revenue Sources Book: Fall 2024.* Last accessed January 28, 2025. https://tax.alaska.gov/programs/programs/reports/RSB.aspx?Year=2024&Type=Fall

of its total state revenue. DBRS Morningstar has commented on the Company's exposure to these risks, stating:

> Alaska, which is the sole service area for the Opcos, has one of the smallest populations in the United States. The Alaskan GDP mainly relies on the oil and gas sector, which tends to be cyclical industry and could potentially face long-term challenges from energy transition.[11]

This relatively high dependence on the oil and gas industry exposes Alaska, and as a result, ENSTAR, not only to the volatile pricing of the commodity, but also to the degree of its availability.

In turn, investors will require higher returns to compensate for the increased relative risk associated with Alaska's geographical isolation and concentration in the oil and gas industry. For example, Moody's factors the service territory's economic indicators into its utility rating methodology:

> Economic diversity is typically a function of the population, size and breadth of the territory and the businesses that drive its gross domestic product (GDP) and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry.[12]

Moody's also considers diversity in regulatory regimes, customer mix, and size of the utility, as explained below:

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[11] Morningstar DBRS, Private Rating Report: Alaska Utility Holdings, Inc., November 25, 2024.

[12] *See,* Moody's Investors Service, Rating Methodology: Regulated Gas and Electric Utilities, at 12 (August 6, 2024).

> In our assessment, we may consider various information sources. We also consider the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. Issuers regulated in multiple jurisdictions typically receive the highest scores in the Market Position sub-factor. Where there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility. Size of the utility is also considered, since a larger utility can better absorb the impact of temporary, or one-time, adverse events.
>
> Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy generally receive a higher score for this sub-factor than issuers that lack these characteristics. Issuers with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, generally receive lower scores for this sub-factor, as do issuers with meaningful exposure to economic dislocations caused by natural disasters.[13]

Q. Please generally describe the risks associated with the harsh climate and severe weather in Alaska.

A. Alaska faces significant climate and severe weather risks due to increased propensity for earthquakes and other natural disasters. Increasing frequency and intensity of storms, wildfires, volcanic activity, heavy rainfall, and flooding create severe

[13] *See*, Moody's Investors Service, *Rating Methodology: Regulated Gas and Electric Utilities*, at 12 (August 6, 2024) (emphasis added).

conditions that threaten the integrity of the energy infrastructure, including natural gas pipelines and distribution infrastructure. Natural disasters and other severe weather events have the potential to disrupt transportation and shipping routes that ENSTAR relies on to source materials and supplies to maintain and repair its system. Please also see the direct testimony of Mr. Sims for additional discussion of how this risk affects ENSTAR's operations.

Q. Do increasing risks from climate and severe weather events in Alaska impact ENSTAR from a financial perspective?

A. Yes, they do. ENSTAR is impacted by increasing risks from several perspectives. First, the Company continues to invest significant capital into upgrading its assets to maintain reliability and safety for its customers. Second, its severe cold climate coupled with the limited diversification of natural gas sources requires the Company to explore alternatives to support customers' demand.[14] Finally, financial pressure associated with ongoing system reliability costs and potential damage restoration costs increases the overall risk profile of the Company. Moody's, for example, notes this factor in their rating methodology for natural gas and electric utilities:

> For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for credit worthiness.[15]

ENSTAR's service territory and pipeline locations within Alaska carry additional risks that should be considered in the determination of an ROE

[14] ENSTAR's 2025 Gas Supply Update at the RCA's Public Meeting held on January 15, 2025. The Company announced steps to create a natural gas receiving terminal on the Kenai Peninsula.

[15] *See, e.g.*, Moody's Investors Service, *Rating Methodology: Regulated Gas and Electric Utilities*, at 16 (June 23, 2017).

commensurate with the Company's overall risk profile. To assess ENSTAR's relative risk not only within the broader United States but also within the state of Alaska, I used the National Risk Index[16] maintained by the Federal Emergency Management Agency ("FEMA"). The tool assesses the relative risk of various natural disasters across communities in the United States, producing an overall risk index that is based on three components: expected annual losses,[17] social vulnerability,[18] and community resilience.[19] FEMA reports each county's overall risk as well as specific hazard type risks such as avalanche, coastal flooding, earthquakes, ice storms, and wildfires, among others. According to this report, the ENSTAR's service territory is in the 95th percentile in the U.S. and 100th percentile in Alaska. This means that 95 percent of U.S. counties and 100 percent of counties (boroughs) in Alaska have a lower risk index than Anchorage when expected annual losses, social vulnerability, and community resilience are factored. Anchorage also ranks "relatively high" for avalanche and earthquake hazard risks. Similarly, Kenai Peninsula is in the 91st and 97th percentiles in the U.S. and Alaska, respectively. The Kenai Peninsula ranks "very high" to

[16] Federal Emergency Management Agency, National Risk Index. https://hazards.fema.gov/nri/. Last accessed April, 12 2025.

[17] Expected Annual Loss (EAL) represents the average economic loss in dollars resulting from natural hazards each year. It is calculated for each hazard type and quantifies loss for relevant consequence types: buildings, people, and agriculture. https://hazards.fema.gov/nri/expected-annual-loss.

[18] Social vulnerability is the susceptibility of social groups to the adverse impacts of natural hazards, including disproportionate death, injury, loss, or disruption of livelihood. https://hazards.fema.gov/nri/social-vulnerability.

[19] Community resilience is the ability of a community to prepare for anticipated natural hazards, adapt to changing conditions, and withstand and recover rapidly from disruptions. A community's Community Resilience score measures its national rank and is inversely proportional to a community's risk. A higher Community Resilience score results in a lower Risk Index score. https://hazards.fema.gov/nri/community-resilience.

"relatively moderate" in its risk index rating for avalanches, earthquakes, riverine flooding, tsunami, volcanic activity, wildfire, and winter weather.

Q. Do the natural gas distribution companies in the proxy group and the resulting cost of equity for those companies reflect ENSTAR's geographical risk?

A. No, they do not. They are all less risky than ENSTAR. As I stated above, all but a single proxy company (NJR) operate in at least two or more jurisdictions in the Lower 48. New Jersey's economy is more diverse, and highly interconnected to the economies of New York (particularly, the New York City area) and Pennsylvania (particularly, Philadelphia), thus diversifying its economic, geographic, and demographic risks.

The remaining proxy companies operate in multiple jurisdictions, which diversifies risk associated with the local and regional economy, service territory and customer bases, and regulatory risk, thereby providing additional revenue stability compared to ENSTAR. ENSTAR's service territory in Kenai and Anchorage are higher risk with respect to both the risk of hazardous conditions as well as the increased reliance on a single economy heavily concentrated in a cyclical industry.

C. Natural Gas Supply and Pipeline Risk

Q. Does ENSTAR face natural gas supply risk?

A. Yes. ENSTAR is solely reliant on natural gas production from the Cook Inlet. As a basin with declining natural gas production, ENSTAR's ability to meet customer demand significantly depends on the availability of natural gas from the Cook Inlet. Further, ENSTAR is also highly dependent on the primary natural gas producer in the region, Hilcorp Alaska, LLC. ("Hilcorp"). ENSTAR's reliance on Hilcorp exposes the Company not only to counterparty risk but also to the risk of potential shortfalls if the supplier fails to deliver the contracted volumes. In 2022, Hilcorp informed local

utilities, including ENSTAR, that it would not be able to commit to new contracts given declining natural gas reserves.[20] While a January 2023 report by the Alaska Department of Natural Resources' Division of Oil and Gas noted that (then-current) gas estimates could meet current level of demand for natural gas until approximately 2027, the estimates were only meant to serve as a tool to gauge the reserves based on then-current conditions and assumptions.[21] Please also see the direct testimony of Mr. Sims and Ms. Johansen for additional discussion of ENSTAR's risk associated with natural gas supply.

Q. From an investor's perspective, how does a decline in the availability of natural gas pose an incremental risk to a natural gas utility like ENSTAR?

A. As explained in Section V, investors commit capital (debt and equity) only if the expected return is greater than or equal to the required return. Ultimately, a decline in the availability of natural gas supply threatens the future viability of the utility, and the future cash flows and earnings paid to investors in the form of a return. As a result, supply risk increases uncertainty in future returns to investors. This risk is more concentrated on equity investors because equity investors have a subordinate claim on earnings after debtholders have been paid. Consequently, investors will require higher returns to compensate them for less certain cash flows and earnings potential due to supply risk.

Declines in the availability of natural gas supply poses additional risks to natural gas utilities and their investors, including alternative supply project

[20] Alaska Business Magazine, *Hilcorp's 2023 Plans for Cook Inlet*, May 2023. https://digital.akbizmag.com/issue/may-2023/hilcorps-2023-plans-for-cook-inlet/. Last accessed April 12, 2025.

[21] *Ibid*.

development and execution risk, cost recovery risk, and stranded cost risk. Each of these risks threaten future cash flows and earnings that generate future returns to investors. Declining supply forces natural gas utilities to develop and invest in alternative supply projects and solutions that are likely to be more costly. The permitting and regulatory approval process for new energy infrastructure projects is also costly, complex, and time consuming and often results in project delays. Nevertheless, the utility must expend significant amounts of cash upfront during the approval and construction process that may not be recovered for years or decades, if at all. These costs are borne by shareholders until they can be recovered in rates.[22] Lastly, to the extent that a lack of supply results in certain assets becoming uneconomic before the end of their depreciable lives, utilities and their investors may be exposed to incremental stranded cost risk.

Q. How does ENSTAR's natural gas supply risk compare to the proxy group?

A. ENSTAR faces greater supply risk in two respects: (1) it is reliant on a single rapidly declining gas basin – the Cook Inlet – for its natural gas supply, and (2) it lacks connectivity to other natural gas basins and pipeline systems. The lack of diversification of natural gas production and the lack of pipeline interconnectivity increase ENSTAR's risk compared to the risks assumed by other natural gas distribution companies. The fact is, no other company in the proxy group faces this risk at all. As shown in Exhibit JEN-11, the proxy companies operate in proximity to

[22] *See* Order U-25-004(5). For example, despite ENSTAR incurring approximately $4.6 million from 2022-2024 to identify a solution to the gas supply issue, the Company has yet to recover any of these amounts in rates.

major shale gas basins[23] and/or are connected to multiple gas hubs and natural gas pipeline systems that provide natural gas for subsequent distribution.

As described earlier, ENSTAR's transmission pipeline system is comprised of two separate pipeline systems that extend from production fields located on either side of Cook Inlet[24] and transport gas into the Anchorage system. Each pipeline system is connected via marine pipelines owned by the producers that cross Cook Inlet. Both transmission systems are connected at the ends and therefore create a level of redundancy mitigating some of the pipeline availability risks. To evaluate the relative risk of ENSTAR's reliance on two pipeline systems, I compared the number of pipelines that are available and contracted by the natural gas distribution companies in my proxy group for transportation of natural gas to their service territories.[25] In the first quarter of 2025, the natural gas distribution companies in my proxy group have an average of 15 contracted pipelines available to meet customers' demand, as depicted in Figure 7. The availability of numerous pipelines mitigates the risk of pipeline inoperability during times of repair or other outages, and provides interconnectivity to other sources of natural gas thereby reducing the overall risk.

[23] Please note that the source of Exhibit JEN-11 (S&P Capital IQ) only maps shale gas basins and may exclude conventional gas resources.

[24] That is, ENSTAR's two pipeline systems source natural gas from one basin, which is the Cook Inlet basin.

[25] Source: S&P Capital IQ.

Figure 7: Contracted Natural Gas Pipelines[26]

Natural Gas Distribution Proxy Company	Number of Contracted Pipelines
NiSource Inc	29
Atmos Energy Corporation	26
Spire, Inc	16
ONE Gas, Inc	14
New Jersey Resources Corporation	9
Southwest Gas Corporation	9
Northwest Natural Holding Company	2[27]
Average	**15**

D. Small Size

Q. Please explain the risk associated with small size.

A. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect."[28] Although empirical evidence of the size effect often includes companies in industries beyond regulated utilities, utility analysts also have noted the risks associated with small market capitalizations. Specifically, a senior consultant with Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification

[26] Source: S&P Capital IQ.

[27] As shown in Exhibit JEN-11, Northwest Natural Holding Co. is near three gas hubs and its two pipelines it contracts with are interconnected with multiple natural gas pipeline systems and shale gas basins to the north, east, and south, providing a level of resiliency and redundancy that ENSTAR does not have.

[28] *See*, Mario Levis, *The Record on Small Companies: A Review of the Evidence*, Journal of Asset Management at 368-397 (Mar. 2002) for a review of literature relating to the size effect.

across customers, energy sources, and geography. These obstacles imply a higher investor return.[29]

Relative to the proxy group, ENSTAR's operations are both smaller in size and, as explained earlier, less diversified.

Q. How does ENSTAR compare in size to the natural gas utility proxy companies?

A. ENSTAR is substantially smaller than the natural gas utility proxy companies in terms of market capitalization, gas plant in service, and number of gas customers. Figure 8 below illustrates the magnitude of ENSTAR's small size relative to the natural gas distribution utilities in the proxy group.

[29] Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly (Oct. 15, 1995).

Figure 8: Proxy Group Size Comparison (Natural Gas LDCs)

Company	Market Capitalization ($million)[30]	Gas Plant in Service ($million)[31]	Natural Gas Customers[32]
Atmos Energy Corp.	$22,295	$23,591.62	3,360,008
New Jersey Resources Corp.	$4,835	$3,859.57	579,540
NiSource Inc.	$17,252	$17,359.49	3,262,951
Northwest Natural Holding Co.	$1,668	$4,387.43	799,106
ONE Gas, Inc.	$4,131	$7,805.89	2,270,099
Southwest Gas Holdings, Inc.	$5,335	$10,140.36	2,206,420
Spire, Inc.	$4,002	$6,251.12	1,738,920
Average	**$8,503**	**$10,485.07**	**2,031,006**
ENSTAR Natural Gas	$357.17[33]	$723.22	155,000
ENSTAR / Average (%)	4.20%	6.90%	7.63%

Q. Are the pipeline companies within the proxy group also considerably larger than ENSTAR in terms of market capitalization?

A. Yes. As of December 31, 2024, the pipeline companies had a 30-day average market capitalization of approximately $73.45 billion.[34]

[30] Source: S&P Capital IQ. As of December 31, 2024.

[31] Source: S&P Capital IQ. As of December 31, 2023. Data for 2024 is not available at the time of preparing my testimony.

[32] Source: S&P Capital IQ. Total end user natural gas customers as of December 31, 2023. Data for 2024 is not available at the time of preparing my testimony. ENSTAR's 2023 Gas Plant In Service from its 2023 Annual Report filed with the RCA.

[33] ENSTAR is not publicly traded. Implied Market Capitalization = ENSTAR Common Equity Balance as of December 31, 2024 x Median Proxy Group Market-to-Book Ratio of 1.54. *See* Exhibit JEN-7.

[34] See Exhibit JEN-7, page 2.

Q. How does the smaller size of ENSTAR affect its business risks relative to the LDCs within the proxy group?

A. The Company's smaller size relative to the LDCs within the proxy group indicates greater relative business risk for the Company because, all else equal, size has a material bearing on risk.

In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. Small companies are more sensitive to swings in the economy and have thinner margins and fewer resources if they experience financial trouble.[35] Any material changes to expected operations and maintenance expenses can have severe consequences on a company's level of operating leverage. Further large companies benefit from economies of scale that smaller companies cannot achieve. Similarly, capital expenditures for non-revenue producing investments such as system maintenance, upgrades, and replacements will put proportionately greater pressure on customer costs, potentially leading to demand reduction. Lastly, larger companies will have an advantage in raising capital and executing larger capital projects.[36] A larger company will have access to a greater number of potential investors and may have more funding opportunities available to it than a smaller company like ENSTAR will have. This places an additional constraint that the Company must manage when determining a capital funding plan. Taken together, these risks affect the return required by investors for smaller companies. As a significantly smaller company, unpredictable

[35] *See, e.g.*, New York Times, *This Stock Market Index is Flashing a Clear Warning Sign About the Economy*, March 14, 2025.

[36] *See, e.g.*, Morningstar DBRS, *Global Methodology for Rating Companies in the Regulated Electric, Natural Gas, and Water Utilities Industry*, at 7 (September 2023).

and adverse events may affect ENSTSAR's revenues or expenses more acutely. It is important that the Company has the financial strength to withstand such events with a margin of safety.

Please see the direct testimony of Mr. Sims for a further discussion of earnings and possible swings in earnings given unexpected changes in costs.

Q. Is there support in the financial community for the use of a small size premium?

A. Yes, there have been several studies that demonstrate the size premium. One of the earliest works in this area found that over a period of 40 years "the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[37] The author, who referred to that finding as the "size effect," suggested that the CAPM was mis-specified, in that on average, smaller firms had significantly larger risk-adjusted returns than larger firms. The author also concluded that the size effect was "most pronounced for the smallest firms in the sample."[38] Since then, additional empirical research has focused on explaining the size effect as a function of lower trading volume and other factors, but the proposition that Beta coefficients fail to reflect the risks of smaller firms persists.[39]

In 1994, Fama and French also focused on the issue of whether the CAPM adequately explained security returns and proposed a "three factor" model for expected security returns. Those factors include: (1) the covariance with the market, (2) size, and (3) financial risk as determined by the book/market ratio. As explained by

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[37] R. W. Banz, *The Relationship Between Return and Market Value of Common Stocks*, Journal of Financial Economics, Vol. 9 Issue 1, 1981 at 3-4.

[38] *Id.* at 16.

[39] *See*, for example, Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset Management, March 2002.

Morningstar, Fama and French "found that the returns on stocks are better explained as a function of size and book-to-market value in addition to the single market factor of the CAPM, with the company's size capturing the size effect and its book-to-market ratio capturing the financial distress of a firm."[40]

Simply put, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Duff & Phelps discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Returns," Duff & Phelps states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. [41]

Q. Do the rating agencies consider size in their credit rating assessments of utilities?

A. Yes. Morningstar DBRS, which rates ENSTAR's parent company, considers the size of a regulated utility's customer base, as well as its asset or rate base in its business risk assessment.[42] As noted earlier, Moody's considers the size of the utility "since a larger

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[40] Morningstar, Ibbotson SBBI 2013 Valuation Yearbook, at 109.

[41] Duff & Phelps Valuation Handbook – U.S. Guide to Cost of Capital, Wiley 2020, at 4-1. Underline emphasis added. Italics in original.

[42] Morningstar DBRS, *Global Methodology for Rating Companies in the Regulated Electric, Natural Gas, and Water Utilities Industry*, at 6 and 7 (September 2023).

utility can better absorb the impact of temporary, or one-time adverse events."[43] S&P[44] and Fitch Ratings[45] also consider company size and scale in their credit rating assessments. This supports the conclusion that the financial community views a company's size or scale to be a material consideration in their assessment of a company's business risk.

Q. Are you aware of studies regarding the existence of size premia for regulated utilities?

A. Yes. A 2002 study by Thomas M. Zepp[46] concludes that size premia do exist for smaller utilities. Developed in response to a 1993 study by Annie Wong, the Zepp study focuses specifically on the utility industry and the effect of the size premium in a regulated environment. For example, one study reviewed by Zepp found that smaller water utilities had a cost of equity that, on average, was 99 basis points higher than the average cost of equity for the larger water utilities, and the result was statistically significant at the 90.00 percent level.[47] Zepp concludes that "to the extent water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones."[48]

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[43] Moody's Investors Service, *Rating Methodology: Regulated Gas and Electric Utilities*, at 12 (August 6, 2024).

[44] S&P Global, *General: Corporate Methodology*, Criteria (January 7, 2024).

[45] FitchRatings, *Sector Navigators: Addendum to the Corporate Rating Criteria*, at 227 (December 2024).

[46] Thomas M. Zepp, *Utility stocks and the size effect – revisited*, Quarterly Review of Economics and Finance, 43 (2003) 578-582.

[47] *Id.* at 580-581.

[48] *Id.* at 582.

Additionally, a 2011 study by Stéphane Chrétien and Frank Coggins in the article "Cost of Equity for Energy Utilities: Beyond the CAPM"[49] considered the Fama-French three-factor model and a model similar to the Empirical CAPM I described earlier. In the article, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins show, the Beta coefficient on the size variable for a group of U.S. natural gas utilities was positive and statistically significant, supporting the position that small size risk is relevant for regulated utilities.[50]

Q. Are small company stocks more volatile than large company stocks?

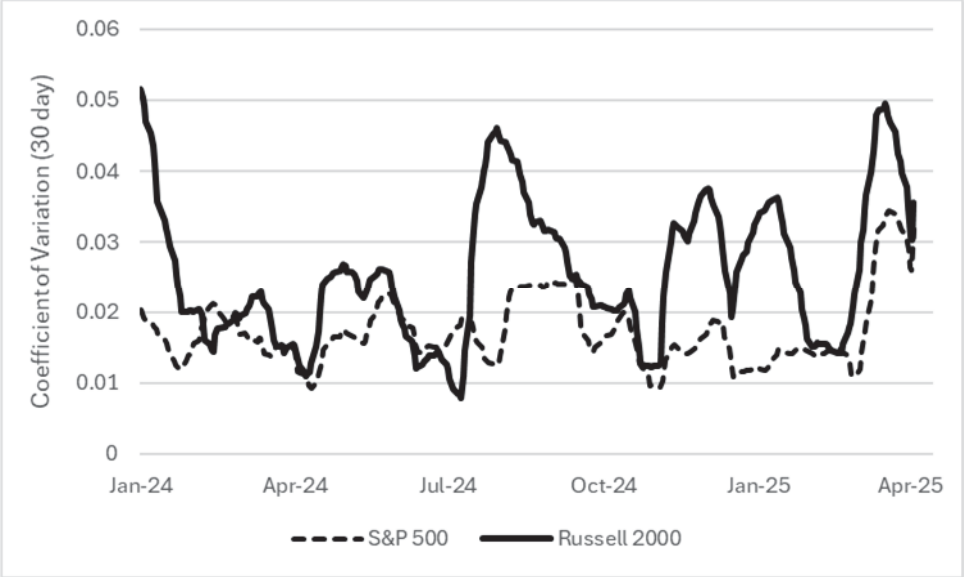
A. Yes. Since 2000, the volatility (as measured by the Coefficient of Variation[51]) of small company stocks traded on the Russell 2000 Index is approximately 44 percent greater than the volatility of large company stocks in the S&P 500 Index. The Russell 2000 Index is a small-cap U.S. stock market index that makes up the smallest 2,000 stocks in the Russell Index. The S&P 500 Index is an index of the 500 largest companies listed on the U.S. stock exchanges. Figure 9 below illustrates the greater volatility (*i.e.*, risk) in the Russell 2000 Index relative to the S&P 500 Index over the last year.

[49] Chrétien, Stéphane, and Frank Coggins. *Cost of Equity For Energy Utilities: Beyond The CAPM.* Energy Studies Review, Vol. 18, No. 2, at 31.

[50] *Id.*

[51] The Coefficient of Variation is a measure of volatility that calculates the standard deviation divided by the average over a period of time. Figure 9 measures the Coefficient of Variation over a rolling 30-day period.

Figure 9: Price Volatility in the Russell 2000 Index vs. the S&P 500 Index[52]



Q. Is it appropriate to consider the risk associated with ENSTAR's small size even though it is a subsidiary of larger entities?

A. Yes. The widely accepted "stand-alone" regulatory principle treats each utility subsidiary as its own company. Parent entities (whether publicly or privately owned), like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. The opportunity cost concept applies regardless of the source of the funding. When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary competes for capital with the parent company's affiliates, and with other similarly situated utility companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to

[52] Source: S&P Capital IQ, data as of April 4, 2025.

provide an appropriate risk-adjusted return. It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective. From that perspective, the fact that ENSTAR is a subsidiary of TSU is not relevant to the consideration of the risk associated with ENSTAR's small size.

Q. Has the RCA previously acknowledged the increased risk faced by ENSTAR due to its small size?

A. Yes. In Docket No. U-16-066, the RCA agreed that both the geographic isolation and the smaller size of ENSTAR increases the Company's risk. The RCA's finding was based on ENSTAR's evidence that its remote geographic location multiplies the "size effect" experienced by smaller firms.[53] These impacts have been further exacerbated by an increasingly higher cost environment amid rising inflation as it pertains to both supply and capital costs.

Q. How do you estimate the size premium for ENSTAR?

A. In its *Cost of Capital Navigator*, Kroll presents its calculation of the size premium for deciles of market capitalizations relative to the S&P 500 Index. An additional estimate of the size premium associated with ENSTAR, therefore, is the difference in the Kroll size risk premia for the proxy group median market capitalization relative to the Company's implied market capitalization. As shown in Exhibit JEN-7, I estimated ENSTAR's size premium compared to the entire proxy group, as well as compared to only the LDC companies with the proxy group.

[53] Order U-16-066(19) at 52.

Turning first to the comparison of ENSTAR to the LDC companies, as shown in Exhibit JEN-7, page 1, the median market capitalization of the natural gas LDC proxy group is $4.835 billion as of December 31, 2024, which corresponds to the fifth decile of Kroll's market capitalization data. Based on Kroll's analysis, that decile corresponds to a size premium of 0.74 percent (or 74 basis points). As noted above, ENSTAR's implied market capitalization is $357.17 million, which falls within the ninth decile and corresponds to a size premium of 1.73 percent (or 173 basis points). The difference between those size premia is 99 basis points (1.73 percent – 0.74 percent).[54]

Regarding to the comparison of ENSTAR to the entire proxy group, page 2 of Exhibit JEN-7 calculates a small size premium of 1.40 percent (140 basis points). The median market capitalization of the entire proxy group including the pipeline companies is approximately $35.89 billion, which corresponds to the second decile of Kroll's market capitalization data, and has a size premium of 0.33 percent. ENSTAR's implied market capitalization of $479.46 million using the median market-to-book ratio of 2.07 still corresponds to the ninth decile and a size premium of 1.73 percent. Compared to the entire proxy group, ENSTAR's size premium is 1.40 percent (1.73 percent – 0.33 percent).

Q. Do Beta coefficients solely capture size risk?

A. No. It is important to note that the Beta coefficient reflects a broad array of risks, not just size. As explained in Section V below, the Beta coefficient measures only market

[54] Exhibit JEN-7.

risk, under the CAPM's assumption that firm-specific risk is diversifiable.[55] Therefore, Beta coefficients do not fully capture a firm's total risk. Nevertheless, the objective in this proceeding is to estimate the cost of equity for one enterprise: ENSTAR, which necessarily requires an assessment of ENSTAR's risk relative to a group of peers that are comparable in risk. The fact that investors can mitigate exposure to risk through diversification does not mean investors ignore firm-specific risk in their return requirements for each investment within a portfolio.

In addition, Kroll's published size premia "are 'beta-adjusted,' meaning that they have been adjusted to remove the portion of excess return that is attributable to beta, leaving only the size effect's contribution to excess return."[56] To the extent that certain companies in the analysis are involved in riskier operations, the size premium analysis controls for risk differences reflected in the Beta coefficient.

Q. Have you considered the comparatively small size of ENSTAR in your estimated return on common equity?

A. Yes. As explained in Section V below, I calculated the difference in the average ROE authorized for Alaska utilities by the RCA (222 basis points) as compared to Lower 48 utilities. Because the RCA has previously considered size and other risk factors in the authorized ROE for Alaska utilities, the ROEs authorized by the RCA encompass several risk factors that Alaska utilities are exposed to, including size. In other words, although I quantified a specific size premium of 99 to 140 basis points for ENSTAR, I

[55] The DCF and Risk Premium models do not assume that firm-specific risks are diversifiable.

[56] Duff & Phelps, *Valuation Handbook 2017, U.S. Guide to Cost of Capital*, John Wiley & Son's, at 2-10 (2017).

do not make an additional adjustment to account for size on top of the 222 basis point adjustment added to the Bond Yield Plus Risk Premium analysis.

E. Capital Expenditure Plan, Regulatory Risk, and Capital Access

Q. Do you have preliminary thoughts on the importance of access to capital for natural gas utilities such as ENSTAR?

A. As a capital-intensive enterprise, the authorized ROE should enable ENSTAR to finance capital expenditures and working capital requirements at reasonable rates and to maintain its financial integrity in a variety of economic and capital market conditions. A return that is adequate to attract capital at reasonable terms enables the utility to secure funds to provide safe, reliable service while maintaining its financial soundness to the benefit of customers.

Natural gas utilities are one of the most capital-intensive market sectors. On average, natural gas utilities generate less than half of the revenue per dollar of assets than the non-utility U.S. companies covered by Value Line.[57] To fund the significant capital expenditures needed to maintain, expand, and modernize existing infrastructure, natural gas utilities require sufficient internally generated cash flow and ongoing access to investor supplied capital. Because natural gas utilities tend to be cash flow negative (*i.e.*, cash spent on plant investment is more than cash flow received from operations), it is critical that regulation provide predictable, adequate, and achievable allowed returns that support the financial integrity of the utility.

[57] Source: Value Line Screener, last accessed February 22, 2025.

Q. Please summarize the Company's capital expenditure plan.

A. The Company estimates that from 2025-2029 it will invest approximately $60 million to $70 million per year in, and to support, its utility system. A significant amount of the investments are related to safety and reliability, with an approximate $70 to $80 million portion of the total capital expenditures over those five years allocated for the Reliability Infrastructure Replacement Program.[58] In total, these capital expenditures will equal approximately 87 to 101 percent of the Company's total net utility plant in service of $345 million as of December 31, 2024.[59] Please also see the direct testimony of Mr. Sims for a discussion of how ENSTAR's current capital plan influences risk.

Q. How does the regulatory environment in which a utility operates affect its cost of capital?

A. The regulatory environment is one of the most important factors investors consider when assessing a utility's risk, as it is a significant driver of earnings and cash flow that are of utmost importance to investors.[60] Regulatory decisions regarding the authorized ROE and capital structure have direct consequences for the subject utility's internal cash flow generation (sometimes referred to as "Funds from Operations," or "FFO"; or "Cash from Operations," or "CFO"). Because credit ratings are intended to reflect the ability to meet financial obligations as they come due, the ability to generate the cash flows required to meet those obligations (and to provide an additional amount for unexpected events) is of critical importance to debt investors. Two of the most

[58] *See,* Direct Testimony of ENSTAR witness Mr. Nathan T. Burke.

[59] Annual Report of ENSTAR for the Year Ended December 31, 2024.

[60] Moody's Investors Service, Rating Methodology, Regulated Electric and Gas Utilities, at 4 (June 23, 2017).

important metrics used to assess that ability are the ratios of FFO to debt, and FFO to interest expense, both of which are directly affected by regulatory decisions regarding the rate of return and capital structure.

Investors and rating agencies understand that a constructive regulatory environment is critical to utilities' credit and financial integrity, especially during stressed market conditions. Ratings agencies also recognize the importance of the regulatory environment when assessing a utility's business risk profile. As Morningstar DBRS, which rates ENSTAR's parent, explains:

> The quality of the regulatory regime is typically the most important [business risk assessment] factor as it lays the foundation for utilities' earning capacity, cost recovery mechanisms, and capital structure. A supportive regulatory framework contributes to stable cash flow and earnings, underpinned by a fair rate of return and a full and timely recovery of costs.[61]

The regulatory factors that Morningstar DBRS considers to be most important in its assessment of a utility's regulatory framework are: (1) the deemed equity ratio, (2) the authorized ROE, (3) recovery of fuel and purchased energy costs, and (4) capital and operating cost recovery.[62]

Similarly, Moody's considers the regulatory structure to be so important that 50.00 percent of the factors that weigh in a ratings determination relate to the nature of regulation. Predictability and consistency of regulatory actions are among the factors considered by Moody's in assessing the regulatory framework:

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[61] DBRS Morningstar, *Global Methodology for Rating Companies in the Regulated Electric, Natural Gas, and Water Utilities Industry*, at 5 (September 2022).

[62] *Id*. at 12-14.

> As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality.
>
> ***
>
> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[63]

Lastly, S&P observes that the regulatory environment in the jurisdictions where a utility operates is a "significant aspect of regulatory risk that influences credit quality."[64] S&P explains:

> [w]hen we evaluate U.S utility regulatory environments, we consider financial stability to be of substantial importance. Cash takes precedence in credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision-making is one that will appeal to creditors.[65]

In short, supportive regulation supports credit profiles. Investors recognize that an authorized capital structure and ROE that are reasonable, but subject to earnings attrition due to unfavorable regulatory or economic factors, do not provide assurance that the utility will have a reasonable opportunity to recover its costs, or to earn a reasonable return. The authorized capital structure and ROE affect not only the cash flow-related metrics that measure financial strength, but also provide an indication of the degree of regulatory support, and risk, associated with a given utility and

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[63] Moody's Investors Service, Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, at 2 (June 18, 2010).

[64] S&P Global Ratings, RatingsDirect, *Assessing U.S. Investor-Owned Utility Regulatory Environments,* at 2 (August 10, 2016).

[65] *Id.*

jurisdiction. They are, therefore, important signals of regulatory support and financial integrity. Consequently, a utility that operates in a less predictable and more challenging regulatory environment is likely to be viewed as a riskier investment, and may result in lower credit ratings, constrained access to capital (particularly in volatile and adverse market environments), and higher costs of both debt and equity, all else equal. To satisfy the utility's obligation to serve, it is in customers' best interests to ensure that a utility has efficient access to capital on reasonable terms in all market environments.

Q. Are there specific factors within the regulatory environment that may impact how investors evaluate relative risk?

A. Yes. Timeliness of recovery is a significant factor that plays an important role in how quickly a utility can recover its prudent costs, and factors into investors' evaluation of the overall regulatory environment. Significant delay in expenditure recovery, especially capital recovery, may erode utilities' credit metrics, especially during challenging macroeconomic conditions, such as rising inflation. The Company's annual gas cost partially alleviate the cost recovery associated with securing gas supply, and interim rates in base rate applications also partially addresses the extended time (*i.e.*, the 450-day review period) required by the RCA to review base rate applications; but the use of historical test year and the lack of alternative rate treatments, such as revenue decoupling mechanisms or capital tracking mechanisms, create a more restrictive and risky regulatory environment compared to other jurisdictions, especially in a period of relatively high capital investment.[66] Moody's incorporates the timeliness

[66] *See*, Exhibit JEN-8.

of recovery of operation and capital costs into its rating methodology for gas and electric utilities, allotting 12.50 percent weight to this factor.[67]

As Mr. Sims explains in his direct testimony, the Company intends to request approval of a formula rate mechanism soon after filing this rate case to mitigate some of the current cost recovery delay and bring the Company further in line with other utilities.

Q. If approved, will this regulatory mechanism decrease ENSTAR's risk compared to its peers?

A. No. The formula rate plan will simply bring the Company in line with, or closer to, the utilities operating in the Lower 48, including those included in the proxy group. For example, regulatory commissions in Alabama, Arkansas, Georgia, Mississippi, Louisiana, Oklahoma, and South Carolina have adopted formula rate plans for natural gas utilities.[68] Three of the gas utility proxy companies (Atmos, Spire, and ONE Gas) currently have formula rate plans in at least one jurisdiction.[69] More recently, the Arizona Corporation Commission (a jurisdiction in which proxy company Southwest Gas Company operates) has accepted a proposal for the adoption of formula rates in its ratemaking models across the state.[70] From a transmission perspective, the Federal Energy Regulatory Commission ("FERC") routinely adopts formula rates for

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[67] *See, e.g.*, Moody's Investors Service, Rating Methodology: Regulated Gas and Electric Utilities, at 2 (August 6, 2024).

[68] National Regulatory Research Institute, *Formula Rate Plans: Do They Promote the Public Interest?*, August 2010; Regulatory Research Associates, *RRA Regulatory Focus: Alternative ratemaking plans in the U.S.*, April 16, 2020.

[69] *See*, Exhibit JEN-8.

[70] Arizona Corporation Commission, *ACC Adopts Formula Rate Plan Policy Statement*, December 6, 2024.

transmission companies. While formula rates are more commonly associated with electric transmission companies that are FERC-regulated, "FERC has made recent changes apparently moving natural gas pipelines closer to the formula rates used in electric transmission."[71] All that being said, ENSTAR's business risks remain higher than its peers.

Q. What are your conclusions regarding the Company's capital investment plan on its cost of equity?

A. ENSTAR requires ongoing access to capital markets on reasonable terms to secure adequate capital to provide safe and reliable service to its customers. The regulatory environment, including the ROE and capital structure authorized in this proceeding, is a key determinant of the Company's ability to attract capital under a variety of market conditions as it executes its capital investment plan. It is in the customers' best interests that the outcome of this proceeding is constructive and the regulatory environment for ENSTAR is viewed as stable and predictable.

F. Summary of ENSTAR's Business Risk Profile

Q. Please summarize ENSTAR's business risks that affect its Cost of Equity.

A. ENSTAR is one of the most unique gas utilities in the U.S. in terms of its operational and risk profile. As explained above, the Company faces a number of business risks that combine to distinguish it from a typical natural gas distribution utility and elevate its risk profile well above the proxy companies, which are primarily gas distribution

[71] Congressional Research Service, *The Natural Gas Act: Overview, Analysis, and Comparison with Federal Power Act Ratemaking Activity*, February 4, 2020.

utilities. These risks have not subsided; if anything the Company's risk has grown more acute as demonstrated by the near-term supply risk ENSTAR faces.

Because equity investors require a higher return to compensate them for taking on additional risk, ENSTAR's higher risk profile should be considered in determining ENSTAR's authorized return. The RCA has previously recognized ENSTAR's higher risk profile, as well as the risks of operating a utility in Alaska, by routinely authorizing returns above those typically authorized for Lower 48 utilities.

Although ENSTAR is a wholly-owned subsidiary of Alaska Utility Holdings, Inc., and ultimately a subsidiary of TSU, its ultimate parent company must make financially prudent and strategic capital allocation decisions. Like all investors, the parent company assesses the Company's overall risk profile, encompassing both financial and business risks, in relation to other investment opportunities in the market. Therefore, it is important to consider ENSTAR's risks on a stand-alone basis relative to the proxy group in the determination of a just and reasonable Cost of Equity.

V. COST OF EQUITY ESTIMATION

A. Regulatory Guidelines and Financial Considerations

Q. Before addressing the specific aspects of this proceeding, please explain the connection between the cost of capital and a utility's cost of service.

A. Under the cost-of-service ratemaking paradigm, the development of utility rates begins with determining the utility's total cost to serve customers. This is known as the revenue requirement because the utility's revenues must be sufficient to recover its costs to serve customers. The revenue requirement consists of four components: (1) operating and maintenance ("O&M") expenses, (2) taxes, (3) the return *of* capital through depreciation expense, and (4) the return *on* capital through the regulated return

on rate base. The return on rate base is calculated as the weighted average cost of capital multiplied by the rate base. The return on capital must be sufficient to allow the utility to repay its debt obligations and compensate equity investors for the use of their financial capital. From that important perspective, the return on capital reflects a cost to the utility just like any other component of the revenue requirement.

Q. Please explain the cost of capital conceptually.

A. The cost of capital is the return that investors require to commit capital to a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of investing capital in the firm. Simply, the cost of capital is the expected rate of return prevailing in the capital markets on alternative investments of similar risk.[72] Conceptually, the cost of capital is: (1) forward-looking and reflects an expected rate of return; (2) an opportunity cost; (3) determined in the capital markets; and (4) dependent on, and proportional to, the risk of the investment.[73]

Because the cost of equity is expectational and premised on the principle of opportunity costs, it cannot be precisely quantified. Instead, it must be estimated by applying market data to various financial models that are simplified representations of investor behavior and expectations. Moreover, equity investors have a subordinate claim to cash flows owed to debt investments and other claims; the uncertainty (or risk) associated with those residual cash flows determines the cost of equity. In the end, the

[72] Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA, at 13 (1985).

[73] *Id.*

cost of equity should reflect the return that investors require considering the subject company's risk profile and the returns available on comparable investments.

Q. How is the cost of equity estimated in regulatory proceedings?

A. Regulated utilities primarily use long-term capital (*e.g.*, common stock and long-term debt) to finance their permanent rate base. The rate of return for a regulated utility is calculated as its weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective book values.

The ROE reflects the cost of raising and retaining equity capital and is estimated by using one or more market-based analytical approaches. Although quantitative models are used to estimate the ROE, the cost of equity cannot be precisely quantified through a strict mathematical exercise. As such, a reasonable and appropriate ROE reflects the financial, economic, and regulatory environment in which the estimate is developed, as well as the subject company's risk profile.

Q. Please briefly summarize the guidelines used in establishing the cost of capital for a regulated utility.

A. Public utility regulation is rooted in the principle that utilities are entitled to receive a fair rate of return sufficient to attract the capital required to provide safe and reliable public utility service for customers at reasonable rates. The U.S. Supreme Court ("Supreme Court") established the guiding principles for establishing a fair return for capital in two seminal cases: (1) *Bluefield Water Works and Improvement Company v.*

Public Service Commission ("*Bluefield*");[74] and (2) *Federal Power Commission v. Hope Natural Gas Company* ("*Hope*").[75] In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[76]

The Supreme Court therefore recognized that: (1) a regulated public utility cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least equal to the cost of capital (the principle relating to the demand for capital); and (2) a regulated public utility will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In *Hope*, the Supreme Court reiterated the three primary standards for a regulated rate of return:

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74 262 U.S. 679 (1923).

75 320 U.S. 591 (1944).

76 *Bluefield*, 262 U.S. at 692.

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on stock…By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[77]

In summary, the Supreme Court has recognized that the fair return should be: (1) commensurate with returns investors expect to earn on other investments of similar risk (the "comparable risk" standard); (2) sufficient to assure confidence in the company's financial integrity (the "financial integrity" standard); and (3) adequate to maintain and support the company's credit and to attract capital (the "capital attraction" standard). Importantly, a fair and reasonable rate of return must satisfy all three standards.

Q. Has the RCA also applied the *Hope* and *Bluefield* standards as guidance for setting rates?

A. Yes, it has. The RCA upholds the precedents of the *Hope* and *Bluefield* cases and regularly acknowledges that a utility is entitled to a fair and reasonable return.[78] Alaska statutes establish the standards in setting reasonable rates for utilities:

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[77] *Hope*, 320 U.S. at 603.

[78] *See, e.g., Alaska Public Utilities Commission v. Greater Anchorage Area Borough*, 534 P.2d 549, 558 n.26 (Alaska 1975); In the Matter of the Tariff Revision Designated as TA28-358 Filed by Potter Creek Water Company for an Increase in Rates for Its Water Service, Order U-08-063(6), July 14, 2009, at 20; In the Matter of the Revenue Requirement Study Designated as TA334-4 Filed by ENSTAR Natural Gas Company, LLC, Order U-22-081(14), at 7, April 8, 2024.

> All rates demanded or received by a public utility, or by any two or more public utilities jointly, for a service furnished or to be furnished shall be just and reasonable.[79]

The state legislature further describes the RCA's obligation with regard to establishing a reasonable return:

> When the commission, after an investigation and hearing, finds that a rate demanded, observed, charged, or collected by a public utility for a service subject to the jurisdiction of the commission, or that a classification, rule, regulation, practice, or contract affecting the rate, is unjust, unreasonable, unduly discriminatory or preferential, the commission shall determine a just and reasonable rate, classification, rule, regulation, practice, or contract to be observed or allowed and shall establish it by order.[80]

Based on those standards, the authorized ROE should provide ENSTAR with the *opportunity* to earn (which is not a guarantee to earn) a fair and reasonable return and should enable efficient access to capital under a variety of market conditions.

Q. Why is it important for a utility to be allowed the opportunity to earn a return adequate to attract capital on reasonable terms?

A. Regulated utilities have a legal obligation to serve regardless of prevailing economic and capital market conditions. Unlike non-regulated firms, a regulated utility cannot decide to whom it provides utility service in its footprint, how much service it delivers, or when it provides service. Non-regulated firms can time investments to coincide with favorable market conditions and defer investments when markets are constrained and

[79] Alaska State Statute Section 42.05.381(a).

[80] Alaska State Statute Section 42.05.431(a).

economic conditions are unfavorable. Utilities, on the other hand, have limited options to do so. Therefore, utilities must ensure they have access to external financial capital on cost-effective and favorable terms not only during times when markets are well-behaving, but also when markets are volatile or constrained (*e.g.*, during periods of high inflation and interest rates, global pandemics, changes in government, and economic recessions). Capital is finite and the Company competes for capital among other utilities and other investment opportunities. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe and reliable service while maintaining its financial integrity. As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return must be commensurate with the returns expected for investments of comparable risk.

The ratemaking process is based on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have a reasonable opportunity to recover the return of, and the market-required return on, invested capital. To meet its legal obligation to serve, the allowed ROE should enable the subject utility to maintain its financial integrity in a variety of economic and capital market conditions. To preserve and enhance service reliability, ENSTAR must generate adequate cash flow from operations and have efficient access to additional capital needed to undertake its capital investment plan regardless of the economic and capital market conditions at the time.

Further, the financial community carefully monitors utility companies' current and expected financial conditions, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most

important factors considered in both debt and equity investors' assessments of risk.[81] That consideration is especially important during uncertain economic and financial conditions in which the utility may require access to capital markets.

The outcome of the RCA's order in this case, therefore, should provide ENSTAR with the opportunity to earn an ROE that is: (1) adequate to attract capital on reasonable terms, (2) sufficient to ensure its financial integrity, and (3) commensurate with returns on investments in enterprises having corresponding risks. To the extent ENSTAR has a reasonable opportunity to earn its market-based cost of equity, neither customers nor shareholders are disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables the Company to provide customers with safe, reliable service while maintaining its financial integrity.

Q. Have recent events illustrated the importance for a utility to maintain a strong financial profile to enable access to capital?

A. Yes. There have been several significant events that have affected utilities in recent years. These include severe weather events and natural disasters that are unpredictable, costly, and beyond utilities' control, such as earthquakes, wildfires, flooding, and storms. The frequency and intensity of extreme events are increasing in Alaska,[82] and utilities must be prepared operationally and financially for significant and unpredictable natural events. Other examples include global events like the COVID-19 pandemic, the war in Ukraine, or the 2008-2009 Great Recession can affect utilities

[81] *See, e.g.*, Moody's Investors Service, Rating Methodology: Regulated Gas and Electric Utilities, at 4 (June 23, 2017).

[82] McFarland, Heather, *Alaska's Changing Environment*, University of Alaska Fairbanks, December 3, 2024.

directly, but also the economic and capital market environments in which utilities raise capital. Because utilities have an obligation to serve and cannot delay investments in critical infrastructure, they must be able to access capital markets efficiently and on reasonable terms even when markets are volatile or constrained. A utility with a strong financial profile has a higher likelihood (though not a guarantee) of withstanding adverse events and accessing capital at reasonable terms when needed for the benefit of customers.

Q. What are your conclusions regarding the regulatory principles pertaining to the cost of capital for a public utility?

A. Congruent with other costs in a utility's cost of service, the regulated return on rate base is a cost that ENSTAR incurs as part of its normal operations, including the need to compensate equity investors for the use of their capital. Under the *Hope* and *Bluefield* standards, the cost of equity authorized for ENSTAR in this proceeding should be: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments having similar risks.

Because utilities are capital-intensive and investors have many investment alternatives, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions. The RCA's decision regarding the authorized ROE and capital structure in this proceeding will directly affect the Company's ability to attract the capital needed to maintain and enhance service to customers.

B. Proxy Group Selection

Q. Why is it necessary to select a group of proxy companies to determine the cost of equity for ENSTAR?

A. The cost of equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. Because the ROE is a market-based concept estimated through the use of market data applied to various financial models, and ENSTAR is not a standalone, publicly traded entity, it is necessary to establish a group consisting of companies that are both publicly traded and reasonably comparable to the Company in certain fundamental respects to serve as its "proxy" in the ROE estimation process. Even if the Company were a publicly traded entity, short-term events could bias its market value during a given period. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

Q. Does the fact that ENSTAR is a subsidiary of a privately held company affect its cost of equity?

A. No. The cost of equity depends on the risk of a firm's operations and the assets supporting those operations. In other words, the cost of equity depends on the *use* of capital, not on the *source* of capital. Therefore, the Company's corporate structure, including whether it (or its parent) is privately held or publicly traded, does not affect the analysis. That is, the ROE is not determined by reference to ENSTAR's parent company.

Q. What criteria do you use to select the proxy group?

A. Because estimating the cost of equity is a comparative exercise, it is necessary to develop a proxy group of publicly traded companies with risk profiles that are

reasonably comparable to the subject company. Although it is the case that no two companies will have identical business and financial risk profiles, as described earlier, this is especially true for ENSTAR. In selecting a proxy group, my objective is to balance the competing interests of selecting companies that are representative of the risks and prospects faced by ENSTAR, while at the same time ensuring that there is a sufficient number of companies in the proxy group. To reflect ENSTAR's operations consisting of both distribution and transmission assets, I developed a proxy group that includes both regulated natural gas utilities and regulated gas pipeline companies. For the natural gas distribution utilities, I first began with the nine publicly traded companies that Value Line classifies as "Natural Gas Utilities" and screened those companies according to the following criteria:

- Because certain of the models used in my analyses assume that earnings and dividends grow over time, I exclude companies that do not consistently pay quarterly cash dividends, or have cut their dividend in the last two years;
- Because certain of the models assume that earnings grow over time, I exclude companies that do not have positive earnings growth rates from at least two sources;
- To ensure that the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group are consistently covered by at least two utility industry equity analysts;
- I exclude companies that do not have (or its primary regulated natural gas utility subsidiary does not have) an investment-grade corporate or senior unsecured bond credit rating from Standard and Poor's ("S&P") and Moody's Investor's Service ("Moody's);
- I eliminate companies that have had significant merger activity or transactions or have had a recent financial event that could affect their market data or financial condition; and

- To ensure that the natural gas utilities are primarily regulated utilities, natural gas utilities included in my proxy group have a majority (greater than 50 percent) of total operating income from regulated natural gas operations from 2021-2023 on average.

To reflect ENSTAR's transmission operations and higher risk, I then reviewed the 26 companies that Value Line classifies as Natural Gas Diversified, Oil or Gas Distribution, or Pipeline Master Limited Partnerships ("MLP") and applied the following additional screening criteria to this subset:

- To ensure that companies are within the same financial standing investors would expect for a regulated gas utility, I excluded companies that do not have a Value Line Safety[83] rating of 1, 2, or 3, and a Value Line Financial Strength[84] rating lower than B+;
- Because ENSTAR has a unique business profile of an integrated natural gas company, with both distribution and transmission assets, I excluded companies that do not have regulated natural gas pipeline operations.

Q. Which companies meet your screening criteria?

A. The criteria discussed above resulted in a proxy group of the following 14 companies:

[83] Value Line's Ranking System for Safety measures the total risk of a stock relative to the approximately 1,700 other stocks in The Value Line Investment Survey. It is derived from a stock's Price Stability Index and Financial Strength rating of a company. Safety ranks are given on a scale from 1 (Highest) to 5 (lowest). See, https://www.valuelinepro.com/value-line-ranking-system.

[84] The Financial Strength Grade Rating ranges from an A++ for the most financially stable firms, to C, for companies that are in serious financial difficulty. There are a number of key factors that determine the Financial Strength of a corporation. The most important of these factors is the amount of debt on the balance sheet. A higher debt to total capital percentage typically results in lower Financial Strength ratings. Other important factors considered in a Financial Strength rating include business risk and the level and direction of profits. See, https://www.valuelinepro.com/value-line-ranking-system.

Figure 10: Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Gas Holding Co.	NWN
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX
Spire, Inc.	SR
Enbridge Inc.	ENB
Energy Transfer LP	ET
Enterprise Products Partners LP	EPD
Kinder Morgan Inc.	KMI
MPLX LP	MPLX
TC Energy Corp.	TRP
Williams Companies Inc.	WMB

Q. Has the RCA previously opined on a proxy group representative of ENSTAR's risk factors?

A. Yes, the RCA has previously noted that ENSTAR's substantial transmission assets result in increased risk relative to the natural gas distribution companies in the Lower 48.[85] In the 2016 rate case, the RCA also noted that the increased risk factor is moderated by a selection of a proxy group that includes both Master Limited Partnership ("MLP") pipeline companies and distribution companies.[86] In an effort to incorporate the RCA's perspective on the relative risk of ENSTAR and its proxy companies, I have also included pipeline companies.

[85] Regulatory Commission of Alaska, Order No. 19 in Docket No. U-16-066, Order Resolving Revenue Requirement and Cost-of-Service Issues and Requiring Filings (September 22, 2017) at 50.

[86] *Id.*

Q. What is your conclusion regarding the proxy group of companies comparable to ENSTAR?

A. ENSTAR's unique operations and profile present significant challenges to developing a group of publicly traded companies that are similar to the Company. However, the screening criteria results in a group of utilities that, on balance, are reasonably comparable (but not identical) to the financial and operational characteristics of ENSTAR. The screening criteria requiring an investment grade credit rating, Value Line Safety of 3 or lower and Financial Strength of B+ or higher ensure that the proxy companies, like ENSTAR, are in sound financial condition and are considered stable like regulated natural gas utilities. Additionally, the criterion screening on the operations primarily in regulated natural gas distribution or transmission distinguishes between companies that are subject to rate regulation and those that are not. On balance, it is my opinion that the proxy group is a reasonable and appropriate basis for the ROE estimation process.

C. Cost of Equity Models

Q. What analytical approaches do you use to determine the Company's ROE?

A. As noted earlier, I rely on the Constant Growth and Quarterly Growth forms of the DCF model, the traditional and empirical forms of the CAPM, and the Bond Yield Plus Risk Premium approach. The models that I apply are commonly used in practice,[87] as well as in regulatory proceedings. Additionally, each model provides a different insight

[87] *See, e.g.*, Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th ed., 1994, at 341.

into investors' views of risk and return. Therefore, the use of multiple methods provides a comprehensive and robust perspective on investors' return requirements.

1. Constant Growth Discounted Cash Flow Model

Q. Please describe the Constant Growth DCF approach.

A. The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplified form, the Constant Growth DCF model shown in Equation [1] below sets the ROE equal to the expected dividend yield plus the expected long-term annual growth rate in perpetuity:

$$k = \frac{D_0\ (1+g)}{P} + g \qquad [1]$$

where:

k = the required ROE,

D_0 = the current annualized dividend,

P = the current stock price, and

g = the expected long-term annual growth rate.

Q. What assumptions underlie the Constant Growth DCF model?

A. The Constant Growth DCF model assumes: (1) a constant average annual growth rate for earnings and dividends; (2) dividends are paid annually, and the dividend payout ratio is stable; (3) a constant Price/Earnings multiple; and (4) a discount rate greater than the expected growth rate. The model also assumes that the current cost of equity will remain constant in perpetuity.

Q. What market data did you use to calculate the dividend yield in your constant growth DCF model?

A. I calculate the Constant Growth DCF result for each of the proxy companies using the following inputs:

- The average daily closing prices for the 30-, 90-, and 180-trading days ended January 31, 2025, for the term *P*;
- The current quarterly dividend as of January 31, 2025 multiplied by 4, for the term D_0; and
- Long-term earnings per share ("EPS") growth rate projections as of January 31, 2025, reported by Zacks, S&P Capital IQ,[88] and *Value Line* for the long-term growth rate, g.

Q. Why do you use three averaging periods to calculate an average stock price?

A. I do so to ensure that the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the average period should reasonably reflect the expected capital market conditions over the long term. Using 30-, 90-, and 180-trading day averaging periods reasonably balances those concerns.

Q. How do you calculate the expected dividend yield over the coming year?

A. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Therefore, I calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That

[88] In prior testimonies, I have relied on analysts' consensus long-term EPS projections from First Call as reported by Yahoo! Finance. As of November 2024, Yahoo! Finance no longer publishes consensus long-term projected EPS growth rates. Therefore, I now rely on analysts' consensus EPS growth rate projections reported by S&P Capital IQ as a third source.

adjustment ensures that the expected dividend yield is, on average, representative of the coming 12-month period.

Q. Why is the projected EPS growth the appropriate measure of long-term growth in the Constant Growth DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [1] above) assumes a single expected growth estimate in perpetuity, which assumes a fixed payout ratio, and the same constant growth rate in EPS, dividends per share, and book value per share. In the long run, dividend growth can only be sustained by earnings growth.

Further, academic studies have clearly and consistently shown that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[89] For example, the research of Vander Weide and Carleton demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[90] Those findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Lastly, the only forward-looking growth rates that are available on a consensus basis are analysts' EPS growth rates. The fact that earnings growth projections are the only widely available estimates of growth further supports the conclusion that earnings

[89] *See, e.g.*, Andreas C. Christofi, Petros C. Christofi, Marcus Lori and Donald M. Moliver, Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate, Journal of Investing (Spring 1999); Harris and Marston, Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts, Financial Management at 21 (Summer 1992); and Vander Weide and Carleton, Investor Growth Expectations: Analysts vs. History, The Journal of Portfolio Management (Spring 1988); Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return, Financial Management (Spring 1986).

[90] See Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

growth is the most meaningful measure of growth among the investment community. For these reasons, earnings growth is the appropriate measure of long-term growth in the DCF model.

Q. Did you review the earnings growth rates included in your analysis for outliers?

A. Yes, I did. Statisticians often define outliers as data points that are more than two standard deviations from the mean (*i.e.*, average). Therefore, I gathered each of the earnings growth rates from Zacks, S&P, and Value Line for the 14 proxy group companies and calculated the average and the standard deviation. I then added two standard deviations above and below the average. Two standard deviations above the mean is a growth rate of 15.55 percent and two standard deviations below the mean is -1.01 percent. Therefore, I removed two earnings growth rates higher than 15.55 percent as being outliers.

Q. What are the results of your Constant Growth DCF analysis?

A. To provide a spectrum of DCF-based ROE estimates, I calculate the low, mean, and high Constant Growth DCF result for each proxy company using the low, mean, and high EPS growth estimate. The mean result combines the average of the three EPS growth rate estimates with each proxy company's expected dividend yield. The high DCF result adds the maximum EPS growth rate estimate with each proxy company's expected dividend yield. Similarly, the low DCF result adds the minimum EPS growth rate estimate for each proxy company to the expected dividend yield. I then calculate the mean and median low, mean, and high DCF results for the proxy group. In developing my ROE recommendation, I rely on the average of the mean and median proxy group Constant Growth DCF results (*see* Figure 11, below, and Exhibit JEN-2).

By relying on the average of the mean and median proxy group results, I consider the individual DCF results of each proxy company while mitigating the effect of the highest and lowest estimates.

Figure 11: Constant Growth DCF Results[91]

	Low	Mean	High
30-Day Average	10.48%	11.55%	13.10%
90-Day Average	10.69%	11.61%	13.15%
180-Day Average	11.04%	11.90%	13.38%

2. Quarterly Growth Discounted Cash Flow Model

Q. Please describe the Quarterly Growth DCF model.

A. As noted earlier, the Constant Growth DCF model is based on several limiting assumptions, one of which is that dividends are paid annually. However, most dividend-paying companies, including utilities, pay dividends on a quarterly basis. Although the dividend yield adjustment discussed earlier is intended to reflect that assumption by increasing the observed dividend yield by one-half of the expected growth rate, it does not fully account for the quarterly receipt and reinvestment of dividends. Consequently, the Constant Growth DCF model likely understates the cost of equity. The Quarterly Growth DCF model specifically incorporates the quarterly payment of dividends, and the associated quarterly compounding of those dividends as they are reinvested at the required ROE. As noted by Dr. Roger Morin:

> Clearly, given that dividends are paid quarterly and that the observed stock price reflects the quarterly nature of dividend payments, the

[91] *See* Exhibit JEN-2. Average of the proxy group mean and median results. Data as of January 31, 2025.

market-required return must recognize quarterly compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule... The annual DCF model inherently understates the investors' true return because it assumes all cash flows received by investors are paid annually.[92]

Q. How is the dividend yield portion of the Quarterly DCF model calculated?

A. To reflect the timing and compounding of quarterly dividends, the model replaces the "D" component of the Constant Growth DCF model with the following equation:

$$D = d_1 (1 + k)^{0.75} + d_2 (1 + k)^{0.50} + d_3 (1 + k)^{0.25} + d_4 (1 + k)^0 \quad [2]$$

where:

d_1, d_2, d_3, d_4 = expected quarterly dividends over the coming year; and

k = the required Return on Equity.[93]

To calculate the expected dividends over the coming year for the proxy companies (*i.e.*, d_1, d_2, d_3, and d_4), I obtained the last four paid quarterly dividends for each company and multiplied them by one plus the growth rate (*i.e.*, $1 + g$). To provide a spectrum of quarterly growth DCF-based ROE estimates, I calculate the low, mean, and high quarterly growth DCF result for each proxy group company using the low, mean, and high ESP growth estimates. For the *P* component of the dividend yield, I used the same average stock prices applied in the Constant Growth DCF analysis for each proxy group company.

[92] Roger A. Morin, Ph.D., New Regulatory Finance, at 344 (2006).

[93] Because the required ROE (k) is a variable in the dividend yield calculation, the Quarterly Growth DCF model is solved iteratively.

Q. What are the results of your Quarterly Growth DCF analyses?

A. My Quarterly Growth DCF results are summarized in Figure 12 below (*see also* Exhibit JEN-3). As with my Constant Growth DCF analysis, I rely on the average of the mean and median proxy group results.

Figure 12: Quarterly Growth DCF Results[94]

	Low	Mean	High
30-Day Average	10.73%	11.81%	13.40%
90-Day Average	10.95%	11.86%	13.46%
180-Day Average	11.30%	12.21%	13.71%

3. Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Q. Please describe the general form of the CAPM.

A. The CAPM is a risk premium method that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. As shown in Equation [3], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

where:

K_e = the required market ROE for a security;

β = the Beta coefficient of that security;

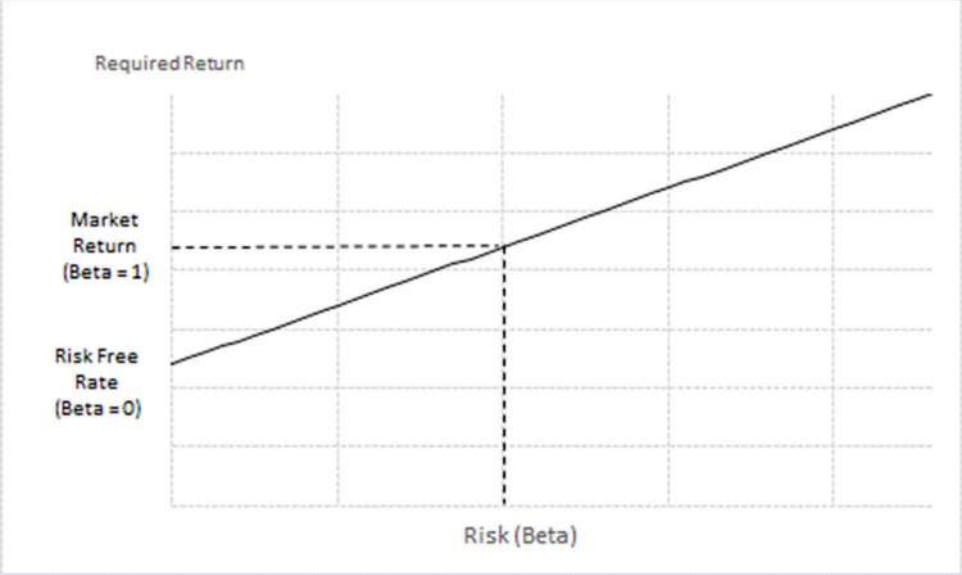
r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

[94] *See* Exhibit JEN-3. Average of the proxy group mean and median results. Data as of January 31, 2025.

Equation [3] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, depicted in Figure 13 below. The intercept is the risk-free rate (r_f) which has a Beta coefficient of zero, and the slope is the expected market risk premium ($r_m - r_f$). As shown in Figure 13, the SML is upward sloping, illustrating the principle that investments of higher risk require a higher return. By definition, r_m, the return on the market, has a Beta coefficient of 1.00. A Beta coefficient of less than 1.00 generally indicates less market risk and a lower required return than the market; conversely, a company with a Beta coefficient greater than 1.00 has higher market risk, thereby warranting a higher required return than the market.

Figure 13: Security Market Line



The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic risk. Systematic (or non-diversifiable) risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} \text{ x } \rho_{j,m} \quad [4]$$

where σ_j is the standard deviation of returns for company "*j*," σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns between company *j* and the broader market. The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Q. What risk-free rate assumptions did you include in your CAPM analysis?

A. I apply two different estimates of the risk-free rate: (1) the 30-day average yield on 30-year Treasury bonds as of January 31, 2025 (*i.e.*, 4.82 percent);[95] and (2) a projected 30-year Treasury yield (*i.e.*, 4.46 percent).[96]

Q. Why do you rely on the 30-year Treasury yield in the CAPM analysis?

A. In determining the security most relevant to the application of the CAPM, the term (or maturity) should approximate the life of the underlying investment. Natural gas utilities are typically long-term duration investments; therefore, the 30-year Treasury yield is most suitable for the risk-free rate applied in the CAPM.

Q. What Beta coefficients do you use in your CAPM model?

A. As shown in Exhibit JEN-5, my CAPM analyses rely on the average Beta coefficients from *Value Line* and Bloomberg for each proxy company as of January 31, 2025. Beta coefficients from both services are calculated using weekly returns over a five-year

[95] Source: Bloomberg Professional Services.

[96] The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q1 2026; and (2) the average long-term projected 30-year Treasury yield for the years 2026-2030 and 2031-2035 reported by Blue Chip Financial Forecast. *See* Blue Chip Financial Forecast, Vol. 43, No. 12, December 1, 2024, at 14 Blue Chip Financial Forecast, Vol. 44, No.2, January 31, 2025 at 2.

period, adjusted to reflect the tendency of Beta coefficients to regress toward the market mean of 1.00.

Q. What estimates of the expected market return do you use to calculate the market risk premium?

A. I consider two estimates of the expected market return. The first estimate is a forward-looking estimate that calculates the market capitalization-weighted ROE of the S&P 500 Index by applying the Constant Growth DCF model to the S&P 500 Index. The second estimate takes the average of the forward estimate and the long-run historical arithmetic average market return of 12.17 percent reported by Kroll (formerly Duff & Phelps) for the years 1926 to 2024.[97]

Q. Please further explain your forward-looking DCF approach to estimating the market return.

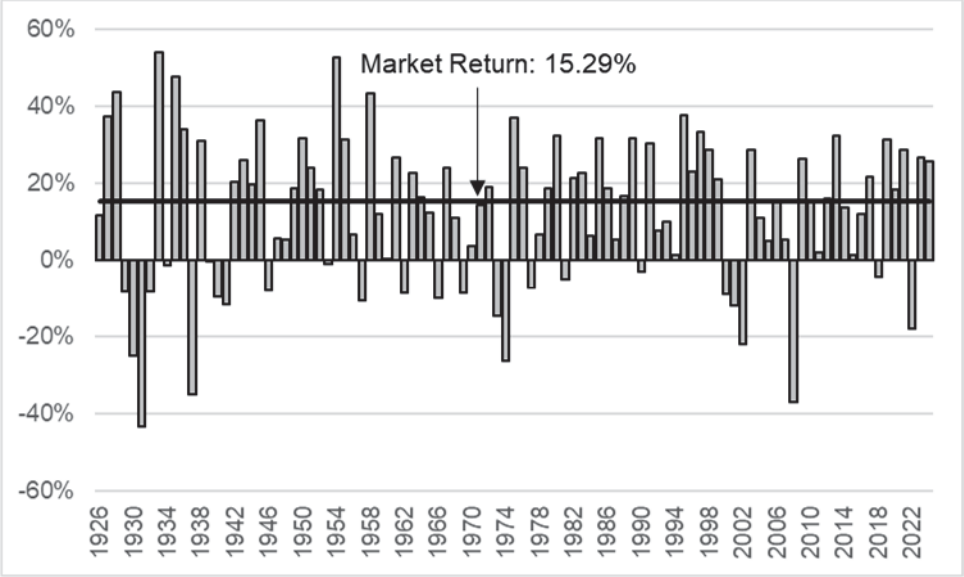
A. Using the Constant Growth DCF model described earlier, I develop two estimates of the expected market return by applying dividend yields from Bloomberg and projected earnings growth rates from Bloomberg and *Value Line*. I calculate a market capitalization-weighted dividend yield and projected earnings growth rate for the S&P 500 Index and applied those estimates to the Constant Growth DCF formula, using the same half-growth rate assumption described earlier. The expected market return from Bloomberg and *Value Line* are 16.34 percent and 15.29 percent, respectively (*see* Exhibit JEN-4). To be conservative, I rely on *Value Line*'s expected market return estimate of 15.29 percent in my CAPM analyses.

[97] Source: Kroll, Cost of Capital Navigator.

Q. Is the *Value Line*-based DCF-based estimate of 15.29 percent consistent with actual observed returns on the market?

A. Yes, it is. As shown in Figure 14 below, an expected market required return of 15.29 percent or higher occurred in 49 of the last 99 years (*i.e.*, 49 percent of the time). Since 2009, the annual market return has averaged 15.58 percent, and equaled or exceeded 15.29 percent in nine of the last 16 years and 11 of the last 22 years. In other words, an annual market return of 15.29 percent, or higher, has occurred frequently.

Figure 14: Annual Market Return (1926-2024)[98]



To moderate the effect of the forward-looking market return, I also average the forward-looking return of 15.29 percent with the long-term average historical return between 1926 and 2024 of 12.17 percent as reported by Kroll (formerly Duff & Phelps). I then subtract the current and projected risk-free rates to calculate a "blended" MRP of 8.91 and 9.27 percent, respectively.

[98] Source: Kroll, 2023 SBBI Yearbook, Appendix A-1, A-7 (years 1926-2022); Cost of Capital Navigator (2023, 2024 data).

Q. With the risk-free rates and required market return estimates described above, how do you calculate the market risk premium?

A. I apply two estimates of the risk-free rate and two estimates of the expected market return. Combined, those variables produce four estimates of the market risk premium, ranging from 8.91 percent to 10.83 percent as shown below in Figure 15.

Figure 15: Market Risk Premium Estimates

	Current Risk-Free Rate (4.82%)	Projected Risk-Free Rate (4.46%)
Value Line Forward Market Return (15.29%)	10.47%	10.83%
Blended Market Return (13.73%)	8.91%	9.27%

Q. What are the results of your CAPM Analysis?

A. As shown in Exhibit JEN-5, the CAPM results range from 12.87 percent to 14.33 percent (*see* Figure 16 below).

Figure 16: Summary of CAPM Results[99]

	Current Risk-Free Rate (4.82%)	Projected Risk-Free Rate (4.46%)
Forward Market Return	14.33%	14.29%
Blended Market Return	12.91%	12.87%

Q. Do you consider another form of the CAPM?

A. Yes, I also consider the Empirical CAPM ("ECAPM") approach, which calculates the product of the adjusted Beta coefficient and the market risk premium and applies a

[99] *See* Exhibit JEN-5. Average of the proxy group mean and median. Data as of January 31, 2025.

weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium, without any effect from the Beta coefficient.[100] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as expressed in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

where:

k_e = the required market ROE;

β = adjusted Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Q. What is the benefit of the ECAPM approach?

A. The ECAPM corrects the tendency of the CAPM to underestimate the cost of equity for companies, such as regulated utilities, with low Beta coefficients, and to overstate the cost of equity for companies with high Beta coefficients. As discussed below, the ECAPM recognizes academic research that indicates that the risk-return relationship is flatter than the relationship estimated by the CAPM, and that the CAPM under-estimates the alpha, or the constant return term.[101]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual SML is not as steeply sloped as the SML predicted by the CAPM formula.[102] Fama and French found that the actual returns on

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[100] *See*, *e.g.*, Roger A. Morin, Ph.D., New Regulatory Finance, at 189-190 (2006).

[101] *Id*. at 191 ("The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks.").

[102] *Id*. at 175.

the low Beta coefficient portfolios were higher than the CAPM-predicted returns, and vice versa for the high Beta coefficient portfolios.[103] Similarly, Dr. Morin states:

> With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.
>
> ***
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,(R_M - R_F) + (1-x)\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$[104]

Q. Does the application of adjusted Beta coefficients in the ECAPM address the empirical issues the CAPM?

A. No, it does not. Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the actual SML is not as steeply sloped as the SML predicted by the CAPM formula. To that point, Dr. Morin explains:

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[103] Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

[104] Roger A. Morin, Ph.D., New Regulatory Finance, at 175, 190 (2006).

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary.[105]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM.

Q. Are you aware of academic studies that support the use of the ECAPM for utilities?

A. Yes, I am. In a 2011 study by Stéphane Chrétien and Frank Coggins, the authors studied the CAPM's ability to estimate the risk premium for the utility industry in particular subgroups of utilities.[106] The study considered the traditional CAPM

[105] *Id*. at 191.

[106] Stéphane Chrétien and Frank Coggins, *Cost of Equity for Energy Utilities: Beyond The CAPM*, Energy Studies Review, Vol. 18, No. 2 (2011).

approach, the Fama-French three-factor model, and a model similar to the ECAPM. In the study, the ECAPM relied on adjusted Beta coefficients similar to *Value Line*'s approach. As Chrétien and Coggins found, the ECAPM significantly outperformed the traditional CAPM model at predicting the observed risk premium for the various utility subgroups.

Q. What are the results of your ECAPM analyses?

A. I apply the same market return estimates, Beta coefficients, and risk-free rates described earlier to the ECAPM formula shown in Equation [5] above. The results of my ECAPM analyses are shown on Exhibit JEN-5 and summarized in Figure 17 below.

Figure 17: Summary of ECAPM Results[107]

	Current Risk-Free Rate (4.82%)	Projected Risk-Free Rate (4.46%)
Forward Market Return	14.57%	14.54%
Blended Market Return	13.11%	13.09%

4. Bond Yield Plus Risk Premium Approach

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. The Bond Yield Plus Risk Premium approach is based on the basic financial principle of risk and return, which states that equity investors require a premium over the return required as a bondholder to compensate for the residual risk associated with equity ownership. Risk Premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds.

[107] *See* Exhibit JEN-5. Average of the proxy group mean and median. Data as of January 31, 2025.

Q. Please explain how you perform your Bond Yield Plus Risk Premium analysis.

A. I first define the equity risk premium as the difference between the authorized ROE and the then-prevailing level of long-term (*i.e.*, 30-year) Treasury yield, using the authorized ROE for 1,335 natural gas distribution utility rate proceedings between January 1, 1980 and January 31, 2025. To reflect the prevailing level of bond yields during the pendency of the proceedings, I calculate the average 30-year Treasury yield over the average period between the filing of the rate case and the date of the final order (approximately 188 days).

Because the data spans several economic cycles over more than four decades, the analysis incorporates changes in the equity risk premium over time. Prior research, for example, has shown that the equity risk premium is inversely related to the level of bond yields.[108]

Q. How do you analyze the relationship between bond yields and the equity risk premium?

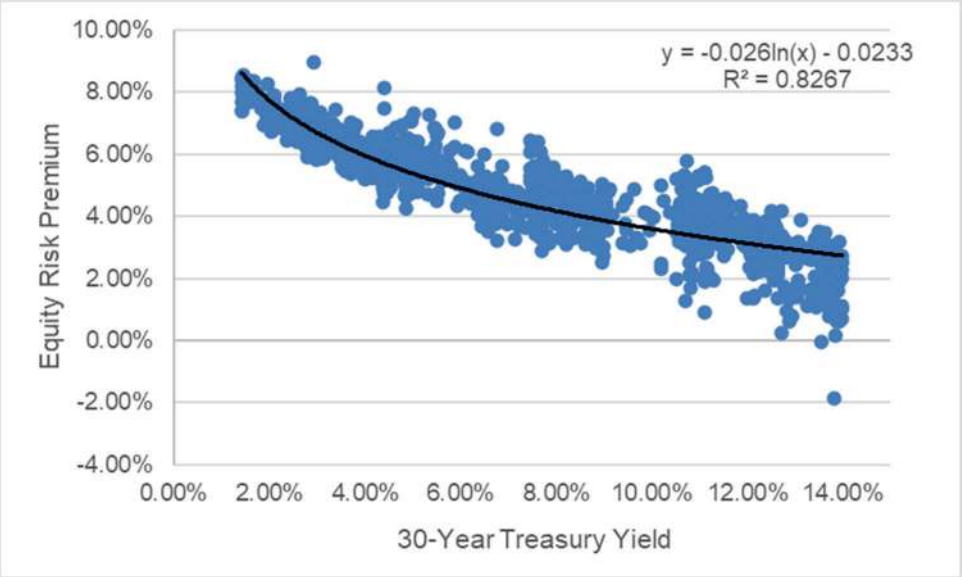
A. I estimate the relationship between bond yields and the equity risk premium by applying regression analysis, in which the observed equity risk premium described above is the dependent variable, and the 30-year Treasury yield is the independent variable. To account for the variability in bond yields and authorized ROEs over

[108] In other words, declines in the 30-year Treasury yield are related to an increase in the Equity Risk Premium and vice versa. *See, e.g.*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992), at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, (Spring 1985), at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, (Autumn 1995), at 89-95.

several decades, I used the semi-log regression, in which the equity risk premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta\ (\mathrm{LN}(T_{30})) \qquad [6]$$

Figure 18: Natural Gas Utility Risk Premium[109]



As Figure 18 illustrates, the equity risk premium increases as interest rates fall. The finding that the equity risk premium and interest rates are inversely related is supported by published research. For example, Dr. Roger Morin cites several studies and concludes that, "beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when interest rates rose."[110] Applying the current and projected bond yields to the regression coefficients in Figure 18 produces base ROE estimates of 10.30 percent and 10.13 percent (*see also* Exhibit JEN-6).

[109] Exhibit JEN-6. Data as of January 31, 2025.

[110] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., at 128 (2006).

Figure 19: Base Bond Yield Plus Risk Premium Results[111]

	30-Year Treasury Bond	Risk Premium	Return on Equity
Current 30-Year Treasury	4.82%	5.47%	10.30%
Projected 30-Year Treasury	4.46%	5.67%	10.13%

Q. Do the base Bond Yield Plus Risk Premium results in Figure 19 reflect the cost of equity for Alaska utilities?

A. No. The Bond Yield Plus Risk Premium estimates the relationship between the equity risk premium and bond yields using primarily authorized ROEs for natural gas utilities in the Lower 48. Therefore, the results in Figure 19 more closely estimate the cost of equity for natural gas utilities that operate in the Lower 48. As discussed earlier, the RCA has previously recognized that utilities operating in Alaska face greater risks than Lower 48 utilities.[112] To quantify the adjustment commensurate with the geographical risk borne by utilities operating in Alaska, I compared the authorized ROEs for electric and natural gas utilities in Alaska since 2010 to the twelve-month trailing average of authorized ROEs in all jurisdictions in the country.

[111] *See* Exhibit JEN-6.

[112] *See, e.g.*, Order U-16-066(19) at 50.

Figure 20: Authorized ROEs for Natural Gas Distribution Utilities in Lower 48 vs. Alaska[113]

Utility Service	Date	Authorized ROE - Alaska	TTM Average Authorized ROE – U.S.	Alaska ROE Adjustment (basis pts)
Gas	8/9/2010	12.55%	10.25%	**230**
	9/22/2017	11.88%	9.67%	**221**
	4/8/2024	11.88%	9.67%	**221**
Electric	9/2/2011	12.88%	10.30%	**258**
	11/15/2017	11.95%	9.77%	**218**
	8/31/2023	11.45%	9.60%	**185**
			Average	**222**

As Figure 20 demonstrates, the ROEs authorized for Alaska utilities have been, on average, 222 basis points above the ROEs authorized in the rest of the U.S. over the last 15 years.

Q. Have you adjusted the Bond Yield Plus Risk Premium analysis to incorporate the additional risk borne by utilities operating in Alaska?

A. Yes, to appropriately reflect the cost of equity for utilities operating in a significantly more remote location than the utilities operating in the Lower 48, I adjusted the Bond Yield Plus Risk Premium results by the average basis point differential shown above in Figure 20, or 222 basis points. Adding the average Alaska ROE adjustment of 222 basis points to the base ROE estimates in Figure 19 produces Alaska utility adjusted

[113] Source: S&P Regulatory Research Associates (RRA). Note that the trailing 12-month average authorized ROE is calculated for each respective utility service (electric or gas) as of the date of each Alaska utility rate case decision.

ROE estimates of 12.35 percent to 12.52 percent (see Figure 21 below and Exhibit JEN-6).

Figure 21: Alaska-Adjusted Bond Yield Plus Risk Premium Results[114]

	30-Year Treasury Bond	Risk Premium	Alaska ROE Adjustment	ROE Estimate
Current 30-Year Treasury	4.82%	5.47%	2.22%	12.52%
Projected 30-Year Treasury	4.46%	5.67%	2.22%	12.35%

VI. CAPITAL STRUCTURE

Q. What is ENSTAR's requested capital structure?

A. The Company requests its actual capital structure as of the end of the test period, December 31, 2024, consisting of 58.57 percent equity and 41.43 percent debt.

Q. How does the capital structure affect the cost of capital?

A. A company's total risk consists of business risk and financial risk. Business risk includes operating, market, regulatory, and competitive uncertainties, whereas financial risk is the incremental risk associated with greater debt. As the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt and the risk of financial distress. Therefore, the capital structure reflects the financial risk that a company may not have adequate cash flows to meet its financial obligations.

[114] *See* Exhibit JEN-6. Data as of January 31, 2025.

Q. What are the guidelines for determining whether a utility's capital structure is within industry standards?

A. In a 2020 publication titled *A Cost of Capital and Capital Markets Primer for Utility Regulators*, the National Association of Regulatory Utility Commissioners ("NARUC") states that actual capital structure ratios should be used unless they "greatly diverge" from sound industry practice:

> A utility management must be permitted latitude, discretion, and flexibility in managing capital structure ratios. Since there is no practical methodology to pinpoint theoretically optimal capital structure ratios, targeted ratios can only be broadly conceptualized. Appropriate ratios may shift over time as capital market conditions or business risk characteristics change. Additionally, the timing of upcoming issuances and maturities may influence the capital structure ratios because both the size and frequency of issuances are affected by the relative cost-effectiveness of various issuance increments.
>
> Given these practical considerations, capital structure ratios cannot be deemed to be inappropriate unless the ratios greatly diverge from sound industry practice and cause a lack of financial flexibility that may lead to higher overall costs.
>
> ***
>
> As increasing financial leverage shifts the weight from common equity to lower cost debt, it also increases both the cost of debt and the cost of common equity. In practice, these offsetting impacts cancel each other out over a wide range of capital structure ratios.[115]

[115] NARUC, *A Cost of Capital and Capital Markets Primer for Utility Regulators* (April 2020), at 11 (emphasis added).

Further, James C. Bonbright explains in his seminal text *Principles of Public Utility Rates* that a hypothetical capital structure should be used only when actual capital structures are "clearly unsound" or "extravagantly conservative," reasoning that using hypothetical capital structures "substitutes an estimate of what the capital cost would be under non-existing conditions for what it actually is or will soon be under prevailing conditions."[116]

Q. Have you assessed whether ENSTAR's recommended capital structure is consistent with sound utility practice?

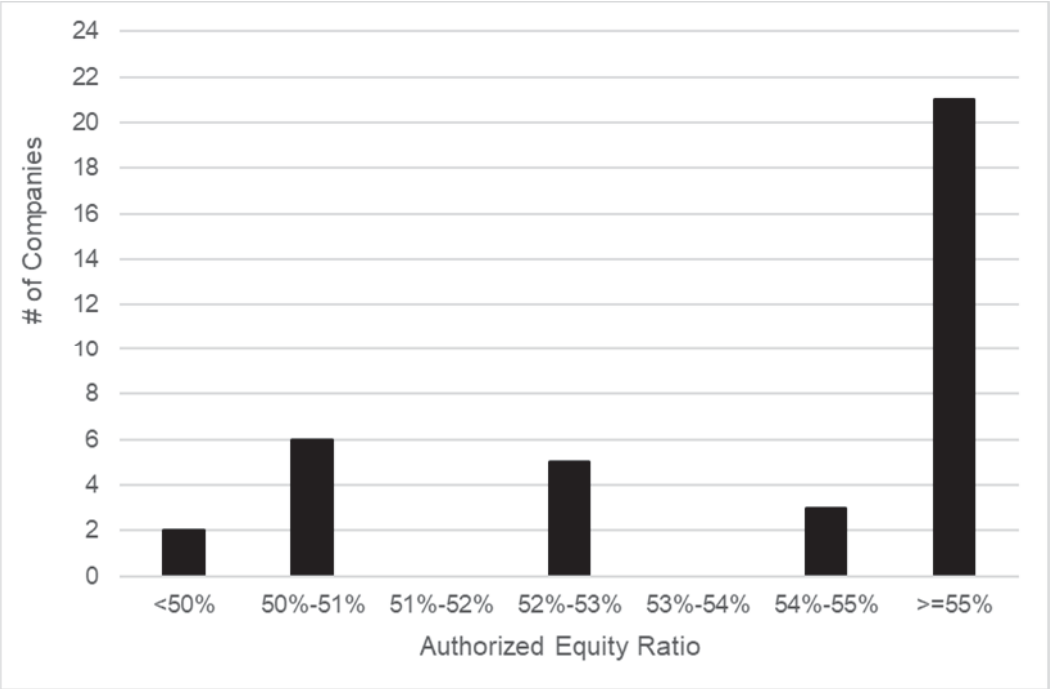
A. Yes, I have. As a measure of industry practice, I calculated the actual capital structure for each of the natural gas distribution operating companies within the proxy group over the last three years. As shown in Exhibit JEN-9, the actual common equity ratios of the proxy group operating companies range from 47.37 percent to 60.03 percent. The Company's equity thickness is clearly within the proxy group range.

Q. Have you also reviewed authorized equity ratios for the natural gas distribution operating companies within the proxy group?

A. Yes. As shown in Figure 22 below, approximately 57 percent of the natural gas distribution operating companies have an authorized equity ratio of 55 percent or higher in the service territories in which they operate (*see also* Exhibit JEN-10).

[116] James C. Bonbright, Principles of Public Utility Rates, at 243-44 (1960). Republished with permission by the Regulatory Assistance Project.

Figure 22: Current Authorized Equity Ratios for Natural Gas Utility Proxy Companies



Furthermore, the Company's requested capital structure is consistent with the equity ratios authorized by the RCA for Alaska utilities over the last 15 years, ranging from 51.40 percent to 60.70 percent.[117]

Q. Are you aware of any recent FERC decisions regarding the authorized equity ratios for natural gas pipeline companies?

A. Yes. Although most FERC pipeline rate cases are resolved by "black box" settlement in which the ROE and capital structure are not explicitly determined, the most recent FERC decision for a natural gas pipeline company I am aware of was issued in December 2022 for Panhandle Eastern Pipe Line Company ("Panhandle"), a natural gas transmission company owned by Energy Transfer, one of the companies in my

[117] Source: Regulatory Research Associates.

proxy group. In FERC Order 885, the FERC approved Panhandle's actual equity ratio of 62.94 percent. In its decision, the FERC stated that the Initial Decision appropriately adopted Panhandle's actual capital structure.[118] The Initial Decision noted the FERC's strong preference for using the pipeline's actual capital structure, and that its capital structure was in line with previously approved capital structures,[119] including a 68.86 percent equity ratio approved for Pacific Gas Transmission Company in 1993 and a 64.29 percent equity ratio approved for Williams Natural Gas Company in 1998.[120] These decisions demonstrate that natural gas pipeline companies are financed with more equity than LDCs are financed with and support ENSTAR's requested equity ratio.

VII. CAPITAL MARKET ENVIRONMENT

Q. Do economic conditions influence the required cost of capital and required return on common equity?

A. Yes. The required cost of capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. Each of the analytical models used to estimate the required ROE is influenced by current and expected capital market conditions. Therefore, an evaluation of current and projected market conditions is integral to any ROE recommendation.

[118] 181 FERC ¶ 61,211, FERC Docket No. RP19-78, Order 885, Opinion and Order on Initial Decision, at P97 (December 16, 2022).

[119] *Id*. at P92.

[120] 174 FERC ¶ 63,026, FERC Docket No. RP19-78, Initial Decision, at P176 (March 26, 2021)

Q. What are the key factors affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utilities is currently affected by several key factors, including: (1) the interest rate environment and central bank monetary policy; (2) inflationary pressure and the longer-term outlook for inflation; and (3) greater market volatility and uncertainty associated with federal trade policy and a change in administration at the federal level. As discussed below, although the Federal Reserve reduced the Federal Funds rate in the fall of 2024 as inflation stabilized and moved closer to the central bank's two percent target, stubborn inflation and greater market and economic uncertainty has prompted the Federal Reserve to pause its easing of monetary policy. Consequently, interest rates and inflation have remained elevated and are expected to remain above the levels experienced prior to the COVID-19 pandemic. Further, the change in the federal administration presents significant uncertainties with respect to the near-term economic and capital market outlook. All those factors affect the ability and cost for utilities to secure capital.

Q. Please summarize the changes in the capital market conditions since early 2020.

A. The COVID-19 pandemic had wide-ranging impacts on markets, affecting all market sectors, including utilities. At the start of the pandemic, both the S&P 500 Index and the electric utility sector lost more than a third of its value.[121] At the same time, the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX", a measure of

[121] Source: Yahoo! Finance. Electric utility sector measured by the S&P 500 Electric Utilities Index.

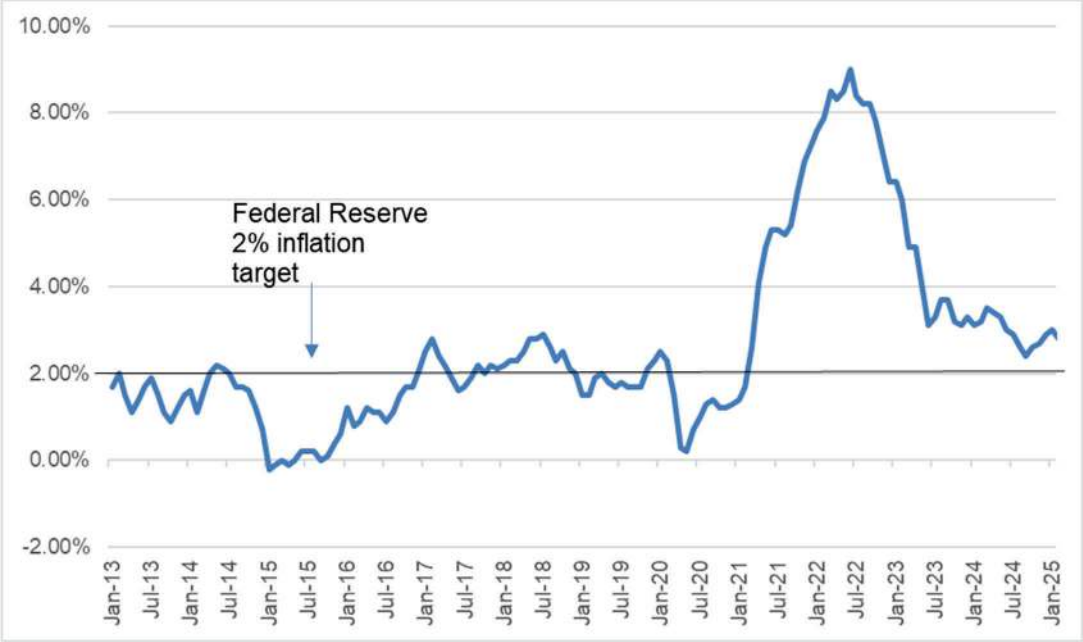
expected market volatility) tripled, from 25.03 on February 24, 2020, to 82.69 on March 16, 2020.[122]

Treasury bond yields declined rapidly as the stock market became extremely volatile and investors sought the relative safety of government bonds, combined with the Federal Reserve's reduction in the Federal Funds rate to a target range of 0 percent to 0.25 percent. Because bond yields and bond prices are inversely related, as demand for safer bonds increases, investors bid up the price of bonds and bid down the yields. Since the decline in bond yields was caused by investors' increased aversion to equity market risk, the cost of equity did not decline commensurately with the decline in bond yields.

As the U.S. economy opened from the COVID-19 lockdowns, economic activity quickly rebounded, causing inflation to reach the highest levels seen in decades. Figure 23 below is a year-over-year of the Consumer Price Index since 2013.

[122] Source: Federal Reserve Bank of St. Louis FRED Database.

Figure 23: Year-Over-Year U.S. Consumer Price Index (2013-2025)[123]



In response, the Federal Reserve tightened monetary policy at the fastest pace since the 1980s by increasing the Federal Funds rate by 525 basis points over the course of 11 consecutive Federal Open Market Committee ("FOMC") meetings between March 2022 and July 2023. Although the pace of inflation subsided from its peak reached in June 2022, year-over-year inflation remained stubbornly above 3.0 percent through the first half of 2024. In October 2024, the CPI reversed its downward trend, increasing 0.2 percent on a year-over-year basis, a trend that continued through January 2025. As of February 2025, annual CPI stood at 2.8 percent.

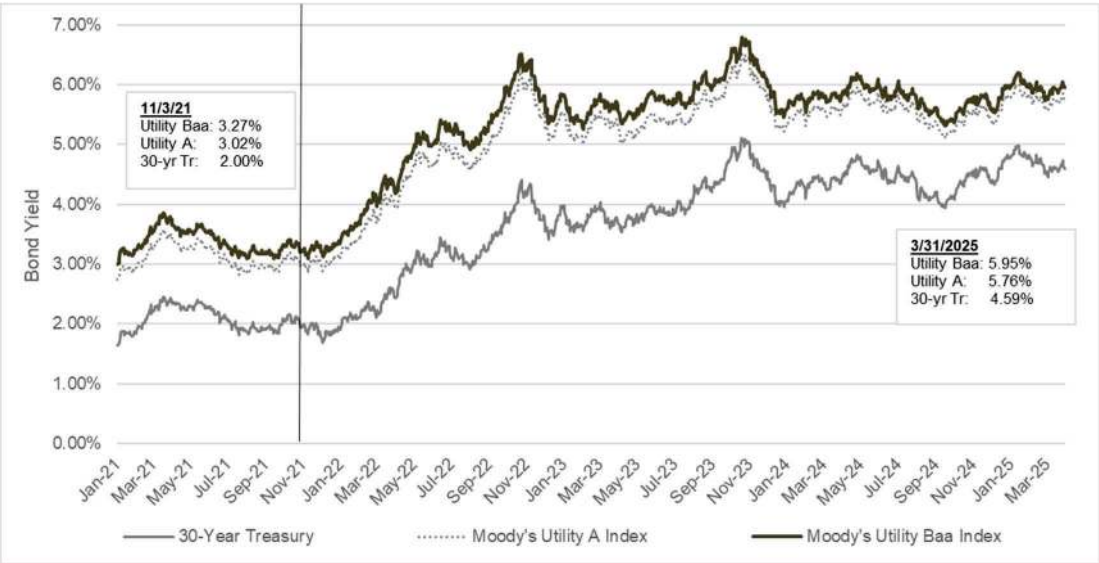
Q. How have government and utility bond yields responded to the Federal Reserve's monetary policy tightening?

A. As the U.S. economy improved in 2021 and the Federal Reserve moved aggressively to tighten monetary policy to fight stubbornly higher inflation, prevailing interest rates

[123] Source: Federal Reserve Bank of St. Louis FRED Database. Data as of March 31, 2025.

rose to their highest levels since 2010.[124] As shown in Figure 24 below, the 30-year Treasury yield has increased 259 basis points since November 3, 2021 when the Federal Reserve signaled it would begin tapering its asset purchases. Utility bond yields have increased by approximately 270 basis points over the same period.

Figure 24: 30-Year Treasury Bond and Utility Bond Yields (2021-2025)[125]



Consensus forecasts from Blue Chip project long-term government and corporate bond yields to remain at current levels over the next six quarters.[126]

Q. Please explain how higher bond yields affect the ROE estimates.

A. The 30-year Treasury bond yield is a direct input to both the CAPM and the Risk Premium models because, as explained earlier, the term of the security aligns with the long life of natural gas utility assets. As yields increase, the cost of capital generally increases, and the ROE estimates from those two models also increase, although not on

[124] Source: Federal Reserve Bank of St. Louis, FRED Database.

[125] Source: Federal Reserve Bank of St. Louis, FRED Database; Bloomberg Professional. Data as of March 31, 2025.

[126] Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2.

a one-to-one basis. Further, while interest rates are not a direct input to the DCF model, dividend yields on utility stocks must compete with yields on Treasury bonds. As interest rates on government bonds increase, utilities must offer a higher dividend yield to attract and retain investors, signaling an increase in the cost of equity for utilities. All else equal, higher dividend yields produce higher ROE estimates in the DCF model.

Q. How have economic and financial market conditions changed in recent months?

A. At the end of 2024, financial markets were optimistic that the Federal Reserve was close to attaining a "soft landing" by taming inflation without a consequential rise in unemployment. Over the past few months, however, federal policy uncertainty has climbed sharply, and financial market volatility has increased. Inflation and interest rates remain elevated, and the fears of an economic slowdown prompted by federal government workforce reductions and significantly lower government spending are growing.

Expectations for inflation are markedly higher than in the five years prior to the pandemic. The University of Michigan's February survey reported that U.S. consumer sentiment continued its decline with expectations of year-ahead inflation expectations increasing from 3.3 percent in January to 5.0 percent in March.[127] Longer-run inflation expectations rose from 3.5 percent in February to 4.1 percent in March. As noted in the March 2025 special report on inflation expectations;

> As of March 2025, long-run expectations have climbed sharply for three consecutive months and are now comparable to the peak readings from the post-pandemic inflationary episode. They exhibit substantial

[127] University of Michigan, Surveys of Consumers, http://www.sca.isr.umich.edu/. Last accessed April 1, 2025.

uncertainty, particularly in light of frequent developments and changes with economic policy.[128]

Q. How might the changes in federal trade policy affect inflation and bond yields?

A. On February 1, 2025, President Trump issued an executive order implementing a 25 percent additional tariff on imports from Canada and Mexico, and a 10 percent additional tariff on imports from China.[129] These tariffs were paused for 30-days and restored on March 4, 2025. Two days later, President Trump temporarily paused tariffs imposed on approximately half of imports from Canada and 38 percent of imports from Mexico until April 2, 2025.[130] Further, on February 10, 2025 President Trump restored a 25 percent tariff on steel and increased the tariff on aluminum to 25 percent.[131] On March 24, 2025, the White House announced it would implement a 25 percent tariff on all goods from any country that imports Venezuelan oil, whether directly or indirectly.[132] Lastly, on April 2, 2025, President Trump announced the administration would impose a 10 percent base tariff on all imports from nearly every country plus an additional tariff customized for each of approximately 60 countries.[133] Although the

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[128] University of Michigan, Surveys of Consumers, March 2025 Update: Current versus Pre-Pandemic Long-Run Inflation Expectations (March 28, 2025) https://data.sca.isr.umich.edu/fetchdoc.php?docid=78367.

[129] https://www.whitehouse.gov/fact-sheets/2025/02/fact-sheet-president-donald-j-trump-imposes-tariffs-on-imports-from-canada-mexico-and-china/. Last Access April 12, 2025.

[130] https://www.whitehouse.gov/presidential-actions/2025/03/amendment-to-duties-to-address-the-flow-of-illicit-drugs-across-our-southern-border/. Last accessed April 12, 2025; https://www.whitehouse.gov/presidential-actions/2025/03/amendment-to-duties-to-address-the-flow-of-illicit-drugs-across-our-northern-border-0c3c/. Last accessed April 12, 2025.

[131] https://www.whitehouse.gov/fact-sheets/2025/02/fact-sheet-president-donald-j-trump-restores-section-232-tariffs/. Last accessed April 12, 2025.

[132] https://www.whitehouse.gov/presidential-actions/2025/03/imposing-tariffs-on-countries-importing-venezuelan-oil/. Last accessed April 12, 2025.

[133] https://www.whitehouse.gov/presidential-actions/2025/04/regulating-imports-with-a-reciprocal-tariff-to-rectify-trade-practices-that-contribute-to-large-and-persistent-annual-united-states-goods-trade-deficits/. Last accessed April 12, 2025.

effect of these tariffs on the economy is uncertain, economists generally agree that higher tariffs increase inflation by increasing the cost of consumer goods. The tariffs could lead to higher inflation and reduce overall demand, as well as higher interest rates and a stronger dollar.[134] The Budget Lab at Yale University estimates that these tariffs would raise consumer prices by 1.4 to 5.1 percent before substitution, which would be the equivalent of the cost of $1,900 to $7,600 in disposable income for the average household.[135]

In a recent article published by S&P Global Market Intelligence, economists noted the "enormous uncertainty" associated with the effect of tariffs on inflation and the economy, but projected that if President Trump's tariffs are imposed as proposed, they "would cause the core consumer price index[136] to run at a 6% annual pace on average over the next two years."[137]

Higher inflation could complicate the Federal Reserve's unwinding of restrictive monetary policies, as well as increase long-term bond yields like the 30-year Treasury yield. The FOMC paused its cuts in the Federal Funds rate at its January 2025 meeting, citing elevated inflation and a stable labor market, and held rates steady at its March 2025 FOMC meeting. Longer-term bonds are more sensitive than shorter-term bonds to inflation expectations because their value is influenced more by inflation due to their longer maturity holding period and reinvestment rate implications. Thus, as the

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[134] J.P. Morgan Asset Management, *Market Insights 2025 Year-Ahead Investment Outlook*, November 21, 2024.

[135] Yale Budget Lab, *Fiscal, Macroeconomic, and Price Estimates of Tariffs Under Both Non-Retaliation and Retaliation Scenarios*, October 16, 2024.

[136] As measured by the Personal Consumption Expenditures ("PCE") price index.

[137] S&P Global Market Intelligence, *Tariffs projected to push US inflation near 2022 highs*, April 9, 2025.

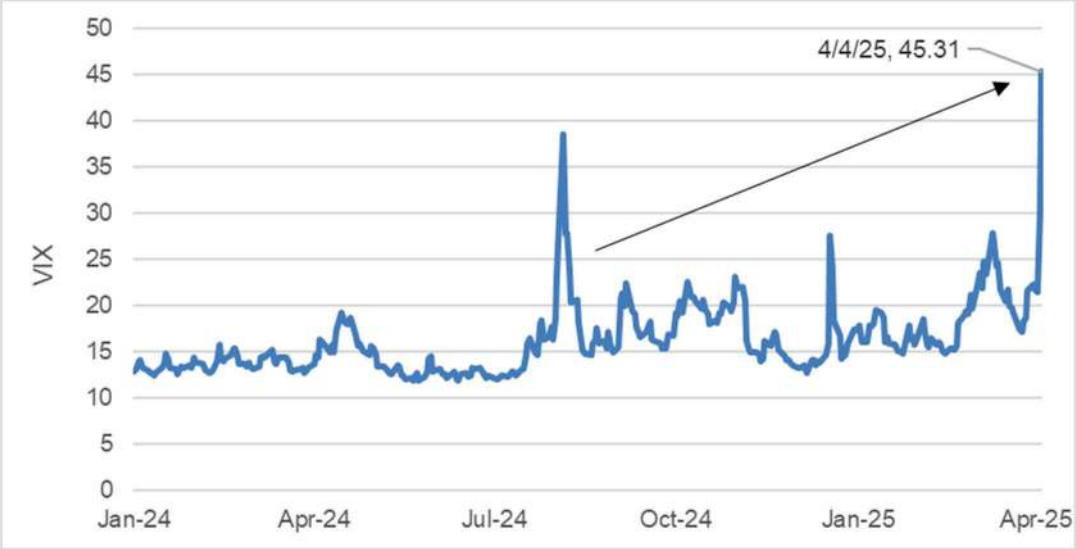
value (price) of bonds declines due to higher inflation expectations, the yield increases. Because utilities are capital intensive enterprises, higher inflation and interest rates tend to have a negative effect on utility stocks. If realized, all these factors would suggest that the cost of capital for utilities may increase in the future.

Q. Has market volatility increased in recent months?

A. Yes, it has. As noted earlier, the VIX is a measure of expected equity market volatility.[138] As shown in Figure 25, the VIX has been on an increasing trend since January 2024. Further, after President Trump's tariff announcement on April 2, 2025, the VIX climbed to levels not seen since 2020 when the COVID-19 pandemic was spreading across the country. Higher market volatility indicates an increase in equity market risk, and as market risk rises, so does the cost of equity since equity investors require higher returns to compensate them for greater market risk.

[138] The VIX is a benchmark index to measure the market's expectation of future volatility. The VIX Index is based on options of the S&P 500® Index, considered the leading indicator of the broad U.S. stock market. The VIX Index is recognized as the world's premier gauge of U.S. equity market volatility. Source: Chicago Board of Options Exchange, https://www.cboe.com/tradable_products/vix/

Figure 25: VIX (2024-2025)[139]



Q. What conclusions do you draw from your review of the current capital market environment and its implications on the Company's cost of equity?

A. Over the last five years, the economic and financial market environment has operated under heightened uncertainty associated with the COVID-19 pandemic, the war in Ukraine, stubborn inflation, and, more recently, uncertainty surrounding the economy and federal trade policy. The effect of the new presidential administration on the economy is highly uncertain, and higher tariffs could complicate investor expectations for inflation and interest rates. Although the Federal Reserve responded to easing inflation by cutting rates in late 2024, it has since paused those cuts to assess how the effects of fluctuating trade policies will affect the economy. These factors underscore the importance of using multiple models when determining ENSTAR's cost of equity to gain a comprehensive perspective of the effect of fluid and evolving market conditions on the cost of equity.

[139] Source: Federal Reserve Bank of St. Louis FRED Economic Data. Data as of April 4, 2025.

VIII. CONCLUSION

Q. What is your recommendation regarding the Company's cost of equity and capital structure?

A. Based on my analyses from three commonly used analytical approaches applied to a proxy group of companies that reflect ENSTAR's hybrid distribution and pipeline operations, I conclude that an ROE in the range of 12.50 percent to 13.50 percent represents the range of equity investors' required return for investment in natural gas utilities comparable to ENSTAR in today's capital market environment. Within that range, I recommend the midpoint, or 13.00 percent.

As to the capital structure, the Company's requested capital structure of 58.57 percent common equity and 41.43 percent long-term debt is within the range of capital structures that finance natural gas utility operations of the proxy group and, therefore, is reasonable and appropriate. That conclusion considers ENSTAR's financial risk inherent in its capital structure, as well as its substantial transmission assets, small size, natural gas supply concerns, and exposure to severe weather and natural disaster risks.

Q. Does this conclude your pre-filed Direct Testimony?

A. Yes, it does.

JENNIFER E. NELSON
VICE PRESIDENT

Ms. Nelson is a Certified Rate of Return Analyst with more than fifteen years of experience in the energy industry. As an expert witness, she has testified to the cost of capital and alternative ratemaking proposals for electric, natural gas, and water utilities. In her time as a consultant, Ms. Nelson has provided consulting services on a variety of utility regulatory matters including ratemaking and regulatory policy, cost of service and revenue requirements, integrated resource planning, renewable power contracts, natural gas pipeline development, utility supply planning issues, and merger and acquisition transactions. Ms. Nelson has extensive experience performing statistical analyses, developing economic and financial models, and providing policy analyses and recommendations.

Prior to joining Concentric, Ms. Nelson was a Director at ScottMadden, Inc., and a managing consultant at Sussex Economic Advisors, LLC. Prior to consulting, she was a staff economist at the Massachusetts Department of Public Utilities and a petroleum economist for the State of Alaska. Ms. Nelson holds a Master of Science degree in Resource and Applied Economics from the University of Alaska and a Bachelor of Science degree in Business Economics from Bentley University.

AREAS OF EXPERTISE

Cost of Capital

- Submitted expert testimony on behalf of electric utilities before regulatory commissions in Arkansas, New Hampshire, New Mexico, North Carolina, South Carolina, Texas and Virginia regarding the cost of capital.
- Submitted expert testimony on behalf of natural gas utilities before regulatory commissions in Florida, North Carolina, Ohio, Oregon, South Carolina, Utah, West Virginia, and Wyoming regarding the cost of capital.
- Submitted expert testimony on behalf of a water utility before the Kentucky Public Service Commission regarding the appropriate capital structure and cost of debt.
- Supported expert testimony regarding the cost of capital before numerous state utility regulatory commissions and the FERC on behalf of electric and natural gas utilities through research, financial analysis and modeling, and testimony development.

Alternative Ratemaking Mechanisms

- Submitted expert testimony on behalf of electric utilities and a water utility before the Arkansas Public Service Commission regarding the utilities' proposed Formula Rate Plans.
- Submitted expert testimony on behalf of an electric utility before the Oklahoma Corporation Commission regarding the utility's proposed Formula Rate Plan.
- Submitted expert testimony on behalf of an electric and natural gas utility before the Delaware Public Service Commission regarding the utility's proposed performance-based rate plan.

- Submitted expert testimony on behalf of an electric and natural gas utility before the Montana Public Service Commission regarding the utility's proposed alternative rate mechanisms.
- Co-sponsored expert testimony on behalf of a natural gas utility before the Maine Public Utilities Commission regarding the utility's proposed capital investment cost recovery mechanism.
- Supported expert testimony and performed research and analysis on alternative ratemaking frameworks.

Resource and Supply Planning

- Supported expert testimony on the reasonableness of utility resource supply portfolio decisions.
- Assisted in a benchmarking analysis on behalf of a Northeast U.S. natural gas utility regarding its supply planning standards and design day demand forecast process.
- Supported rebuttal testimony filed on behalf of an Alaska natural gas utility regarding the utility's gas supply planning standards.
- Supported the development of a New Hampshire electric utility's Integrated Resource Plan filed with the New Hampshire Public Utility Commission.
- Performed research and financial analysis to evaluate the benefits, costs, and policy options associated with natural gas expansion by Massachusetts natural gas utilities as part of a prepared report for the Massachusetts Department of Energy Resources.
- Developed a dynamic natural gas demand forecast model for in-state use for the State of Alaska, which included forecasting demand from both existing and anticipated natural gas utilities, power consumption, and large commercial operations.
- Conducted research and prepared analyses for a natural gas pipeline Open Season.

Other Regulatory Financial Issues

- Filed expert testimony before the California PUC regarding the benefits of financial flexibility and diversity in sources of financial capital associated with an electric utility's request to lease entitlements as a means of raising capital.
- Supported expert testimony on the appropriate level of remuneration associated with the Massachusetts electric utilities' long-term contracts for wind power through research, financial analysis and modeling, and testimony development.
- Provided research and analytical support estimating financial damages incurred as a result of construction delays for an electric transmission company.
- Prepared a Feasibility Study for an electric cooperative utility supporting a utility-owned solar project.

Mergers & Acquisitions

- Performed buy-side benchmarking and regulatory analysis for utility acquisitions.

RELEVANT PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2021-present)
Vice President
Assistant Vice President

ScottMadden, Inc. (2016-2021)
Director
Manager

Sussex Economic Advisors, LLC (2013-2016)
Managing Consultant

Massachusetts Department of Public Utilities (2011-2013)
Economist, Electric Power Division

State of Alaska Department of Revenue, Tax Division (2007-2010)
Petroleum Economist

Federal Reserve Bank of Boston (2000-2002)
Research Assistant, Economic Research Department

EDUCATION AND RELEVANT COURSEWORK

University of Alaska
Master of Science, Resource and Applied Economics

Bentley University (formerly Bentley College)
Bachelor of Science, Business Economics
Graduated *magna cum laude*

New Mexico State University
Center for Public Utilities, Regulatory Basics

ISO New England
Wholesale Energy Markets (WEM-101)

Colorado School of Mines
Petroleum Engineering SuperSchool

EUCI
Course Instructor – Performance-Based Ratemaking

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts
Member, Society of Utility and Regulatory Financial Analysts

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Arkansas Public Service Commission				
Liberty Utilities (Pine Bluff Water)	10/18	Liberty Utilities (Pine Bluff Water)	18-027-U	Formula Rate Plan and tariff
Entergy Arkansas, LLC	11/20	Entergy Arkansas, LLC	16-036-FR	Sponsored testimony evaluating the Return on Equity included in Rider FRP
Oklahoma Gas & Electric	10/21	Oklahoma Gas & Electric	21-087-U	Formula Rate Plan
California Public Utilities Commission				
Pacific Gas & Electric Co.	01/25	Pacific Gas & Electric Co.	A-24-03-009	Financial flexibility and capital diversity
Delaware Public Service Commission				
Delmarva Power & Light Company	08/24	Delmarva Power & Light Company	24-0868	Alternative Ratemaking Proposal
Florida Public Service Commission				
Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	05/22	Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	20220069-GU	Cost of Capital
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company, LLC	09/20	Bluegrass Water Utility Operating Company, LLC	2020-290	Capital Structure and Cost of Long-Term Debt
Maine Public Utilities Commission				
Unitil Corporation	06/19	Northern Utilities, Inc.	19-00092	Co-sponsored testimony supporting a proposed CIRA capital tracking mechanism
Montana Public Utilities Commission				
NorthWestern Corporation	08/22	NorthWestern Corporation	2022-7-78 (elect.) 2022-7-78 (gas)	Alternative Ratemaking Proposals
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	04/21	Unitil Energy Systems, Inc.	DE 21-030	Cost of Capital
New Mexico Public Regulation Commission				
El Paso Electric Company	07/20	El Paso Electric Company	20-00104-UT	Cost of Capital
North Carolina Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	04/21	Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	G-5, Sub 632	Cost of Capital
Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	03/24	Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	E-22, Sub 694	Cost of Capital
Public Service Company of North Carolina	04/25	Public Service Company of North Carolina	G-5, Sub 686	Cost of Capital
Public Utilities Commission of Ohio				
The East Ohio Gas Company d/b/a Dominion Energy Ohio	11/23	The East Ohio Gas Company d/b/a Dominion Energy Ohio	23-0894-GA-AIR	Cost of Capital
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	PUD202100164	Formula Rate Plan
Public Utility Commission of Oregon				
Northwest Natural Gas Company dba NW Natural	12/23	Northwest Natural Gas Company dba NW Natural	UG 490	Cost of Capital
Northwest Natural Gas Company dba NW Natural	12/24	Northwest Natural Gas Company dba NW Natural	UG 520	Cost of Capital
Public Utilities Commission of South Carolina				
Dominion Energy South Carolina	04/23	Dominion Energy South Carolina	2023-70-G	Cost of Capital
Dominion Energy South Carolina	03/24	Dominion Energy South Carolina	2024-34-E	Cost of Capital
Public Utilities Commission of Texas				
Sharyland Utilities L.L.C.	12/20	Sharyland Utilities L.L.C.	51611	Cost of Capital
El Paso Electric Company	06/21	El Paso Electric Company	52195	Cost of Capital
Wind Energy Transmission Texas, LLC dba WETT	12/24	Wind Energy Transmission Texas, LLC dba WETT	52799	Cost of Capital
El Paso Electric Company	01/25	El Paso Electric Company	56851	Cost of Capital
Utah Public Service Commission				
Dominion Energy Utah	05/22	Dominion Energy Utah	22-057-03	Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Virginia State Corporation Commission				
Virginia Electric & Power Company (Dominion Energy Virginia)	03/25	Virginia Electric & Power Company (Dominion Energy Virginia)	PUR-2025-00058	Cost of Capital
Public Service Commission of West Virginia				
Hope Gas, Inc. d/b/a Dominion Energy West Virginia	11/20	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	20-0746-G-42T	Cost of Capital
Wyoming Public Service Commission				
Dominion Energy Wyoming	03/23	Dominion Energy Wyoming	30010-215-GR-23	Cost of Capital

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] CIQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Atmos Energy Corporation	ATO	$3.48	$140.21	2.48%	2.57%	7.10%	8.00%	7.00%	7.37%	9.57%	9.94%	10.58%
New Jersey Resources Corporation	NJR	$1.80	$46.68	3.86%	3.96%	n/a	5.90%	5.00%	5.45%	8.95%	9.41%	9.87%
NiSource Inc.	NI	$1.12	$36.76	3.05%	3.18%	8.10%	7.90%	9.50%	8.50%	11.07%	11.68%	12.69%
Northwest Natural Gas Company	NWN	$1.96	$39.69	4.94%	5.09%	n/a	6.00%	6.50%	6.25%	11.09%	11.34%	11.60%
ONE Gas, Inc.	OGS	$2.68	$69.59	3.85%	3.92%	4.70%	2.89%	3.50%	3.70%	6.80%	7.62%	8.64%
Southwest Gas Corporation	SWX	$2.48	$71.19	3.48%	3.63%	6.50%	n/a	10.00%	8.25%	10.10%	11.88%	13.66%
Spire, Inc.	SR	$3.14	$68.19	4.60%	4.74%	5.80%	6.82%	4.50%	5.71%	9.21%	10.44%	11.58%
Enbridge Inc	ENB.TO	$3.77	$62.47	6.03%	6.18%	5.00%	4.40%	5.00%	4.80%	10.57%	10.98%	11.19%
Energy Transfer LP	ET	$1.30	$19.80	6.56%	6.81%	26.20%	17.09%	7.50%	7.50%	14.31%	14.31%	14.31%
Enterprise Products Partners LP	EPD	$2.14	$32.39	6.61%	6.81%	7.40%	4.72%	6.00%	6.04%	11.48%	12.85%	14.25%
Kinder Morgan Inc	KMI	$1.15	$28.19	4.08%	4.24%	6.90%	6.39%	10.00%	7.76%	10.60%	12.00%	14.28%
MPLX LP	MPLX	$3.83	$49.45	7.74%	7.97%	5.10%	4.57%	8.00%	5.89%	12.49%	13.86%	16.05%
TC Energy Corp.	TRP	$3.29	$46.45	7.08%	7.37%	4.00%	Negative	12.50%	8.25%	11.22%	15.62%	20.03%
The Williams Companies, Inc	WMB	$2.00	$55.96	3.57%	3.69%	5.50%	4.31%	10.00%	6.60%	7.96%	10.29%	13.75%
Proxy Group Mean				4.85%	5.01%	7.69%	6.58%	7.50%	6.58%	10.39%	11.59%	13.03%
Proxy Group Median				4.34%	4.49%	6.15%	5.95%	7.25%	6.43%	10.58%	11.51%	13.17%
Average of Mean and Median				4.60%	4.75%	6.92%	6.27%	7.38%	6.50%	10.48%	11.55%	13.10%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Capital IQ
[7] Source: Value Line
[8] Equals Average (Cols. [5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] CIQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Atmos Energy Corporation	ATO	$3.48	$141.57	2.46%	2.55%	7.10%	8.00%	7.00%	7.37%	9.54%	9.92%	10.56%
New Jersey Resources Corporation	NJR	$1.80	$47.23	3.81%	3.91%	n/a	5.90%	5.00%	5.45%	8.91%	9.36%	9.82%
NiSource Inc.	NI	$1.12	$36.03	3.11%	3.24%	8.10%	7.90%	9.50%	8.50%	11.13%	11.74%	12.76%
Northwest Natural Gas Company	NWN	$1.96	$40.51	4.84%	4.99%	n/a	6.00%	6.50%	6.25%	10.98%	11.24%	11.50%
ONE Gas, Inc.	OGS	$2.68	$72.35	3.70%	3.77%	4.70%	2.89%	3.50%	3.70%	6.65%	7.47%	8.49%
Southwest Gas Corporation	SWX	$2.48	$73.75	3.36%	3.50%	6.50%	n/a	10.00%	8.25%	9.97%	11.75%	13.53%
Spire, Inc.	SR	$3.14	$67.41	4.66%	4.79%	5.80%	6.82%	4.50%	5.71%	9.26%	10.50%	11.63%
Enbridge Inc	ENB.TO	$3.77	$59.58	6.33%	6.48%	5.00%	4.40%	5.00%	4.80%	10.87%	11.28%	11.49%
Energy Transfer LP	ET	$1.30	$18.15	7.16%	7.43%	26.20%	17.09%	7.50%	7.50%	14.93%	14.93%	14.93%
Enterprise Products Partners LP	EPD	$2.14	$31.14	6.87%	7.08%	7.40%	4.72%	6.00%	6.04%	11.75%	13.12%	14.53%
Kinder Morgan Inc	KMI	$1.15	$26.41	4.35%	4.52%	6.90%	6.39%	10.00%	7.76%	10.88%	12.29%	14.57%
MPLX LP	MPLX	$3.83	$47.28	8.09%	8.33%	5.10%	4.57%	8.00%	5.89%	12.85%	14.22%	16.42%
TC Energy Corp.	TRP	$3.29	$46.83	7.03%	7.32%	4.00%	Negative	12.50%	8.25%	11.17%	15.57%	19.96%
The Williams Companies, Inc	WMB	$2.00	$54.05	3.70%	3.82%	5.50%	4.31%	10.00%	6.60%	8.09%	10.43%	13.89%
Proxy Group Mean				4.96%	5.12%	7.69%	6.58%	7.50%	6.58%	10.50%	11.70%	13.15%
Proxy Group Median				4.51%	4.66%	6.15%	5.95%	7.25%	6.43%	10.87%	11.51%	13.14%
Average of Mean and Median				4.73%	4.89%	6.92%	6.27%	7.38%	6.50%	10.69%	11.61%	13.15%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Capital IQ
[7] Source: Value Line
[8] Equals Average (Cols. [5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] CIQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Atmos Energy Corporation	ATO	$3.48	$132.51	2.63%	2.72%	7.10%	8.00%	7.00%	7.37%	9.72%	10.09%	10.73%
New Jersey Resources Corporation	NJR	$1.80	$45.94	3.92%	4.03%	n/a	5.90%	5.00%	5.45%	9.02%	9.48%	9.93%
NiSource Inc.	NI	$1.12	$33.30	3.36%	3.51%	8.10%	7.90%	9.50%	8.50%	11.40%	12.01%	13.02%
Northwest Natural Gas Company	NWN	$1.96	$39.29	4.99%	5.14%	n/a	6.00%	6.50%	6.25%	11.14%	11.39%	11.65%
ONE Gas, Inc.	OGS	$2.68	$69.11	3.88%	3.95%	4.70%	2.89%	3.50%	3.70%	6.83%	7.65%	8.67%
Southwest Gas Corporation	SWX	$2.48	$73.42	3.38%	3.52%	6.50%	n/a	10.00%	8.25%	9.99%	11.77%	13.55%
Spire, Inc.	SR	$3.14	$65.26	4.81%	4.95%	5.80%	6.82%	4.50%	5.71%	9.42%	10.65%	11.79%
Enbridge Inc	ENB.TO	$3.77	$55.36	6.81%	6.97%	5.00%	4.40%	5.00%	4.80%	11.36%	11.77%	11.98%
Energy Transfer LP	ET	$1.30	$17.04	7.63%	7.91%	26.20%	17.09%	7.50%	7.50%	15.41%	15.41%	15.41%
Enterprise Products Partners LP	EPD	$2.14	$30.05	7.12%	7.34%	7.40%	4.72%	6.00%	6.04%	12.01%	13.38%	14.79%
Kinder Morgan Inc	KMI	$1.15	$23.45	4.90%	5.09%	6.90%	6.39%	10.00%	7.76%	11.45%	12.86%	15.15%
MPLX LP	MPLX	$3.83	$44.63	8.57%	8.83%	5.10%	4.57%	8.00%	5.89%	13.34%	14.72%	16.92%
TC Energy Corp.	TRP	$3.29	$42.32	7.77%	8.09%	4.00%	Negative	12.50%	8.25%	11.93%	16.34%	20.76%
The Williams Companies, Inc	WMB	$2.00	$48.49	4.12%	4.26%	5.50%	4.31%	10.00%	6.60%	8.52%	10.86%	14.33%
Proxy Group Mean				5.28%	5.45%	7.69%	6.58%	7.50%	6.58%	10.82%	12.03%	13.48%
Proxy Group Median				4.86%	5.02%	6.15%	5.95%	7.25%	6.43%	11.25%	11.77%	13.29%
Average of Mean and Median				5.07%	5.24%	6.92%	6.27%	7.38%	6.50%	11.04%	11.90%	13.38%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Capital IQ
[7] Source: Value Line
[8] Equals Average (Cols. [5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Quarterly Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] CIQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$0.81	$0.81	$0.81	$0.87	$0.86	$0.86	$0.86	$0.93	$140.21	7.10%	8.00%	7.00%	7.37%	9.59%	9.97%	10.63%
New Jersey Resources Corporation	NJR	$0.42	$0.45	$0.45	$0.45	$0.44	$0.47	$0.47	$0.47	$46.68	n/a	5.90%	5.00%	5.45%	9.11%	9.59%	10.06%
NiSource Inc.	NI	$0.27	$0.27	$0.27	$0.28	$0.29	$0.29	$0.29	$0.30	$36.76	8.10%	7.90%	9.50%	8.50%	11.18%	11.81%	12.85%
Northwest Natural Gas Company	NWN	$0.49	$0.49	$0.49	$0.49	$0.52	$0.52	$0.52	$0.52	$39.69	n/a	6.00%	6.50%	6.25%	11.44%	11.71%	11.98%
ONE Gas, Inc.	OGS	$0.66	$0.66	$0.66	$0.67	$0.68	$0.68	$0.68	$0.69	$69.59	4.70%	2.89%	3.50%	3.70%	6.91%	7.76%	8.82%
Southwest Gas Corporation	SWX	$0.62	$0.62	$0.62	$0.62	$0.67	$0.67	$0.67	$0.67	$71.19	6.50%	n/a	10.00%	8.25%	10.35%	12.19%	14.03%
Spire, Inc.	SR	$0.76	$0.76	$0.79	$0.79	$0.80	$0.80	$0.83	$0.83	$68.19	5.80%	6.82%	4.50%	5.71%	9.38%	10.66%	11.85%
Enbridge Inc	ENB.TO	$0.92	$0.92	$0.92	$0.94	$0.96	$0.96	$0.96	$0.99	$62.47	5.00%	4.40%	5.00%	4.80%	10.80%	11.24%	11.46%
Energy Transfer LP	ET	$0.32	$0.32	$0.32	$0.33	$0.34	$0.34	$0.35	$0.35	$19.80	26.20%	17.09%	7.50%	7.50%	14.85%	14.85%	14.85%
Enterprise Products Partners LP	EPD	$0.52	$0.53	$0.53	$0.54	$0.55	$0.56	$0.56	$0.57	$32.39	7.40%	4.72%	6.00%	6.04%	11.80%	13.24%	14.73%
Kinder Morgan Inc	KMI	$0.29	$0.29	$0.29	$0.29	$0.31	$0.32	$0.31	$0.31	$28.19	6.90%	6.39%	10.00%	7.76%	10.90%	12.38%	14.73%
MPLX LP	MPLX	$0.85	$0.85	$0.96	$0.96	$0.90	$0.90	$1.01	$1.01	$49.45	5.10%	4.57%	8.00%	5.89%	12.55%	14.01%	16.34%
TC Energy Corp.	TRP	$0.82	$0.82	$0.82	$0.82	$0.89	$0.89	$0.89	$0.89	$46.45	4.00%	Negative	12.50%	8.25%	11.68%	16.37%	21.07%
The Williams Companies, Inc	WMB	$0.48	$0.48	$0.48	$0.50	$0.51	$0.51	$0.51	$0.53	$55.96	5.50%	4.31%	10.00%	6.60%	8.00%	10.41%	13.97%
Proxy Group Mean											7.69%	6.58%	7.50%	6.58%	10.61%	11.87%	13.38%
Proxy Group Median											6.15%	5.95%	7.25%	6.43%	10.85%	11.76%	13.41%
Average of Mean and Median															10.73%	11.81%	13.40%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2025
[10] Source: Zacks
[11] Source: Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
90 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] CIQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$0.81	$0.81	$0.81	$0.87	$0.86	$0.86	$0.86	$0.93	$141.57	7.10%	8.00%	7.00%	7.37%	9.57%	9.95%	10.60%
New Jersey Resources Corporation	NJR	$0.42	$0.45	$0.45	$0.45	$0.44	$0.47	$0.47	$0.47	$47.23	n/a	5.90%	5.00%	5.45%	9.06%	9.54%	10.01%
NiSource Inc.	NI	$0.27	$0.27	$0.27	$0.28	$0.29	$0.29	$0.29	$0.30	$36.03	8.10%	7.90%	9.50%	8.50%	11.25%	11.88%	12.92%
Northwest Natural Gas Company	NWN	$0.49	$0.49	$0.49	$0.49	$0.52	$0.52	$0.52	$0.52	$40.51	n/a	6.00%	6.50%	6.25%	11.33%	11.60%	11.86%
ONE Gas, Inc.	OGS	$0.66	$0.66	$0.66	$0.67	$0.68	$0.68	$0.68	$0.69	$72.35	4.70%	2.89%	3.50%	3.70%	6.76%	7.60%	8.66%
Southwest Gas Corporation	SWX	$0.62	$0.62	$0.62	$0.62	$0.67	$0.67	$0.67	$0.67	$73.75	6.50%	n/a	10.00%	8.25%	10.22%	12.05%	13.89%
Spire, Inc.	SR	$0.76	$0.76	$0.79	$0.79	$0.80	$0.80	$0.83	$0.83	$67.41	5.80%	6.82%	4.50%	5.71%	9.44%	10.72%	11.91%
Enbridge Inc	ENB.TO	$0.92	$0.92	$0.92	$0.94	$0.96	$0.96	$0.96	$0.99	$59.58	5.00%	4.40%	5.00%	4.80%	11.12%	11.56%	11.78%
Energy Transfer LP	ET	$0.32	$0.32	$0.32	$0.33	$0.34	$0.34	$0.35	$0.35	$18.15	26.20%	17.09%	7.50%	7.50%	15.54%	15.54%	15.54%
Enterprise Products Partners LP	EPD	$0.52	$0.53	$0.53	$0.54	$0.55	$0.56	$0.56	$0.57	$31.14	7.40%	4.72%	6.00%	6.04%	12.09%	13.54%	15.04%
Kinder Morgan Inc	KMI	$0.29	$0.29	$0.29	$0.29	$0.31	$0.31	$0.31	$0.31	$26.41	6.90%	6.39%	10.00%	7.76%	11.21%	12.67%	15.05%
MPLX LP	MPLX	$0.85	$0.85	$0.96	$0.96	$0.90	$0.90	$1.01	$1.01	$47.28	5.10%	4.57%	8.00%	5.89%	12.92%	14.39%	16.73%
TC Energy Corp.	TRP	$0.82	$0.82	$0.82	$0.82	$0.89	$0.89	$0.89	$0.89	$46.83	4.00%	Negative	12.50%	8.25%	11.62%	16.31%	21.00%
The Williams Companies, Inc	WMB	$0.48	$0.48	$0.48	$0.50	$0.51	$0.51	$0.51	$0.53	$54.05	5.50%	4.31%	10.00%	6.60%	8.13%	10.54%	14.12%
Proxy Group Mean											7.69%	6.58%	7.50%	6.58%	10.73%	11.99%	13.51%
Proxy Group Median											6.15%	5.95%	7.25%	6.43%	11.17%	11.74%	13.40%
Average of Mean and Median															10.95%	11.86%	13.46%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2025
[10] Source: Zacks
[11] Source: Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] CIQ Earnings Growth	[12] Value Line Earnings Growth	[14] Average Earnings Growth	[15] Low ROE	[16] Mean ROE	[17] High ROE
Atmos Energy Corporation	ATO	$0.81	$0.81	$0.81	$0.87	$0.86	$0.86	$0.86	$0.93	$132.51	7.10%	8.00%	7.00%	7.37%	9.75%	10.13%	10.78%
New Jersey Resources Corporation	NJR	$0.42	$0.45	$0.45	$0.45	$0.44	$0.47	$0.47	$0.47	$45.94	n/a	5.90%	5.00%	5.45%	9.18%	9.65%	10.13%
NiSource Inc.	NI	$0.27	$0.27	$0.27	$0.28	$0.29	$0.29	$0.29	$0.30	$33.30	8.10%	7.90%	9.50%	8.50%	11.53%	12.16%	13.20%
Northwest Natural Gas Company	NWN	$0.49	$0.49	$0.49	$0.49	$0.52	$0.52	$0.52	$0.52	$39.29	n/a	6.00%	6.50%	6.25%	11.50%	11.76%	12.03%
ONE Gas, Inc.	OGS	$0.66	$0.66	$0.66	$0.67	$0.68	$0.68	$0.68	$0.69	$69.11	4.70%	2.89%	3.50%	3.70%	6.94%	7.79%	8.85%
Southwest Gas Corporation	SWX	$0.62	$0.62	$0.62	$0.62	$0.67	$0.67	$0.67	$0.67	$73.42	6.50%	n/a	10.00%	8.25%	10.23%	12.07%	13.90%
Spire, Inc.	SR	$0.76	$0.76	$0.79	$0.79	$0.80	$0.80	$0.83	$0.83	$65.26	5.80%	6.82%	4.50%	5.71%	9.60%	10.89%	12.08%
Enbridge Inc	ENB.TO	$0.92	$0.92	$0.92	$0.94	$0.96	$0.96	$0.96	$0.99	$55.36	5.00%	4.40%	5.00%	4.80%	11.65%	12.09%	12.31%
Energy Transfer LP	ET	$0.32	$0.32	$0.32	$0.33	$0.34	$0.34	$0.35	$0.35	$17.04	26.20%	17.09%	7.50%	7.50%	16.08%	16.08%	16.08%
Enterprise Products Partners LP	EPD	$0.52	$0.53	$0.53	$0.54	$0.55	$0.56	$0.56	$0.57	$30.05	7.40%	4.72%	6.00%	6.04%	12.37%	13.82%	15.32%
Kinder Morgan Inc	KMI	$0.29	$0.29	$0.29	$0.29	$0.31	$0.31	$0.31	$0.31	$23.45	6.90%	6.39%	10.00%	7.76%	11.83%	13.30%	15.70%
MPLX LP	MPLX	$0.85	$0.85	$0.96	$0.96	$0.90	$0.90	$1.01	$1.01	$44.63	5.10%	4.57%	8.00%	5.89%	13.43%	14.91%	17.27%
TC Energy Corp.	TRP	$0.82	$0.82	$0.82	$0.82	$0.89	$0.89	$0.89	$0.89	$42.32	4.00%	Negative	12.50%	8.25%	12.45%	17.19%	21.94%
The Williams Companies, Inc	WMB	$0.48	$0.48	$0.48	$0.50	$0.51	$0.51	$0.51	$0.53	$48.49	5.50%	4.31%	10.00%	6.60%	8.58%	11.00%	14.60%
Proxy Group Mean											7.69%	6.58%	7.50%	6.58%	11.08%	12.35%	13.87%
Proxy Group Median											6.15%	5.95%	7.25%	6.43%	11.51%	12.08%	13.55%
Average of Mean and Median															11.30%	12.21%	13.71%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional, equals indicated number of trading day average as of 01/31/2025
[10] Source: Zacks
[11] Source: Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Expected Market Return
Market DCF Based Method - Bloomberg EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.23%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	15.02%
[3] Market Cap. Weighted Estimated Required Market Return	16.34%

Notes:
[1] Equals Sum of Col. [8]
[2] Equals Sum of Col. [9]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Agilent Technologies Inc	A	$43,227	0.087%	0.65%	8.09%	0.0006%	0.0070%
Apple Inc	AAPL	$3,545,209	7.119%	0.42%	14.47%	0.0302%	1.0301%
AbbVie Inc	ABBV	$324,977	0.653%	3.57%	11.47%	0.0233%	0.0749%
Airbnb Inc	ABNB	$57,715	0.116%	N/A	19.27%	N/A	0.0223%
Abbott Laboratories	ABT	$221,889	0.446%	1.84%	10.26%	0.0082%	0.0457%
Arch Capital Group Ltd	ACGL	$35,017	0.070%	N/A	3.91%	N/A	0.0027%
Accenture PLC	ACN	$240,779	0.483%	1.54%	7.94%	0.0074%	0.0384%
Adobe Inc	ADBE	$190,422	0.382%	N/A	13.61%	N/A	0.0520%
Analog Devices Inc	ADI	$105,120	0.211%	1.74%	14.05%	0.0037%	0.0296%
Archer-Daniels-Midland Co	ADM	$24,515	0.049%	3.90%	-6.26%	0.0019%	-0.0031%
Automatic Data Processing Inc	ADP	$123,286	0.248%	2.03%	9.07%	0.0050%	0.0225%
Autodesk Inc	ADSK	$66,938	0.134%	N/A	12.84%	N/A	0.0173%
Ameren Corp	AEE	$25,105	0.050%	2.85%	6.59%	0.0014%	0.0033%
American Electric Power Co Inc	AEP	$52,383	0.105%	3.78%	6.01%	0.0040%	0.0063%
AES Corp/The	AES	$7,821	0.016%	6.40%	6.40%	0.0010%	0.0010%
Aflac Inc	AFL	$59,653	0.120%	2.16%	8.07%	0.0026%	0.0097%
American International Group Inc	AIG	$45,947	0.092%	2.17%	10.49%	0.0020%	0.0097%
Assurant Inc	AIZ	n/a	N/A	1.49%	N/A	N/A	N/A
Arthur J Gallagher & Co	AJG	$76,770	0.154%	0.86%	14.00%	0.0013%	0.0216%
Akamai Technologies Inc	AKAM	$15,008	0.030%	N/A	7.09%	N/A	0.0021%
Albemarle Corp	ALB	$9,896	0.020%	1.92%	-44.30%	0.0004%	-0.0088%
Align Technology Inc	ALGN	$16,357	0.033%	N/A	5.64%	N/A	0.0019%
Allstate Corp/The	ALL	$50,930	0.102%	1.91%	179.34%	0.0020%	0.1834%
Allegion plc	ALLE	$11,538	0.023%	1.45%	8.16%	0.0003%	0.0019%
Applied Materials Inc	AMAT	$146,571	0.294%	0.89%	10.95%	0.0026%	0.0322%
Amcor PLC	AMCR	$14,049	0.028%	5.25%	7.10%	0.0015%	0.0020%
Advanced Micro Devices Inc	AMD	$188,165	0.378%	N/A	39.82%	N/A	0.1504%
AMETEK Inc	AME	$42,690	0.086%	0.61%	8.42%	0.0005%	0.0072%
Amgen Inc	AMGN	$153,423	0.308%	3.34%	5.37%	0.0103%	0.0165%
Ameriprise Financial Inc	AMP	$52,714	0.106%	1.09%	11.93%	0.0012%	0.0126%
American Tower Corp	AMT	$86,425	0.174%	3.50%	13.39%	0.0061%	0.0232%
Amazon.com Inc	AMZN	$2,499,208	5.018%	N/A	35.09%	N/A	1.7610%
Arista Networks Inc	ANET	$145,162	0.291%	N/A	17.86%	N/A	0.0520%
ANSYS Inc	ANSS	$30,651	0.062%	N/A	11.53%	N/A	0.0071%
Aon PLC	AON	$80,196	0.161%	0.73%	11.33%	0.0012%	0.0182%
A O Smith Corp	AOS	n/a	N/A	2.02%	N/A	N/A	N/A
APA Corp	APA	$8,113	0.016%	4.56%	-13.72%	0.0007%	-0.0022%
Air Products and Chemicals Inc	APD	$74,555	0.150%	2.14%	8.71%	0.0032%	0.0130%
Amphenol Corp	APH	$85,333	0.171%	0.93%	14.94%	0.0016%	0.0256%
Apollo Global Management Inc	APO	$96,743	0.194%	1.08%	14.87%	0.0021%	0.0289%
Aptiv PLC	APTV	$14,671	0.029%	N/A	13.79%	N/A	0.0041%
Alexandria Real Estate Equities Inc	ARE	$16,850	0.034%	5.42%	2.82%	0.0018%	0.0010%
Atmos Energy Corp	ATO	$22,149	0.044%	2.44%	7.01%	0.0011%	0.0031%
AvalonBay Communities Inc	AVB	$31,507	0.063%	3.07%	5.41%	0.0019%	0.0034%
Broadcom Inc	AVGO	$1,037,171	2.083%	1.07%	21.19%	0.0222%	0.4413%
Avery Dennison Corp	AVY	$14,923	0.030%	1.90%	8.96%	0.0006%	0.0027%
American Water Works Co Inc	AWK	$24,292	0.049%	2.46%	7.83%	0.0012%	0.0038%
Axon Enterprise Inc	AXON	$49,732	0.100%	N/A	24.64%	N/A	0.0246%
American Express Co	AXP	$223,626	0.449%	0.88%	15.24%	0.0040%	0.0684%
AutoZone Inc	AZO	$56,224	0.113%	N/A	9.66%	N/A	0.0109%
Boeing Co/The	BA	$131,891	0.265%	N/A	30.85%	N/A	0.0817%
Bank of America Corp	BAC	n/a	N/A	2.25%	N/A	N/A	N/A
Ball Corp	BALL	$16,622	0.033%	1.44%	12.66%	0.0005%	0.0042%
Baxter International Inc	BAX	n/a	N/A	2.09%	N/A	N/A	N/A
Best Buy Co Inc	BBY	$18,356	0.037%	4.38%	4.89%	0.0016%	0.0018%
Becton Dickinson & Co	BDX	$71,806	0.144%	1.68%	9.07%	0.0024%	0.0131%
Franklin Resources Inc	BEN	$11,685	0.023%	5.76%	0.85%	0.0014%	0.0002%
Brown-Forman Corp	BF/B	$10,020	0.020%	2.74%	-2.71%	0.0006%	-0.0005%
Bunge Global SA	BG	$10,630	0.021%	3.57%	-9.47%	0.0008%	-0.0020%
Biogen Inc	BIIB	$20,973	0.042%	N/A	3.25%	N/A	0.0014%
Bank of New York Mellon Corp/The	BK	$62,478	0.125%	2.19%	12.56%	0.0027%	0.0158%
Booking Holdings Inc	BKNG	$156,798	0.315%	0.74%	16.55%	0.0023%	0.0521%
Baker Hughes Co	BKR	$45,696	0.092%	1.99%	20.36%	0.0018%	0.0187%
Builders FirstSource Inc	BLDR	$19,251	0.039%	N/A	-1.50%	N/A	-0.0006%
Blackrock Inc	BLK	$166,572	0.334%	1.94%	12.13%	0.0065%	0.0406%
Bristol-Myers Squibb Co	BMY	$119,561	0.240%	4.21%	-1.32%	0.0101%	-0.0032%
Broadridge Financial Solutions Inc	BR	n/a	N/A	1.48%	N/A	N/A	N/A
Berkshire Hathaway Inc	BRK/B	n/a	N/A	N/A	N/A	N/A	N/A
Brown & Brown Inc	BRO	$29,928	0.060%	0.57%	9.15%	0.0003%	0.0055%
Boston Scientific Corp	BSX	$150,861	0.303%	N/A	12.64%	N/A	0.0383%
BorgWarner Inc	BWA	$6,977	0.014%	1.38%	5.61%	0.0002%	0.0008%
Blackstone Inc	BX	$127,874	0.257%	3.25%	22.47%	0.0084%	0.0577%
BXP Inc	BXP	$11,564	0.023%	5.36%	0.65%	0.0012%	0.0002%
Citigroup Inc	C	n/a	N/A	2.75%	N/A	N/A	N/A
Conagra Brands Inc	CAG	$12,358	0.025%	5.41%	-1.65%	0.0013%	-0.0004%
Cardinal Health Inc	CAH	$29,872	0.060%	1.64%	9.07%	0.0010%	0.0054%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Carrier Global Corp	CARR	$58,661	0.118%	1.38%	11.85%	0.0016%	0.0140%
Caterpillar Inc	CAT	$179,332	0.360%	1.52%	7.23%	0.0055%	0.0260%
Chubb Ltd	CB	$109,594	0.220%	1.34%	2.85%	0.0029%	0.0063%
Cboe Global Markets Inc	CBOE	$21,390	0.043%	1.23%	10.77%	0.0005%	0.0046%
CBRE Group Inc	CBRE	n/a	N/A	N/A	N/A	N/A	N/A
Crown Castle Inc	CCI	$38,801	0.078%	7.01%	2.12%	0.0055%	0.0016%
Carnival Corp	CCL	$32,213	0.065%	N/A	18.12%	N/A	0.0117%
Cadence Design Systems Inc	CDNS	$81,626	0.164%	N/A	15.76%	N/A	0.0258%
CDW Corp/DE	CDW	$26,538	0.053%	1.26%	3.96%	0.0007%	0.0021%
Celanese Corp	CE	$7,766	0.016%	3.94%	7.56%	0.0006%	0.0012%
Constellation Energy Corp	CEG	$94,530	0.190%	0.47%	15.78%	0.0009%	0.0300%
CF Industries Holdings Inc	CF	$16,046	0.032%	2.17%	-7.85%	0.0007%	-0.0025%
Citizens Financial Group Inc	CFG	$20,964	0.042%	3.53%	21.23%	0.0015%	0.0089%
Church & Dwight Co Inc	CHD	$25,852	0.052%	1.12%	7.39%	0.0006%	0.0038%
CH Robinson Worldwide Inc	CHRW	$11,760	0.024%	2.49%	14.98%	0.0006%	0.0035%
Charter Communications Inc	CHTR	$49,041	0.098%	N/A	10.04%	N/A	0.0099%
Cigna Group/The	CI	$81,835	0.164%	2.05%	8.04%	0.0034%	0.0132%
Cincinnati Financial Corp	CINF	$21,423	0.043%	2.54%	8.08%	0.0011%	0.0035%
Colgate-Palmolive Co	CL	$70,835	0.142%	2.31%	7.47%	0.0033%	0.0106%
Clorox Co/The	CLX	$19,642	0.039%	3.08%	10.56%	0.0012%	0.0042%
Comcast Corp	CMCSA	$126,951	0.255%	3.92%	6.28%	0.0100%	0.0160%
CME Group Inc	CME	$85,232	0.171%	1.94%	4.05%	0.0033%	0.0069%
Chipotle Mexican Grill Inc	CMG	$79,507	0.160%	N/A	20.89%	N/A	0.0334%
Cummins Inc	CMI	$48,871	0.098%	2.04%	11.10%	0.0020%	0.0109%
CMS Energy Corp	CMS	$19,720	0.040%	3.12%	7.53%	0.0012%	0.0030%
Centene Corp	CNC	$32,327	0.065%	N/A	6.35%	N/A	0.0041%
CenterPoint Energy Inc	CNP	$21,227	0.043%	2.70%	7.88%	0.0012%	0.0034%
Capital One Financial Corp	COF	$77,717	0.156%	1.18%	14.71%	0.0018%	0.0230%
Cooper Cos Inc/The	COO	$19,270	0.039%	N/A	10.42%	N/A	0.0040%
ConocoPhillips	COP	$127,843	0.257%	3.16%	4.50%	0.0081%	0.0116%
Cencora Inc	COR	$49,280	0.099%	0.87%	10.89%	0.0009%	0.0108%
Costco Wholesale Corp	COST	$434,968	0.873%	0.47%	8.86%	0.0041%	0.0774%
Corpay Inc	CPAY	$26,524	0.053%	N/A	14.42%	N/A	0.0077%
The Campbell's Company	CPB	$11,558	0.023%	4.02%	4.16%	0.0009%	0.0010%
Copart Inc	CPRT	n/a	N/A	N/A	N/A	N/A	N/A
Camden Property Trust	CPT	$12,131	0.024%	3.62%	2.11%	0.0009%	0.0005%
Charles River Laboratories Internatio	CRL	n/a	N/A	N/A	N/A	N/A	N/A
Salesforce Inc	CRM	$327,007	0.657%	0.47%	17.42%	0.0031%	0.1144%
Crowdstrike Holdings Inc	CRWD	$93,089	0.187%	N/A	54.97%	N/A	0.1028%
Cisco Systems Inc	CSCO	$241,355	0.485%	2.64%	4.04%	0.0128%	0.0196%
CoStar Group Inc	CSGP	n/a	N/A	N/A	N/A	N/A	N/A
CSX Corp	CSX	$63,387	0.127%	1.46%	9.46%	0.0019%	0.0120%
Cintas Corp	CTAS	n/a	N/A	0.78%	N/A	N/A	N/A
Coterra Energy Inc	CTRA	$20,419	0.041%	3.03%	15.54%	0.0012%	0.0064%
Cognizant Technology Solutions Cor	CTSH	$40,960	0.082%	1.45%	6.20%	0.0012%	0.0051%
Corteva Inc	CTVA	$45,183	0.091%	1.04%	9.10%	0.0009%	0.0083%
CVS Health Corp	CVS	$71,075	0.143%	4.71%	-4.24%	0.0067%	-0.0060%
Chevron Corp	CVX	$268,108	0.538%	4.58%	0.15%	0.0247%	0.0008%
Caesars Entertainment Inc	CZR	$7,660	0.015%	N/A	97.08%	N/A	0.0149%
Dominion Energy Inc	D	$46,696	0.094%	4.80%	10.92%	0.0045%	0.0102%
Delta Air Lines Inc	DAL	$43,408	0.087%	0.89%	13.85%	0.0008%	0.0121%
Dayforce Inc	DAY	n/a	N/A	N/A	N/A	N/A	N/A
DuPont de Nemours Inc	DD	$32,099	0.064%	1.98%	3.50%	0.0013%	0.0023%
Deere & Co	DE	$129,792	0.261%	1.36%	1.12%	0.0035%	0.0029%
Deckers Outdoor Corp	DECK	$26,945	0.054%	N/A	15.15%	N/A	0.0082%
Dell Technologies Inc	DELL	$37,020	0.074%	1.72%	13.01%	0.0013%	0.0097%
Discover Financial Services	DFS	$50,536	0.101%	1.39%	0.34%	0.0014%	0.0003%
Dollar General Corp	DG	$15,628	0.031%	3.32%	-11.33%	0.0010%	-0.0036%
Quest Diagnostics Inc	DGX	$18,204	0.037%	1.96%	1.54%	0.0007%	0.0006%
DR Horton Inc	DHI	$44,716	0.090%	1.13%	7.26%	0.0010%	0.0065%
Danaher Corp	DHR	$160,880	0.323%	0.48%	2.89%	0.0016%	0.0093%
Walt Disney Co/The	DIS	$204,464	0.411%	0.88%	15.80%	0.0036%	0.0649%
Digital Realty Trust Inc	DLR	$54,354	0.109%	2.98%	4.05%	0.0033%	0.0044%
Dollar Tree Inc	DLTR	$15,773	0.032%	N/A	7.94%	N/A	0.0025%
Healthpeak Properties Inc	DOC	$14,450	0.029%	5.81%	4.99%	0.0017%	0.0014%
Dover Corp	DOV	$27,943	0.056%	1.01%	10.22%	0.0006%	0.0057%
Dow Inc	DOW	$27,339	0.055%	7.17%	-2.76%	0.0039%	-0.0015%
Domino's Pizza Inc	DPZ	$15,509	0.031%	1.34%	10.34%	0.0004%	0.0032%
Darden Restaurants Inc	DRI	$22,872	0.046%	2.87%	9.85%	0.0013%	0.0045%
DTE Energy Co	DTE	$24,806	0.050%	3.64%	10.98%	0.0018%	0.0055%
Duke Energy Corp	DUK	$86,344	0.173%	3.73%	6.30%	0.0065%	0.0109%
DaVita Inc	DVA	$14,448	0.029%	N/A	17.90%	N/A	0.0052%
Devon Energy Corp	DVN	$22,400	0.045%	2.58%	-5.51%	0.0012%	-0.0025%
Dexcom Inc	DXCM	$33,915	0.068%	N/A	20.53%	N/A	0.0140%
Electronic Arts Inc	EA	$32,236	0.065%	0.62%	6.20%	0.0004%	0.0040%
eBay Inc	EBAY	$32,323	0.065%	1.60%	9.96%	0.0010%	0.0065%
Ecolab Inc	ECL	$70,844	0.142%	1.04%	18.25%	0.0015%	0.0260%
Consolidated Edison Inc	ED	$32,473	0.065%	3.63%	5.99%	0.0024%	0.0039%
Equifax Inc	EFX	$34,060	0.068%	0.57%	15.25%	0.0004%	0.0104%
Everest Group Ltd	EG	$14,935	0.030%	2.30%	0.47%	0.0007%	0.0001%
Edison International	EIX	$20,906	0.042%	6.13%	7.77%	0.0026%	0.0033%
Estee Lauder Cos Inc/The	EL	$19,476	0.039%	1.68%	9.82%	0.0007%	0.0038%
Elevance Health Inc	ELV	$91,772	0.184%	1.73%	8.18%	0.0032%	0.0151%
Eastman Chemical Co	EMN	$11,551	0.023%	3.33%	5.52%	0.0008%	0.0013%
Emerson Electric Co	EMR	$74,011	0.149%	1.62%	12.91%	0.0024%	0.0192%
Enphase Energy Inc	ENPH	$8,414	0.017%	N/A	3.99%	N/A	0.0007%
EOG Resources Inc	EOG	$70,751	0.142%	3.10%	-3.30%	0.0044%	-0.0047%
EPAM Systems Inc	EPAM	$14,405	0.029%	N/A	6.44%	N/A	0.0019%
Equinix Inc	EQIX	$88,157	0.177%	1.87%	15.85%	0.0033%	0.0281%
Equity Residential	EQR	$26,799	0.054%	3.82%	3.08%	0.0021%	0.0017%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization Excluding No Growth Rate	Weight in Index	Dividend Yield	Long-Term Growth Est.	Weighted Dividend Yield	Weighted Long-Term Growth Rate
EQT Corp	EQT	$30,502	0.061%	1.23%	9.58%	0.0008%	0.0059%
Erie Indemnity Co	ERIE	n/a	N/A	1.36%	N/A	N/A	N/A
Eversource Energy	ES	$21,134	0.042%	5.22%	5.09%	0.0022%	0.0022%
Essex Property Trust Inc	ESS	$18,289	0.037%	3.44%	2.91%	0.0013%	0.0011%
Eaton Corp PLC	ETN	$129,009	0.259%	1.15%	15.49%	0.0030%	0.0401%
Entergy Corp	ETR	$34,768	0.070%	2.96%	8.55%	0.0021%	0.0060%
Evergy Inc	EVRG	$14,743	0.030%	4.16%	5.69%	0.0012%	0.0017%
Edwards Lifesciences Corp	EW	$42,731	0.086%	N/A	6.80%	N/A	0.0058%
Exelon Corp	EXC	$40,193	0.081%	3.80%	5.24%	0.0031%	0.0042%
Expeditors International of Washingtc	EXPD	$15,898	0.032%	1.29%	5.60%	0.0004%	0.0018%
Expedia Group Inc	EXPE	$20,997	0.042%	N/A	22.64%	N/A	0.0095%
Extra Space Storage Inc	EXR	$32,645	0.066%	4.21%	1.62%	0.0028%	0.0011%
Ford Motor Co	F	$39,347	0.079%	5.95%	3.06%	0.0047%	0.0024%
Diamondback Energy Inc	FANG	$47,991	0.096%	2.19%	-7.45%	0.0021%	-0.0072%
Fastenal Co	FAST	$41,958	0.084%	2.35%	10.52%	0.0020%	0.0089%
Freeport-McMoRan Inc	FCX	$51,514	0.103%	1.67%	9.05%	0.0017%	0.0094%
FactSet Research Systems Inc	FDS	n/a	N/A	0.88%	N/A	N/A	N/A
FedEx Corp	FDX	$63,794	0.128%	2.08%	14.88%	0.0027%	0.0191%
FirstEnergy Corp	FE	$22,937	0.046%	4.27%	5.81%	0.0020%	0.0027%
F5 Inc	FFIV	$17,246	0.035%	N/A	7.07%	N/A	0.0024%
Fiserv Inc	FI	$122,909	0.247%	N/A	13.26%	N/A	0.0327%
Fair Isaac Corp	FICO	$45,795	0.092%	N/A	30.00%	N/A	0.0276%
Fidelity National Information Services	FIS	$43,860	0.088%	1.96%	15.60%	0.0017%	0.0137%
Fifth Third Bancorp	FITB	n/a	N/A	3.34%	N/A	N/A	N/A
FMC Corp	FMC	$6,963	0.014%	4.16%	-4.52%	0.0006%	-0.0006%
Fox Corp	FOX	$11,449	0.023%	1.11%	9.54%	0.0003%	0.0022%
Fox Corp	FOXA	$11,319	0.023%	1.06%	9.54%	0.0002%	0.0022%
Federal Realty Investment Trust	FRT	$9,230	0.019%	4.05%	4.65%	0.0008%	0.0009%
First Solar Inc	FSLR	$17,934	0.036%	N/A	41.38%	N/A	0.0149%
Fortinet Inc	FTNT	$77,320	0.155%	N/A	17.59%	N/A	0.0273%
Fortive Corp	FTV	$28,217	0.057%	0.39%	10.54%	0.0002%	0.0060%
General Dynamics Corp	GD	$70,661	0.142%	2.21%	14.58%	0.0031%	0.0207%
GoDaddy Inc	GDDY	n/a	N/A	N/A	N/A	N/A	N/A
General Electric Co	GE	$220,323	0.442%	0.55%	18.22%	0.0024%	0.0806%
GE HealthCare Technologies Inc	GEHC	$40,342	0.081%	0.16%	10.24%	0.0001%	0.0083%
Gen Digital Inc	GEN	$16,585	0.033%	1.86%	11.23%	0.0006%	0.0037%
GE Vernova Inc	GEV	$102,785	0.206%	0.27%	97.07%	0.0006%	0.2003%
Gilead Sciences Inc	GILD	$121,137	0.243%	3.17%	17.57%	0.0077%	0.0427%
General Mills Inc	GIS	$33,151	0.067%	3.99%	1.31%	0.0027%	0.0009%
Globe Life Inc	GL	$10,249	0.021%	0.79%	6.00%	0.0002%	0.0012%
Corning Inc	GLW	$44,591	0.090%	2.15%	14.54%	0.0019%	0.0130%
General Motors Co	GM	$49,213	0.099%	0.97%	8.53%	0.0010%	0.0084%
Generac Holdings Inc	GNRC	n/a	N/A	N/A	N/A	N/A	N/A
Alphabet Inc	GOOG	$1,137,790	2.285%	0.39%	15.58%	0.0089%	0.3558%
Alphabet Inc	GOOGL	$1,192,089	2.394%	0.39%	15.58%	0.0094%	0.3728%
Genuine Parts Co	GPC	n/a	N/A	3.44%	N/A	N/A	N/A
Global Payments Inc	GPN	$28,720	0.058%	0.89%	10.15%	0.0005%	0.0059%
Garmin Ltd	GRMN	$41,449	0.083%	1.39%	21.60%	0.0012%	0.0180%
Goldman Sachs Group Inc/The	GS	$198,812	0.399%	1.87%	9.26%	0.0075%	0.0370%
WW Grainger Inc	GWW	$51,752	0.104%	0.77%	5.61%	0.0008%	0.0058%
Halliburton Co	HAL	$22,859	0.046%	2.61%	-2.16%	0.0012%	-0.0010%
Hasbro Inc	HAS	$8,069	0.016%	4.84%	26.82%	0.0008%	0.0043%
Huntington Bancshares Inc/OH	HBAN	$24,988	0.050%	3.60%	12.08%	0.0018%	0.0061%
HCA Healthcare Inc	HCA	$83,565	0.168%	0.87%	9.26%	0.0015%	0.0155%
Home Depot Inc/The	HD	$409,246	0.822%	2.18%	3.56%	0.0180%	0.0293%
Hess Corp	HES	n/a	N/A	1.44%	N/A	N/A	N/A
Hartford Financial Services Group Inc	HIG	$32,337	0.065%	1.86%	9.03%	0.0012%	0.0059%
Huntington Ingalls Industries Inc	HII	$7,719	0.015%	2.74%	7.36%	0.0004%	0.0011%
Hilton Worldwide Holdings Inc	HLT	$62,425	0.125%	0.23%	14.37%	0.0003%	0.0180%
Hologic Inc	HOLX	$16,284	0.033%	N/A	8.12%	N/A	0.0027%
Honeywell International Inc	HON	$145,473	0.292%	2.02%	7.42%	0.0059%	0.0217%
Hewlett Packard Enterprise Co	HPE	$27,872	0.056%	2.45%	4.65%	0.0014%	0.0026%
HP Inc	HPQ	$30,478	0.061%	3.56%	3.80%	0.0022%	0.0023%
Hormel Foods Corp	HRL	$16,459	0.033%	3.87%	7.81%	0.0013%	0.0026%
Henry Schein Inc	HSIC	$9,975	0.020%	N/A	6.32%	N/A	0.0013%
Host Hotels & Resorts Inc	HST	$11,681	0.023%	4.79%	-0.66%	0.0011%	-0.0002%
Hershey Co/The	HSY	$22,050	0.044%	3.67%	-6.93%	0.0016%	-0.0031%
Hubbell Inc	HUBB	$22,703	0.046%	1.25%	18.00%	0.0006%	0.0082%
Humana Inc	HUM	$35,308	0.071%	1.21%	3.00%	0.0009%	0.0021%
Howmet Aerospace Inc	HWM	$51,424	0.103%	0.32%	27.36%	0.0003%	0.0282%
International Business Machines Cor	IBM	$236,432	0.475%	2.61%	3.46%	0.0124%	0.0164%
Intercontinental Exchange Inc	ICE	$91,771	0.184%	1.13%	10.00%	0.0021%	0.0184%
IDEXX Laboratories Inc	IDXX	$34,559	0.069%	N/A	9.71%	N/A	0.0067%
IDEX Corp	IEX	n/a	N/A	1.23%	N/A	N/A	N/A
International Flavors & Fragrances In	IFF	$22,267	0.045%	1.84%	3.01%	0.0008%	0.0013%
Incyte Corp	INCY	$14,287	0.029%	N/A	39.79%	N/A	0.0114%
Intel Corp	INTC	$84,132	0.169%	N/A	12.22%	N/A	0.0206%
Intuit Inc	INTU	$168,373	0.338%	0.69%	18.41%	0.0023%	0.0622%
Invitation Homes Inc	INVH	$19,083	0.038%	3.72%	3.63%	0.0014%	0.0014%
International Paper Co	IP	$19,326	0.039%	3.33%	-2.00%	0.0013%	-0.0008%
Interpublic Group of Cos Inc/The	IPG	n/a	N/A	4.60%	N/A	N/A	N/A
IQVIA Holdings Inc	IQV	$36,547	0.073%	N/A	8.26%	N/A	0.0061%
Ingersoll Rand Inc	IR	$37,803	0.076%	0.09%	17.00%	0.0001%	0.0129%
Iron Mountain Inc	IRM	$29,807	0.060%	2.82%	4.00%	0.0017%	0.0024%
Intuitive Surgical Inc	ISRG	$203,965	0.410%	N/A	16.58%	N/A	0.0679%
Gartner Inc	IT	$41,871	0.084%	N/A	9.00%	N/A	0.0076%
Illinois Tool Works Inc	ITW	$76,530	0.154%	2.32%	7.56%	0.0036%	0.0116%
Invesco Ltd	IVZ	$8,643	0.017%	4.26%	11.53%	0.0007%	0.0020%
Jacobs Solutions Inc	J	n/a	N/A	0.91%	N/A	N/A	N/A
JB Hunt Transport Services Inc	JBHT	$17,264	0.035%	1.03%	16.43%	0.0004%	0.0057%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Jabil Inc	JBL	$17,732	0.036%	0.20%	12.52%	0.0001%	0.0045%
Johnson Controls International plc	JCI	$51,491	0.103%	1.90%	9.25%	0.0020%	0.0096%
Jack Henry & Associates Inc	JKHY	$12,701	0.026%	1.26%	9.30%	0.0003%	0.0024%
Johnson & Johnson	JNJ	n/a	N/A	3.26%	N/A	N/A	N/A
Juniper Networks Inc	JNPR	$11,542	0.023%	2.52%	3.56%	0.0006%	0.0008%
JPMorgan Chase & Co	JPM	n/a	N/A	1.87%	N/A	N/A	N/A
Kellanova	K	$28,172	0.057%	2.79%	9.41%	0.0016%	0.0053%
Keurig Dr Pepper Inc	KDP	$43,542	0.087%	2.87%	6.98%	0.0025%	0.0061%
KeyCorp	KEY	$19,900	0.040%	4.56%	19.06%	0.0018%	0.0076%
Keysight Technologies Inc	KEYS	$30,838	0.062%	N/A	13.10%	N/A	0.0081%
Kraft Heinz Co/The	KHC	$36,082	0.072%	5.36%	1.65%	0.0039%	0.0012%
Kimco Realty Corp	KIM	$15,134	0.030%	4.45%	4.54%	0.0014%	0.0014%
KKR & Co Inc	KKR	$148,396	0.298%	0.42%	29.00%	0.0012%	0.0864%
KLA Corp	KLAC	$98,102	0.197%	0.92%	15.45%	0.0018%	0.0304%
Kimberly-Clark Corp	KMB	$43,343	0.087%	3.88%	3.87%	0.0034%	0.0034%
Kinder Morgan Inc	KMI	$61,051	0.123%	4.18%	6.39%	0.0051%	0.0078%
CarMax Inc	KMX	$13,171	0.026%	N/A	16.70%	N/A	0.0044%
Coca-Cola Co/The	KO	$273,459	0.549%	3.06%	5.98%	0.0168%	0.0328%
Kroger Co/The	KR	$44,603	0.090%	2.08%	3.79%	0.0019%	0.0034%
Kenvue Inc	KVUE	$40,818	0.082%	3.85%	10.49%	0.0032%	0.0086%
Loews Corp	L	n/a	N/A	0.29%	N/A	N/A	N/A
Leidos Holdings Inc	LDOS	$18,952	0.038%	1.13%	15.41%	0.0004%	0.0059%
Lennar Corp	LEN	$30,646	0.062%	1.52%	9.85%	0.0009%	0.0061%
Labcorp Holdings Inc	LH	$20,893	0.042%	1.15%	9.31%	0.0005%	0.0039%
L3Harris Technologies Inc	LHX	$40,212	0.081%	2.19%	9.00%	0.0018%	0.0073%
Lennox International Inc	LII	n/a	N/A	0.78%	N/A	N/A	N/A
Linde PLC	LIN	$212,424	0.427%	1.25%	10.80%	0.0053%	0.0461%
LKQ Corp	LKQ	n/a	N/A	3.21%	N/A	N/A	N/A
Eli Lilly & Co	LLY	$769,971	1.546%	0.74%	28.50%	0.0114%	0.4406%
Lockheed Martin Corp	LMT	$108,972	0.219%	2.85%	2.61%	0.0062%	0.0057%
Alliant Energy Corp	LNT	$15,109	0.030%	3.45%	6.72%	0.0010%	0.0020%
Lowe's Cos Inc	LOW	$146,832	0.295%	1.77%	-0.44%	0.0052%	-0.0013%
Lam Research Corp	LRCX	$104,041	0.209%	1.14%	16.74%	0.0024%	0.0350%
Lululemon Athletica Inc	LULU	$48,324	0.097%	N/A	9.55%	N/A	0.0093%
Southwest Airlines Co	LUV	$18,418	0.037%	2.34%	49.98%	0.0009%	0.0185%
Las Vegas Sands Corp	LVS	$33,228	0.067%	2.18%	7.60%	0.0015%	0.0051%
Lamb Weston Holdings Inc	LW	$8,550	0.017%	2.47%	-11.26%	0.0004%	-0.0019%
LyondellBasell Industries NV	LYB	$24,584	0.049%	7.08%	-13.50%	0.0035%	-0.0067%
Live Nation Entertainment Inc	LYV	$33,617	0.068%	N/A	32.27%	N/A	0.0218%
Mastercard Inc	MA	$505,868	1.016%	0.55%	14.42%	0.0056%	0.1465%
Mid-America Apartment Communities	MAA	$17,834	0.036%	3.97%	0.29%	0.0014%	0.0001%
Marriott International Inc/MD	MAR	$80,753	0.162%	0.87%	5.89%	0.0014%	0.0096%
Masco Corp	MAS	$17,105	0.034%	1.46%	8.38%	0.0005%	0.0029%
McDonald's Corp	MCD	$206,888	0.415%	2.45%	4.43%	0.0102%	0.0184%
Microchip Technology Inc	MCHP	n/a	N/A	3.35%	N/A	N/A	N/A
McKesson Corp	MCK	$75,498	0.152%	0.48%	15.21%	0.0007%	0.0231%
Moody's Corp	MCO	n/a	N/A	0.68%	N/A	N/A	N/A
Mondelez International Inc	MDLZ	$77,544	0.156%	3.24%	4.95%	0.0050%	0.0077%
Medtronic PLC	MDT	$116,457	0.234%	3.08%	6.49%	0.0072%	0.0152%
MetLife Inc	MET	$59,901	0.120%	2.52%	13.68%	0.0030%	0.0165%
Meta Platforms Inc	META	$1,509,234	3.031%	0.29%	15.91%	0.0088%	0.4820%
MGM Resorts International	MGM	$10,266	0.021%	N/A	5.61%	N/A	0.0012%
Mohawk Industries Inc	MHK	$7,720	0.016%	N/A	1.57%	N/A	0.0002%
McCormick & Co Inc/MD	MKC	$19,502	0.039%	2.33%	6.37%	0.0009%	0.0025%
MarketAxess Holdings Inc	MKTX	$8,319	0.017%	1.34%	3.93%	0.0002%	0.0007%
Martin Marietta Materials Inc	MLM	$33,256	0.067%	0.58%	5.83%	0.0004%	0.0039%
Marsh & McLennan Cos Inc	MMC	$106,514	0.214%	1.50%	8.58%	0.0032%	0.0184%
3M Co	MMM	$82,882	0.166%	1.84%	6.59%	0.0031%	0.0110%
Monster Beverage Corp	MNST	$47,371	0.095%	N/A	9.94%	N/A	0.0095%
Altria Group Inc	MO	$88,520	0.178%	7.81%	4.48%	0.0139%	0.0080%
Molina Healthcare Inc	MOH	$17,755	0.036%	N/A	11.73%	N/A	0.0042%
Mosaic Co/The	MOS	$8,859	0.018%	3.16%	-22.38%	0.0006%	-0.0040%
Marathon Petroleum Corp	MPC	$46,830	0.094%	2.50%	-16.36%	0.0023%	-0.0154%
Monolithic Power Systems Inc	MPWR	$31,091	0.062%	0.78%	22.00%	0.0005%	0.0137%
Merck & Co Inc	MRK	$249,979	0.502%	3.28%	13.00%	0.0165%	0.0653%
Moderna Inc	MRNA	$15,170	0.030%	N/A	-20.92%	N/A	-0.0064%
Morgan Stanley	MS	$223,016	0.448%	2.67%	11.82%	0.0120%	0.0529%
MSCI Inc	MSCI	$46,770	0.094%	1.21%	12.00%	0.0011%	0.0113%
Microsoft Corp	MSFT	$3,085,549	6.196%	0.80%	15.39%	0.0496%	0.9537%
Motorola Solutions Inc	MSI	$78,421	0.157%	0.93%	9.48%	0.0015%	0.0149%
M&T Bank Corp	MTB	$33,390	0.067%	2.68%	8.44%	0.0018%	0.0057%
Match Group Inc	MTCH	$8,964	0.018%	2.13%	25.21%	0.0004%	0.0045%
Mettler-Toledo International Inc	MTD	$28,793	0.058%	N/A	8.58%	N/A	0.0050%
Micron Technology Inc	MU	n/a	N/A	0.50%	N/A	N/A	N/A
Norwegian Cruise Line Holdings Ltd	NCLH	$12,466	0.025%	N/A	58.74%	N/A	0.0147%
Nasdaq Inc	NDAQ	$47,326	0.095%	1.17%	13.47%	0.0011%	0.0128%
Nordson Corp	NDSN	n/a	N/A	1.42%	N/A	N/A	N/A
NextEra Energy Inc	NEE	$147,156	0.295%	2.88%	7.52%	0.0085%	0.0222%
Newmont Corp	NEM	$48,635	0.098%	2.34%	34.25%	0.0023%	0.0334%
Netflix Inc	NFLX	$417,816	0.839%	N/A	22.93%	N/A	0.1924%
NiSource Inc	NI	$17,411	0.035%	3.00%	8.00%	0.0010%	0.0028%
NIKE Inc	NKE	$90,837	0.182%	2.08%	-5.68%	0.0038%	-0.0104%
Northrop Grumman Corp	NOC	$70,535	0.142%	1.69%	19.22%	0.0024%	0.0272%
ServiceNow Inc	NOW	$209,786	0.421%	N/A	25.00%	N/A	0.1053%
NRG Energy Inc	NRG	$20,751	0.042%	1.72%	9.40%	0.0007%	0.0039%
Norfolk Southern Corp	NSC	$57,759	0.116%	2.12%	12.12%	0.0025%	0.0141%
NetApp Inc	NTAP	$24,824	0.050%	1.70%	7.66%	0.0008%	0.0038%
Northern Trust Corp	NTRS	$22,258	0.045%	2.67%	8.91%	0.0012%	0.0040%
Nucor Corp	NUE	$30,157	0.061%	1.71%	-10.41%	0.0010%	-0.0063%
NVIDIA Corp	NVDA	$2,940,514	5.905%	0.03%	35.00%	0.0020%	2.0666%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
NVR Inc	NVR	$24,561	0.049%	N/A	6.01%	N/A	0.0030%
News Corp	NWS	n/a	N/A	0.63%	N/A	N/A	N/A
News Corp	NWSA	n/a	N/A	0.71%	N/A	N/A	N/A
NXP Semiconductors NV	NXPI	$53,004	0.106%	1.94%	1.29%	0.0021%	0.0014%
Realty Income Corp	O	$47,822	0.096%	5.80%	3.78%	0.0056%	0.0036%
Old Dominion Freight Line Inc	ODFL	$39,627	0.080%	0.56%	1.25%	0.0004%	0.0010%
ONEOK Inc	OKE	$56,765	0.114%	4.24%	7.39%	0.0048%	0.0084%
Omnicom Group Inc	OMC	$16,932	0.034%	3.23%	5.46%	0.0011%	0.0019%
ON Semiconductor Corp	ON	$22,286	0.045%	N/A	-10.33%	N/A	-0.0046%
Oracle Corp	ORCL	$475,650	0.955%	0.94%	10.49%	0.0090%	0.1002%
O'Reilly Automotive Inc	ORLY	$74,728	0.150%	N/A	9.11%	N/A	0.0137%
Otis Worldwide Corp	OTIS	$38,117	0.077%	1.63%	10.00%	0.0013%	0.0077%
Occidental Petroleum Corp	OXY	$43,774	0.088%	1.89%	12.00%	0.0017%	0.0105%
Palo Alto Networks Inc	PANW	$121,016	0.243%	N/A	13.38%	N/A	0.0325%
Paramount Global	PARA	$6,814	0.014%	1.84%	45.00%	0.0003%	0.0062%
Paycom Software Inc	PAYC	$11,968	0.024%	0.72%	10.23%	0.0002%	0.0025%
Paychex Inc	PAYX	$53,171	0.107%	2.65%	7.11%	0.0028%	0.0076%
PACCAR Inc	PCAR	$58,134	0.117%	1.19%	-2.82%	0.0014%	-0.0033%
PG&E Corp	PCG	$34,214	0.069%	0.64%	9.81%	0.0004%	0.0067%
Public Service Enterprise Group Inc	PEG	$41,622	0.084%	2.87%	6.74%	0.0024%	0.0056%
PepsiCo Inc	PEP	$206,745	0.415%	3.60%	6.06%	0.0149%	0.0251%
Pfizer Inc	PFE	$150,289	0.302%	6.49%	11.28%	0.0196%	0.0340%
Principal Financial Group Inc	PFG	$18,858	0.038%	3.54%	12.60%	0.0013%	0.0048%
Procter & Gamble Co/The	PG	$389,222	0.782%	2.43%	6.24%	0.0190%	0.0488%
Progressive Corp/The	PGR	$144,367	0.290%	0.16%	23.43%	0.0005%	0.0679%
Parker-Hannifin Corp	PH	$91,043	0.183%	0.92%	7.51%	0.0017%	0.0137%
PulteGroup Inc	PHM	$23,334	0.047%	0.77%	4.49%	0.0004%	0.0021%
Packaging Corp of America	PKG	$19,098	0.038%	2.35%	8.99%	0.0009%	0.0034%
Prologis Inc	PLD	$110,446	0.222%	3.22%	6.63%	0.0071%	0.0147%
Palantir Technologies Inc	PLTR	$179,882	0.361%	N/A	36.08%	N/A	0.1303%
Philip Morris International Inc	PM	$202,439	0.407%	4.15%	9.45%	0.0169%	0.0384%
PNC Financial Services Group Inc/Th	PNC	$79,734	0.160%	3.18%	8.09%	0.0051%	0.0130%
Pentair PLC	PNR	$17,131	0.034%	0.96%	11.80%	0.0003%	0.0041%
Pinnacle West Capital Corp	PNW	$9,887	0.020%	4.12%	5.96%	0.0008%	0.0012%
Insulet Corp	PODD	$19,527	0.039%	N/A	31.17%	N/A	0.0122%
Pool Corp	POOL	$13,101	0.026%	1.39%	-0.14%	0.0004%	0.0000%
PPG Industries Inc	PPG	$26,768	0.054%	2.36%	6.81%	0.0013%	0.0037%
PPL Corp	PPL	$24,796	0.050%	3.07%	7.41%	0.0015%	0.0037%
Prudential Financial Inc	PRU	$42,991	0.086%	4.31%	1.74%	0.0037%	0.0015%
Public Storage	PSA	$52,444	0.105%	4.02%	2.10%	0.0042%	0.0022%
Phillips 66	PSX	$48,679	0.098%	3.90%	-9.89%	0.0038%	-0.0097%
PTC Inc	PTC	$23,286	0.047%	N/A	16.59%	N/A	0.0078%
Quanta Services Inc	PWR	$45,407	0.091%	0.13%	21.40%	0.0001%	0.0195%
PayPal Holdings Inc	PYPL	$88,805	0.178%	N/A	14.01%	N/A	0.0250%
QUALCOMM Inc	QCOM	$191,155	0.384%	1.97%	8.45%	0.0075%	0.0324%
Royal Caribbean Cruises Ltd	RCL	$71,682	0.144%	0.83%	18.10%	0.0012%	0.0261%
Regency Centers Corp	REG	$13,039	0.026%	3.93%	4.31%	0.0010%	0.0011%
Regeneron Pharmaceuticals Inc	REGN	$72,731	0.146%	N/A	28.35%	N/A	0.0414%
Regions Financial Corp	RF	$22,394	0.045%	4.06%	6.45%	0.0018%	0.0029%
Raymond James Financial Inc	RJF	$34,430	0.069%	1.19%	12.71%	0.0008%	0.0088%
Ralph Lauren Corp	RL	$10,042	0.020%	1.32%	11.25%	0.0003%	0.0023%
ResMed Inc	RMD	$34,687	0.070%	0.90%	14.08%	0.0006%	0.0098%
Rockwell Automation Inc	ROK	$31,436	0.063%	1.88%	14.93%	0.0012%	0.0094%
Rollins Inc	ROL	$23,973	0.048%	1.33%	14.00%	0.0006%	0.0067%
Roper Technologies Inc	ROP	n/a	N/A	0.57%	N/A	N/A	N/A
Ross Stores Inc	ROST	$49,674	0.100%	0.98%	98.30%	0.0010%	0.0980%
Republic Services Inc	RSG	$67,913	0.136%	1.07%	11.25%	0.0015%	0.0153%
RTX Corp	RTX	$171,635	0.345%	1.95%	9.83%	0.0067%	0.0339%
Revvity Inc	RVTY	$15,350	0.031%	0.22%	8.91%	0.0001%	0.0027%
SBA Communications Corp	SBAC	$21,242	0.043%	1.98%	17.51%	0.0008%	0.0075%
Starbucks Corp	SBUX	$122,314	0.246%	2.27%	9.20%	0.0056%	0.0226%
Charles Schwab Corp/The	SCHW	$147,214	0.296%	1.31%	9.92%	0.0039%	0.0293%
Sherwin-Williams Co/The	SHW	$90,204	0.181%	0.80%	8.60%	0.0014%	0.0156%
J M Smucker Co/The	SJM	$11,375	0.023%	4.04%	4.72%	0.0009%	0.0011%
Schlumberger NV	SLB	$56,426	0.113%	2.83%	1.25%	0.0032%	0.0014%
Super Micro Computer Inc	SMCI	n/a	N/A	N/A	N/A	N/A	N/A
Snap-on Inc	SNA	$18,648	0.037%	2.41%	4.81%	0.0009%	0.0018%
Synopsys Inc	SNPS	$81,228	0.163%	N/A	11.37%	N/A	0.0185%
Southern Co/The	SO	$91,894	0.185%	3.43%	8.20%	0.0063%	0.0151%
Solventum Corp	SOLV	$12,794	0.026%	N/A	-3.78%	N/A	-0.0010%
Simon Property Group Inc	SPG	$56,725	0.114%	4.83%	1.34%	0.0055%	0.0015%
S&P Global Inc	SPGI	$165,548	0.332%	0.74%	14.00%	0.0024%	0.0465%
Sempra	SRE	$52,528	0.105%	2.99%	9.80%	0.0032%	0.0103%
STERIS PLC	STE	n/a	N/A	1.03%	N/A	N/A	N/A
Steel Dynamics Inc	STLD	$19,518	0.039%	1.44%	-3.48%	0.0006%	-0.0014%
State Street Corp	STT	$29,790	0.060%	2.99%	10.32%	0.0018%	0.0062%
Seagate Technology Holdings PLC	STX	n/a	N/A	2.99%	N/A	N/A	N/A
Constellation Brands Inc	STZ	$32,671	0.066%	2.23%	9.34%	0.0015%	0.0061%
Smurfit WestRock PLC	SW	$27,630	0.055%	3.25%	-1.71%	0.0018%	-0.0009%
Stanley Black & Decker Inc	SWK	n/a	N/A	3.72%	N/A	N/A	N/A
Skyworks Solutions Inc	SWKS	$14,195	0.029%	3.15%	15.09%	0.0009%	0.0043%
Synchrony Financial	SYF	$26,857	0.054%	1.45%	15.80%	0.0008%	0.0085%
Stryker Corp	SYK	$149,166	0.300%	0.86%	9.97%	0.0026%	0.0299%
Sysco Corp	SYY	n/a	N/A	2.80%	N/A	N/A	N/A
AT&T Inc	T	$170,270	0.342%	4.68%	4.08%	0.0160%	0.0139%
Molson Coors Beverage Co	TAP	$10,598	0.021%	3.21%	4.00%	0.0007%	0.0009%
TransDigm Group Inc	TDG	$75,841	0.152%	N/A	13.09%	N/A	0.0199%
Teledyne Technologies Inc	TDY	$23,829	0.048%	N/A	7.41%	N/A	0.0035%
Bio-Techne Corp	TECH	n/a	N/A	0.44%	N/A	N/A	N/A
TE Connectivity PLC	TEL	$44,147	0.089%	1.76%	7.32%	0.0016%	0.0065%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Teradyne Inc	TER	$18,858	0.038%	0.41%	10.80%	0.0002%	0.0041%
Truist Financial Corp	TFC	$63,217	0.127%	4.37%	8.22%	0.0055%	0.0104%
Teleflex Inc	TFX	$8,371	0.017%	0.75%	7.34%	0.0001%	0.0012%
Target Corp	TGT	$63,192	0.127%	3.25%	11.09%	0.0041%	0.0141%
TJX Cos Inc/The	TJX	$140,284	0.282%	1.20%	8.57%	0.0034%	0.0241%
Thermo Fisher Scientific Inc	TMO	$228,640	0.459%	0.26%	9.62%	0.0012%	0.0442%
T-Mobile US Inc	TMUS	$265,992	0.534%	1.51%	5.00%	0.0081%	0.0267%
Texas Pacific Land Corp	TPL	n/a	N/A	0.49%	N/A	N/A	N/A
Tapestry Inc	TPR	$16,998	0.034%	1.92%	8.62%	0.0007%	0.0029%
Targa Resources Corp	TRGP	$42,915	0.086%	1.52%	27.68%	0.0013%	0.0239%
Trimble Inc	TRMB	n/a	N/A	N/A	N/A	N/A	N/A
T Rowe Price Group Inc	TROW	$25,975	0.052%	4.24%	7.65%	0.0022%	0.0040%
Travelers Cos Inc/The	TRV	n/a	N/A	1.71%	N/A	N/A	N/A
Tractor Supply Co	TSCO	$29,039	0.058%	1.62%	7.56%	0.0009%	0.0044%
Tesla Inc	TSLA	$1,301,403	2.613%	N/A	1.00%	N/A	0.0261%
Tyson Foods Inc	TSN	$16,165	0.032%	3.54%	18.97%	0.0011%	0.0062%
Trane Technologies PLC	TT	$81,627	0.164%	0.93%	14.99%	0.0015%	0.0246%
Take-Two Interactive Software Inc	TTWO	$32,581	0.065%	N/A	60.38%	N/A	0.0395%
Texas Instruments Inc	TXN	$168,404	0.338%	2.95%	7.84%	0.0100%	0.0265%
Textron Inc	TXT	$14,193	0.029%	0.10%	10.03%	0.0000%	0.0029%
Tyler Technologies Inc	TYL	n/a	N/A	N/A	N/A	N/A	N/A
United Airlines Holdings Inc	UAL	$34,801	0.070%	N/A	14.48%	N/A	0.0101%
Uber Technologies Inc	UBER	$140,767	0.283%	N/A	60.82%	N/A	0.1719%
UDR Inc	UDR	$13,773	0.028%	4.07%	1.46%	0.0011%	0.0004%
Universal Health Services Inc	UHS	$11,071	0.022%	0.42%	23.30%	0.0001%	0.0052%
Ulta Beauty Inc	ULTA	$19,112	0.038%	N/A	0.34%	N/A	0.0001%
UnitedHealth Group Inc	UNH	$499,245	1.003%	1.55%	11.45%	0.0155%	0.1148%
Union Pacific Corp	UNP	$150,224	0.302%	2.16%	10.20%	0.0065%	0.0308%
United Parcel Service Inc	UPS	$83,544	0.168%	5.71%	3.73%	0.0096%	0.0063%
United Rentals Inc	URI	$49,507	0.099%	0.94%	9.68%	0.0009%	0.0096%
US Bancorp	USB	$74,538	0.150%	4.19%	11.17%	0.0063%	0.0167%
Visa Inc	V	$589,045	1.183%	0.69%	12.53%	0.0082%	0.1482%
VICI Properties Inc	VICI	$31,054	0.062%	5.81%	2.72%	0.0036%	0.0017%
Valero Energy Corp	VLO	$42,106	0.085%	3.40%	-22.33%	0.0029%	-0.0189%
Veralto Corp	VLTO	n/a	N/A	0.43%	N/A	N/A	N/A
Vulcan Materials Co	VMC	$36,205	0.073%	0.67%	14.67%	0.0005%	0.0107%
Verisk Analytics Inc	VRSK	$40,590	0.082%	0.54%	12.00%	0.0004%	0.0098%
VeriSign Inc	VRSN	n/a	N/A	N/A	N/A	N/A	N/A
Vertex Pharmaceuticals Inc	VRTX	$118,896	0.239%	N/A	12.20%	N/A	0.0291%
Vistra Corp	VST	$57,168	0.115%	0.53%	28.69%	0.0006%	0.0329%
Ventas Inc	VTR	$25,337	0.051%	2.98%	7.65%	0.0015%	0.0039%
Viatris Inc	VTRS	$13,464	0.027%	4.26%	-3.41%	0.0012%	-0.0009%
Verizon Communications Inc	VZ	$165,817	0.333%	6.88%	1.01%	0.0229%	0.0034%
Westinghouse Air Brake Technologie	WAB	$35,739	0.072%	0.38%	18.56%	0.0003%	0.0133%
Waters Corp	WAT	$24,670	0.050%	N/A	6.12%	N/A	0.0030%
Walgreens Boots Alliance Inc	WBA	$8,883	0.018%	N/A	-21.75%	N/A	-0.0039%
Warner Bros Discovery Inc	WBD	$25,611	0.051%	N/A	29.09%	N/A	0.0150%
Workday Inc	WDAY	$56,081	0.113%	N/A	20.00%	N/A	0.0225%
Western Digital Corp	WDC	n/a	N/A	N/A	N/A	N/A	N/A
WEC Energy Group Inc	WEC	$31,401	0.063%	3.60%	7.24%	0.0023%	0.0046%
Welltower Inc	WELL	$84,985	0.171%	1.96%	15.99%	0.0034%	0.0273%
Wells Fargo & Co	WFC	$262,364	0.527%	2.03%	16.95%	0.0107%	0.0893%
Waste Management Inc	WM	$88,405	0.178%	1.36%	10.93%	0.0024%	0.0194%
Williams Cos Inc/The	WMB	$67,570	0.136%	3.61%	5.96%	0.0049%	0.0081%
Walmart Inc	WMT	$788,557	1.583%	0.85%	9.86%	0.0134%	0.1561%
W R Berkley Corp	WRB	$22,418	0.045%	0.54%	10.96%	0.0002%	0.0049%
West Pharmaceutical Services Inc	WST	$24,736	0.050%	0.25%	4.65%	0.0001%	0.0023%
Willis Towers Watson PLC	WTW	$33,196	0.067%	1.07%	11.15%	0.0007%	0.0074%
Weyerhaeuser Co	WY	$22,248	0.045%	2.61%	-13.66%	0.0012%	-0.0061%
Wynn Resorts Ltd	WYNN	$9,537	0.019%	1.15%	-14.72%	0.0002%	-0.0028%
Xcel Energy Inc	XEL	$40,005	0.080%	3.26%	7.56%	0.0026%	0.0061%
Exxon Mobil Corp	XOM	$469,528	0.943%	3.71%	-7.15%	0.0349%	-0.0674%
Xylem Inc/NY	XYL	n/a	N/A	1.16%	N/A	N/A	N/A
Yum! Brands Inc	YUM	$36,419	0.073%	2.05%	9.24%	0.0015%	0.0068%
Zimmer Biomet Holdings Inc	ZBH	$21,795	0.044%	0.88%	6.50%	0.0004%	0.0028%
Zebra Technologies Corp	ZBRA	n/a	N/A	N/A	N/A	N/A	N/A
Zoetis Inc	ZTS	$77,104	0.155%	1.17%	8.90%	0.0018%	0.0138%
		$49,799,952					

[4] Bloomberg Financial as of January 31, 2025
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional as of January 31, 2025
[7] Source: Bloomberg Professional as of January 31, 2025
[8] Equals [5] x [6]
[9] Equals [5] x [7]

Expected Market Return
Market DCF Based Method - Value Line EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.30%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	13.90%
[3] Market Cap. Weighted Estimated Required Market Return	15.29%

Notes:
[1] Equals Sum of Col. [8]
[2] Equals Sum of Col. [9]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Agilent Technologies Inc	A	$43,227	0.09%	0.65%	6.50%	0.0006%	0.0057%
Apple Inc	AAPL	$3,545,209	7.13%	0.42%	9.00%	0.0302%	0.6419%
AbbVie Inc	ABBV	$324,977	0.65%	3.57%	4.00%	0.0233%	0.0262%
Airbnb Inc	ABNB	$57,715	0.12%	N/A	23.00%	N/A	0.0267%
Abbott Laboratories	ABT	$221,889	0.45%	1.84%	4.50%	0.0082%	0.0201%
Arch Capital Group Ltd	ACGL	$35,017	0.07%	N/A	18.00%	N/A	0.0127%
Accenture PLC	ACN	$240,779	0.48%	1.54%	12.50%	0.0074%	0.0605%
Adobe Inc	ADBE	$190,422	0.38%	N/A	13.50%	N/A	0.0517%
Analog Devices Inc	ADI	$105,120	0.21%	1.74%	9.00%	0.0037%	0.0190%
Archer-Daniels-Midland Co	ADM	$24,515	0.05%	3.90%	3.00%	0.0019%	0.0015%
Automatic Data Processing Inc	ADP	$123,286	0.25%	2.03%	8.50%	0.0050%	0.0211%
Autodesk Inc	ADSK	$66,938	0.13%	N/A	14.00%	N/A	0.0189%
Ameren Corp	AEE	$25,105	0.05%	2.85%	6.50%	0.0014%	0.0033%
American Electric Power Co Inc	AEP	$52,383	0.11%	3.78%	6.50%	0.0040%	0.0069%
AES Corp/The	AES	$7,821	0.02%	6.40%	14.00%	0.0010%	0.0022%
Aflac Inc	AFL	$59,653	0.12%	2.16%	7.50%	0.0026%	0.0090%
American International Group Inc	AIG	$45,947	0.09%	2.17%	12.50%	0.0020%	0.0116%
Assurant Inc	AIZ	$11,037	0.02%	1.49%	9.50%	0.0003%	0.0021%
Arthur J Gallagher & Co	AJG	$76,770	0.15%	0.86%	16.50%	0.0013%	0.0255%
Akamai Technologies Inc	AKAM	$15,008	0.03%	N/A	6.00%	N/A	0.0018%
Albemarle Corp	ALB	$9,896	0.02%	1.92%	-3.50%	0.0004%	-0.0007%
Align Technology Inc	ALGN	$16,357	0.03%	N/A	17.00%	N/A	0.0056%
Allstate Corp/The	ALL	$50,930	0.10%	1.91%	32.00%	0.0020%	0.0328%
Allegion plc	ALLE	$11,538	0.02%	1.45%	8.50%	0.0003%	0.0020%
Applied Materials Inc	AMAT	$146,571	0.29%	0.89%	9.00%	0.0026%	0.0265%
Amcor PLC	AMCR	$14,049	0.03%	5.25%	11.50%	0.0015%	0.0033%
Advanced Micro Devices Inc	AMD	$188,165	0.38%	N/A	17.00%	N/A	0.0644%
AMETEK Inc	AME	$42,690	0.09%	0.61%	10.00%	0.0005%	0.0086%
Amgen Inc	AMGN	$153,423	0.31%	3.34%	4.50%	0.0103%	0.0139%
Ameriprise Financial Inc	AMP	$52,714	0.11%	1.09%	10.00%	0.0012%	0.0106%
American Tower Corp	AMT	$86,425	0.17%	3.50%	11.00%	0.0061%	0.0191%
Amazon.com Inc	AMZN	$2,499,208	5.03%	N/A	24.50%	N/A	1.2318%
Arista Networks Inc	ANET	$145,162	0.29%	N/A	19.50%	N/A	0.0569%
ANSYS Inc	ANSS	$30,651	0.06%	N/A	9.50%	N/A	0.0059%
Aon PLC	AON	$80,196	0.16%	0.73%	12.50%	0.0012%	0.0202%
A O Smith Corp	AOS	$8,016	0.02%	2.02%	9.00%	0.0003%	0.0015%
APA Corp	APA	$8,113	0.02%	4.56%	6.00%	0.0007%	0.0010%
Air Products and Chemicals Inc	APD	$74,555	0.15%	2.14%	10.50%	0.0032%	0.0157%
Amphenol Corp	APH	$85,333	0.17%	0.93%	14.00%	0.0016%	0.0240%
Apollo Global Management Inc	APO	$96,743	0.19%	1.08%	23.50%	0.0021%	0.0457%
Aptiv PLC	APTV	$14,671	0.03%	N/A	28.50%	N/A	0.0084%
Alexandria Real Estate Equities Inc	ARE	$16,850	0.03%	5.42%	9.50%	0.0018%	0.0032%
Atmos Energy Corp	ATO	$22,149	0.04%	2.44%	7.00%	0.0011%	0.0031%
AvalonBay Communities Inc	AVB	$31,507	0.06%	3.07%	5.50%	0.0019%	0.0035%
Broadcom Inc	AVGO	$1,037,171	2.09%	1.07%	30.00%	0.0223%	0.6260%
Avery Dennison Corp	AVY	$14,923	0.03%	1.90%	2.00%	0.0006%	0.0006%
American Water Works Co Inc	AWK	$24,292	0.05%	2.46%	4.50%	0.0012%	0.0022%
Axon Enterprise Inc	AXON	$49,732	0.10%	N/A	26.50%	N/A	0.0265%
American Express Co	AXP	$223,626	0.45%	0.88%	9.00%	0.0040%	0.0405%
AutoZone Inc	AZO	$56,224	0.11%	N/A	11.50%	N/A	0.0130%
Boeing Co/The	BA	n/a	N/A	N/A	N/A	N/A	N/A
Bank of America Corp	BAC	$355,254	0.71%	2.25%	7.00%	0.0161%	0.0500%
Ball Corp	BALL	$16,622	0.03%	1.44%	10.50%	0.0005%	0.0035%
Baxter International Inc	BAX	$16,625	0.03%	2.09%	3.50%	0.0007%	0.0012%
Best Buy Co Inc	BBY	$18,356	0.04%	4.38%	1.00%	0.0016%	0.0004%
Becton Dickinson & Co	BDX	$71,806	0.14%	1.68%	7.00%	0.0024%	0.0101%
Franklin Resources Inc	BEN	$11,685	0.02%	5.76%	4.00%	0.0014%	0.0009%
Brown-Forman Corp	BF/B	n/a	N/A	2.74%	N/A	N/A	N/A
Bunge Global SA	BG	$10,630	0.02%	3.57%	0.00%	0.0008%	0.0000%
Biogen Inc	BIIB	$20,973	0.04%	N/A	0.50%	N/A	0.0002%
Bank of New York Mellon Corp/The	BK	$62,478	0.13%	2.19%	15.00%	0.0027%	0.0189%
Booking Holdings Inc	BKNG	$156,798	0.32%	0.74%	22.00%	0.0023%	0.0694%
Baker Hughes Co	BKR	$45,696	0.09%	1.99%	30.00%	0.0018%	0.0276%
Builders FirstSource Inc	BLDR	$19,251	0.04%	N/A	6.50%	N/A	0.0025%
Blackrock Inc	BLK	$166,572	0.34%	1.94%	9.50%	0.0065%	0.0318%
Bristol-Myers Squibb Co	BMY	$119,561	0.24%	4.21%	1.00%	0.0101%	0.0024%
Broadridge Financial Solutions Inc	BR	$27,876	0.06%	1.48%	9.50%	0.0008%	0.0053%
Berkshire Hathaway Inc	BRK/B	n/a	N/A	N/A	N/A	N/A	N/A
Brown & Brown Inc	BRO	$29,928	0.06%	0.57%	12.50%	0.0003%	0.0075%
Boston Scientific Corp	BSX	$150,861	0.30%	N/A	12.50%	N/A	0.0379%
BorgWarner Inc	BWA	$6,977	0.01%	1.38%	5.50%	0.0002%	0.0008%
Blackstone Inc	BX	$127,874	0.26%	3.25%	16.00%	0.0084%	0.0412%
BXP Inc	BXP	$11,564	0.02%	5.36%	0.50%	0.0012%	0.0001%
Citigroup Inc	C	$154,006	0.31%	2.75%	3.00%	0.0085%	0.0093%
Conagra Brands Inc	CAG	$12,358	0.02%	5.41%	2.00%	0.0013%	0.0005%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Cardinal Health Inc	CAH	$29,872	0.06%	1.64%	6.50%	0.0010%	0.0039%
Carrier Global Corp	CARR	$58,661	0.12%	1.38%	13.00%	0.0016%	0.0153%
Caterpillar Inc	CAT	$179,332	0.36%	1.52%	10.50%	0.0055%	0.0379%
Chubb Ltd	CB	$109,594	0.22%	1.34%	13.00%	0.0030%	0.0287%
Cboe Global Markets Inc	CBOE	$21,390	0.04%	1.23%	14.50%	0.0005%	0.0062%
CBRE Group Inc	CBRE	$44,293	0.09%	N/A	6.50%	N/A	0.0058%
Crown Castle Inc	CCI	$38,801	0.08%	7.01%	-0.50%	0.0055%	-0.0004%
Carnival Corp	CCL	n/a	N/A	N/A	N/A	N/A	N/A
Cadence Design Systems Inc	CDNS	$81,626	0.16%	N/A	12.00%	N/A	0.0197%
CDW Corp/DE	CDW	$26,538	0.05%	1.26%	7.00%	0.0007%	0.0037%
Celanese Corp	CE	$7,766	0.02%	3.94%	4.50%	0.0006%	0.0007%
Constellation Energy Corp	CEG	n/a	N/A	0.47%	N/A	N/A	N/A
CF Industries Holdings Inc	CF	n/a	N/A	2.17%	N/A	N/A	N/A
Citizens Financial Group Inc	CFG	$20,964	0.04%	3.53%	7.50%	0.0015%	0.0032%
Church & Dwight Co Inc	CHD	$25,852	0.05%	1.12%	6.50%	0.0006%	0.0034%
CH Robinson Worldwide Inc	CHRW	$11,760	0.02%	2.49%	5.50%	0.0006%	0.0013%
Charter Communications Inc	CHTR	$49,041	0.10%	N/A	6.50%	N/A	0.0064%
Cigna Group/The	CI	$81,835	0.16%	2.05%	12.00%	0.0034%	0.0198%
Cincinnati Financial Corp	CINF	$21,423	0.04%	2.54%	9.50%	0.0011%	0.0041%
Colgate-Palmolive Co	CL	$70,835	0.14%	2.31%	11.50%	0.0033%	0.0164%
Clorox Co/The	CLX	$19,642	0.04%	3.08%	7.00%	0.0012%	0.0028%
Comcast Corp	CMCSA	$126,951	0.26%	3.92%	7.50%	0.0100%	0.0192%
CME Group Inc	CME	$85,232	0.17%	1.94%	6.00%	0.0033%	0.0103%
Chipotle Mexican Grill Inc	CMG	$79,507	0.16%	N/A	20.00%	N/A	0.0320%
Cummins Inc	CMI	$48,871	0.10%	2.04%	8.50%	0.0020%	0.0084%
CMS Energy Corp	CMS	$19,720	0.04%	3.12%	6.00%	0.0012%	0.0024%
Centene Corp	CNC	$32,327	0.07%	N/A	10.00%	N/A	0.0065%
CenterPoint Energy Inc	CNP	$21,227	0.04%	2.70%	6.50%	0.0012%	0.0028%
Capital One Financial Corp	COF	$77,717	0.16%	1.18%	2.50%	0.0018%	0.0039%
Cooper Cos Inc/The	COO	$19,270	0.04%	N/A	8.50%	N/A	0.0033%
ConocoPhillips	COP	$127,843	0.26%	3.16%	4.00%	0.0081%	0.0103%
Cencora Inc	COR	$49,280	0.10%	0.87%	6.50%	0.0009%	0.0064%
Costco Wholesale Corp	COST	$434,968	0.88%	0.47%	11.50%	0.0041%	0.1006%
Corpay Inc	CPAY	$26,524	0.05%	N/A	15.50%	N/A	0.0083%
The Campbell's Company	CPB	$11,558	0.02%	4.02%	7.00%	0.0009%	0.0016%
Copart Inc	CPRT	$55,817	0.11%	N/A	9.00%	N/A	0.0101%
Camden Property Trust	CPT	$12,131	0.02%	3.62%	-8.50%	0.0009%	-0.0021%
Charles River Laboratories Internatio	CRL	$8,425	0.02%	N/A	5.50%	N/A	0.0009%
Salesforce Inc	CRM	$327,007	0.66%	0.47%	24.50%	0.0031%	0.1612%
Crowdstrike Holdings Inc	CRWD	n/a	N/A	N/A	N/A	N/A	N/A
Cisco Systems Inc	CSCO	$241,355	0.49%	2.64%	3.50%	0.0128%	0.0170%
CoStar Group Inc	CSGP	$31,403	0.06%	N/A	13.00%	N/A	0.0082%
CSX Corp	CSX	$63,387	0.13%	1.46%	9.00%	0.0019%	0.0115%
Cintas Corp	CTAS	$80,939	0.16%	0.78%	14.00%	0.0013%	0.0228%
Coterra Energy Inc	CTRA	$20,419	0.04%	3.03%	4.50%	0.0012%	0.0018%
Cognizant Technology Solutions Cor	CTSH	$40,960	0.08%	1.45%	9.00%	0.0012%	0.0074%
Corteva Inc	CTVA	$45,183	0.09%	1.04%	7.00%	0.0009%	0.0064%
CVS Health Corp	CVS	$71,075	0.14%	4.71%	1.50%	0.0067%	0.0021%
Chevron Corp	CVX	$268,108	0.54%	4.58%	4.00%	0.0247%	0.0216%
Caesars Entertainment Inc	CZR	n/a	N/A	N/A	N/A	N/A	N/A
Dominion Energy Inc	D	$46,696	0.09%	4.80%	3.50%	0.0045%	0.0033%
Delta Air Lines Inc	DAL	n/a	N/A	0.89%	N/A	N/A	N/A
Dayforce Inc	DAY	n/a	N/A	N/A	N/A	N/A	N/A
DuPont de Nemours Inc	DD	$32,099	0.06%	1.98%	9.00%	0.0013%	0.0058%
Deere & Co	DE	$129,792	0.26%	1.36%	3.00%	0.0036%	0.0078%
Deckers Outdoor Corp	DECK	$26,945	0.05%	N/A	16.00%	N/A	0.0087%
Dell Technologies Inc	DELL	$37,020	0.07%	1.72%	2.50%	0.0013%	0.0019%
Discover Financial Services	DFS	$50,536	0.10%	1.39%	4.00%	0.0014%	0.0041%
Dollar General Corp	DG	$15,628	0.03%	3.32%	-0.50%	0.0010%	-0.0002%
Quest Diagnostics Inc	DGX	$18,204	0.04%	1.96%	3.00%	0.0007%	0.0011%
DR Horton Inc	DHI	$44,716	0.09%	1.13%	4.00%	0.0010%	0.0036%
Danaher Corp	DHR	$160,880	0.32%	0.48%	2.00%	0.0016%	0.0065%
Walt Disney Co/The	DIS	$204,464	0.41%	0.88%	31.00%	0.0036%	0.1275%
Digital Realty Trust Inc	DLR	$54,354	0.11%	2.98%	-5.00%	0.0033%	-0.0055%
Dollar Tree Inc	DLTR	$15,773	0.03%	N/A	20.00%	N/A	0.0063%
Healthpeak Properties Inc	DOC	$14,450	0.03%	5.81%	7.00%	0.0017%	0.0020%
Dover Corp	DOV	$27,943	0.06%	1.01%	5.00%	0.0006%	0.0028%
Dow Inc	DOW	n/a	N/A	7.17%	N/A	N/A	N/A
Domino's Pizza Inc	DPZ	$15,509	0.03%	1.34%	12.50%	0.0004%	0.0039%
Darden Restaurants Inc	DRI	$22,872	0.05%	2.87%	10.00%	0.0013%	0.0046%
DTE Energy Co	DTE	$24,806	0.05%	3.64%	4.50%	0.0018%	0.0022%
Duke Energy Corp	DUK	$86,344	0.17%	3.73%	6.00%	0.0065%	0.0104%
DaVita Inc	DVA	$14,448	0.03%	N/A	9.50%	N/A	0.0028%
Devon Energy Corp	DVN	$22,400	0.05%	2.58%	3.50%	0.0012%	0.0016%
Dexcom Inc	DXCM	n/a	N/A	N/A	N/A	N/A	N/A
Electronic Arts Inc	EA	$32,236	0.06%	0.62%	14.00%	0.0004%	0.0091%
eBay Inc	EBAY	$32,323	0.07%	1.60%	11.50%	0.0010%	0.0075%
Ecolab Inc	ECL	$70,844	0.14%	1.04%	12.00%	0.0015%	0.0171%
Consolidated Edison Inc	ED	$32,473	0.07%	3.63%	6.00%	0.0024%	0.0039%
Equifax Inc	EFX	$34,060	0.07%	0.57%	7.00%	0.0004%	0.0048%
Everest Group Ltd	EG	$14,935	0.03%	2.30%	14.50%	0.0007%	0.0044%
Edison International	EIX	$20,906	0.04%	6.13%	6.50%	0.0026%	0.0027%
Estee Lauder Cos Inc/The	EL	$19,476	0.04%	1.68%	3.50%	0.0007%	0.0014%
Elevance Health Inc	ELV	$91,772	0.18%	1.73%	11.00%	0.0032%	0.0203%
Eastman Chemical Co	EMN	$11,551	0.02%	3.33%	3.50%	0.0008%	0.0008%
Emerson Electric Co	EMR	$74,011	0.15%	1.62%	12.50%	0.0024%	0.0186%
Enphase Energy Inc	ENPH	$8,414	0.02%	N/A	14.00%	N/A	0.0024%
EOG Resources Inc	EOG	$70,751	0.14%	3.10%	7.50%	0.0044%	0.0107%
EPAM Systems Inc	EPAM	$14,405	0.03%	N/A	20.50%	N/A	0.0059%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Equinix Inc	EQIX	$88,157	0.18%	1.87%	15.00%	0.0033%	0.0266%
Equity Residential	EQR	$26,799	0.05%	3.82%	-4.00%	0.0021%	-0.0022%
EQT Corp	EQT	n/a	N/A	1.23%	N/A	N/A	N/A
Erie Indemnity Co	ERIE	$18,612	0.04%	1.36%	20.00%	0.0005%	0.0075%
Eversource Energy	ES	$21,134	0.04%	5.22%	5.50%	0.0022%	0.0023%
Essex Property Trust Inc	ESS	$18,289	0.04%	3.44%	4.00%	0.0013%	0.0015%
Eaton Corp PLC	ETN	$129,009	0.26%	1.15%	11.00%	0.0030%	0.0285%
Entergy Corp	ETR	$34,768	0.07%	2.96%	0.50%	0.0021%	0.0003%
Evergy Inc	EVRG	$14,743	0.03%	4.16%	7.50%	0.0012%	0.0022%
Edwards Lifesciences Corp	EW	$42,731	0.09%	N/A	6.50%	N/A	0.0056%
Exelon Corp	EXC	n/a	N/A	3.80%	N/A	N/A	N/A
Expeditors International of Washingtc	EXPD	$15,898	0.03%	1.29%	-1.50%	0.0004%	-0.0005%
Expedia Group Inc	EXPE	$20,997	0.04%	N/A	39.00%	N/A	0.0165%
Extra Space Storage Inc	EXR	$32,645	0.07%	4.21%	5.00%	0.0028%	0.0033%
Ford Motor Co	F	$39,347	0.08%	5.95%	17.00%	0.0047%	0.0135%
Diamondback Energy Inc	FANG	$47,991	0.10%	2.19%	2.50%	0.0021%	0.0024%
Fastenal Co	FAST	$41,958	0.08%	2.35%	9.00%	0.0020%	0.0076%
Freeport-McMoRan Inc	FCX	$51,514	0.10%	1.67%	11.00%	0.0017%	0.0114%
FactSet Research Systems Inc	FDS	$18,042	0.04%	0.88%	11.00%	0.0003%	0.0040%
FedEx Corp	FDX	$63,794	0.13%	2.08%	3.50%	0.0027%	0.0045%
FirstEnergy Corp	FE	$22,937	0.05%	4.27%	5.50%	0.0020%	0.0025%
F5 Inc	FFIV	$17,246	0.03%	N/A	10.00%	N/A	0.0035%
Fiserv Inc	FI	$122,909	0.25%	N/A	9.50%	N/A	0.0235%
Fair Isaac Corp	FICO	$45,795	0.09%	N/A	17.00%	N/A	0.0157%
Fidelity National Information Services	FIS	$43,860	0.09%	1.96%	4.50%	0.0017%	0.0040%
Fifth Third Bancorp	FITB	$29,712	0.06%	3.34%	4.50%	0.0020%	0.0027%
FMC Corp	FMC	$6,963	0.01%	4.16%	3.50%	0.0006%	0.0005%
Fox Corp	FOX	n/a	N/A	1.11%	N/A	N/A	N/A
Fox Corp	FOXA	$11,319	0.02%	1.06%	8.50%	0.0002%	0.0019%
Federal Realty Investment Trust	FRT	$9,230	0.02%	4.05%	2.50%	0.0008%	0.0005%
First Solar Inc	FSLR	$17,934	0.04%	N/A	34.50%	N/A	0.0124%
Fortinet Inc	FTNT	$77,320	0.16%	N/A	18.00%	N/A	0.0280%
Fortive Corp	FTV	$28,217	0.06%	0.39%	10.50%	0.0002%	0.0060%
General Dynamics Corp	GD	$70,661	0.14%	2.21%	10.50%	0.0031%	0.0149%
GoDaddy Inc	GDDY	$29,854	0.06%	N/A	27.00%	N/A	0.0162%
General Electric Co	GE	$220,323	0.44%	0.55%	23.00%	0.0024%	0.1019%
GE HealthCare Technologies Inc	GEHC	n/a	N/A	0.16%	N/A	N/A	N/A
Gen Digital Inc	GEN	$16,585	0.03%	1.86%	10.50%	0.0006%	0.0035%
GE Vernova Inc	GEV	n/a	N/A	0.27%	N/A	N/A	N/A
Gilead Sciences Inc	GILD	$121,137	0.24%	3.17%	2.50%	0.0077%	0.0061%
General Mills Inc	GIS	$33,151	0.07%	3.99%	4.50%	0.0027%	0.0030%
Globe Life Inc	GL	$10,249	0.02%	0.79%	11.00%	0.0002%	0.0023%
Corning Inc	GLW	$44,591	0.09%	2.15%	17.50%	0.0019%	0.0157%
General Motors Co	GM	$49,213	0.10%	0.97%	7.50%	0.0010%	0.0074%
Generac Holdings Inc	GNRC	$8,885	0.02%	N/A	12.50%	N/A	0.0022%
Alphabet Inc	GOOG	$1,137,790	2.29%	0.39%	13.50%	0.0089%	0.3090%
Alphabet Inc	GOOGL	n/a	N/A	0.39%	N/A	N/A	N/A
Genuine Parts Co	GPC	$16,163	0.03%	3.44%	3.50%	0.0011%	0.0011%
Global Payments Inc	GPN	$28,720	0.06%	0.89%	13.50%	0.0005%	0.0078%
Garmin Ltd	GRMN	$41,449	0.08%	1.39%	8.00%	0.0012%	0.0067%
Goldman Sachs Group Inc/The	GS	$198,812	0.40%	1.87%	7.50%	0.0075%	0.0300%
WW Grainger Inc	GWW	$51,752	0.10%	0.77%	7.50%	0.0008%	0.0078%
Halliburton Co	HAL	$22,859	0.05%	2.61%	16.00%	0.0012%	0.0074%
Hasbro Inc	HAS	$8,069	0.02%	4.84%	8.50%	0.0008%	0.0014%
Huntington Bancshares Inc/OH	HBAN	$24,988	0.05%	3.60%	7.50%	0.0018%	0.0038%
HCA Healthcare Inc	HCA	$83,565	0.17%	0.87%	10.50%	0.0015%	0.0177%
Home Depot Inc/The	HD	$409,246	0.82%	2.18%	6.50%	0.0180%	0.0535%
Hess Corp	HES	$42,838	0.09%	1.44%	8.00%	0.0012%	0.0069%
Hartford Financial Services Group Inc	HIG	$32,337	0.07%	1.86%	7.00%	0.0012%	0.0046%
Huntington Ingalls Industries Inc	HII	$7,719	0.02%	2.74%	10.00%	0.0004%	0.0016%
Hilton Worldwide Holdings Inc	HLT	n/a	N/A	0.23%	N/A	N/A	N/A
Hologic Inc	HOLX	$16,284	0.03%	N/A	2.00%	N/A	0.0007%
Honeywell International Inc	HON	$145,473	0.29%	2.02%	11.00%	0.0059%	0.0322%
Hewlett Packard Enterprise Co	HPE	$27,872	0.06%	2.45%	7.50%	0.0014%	0.0042%
HP Inc	HPQ	$30,478	0.06%	3.56%	12.50%	0.0022%	0.0077%
Hormel Foods Corp	HRL	$16,459	0.03%	3.87%	6.00%	0.0013%	0.0020%
Henry Schein Inc	HSIC	$9,975	0.02%	N/A	8.00%	N/A	0.0016%
Host Hotels & Resorts Inc	HST	$11,681	0.02%	4.79%	15.00%	0.0011%	0.0035%
Hershey Co/The	HSY	$22,050	0.04%	3.67%	7.00%	0.0016%	0.0031%
Hubbell Inc	HUBB	$22,703	0.05%	1.25%	9.50%	0.0006%	0.0043%
Humana Inc	HUM	$35,308	0.07%	1.21%	0.50%	0.0009%	0.0004%
Howmet Aerospace Inc	HWM	$51,424	0.10%	0.32%	12.00%	0.0003%	0.0124%
International Business Machines Corp	IBM	$236,432	0.48%	2.61%	3.00%	0.0124%	0.0143%
Intercontinental Exchange Inc	ICE	$91,771	0.18%	1.13%	7.50%	0.0021%	0.0138%
IDEXX Laboratories Inc	IDXX	$34,559	0.07%	N/A	10.50%	N/A	0.0073%
IDEX Corp	IEX	$16,985	0.03%	1.23%	5.00%	0.0004%	0.0017%
International Flavors & Fragrances In	IFF	$22,267	0.04%	1.84%	0.50%	0.0008%	0.0002%
Incyte Corp	INCY	$14,287	0.03%	N/A	18.50%	N/A	0.0053%
Intel Corp	INTC	$84,132	0.17%	N/A	-2.00%	N/A	-0.0034%
Intuit Inc	INTU	$168,373	0.34%	0.69%	13.50%	0.0023%	0.0457%
Invitation Homes Inc	INVH	$19,083	0.04%	3.72%	7.50%	0.0014%	0.0029%
International Paper Co	IP	$19,326	0.04%	3.33%	5.50%	0.0013%	0.0021%
Interpublic Group of Cos Inc/The	IPG	$10,684	0.02%	4.60%	8.50%	0.0010%	0.0018%
IQVIA Holdings Inc	IQV	$36,547	0.07%	N/A	11.00%	N/A	0.0081%
Ingersoll Rand Inc	IR	$37,803	0.08%	0.09%	10.50%	0.0001%	0.0080%
Iron Mountain Inc	IRM	$29,807	0.06%	2.82%	8.00%	0.0017%	0.0048%
Intuitive Surgical Inc	ISRG	$203,965	0.41%	N/A	14.00%	N/A	0.0574%
Gartner Inc	IT	$41,871	0.08%	N/A	8.00%	N/A	0.0067%
Illinois Tool Works Inc	ITW	$76,530	0.15%	2.32%	9.00%	0.0036%	0.0139%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Invesco Ltd	IVZ	$8,643	0.02%	4.26%	10.50%	0.0007%	0.0018%
Jacobs Solutions Inc	J	$17,379	0.03%	0.91%	11.00%	0.0003%	0.0038%
JB Hunt Transport Services Inc	JBHT	$17,264	0.03%	1.03%	6.00%	0.0004%	0.0021%
Jabil Inc	JBL	$17,732	0.04%	0.20%	13.50%	0.0001%	0.0048%
Johnson Controls International plc	JCI	$51,491	0.10%	1.90%	13.00%	0.0020%	0.0135%
Jack Henry & Associates Inc	JKHY	$12,701	0.03%	1.26%	6.50%	0.0003%	0.0017%
Johnson & Johnson	JNJ	$366,320	0.74%	3.26%	3.00%	0.0240%	0.0221%
Juniper Networks Inc	JNPR	$11,542	0.02%	2.52%	6.50%	0.0006%	0.0015%
JPMorgan Chase & Co	JPM	$752,540	1.51%	1.87%	7.00%	0.0283%	0.1060%
Kellanova	K	$28,172	0.06%	2.79%	2.50%	0.0016%	0.0014%
Keurig Dr Pepper Inc	KDP	$43,542	0.09%	2.87%	9.50%	0.0025%	0.0083%
KeyCorp	KEY	$19,900	0.04%	4.56%	-2.00%	0.0018%	-0.0008%
Keysight Technologies Inc	KEYS	$30,838	0.06%	N/A	5.50%	N/A	0.0034%
Kraft Heinz Co/The	KHC	$36,082	0.07%	5.36%	4.50%	0.0039%	0.0033%
Kimco Realty Corp	KIM	$15,134	0.03%	4.45%	18.00%	0.0014%	0.0055%
KKR & Co Inc	KKR	$148,396	0.30%	0.42%	5.00%	0.0013%	0.0149%
KLA Corp	KLAC	$98,102	0.20%	0.92%	13.00%	0.0018%	0.0257%
Kimberly-Clark Corp	KMB	$43,343	0.09%	3.88%	7.50%	0.0034%	0.0065%
Kinder Morgan Inc	KMI	$61,051	0.12%	4.18%	10.00%	0.0051%	0.0123%
CarMax Inc	KMX	$13,171	0.03%	N/A	3.00%	N/A	0.0008%
Coca-Cola Co/The	KO	$273,459	0.55%	3.06%	7.00%	0.0168%	0.0385%
Kroger Co/The	KR	$44,603	0.09%	2.08%	5.00%	0.0019%	0.0045%
Kenvue Inc	KVUE	n/a	N/A	3.85%	N/A	N/A	N/A
Loews Corp	L	$18,609	0.04%	0.29%	15.50%	0.0001%	0.0058%
Leidos Holdings Inc	LDOS	$18,952	0.04%	1.13%	10.00%	0.0004%	0.0038%
Lennar Corp	LEN	$30,646	0.06%	1.52%	6.00%	0.0009%	0.0037%
Labcorp Holdings Inc	LH	$20,893	0.04%	1.15%	1.00%	0.0005%	0.0004%
L3Harris Technologies Inc	LHX	$40,212	0.08%	2.19%	11.00%	0.0018%	0.0089%
Lennox International Inc	LII	$21,104	0.04%	0.78%	12.50%	0.0003%	0.0053%
Linde PLC	LIN	$212,424	0.43%	1.25%	8.00%	0.0053%	0.0342%
LKQ Corp	LKQ	$9,720	0.02%	3.21%	7.00%	0.0006%	0.0014%
Eli Lilly & Co	LLY	$769,971	1.55%	0.74%	28.50%	0.0115%	0.4415%
Lockheed Martin Corp	LMT	$108,972	0.22%	2.85%	9.50%	0.0063%	0.0208%
Alliant Energy Corp	LNT	$15,109	0.03%	3.45%	6.00%	0.0010%	0.0018%
Lowe's Cos Inc	LOW	$146,832	0.30%	1.77%	5.50%	0.0052%	0.0162%
Lam Research Corp	LRCX	$104,041	0.21%	1.14%	12.50%	0.0024%	0.0262%
Lululemon Athletica Inc	LULU	$48,324	0.10%	N/A	13.00%	N/A	0.0126%
Southwest Airlines Co	LUV	n/a	N/A	2.34%	N/A	N/A	N/A
Las Vegas Sands Corp	LVS	n/a	N/A	2.18%	N/A	N/A	N/A
Lamb Weston Holdings Inc	LW	$8,550	0.02%	2.47%	10.50%	0.0004%	0.0018%
LyondellBasell Industries NV	LYB	$24,584	0.05%	7.08%	-2.50%	0.0035%	-0.0012%
Live Nation Entertainment Inc	LYV	n/a	N/A	N/A	N/A	N/A	N/A
Mastercard Inc	MA	$505,868	1.02%	0.55%	14.50%	0.0056%	0.1476%
Mid-America Apartment Communities	MAA	$17,834	0.04%	3.97%	-15.00%	0.0014%	-0.0054%
Marriott International Inc/MD	MAR	$80,753	0.16%	0.87%	11.00%	0.0014%	0.0179%
Masco Corp	MAS	$17,105	0.03%	1.46%	9.50%	0.0005%	0.0033%
McDonald's Corp	MCD	$206,888	0.42%	2.45%	8.50%	0.0102%	0.0354%
Microchip Technology Inc	MCHP	$29,160	0.06%	3.35%	1.50%	0.0020%	0.0009%
McKesson Corp	MCK	$75,498	0.15%	0.48%	10.00%	0.0007%	0.0152%
Moody's Corp	MCO	$90,499	0.18%	0.68%	9.00%	0.0012%	0.0164%
Mondelez International Inc	MDLZ	$77,544	0.16%	3.24%	7.50%	0.0051%	0.0117%
Medtronic PLC	MDT	$116,457	0.23%	3.08%	6.00%	0.0072%	0.0141%
MetLife Inc	MET	$59,901	0.12%	2.52%	7.50%	0.0030%	0.0090%
Meta Platforms Inc	META	$1,509,234	3.04%	0.29%	19.00%	0.0088%	0.5769%
MGM Resorts International	MGM	$10,266	0.02%	N/A	25.00%	N/A	0.0052%
Mohawk Industries Inc	MHK	$7,720	0.02%	N/A	1.00%	N/A	0.0002%
McCormick & Co Inc/MD	MKC	$19,502	0.04%	2.33%	4.50%	0.0009%	0.0018%
MarketAxess Holdings Inc	MKTX	$8,319	0.02%	1.34%	9.00%	0.0002%	0.0015%
Martin Marietta Materials Inc	MLM	$33,256	0.07%	0.58%	11.00%	0.0004%	0.0074%
Marsh & McLennan Cos Inc	MMC	$106,514	0.21%	1.50%	12.50%	0.0032%	0.0268%
3M Co	MMM	$82,882	0.17%	1.84%	31.00%	0.0031%	0.0517%
Monster Beverage Corp	MNST	$47,371	0.10%	N/A	11.50%	N/A	0.0110%
Altria Group Inc	MO	$88,520	0.18%	7.81%	6.00%	0.0139%	0.0107%
Molina Healthcare Inc	MOH	$17,755	0.04%	N/A	12.00%	N/A	0.0043%
Mosaic Co/The	MOS	$8,859	0.02%	3.16%	-11.00%	0.0006%	-0.0020%
Marathon Petroleum Corp	MPC	$46,830	0.09%	2.50%	-6.00%	0.0024%	-0.0057%
Monolithic Power Systems Inc	MPWR	$31,091	0.06%	0.78%	12.00%	0.0005%	0.0075%
Merck & Co Inc	MRK	$249,979	0.50%	3.28%	15.50%	0.0165%	0.0780%
Moderna Inc	MRNA	$15,170	0.03%	N/A	-18.50%	N/A	-0.0056%
Morgan Stanley	MS	$223,016	0.45%	2.67%	9.50%	0.0120%	0.0426%
MSCI Inc	MSCI	$46,770	0.09%	1.21%	10.00%	0.0011%	0.0094%
Microsoft Corp	MSFT	$3,085,549	6.21%	0.80%	14.50%	0.0497%	0.9001%
Motorola Solutions Inc	MSI	$78,421	0.16%	0.93%	10.00%	0.0015%	0.0158%
M&T Bank Corp	MTB	n/a	N/A	2.68%	N/A	N/A	N/A
Match Group Inc	MTCH	$8,964	0.02%	2.13%	11.00%	0.0004%	0.0020%
Mettler-Toledo International Inc	MTD	$28,793	0.06%	N/A	9.50%	N/A	0.0055%
Micron Technology Inc	MU	$101,657	0.20%	0.50%	47.50%	0.0010%	0.0971%
Norwegian Cruise Line Holdings Ltd	NCLH	n/a	N/A	N/A	N/A	N/A	N/A
Nasdaq Inc	NDAQ	$47,326	0.10%	1.17%	3.50%	0.0011%	0.0033%
Nordson Corp	NDSN	$12,572	0.03%	1.42%	10.50%	0.0004%	0.0027%
NextEra Energy Inc	NEE	$147,156	0.30%	2.88%	8.50%	0.0085%	0.0252%
Newmont Corp	NEM	$48,635	0.10%	2.34%	13.00%	0.0023%	0.0127%
Netflix Inc	NFLX	$417,816	0.84%	N/A	16.50%	N/A	0.1387%
NiSource Inc	NI	$17,411	0.04%	3.00%	9.50%	0.0011%	0.0033%
NIKE Inc	NKE	$90,837	0.18%	2.08%	10.50%	0.0038%	0.0192%
Northrop Grumman Corp	NOC	$70,535	0.14%	1.69%	8.00%	0.0024%	0.0114%
ServiceNow Inc	NOW	$209,786	0.42%	N/A	32.50%	N/A	0.1372%
NRG Energy Inc	NRG	$20,751	0.04%	1.72%	11.00%	0.0007%	0.0046%
Norfolk Southern Corp	NSC	$57,759	0.12%	2.12%	11.50%	0.0025%	0.0134%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
NetApp Inc	NTAP	$24,824	0.05%	1.70%	9.00%	0.0009%	0.0045%
Northern Trust Corp	NTRS	$22,258	0.04%	2.67%	6.00%	0.0012%	0.0027%
Nucor Corp	NUE	n/a	N/A	1.71%	N/A	N/A	N/A
NVIDIA Corp	NVDA	$2,940,514	5.92%	0.03%	41.00%	0.0020%	2.4255%
NVR Inc	NVR	$24,561	0.05%	N/A	1.50%	N/A	0.0007%
News Corp	NWS	n/a	N/A	0.63%	N/A	N/A	N/A
News Corp	NWSA	$10,655	0.02%	0.71%	14.50%	0.0002%	0.0031%
NXP Semiconductors NV	NXPI	$53,004	0.11%	1.94%	7.50%	0.0021%	0.0080%
Realty Income Corp	O	$47,822	0.10%	5.80%	5.00%	0.0056%	0.0048%
Old Dominion Freight Line Inc	ODFL	$39,627	0.08%	0.56%	7.00%	0.0004%	0.0056%
ONEOK Inc	OKE	$56,765	0.11%	4.24%	12.00%	0.0048%	0.0137%
Omnicom Group Inc	OMC	$16,932	0.03%	3.23%	7.00%	0.0011%	0.0024%
ON Semiconductor Corp	ON	$22,286	0.04%	N/A	7.00%	N/A	0.0031%
Oracle Corp	ORCL	$475,650	0.96%	0.94%	10.00%	0.0090%	0.0957%
O'Reilly Automotive Inc	ORLY	$74,728	0.15%	N/A	10.50%	N/A	0.0158%
Otis Worldwide Corp	OTIS	$38,117	0.08%	1.63%	11.00%	0.0013%	0.0084%
Occidental Petroleum Corp	OXY	$43,774	0.09%	1.89%	6.00%	0.0017%	0.0053%
Palo Alto Networks Inc	PANW	n/a	N/A	N/A	N/A	N/A	N/A
Paramount Global	PARA	$6,814	0.01%	1.84%	3.00%	0.0003%	0.0004%
Paycom Software Inc	PAYC	$11,968	0.02%	0.72%	14.00%	0.0002%	0.0034%
Paychex Inc	PAYX	$53,171	0.11%	2.65%	8.00%	0.0028%	0.0086%
PACCAR Inc	PCAR	$58,134	0.12%	1.19%	14.50%	0.0014%	0.0170%
PG&E Corp	PCG	$34,214	0.07%	0.64%	9.00%	0.0004%	0.0062%
Public Service Enterprise Group Inc	PEG	$41,622	0.08%	2.87%	6.00%	0.0024%	0.0050%
PepsiCo Inc	PEP	$206,745	0.42%	3.60%	7.50%	0.0150%	0.0312%
Pfizer Inc	PFE	$150,289	0.30%	6.49%	2.50%	0.0196%	0.0076%
Principal Financial Group Inc	PFG	$18,858	0.04%	3.54%	4.00%	0.0013%	0.0015%
Procter & Gamble Co/The	PG	$389,222	0.78%	2.43%	5.00%	0.0190%	0.0392%
Progressive Corp/The	PGR	$144,367	0.29%	0.16%	22.50%	0.0005%	0.0653%
Parker-Hannifin Corp	PH	$91,043	0.18%	0.92%	12.50%	0.0017%	0.0229%
PulteGroup Inc	PHM	$23,334	0.05%	0.77%	8.00%	0.0004%	0.0038%
Packaging Corp of America	PKG	$19,098	0.04%	2.35%	9.00%	0.0009%	0.0035%
Prologis Inc	PLD	$110,446	0.22%	3.22%	0.50%	0.0072%	0.0011%
Palantir Technologies Inc	PLTR	n/a	N/A	N/A	N/A	N/A	N/A
Philip Morris International Inc	PM	$202,439	0.41%	4.15%	5.00%	0.0169%	0.0204%
PNC Financial Services Group Inc/Th	PNC	$79,734	0.16%	3.18%	6.50%	0.0051%	0.0104%
Pentair PLC	PNR	$17,131	0.03%	0.96%	12.00%	0.0003%	0.0041%
Pinnacle West Capital Corp	PNW	$9,887	0.02%	4.12%	4.00%	0.0008%	0.0008%
Insulet Corp	PODD	n/a	N/A	N/A	N/A	N/A	N/A
Pool Corp	POOL	$13,101	0.03%	1.39%	0.50%	0.0004%	0.0001%
PPG Industries Inc	PPG	$26,768	0.05%	2.36%	5.00%	0.0013%	0.0027%
PPL Corp	PPL	$24,796	0.05%	3.07%	7.50%	0.0015%	0.0037%
Prudential Financial Inc	PRU	$42,991	0.09%	4.31%	4.00%	0.0037%	0.0035%
Public Storage	PSA	$52,444	0.11%	4.02%	7.00%	0.0042%	0.0074%
Phillips 66	PSX	$48,679	0.10%	3.90%	0.50%	0.0038%	0.0005%
PTC Inc	PTC	$23,286	0.05%	N/A	29.00%	N/A	0.0136%
Quanta Services Inc	PWR	$45,407	0.09%	0.13%	18.00%	0.0001%	0.0164%
PayPal Holdings Inc	PYPL	$88,805	0.18%	N/A	11.50%	N/A	0.0205%
QUALCOMM Inc	QCOM	$191,155	0.38%	1.97%	6.00%	0.0076%	0.0231%
Royal Caribbean Cruises Ltd	RCL	n/a	N/A	0.83%	N/A	N/A	N/A
Regency Centers Corp	REG	$13,039	0.03%	3.93%	11.50%	0.0010%	0.0030%
Regeneron Pharmaceuticals Inc	REGN	$72,731	0.15%	N/A	1.50%	N/A	0.0022%
Regions Financial Corp	RF	$22,394	0.05%	4.06%	4.50%	0.0018%	0.0020%
Raymond James Financial Inc	RJF	$34,430	0.07%	1.19%	10.00%	0.0008%	0.0069%
Ralph Lauren Corp	RL	$10,042	0.02%	1.32%	12.00%	0.0003%	0.0024%
ResMed Inc	RMD	$34,687	0.07%	0.90%	11.00%	0.0006%	0.0077%
Rockwell Automation Inc	ROK	$31,436	0.06%	1.88%	9.50%	0.0012%	0.0060%
Rollins Inc	ROL	$23,973	0.05%	1.33%	9.00%	0.0006%	0.0043%
Roper Technologies Inc	ROP	$61,726	0.12%	0.57%	9.00%	0.0007%	0.0112%
Ross Stores Inc	ROST	$49,674	0.10%	0.98%	9.50%	0.0010%	0.0095%
Republic Services Inc	RSG	$67,913	0.14%	1.07%	11.00%	0.0015%	0.0150%
RTX Corp	RTX	$171,635	0.35%	1.95%	12.00%	0.0067%	0.0414%
Revvity Inc	RVTY	$15,350	0.03%	0.22%	-1.50%	0.0001%	-0.0005%
SBA Communications Corp	SBAC	$21,242	0.04%	1.98%	19.00%	0.0008%	0.0081%
Starbucks Corp	SBUX	$122,314	0.25%	2.27%	6.00%	0.0056%	0.0148%
Charles Schwab Corp/The	SCHW	$147,214	0.30%	1.31%	10.50%	0.0039%	0.0311%
Sherwin-Williams Co/The	SHW	$90,204	0.18%	0.80%	12.00%	0.0014%	0.0218%
J M Smucker Co/The	SJM	$11,375	0.02%	4.04%	6.50%	0.0009%	0.0015%
Schlumberger NV	SLB	$56,426	0.11%	2.83%	18.00%	0.0032%	0.0204%
Super Micro Computer Inc	SMCI	$16,700	0.03%	N/A	39.00%	N/A	0.0131%
Snap-on Inc	SNA	$18,648	0.04%	2.41%	5.50%	0.0009%	0.0021%
Synopsys Inc	SNPS	$81,228	0.16%	N/A	12.00%	N/A	0.0196%
Southern Co/The	SO	$91,894	0.18%	3.43%	6.50%	0.0063%	0.0120%
Solventum Corp	SOLV	n/a	N/A	N/A	N/A	N/A	N/A
Simon Property Group Inc	SPG	$56,725	0.11%	4.83%	3.50%	0.0055%	0.0040%
S&P Global Inc	SPGI	$165,548	0.33%	0.74%	8.00%	0.0025%	0.0266%
Sempra	SRE	$52,528	0.11%	2.99%	6.00%	0.0032%	0.0063%
STERIS PLC	STE	$21,780	0.04%	1.03%	8.00%	0.0005%	0.0035%
Steel Dynamics Inc	STLD	$19,518	0.04%	1.44%	2.00%	0.0006%	0.0008%
State Street Corp	STT	n/a	N/A	2.99%	N/A	N/A	N/A
Seagate Technology Holdings PLC	STX	$20,400	0.04%	2.99%	31.00%	0.0012%	0.0127%
Constellation Brands Inc	STZ	$32,671	0.07%	2.23%	7.50%	0.0015%	0.0049%
Smurfit WestRock PLC	SW	n/a	N/A	3.25%	N/A	N/A	N/A
Stanley Black & Decker Inc	SWK	$13,577	0.03%	3.72%	11.00%	0.0010%	0.0030%
Skyworks Solutions Inc	SWKS	n/a	N/A	3.15%	N/A	N/A	N/A
Synchrony Financial	SYF	$26,857	0.05%	1.45%	47.00%	0.0008%	0.0254%
Stryker Corp	SYK	$149,166	0.30%	0.86%	9.50%	0.0026%	0.0285%
Sysco Corp	SYY	$35,675	0.07%	2.80%	9.50%	0.0020%	0.0068%
AT&T Inc	T	$170,270	0.34%	4.68%	4.00%	0.0160%	0.0137%

Company	Ticker	[4] Market Capitalization Excluding No Growth Rate ($ mill)	[5] Weight in Index	[6] Dividend Yield	[7] Long-Term Growth Est.	[8] Weighted Dividend Yield	[9] Weighted Long-Term Growth Rate
Molson Coors Beverage Co	TAP	$10,598	0.02%	3.21%	11.50%	0.0007%	0.0025%
TransDigm Group Inc	TDG	$75,841	0.15%	N/A	20.00%	N/A	0.0305%
Teledyne Technologies Inc	TDY	$23,829	0.05%	N/A	7.00%	N/A	0.0034%
Bio-Techne Corp	TECH	$11,686	0.02%	0.44%	11.00%	0.0001%	0.0026%
TE Connectivity PLC	TEL	$44,147	0.09%	1.76%	10.50%	0.0016%	0.0093%
Teradyne Inc	TER	$18,858	0.04%	0.41%	10.50%	0.0002%	0.0040%
Truist Financial Corp	TFC	$63,217	0.13%	4.37%	1.50%	0.0056%	0.0019%
Teleflex Inc	TFX	$8,371	0.02%	0.75%	8.50%	0.0001%	0.0014%
Target Corp	TGT	$63,192	0.13%	3.25%	8.00%	0.0041%	0.0102%
TJX Cos Inc/The	TJX	$140,284	0.28%	1.20%	12.50%	0.0034%	0.0353%
Thermo Fisher Scientific Inc	TMO	$228,640	0.46%	0.26%	6.00%	0.0012%	0.0276%
T-Mobile US Inc	TMUS	$265,992	0.54%	1.51%	20.00%	0.0081%	0.1070%
Texas Pacific Land Corp	TPL	$29,802	0.06%	0.49%	10.50%	0.0003%	0.0063%
Tapestry Inc	TPR	$16,998	0.03%	1.92%	9.00%	0.0007%	0.0031%
Targa Resources Corp	TRGP	$42,915	0.09%	1.52%	21.00%	0.0013%	0.0181%
Trimble Inc	TRMB	$18,425	0.04%	N/A	6.00%	N/A	0.0022%
T Rowe Price Group Inc	TROW	$25,975	0.05%	4.24%	5.50%	0.0022%	0.0029%
Travelers Cos Inc/The	TRV	$55,661	0.11%	1.71%	12.00%	0.0019%	0.0134%
Tractor Supply Co	TSCO	$29,039	0.06%	1.62%	10.50%	0.0009%	0.0061%
Tesla Inc	TSLA	$1,301,403	2.62%	N/A	16.50%	N/A	0.4320%
Tyson Foods Inc	TSN	$16,165	0.03%	3.54%	6.00%	0.0012%	0.0020%
Trane Technologies PLC	TT	$81,627	0.16%	0.93%	14.00%	0.0015%	0.0230%
Take-Two Interactive Software Inc	TTWO	n/a	N/A	N/A	N/A	N/A	N/A
Texas Instruments Inc	TXN	$168,404	0.34%	2.95%	3.00%	0.0100%	0.0102%
Textron Inc	TXT	$14,193	0.03%	0.10%	13.00%	0.0000%	0.0037%
Tyler Technologies Inc	TYL	$25,749	0.05%	N/A	8.00%	N/A	0.0041%
United Airlines Holdings Inc	UAL	n/a	N/A	N/A	N/A	N/A	N/A
Uber Technologies Inc	UBER	n/a	N/A	N/A	N/A	N/A	N/A
UDR Inc	UDR	$13,773	0.03%	4.07%	1.50%	0.0011%	0.0004%
Universal Health Services Inc	UHS	$11,071	0.02%	0.42%	12.00%	0.0001%	0.0027%
Ulta Beauty Inc	ULTA	$19,112	0.04%	N/A	6.00%	N/A	0.0023%
UnitedHealth Group Inc	UNH	$499,245	1.00%	1.55%	11.50%	0.0156%	0.1155%
Union Pacific Corp	UNP	$150,224	0.30%	2.16%	8.00%	0.0065%	0.0242%
United Parcel Service Inc	UPS	$83,544	0.17%	5.71%	3.50%	0.0096%	0.0059%
United Rentals Inc	URI	$49,507	0.10%	0.94%	19.00%	0.0009%	0.0189%
US Bancorp	USB	$74,538	0.15%	4.19%	4.00%	0.0063%	0.0060%
Visa Inc	V	$589,045	1.19%	0.69%	13.50%	0.0082%	0.1600%
VICI Properties Inc	VICI	$31,054	0.06%	5.81%	10.50%	0.0036%	0.0066%
Valero Energy Corp	VLO	$42,106	0.08%	3.40%	-6.00%	0.0029%	-0.0051%
Veralto Corp	VLTO	$25,569	0.05%	0.43%	6.00%	0.0002%	0.0031%
Vulcan Materials Co	VMC	$36,205	0.07%	0.67%	8.00%	0.0005%	0.0058%
Verisk Analytics Inc	VRSK	$40,590	0.08%	0.54%	11.00%	0.0004%	0.0090%
VeriSign Inc	VRSN	$20,662	0.04%	N/A	12.00%	N/A	0.0050%
Vertex Pharmaceuticals Inc	VRTX	$118,896	0.24%	N/A	11.00%	N/A	0.0263%
Vistra Corp	VST	n/a	N/A	0.53%	N/A	N/A	N/A
Ventas Inc	VTR	$25,337	0.05%	2.98%	23.00%	0.0015%	0.0117%
Viatris Inc	VTRS	$13,464	0.03%	4.26%	-1.50%	0.0012%	-0.0004%
Verizon Communications Inc	VZ	$165,817	0.33%	6.88%	0.50%	0.0230%	0.0017%
Westinghouse Air Brake Technologie	WAB	$35,739	0.07%	0.38%	16.00%	0.0003%	0.0115%
Waters Corp	WAT	$24,670	0.05%	N/A	6.50%	N/A	0.0032%
Walgreens Boots Alliance Inc	WBA	$8,883	0.02%	N/A	-13.00%	N/A	-0.0023%
Warner Bros Discovery Inc	WBD	n/a	N/A	N/A	N/A	N/A	N/A
Workday Inc	WDAY	$56,081	0.11%	N/A	15.50%	N/A	0.0175%
Western Digital Corp	WDC	$22,654	0.05%	N/A	22.50%	N/A	0.0103%
WEC Energy Group Inc	WEC	$31,401	0.06%	3.60%	6.00%	0.0023%	0.0038%
Welltower Inc	WELL	$84,985	0.17%	1.96%	27.50%	0.0034%	0.0470%
Wells Fargo & Co	WFC	$262,364	0.53%	2.03%	9.50%	0.0107%	0.0501%
Waste Management Inc	WM	$88,405	0.18%	1.36%	8.50%	0.0024%	0.0151%
Williams Cos Inc/The	WMB	$67,570	0.14%	3.61%	10.00%	0.0049%	0.0136%
Walmart Inc	WMT	$788,557	1.59%	0.85%	9.50%	0.0134%	0.1507%
W R Berkley Corp	WRB	$22,418	0.05%	0.54%	13.00%	0.0002%	0.0059%
West Pharmaceutical Services Inc	WST	$24,736	0.05%	0.25%	7.50%	0.0001%	0.0037%
Willis Towers Watson PLC	WTW	$33,196	0.07%	1.07%	9.50%	0.0007%	0.0063%
Weyerhaeuser Co	WY	$22,248	0.04%	2.61%	-2.00%	0.0012%	-0.0009%
Wynn Resorts Ltd	WYNN	$9,537	0.02%	1.15%	27.00%	0.0002%	0.0052%
Xcel Energy Inc	XEL	$40,005	0.08%	3.26%	6.50%	0.0026%	0.0052%
Exxon Mobil Corp	XOM	$469,528	0.94%	3.71%	-3.00%	0.0350%	-0.0283%
Xylem Inc/NY	XYL	$30,135	0.06%	1.16%	12.00%	0.0007%	0.0073%
Yum! Brands Inc	YUM	$36,419	0.07%	2.05%	10.00%	0.0015%	0.0073%
Zimmer Biomet Holdings Inc	ZBH	$21,795	0.04%	0.88%	6.50%	0.0004%	0.0029%
Zebra Technologies Corp	ZBRA	$20,216	0.04%	N/A	1.00%	N/A	0.0004%
Zoetis Inc	ZTS	$77,104	0.16%	1.17%	7.50%	0.0018%	0.0116%
		$49,706,613					

[4] Bloomberg Financial as of January 31, 2025
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional as of January 31, 2025
[7] Source: Value Line as of January 31, 2025
[8] Equals [5] x [6]
[9] Equals [5] x [7]

Ex Ante Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Expected and Historical Market Return

Company	Ticker	[1] Current 30-Year Treasury Yield	[2] Bloomberg Beta Coefficient	[3] Value Line Beta Coefficient	[4] Average Beta Coefficient	[5] DCF Expected Market Return	[6] Long-Term Average Historical Market Return (1926-2024)	[7] Market Risk Premium	[8] Traditional CAPM	[9] Empirical CAPM
Atmos Energy Corporation	ATO	4.82%	0.83	0.90	0.86	15.29%	12.17%	8.91%	12.51%	12.81%
New Jersey Resources Corporation	NJR	4.82%	0.84	1.00	0.92	15.29%	12.17%	8.91%	13.01%	13.19%
NiSource Inc.	NI	4.82%	0.88	0.95	0.91	15.29%	12.17%	8.91%	12.95%	13.15%
Northwest Natural Gas Company	NWN	4.82%	0.75	0.85	0.80	15.29%	12.17%	8.91%	11.97%	12.41%
ONE Gas, Inc.	OGS	4.82%	0.83	0.85	0.84	15.29%	12.17%	8.91%	12.31%	12.66%
Southwest Gas Corporation	SWX	4.82%	0.92	0.95	0.93	15.29%	12.17%	8.91%	13.15%	13.29%
Spire, Inc.	SR	4.82%	0.84	0.90	0.87	15.29%	12.17%	8.91%	12.59%	12.87%
Enbridge Inc	ENB.TO	4.82%	0.92	0.85	0.88	15.29%	12.17%	8.91%	12.69%	12.95%
Energy Transfer LP	ET	4.82%	0.92	1.10	1.01	15.29%	12.17%	8.91%	13.80%	13.78%
Enterprise Products Partners LP	EPD	4.82%	0.78	1.00	0.89	15.29%	12.17%	8.91%	12.74%	12.99%
Kinder Morgan Inc	KMI	4.82%	0.94	1.10	1.02	15.29%	12.17%	8.91%	13.90%	13.85%
MPLX LP	MPLX	4.82%	0.77	0.95	0.86	15.29%	12.17%	8.91%	12.48%	12.79%
TC Energy Corp.	TRP	4.82%	0.84	1.05	0.95	15.29%	12.17%	8.91%	13.25%	13.37%
The Williams Companies, Inc	WMB	4.82%	1.01	1.10	1.05	15.29%	12.17%	8.91%	14.22%	14.10%
								Mean:	12.97%	13.16%
								Median:	12.85%	13.07%
								Average of the Mean and Median:	12.91%	13.11%

Company	Ticker	[10] Projected 30-Year Treasury Yield	[11] Bloomberg Beta Coefficient	[12] Value Line Beta Coefficient	[13] Average Beta Coefficient	[14] DCF Expected Market Return	[15] Long-Term Average Historical Market Return (1926-2024)	[16] Market Risk Premium	[17] Traditional CAPM	[18] Empirical CAPM
Atmos Energy Corporation	ATO	4.46%	0.83	0.90	0.86	15.29%	12.17%	9.27%	12.46%	12.78%
New Jersey Resources Corporation	NJR	4.46%	0.84	1.00	0.92	15.29%	12.17%	9.27%	12.98%	13.16%
NiSource Inc.	NI	4.46%	0.88	0.95	0.91	15.29%	12.17%	9.27%	12.92%	13.13%
Northwest Natural Gas Company	NWN	4.46%	0.75	0.85	0.80	15.29%	12.17%	9.27%	11.90%	12.36%
ONE Gas, Inc.	OGS	4.46%	0.83	0.85	0.84	15.29%	12.17%	9.27%	12.25%	12.62%
Southwest Gas Corporation	SWX	4.46%	0.92	0.95	0.93	15.29%	12.17%	9.27%	13.13%	13.28%
Spire, Inc.	SR	4.46%	0.84	0.90	0.87	15.29%	12.17%	9.27%	12.54%	12.84%
Enbridge Inc	ENB.TO	4.46%	0.92	0.85	0.88	15.29%	12.17%	9.27%	12.64%	12.92%
Energy Transfer LP	ET	4.46%	0.92	1.10	1.01	15.29%	12.17%	9.27%	13.80%	13.79%
Enterprise Products Partners LP	EPD	4.46%	0.78	1.00	0.89	15.29%	12.17%	9.27%	12.70%	12.96%
Kinder Morgan Inc	KMI	4.46%	0.94	1.10	1.02	15.29%	12.17%	9.27%	13.90%	13.86%
MPLX LP	MPLX	4.46%	0.77	0.95	0.86	15.29%	12.17%	9.27%	12.43%	12.75%
TC Energy Corp.	TRP	4.46%	0.84	1.05	0.95	15.29%	12.17%	9.27%	13.23%	13.35%
The Williams Companies, Inc	WMB	4.46%	1.01	1.10	1.05	15.29%	12.17%	9.27%	14.24%	14.11%
								Mean:	12.94%	13.14%
								Median:	12.81%	13.04%
								Average of the Mean and Median:	12.87%	13.09%

Notes:
[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Source: JEN-4; Value Line DCF-based expected market return
[6] Kroll, Cost of Capital Navigator as of December 31, 2024.
[7] Equals (Col. [5] + Col. [6]) /2 - Col. [1]
[8] Equals Col. [1] + (Col. [4] x Col. [7])
[9] Equals Col. [1] + (0.75 x Col. [4] x Col. [7]) + (0.25 x Col. [7])
[10] Source: Blue Chip Financial Forecasts, Vol. 43, No.12, November 27, 2024 at 14 and Vol. 44, No. 2, January 31, 2025 at 2
[11] See Note [2]
[12] See Note [3]
[13] Equals Average of Col. [11] and Col. [12]
[14] See Note [5]
[15] See Note [6]
[16] Equals (Col. [15] + Col. [16]) /2 - Col. [9]
[17] Equals Col. [10] + (Col. [13] x Col. [16])
[18] Equals Col. [10] + (0.75 x Col. [13] x Col. [16]) + (0.25 x Col. [16])

Ex Ante Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Expected Market Return

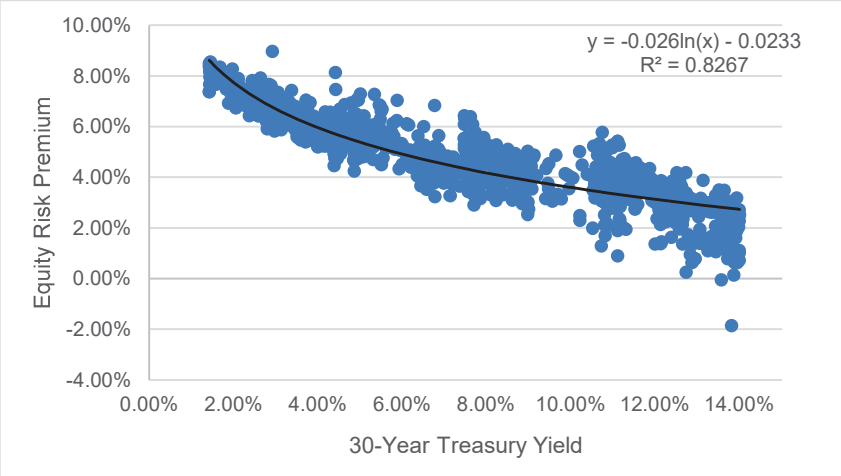
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Current 30-Year Treasury Yield	Bloomberg Beta Coefficient	Value Line Beta Coefficient	Average Beta Coefficient	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.82%	0.83	0.90	0.86	15.29%	10.47%	13.85%	14.21%
New Jersey Resources Corporation	NJR	4.82%	0.84	1.00	0.92	15.29%	10.47%	14.44%	14.65%
NiSource Inc.	NI	4.82%	0.88	0.95	0.91	15.29%	10.47%	14.38%	14.61%
Northwest Natural Gas Company	NWN	4.82%	0.75	0.85	0.80	15.29%	10.47%	13.22%	13.74%
ONE Gas, Inc.	OGS	4.82%	0.83	0.85	0.84	15.29%	10.47%	13.62%	14.04%
Southwest Gas Corporation	SWX	4.82%	0.92	0.95	0.93	15.29%	10.47%	14.61%	14.78%
Spire, Inc.	SR	4.82%	0.84	0.90	0.87	15.29%	10.47%	13.95%	14.28%
Enbridge Inc	ENB.TO	4.82%	0.92	0.85	0.88	15.29%	10.47%	14.06%	14.37%
Energy Transfer LP	ET	4.82%	0.92	1.10	1.01	15.29%	10.47%	15.37%	15.35%
Enterprise Products Partners LP	EPD	4.82%	0.78	1.00	0.89	15.29%	10.47%	14.13%	14.42%
Kinder Morgan Inc	KMI	4.82%	0.94	1.10	1.02	15.29%	10.47%	15.49%	15.44%
MPLX LP	MPLX	4.82%	0.77	0.95	0.86	15.29%	10.47%	13.82%	14.19%
TC Energy Corp.	TRP	4.82%	0.84	1.05	0.95	15.29%	10.47%	14.72%	14.87%
The Williams Companies, Inc	WMB	4.82%	1.01	1.10	1.05	15.29%	10.47%	15.87%	15.72%
							Mean:	14.40%	14.62%
							Median:	14.26%	14.51%
							Average of the Mean and Median:	14.33%	14.57%

		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30-Year Treasury Yield	Bloomberg Beta Coefficient	Value Line Beta Coefficient	Average Beta Coefficient	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.46%	0.83	0.90	0.86	15.29%	10.83%	13.80%	14.18%
New Jersey Resources Corporation	NJR	4.46%	0.84	1.00	0.92	15.29%	10.83%	14.41%	14.63%
NiSource Inc.	NI	4.46%	0.88	0.95	0.91	15.29%	10.83%	14.35%	14.58%
Northwest Natural Gas Company	NWN	4.46%	0.75	0.85	0.80	15.29%	10.83%	13.15%	13.69%
ONE Gas, Inc.	OGS	4.46%	0.83	0.85	0.84	15.29%	10.83%	13.56%	13.99%
Southwest Gas Corporation	SWX	4.46%	0.92	0.95	0.93	15.29%	10.83%	14.58%	14.76%
Spire, Inc.	SR	4.46%	0.84	0.90	0.87	15.29%	10.83%	13.90%	14.25%
Enbridge Inc	ENB.TO	4.46%	0.92	0.85	0.88	15.29%	10.83%	14.02%	14.34%
Energy Transfer LP	ET	4.46%	0.92	1.10	1.01	15.29%	10.83%	15.38%	15.36%
Enterprise Products Partners LP	EPD	4.46%	0.78	1.00	0.89	15.29%	10.83%	14.09%	14.39%
Kinder Morgan Inc	KMI	4.46%	0.94	1.10	1.02	15.29%	10.83%	15.49%	15.44%
MPLX LP	MPLX	4.46%	0.77	0.95	0.86	15.29%	10.83%	13.77%	14.15%
TC Energy Corp.	TRP	4.46%	0.84	1.05	0.95	15.29%	10.83%	14.70%	14.85%
The Williams Companies, Inc	WMB	4.46%	1.01	1.10	1.05	15.29%	10.83%	15.89%	15.74%
							Mean:	14.36%	14.60%
							Median:	14.22%	14.49%
							Average of the Mean and Median:	14.29%	14.54%

Notes:
[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Source: JEN-4; Value Line DCF-based expected market return
[6] Equals Col. [5] - Col. [1]
[7] Equals Col. [1] + (Col. [4] x Col. [6])
[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])
[9] Source: Blue Chip Financial Forecasts, Vol. 43, No.12, November 27, 2024 at 14 and Vol. 44, No. 2, January 31, 2025 at 2
[10] See Note [2]
[11] See Note [3]
[12] Equals Average of Col. [10] and Col. [11]
[13] See Note [5]
[14] Equals Col. [13] - Col. [9]
[15] Equals Col. [9] + (Col. [12] x Col. [14])
[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Bond Yield Plus Risk Premium

[1]	[2]	[3]	[4]	[5]	[6]
Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity	Alaska Risk Premium
-2.33%	-2.57%				
Current 30-Year Treasury		4.82%	5.47%	10.30%	12.52%
Projected 30-Year Treasury		4.46%	5.67%	10.13%	12.35%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Bloomberg Professional,
Projected = Average of near-term and long-term projected 30-year Treasury yield from
Blue Chip Financial Forecasts, Vol. 44, No. 2, January 31, 2025 at 2
Blue Chip Financial Forecasts, Vol. 43, No.12, November 27, 2024 at 14
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Equals [5] + 222 basis point Alaska Premium
[7] Source: S&P Capital IQ
[8] Source: Bloomberg Professional, equals 188-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/3/1980	12.55%	9.39%	3.16%
1/4/1980	13.75%	9.40%	4.35%
1/14/1980	13.20%	9.44%	3.76%
1/18/1980	14.00%	9.47%	4.53%
1/31/1980	12.61%	9.56%	3.05%
2/8/1980	14.50%	9.63%	4.87%
2/14/1980	13.00%	9.67%	3.33%
2/15/1980	13.00%	9.69%	3.31%
2/29/1980	14.00%	9.86%	4.14%
3/5/1980	14.00%	9.91%	4.09%
3/7/1980	13.50%	9.95%	3.55%
3/14/1980	14.00%	10.04%	3.96%
3/27/1980	12.69%	10.20%	2.49%
4/1/1980	14.75%	10.26%	4.49%
4/29/1980	12.50%	10.51%	1.99%
5/7/1980	14.27%	10.56%	3.71%
5/8/1980	13.75%	10.56%	3.19%
5/19/1980	15.50%	10.62%	4.88%
5/27/1980	14.60%	10.65%	3.95%
5/29/1980	16.00%	10.67%	5.33%
6/10/1980	13.78%	10.71%	3.07%
6/25/1980	14.25%	10.74%	3.51%
7/9/1980	14.51%	10.77%	3.74%
7/17/1980	12.90%	10.79%	2.11%
7/18/1980	13.80%	10.79%	3.01%
7/22/1980	14.10%	10.79%	3.31%
7/23/1980	14.19%	10.79%	3.40%
8/1/1980	12.50%	10.80%	1.70%
8/11/1980	14.85%	10.81%	4.04%
8/21/1980	13.03%	10.84%	2.19%
8/28/1980	13.61%	10.87%	2.74%
8/28/1980	14.00%	10.87%	3.13%
9/4/1980	14.00%	10.90%	3.10%
9/24/1980	15.00%	10.98%	4.02%
10/9/1980	14.50%	11.05%	3.45%
10/9/1980	14.50%	11.05%	3.45%
10/24/1980	14.00%	11.09%	2.91%
10/27/1980	15.20%	11.10%	4.10%
10/27/1980	15.20%	11.10%	4.10%
10/28/1980	12.00%	11.10%	0.90%
10/28/1980	13.00%	11.10%	1.90%
10/31/1980	14.50%	11.12%	3.38%
11/4/1980	15.00%	11.12%	3.88%
11/6/1980	14.35%	11.13%	3.22%
11/10/1980	13.25%	11.14%	2.11%
11/17/1980	15.50%	11.15%	4.35%
11/19/1980	13.50%	11.14%	2.36%
12/5/1980	14.60%	11.13%	3.47%
12/8/1980	16.40%	11.13%	5.27%
12/12/1980	15.45%	11.15%	4.30%
12/17/1980	14.20%	11.16%	3.04%
12/17/1980	14.40%	11.16%	3.24%
12/18/1980	14.00%	11.16%	2.84%
12/22/1980	13.45%	11.16%	2.29%
12/26/1980	14.00%	11.15%	2.85%
12/30/1980	14.50%	11.14%	3.36%
12/31/1980	14.56%	11.14%	3.42%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/7/1981	14.30%	11.13%	3.17%
1/12/1981	14.95%	11.14%	3.81%
1/26/1981	15.25%	11.20%	4.05%
1/30/1981	13.25%	11.23%	2.02%
2/11/1981	14.50%	11.33%	3.17%
2/20/1981	14.50%	11.40%	3.10%
3/12/1981	15.65%	11.60%	4.05%
3/25/1981	15.30%	11.74%	3.56%
4/1/1981	15.30%	11.82%	3.48%
4/9/1981	15.00%	11.91%	3.09%
4/29/1981	13.50%	12.12%	1.38%
4/29/1981	14.25%	12.12%	2.13%
4/30/1981	13.60%	12.14%	1.46%
4/30/1981	15.00%	12.14%	2.86%
5/21/1981	14.00%	12.37%	1.63%
6/3/1981	14.67%	12.46%	2.21%
6/22/1981	16.00%	12.57%	3.43%
6/25/1981	14.75%	12.60%	2.15%
7/2/1981	14.00%	12.64%	1.36%
7/10/1981	16.00%	12.69%	3.31%
7/14/1981	16.90%	12.71%	4.19%
7/21/1981	15.78%	12.78%	3.00%
7/27/1981	13.77%	12.82%	0.95%
7/27/1981	15.50%	12.82%	2.68%
7/31/1981	13.50%	12.86%	0.64%
7/31/1981	14.20%	12.86%	1.34%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	14.41%	12.93%	1.48%
8/25/1981	15.45%	13.02%	2.43%
8/27/1981	14.43%	13.04%	1.39%
8/28/1981	15.00%	13.05%	1.95%
9/23/1981	14.34%	13.24%	1.10%
9/24/1981	16.25%	13.26%	2.99%
9/29/1981	14.50%	13.31%	1.19%
9/30/1981	15.94%	13.32%	2.62%
10/2/1981	14.80%	13.36%	1.44%
10/12/1981	16.25%	13.43%	2.82%
10/20/1981	15.25%	13.50%	1.75%
10/20/1981	16.50%	13.50%	3.00%
10/20/1981	17.00%	13.50%	3.50%
10/23/1981	15.50%	13.54%	1.96%
10/26/1981	13.50%	13.56%	-0.06%
10/29/1981	16.50%	13.60%	2.90%
11/4/1981	15.33%	13.62%	1.71%
11/6/1981	15.17%	13.64%	1.53%
11/12/1981	15.00%	13.65%	1.35%
11/25/1981	15.25%	13.66%	1.59%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	16.10%	13.66%	2.44%
11/30/1981	16.75%	13.66%	3.09%
12/1/1981	15.70%	13.66%	2.04%
12/1/1981	16.00%	13.66%	2.34%
12/15/1981	15.81%	13.69%	2.12%
12/17/1981	14.75%	13.70%	1.05%
12/22/1981	15.70%	13.72%	1.98%
12/22/1981	16.00%	13.72%	2.28%
12/30/1981	16.00%	13.74%	2.26%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/30/1981	16.25%	13.74%	2.51%
1/4/1982	15.50%	13.75%	1.75%
1/14/1982	11.95%	13.80%	-1.85%
1/25/1982	16.25%	13.84%	2.41%
1/27/1982	16.84%	13.85%	2.99%
1/31/1982	14.00%	13.86%	0.14%
2/2/1982	16.24%	13.86%	2.38%
2/8/1982	15.50%	13.87%	1.63%
2/9/1982	14.95%	13.88%	1.07%
2/9/1982	15.75%	13.88%	1.87%
2/11/1982	16.00%	13.89%	2.11%
3/1/1982	15.96%	13.91%	2.05%
3/3/1982	15.00%	13.91%	1.09%
3/8/1982	17.10%	13.92%	3.18%
3/26/1982	16.00%	13.97%	2.03%
3/31/1982	16.25%	13.98%	2.27%
4/1/1982	16.50%	13.98%	2.52%
4/6/1982	15.00%	13.99%	1.01%
4/9/1982	16.50%	13.99%	2.51%
4/12/1982	15.10%	13.99%	1.11%
4/12/1982	16.70%	13.99%	2.71%
4/18/1982	14.70%	13.99%	0.71%
4/27/1982	15.00%	13.97%	1.03%
5/10/1982	14.57%	13.94%	0.63%
5/14/1982	15.80%	13.92%	1.88%
5/20/1982	15.82%	13.91%	1.91%
5/21/1982	15.50%	13.90%	1.60%
5/25/1982	16.25%	13.90%	2.35%
6/2/1982	14.50%	13.87%	0.63%
6/7/1982	16.00%	13.85%	2.15%
6/23/1982	15.50%	13.81%	1.69%
6/25/1982	16.50%	13.81%	2.69%
7/1/1982	15.55%	13.79%	1.76%
7/1/1982	16.00%	13.79%	2.21%
7/2/1982	15.10%	13.79%	1.31%
7/13/1982	16.80%	13.75%	3.05%
7/22/1982	14.50%	13.71%	0.79%
7/28/1982	16.10%	13.68%	2.42%
7/30/1982	14.82%	13.66%	1.16%
8/4/1982	15.58%	13.64%	1.94%
8/6/1982	16.50%	13.63%	2.87%
8/11/1982	17.11%	13.62%	3.49%
8/25/1982	16.00%	13.59%	2.41%
8/30/1982	16.25%	13.58%	2.67%
9/3/1982	15.50%	13.57%	1.93%
9/9/1982	16.04%	13.55%	2.49%
9/15/1982	16.04%	13.52%	2.52%
9/17/1982	15.25%	13.51%	1.74%
9/29/1982	14.50%	13.43%	1.07%
9/30/1982	14.74%	13.42%	1.32%
9/30/1982	15.50%	13.42%	2.08%
9/30/1982	16.50%	13.42%	3.08%
9/30/1982	16.70%	13.42%	3.28%
10/1/1982	16.50%	13.41%	3.09%
10/8/1982	15.00%	13.33%	1.67%
10/15/1982	15.90%	13.26%	2.64%
10/19/1982	15.90%	13.22%	2.68%
10/27/1982	17.00%	13.12%	3.88%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/28/1982	14.75%	13.11%	1.64%
11/2/1982	16.25%	13.07%	3.18%
11/4/1982	15.75%	13.03%	2.72%
11/5/1982	14.73%	13.01%	1.72%
11/17/1982	16.00%	12.86%	3.14%
11/23/1982	15.50%	12.79%	2.71%
11/24/1982	14.50%	12.77%	1.73%
11/24/1982	16.02%	12.77%	3.25%
11/30/1982	12.98%	12.72%	0.26%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	15.65%	12.72%	2.93%
11/30/1982	16.00%	12.72%	3.28%
11/30/1982	16.10%	12.72%	3.38%
12/3/1982	15.33%	12.68%	2.65%
12/8/1982	15.75%	12.63%	3.12%
12/13/1982	16.00%	12.58%	3.42%
12/14/1982	16.40%	12.57%	3.83%
12/17/1982	16.25%	12.52%	3.73%
12/20/1982	15.00%	12.51%	2.49%
12/21/1982	15.70%	12.49%	3.21%
12/28/1982	15.25%	12.42%	2.83%
12/28/1982	15.25%	12.42%	2.83%
12/29/1982	16.25%	12.41%	3.84%
12/29/1982	16.25%	12.41%	3.84%
1/11/1983	15.90%	12.26%	3.64%
1/12/1983	15.50%	12.24%	3.26%
1/18/1983	15.00%	12.18%	2.82%
1/24/1983	15.50%	12.13%	3.37%
1/24/1983	16.00%	12.13%	3.87%
1/28/1983	14.90%	12.08%	2.82%
1/31/1983	15.00%	12.07%	2.93%
2/10/1983	15.00%	11.97%	3.03%
2/25/1983	15.70%	11.84%	3.86%
3/2/1983	15.25%	11.79%	3.46%
3/16/1983	16.00%	11.62%	4.38%
3/21/1983	14.96%	11.57%	3.39%
3/23/1983	15.40%	11.53%	3.87%
3/23/1983	16.10%	11.53%	4.57%
3/24/1983	15.00%	11.51%	3.49%
4/12/1983	13.25%	11.30%	1.95%
4/29/1983	15.05%	11.09%	3.96%
5/3/1983	15.40%	11.06%	4.34%
5/9/1983	15.50%	11.00%	4.50%
5/19/1983	14.85%	10.90%	3.95%
5/31/1983	14.00%	10.84%	3.16%
6/2/1983	14.50%	10.82%	3.68%
6/7/1983	14.50%	10.80%	3.70%
6/9/1983	14.85%	10.79%	4.06%
6/20/1983	14.15%	10.74%	3.41%
6/20/1983	16.50%	10.74%	5.76%
6/27/1983	14.50%	10.71%	3.79%
6/30/1983	14.80%	10.70%	4.10%
6/30/1983	15.90%	10.70%	5.20%
7/1/1983	14.80%	10.70%	4.10%
7/5/1983	15.00%	10.69%	4.31%
7/8/1983	15.50%	10.69%	4.81%
7/19/1983	15.00%	10.70%	4.30%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/19/1983	15.10%	10.70%	4.40%
8/18/1983	15.30%	10.81%	4.49%
8/19/1983	15.79%	10.82%	4.97%
8/29/1983	16.00%	10.85%	5.15%
8/31/1983	14.75%	10.87%	3.88%
8/31/1983	15.25%	10.87%	4.38%
9/8/1983	14.75%	10.89%	3.86%
9/16/1983	15.51%	10.93%	4.58%
9/26/1983	14.50%	10.96%	3.54%
9/28/1983	14.25%	10.97%	3.28%
9/30/1983	16.15%	10.98%	5.17%
9/30/1983	16.25%	10.98%	5.27%
10/1/1983	16.25%	10.98%	5.27%
10/13/1983	15.52%	11.02%	4.50%
10/19/1983	15.20%	11.04%	4.16%
10/26/1983	14.75%	11.06%	3.69%
10/27/1983	14.88%	11.07%	3.81%
10/27/1983	15.33%	11.07%	4.26%
11/9/1983	14.82%	11.10%	3.72%
11/9/1983	16.51%	11.10%	5.41%
11/9/1983	16.51%	11.10%	5.41%
12/1/1983	14.50%	11.17%	3.33%
12/8/1983	15.90%	11.20%	4.70%
12/9/1983	15.30%	11.21%	4.09%
12/12/1983	14.50%	11.22%	3.28%
12/12/1983	15.50%	11.22%	4.28%
12/20/1983	15.40%	11.26%	4.14%
12/20/1983	16.00%	11.26%	4.74%
12/22/1983	15.75%	11.27%	4.48%
12/29/1983	15.00%	11.30%	3.70%
12/30/1983	15.00%	11.30%	3.70%
1/10/1984	15.90%	11.34%	4.56%
1/13/1984	15.50%	11.36%	4.14%
1/18/1984	15.53%	11.38%	4.15%
1/26/1984	15.90%	11.42%	4.48%
2/14/1984	14.25%	11.51%	2.74%
2/28/1984	14.50%	11.58%	2.92%
3/20/1984	16.00%	11.70%	4.30%
3/23/1984	15.50%	11.72%	3.78%
4/9/1984	15.20%	11.81%	3.39%
4/18/1984	16.20%	11.86%	4.34%
4/27/1984	15.85%	11.90%	3.95%
5/15/1984	13.35%	11.99%	1.36%
5/16/1984	15.00%	12.00%	3.00%
5/22/1984	14.40%	12.04%	2.36%
6/13/1984	15.50%	12.18%	3.32%
7/10/1984	16.00%	12.37%	3.63%
8/7/1984	16.69%	12.51%	4.18%
8/9/1984	15.33%	12.51%	2.82%
8/17/1984	14.82%	12.54%	2.28%
8/21/1984	14.64%	12.54%	2.10%
8/27/1984	14.52%	12.56%	1.96%
8/28/1984	14.75%	12.57%	2.18%
8/30/1984	15.60%	12.58%	3.02%
9/12/1984	15.60%	12.60%	3.00%
9/12/1984	15.90%	12.60%	3.30%
9/25/1984	16.25%	12.61%	3.64%
10/2/1984	14.80%	12.62%	2.18%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/9/1984	14.75%	12.63%	2.12%
10/10/1984	15.50%	12.63%	2.87%
10/18/1984	15.00%	12.65%	2.35%
10/24/1984	15.50%	12.65%	2.85%
11/7/1984	15.00%	12.64%	2.36%
11/20/1984	15.92%	12.63%	3.29%
11/30/1984	15.50%	12.60%	2.90%
12/18/1984	15.00%	12.55%	2.45%
12/20/1984	15.00%	12.54%	2.46%
12/28/1984	15.75%	12.51%	3.24%
12/28/1984	16.25%	12.51%	3.74%
1/2/1985	16.00%	12.50%	3.50%
1/31/1985	14.75%	12.37%	2.38%
2/7/1985	14.85%	12.33%	2.52%
2/15/1985	15.00%	12.27%	2.73%
2/20/1985	14.50%	12.25%	2.25%
2/22/1985	14.86%	12.25%	2.61%
3/14/1985	15.50%	12.16%	3.34%
3/28/1985	14.80%	12.08%	2.72%
4/9/1985	15.50%	12.02%	3.48%
4/16/1985	15.70%	11.96%	3.74%
6/10/1985	15.75%	11.58%	4.17%
6/26/1985	14.82%	11.46%	3.36%
7/9/1985	15.00%	11.38%	3.62%
7/26/1985	14.50%	11.26%	3.24%
8/29/1985	14.50%	11.11%	3.39%
8/30/1985	14.38%	11.11%	3.27%
9/12/1985	15.25%	11.07%	4.18%
9/23/1985	15.30%	11.03%	4.27%
9/25/1985	14.50%	11.02%	3.48%
9/26/1985	13.80%	11.02%	2.78%
9/26/1985	14.50%	11.02%	3.48%
10/25/1985	15.25%	10.91%	4.34%
11/8/1985	12.94%	10.85%	2.09%
11/20/1985	14.90%	10.81%	4.09%
11/25/1985	13.30%	10.79%	2.51%
12/6/1985	12.00%	10.71%	1.29%
12/11/1985	14.90%	10.68%	4.22%
12/20/1985	14.88%	10.59%	4.29%
12/20/1985	15.00%	10.59%	4.41%
12/20/1985	15.00%	10.59%	4.41%
12/30/1985	15.75%	10.53%	5.22%
12/31/1985	14.00%	10.51%	3.49%
12/31/1985	14.50%	10.51%	3.99%
1/17/1986	14.50%	10.38%	4.12%
2/11/1986	12.50%	10.20%	2.30%
2/12/1986	15.20%	10.19%	5.01%
3/11/1986	14.00%	9.98%	4.02%
4/2/1986	12.90%	9.76%	3.14%
4/28/1986	13.01%	9.47%	3.54%
5/21/1986	13.25%	9.18%	4.07%
5/28/1986	14.00%	9.12%	4.88%
5/29/1986	13.90%	9.10%	4.80%
6/2/1986	13.00%	9.08%	3.92%
6/11/1986	14.00%	8.97%	5.03%
6/13/1986	13.55%	8.94%	4.61%
6/27/1986	11.88%	8.77%	3.11%
7/14/1986	12.60%	8.59%	4.01%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/30/1986	13.30%	8.38%	4.92%
8/14/1986	13.50%	8.22%	5.28%
9/5/1986	13.30%	8.02%	5.28%
9/23/1986	12.75%	7.91%	4.84%
10/30/1986	13.00%	7.67%	5.33%
10/31/1986	13.75%	7.66%	6.09%
11/10/1986	14.00%	7.61%	6.39%
11/19/1986	13.75%	7.56%	6.19%
11/25/1986	13.15%	7.54%	5.61%
12/22/1986	13.80%	7.47%	6.33%
12/30/1986	13.90%	7.47%	6.43%
1/20/1987	12.75%	7.47%	5.28%
1/23/1987	13.55%	7.47%	6.08%
1/27/1987	12.16%	7.47%	4.69%
2/13/1987	12.60%	7.47%	5.13%
2/24/1987	12.00%	7.47%	4.53%
3/30/1987	12.20%	7.46%	4.74%
3/31/1987	13.00%	7.47%	5.53%
5/5/1987	12.85%	7.60%	5.25%
5/28/1987	13.50%	7.73%	5.77%
6/15/1987	13.20%	7.80%	5.40%
6/30/1987	12.60%	7.85%	4.75%
7/10/1987	12.90%	7.88%	5.02%
7/27/1987	13.50%	7.93%	5.57%
8/25/1987	11.40%	8.09%	3.31%
9/18/1987	13.00%	8.27%	4.73%
10/20/1987	12.60%	8.55%	4.05%
10/20/1987	12.98%	8.55%	4.43%
11/12/1987	12.75%	8.68%	4.07%
11/13/1987	12.75%	8.68%	4.07%
11/24/1987	12.50%	8.73%	3.77%
12/8/1987	12.50%	8.81%	3.69%
12/22/1987	12.00%	8.90%	3.10%
12/31/1987	12.85%	8.94%	3.91%
12/31/1987	13.25%	8.94%	4.31%
1/15/1988	13.15%	8.99%	4.16%
1/20/1988	12.75%	8.99%	3.76%
1/29/1988	13.20%	8.99%	4.21%
2/4/1988	12.60%	8.99%	3.61%
3/23/1988	13.00%	8.95%	4.05%
5/27/1988	13.18%	9.02%	4.16%
6/14/1988	13.50%	9.00%	4.50%
6/17/1988	11.72%	8.99%	2.73%
6/24/1988	11.50%	8.97%	2.53%
7/1/1988	12.75%	8.95%	3.80%
7/8/1988	12.00%	8.93%	3.07%
7/18/1988	12.00%	8.91%	3.09%
7/20/1988	13.40%	8.90%	4.50%
8/8/1988	12.74%	8.90%	3.84%
9/20/1988	12.90%	8.93%	3.97%
9/26/1988	12.40%	8.93%	3.47%
9/27/1988	13.65%	8.93%	4.72%
9/30/1988	13.25%	8.94%	4.31%
10/13/1988	13.10%	8.93%	4.17%
10/21/1988	12.80%	8.94%	3.86%
10/25/1988	13.25%	8.94%	4.31%
10/26/1988	13.50%	8.94%	4.56%
10/27/1988	12.95%	8.94%	4.01%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/28/1988	13.00%	8.95%	4.05%
11/15/1988	12.00%	8.98%	3.02%
11/29/1988	12.75%	9.01%	3.74%
12/19/1988	13.00%	9.05%	3.95%
12/21/1988	12.90%	9.05%	3.85%
12/22/1988	13.50%	9.05%	4.45%
1/26/1989	12.60%	9.06%	3.54%
1/27/1989	13.00%	9.06%	3.94%
2/8/1989	13.37%	9.05%	4.32%
3/8/1989	13.00%	9.04%	3.96%
5/4/1989	13.00%	9.04%	3.96%
6/8/1989	13.50%	8.96%	4.54%
7/19/1989	11.80%	8.84%	2.96%
7/25/1989	12.80%	8.82%	3.98%
7/31/1989	13.00%	8.81%	4.19%
8/14/1989	12.50%	8.76%	3.74%
8/22/1989	12.80%	8.73%	4.07%
8/23/1989	12.90%	8.72%	4.18%
9/21/1989	12.10%	8.62%	3.48%
10/6/1989	13.00%	8.58%	4.42%
10/17/1989	12.41%	8.54%	3.87%
10/18/1989	13.25%	8.54%	4.71%
10/20/1989	12.90%	8.53%	4.37%
10/31/1989	13.60%	8.50%	5.10%
11/3/1989	12.93%	8.48%	4.45%
11/5/1989	13.20%	8.48%	4.72%
11/9/1989	12.60%	8.45%	4.15%
11/9/1989	13.00%	8.45%	4.55%
11/28/1989	12.75%	8.37%	4.38%
12/7/1989	13.25%	8.32%	4.93%
12/15/1989	13.00%	8.28%	4.72%
12/20/1989	12.90%	8.26%	4.64%
12/21/1989	12.80%	8.25%	4.55%
12/21/1989	12.90%	8.25%	4.65%
12/27/1989	12.50%	8.23%	4.27%
1/9/1990	13.00%	8.19%	4.81%
1/18/1990	12.50%	8.16%	4.34%
1/26/1990	12.10%	8.14%	3.96%
3/21/1990	12.80%	8.15%	4.65%
3/28/1990	13.00%	8.16%	4.84%
4/5/1990	12.20%	8.17%	4.03%
4/12/1990	13.25%	8.19%	5.06%
4/30/1990	12.45%	8.24%	4.21%
5/31/1990	12.40%	8.31%	4.09%
6/15/1990	13.20%	8.33%	4.87%
6/27/1990	12.90%	8.34%	4.56%
6/29/1990	13.25%	8.35%	4.90%
7/6/1990	12.10%	8.36%	3.74%
7/19/1990	11.70%	8.38%	3.32%
8/31/1990	12.50%	8.53%	3.97%
8/31/1990	12.50%	8.53%	3.97%
9/13/1990	12.50%	8.58%	3.92%
9/18/1990	12.75%	8.60%	4.15%
9/20/1990	12.50%	8.61%	3.89%
10/2/1990	13.00%	8.65%	4.35%
10/17/1990	11.90%	8.68%	3.22%
10/31/1990	12.95%	8.70%	4.25%
11/9/1990	13.25%	8.70%	4.55%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/19/1990	13.00%	8.70%	4.30%
11/21/1990	12.10%	8.70%	3.40%
11/21/1990	12.50%	8.70%	3.80%
11/28/1990	12.75%	8.70%	4.05%
11/29/1990	12.75%	8.70%	4.05%
12/18/1990	13.10%	8.68%	4.42%
12/20/1990	12.50%	8.67%	3.83%
12/21/1990	12.50%	8.67%	3.83%
12/21/1990	13.00%	8.67%	4.33%
12/21/1990	13.60%	8.67%	4.93%
1/3/1991	13.02%	8.66%	4.36%
1/16/1991	13.25%	8.63%	4.62%
1/25/1991	11.70%	8.61%	3.09%
2/15/1991	12.70%	8.56%	4.14%
2/15/1991	12.80%	8.56%	4.24%
4/3/1991	13.00%	8.51%	4.49%
4/30/1991	12.45%	8.48%	3.97%
4/30/1991	13.00%	8.48%	4.52%
6/25/1991	11.70%	8.34%	3.36%
6/28/1991	12.50%	8.34%	4.16%
7/1/1991	11.70%	8.34%	3.36%
7/19/1991	12.10%	8.31%	3.79%
7/19/1991	12.30%	8.31%	3.99%
7/22/1991	12.90%	8.30%	4.60%
8/15/1991	12.25%	8.28%	3.97%
8/29/1991	13.30%	8.26%	5.04%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.40%	8.23%	4.17%
10/3/1991	11.30%	8.22%	3.08%
10/9/1991	11.70%	8.21%	3.49%
10/15/1991	13.40%	8.20%	5.20%
11/1/1991	12.90%	8.20%	4.70%
11/8/1991	12.75%	8.20%	4.55%
11/26/1991	11.60%	8.18%	3.42%
11/26/1991	12.00%	8.18%	3.82%
11/27/1991	12.70%	8.18%	4.52%
12/6/1991	12.70%	8.16%	4.54%
12/10/1991	11.75%	8.15%	3.60%
12/19/1991	12.60%	8.14%	4.46%
12/19/1991	12.80%	8.14%	4.66%
12/30/1991	12.10%	8.11%	3.99%
1/22/1992	12.84%	8.05%	4.79%
1/31/1992	12.00%	8.03%	3.97%
2/20/1992	13.00%	8.00%	5.00%
2/27/1992	11.75%	7.98%	3.77%
3/18/1992	12.50%	7.94%	4.56%
5/15/1992	12.75%	7.86%	4.89%
6/24/1992	12.20%	7.85%	4.35%
6/29/1992	11.00%	7.85%	3.15%
7/14/1992	12.00%	7.83%	4.17%
7/22/1992	11.20%	7.82%	3.38%
8/10/1992	12.10%	7.79%	4.31%
8/26/1992	12.43%	7.75%	4.68%
9/30/1992	11.60%	7.72%	3.88%
10/6/1992	12.25%	7.72%	4.53%
10/13/1992	12.75%	7.71%	5.04%
10/23/1992	11.65%	7.71%	3.94%
10/28/1992	12.25%	7.71%	4.54%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/29/1992	12.75%	7.70%	5.05%
10/30/1992	11.40%	7.70%	3.70%
11/9/1992	10.60%	7.70%	2.90%
11/25/1992	11.00%	7.68%	3.32%
11/25/1992	12.00%	7.68%	4.32%
12/3/1992	11.85%	7.66%	4.19%
12/16/1992	11.90%	7.64%	4.26%
12/22/1992	12.30%	7.62%	4.68%
12/22/1992	12.40%	7.62%	4.78%
12/30/1992	12.00%	7.61%	4.39%
12/31/1992	12.00%	7.61%	4.39%
1/12/1993	12.00%	7.59%	4.41%
1/12/1993	12.00%	7.59%	4.41%
2/2/1993	11.40%	7.53%	3.87%
2/22/1993	11.60%	7.48%	4.12%
4/23/1993	11.75%	7.27%	4.48%
5/3/1993	11.50%	7.25%	4.25%
5/3/1993	11.75%	7.25%	4.50%
6/3/1993	12.00%	7.20%	4.80%
6/7/1993	11.50%	7.20%	4.30%
6/22/1993	11.75%	7.16%	4.59%
7/21/1993	11.78%	7.06%	4.72%
7/21/1993	11.90%	7.06%	4.84%
7/23/1993	11.50%	7.05%	4.45%
7/29/1993	11.50%	7.03%	4.47%
8/12/1993	10.75%	6.97%	3.78%
8/24/1993	11.50%	6.92%	4.58%
8/31/1993	11.90%	6.88%	5.02%
9/1/1993	11.25%	6.87%	4.38%
9/1/1993	11.47%	6.87%	4.60%
9/27/1993	10.50%	6.74%	3.76%
9/29/1993	11.00%	6.72%	4.28%
9/30/1993	11.60%	6.72%	4.88%
10/8/1993	11.50%	6.67%	4.83%
10/14/1993	11.20%	6.65%	4.55%
10/15/1993	11.75%	6.64%	5.11%
10/25/1993	11.55%	6.60%	4.95%
10/28/1993	11.50%	6.58%	4.92%
10/29/1993	10.10%	6.57%	3.53%
10/29/1993	10.20%	6.57%	3.63%
10/29/1993	11.25%	6.57%	4.68%
11/2/1993	10.80%	6.56%	4.24%
11/12/1993	11.80%	6.53%	5.27%
11/23/1993	12.50%	6.51%	5.99%
11/26/1993	11.00%	6.50%	4.50%
12/1/1993	11.45%	6.49%	4.96%
12/16/1993	10.60%	6.45%	4.15%
12/16/1993	11.20%	6.45%	4.75%
12/21/1993	11.30%	6.44%	4.86%
12/22/1993	11.00%	6.44%	4.56%
12/23/1993	10.10%	6.44%	3.66%
1/5/1994	11.50%	6.41%	5.09%
1/10/1994	11.00%	6.40%	4.60%
1/25/1994	12.00%	6.37%	5.63%
2/2/1994	10.40%	6.35%	4.05%
2/9/1994	10.70%	6.34%	4.36%
4/6/1994	11.24%	6.35%	4.89%
4/25/1994	11.00%	6.39%	4.61%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/16/1994	10.50%	6.63%	3.87%
6/23/1994	10.60%	6.67%	3.93%
7/19/1994	10.70%	6.83%	3.87%
9/29/1994	10.90%	7.20%	3.70%
9/29/1994	11.00%	7.20%	3.80%
10/7/1994	11.87%	7.26%	4.61%
10/18/1994	11.50%	7.32%	4.18%
10/18/1994	11.50%	7.32%	4.18%
10/24/1994	11.00%	7.35%	3.65%
11/22/1994	12.12%	7.52%	4.60%
11/29/1994	11.30%	7.55%	3.75%
12/1/1994	11.00%	7.56%	3.44%
12/8/1994	11.50%	7.59%	3.91%
12/8/1994	11.70%	7.59%	4.11%
12/12/1994	11.82%	7.60%	4.22%
12/14/1994	11.50%	7.61%	3.89%
12/19/1994	11.50%	7.62%	3.88%
4/19/1995	11.00%	7.72%	3.28%
9/11/1995	11.30%	7.16%	4.14%
9/15/1995	10.40%	7.13%	3.27%
9/29/1995	11.50%	7.06%	4.44%
10/13/1995	10.76%	6.98%	3.78%
11/7/1995	12.50%	6.86%	5.64%
11/8/1995	11.10%	6.85%	4.25%
11/8/1995	11.30%	6.85%	4.45%
11/17/1995	10.90%	6.81%	4.09%
11/20/1995	11.40%	6.80%	4.60%
11/27/1995	13.60%	6.77%	6.83%
12/14/1995	11.30%	6.68%	4.62%
12/20/1995	11.60%	6.65%	4.95%
1/31/1996	11.30%	6.45%	4.85%
3/11/1996	11.60%	6.40%	5.20%
4/3/1996	11.13%	6.41%	4.72%
4/15/1996	10.50%	6.41%	4.09%
4/17/1996	10.77%	6.40%	4.37%
4/26/1996	10.60%	6.40%	4.20%
5/10/1996	11.00%	6.40%	4.60%
5/13/1996	11.25%	6.41%	4.84%
7/3/1996	11.25%	6.49%	4.76%
7/22/1996	11.25%	6.54%	4.71%
10/3/1996	10.00%	6.77%	3.23%
10/29/1996	11.30%	6.84%	4.46%
11/26/1996	11.30%	6.86%	4.44%
11/27/1996	11.30%	6.86%	4.44%
11/29/1996	11.00%	6.86%	4.14%
12/12/1996	11.96%	6.85%	5.11%
12/17/1996	11.50%	6.85%	4.65%
1/22/1997	11.30%	6.83%	4.47%
1/27/1997	11.25%	6.83%	4.42%
1/31/1997	11.25%	6.83%	4.42%
2/13/1997	11.00%	6.82%	4.18%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.81%	4.99%
3/27/1997	10.75%	6.79%	3.96%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
10/29/1997	10.75%	6.70%	4.05%
10/31/1997	11.25%	6.70%	4.55%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/24/1997	10.75%	6.53%	4.22%
4/28/1998	10.90%	6.11%	4.79%
4/30/1998	12.20%	6.10%	6.10%
6/30/1998	11.00%	5.94%	5.06%
8/26/1998	10.93%	5.82%	5.11%
9/3/1998	11.40%	5.80%	5.60%
9/15/1998	11.90%	5.77%	6.13%
10/7/1998	11.06%	5.70%	5.36%
10/30/1998	11.40%	5.63%	5.77%
12/10/1998	12.20%	5.52%	6.68%
12/17/1998	12.10%	5.49%	6.61%
2/19/1999	11.15%	5.32%	5.83%
3/1/1999	10.65%	5.31%	5.34%
3/1/1999	10.65%	5.31%	5.34%
6/8/1999	11.25%	5.35%	5.90%
11/12/1999	10.25%	5.92%	4.33%
12/14/1999	10.50%	5.99%	4.51%
1/28/2000	10.71%	6.16%	4.55%
2/17/2000	10.60%	6.20%	4.40%
5/25/2000	10.80%	6.19%	4.61%
6/19/2000	11.05%	6.18%	4.87%
6/22/2000	11.25%	6.18%	5.07%
7/17/2000	11.06%	6.15%	4.91%
7/20/2000	12.20%	6.14%	6.06%
8/11/2000	11.00%	6.11%	4.89%
9/27/2000	11.25%	6.00%	5.25%
9/29/2000	11.16%	6.00%	5.16%
10/5/2000	11.30%	5.98%	5.32%
11/28/2000	12.90%	5.87%	7.03%
11/30/2000	12.10%	5.86%	6.24%
2/5/2001	11.50%	5.75%	5.75%
3/15/2001	11.25%	5.66%	5.59%
5/8/2001	10.75%	5.61%	5.14%
10/24/2001	10.30%	5.54%	4.76%
10/24/2001	11.00%	5.54%	5.46%
1/9/2002	10.00%	5.50%	4.50%
1/30/2002	11.00%	5.47%	5.53%
1/31/2002	11.00%	5.47%	5.53%
4/17/2002	11.50%	5.44%	6.06%
4/29/2002	11.00%	5.45%	5.55%
6/11/2002	11.77%	5.48%	6.29%
6/20/2002	12.30%	5.48%	6.82%
8/28/2002	11.00%	5.49%	5.51%
9/11/2002	11.20%	5.45%	5.75%
9/12/2002	12.30%	5.45%	6.85%
10/28/2002	11.30%	5.35%	5.95%
10/30/2002	10.60%	5.34%	5.26%
11/1/2002	12.60%	5.34%	7.26%
11/7/2002	11.40%	5.33%	6.07%
11/8/2002	10.75%	5.33%	5.42%
11/20/2002	10.00%	5.30%	4.70%
11/20/2002	10.50%	5.30%	5.20%
12/4/2002	10.75%	5.27%	5.48%
12/30/2002	11.20%	5.19%	6.01%
1/6/2003	11.25%	5.16%	6.09%
2/28/2003	12.30%	5.01%	7.29%
3/7/2003	9.96%	4.99%	4.97%
3/12/2003	11.40%	4.97%	6.43%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
3/20/2003	12.00%	4.95%	7.05%
4/3/2003	12.00%	4.92%	7.08%
5/2/2003	11.40%	4.88%	6.52%
5/15/2003	11.05%	4.87%	6.18%
6/26/2003	11.00%	4.80%	6.20%
7/1/2003	11.00%	4.80%	6.20%
7/29/2003	11.71%	4.78%	6.93%
8/22/2003	10.20%	4.81%	5.39%
9/17/2003	9.90%	4.85%	5.05%
9/25/2003	10.25%	4.85%	5.40%
10/17/2003	10.54%	4.87%	5.67%
10/22/2003	10.46%	4.87%	5.59%
10/22/2003	10.71%	4.87%	5.84%
10/30/2003	11.00%	4.88%	6.12%
10/31/2003	10.20%	4.88%	5.32%
10/31/2003	10.75%	4.88%	5.87%
11/10/2003	10.60%	4.89%	5.71%
12/9/2003	10.50%	4.93%	5.57%
12/18/2003	10.50%	4.94%	5.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
1/13/2004	10.25%	4.95%	5.30%
1/13/2004	12.00%	4.95%	7.05%
2/9/2004	11.25%	4.98%	6.27%
3/16/2004	10.90%	5.05%	5.85%
3/16/2004	10.90%	5.05%	5.85%
5/25/2004	10.00%	5.06%	4.94%
6/2/2004	11.22%	5.07%	6.15%
6/30/2004	10.50%	5.10%	5.40%
7/8/2004	10.00%	5.10%	4.90%
7/22/2004	10.25%	5.10%	5.15%
8/26/2004	10.50%	5.10%	5.40%
8/26/2004	10.50%	5.10%	5.40%
9/9/2004	10.40%	5.10%	5.30%
9/21/2004	10.50%	5.09%	5.41%
9/27/2004	10.30%	5.09%	5.21%
9/27/2004	10.50%	5.09%	5.41%
10/20/2004	10.20%	5.08%	5.12%
11/30/2004	10.60%	5.08%	5.52%
12/8/2004	9.90%	5.09%	4.81%
12/21/2004	11.50%	5.09%	6.41%
12/22/2004	11.50%	5.09%	6.41%
12/28/2004	10.25%	5.09%	5.16%
2/18/2005	10.30%	4.95%	5.35%
3/29/2005	11.00%	4.86%	6.14%
4/13/2005	10.60%	4.84%	5.76%
4/28/2005	11.00%	4.80%	6.20%
5/17/2005	10.00%	4.77%	5.23%
6/8/2005	10.18%	4.71%	5.47%
6/10/2005	10.90%	4.71%	6.19%
7/6/2005	10.50%	4.65%	5.85%
7/19/2005	11.50%	4.63%	6.87%
8/11/2005	10.40%	4.60%	5.80%
9/19/2005	9.45%	4.53%	4.92%
9/30/2005	10.51%	4.52%	5.99%
10/4/2005	9.90%	4.52%	5.38%
10/4/2005	10.75%	4.52%	6.23%
10/14/2005	10.40%	4.52%	5.88%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/31/2005	10.25%	4.53%	5.72%
11/2/2005	9.70%	4.53%	5.17%
11/30/2005	10.00%	4.53%	5.47%
12/9/2005	9.70%	4.53%	5.17%
12/12/2005	11.00%	4.53%	6.47%
12/20/2005	10.13%	4.53%	5.60%
12/21/2005	10.40%	4.52%	5.88%
12/21/2005	11.00%	4.52%	6.48%
12/22/2005	10.20%	4.52%	5.68%
12/22/2005	11.00%	4.52%	6.48%
12/28/2005	10.00%	4.52%	5.48%
1/5/2006	11.00%	4.52%	6.48%
1/25/2006	11.20%	4.52%	6.68%
1/25/2006	11.20%	4.52%	6.68%
2/3/2006	10.50%	4.52%	5.98%
2/15/2006	9.50%	4.53%	4.97%
4/26/2006	10.60%	4.65%	5.95%
7/24/2006	9.60%	4.87%	4.73%
7/24/2006	10.00%	4.87%	5.13%
9/20/2006	11.00%	4.93%	6.07%
9/26/2006	10.75%	4.93%	5.82%
10/20/2006	9.80%	4.96%	4.84%
11/2/2006	9.71%	4.97%	4.74%
11/9/2006	10.00%	4.97%	5.03%
11/21/2006	11.00%	4.98%	6.02%
12/5/2006	10.20%	4.97%	5.23%
1/5/2007	10.40%	4.95%	5.45%
1/9/2007	11.00%	4.94%	6.06%
1/11/2007	10.90%	4.94%	5.96%
1/19/2007	10.80%	4.93%	5.87%
1/26/2007	10.00%	4.92%	5.08%
2/8/2007	10.40%	4.91%	5.49%
3/14/2007	10.10%	4.86%	5.24%
3/20/2007	10.25%	4.84%	5.41%
3/21/2007	11.35%	4.84%	6.51%
3/22/2007	10.50%	4.84%	5.66%
3/29/2007	10.00%	4.83%	5.17%
6/13/2007	10.75%	4.81%	5.94%
6/29/2007	9.53%	4.84%	4.69%
6/29/2007	10.10%	4.84%	5.26%
7/3/2007	10.25%	4.85%	5.40%
7/13/2007	9.50%	4.86%	4.64%
7/24/2007	10.40%	4.87%	5.53%
8/1/2007	10.15%	4.88%	5.27%
8/29/2007	10.50%	4.91%	5.59%
9/10/2007	9.71%	4.91%	4.80%
9/19/2007	10.00%	4.91%	5.09%
9/25/2007	9.70%	4.92%	4.78%
10/8/2007	10.48%	4.92%	5.56%
10/19/2007	10.50%	4.91%	5.59%
10/25/2007	9.65%	4.91%	4.74%
11/15/2007	10.00%	4.89%	5.11%
11/20/2007	9.90%	4.89%	5.01%
11/27/2007	10.00%	4.88%	5.12%
11/29/2007	10.90%	4.88%	6.02%
12/14/2007	10.80%	4.87%	5.93%
12/18/2007	10.40%	4.86%	5.54%
12/19/2007	9.80%	4.86%	4.94%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	10.20%	4.86%	5.34%
12/21/2007	9.10%	4.86%	4.24%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/17/2008	10.75%	4.81%	5.94%
2/5/2008	9.99%	4.78%	5.21%
2/5/2008	10.19%	4.78%	5.41%
2/13/2008	10.20%	4.76%	5.44%
3/31/2008	10.00%	4.63%	5.37%
5/28/2008	10.50%	4.53%	5.97%
6/24/2008	10.00%	4.52%	5.48%
6/27/2008	10.00%	4.52%	5.48%
7/31/2008	10.70%	4.50%	6.20%
7/31/2008	10.82%	4.50%	6.32%
8/27/2008	10.25%	4.50%	5.75%
9/2/2008	10.25%	4.50%	5.75%
9/19/2008	10.70%	4.48%	6.22%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/30/2008	10.20%	4.48%	5.72%
10/3/2008	10.30%	4.48%	5.82%
10/8/2008	10.15%	4.47%	5.68%
10/20/2008	10.06%	4.47%	5.59%
10/24/2008	10.60%	4.46%	6.14%
10/24/2008	10.60%	4.46%	6.14%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/24/2008	10.50%	4.41%	6.09%
12/3/2008	10.39%	4.37%	6.02%
12/24/2008	10.00%	4.26%	5.74%
12/26/2008	10.10%	4.24%	5.86%
12/29/2008	10.20%	4.23%	5.97%
1/13/2009	10.45%	4.14%	6.31%
2/2/2009	10.05%	4.04%	6.01%
3/9/2009	10.30%	3.89%	6.41%
3/25/2009	10.17%	3.84%	6.33%
4/2/2009	10.75%	3.81%	6.94%
5/5/2009	10.75%	3.71%	7.04%
5/15/2009	10.20%	3.70%	6.50%
5/29/2009	9.54%	3.70%	5.84%
6/3/2009	10.10%	3.71%	6.39%
6/22/2009	10.00%	3.73%	6.27%
6/29/2009	10.21%	3.74%	6.47%
6/30/2009	9.31%	3.74%	5.57%
7/17/2009	9.26%	3.75%	5.51%
7/17/2009	10.50%	3.75%	6.75%
10/16/2009	10.40%	4.09%	6.31%
10/26/2009	10.10%	4.11%	5.99%
10/28/2009	10.15%	4.12%	6.03%
10/28/2009	10.15%	4.12%	6.03%
10/30/2009	9.95%	4.12%	5.83%
11/20/2009	9.45%	4.18%	5.27%
12/14/2009	10.50%	4.24%	6.26%
12/16/2009	10.75%	4.25%	6.50%
12/17/2009	10.30%	4.26%	6.04%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.40%	4.26%	6.14%
12/18/2009	10.50%	4.26%	6.24%
12/22/2009	10.20%	4.27%	5.93%
12/22/2009	10.40%	4.27%	6.13%
12/28/2009	10.85%	4.29%	6.56%
12/29/2009	10.38%	4.30%	6.08%
1/11/2010	10.24%	4.34%	5.90%
1/21/2010	10.23%	4.37%	5.86%
1/21/2010	10.33%	4.37%	5.96%
1/26/2010	10.40%	4.37%	6.03%
2/10/2010	10.00%	4.39%	5.61%
2/23/2010	10.50%	4.40%	6.10%
3/9/2010	9.60%	4.40%	5.20%
3/24/2010	10.13%	4.42%	5.71%
3/31/2010	10.70%	4.43%	6.27%
4/1/2010	9.50%	4.43%	5.07%
4/2/2010	10.10%	4.44%	5.66%
4/8/2010	10.35%	4.44%	5.91%
4/29/2010	9.19%	4.46%	4.73%
4/29/2010	9.40%	4.46%	4.94%
4/29/2010	9.40%	4.46%	4.94%
5/17/2010	10.55%	4.46%	6.09%
5/24/2010	10.05%	4.46%	5.59%
6/3/2010	11.00%	4.46%	6.54%
6/16/2010	10.00%	4.46%	5.54%
6/18/2010	10.30%	4.46%	5.84%
8/9/2010	12.55%	4.41%	8.14%
8/17/2010	10.10%	4.40%	5.70%
9/16/2010	9.60%	4.31%	5.29%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.30%	4.31%	5.99%
10/21/2010	10.40%	4.20%	6.20%
11/2/2010	9.75%	4.17%	5.58%
11/2/2010	9.75%	4.17%	5.58%
11/3/2010	10.75%	4.17%	6.58%
11/19/2010	10.20%	4.15%	6.05%
12/1/2010	10.00%	4.13%	5.87%
12/6/2010	9.56%	4.12%	5.44%
12/6/2010	10.09%	4.12%	5.97%
12/9/2010	10.25%	4.12%	6.13%
12/14/2010	10.33%	4.11%	6.22%
12/17/2010	10.10%	4.11%	5.99%
12/20/2010	10.10%	4.11%	5.99%
12/23/2010	9.92%	4.10%	5.82%
1/6/2011	10.35%	4.09%	6.26%
1/12/2011	10.30%	4.09%	6.21%
1/13/2011	10.30%	4.09%	6.21%
3/10/2011	10.10%	4.16%	5.94%
3/31/2011	9.45%	4.20%	5.25%
4/18/2011	10.05%	4.23%	5.82%
5/26/2011	10.50%	4.32%	6.18%
6/21/2011	10.00%	4.36%	5.64%
6/29/2011	8.83%	4.38%	4.45%
8/1/2011	9.20%	4.41%	4.79%
9/1/2011	10.10%	4.33%	5.77%
11/14/2011	9.60%	3.93%	5.67%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/13/2011	9.50%	3.76%	5.74%
12/20/2011	10.00%	3.72%	6.28%
12/22/2011	10.40%	3.70%	6.70%
1/10/2012	9.06%	3.59%	5.47%
1/10/2012	9.45%	3.59%	5.86%
1/10/2012	9.45%	3.59%	5.86%
1/23/2012	10.20%	3.53%	6.67%
1/31/2012	10.00%	3.49%	6.51%
4/24/2012	9.50%	3.16%	6.34%
4/24/2012	9.75%	3.16%	6.59%
5/7/2012	9.80%	3.13%	6.67%
5/22/2012	9.60%	3.10%	6.50%
5/24/2012	9.70%	3.09%	6.61%
6/7/2012	10.30%	3.06%	7.24%
6/15/2012	10.40%	3.05%	7.35%
6/18/2012	9.60%	3.05%	6.55%
7/2/2012	9.75%	3.04%	6.71%
10/24/2012	10.30%	2.92%	7.38%
10/26/2012	9.50%	2.92%	6.58%
10/31/2012	9.30%	2.92%	6.38%
10/31/2012	9.90%	2.92%	6.98%
10/31/2012	10.00%	2.92%	7.08%
11/1/2012	9.45%	2.91%	6.54%
11/8/2012	10.10%	2.91%	7.19%
11/9/2012	10.30%	2.90%	7.40%
11/26/2012	10.00%	2.89%	7.11%
11/28/2012	10.40%	2.88%	7.52%
11/28/2012	10.50%	2.88%	7.62%
12/4/2012	10.00%	2.87%	7.13%
12/4/2012	10.50%	2.87%	7.63%
12/20/2012	9.50%	2.84%	6.66%
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.25%	2.84%	7.41%
12/20/2012	10.30%	2.84%	7.46%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.50%	2.84%	7.66%
12/26/2012	9.80%	2.83%	6.97%
2/22/2013	9.60%	2.86%	6.74%
3/14/2013	9.30%	2.89%	6.41%
3/27/2013	9.80%	2.92%	6.88%
4/23/2013	9.80%	2.96%	6.84%
5/10/2013	9.25%	2.96%	6.29%
6/13/2013	9.40%	3.01%	6.39%
6/18/2013	9.28%	3.02%	6.26%
6/18/2013	9.28%	3.02%	6.26%
6/25/2013	9.80%	3.04%	6.76%
9/23/2013	9.60%	3.33%	6.27%
11/6/2013	10.20%	3.42%	6.78%
11/13/2013	9.84%	3.44%	6.40%
11/14/2013	10.25%	3.44%	6.81%
11/22/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.50%	6.70%
12/13/2013	9.60%	3.52%	6.08%
12/16/2013	9.73%	3.53%	6.20%
12/17/2013	10.00%	3.53%	6.47%
12/18/2013	9.08%	3.53%	5.55%
12/23/2013	9.72%	3.55%	6.17%
12/30/2013	10.00%	3.57%	6.43%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/21/2014	9.65%	3.66%	5.99%
1/22/2014	9.18%	3.66%	5.52%
2/20/2014	9.30%	3.71%	5.59%
2/21/2014	9.85%	3.72%	6.13%
2/28/2014	9.55%	3.73%	5.82%
3/16/2014	9.72%	3.74%	5.98%
4/21/2014	9.50%	3.73%	5.77%
4/22/2014	9.80%	3.73%	6.07%
5/8/2014	9.10%	3.71%	5.39%
5/8/2014	9.59%	3.71%	5.88%
6/6/2014	10.40%	3.66%	6.74%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
7/7/2014	9.30%	3.63%	5.67%
7/25/2014	9.30%	3.60%	5.70%
7/31/2014	9.90%	3.59%	6.31%
9/4/2014	9.10%	3.50%	5.60%
9/24/2014	9.35%	3.46%	5.89%
9/30/2014	9.75%	3.44%	6.31%
10/29/2014	10.80%	3.37%	7.43%
11/6/2014	10.20%	3.35%	6.85%
11/14/2014	10.20%	3.33%	6.87%
11/14/2014	10.30%	3.33%	6.97%
11/26/2014	10.20%	3.30%	6.90%
12/3/2014	10.00%	3.29%	6.71%
1/13/2015	10.30%	3.16%	7.14%
1/21/2015	9.05%	3.13%	5.92%
1/21/2015	9.05%	3.13%	5.92%
4/9/2015	9.50%	2.88%	6.62%
5/11/2015	9.80%	2.82%	6.98%
6/17/2015	9.00%	2.79%	6.21%
8/21/2015	9.75%	2.78%	6.97%
10/7/2015	9.55%	2.82%	6.73%
10/13/2015	9.75%	2.83%	6.92%
10/15/2015	9.00%	2.84%	6.16%
10/30/2015	9.80%	2.87%	6.93%
11/19/2015	10.00%	2.89%	7.11%
12/3/2015	10.00%	2.91%	7.09%
12/9/2015	9.60%	2.92%	6.68%
12/11/2015	9.90%	2.92%	6.98%
12/18/2015	9.50%	2.94%	6.56%
1/6/2016	9.50%	2.97%	6.53%
1/6/2016	9.50%	2.97%	6.53%
1/28/2016	9.40%	2.97%	6.43%
2/10/2016	9.60%	2.95%	6.65%
2/16/2016	9.50%	2.94%	6.56%
2/29/2016	9.40%	2.92%	6.48%
4/29/2016	9.80%	2.83%	6.97%
5/5/2016	9.49%	2.82%	6.67%
6/1/2016	9.55%	2.80%	6.75%
6/3/2016	9.65%	2.79%	6.86%
6/15/2016	9.00%	2.77%	6.23%
6/15/2016	9.00%	2.77%	6.23%
9/2/2016	9.50%	2.56%	6.94%
9/23/2016	9.75%	2.52%	7.23%
9/27/2016	9.50%	2.51%	6.99%
9/29/2016	9.11%	2.50%	6.61%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/13/2016	10.20%	2.48%	7.72%
10/28/2016	9.70%	2.47%	7.23%
11/9/2016	9.80%	2.47%	7.33%
11/18/2016	10.00%	2.49%	7.51%
12/9/2016	10.10%	2.51%	7.59%
12/15/2016	9.00%	2.53%	6.47%
12/15/2016	9.00%	2.53%	6.47%
12/20/2016	9.75%	2.53%	7.22%
12/22/2016	9.50%	2.54%	6.96%
1/24/2017	9.00%	2.59%	6.41%
2/21/2017	10.55%	2.63%	7.92%
3/1/2017	9.25%	2.65%	6.60%
4/11/2017	9.50%	2.77%	6.73%
4/20/2017	8.70%	2.79%	5.91%
4/28/2017	9.50%	2.81%	6.69%
5/23/2017	9.60%	2.88%	6.72%
6/6/2017	9.70%	2.91%	6.79%
6/22/2017	9.70%	2.93%	6.77%
6/30/2017	9.60%	2.94%	6.66%
7/20/2017	9.55%	2.97%	6.58%
7/31/2017	10.10%	2.98%	7.12%
9/13/2017	9.40%	2.93%	6.47%
9/19/2017	9.70%	2.92%	6.78%
9/22/2017	11.88%	2.92%	8.96%
9/27/2017	10.20%	2.92%	7.28%
10/20/2017	9.60%	2.90%	6.70%
10/26/2017	10.20%	2.90%	7.30%
10/30/2017	10.05%	2.90%	7.15%
12/5/2017	9.50%	2.86%	6.64%
12/7/2017	9.80%	2.86%	6.94%
12/13/2017	9.25%	2.85%	6.40%
12/28/2017	9.50%	2.84%	6.66%
1/31/2018	9.80%	2.83%	6.97%
2/21/2018	9.80%	2.84%	6.96%
2/21/2018	9.80%	2.84%	6.96%
2/28/2018	9.50%	2.85%	6.65%
3/15/2018	9.00%	2.87%	6.13%
3/26/2018	10.19%	2.88%	7.31%
4/26/2018	9.50%	2.91%	6.59%
4/27/2018	9.30%	2.91%	6.39%
5/2/2018	9.50%	2.91%	6.59%
5/3/2018	9.70%	2.91%	6.79%
5/29/2018	9.40%	2.95%	6.45%
6/6/2018	9.80%	2.96%	6.84%
6/14/2018	8.80%	2.97%	5.83%
7/16/2018	9.60%	2.98%	6.62%
7/20/2018	9.40%	2.99%	6.41%
8/24/2018	9.28%	3.02%	6.26%
8/28/2018	10.00%	3.03%	6.97%
9/13/2018	10.00%	3.04%	6.96%
9/14/2018	10.00%	3.05%	6.95%
9/19/2018	9.85%	3.05%	6.80%
9/20/2018	9.80%	3.05%	6.75%
9/26/2018	9.40%	3.06%	6.34%
9/26/2018	10.20%	3.06%	7.14%
9/28/2018	9.50%	3.07%	6.43%
9/28/2018	9.50%	3.07%	6.43%
10/5/2018	9.61%	3.08%	6.53%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/15/2018	9.80%	3.09%	6.71%
10/26/2018	9.40%	3.11%	6.29%
10/29/2018	9.60%	3.11%	6.49%
11/1/2018	9.87%	3.11%	6.76%
11/8/2018	9.70%	3.12%	6.58%
11/8/2018	9.70%	3.12%	6.58%
12/11/2018	9.70%	3.14%	6.56%
12/12/2018	9.30%	3.14%	6.16%
12/13/2018	9.60%	3.14%	6.46%
12/19/2018	9.30%	3.14%	6.16%
12/21/2018	9.35%	3.14%	6.21%
12/24/2018	9.25%	3.14%	6.11%
12/24/2018	9.25%	3.14%	6.11%
1/4/2019	9.80%	3.14%	6.66%
1/18/2019	9.70%	3.14%	6.56%
3/14/2019	9.00%	3.12%	5.88%
3/27/2019	9.70%	3.12%	6.58%
4/30/2019	9.73%	3.11%	6.62%
5/7/2019	9.65%	3.10%	6.55%
5/21/2019	9.80%	3.10%	6.70%
9/4/2019	10.00%	2.76%	7.24%
9/26/2019	9.90%	2.69%	7.21%
10/2/2019	9.73%	2.67%	7.06%
10/2/2019	9.90%	2.67%	7.23%
10/8/2019	9.40%	2.64%	6.76%
10/15/2019	9.70%	2.62%	7.08%
10/21/2019	9.40%	2.60%	6.80%
10/31/2019	9.70%	2.57%	7.13%
10/31/2019	10.00%	2.57%	7.43%
10/31/2019	10.00%	2.57%	7.43%
10/31/2019	10.20%	2.57%	7.63%
11/7/2019	9.35%	2.55%	6.80%
11/13/2019	9.60%	2.54%	7.06%
11/13/2019	9.60%	2.54%	7.06%
12/6/2019	9.87%	2.47%	7.40%
12/11/2019	9.40%	2.46%	6.94%
12/17/2019	9.75%	2.44%	7.31%
12/18/2019	9.60%	2.44%	7.16%
12/18/2019	9.60%	2.44%	7.16%
12/19/2019	10.05%	2.44%	7.61%
12/19/2019	10.20%	2.44%	7.76%
12/19/2019	10.25%	2.44%	7.81%
12/20/2019	9.20%	2.44%	6.76%
12/26/2019	9.75%	2.42%	7.33%
1/15/2020	9.35%	2.37%	6.98%
1/16/2020	8.80%	2.37%	6.43%
1/24/2020	9.44%	2.35%	7.09%
2/3/2020	9.40%	2.32%	7.08%
2/24/2020	9.10%	2.27%	6.83%
2/25/2020	9.50%	2.27%	7.23%
2/28/2020	9.70%	2.25%	7.45%
3/25/2020	9.40%	2.15%	7.25%
3/26/2020	9.48%	2.14%	7.34%
4/21/2020	9.80%	2.02%	7.78%
5/19/2020	9.20%	1.94%	7.26%
6/16/2020	9.65%	1.86%	7.79%
7/8/2020	9.40%	1.80%	7.60%
8/4/2020	9.50%	1.70%	7.80%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/20/2020	9.90%	1.64%	8.26%
8/21/2020	9.35%	1.64%	7.71%
9/10/2020	9.90%	1.57%	8.33%
9/23/2020	9.60%	1.53%	8.07%
9/25/2020	9.25%	1.52%	7.73%
9/25/2020	9.25%	1.52%	7.73%
10/4/2020	9.80%	1.50%	8.30%
10/7/2020	9.70%	1.49%	8.21%
10/12/2020	9.20%	1.48%	7.72%
10/16/2020	9.40%	1.46%	7.94%
10/30/2020	9.90%	1.44%	8.46%
11/7/2020	9.60%	1.43%	8.17%
11/19/2020	8.80%	1.42%	7.38%
11/19/2020	8.80%	1.42%	7.38%
11/19/2020	9.90%	1.42%	8.48%
11/24/2020	9.80%	1.42%	8.38%
12/9/2020	9.10%	1.43%	7.67%
12/10/2020	9.40%	1.43%	7.97%
12/16/2020	9.38%	1.44%	7.94%
12/16/2020	9.65%	1.44%	8.21%
12/23/2020	10.00%	1.45%	8.55%
1/6/2021	9.40%	1.47%	7.93%
1/6/2021	9.60%	1.47%	8.13%
1/13/2021	9.67%	1.49%	8.18%
1/26/2021	9.50%	1.51%	7.99%
2/16/2021	9.80%	1.56%	8.24%
2/19/2021	9.86%	1.57%	8.29%
2/24/2021	9.25%	1.57%	7.68%
3/25/2021	10.00%	1.67%	8.33%
3/25/2021	10.00%	1.67%	8.33%
3/25/2021	10.00%	1.67%	8.33%
4/9/2021	9.70%	1.73%	7.97%
5/5/2021	9.30%	1.83%	7.47%
5/18/2021	9.40%	1.87%	7.53%
5/19/2021	8.80%	1.88%	6.92%
6/17/2021	10.24%	1.97%	8.27%
6/30/2021	9.43%	2.00%	7.43%
7/27/2021	9.54%	2.03%	7.51%
7/30/2021	9.30%	2.04%	7.26%
8/12/2021	8.80%	2.05%	6.75%
8/12/2021	8.80%	2.05%	6.75%
9/1/2021	9.40%	2.07%	7.33%
9/8/2021	9.67%	2.08%	7.59%
9/9/2021	9.85%	2.08%	7.77%
9/14/2021	9.50%	2.08%	7.42%
9/27/2021	9.40%	2.09%	7.31%
9/29/2021	9.80%	2.10%	7.70%
9/30/2021	9.70%	2.10%	7.60%
10/6/2021	9.70%	2.10%	7.60%
10/27/2021	9.37%	2.12%	7.25%
11/17/2021	9.60%	2.11%	7.49%
11/17/2021	9.80%	2.11%	7.69%
11/18/2021	9.00%	2.11%	6.89%
11/18/2021	9.75%	2.11%	7.64%
11/18/2021	10.00%	2.11%	7.89%
11/18/2021	10.00%	2.11%	7.89%
11/23/2021	9.80%	2.10%	7.70%
11/30/2021	9.40%	2.09%	7.31%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/3/2021	9.65%	2.08%	7.57%
12/9/2021	9.90%	2.07%	7.83%
12/13/2021	9.20%	2.06%	7.14%
12/28/2021	9.35%	2.03%	7.32%
12/28/2021	9.38%	2.03%	7.35%
12/28/2021	9.60%	2.03%	7.57%
1/3/2022	9.25%	2.03%	7.22%
1/6/2022	9.60%	2.02%	7.58%
1/20/2022	9.00%	2.01%	6.99%
1/21/2022	9.60%	2.01%	7.59%
3/22/2022	9.40%	2.02%	7.38%
3/22/2022	9.40%	2.02%	7.38%
4/14/2022	9.20%	2.08%	7.12%
5/19/2022	9.23%	2.23%	7.00%
6/16/2022	9.25%	2.36%	6.89%
7/7/2022	9.90%	2.45%	7.45%
7/20/2022	9.30%	2.50%	6.80%
7/27/2022	9.85%	2.53%	7.32%
8/2/2022	9.40%	2.56%	6.84%
8/17/2022	9.60%	2.62%	6.98%
8/18/2022	9.39%	2.63%	6.76%
8/23/2022	9.40%	2.65%	6.75%
9/15/2022	9.30%	2.79%	6.51%
10/10/2022	9.60%	2.94%	6.66%
10/12/2022	9.60%	2.96%	6.64%
10/24/2022	9.40%	3.04%	6.36%
10/25/2022	9.20%	3.05%	6.15%
10/27/2022	9.70%	3.07%	6.63%
10/27/2022	9.80%	3.07%	6.73%
11/3/2022	10.20%	3.12%	7.08%
11/17/2022	9.65%	3.22%	6.43%
11/30/2022	9.38%	3.29%	6.09%
12/15/2022	9.80%	3.35%	6.45%
12/21/2022	9.60%	3.38%	6.22%
12/22/2022	9.40%	3.39%	6.01%
12/22/2022	9.80%	3.39%	6.41%
12/23/2022	9.60%	3.39%	6.21%
12/29/2022	9.80%	3.42%	6.38%
12/29/2022	9.80%	3.42%	6.38%
1/19/2023	9.60%	3.48%	6.12%
1/23/2023	9.30%	3.49%	5.81%
1/24/2023	10.25%	3.49%	6.76%
1/26/2023	9.60%	3.49%	6.11%
3/23/2023	9.57%	3.63%	5.94%
3/28/2023	9.50%	3.64%	5.86%
5/4/2023	9.30%	3.73%	5.57%
6/30/2023	9.50%	3.81%	5.69%
7/20/2023	9.25%	3.79%	5.46%
8/30/2023	9.80%	3.85%	5.95%
8/30/2023	9.90%	3.85%	6.05%
8/31/2023	9.40%	3.85%	5.55%
9/20/2023	9.35%	3.90%	5.45%
9/20/2023	9.49%	3.90%	5.59%
10/5/2023	9.30%	3.96%	5.34%
10/6/2023	9.80%	3.97%	5.83%
10/12/2023	9.20%	3.99%	5.21%
10/12/2023	9.20%	3.99%	5.21%
10/25/2023	9.55%	4.06%	5.49%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/26/2023	9.50%	4.06%	5.44%
10/26/2023	9.65%	4.06%	5.59%
11/1/2023	9.60%	4.09%	5.51%
11/3/2023	9.70%	4.10%	5.60%
11/7/2023	9.65%	4.11%	5.54%
11/9/2023	9.80%	4.12%	5.68%
11/9/2023	9.80%	4.12%	5.68%
11/9/2023	10.15%	4.12%	6.03%
11/16/2023	9.38%	4.14%	5.24%
11/16/2023	9.38%	4.14%	5.24%
11/16/2023	9.44%	4.14%	5.30%
11/16/2023	9.51%	4.14%	5.37%
12/4/2023	9.80%	4.18%	5.62%
12/14/2023	9.45%	4.21%	5.24%
12/14/2023	9.50%	4.21%	5.29%
12/15/2023	9.65%	4.21%	5.44%
12/21/2023	9.75%	4.22%	5.53%
12/22/2023	10.50%	4.22%	6.28%
1/17/2024	9.85%	4.26%	5.59%
1/31/2024	9.70%	4.29%	5.41%
3/24/2024	9.30%	4.38%	4.92%
4/8/2024	9.50%	4.41%	5.09%
4/8/2024	9.50%	4.41%	5.09%
4/8/2024	11.88%	4.41%	7.47%
4/17/2024	9.75%	4.44%	5.31%
6/26/2024	9.80%	4.48%	5.32%
6/28/2024	9.40%	4.48%	4.92%
7/18/2024	9.50%	4.44%	5.06%
7/23/2024	9.90%	4.43%	5.47%
7/25/2024	9.38%	4.43%	4.95%
7/31/2024	9.75%	4.42%	5.33%
8/15/2024	9.35%	4.40%	4.95%
8/15/2024	9.35%	4.40%	4.95%
9/17/2024	9.65%	4.38%	5.27%
9/18/2024	9.45%	4.38%	5.07%
9/26/2024	9.86%	4.38%	5.48%
10/1/2024	9.85%	4.38%	5.47%
10/9/2024	9.60%	4.38%	5.22%
10/17/2024	10.08%	4.38%	5.70%
10/25/2024	9.35%	4.39%	4.96%
10/25/2024	9.40%	4.39%	5.01%
10/31/2024	9.90%	4.39%	5.51%
11/6/2024	10.00%	4.39%	5.61%
11/7/2024	9.80%	4.40%	5.40%
11/7/2024	9.90%	4.40%	5.50%
11/7/2024	9.90%	4.40%	5.50%
11/18/2024	9.15%	4.40%	4.75%
11/18/2024	9.15%	4.40%	4.75%
11/20/2024	9.70%	4.40%	5.30%
11/21/2024	9.60%	4.40%	5.20%
11/21/2024	9.60%	4.40%	5.20%
11/21/2024	9.85%	4.40%	5.45%
12/19/2024	9.70%	4.42%	5.28%
12/19/2024	9.80%	4.42%	5.38%
12/19/2024	9.80%	4.42%	5.38%
12/19/2024	9.80%	4.42%	5.38%
12/20/2024	9.80%	4.42%	5.38%
12/30/2024	9.75%	4.43%	5.32%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/7/2025	9.80%	4.43%	5.37%
1/15/2025	9.90%	4.44%	5.46%
		# of Cases:	1,335

Small Size Premium

	[1] ($Mil)
ENSTAR Equity	$231.36
Median Market to Book for Gas Proxy Group	1.54
ENSTAR Implied Market Cap	$357.17

Company Name	Ticker	[2] Market Cap ($Mil)	[3] Market to Book Ratio
Atmos Energy Corporation	ATO	$ 22,295	1.83
New Jersey Resources Corporation	NJR	$ 4,835	2.20
NiSource Inc.	NI	$ 17,252	2.07
Northwest Natural Gas Company	NWN	$ 1,668	1.23
ONE Gas, Inc.	OGS	$ 4,131	1.44
Southwest Gas Corporation	SWX	$ 5,335	1.54
Spire, Inc.	SR	$ 4,002	1.33
MEDIAN		$ 4,835.48	1.54
MEAN		$ 8,503	1.66

	Market Capitalization ($Mil) [4]		
Decile	Low End Market Capitalization	High End Market Capitalization	Size Premium
2	$ 20,191.220	$ 46,949.060	0.33%
3	$ 9,937.940	$ 20,178.360	0.49%
4	$ 6,196.710	$ 9,937.350	0.50%
5	$ 3,948.050	$ 6,181.270	0.74%
6	$ 2,481.780	$ 3,946.150	1.00%
7	$ 1,422.890	$ 2,464.500	1.19%
8	$ 731.190	$ 1,417.450	0.88%
9	$ 304.620	$ 729.920	1.73%
10	$ 1.110	$ 304.480	4.47%
Proxy Group Median		$ 4,835.479	0.74%
9th Decile Size Premium		$ 357.171	1.73%
		Difference from Proxy Group Median	0.99%

Notes:
[1] Source: Company's Annual Report submitted to RCA , Total Proprietary Capital as of December 31, 2024.
[2] Source: S&P Global Market Intelligence, 30-day average as of December 31, 2024
[3] Source: S&P Global Market Intelligence, 30-day average, as of December 31, 2024
[4] Source: Kroll Cost of Capital Navigator, Size Premia Deciles as of December 31, 2024.

Small Size Premium

	[1] ($Mil)
ENSTAR Equity	$231.36
Median Market to Book for Gas Proxy Group	2.07
ENSTAR Implied Market Cap	$479.46

Company Name	Ticker	[2] Market Cap ($Mil)	[3] Market to Book Ratio
Atmos Energy Corporation	ATO	$ 22,294.60	1.83
New Jersey Resources Corporation	NJR	$ 4,835.48	2.20
NiSource Inc.	NI	$ 17,251.68	2.07
Northwest Natural Gas Company	NWN	$ 1,668.42	1.23
ONE Gas, Inc.	OGS	$ 4,130.68	1.44
Southwest Gas Corporation	SWX	$ 5,334.74	1.54
Spire, Inc.	SR	$ 4,001.95	1.33
Enbridge Inc	ENB.TO	$ 131,030.78	2.22
Energy Transfer LP	ET	$ 70,038.90	2.51
Enterprise Products Partners LP	EPD	$ 60,808.59	2.00
Kinder Morgan Inc	KMI	$ 68,014.97	5.49
MPLX LP	MPLX	$ 69,603.07	2.46
TC Energy Corp.	TRP	$ 65,141.78	2.08
The Williams Companies, Inc	WMB	$ 49,480.88	3.65
MEDIAN		$ 35,887.74	2.07
MEAN		$ 40,974.04	2.29

	Market Capitalization ($Mil) [4]		
Decile	Low End Market Capitalization	High End Market Capitalization	Size Premium
2	$ 20,191.220	$ 46,949.060	0.33%
3	$ 9,937.940	$ 20,178.360	0.49%
4	$ 6,196.710	$ 9,937.350	0.50%
5	$ 3,948.050	$ 6,181.270	0.74%
6	$ 2,481.780	$ 3,946.150	1.00%
7	$ 1,422.890	$ 2,464.500	1.19%
8	$ 731.190	$ 1,417.450	0.88%
9	$ 304.620	$ 729.920	1.73%
10	$ 1.110	$ 304.480	4.47%
Proxy Group Median		$ 35,887.737	0.33%
9th Decile Size Premium		$ 479.456	1.73%
		Difference from Proxy Group Median	1.40%

Notes:
[1] Source: Company's Annual Report submitted to RCA , Total Proprietary Capital as of December 31, 2024.
[2] Source: S&P Global Market Intelligence, 30-day average as of December 31, 2024
[3] Source: S&P Global Market Intelligence, 30-day average, as of December 31, 2024
[4] Source: Kroll Cost of Capital Navigator, Size Premia Deciles as of December 31, 2024.

Proxy Group Regulatory Risk Comparative Assessment

Company	Parent	Jurisdiction	Natural Gas Commodity	Decoupling (F/P) [1]	New Capital Investment [2]	Energy Efficiency [3]	Other [4]	Test Year	Rate Base Methodology	Formula-Based Rates / Annual Rate Review Mechanism
Atmos Energy	ATO	Colorado	✓	P	✓	✓	✓	Historical	Average	
Atmos Energy	ATO	Kansas	✓	P	✓		✓	Historical	Year End	
Atmos Energy	ATO	Kentucky	✓	P	✓	✓	✓	Historical	Year End	
Atmos Energy	ATO	Louisiana — PSC	✓	P	✓	✓	✓	Historical	Average	✓
Atmos Energy	ATO	Mississippi	✓	P	✓	✓	✓	Forecast Permitted	Average	✓
Atmos Energy	ATO	Tennessee	✓	P	✓		✓	Forecast	Average	✓
Atmos Energy	ATO	Texas — RRC	✓	P	✓	✓	✓	Historical	Year End	✓
Atmos Energy	ATO	Virginia	✓	P	✓			Forecast Permitted	Average	
New Jersey Natural Gas	NJR	New Jersey	✓	F	✓	✓	✓	Partially Forecast	Year End	
Northern Indiana Public Service Co.	NI	Indiana	✓	P	✓	✓	✓	Historical	Year End	
Columbia Gas of Kentucky Inc	NI	Kentucky	✓	P	✓	✓	✓	Historical	Year End	
Columbia Gas of Maryland Inc.	NI	Maryland	✓	P	✓	✓	✓	Forecast Permitted	Average	
Columbia Gas of Ohio Inc.	NI	Ohio	NA	F	✓	✓	✓	Partially Forecast	Year End	
Columbia Gas of Pennsylvania Inc.	NI	Pennsylvania	✓	P	✓	✓	✓	Forecast	Year End	
Columbia Gas of Virginia Inc.	NI	Virginia	✓	F	✓	✓	✓	Forecast Permitted	Year End	
Northwest Natural Gas Company	NWN	Oregon	✓	P	✓	✓	✓	Partially Forecast	Average	
Northwest Natural Gas Company	NWN	Washington	✓			✓	✓	Forecast Permitted	Average	
Kansas Gas Service	OGS	Kansas	✓	P	✓		✓	Historical	Year End	
Oklahoma Natural Gas	OGS	Oklahoma	✓	P	✓	✓	✓	Historical	Year End	✓
Texas Gas Service	OGS	Texas — RRC	✓	P	✓	✓	✓	Historical	Year End	
Southwest Gas Corp	SWX	Arizona	✓	F	✓	✓	✓	Historical	Year End	
Southwest Gas Corp	SWX	California	✓	F	✓	✓	✓	Forecast	Average	
Southwest Gas Corp	SWX	Nevada	✓	F	✓	✓	✓	Forecast Permitted	Year End	
Spire Alabama	SR	Alabama	✓	P	✓		✓	Historical	Average	✓
Spire Gulf, Inc.	SR	Alabama	✓	P	✓		✓	Historical	Average	✓
Spire Mississippi	SR	Mississippi	✓	P	✓	✓		Forecast Permitted	Year End	✓
Spire Missouri - East	SR	Missouri	✓	P	✓		✓	Partially Forecast	Year End	
Spire Missouri - West	SR	Missouri	✓	P	✓		✓	Partially Forecast	Year End	
	% of Proxy Group (OpCo)		100%	96%	96%	71%	93%	54%	61%	29%
ENSTAR		Alaska	✓				✓	Historical	Year End	

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category. Columbia Gas of Ohio does not have supply obligation for retail customers.

[1] Full or partial decoupling (such as Straight-Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs).
[2] Includes recovery of costs related to Includes recovery of capital costs including infrastructure replacement programs and capital/plant additions.
[3] Utility-sponsored conservation, energy efficiency, or other demand side management programs.
[4] Pension expenses, bad debt costs, storm costs, environmental costs, regulatory fee, government & franchise fees and taxes, economic development, and low income assistance programs.

Sources: Company SEC Form 10-Ks; Operating company tariffs; Regulatory Research Associates, *State Regulatory Evaluations Quarterly Update* , December 2024; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview,* July 18, 2022; Regulatory Research Associates, Alternative Ratemaking Frameworks in the U.S., April 16, 2020.

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	60.20%	60.01%	59.88%	60.03%
New Jersey Resources Corporation	NJR	55.15%	53.98%	55.19%	54.77%
NiSource Inc.	NI	55.44%	54.17%	54.85%	54.82%
Northwest Natural Gas Company	NWN	47.26%	53.27%	49.57%	50.03%
ONE Gas, Inc.	OGS	60.41%	58.24%	61.09%	59.92%
Southwest Gas Corporation	SWX	47.45%	43.96%	50.70%	47.37%
Spire, Inc.	SR	51.91%	57.15%	55.30%	54.79%
Proxy Group					
MEAN		53.98%	54.40%	55.23%	54.53%
MEDIAN		55.15%	54.17%	55.19%	54.79%
LOW		47.26%	43.96%	49.57%	47.37%
HIGH		60.41%	60.01%	61.09%	60.03%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	60.20%	60.01%	59.88%	60.03%
New Jersey Natural Gas Company	NJR	55.15%	53.98%	55.19%	54.77%
Columbia Gas of Kentucky, Incorporated	NI	53.66%	54.91%	53.87%	54.15%
Columbia Gas of Maryland, Incorporated	NI	52.00%	51.96%	55.26%	53.07%
Columbia Gas of Ohio, Inc.	NI	50.50%	50.67%	50.79%	50.65%
Columbia Gas of Pennsylvania, Inc.	NI	55.88%	56.64%	56.05%	56.19%
Columbia Gas of Virginia, Incorporated	NI	45.25%	44.25%	44.52%	44.67%
Northern Indiana Public Service Company, LLC	NI	59.26%	56.92%	58.59%	58.26%
Kansas Gas Service Company, Inc.	OGS	60.44%	58.37%	61.37%	60.06%
Oklahoma Natural Gas Company	OGS	60.46%	58.26%	60.99%	59.90%
Texas Gas Service Company, Inc.	OGS	60.35%	58.13%	60.98%	59.82%
Southwest Gas Corporation	SWX	47.45%	43.96%	50.70%	47.37%
Spire Alabama Inc.	SR	55.31%	61.18%	58.51%	58.33%
Spire Gulf Inc.	SR	46.42%	51.61%	49.48%	49.17%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	50.66%	55.55%	53.96%	53.39%
Northwest Natural Gas Company	NWN	47.26%	53.27%	49.57%	50.03%
Operating Company					
MEAN		53.76%	54.35%	54.98%	54.37%
MEDIAN		54.40%	55.23%	55.23%	54.46%
LOW		45.25%	43.96%	44.52%	44.67%
HIGH		60.46%	61.18%	61.37%	60.06%

Notes:
Sources: Operating Company Annual LDC Reports; S&P Capital IQ
[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.
[2] Spire Mississippi was excluded because it does not report long-term debt.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	39.80%	39.99%	40.12%	39.97%
New Jersey Resources Corporation	NJR	44.85%	46.02%	44.81%	45.23%
NiSource Inc.	NI	44.56%	45.83%	45.15%	45.18%
Northwest Natural Gas Company	NWN	52.74%	46.73%	50.43%	49.97%
ONE Gas, Inc.	OGS	39.59%	41.76%	38.91%	40.08%
Southwest Gas Corporation	SWX	52.55%	56.04%	49.30%	52.63%
Spire, Inc.	SR	48.09%	42.85%	44.70%	45.21%
Proxy Group					
MEAN		46.02%	45.60%	44.77%	45.47%
MEDIAN		44.85%	45.83%	44.81%	45.21%
LOW		39.59%	39.99%	38.91%	39.97%
HIGH		52.74%	56.04%	50.43%	52.63%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2023	2022	2021	Average
Atmos Energy Corporation	ATO	39.80%	39.99%	40.12%	39.97%
New Jersey Natural Gas Company	NJR	44.85%	46.02%	44.81%	45.23%
Columbia Gas of Kentucky, Incorporated	NI	46.34%	45.09%	46.13%	45.85%
Columbia Gas of Maryland, Incorporated	NI	48.00%	48.04%	44.74%	46.93%
Columbia Gas of Ohio, Inc.	NI	49.50%	49.33%	49.21%	49.35%
Columbia Gas of Pennsylvania, Inc.	NI	44.12%	43.36%	43.95%	43.81%
Columbia Gas of Virginia, Incorporated	NI	54.75%	55.75%	55.48%	55.33%
Northern Indiana Public Service Company, LLC	NI	40.74%	43.08%	41.41%	41.74%
Kansas Gas Service Company, Inc.	OGS	39.56%	41.63%	38.63%	39.94%
Oklahoma Natural Gas Company	OGS	39.54%	41.74%	39.01%	40.10%
Texas Gas Service Company, Inc.	OGS	39.65%	41.87%	39.02%	40.18%
Southwest Gas Corporation	SWX	52.55%	56.04%	49.30%	52.63%
Spire Alabama Inc.	SR	44.69%	38.82%	41.49%	41.67%
Spire Gulf Inc.	SR	53.58%	48.39%	50.52%	50.83%
Spire Mississippi Inc.	SR				NA
Spire Missouri Inc.	SR	49.34%	44.45%	46.04%	46.61%
Northwest Natural Gas Company	NWN	52.74%	46.73%	50.43%	49.97%
Operating Company					
MEAN		46.24%	45.65%	45.02%	45.63%
MEDIAN		45.60%	44.77%	44.77%	45.54%
LOW		39.54%	38.82%	38.63%	39.94%
HIGH		54.75%	56.04%	55.48%	55.33%

Notes:
Sources: Operating Company Annual LDC Reports; S&P Capital IQ
[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.
[2] Spire Mississippi was excluded because it does not report long-term debt.

Proxy Group Current Authorized Equity Ratio by Jurisdiction

Ticker	Company Name	Docket Number	Jurisdiction	Date Authorized	Current Authorized Equity Ratio	
ATO	Atmos Energy Corporation					
	Colorado Division	D-22AL-0348G	CO	5/4/2023	58.00%	
	Kansas Division	D-23-ATMG-359-RTS	KS	5/9/2023	NA	
	Kansas Division	D-19-ATMG-525-RTS	KS	2/24/2020	56.32%	
	Kentucky Division	C-2021-00214	KY	5/19/2022	54.50%	
	Louisiana Division	D-U-21484 (LGS)	LA	7/1/2023	NA	
	Louisiana Division	D-U-21484 (LGS)	LA	7/1/2022	NA	
	Louisiana Division	D-U-21484 (LGS)	LA	7/1/2020	58.00%	
	Mississippi Division	C-2005-UN-503	MS	10/4/2022	60.74%	
	Tennessee Division	D-24-00006	TN	6/1/2024	62.38%	
	West Texas (Environs)	D-GUD-10743	TX RRC	6/1/2023	60.00%	
	West Texas (Cities)	[1]	TX RRC	10/1/2022	58.00%	
	West Texas Triangle	D-GUD-10900	TX RRC	6/1/2023	60.00%	
	West Texas (ALDC)	[1]	TX RRC	6/9/2023	59.00%	
	Mid-Tex (Cities)	[1]	TX RRC	10/1/2022	58.00%	
	Mid-Tex (Environs)	[1]	TX RRC	6/1/2023	60.00%	
	Mid-Tex (Dallas)	[1]	TX RRC	6/1/2023	60.00%	
	Mid-Tex (ATM Cities)	D-GUD-10779	TX RRC	5/21/2019	60.18%	
	Virginia Division	PUR-2023-0008	VA	5/13/2024	60.59%	
NI	NiSource Inc.					
	Columbia Gas of Kentucky, Incorporated	C-2024-00092	KY	12/30/2024	52.64%	
	Columbia Gas of Maryland, Incorporated	C-9701	MD	10/26/2023	NA	
	Columbia Gas of Maryland, Incorporated	C-9680	MD	11/17/2022	52.97%	
	Columbia Gas of Ohio, Inc.	C-21-0637-GA-AIR	OH	1/26/2023	50.60%	
	Columbia Gas of Pennsylvania, Inc.	D-R-2024-3046519	PA	11/21/2024	NA	
	Columbia Gas of Pennsylvania, Inc.	D-R-2022-3031211	PA	12/8/2022	NA	
	Columbia Gas of Pennsylvania, Inc.	D-R-2021-3024296	PA	12/16/2021	NA	
	Columbia Gas of Pennsylvania, Inc.	D-R-2020-3018835	PA	2/19/2021	54.19%	
	Columbia Gas of Virginia, Incorporated	C-PUR-2022-00036	VA	5/15/2023	NA	
	Columbia Gas of Virginia, Incorporated	C-PUR-2018-00131	VA	6/12/2019	NA	
	Northern Indiana Public Service Company	Ca-45967	IN	7/31/2024	58.51%	
NJR	New Jersey Resources Corporation					[2]
	New Jersey Natural Gas Company	D-GR24010071	NJ	11/21/2024	54.00%	
NWN	Northwest Natural Holding Company					
	Northwest Natural Gas Company	UG-490	OR	10/25/2024	50.00%	
	Northwest Natural Gas Company	D-UG-200994	WA	10/21/2021	NA	
	Northwest Natural Gas Company	D-UG-181053	WA	10/21/2019	49.00%	
OGS	ONE Gas, Inc.					
	Kansas Gas Service Company, Inc.	D-24-KGSG-610-RTS	KS	10/3/2024	NA	
	Kansas Gas Service Company, Inc.	D-18-KGSG-560-RTS	KS	2/5/2019	NA	
	Oklahoma Natural Gas Company	Ca-PUD2024-000010	OK	8/27/2024	NA	
	Oklahoma Natural Gas Company	Ca-PUD202200023	OK	11/29/2022	NA	
	Oklahoma Natural Gas Company	Ca-PUD202100063	OK	11/30/2021	58.55%	
	Texas Gas Service Company, Inc. (Central-Gul	D-OS-24-00017471	TX RRC	11/20/2024	59.58%	
	Texas Gas Service Company, Inc. (Rio Grande	D-OSS-23-00014399	TX RRC	1/31/2024	59.07%	
	Texas Gas Service Company, Inc. (WTX North)	D-OSS-22-00009896	TX RRC	1/19/2023	59.74%	
SR	Spire Inc.					
	Spire Alabama Inc.	D-18328	AL	9/30/2022	55.50%	
	Spire Missouri Inc.	C-GR-2021-0108	MO	10/27/2021	49.86%	[3]
	Spire Mississippi	D-2015-UN-109	MS	12/2/2022	50.00%	
	Spire Gulf Inc.	D-28101	AL	9/30/2021	55.50%	
SWX	Southwest Gas Corp.					[3]
	Arizona Division	D-G-01551A-21-0368	AZ	1/23/2023	50.00%	
	California Division (SoCal)	A-19-08-015 (SoCal)	CA	3/25/2021	52.00%	
	California Division (NoCal)	A-19-08-015 (NoCal)	CA	3/25/2021	52.00%	
	California Division (LkTah)	A-19-08-015 (LkTah)	CA	3/25/2021	52.00%	
	Nevada Division (Northern)	D-23-09012 (Northern)	NV	9/11/2023	50.00%	
	Nevada Division (Southern)	D-23-09012 (Southern	NV	9/11/2023	50.00%	
	Average				55.71%	
	Median				56.32%	
	High				62.38%	
	Low				49.00%	
	Count ≥55%				21	
	Total Count				37	

Source: Regulatory Research Associates; SEC Form 10-K for ATO and SR
If the capital structure was not determined in the most recent rate proceeding, the authorized equity ratio determined in the next most recent proceeding with a determination in the last five years was used.

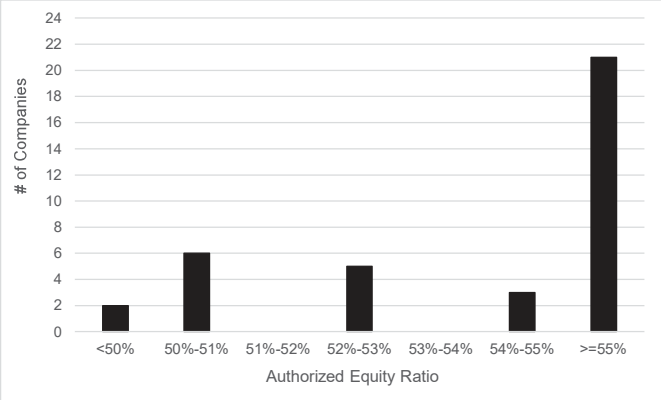
Notes:

[1] Gas utilities regulated by the Texas Rail Road Commission (RRC) have a general rate case only if they are unable to reach a settlement with the cities and unincorporated areas ("environs") within their service territories. Current authorized equity ratio for Atmos Texas' territories is published in ATO's 2024 10-K.

[2] Calculated using investor-supplied capital sources only. Indiana includes non-investor supplied capital in the ratemaking capital structure reported by RRA. Including non-investor supplied capital, NIPSCO's authorized equity ratio was 49.47% in 2021 and 52.39% in 2024.

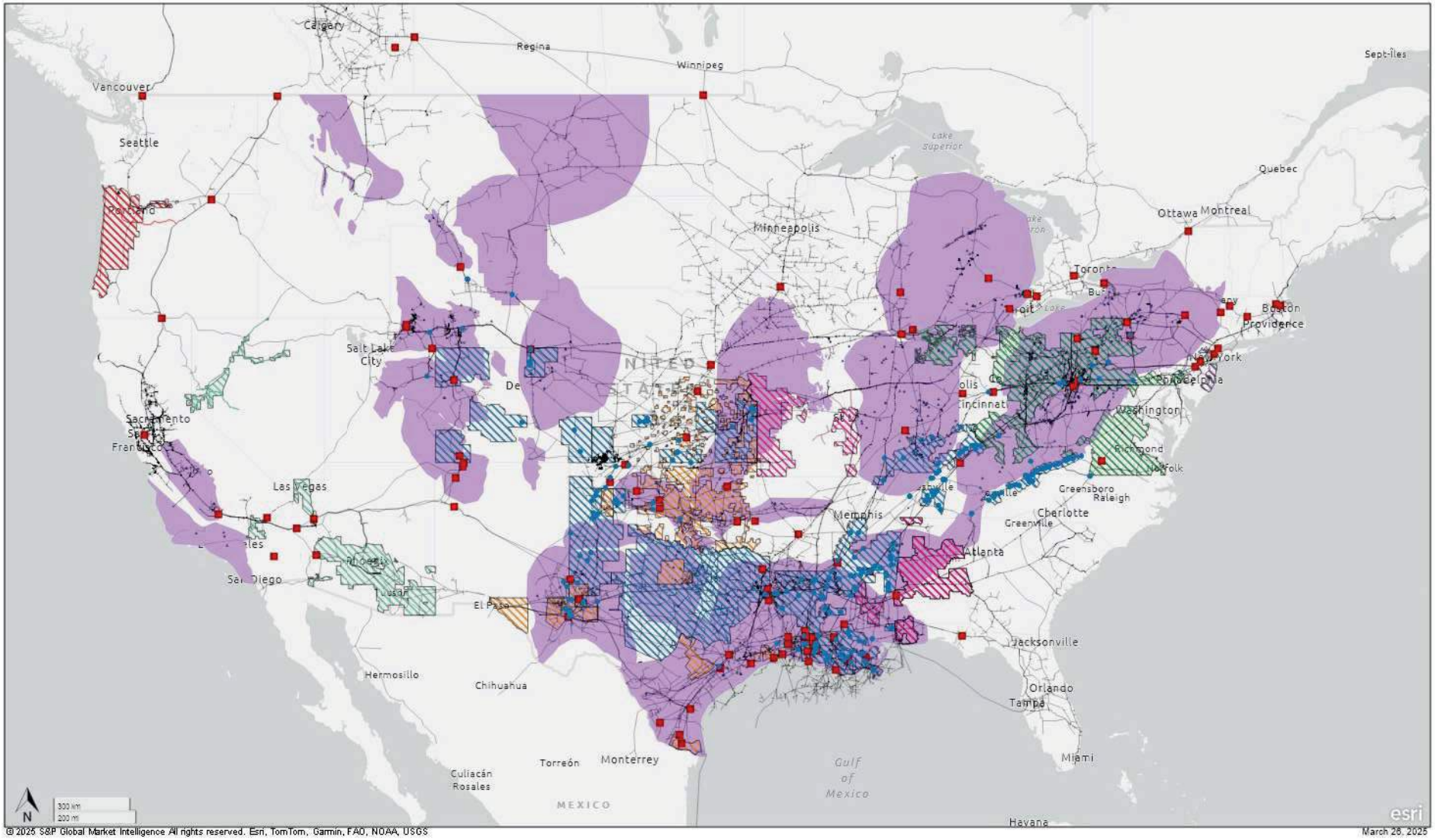
[3] Source: Spire, Inc. 2022 10-K; authorized in Spire's RSE proceedings, not a general rate case

Equity Ratio	Count	
<50%	2	
50%-51%	6	
51%-52%	0	
52%-53%	5	
53%-54%	0	
54%-55%	3	
>=55%	21	56.76%



S&P Capital IQ PRO

Lower 48 Gas Supply and Transmission



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March 26, 2025

(SWX) Southwest Gas Holdings Inc.

Gas Territories

Pipeline Operating

(SR) Spire Inc.

Gas Territories

Pipeline Operating

(OGS) One Gas Inc.

Gas Territories

(NJR) New Jersey Resources Corp.

Gas Territories

Pipeline Operating

(NI) NiSource Inc.

Gas Territories

Pipeline Operating

Transmission Lines Operating

(ATO) Atmos Energy Corp.

Pipeline Operating

Gas Territories

Storage Field Operating

GasStorageCapacity

0 - 5,000,000

5,000,000 - 10,000,000

10,000,000 - 10,000,000

Receipt/Delivery Points

(NWN) Northwest Natural Holding Co.

Gas Territories

Pipeline Projects

Pipeline Operating

Pipeline Operating

Pipeline Operating

Gas Hubs

Gas Hubs

Storage Field Operating

GasStorageCapacity

0 - 5,000,000

5,000,000 - 10,000,000

10,000,000 - 10,000,000

Shale Gas Basins

Shale Gas Basins

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

John M. Espindola, Chairman
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Consideration of the Revenue Requirement Designated as TA 354-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF BRUCE H. FAIRCHILD

PREFILED DIRECT TESTIMONY
OF
BRUCE H. FAIRCHILD

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EXHIBITS

Exhibit BHF-1 Resume of Bruce H. Fairchild

I. POSITION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Bruce H. Fairchild. My business address is 3907 Red River, Austin, Texas 78751.

Q. By whom are you employed and in what position?

A. I am a principal in Financial Concepts and Applications, Inc. ("FINCAP"), a firm engaged in financial, economic, and policy consulting to business and government.

Q. Describe your educational background, professional qualifications, and prior experience.

A. I hold a BBA degree from Southern Methodist University and MBA and PhD degrees from the University of Texas at Austin. I am also a Certified Public Accountant. My previous employment includes working in the Controllers Department at Sears, Roebuck and Company and serving as Assistant Director of Economic Research at the Public Utility Commission of Texas ("PUCT"). I have also been on the business school faculties at the University of Colorado at Boulder and the University of Texas at Austin, where I taught undergraduate and graduate courses in finance and accounting.

Q. Briefly describe your experience in utility-related matters.

A. While at the PUCT, I assisted in managing a division comprised of approximately twenty-five professionals responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems. I testified on behalf of the PUCT staff in numerous cases involving most major investor-owned and cooperative electric, telephone, and water/sewer utilities in the state regarding a

variety of financial, accounting, and economic issues. Since forming FINCAP in 1979, I have participated in a wide range of analytical assignments involving utility-related matters on behalf of utilities, industrial consumers, municipalities, and regulatory commissions. I have also prepared and presented expert witness testimony before a number of regulatory authorities addressing revenue requirements, cost allocation, and rate design issues for gas, electric, telephone, and water/sewer service. I have been a frequent speaker at regulatory conferences and seminars, and have published research concerning various regulatory issues. Exhibit BHF-1 includes a resume with my experience and qualifications, including a listing of my prior testimony before regulatory agencies since leaving the PUCT.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony on behalf of ENSTAR Natural Gas Company, LLC, and Alaska Pipeline Company, LLC (collectively, "ENSTAR")[1] is to address four items in its 275(a) filing[2] (Attachment B to TA354-4) and 275(h) filing[3] (Attachment C to TA354-4). First, I opine on the reasonableness of the calculation of the weather adjustments to normalize gas usage during the 2024 test year for selected customer classes. Second, I sponsor the calculation of the income tax expense included in the requested revenue requirement on Schedule F to ENSTAR's 275(a) filing, which

[1] The Commission regulates APC and ENSTAR as a single entity. The use of the name "ENSTAR" or "Company" in this filing is intended to include both APC and ENSTAR, unless the context clearly requires otherwise.

[2] A "275(a)" filing refers to a filing in compliance with the Commission's regulations at 3 AAC 48.275(a), which specifies the information necessary to support a new revenue requirement filing.

[3] 3 AAC 48.275(h) states: "In addition to any other supporting studies required by this chapter, if a proposed tariff revision includes a rate redesign, other than an across-the-board increase, a cost-of-service study and a narrative explaining the methodology used in the study must be submitted…"

includes an adjustment to amortize excess accumulated deferred income taxes ("ADIT") resulting from the Tax Cuts and Jobs Act of 2017 ("TCJA"). Third, I sponsor ENSTAR's 275(h) filing, which consists of a cost-of-service ("COS") study that allocates ENSTAR's requested revenue requirement among its various customer classes. Finally, I develop specific rates for ENSTAR's customer classes.

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A. In preparing my analysis and testimony in this case, I utilized a variety of sources of information that would normally be relied upon by a person in my role. I am generally knowledgeable about the natural gas industry from my prior work with many of the major intrastate gas distribution and transmission companies in the Southwest and elsewhere. In addition, I have worked with ENSTAR for over thirty-five years on various rate and regulatory matters, many of which are included in Exhibit BHF-1.

III. 3 AAC.275(a) FILING

A. Weather Normalization

Q. Have you reviewed the methodology ENSTAR used to normalize customer usage to account for the colder than normal weather during 2024?

A. Yes. The methodology used to weather normalize usage for the test year, sponsored by ENSTAR witness, Ms. Inna B. Johansen, begins by determining the annual base usage per customer based on months with no, or in the case of Alaska minimal, heating load. Per-customer usage in 2024 is then reduced by the base usage to calculate per-customer 2024 heating load. This 2024 heating load is then decreased based on the greater heating degree days in 2024 versus an average year. The

resulting adjusted heating degree days are then added to base usage to calculate normalized usage per customer. This normalized usage serves as the basis for adjusting certain operating expenses and revenues to develop the requested revenue requirement for the test year and to allocate costs in a COS study and design rates.

Q. Is this methodology a reasonable basis to weather normalize test year usage?

A. Yes. The methodology used by ENSTAR in this case to adjust 2024 usage by customers in its general service customer classes is a standard method of weather normalization. It is the same methodology used to normalize usage to develop the revenue requirement, allocate costs in the COS study, and design rates in Docket Nos. U-00-088, U-09-069/U-09-070, and U-22-081.[4]

B. Income Tax Expense

Q. Do you sponsor the Income Tax pro forma found on Schedule F of the 275(a) filing?

A. Yes.

Q. How is the income tax expense included in ENSTAR's requested revenue requirement calculated?

A. The income tax expense included in ENSTAR's requested revenue requirement, which as I discuss below is adjusted for the amortization of excess ADIT, is developed on Schedule F of the 275(a) filing. Beginning with ENSTAR's requested after-tax return on equity of $27,490,695 from page 3 of the 275(a) filing, $831,570 in amortization of excess ADIT is subtracted to arrive at a net after-tax equity return

[4] The U-00-088 revenue requirement was adjudicated by the Commission and set in Order U-00-088(12), dated August 8, 2002, which included the results of the weather normalization adjustment proposed by ENSTAR. The 2009 and 2021 test year rate cases were settled, and the Commission accepted the stipulation in Order U-09-069(10)/U-09-070(10) and Order U-22-081(11), respectively. The weather normalized volumes per customer proposed by ENSTAR were used to derive the tariff rates that were approved in those Orders.

of $26,659,125. This amount is then multiplied by a combined state/federal income tax factor of 0.3971554[5] to calculate total state and federal income tax expense of $10,587,816.

Q. What portion of this total is state income tax?

A. Combining ENSTAR's requested net after-tax return on equity with the total combined state/federal income tax expenses produces state taxable income of $37,246,941. Multiplying this amount by Alaska's 9.4% corporate income tax rate results in state income tax expense of $3,501,212, which compares with the $1,598,902 recorded on ENSTAR's books during 2024. These values are also shown on pages 1 and 4 of the 275(a) filing.

Q. What are the federal income taxes associated with ENSTAR's requested return on equity?

A. Deducting state income tax expense from state taxable income leaves federal taxable income of $33,745,728. Multiplying this amount by the U.S. corporate income tax rate of 21% produces federal income tax expense of $7,086,603.

Q. Is this the federal income tax included in ENSTAR's requested revenue requirement?

A. No, this federal income tax expense does not include the amortization of excess ADIT.

Q. Please explain the amortization of excess ADIT.

A. ADIT are debits (assets) or credits (liabilities) that reflect future tax benefits/costs resulting from timing differences between when revenues and expenses are

[5] The combined state/federal income tax factor may be calculated as: (1/((1-state tax rate) x (1-federal income tax rate)))-1.

recognized for tax accounting versus book or regulatory accounting. When the TCJA reduced the federal corporate income tax rate from 34% to 21%, the future tax benefits/costs reflected in ADIT decreased effective January 1, 2018. This decrease in ADIT produced "excess" ADIT, which for utilities may be amortized through rates.

Q. How is the amortization of excess ADIT reflected in a utility's rates?

A. Amortizing excess ADIT in a utility's rates can be accomplished in different ways. One approach is to reflect the amortization as a separate component, or line item, of the revenue requirement. Another is to incorporate the amortization through a reduction in the income tax expense included in the revenue requirement. If correctly applied, both approaches produce the same end-result, and in both the amortization of excess ADIT is "grossed-up" for income taxes. ENSTAR selected the second approach and amortized excess ADIT by reducing the federal income tax expense included in its requested revenue requirement.

Q. How much excess ADIT is being amortized annually through ENSTAR's rates?

A. ENSTAR's annual amortization of excess ADIT consists of three items. The first is a "protected" ADIT liability, which is related to the timing differences between accelerated depreciation expense used for tax purposes versus straight-line depreciation expense used for book and regulatory accounting. The excess ADIT liability at January 1, 2018 is being amortized over a remaining life of 23.87 years at $861,431 per year. The second item is an "unprotected" excess ADIT asset, which relates to timing differences other than accelerated depreciation, which is being amortized over 15 years at $499,965 per year. The third item is a regulatory liability

created in the Stipulation accepted by the Commission in Order U-22-081(11) ("U-22-081 Stipulation") to account for previously unamortized protected excess ADIT. This regulatory liability is being amortized over four years, or $470,104 per year. As shown at the bottom of Schedule F, the net sum of these liability and asset amortizations is $831,570, which corresponds to the amortization amount identified in the U-22-081 Stipulation. Please note that this annual excess ADIT amortization is effectively grossed-up for income taxes because it is deducted from the after-tax equity return before the composite income tax factor is applied.

Q. What then is the federal income tax expense included in ENSTAR's requested revenue requirement?

A. As shown in the lower portion of Schedule F of the 275(a) filing, the $831,570 amortization of excess ADIT is deducted from the federal income tax expense of $7,086,603 to calculate the federal income tax expense of $6,255,033 included in the revenue requirement, which compares with the $2,404,676 recorded during 2024 also shown on pages 1 and 4 of the 275(a) filing.

IV. 3 AAC 48.275(h) FILING

A. Cost of Service Study

Q. Please describe the purpose of this section of your testimony.

A. The purpose of this section is to fulfill the requirements of 3 AAC 48.275(h), which states that "if a proposed tariff revision includes a rate redesign, other than an across-the-board increase, a cost-of-service study and a narrative explaining the methodology used in the study must be submitted."

Q. Do the tariff revisions in this case include a rate redesign other than an across-the-board increase?

A. Yes. Accordingly, I sponsor the COS study attached to TA354-4 as Attachment C that allocates ENSTAR's requested revenue requirement among its customer classes. The results of this COS study establish the cost basis for developing rates for ENSTAR's various customer classes, which are described in the next section of my testimony.

Q. Would you briefly describe a COS study?

A. A COS study is an engineering, accounting, and economic analysis designed to allocate a utility's total cost of providing service to specific customers or customer classes. Many of a utility's operating expenses and much of its capital investment are incurred to serve all customers, to a greater or lesser extent. Because these joint and common costs cannot be directly tied to specific customers, they must be apportioned among customers and/or customer classes. This apportionment is accomplished through a COS study, in which operating and capital costs are allocated using factors developed from various operating data reflecting cost causation. The sum of the costs allocated to each customer and/or customer class in the COS study represents class revenue requirements, or that portion of the utility's total costs for which a particular customer or customer class is responsible.

Q. What methodology was followed in this COS study?

A. Pursuant to the U-22-081 Stipulation, this COS study follows the methodology adjudicated in Docket U-16-066, as modified in TA303-4.

Q. Please describe how the COS study was conducted.

A. The first step in conducting the COS study is to assign the components of ENSTAR's respective revenue requirement and rate base to Federal Energy Regulatory

Commission ("FERC") accounts. The next step is to examine each account to judge its nature and cost-causal characteristics. This initially involves classifying a particular account as primarily customer-related (*i.e.*, varying with the number of customers), capacity-related (*i.e.*, varying with the need to meet peak demands), or commodity-related (*i.e.*, varying with the amount of gas delivered). The manner in which each operating and capital account is classified is identified in the COS study under the heading "Cost Classification."

The next step is to develop various allocation factors to reflect the responsibility of each customer class for different costs based on cost-causal relationships. These allocation factors are derived from usage, operating, and other data for the normalized test year, and are intended to capture the relative contribution of each customer class to the system as a whole. The allocation factor used to apportion each operating and capital account between customer classes is identified in the COS study under the heading "Alloc. Factor." The details underlying the derivation of each allocation factor are contained in separate pages of the COS study.

Finally, the amounts in each operating and capital account are allocated among customer classes using the indicated allocation factor. The amounts allocated to each customer class are then summed to calculate the cost of serving each.

Q. What revenue requirement and rate base are allocated among ENSTAR's customer classes in the COS study?

A. The basis for the COS study is ENSTAR's requested revenue requirement and rate base summarized on page 4 of the 275(a) filing. First, because the cost of gas is recovered separately through ENSTAR's gas cost adjustment ("GCA"), these

expenses are excluded and the COS study only allocates amounts that are incorporated into base rates. Second, $1,556,675 in miscellaneous service revenues received during the test year are used to offset the cost of providing service to customers. Thus, a net revenue requirement of $116,255,167 and rate base of $361,049,827 are allocated among customer classes in the COS study.

Q. How are ENSTAR's customers grouped for purposes of allocating costs using its existing customer classes?

A. For COS study purposes, ENSTAR's customers are grouped into the following six rate classes. These are the same classes as in Docket U-22-081, except that the Mid-sized Firm Transport class is deleted because there are no longer any customers in this rate class:

- General Service 1 ("G-1");
- General Service 2 ("G-2");
- General Service 3 ("G-3");
- General Service 4 ("G-4");
- Very Large Firm Transport ("VLFT"); and
- Interruptible Industrial Transportation ("IIT")/Interruptible Transportation Service to Storage ("ITS").

Q. What features of the COS study are particularly noteworthy?

A. As approved by the Commission in Order U-16-066(19), most capacity-related costs, which are primarily related to ENSTAR's transmission activities, are apportioned between customer classes using an allocation factor calculated by weighting equally the relative contributions of each customer class to the test year coincident system peak demand and average day demand, which is the equivalent of volumes. Also consistent with Order U-16-066(19), administrative and general expenses and general plant are apportioned using a payroll allocator and uncollectible accounts expenses

are borne solely by the general service customer classes.

Q. Are there any items in this COS study that were not addressed in Order U-16-066(19)?

A. Yes. Pursuant to the Commission's Order U-25-004(5), ENSTAR is requesting recovery of the regulatory asset authorized in U-22-090(2) for the costs associated with studying and securing long-term gas supplies for the Alaska Railbelt. The unamortized balance of $4.6 million is included in rate base and the approximately $1.5 million of amortization expense in the revenue requirement. As discussed in direct testimony of Ms. Johansen, these costs are allocated between customer classes in the COS study based on adjusted test year gas volumes sold to General Service customers and transported to Firm Transportation customers.

Q. What are the results of the COS study?

A. Table 1 summarizes the cost of providing service (excluding gas costs) to each customer class. In addition, the COS study breaks out the total cost of providing service for each class into customer-related costs (*i.e.*, those associated with providing service irrespective of consumption), demand-related costs (*i.e.*, those associated with having sufficient capacity available to meet customers' demand for gas), and commodity-related costs (*i.e.*, those associated with gas, excluding expenses included in the GCA):

Table 1

Cost of Service (Excluding Gas Cost)

Class	Customer	Capacity	Commodity	Total
G-1	38,178,728	33,031,235	776,556	71,986,519
G-2	3,134,618	3,412,517	82,341	6,629,476
G-3	3,874,056	6,749,416	167,518	10,790,990
G-4	2,132,763	11,905,941	297,732	14,336,436
VLFT	231,911	11,010,856	970,904	12,213,671
MSFT	-	-	-	-
IIT/ITS	28,989	234,248	34,838	298,075
Total	47,581,065	66,344,212	2,329,889	116,255,167

Q. How do the results of this COS study compare with the revenues being produced under existing rates?

A. Table 2 compares the results of the COS study with test year revenues (excluding gas costs) by customer class:

Table 2

Under Recovery of Cost of Service

Class	Cost-of-Service	Current Base Revenues	Base Revenue Shortfall	Percent Increase
G-1	71,986,519	56,749,246	15,237,274	26.85%
G-2	6,629,476	4,506,980	2,122,496	47.09%
G-3	10,790,990	9,011,201	1,779,789	19.75%
G-4	14,336,436	11,450,729	2,885,707	25.20%
VLFT	12,213,671	9,491,917	2,721,754	28.67%
MSFT	-	-	-	0.00%
IIT/ITS	298,075	152,021	146,054	96.08%
Total	116,255,167	91,362,093	24,893,073	27.25%

As shown above, the rates currently being charged to each customer class are below ENSTAR's cost of providing service, especially those of the G-2 and IIT/ITS classes.

B. Rate Design

Q. What rate design is ENSTAR proposing for its General Service classes?

A. Consistent with the U-22-081 Stipulation, ENSTAR is proposing rates for its General Service classes based on the costs allocated to each in the respective COS studies. Also, the monthly service charge for each of the General Service classes is calculated as the sum of 50% of customer-related costs plus 50% of capacity-related costs. The volume charge is calculated using the remaining 50% of customer- and capacity-related costs, plus the commodity-related costs. This rate design produces the following monthly customer charges (rounded up to the nearest dollar) and volumetric charges for each of the General Service classes, as shown on Table 3 below:

Table 3

Class G1-G4 Proposed Permanent Rates

Class	G-1	G-2	G-3	G-4
Monthly Service Charge	$21.00	$46.00	$118.00	$575.00
Volumetric Rate (Mcf)	$1.8662	$1.6259	$1.3060	$0.9822

Q. How are the rates for ENSTAR's VLFT customer class developed?

A. Again, consistent with the U-22-081 Stipulation, ENSTAR's proposed rates for the VLFT class are based on the costs allocated to it in the COS studies. Customer-related costs of $231,911 are divided by eight customer delivery locations and twelve months to calculate a monthly customer charge (rounded to the nearest hundred) of $2,400. The monthly demand charges for each Mcf of a customer's contracted maximum demand is 50% of capacity costs related to peak demand divided by total contracted peak demand of 94,300 Mcf to calculate a monthly capacity charge for VLFT customers of $4.87 per Mcf (rounded to the nearest hundredth) of contracted

demand. Finally, the remaining 50% of capacity costs related to average demand of $5,505,428, the difference related to the rounding of the customer charge and capacity charge, and 100% of the $970,904 in commodity-related costs, are divided by test year volumes to calculate a volumetric charge of $0.2704 per Mcf.

Q. How did you develop the VLFT/SPPFT Peak Reduction Credit ("Peak Reduction Credit") ENSTAR proposes under Section 2170 discussed in Ms. Johansen's testimony?

A. As explained by Ms. Johansen, ENSTAR proposes to offer VLFT/SCPPFT customers having alternative fuel capability and meeting other requirements a monthly Peak Reduction Credit if they agree to reduce consumption when ENSTAR needs gas to meet other customers' requirements. This credit is intended to provide qualifying customers an incentive to reduce consumption, allow gas to be diverted, and partially compensate for the costs of having alternative fuel capability available. The calculation of the Peak Reduction Credit is based on the monthly VLFT demand charge of $4.87 per Mcf of contracted demand. Because the customer's contracted demand for pipeline capacity remains fully available, ENSTAR proposes to reduce the monthly demand charge by only 50% and only for the four winter months (*i.e.*, November through February) during which a consumption reduction might be required. Thus, for each Mcf per day reduction a customer elects, the annual credit would be calculated as $4.87 per Mcf times 50% times four months, or $9.74 per Mcf. Spread over the twelve months in a year, this equates to a Peak Reduction Credit of $0.81 per Mcf per month for each elected Mcf reduction.

Q. What rates does ENSTAR propose for IIT and ITS service?

A. ENSTAR is not proposing any changes to the structure of the IIT/ITS rates, with the rates for interruptible service being entirely volumetric and a flat rate structure. Accordingly, the IIT/ITS class revenue requirement of $298,075 is divided by test year billing units of 858,875 Mcf to produce a volumetric rate $0.3471 per Mcf. ENSTAR also proposes to retain the minimum charge equal to 100,000 Mcf, which equates to $34,700, for any month gas is transported by an IIT customer and for any year gas is transported by an ITS customer, in an effort to prevent the IIT tariff from being misused by customers that are not true large volume users.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

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Summary of Qualifications

M.B.A. and Ph.D. in finance, accounting, and economics; Certified Public Accountant. Extensive consulting experience involving regulated industries, valuation of closely-held businesses, and other economic analyses. Previously held managerial and technical positions in government, academia, and business, and taught at the undergraduate, graduate, and executive education levels. Broad experience in technical research, computer modeling, and expert witness testimony.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included revenue requirements, rate of return, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Other assignments have involved some seventy valuations as well as various economic (e.g., damage) analyses, typically in connection with litigation. Presented expert witness testimony before courts and regulatory agencies on over one hundred occasions.
Adjunct Assistant Professor, University of Texas at Austin (Sep. 1979 to May. 1981)	Taught undergraduate courses in finance: Fin. 370 – Integrative Finance and Fin. 357 – Managerial Finance.
Assistant Director, Economic Research Division, Public Utility Commission of Texas (Sep. 1976 to Aug. 1979)	Division consisted of approximately twenty-five financial analysts, economists, and systems analysts responsible for rate of return, rate design, special projects, and computer systems. Directed Staff participation in rate cases, presented testimony on approximately thirty-five occasions, and was involved in some forty other cases ultimately settled. Instrumental in the initial development of rate of return and financial policy for newly-created agency. Performed independent research and managed State and Federal funded projects. Assisted in preparing appeals to the Texas Supreme Court and testimony presented before the Interstate Commerce Commission and Department of Energy. Maintained communications with financial community, industry representatives, media, and consumer groups. Appointed by Commissioners as Acting Director.

Assistant Professor, College of Business Administration, University of Colorado at Boulder (Jan. 1977 to Dec. 1978)	Taught graduate and undergraduate courses in finance: Fin. 305 – Introductory Finance, Fin. 401 – Managerial Finance, Fin. 402 – Case Problems in Finance, and Fin. 602 – Graduate Corporate Finance.
Teaching Assistant, University of Texas at Austin (Jan. 1973 to Dec. 1976)	Taught undergraduate courses in finance and accounting: Acc. 311 – Financial Accounting, Acc. 312 – Managerial Accounting, and Fin. 357 – Managerial Finance. Elected to College of Business Administration Teaching Assistants' Committee.
Internal Auditor, Sears, Roebuck and Company, Dallas, Texas (Nov. 1970 to Aug 1972)	Performed audits on internal operations involving cash, accounts receivable, merchandise, accounting, and operational controls, purchasing, payroll, etc. Developed operating and administrative policy and instruction. Performed special assignments on inventory irregularities and Justice Department Civil Investigative Demands.
Accounts Payable Clerk, Transcontinental Gas Pipeline Corp., Houston, Texas (May. 1969 to Aug. 1969)	Processed documentation and authorized payments to suppliers and creditors.

Education

Ph.D., Finance, Accounting, and Economics, University of Texas at Austin (Sep. 1974 to May 1980)	Doctoral program included coursework in corporate finance, investment theory, accounting, and economics. Elected to honor society of Phi Kappa Phi. Received University outstanding doctoral dissertation award. Dissertation: *Estimating the Cost of Equity to Texas Public Utility Companies*
M.B.A., Finance and Accounting, University of Texas at Austin, (Sep. 1972 to Aug. 1974)	Awarded Wright Patman Scholarship by World and Texas Credit Union Leagues. Professional Report: *Planning a Small Business Enterprise in Austin, Texas*
B.B.A., Accounting and Finance, Southern Methodist University, Dallas, Texas (Sep. 1967 to Dec. 1971)	Dean's List 1967-1971 and member of Phi Gamma Delta Fraternity.

Other Professional Activities

Certified Public Accountant, Texas Certificate No. 13,710 (October 1974); entire exam passed in May 1972. Member of the American Institute of Certified Public Accountants (Honorary).

Participated as session chairman, moderator, and paper discussant at annual meetings of Financial Management Association, Southwestern Finance Association, American Finance Association, and other professional associations.

Visiting lecturer in Executive M.B.A program at the University of Stellenbosch Graduate Business School, Belleville, South Africa (1983 and 1984).

Associate Editor of *Austin Financial Digest*, 1974-1975. Wrote and edited a series of investment and economic articles published in a local investment advisory service.

Military

Texas Army National Guard, Feb. 1970 to Sep. 1976. Specialist 5th Class with duty assignments including recovery vehicle operator for armor unit and company clerk for finance unit.

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"On the Use of Security Analysts' Growth Projections in the DCF Model," with William E. Avera, *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds., Institute for Study of Regulation (1982).

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"Energy Conservation in Existing Residences, Project Director for development of instruction manual and workshops promoting retrofitting of existing homes, *Governor's Office of Energy Resources* and *Department of Energy* (1977-1978).

"Linear Algebra," "Calculus," "Sets and Functions," and "Simulation Techniques," contributed to and edited four mathematics programmed learning texts for MBA students, *Texas Bureau of Business Research* (1975).

Articles and Notes

"How to Value Personal Service Practices," with Keith Wm. Fairchild, *The Practical Accountant* (August 1989).

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"Capital Costs Within a Firm," *Proceedings of the Southwestern Finance Association* (1977).

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"Federal Energy Regulatory Commission Audits of Common Carriers (Procedures for Audit Compliance)", Energy Transfer Accounting Employee Education, Dallas and Houston, Texas (December 2018).

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"Rate of Return," "Origins of Information," Economics," and "Deferred Taxes and ITC's," New Mexico State University and National Association of Regulatory Utility Commissioners Public Utility Conferences on Regulation and the Rate-Making Process, Albuquerque, New Mexico (October 1983, 1984, 1985, 1986, 1987, 1988, 1990, 1991, 1992, 1994, and 1995, and September 1989); Pittsburgh, Pennsylvania (April 1993); and Baltimore, Maryland (May 1994 and 1995).

"Developing a Cost-of-Service Study," 1994 Texas Section American Water Works Association Annual Conference, Amarillo, Texas (March 1994).

"Financial Aspects of Cost of Capital and Common Cost Considerations," Kidder, Peabody & Co. Two-Day Rate Case Workshop for Regulated Utility Companies, New York, New York (June 1993).

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

"Rate Base and Revenue Requirements," The University of Texas Regulatory Institute Fundamentals of Utility Regulation, Austin, Texas (June 1989 and 1990).

"Determining the Cost of Capital in Today's Diversified Companies," New Mexico State University Public Utilities Course Part II, Advanced Analysis of Pricing and Utility Revenues, San Francisco, California (June 1990).

"Estimating the Cost of Equity," Oklahoma Association of Tax Representatives, Tulsa, Oklahoma (May 1990).

"Impact of Regulations," Business and the Economy, Leadership Dallas, Dallas, Texas (November 1989).

"Accounting and Finance Workshop" and "Divisional Cost of Capital," New Mexico State University Current Issues Challenging the Regulatory Process, Albuquerque, New Mexico (April 1985 and 1986) and Santa Fe, New Mexico (March 1989).

"Divisional Cost of Equity by Risk Comparability and DCF Analyses," NARUC Advanced Regulatory Studies Program, Williamsburg, Virginia (February 1988) and USTA Rate of Return Task Force, Chicago, Illinois (June 1988).

"Revenue Requirements," Revenue, Pricing, and Regulation in Texas Water Utilities, Texas Water Utilities Conference, Austin, Texas (August 1987 and May 1988).

"Rate Filing – Basic Ratemaking," Texas Gas Association Accounting Workshop, Austin, Texas (March 1988).

"The Effects of Regulation on Fair Market Value: P.H. Robinson – A Case Study," Annual Meeting of the Texas Committee of Utility and Railroad Tax Representatives, Austin, Texas (September 1987).

"How to Value Closely-held Businesses," TSCPA 1987 Entrepreneurs Conference, San Antonio, Texas (May 1987).

"Revenue Requirements" and "Determining the Rate of Return", New Mexico State University Regulation and the Rate-Making Process, Southwestern Water Utilities Conference, Albuquerque, New Mexico (July 1986) and El Paso, Texas (November 1980).

"How to Evaluate Personal Service Practices," TSCPA CPE Exposition 1985, Houston and Dallas, Texas (December 1985).

"How to Start a Small Business – Accounting and Record Keeping," University of Texas Management Development Program, Austin, Texas (October 1984).

"Project Financing of Public Utility Facilities", TSCPA Conference on Public Utilities Accounting and Ratemaking, San Antonio, Texas (April 1984).

"Valuation of Closely-Held Businesses," Concho Valley Estate Planning Council, San Angelo, Texas (September 1982).

"Rating Regulatory Performance and Its Impact on the Cost of Capital," New Mexico State University Seminar on Regulation and the Cost of Capital, El Paso, Texas (May 1982).

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"The Entrepreneur and Management: A Case Study," Small Business Administration Seminar, Austin, Texas (October 1979).

"Capital Budgeting by Public Utilities: A New Perspective," with W. Clifford Atherton, Jr., Financial Management Association, Boston, Massachusetts (October 1979).

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"The Cost of Equity to Wholly-Owned Electric Utility Subsidiaries," with William L. Beedles, Financial Management Association, Minneapolis, Minnesota (October 1978).

"PUC Retrofitting Program," Texas Electric Cooperatives Spring Workshop, Austin, Texas (May 1978).

"The Economics of Regulated Industries," Consumer Economics Forum, Houston, Texas (November 1977).

"Public Utilities as Consumer Targets – Is the Pressure Justified?" University of Texas at Dallas 2nd Annual Public Utilities Conference, Dallas, Texas (July 1977).

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: John M. Espindola, Chairman
Steve DeVries
Mark Johnston
Robert M. Pickett
John C. Springsteen

In the Matter of the Consideration of the Revenue Requirement Designated as TA 354-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF HAROLD WALKER, III

PREFILED DIRECT TESTIMONY
OF
HAROLD WALKER, III

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EXHIBITS
Exhibit HW-1 Professional Qualifications
Exhibit HW-2 Lead-Lag Study

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Harold Walker, III. My business address is 1010 Adams Avenue, Audubon, Pennsylvania, 19403.

Q. By whom are you employed?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC as Manager, Financial Studies.

Q. What is your educational background and employment experience?

A. My educational background, business experience, and qualifications are attached as Exhibit HW-1.

II. SCOPE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to recommend an appropriate cash working capital allowance for inclusion in ENSTAR Natural Gas Company, LLC's, and Alaska Pipeline Company, LLC's (collectively, "ENSTAR" or "Company") rate base in this proceeding before the Regulatory Commission of Alaska ("Commission").[1] My recommendation is based on the results of a lead-lag study that was performed under my direct supervision.

Q. Have you prepared an exhibit presenting the results of your study?

A. Yes. I have prepared Exhibit HW-2 which contains the 17 supporting schedules, identified as Schedule HW-1 through Schedule HW-17, summarizing the Company's

[1] The Commission regulates APC and ENSTAR as a single entity. The use of the name "ENSTAR" or "Company" in this filing is intended to include both APC and ENSTAR, unless the context clearly requires otherwise.

cash working capital requirement in this proceeding.

III. PRINCIPLES OF CASH WORKING CAPITAL

Q. Would you please explain the ratemaking principles concerning the inclusion of working capital as an element of rate base?

A. Yes. The working capital allowance is a component of rate base. A utility's need for working capital was first recognized in the noted United States Supreme Court case, *Smyth v. Ames*.[2] Among the many benchmarks established in the case was the "property devoted to public use" doctrine as a basis for fixing rates. The case recognized that among the matters to be considered in determining the value of property used was "the sum required to meet operating expenses."[3] Since that time, working capital has generally been recognized as a proper item to be included in the rate base on which a utility is entitled to earn a return.

Q. What is cash working capital?

A. Cash working capital is a component of working capital, representing the amount of funds necessary to finance the day-to-day operations of the Company. For ratemaking purposes, cash working capital is included as a component of a utility's rate base.

Q. Why is cash working capital included as an element of rate base?

A. Working capital is included in rate base to compensate investors for the use of their funds over and above their investment in plant, and to provide investors with a return on the funds required by the Company for daily operations. Cash working capital

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[2] *Smyth v. Ames*, 169 U.S. 466 (1898), overruled on other grounds by *Fed Power Comm'n v. Nat. Gas Pipeline Co. of Am.*, 315 U.S. 575, 586 (1942). Specifically, *Fed. Power Comm'n* departed from the holding in *Smyth* that fair market value in cost-of-service ratemaking must be used and instead concluded that "[t]he Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas."

[3] *Id*. at 547.

bridges the gap between the time when funds are provided to the Company by investors to allow the Company to provide service to customers, and the time revenues are received from customers as reimbursement for these services.

IV. OVERVIEW OF A LEAD-LAG STUDY

Q. How was the cash working capital requirement determined?

A. I conducted a lead-lag study to determine ENSTAR's cash working capital requirement. The lead-lag study in this case measured the level of funding required to operate on a day-to-day basis in a sufficient amount to cover the cost of service. This was measured by calculating the net lag between: (1) the amount of time elapsed between the provision of the cost of service and the receipt of the revenue requirement from the Company's customers (known as the revenue lag); and (2) the amount of time elapsed between when the Company receives goods and services used by the Company to provide service and the payment by the Company for those cost-of-service items (known as the expense lead). The difference between these two elapsed periods of time is known as the "net lag." The net lag was multiplied by the average daily cost of service (or revenue requirement) to determine the Company's cash working capital requirement.

Q. Please describe the components of a cash working capital analysis.

A. As I've touched on above, the two primary components of a cash working capital analysis are revenue lags and expense leads. The revenue lag is the elapsed time between when the delivery of a company's product, or provision of service, to its customers occurs and when a company receives payment for the delivery of the product. Investor-provided funds are required to keep a company running during the revenue lag time period, when the revenue stream is temporarily insufficient to finance

daily operational needs.

As mentioned above, the expense lead is the elapsed time between when a good or service is provided to a company and when a company pays its supplier, or vendor, for the good or service. During the expense lead time period, cash received from customers may temporarily exceed a company's payments to its suppliers for goods or services, and the excess may be used to repay investor-provided funds.

The net difference between the revenue lag and expense lead determines a company's cash working capital requirement. Additional details of the revenue lag and the expense lead calculations are provided below.

Q. Generally speaking, how did you calculate the revenue lag?

A. The revenue lag is the sum of three distinct components: the service period lag, the billing lag, and the collection lag.

Q. What is the service period lag?

A. The service period lag is the average time between meter readings. The average, or mid-point, between meter readings, based on monthly meter readings, is roughly 15 days. The mid-point service period lag is produced by dividing the service period of roughly 30 days by two.

Q. What is the billing lag?

A. The billing lag is the time from the meter reading date to the date the customer is billed. On the customer billing date, the bill is mailed to the customer, and the total billing amount for the cycle is recorded to ENSTAR's accounts receivable. The bills are

prepared and mailed roughly five days after meters are read.

Q. What is the collection lag?

A. The collection lag is the average number of days from the date the bills are mailed to customers to the date payments are received by ENSTAR. This was determined by summing the daily accounts receivable balance during the twelve months ended December 31, 2024, and dividing by the sum of the daily receipts for the same period.

Q. Generally speaking, how did you calculate the expense lead?

A. In a lead-lag study, the cost-of-service, or expense, lead days are calculated for each invoice or account by subtracting the midpoints of the service periods (the service lead) from the date the Company paid the invoices or accounts (the payment lead) and then summing these two data points.

The service lead is the average time that a service or good was provided to the Company. If a service or good was provided for 20 days, the 20-day service period is divided by two to produce a midpoint of ten days for the service period lead.

The payment lead is the number of days from the midpoint of the service period to the payment date for the service or good. If payment for the service or good was provided on the 30th day and the midpoint of the service period was the 10th day, the payment lead is 20 days (30 days – ten days).

Q. Why are midpoints used in the cash working capital analysis?

A. Midpoints are used to determine the average period during which a service or good is rendered or provided during the service period, or between meter reads. The midpoint assumes that, on average, service is provided evenly over the service period. For example, if a service is provided over a 30-day period, then on average, 30 days of

service was provided evenly for 15 days (30 ÷ 2) of the service period. Mathematically, the midpoint is the weighted average number of days that the full service period number of days (*e.g.*, 30 days) was provided.

V. ENSTAR'S LEAD-LAG STUDY

Q. Did you consider only a part of ENSTAR's overall cost of service in your lead-lag study?

A. Yes, I considered only a portion of ENSTAR's overall cost of service in my lead-lag study to determine its cash working capital requirement to be consistent with the Commission-approved methodology from Docket U-16-066 and used for settlement in Docket U-22-081. A lead-lag study based on the Commission-approved methodology from Docket U-16-066 likely understates the full cash working capital requirement and affords the minimum cash working capital requirement. A lead-lag study that was based on the entire revenue requirement (cost of service), including depreciation expense and operating income, would provide a more accurate measure of the cash working capital requirement.

Q. What data set did you utilize in your lead-lag study?

A. The data sets were selected after developing an understanding of the Company's collections, payment policies, and procedures. To inform my understanding of these items, I requested representative data sets from the Company. Once the requested raw data had been provided, I performed data validation by comparing an actual invoice or a bill with data from the utility's systems to ensure accuracy.

The revenue lag data set for the Company was based on an accounts receivable analysis of the beginning balance, the daily charges to this balance as bills were processed and mailed, and the daily receipts for all the days of the year during the 12

months ended December 31, 2024. The revenue lag data set for the Company also included an analysis of the cycle billing, the beginning and ending service dates (meter read dates), and the date bills were mailed (or posted).

The expense lead data set was based on information generated from the Company's central accounts payable system. The expense lead data sets for the 12 months ended December 31, 2024 were analyzed to develop the service beginning and ending dates, the amount purchased, and the date of payment. For some of the larger expense and tax accounts (line items), we randomly sampled the invoices to gather the required information. In instances where there were large differences in the dollar amount of the invoices in a single expense category, sampling was focused on the largest invoices within the expense category. For example, the larger "other third-party O&M expenses" accounts were sampled instead of the smaller accounts. In total, the samples analyzed averaged almost 100% of the Company's total expense and tax dollars.[4]

Q. What time period does your lead-lag study encompass?

A. The lead-lag study in this case analyzed the revenues and the associated cost of service during the 12 months ended December 31, 2024, to derive the lag (lead) days for the revenue requirement and the related cost-of-service line items.

Q. How were the revenue lag days and expense lead days used to calculate ENSTAR's cash working capital requirement?

A. For each cost-of-service line item, the lead days (expense) were subtracted from the lag

[4] As shown on page 2 of Schedule HW-3, the sampling for the total expense and tax dollars paid totaled 100% (~ 99.92%) and reflected a range of sampling from 76% to over 100% of the total line-item dollars (or expenses). Sampling of total line-item dollars greater than 100% of the expense occurred for those line items which included the capital portion, employee contributions, or deferred amounts.

days (revenue) to determine the net lag days for that cost-of-service line item. Next, the cost-of-service line item amount (dollars) was divided by 365 to determine the average daily amount. This average daily amount was then multiplied by net lag days for that cost-of-service line item to produce the cash working capital for each cost-of-service line item. This process was followed for each cost-of-service line item. Finally, the cash working capital requirements of each cost-of-service line item were totaled (summed) to calculate ENSTAR's total cash working capital requirement.

VI. RESULTS OF THE LEAD-LAG STUDY

Q. What are the results of the lead-lag study?

A. The lead-lag schedules are set forth in Schedule HW-1 through Schedule HW-17 provided in my Exhibit HW-2. Schedule HW-1 summarizes ENSTAR's cash working capital requirements. The cash working capital requirement for ENSTAR is $6,950,657.

Q. Please describe Schedule HW-1.

A. As shown on Schedule HW-1, the cash working capital requirement is based on the net lag days required to finance each cost-of-service line item. The net lag day calculations are a result of subtracting their respective expense lead days from the revenue lag days to determine the appropriate net lag days, which was then multiplied by the average daily expense (expenses ÷ 365 days) line item. The lag days for the receipt of the revenue requirement is developed on Schedule HW-2. The lead days for the cost-of-service line items are developed on Schedules HW-4 through HW-17, and the schedule references for the lead days for the cost-of-service line items is shown on page 1 of

Schedule HW-3.

Q. Please explain the procedures used to determine ENSTAR's cash working capital requirement shown on Schedule HW-1.

A. The process used to determine ENSTAR's cash working capital requirement, shown on Schedule HW-1, is generally the same for each line item. Because the process is generally the same, I will discuss the purchased gas costs line item as a means of explaining the methodology used for each line item.[5]

The purchased gas costs line item amount of $338,327,971 was divided by 365 to determine the average daily amount, $926,926. This average daily amount was then multiplied by the 2.5 net lag days to produce the cash working capital requirement of $2,317,315 for purchased gas costs ($338,327,971 ÷ 365 days = $926,926 × 2.5 net lag days = $2,317,315). The 2.5-day net lag for purchased gas costs was determined by subtracting the purchased gas costs 38.8-day expense lead from the 41.3-day revenue lag (41.3 lag days – 38.8 lead days = 2.5 net lag days).

A similar process was followed for each cost-of-service line item. The cash working capital requirement of all line items were totaled (summed) to calculate ENSTAR's $6,950,657 total cash working capital requirement.

Q. Please explain the procedures used to determine the revenue lag.

A. Schedule HW-2 shows the development of the 41.3-day lag for the Company's revenue requirement. The Company's 41.3-day revenue lag is developed on page 1 of Schedule HW-2. The revenue requirement lag reflects the Company's service, billings, and

[5] All expense and tax line items were handled in an identical manner. The two non-revenue requirement (cost-of-service) line items are included in the other adjustments sub account line item shown on Schedule HW-1 and consist of local sales tax and regulatory cost charge ("RCC"). For these two items, the revenue lag used in the determination of the net lag only considered the revenue collection lag days.

collections frequencies.

Q. Please explain the procedures used to determine the service period and the billing lag days for customer revenues.

A. The lag days for the service period and the billing lag are developed on page 2 of Schedule HW-2. As mentioned previously, the service period lag was measured from the midpoint of the service period to the meter reading date, and the billing lag was measured from the meter reading date to the billing date.

A weighted average service period lag of 15.2 days is shown on page 2 of Schedule HW-2.[6] ENSTAR's bills are prepared, mailed, and recorded to accounts receivable 5.1 days after meters are read. Adding the service period lag to the billing lag produces a combined 20.3-day service period and billing lag (15.2 days + 5.1 days = 20.3 days) as shown on page 2 of Schedule HW-2.

Q. Please describe the procedure used to calculate the collection lag.

A. As mentioned previously, the collection lag is the average number of days from the date the bills were mailed to the date payments are received and was determined by summing the daily accounts receivable balance during the test year and dividing by the sum of the daily test year receipts. This results in an average collection lag of 21.0 days as shown on page 3 of Schedule HW-2.

Q. Please summarize the total revenue lag.

A. The total revenue lag of 41.3 lag days is the result of adding the 20.3-day service period and billing lag and an average collection lag of 21.0 days as shown on page 1 of

[6] The average service period lag of 15.2 days was determined as follows: 365 days ÷ 12 bills per year = 30.4 service period ÷ 2 = 15.2 mid-point monthly service period.

Schedule HW-2.

Q. Please explain the calculation of lead days for the cost-of-service expenses shown on Schedule HW-1.

A. For each cost-of-service expense item that is shown, the lead days were calculated for each invoice or account based on the midpoints of the service periods to the dates the Company paid the invoices or accounts. Schedule HW-3 shows the schedule references for the cost-of-service lead days for the Company.

Q. How were the lead days determined for the operating expenses sub-account line items shown on Schedule HW-1?

A. For the operating expense sub-accounts line items shown, the lead days were determined for each invoice or account sampled based on the midpoints of the service periods to the dates the Company paid the invoices or accounts. As explained previously, sampling was randomly done for the invoices within the larger expense and tax categories.

For example, the weighted average lead days for purchased gas cost is 38.8-days (see Schedule HW-4). The lead days for purchased gas cost were calculated for each invoice examined based on the midpoints of the service periods to the dates the Company paid the invoices. In total, 100% of the purchased gas cost were sampled. Similar analyses were conducted for payroll expenses (see Schedule HW-5), salary and wage expenses (see Schedule HW-6), salary and wage bonus expenses (see Schedule HW-7), 401k matching expense (see Schedule HW-8), federal payroll taxes - FICA, Medicare & FUTA (see Schedule HW-9), FICA, Medicare and FUTA (see Schedule HW-9), state payroll taxes - SUTA (see Schedule HW-10), affiliate charges (see

Schedule HW-11), and other third-party O&M expenses (see Schedule HW-12).

Q. How were the lead days determined for the income taxes sub-account line items shown on Schedule HW-1?

For the federal taxes (current) and state taxes (current) sub-account line items shown, the lead days were calculated based on the midpoint of the tax period to the payment date, weighted by the percent of the payment required. The derivation of the federal taxes (current) 38.0 lead days is shown on Schedule HW-13, and the derivation of the state taxes (current) 38.0 lead days is shown on Schedule HW-14.

Q. How were the lead days determined for the taxes other than income taxes sub-account line items shown on Schedule HW-1?

A. For the taxes other than income taxes sub-account line item, the lead days were calculated based on the midpoint of the tax service period to the payment date, weighted by the actual amount paid. The taxes other than income taxes sub-account, property tax (ad valorem taxes), is shown on Schedule HW-15.

Q. What are the other adjustments sub account line item shown on Schedule HW-1?

A. The other adjustments sub account line item shown on Schedule HW-1 consists of local sales tax and RCC. The local sales tax and RCC are included in the lead-lag study because the Company pays them to the local governments and the State and must finance their collection and payment even though they are not considered part of the Company's revenue requirement/cost of service. The derivation of the local sales tax 73.6 lead days is shown on Schedule HW-16, and the derivation of the regulatory cost charge 70.1 lead days is shown on Schedule HW-17.

VII. CONCLUSION

Q. What are the results of the lead-lag study?

A. The results of the lead-lag study on Schedule HW-1 demonstrate that the Company requires $6,950,657 of cash working capital to bridge the gap between the time when funds are provided to the Company by investors to allow the Company to provide service to customers, and the time revenues are received from customers as reimbursement for these services.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Professional Qualifications
of
Harold Walker, III
Manager, Financial Studies
Gannett Fleming Valuation and Rate Consultants, LLC.

EDUCATION

Mr. Walker graduated from Pennsylvania State University in 1984 with a Bachelor of Science Degree in Finance. His studies concentrated on securities analysis and portfolio management with an emphasis on economics and quantitative business analysis. He has also completed the regulation and the rate-making process courses presented by the College of Business Administration and Economics Center for Public Utilities at New Mexico State University. Additionally, he has attended programs presented by The Institute of Chartered Financial Analysts (CFA).

Mr. Walker was awarded the professional designation "Certified Rate of Return Analyst" (CRRA) by the Society of Utility and Regulatory Financial Analysts. This designation is based upon education, experience and the successful completion of a comprehensive examination. He is also a member of the Society of Utility and Regulatory Financial Analysts (SURFA) and has attended numerous financial forums sponsored by the Society. The SURFA forums are recognized by the Association for Investment Management and Research (AIMR) and the National Association of State Boards of Accountancy for continuing education credits.

Mr. Walker obtained a license as a Municipal Advisor Representative (Series 50) by Municipal Securities Rulemaking Board (MSRB) and Financial Industry Regulatory Authority (FINRA).

BUSINESS EXPERIENCE

Prior to joining Gannett Fleming Valuation and Rate Consultants, LLC., Mr. Walker was employed by AUS Consultants - Utility Services. He held various positions during his eleven years with AUS, concluding his employment there as a Vice President. His duties included providing and supervising financial and economic studies on behalf of investor owned and municipally owned water, wastewater, electric, natural gas distribution and transmission, oil pipeline and telephone utilities as well as resource recovery companies.

In 1996, Mr. Walker joined Gannett Fleming Valuation and Rate Consultants, LLC. In his capacity as Manager, Financial Studies and for the past twenty-five years, he has continuously studied rates of return requirements for regulated firms. In this regard, he supervised the preparation of rate of return studies in connection with his testimony and in the past, for other individuals. He also assisted and/or developed dividend policy studies, nuclear prudence studies, calculated fixed charge rates for avoided costs involving cogeneration projects,

financial decision studies for capital budgeting purposes and developed financial models for determining future capital requirements and the effect of those requirements on investors and ratepayers, valued utility property for acquisition and divestiture, and assisted in the private placement of fixed capital securities for public utilities.

Head, Gannett Fleming GASB 34 Task Force responsible for developing Governmental Accounting Standards Board (GASB) 34 services and educating Gannett Fleming personnel and Gannett Fleming clients on GASB 34 and how it may affect them. The GASB 34 related services include inventory of assets, valuation of assets, salvage estimation, annual depreciation rate determination, estimation of depreciation reserve, asset service life determination, asset condition assessment, condition assessment documentation, maintenance estimate for asset preservation, establishment of condition level index, geographic information system (GIS) and data management services, management discussion and analysis (MD&A) reporting, required supplemental information (RSI) reporting, auditor interface, and GASB 34 compliance review.

In 2004, Mr. Walker was elected to serve on the Board of Directors of SURFA. Previously, he served as an ex officio director as an advisor to SURFA's existing President. In 2000, Mr. Walker was elected President of SURFA for the 2001-2002 term. Prior to that, he was elected to serve on the Board of Directors of SURFA during the period 1997-1998 and 1999-2000. He also previously served on the Pennsylvania Municipal Authorities Association, Electric Deregulation Committee.

EXPERT TESTIMONY

Mr. Walker has submitted testimony or been deposed on various topics before regulatory commissions and courts in 29 states including: Alaska, Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Idaho, Illinois, Indiana, Iowa, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Hampshire, Nevada, New Jersey, New York, North Carolina, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Vermont, Virginia, and West Virginia. His testimonies covered various subjects including: cash working capital, lead-lag studies, fair rate of return, fair market value, the taking of natural resources, benchmarking, appropriate capital structure and fixed capital cost rates, depreciation, purchased water adjustments, synchronization of interest charges for income tax purposes, valuation, financial analyses of investment alternatives, and fair value. The following tabulation provides a listing of the electric power, natural gas distribution, telephone, wastewater, and water service utility cases in which he has been involved as a witness.

Client	Docket No.
Alpena Power Company	U-10020

Armstrong Telephone Company - Northern Division	92-0884-T-42T
Armstrong Telephone Company - Northern Division	95-0571-T-42T
Artesian Water Company, Inc.	90 10
Artesian Water Company, Inc.	06 158
Aqua Illinois Consolidated Water Divisions and Consolidated Sewer Divisions	11-0436
Aqua Illinois Hawthorn Woods Wastewater Division	07 0620/07 0621/08 0067
Aqua Illinois Hawthorn Woods Water Division	07 0620/07 0621/08 0067
Aqua Illinois Kankakee Water Division	10-0194
Aqua Illinois Kankakee Water Division	14-0419
Aqua Illinois Vermilion Division	07 0620/07 0621/08 0067
Aqua Illinois Willowbrook Wastewater Division	07 0620/07 0621/08 0067
Aqua Illinois Willowbrook Water Division	07 0620/07 0621/08 0067
Aqua Illinois, Inc.	24-0044
Aqua Pennsylvania, Inc	A-2022-3034143
Aqua Pennsylvania, Inc	R-2024-3047822
Aqua Pennsylvania, Inc	R-2024-3047824
Aqua Pennsylvania Wastewater Inc	A-2016-2580061
Aqua Pennsylvania Wastewater Inc	A-2017-2605434
Aqua Pennsylvania Wastewater Inc	A-2018-3001582
Aqua Pennsylvania Wastewater Inc	A-2019-3008491
Aqua Pennsylvania Wastewater Inc	A-2019-3009052
Aqua Pennsylvania Wastewater Inc	A-2019-3015173
Aqua Pennsylvania Wastewater Inc	A-2021-3024267
Aqua Pennsylvania Wastewater Inc	A-2021-3026132
Aqua Pennsylvania Wastewater Inc	A-2021-3027268
Aqua Pennsylvania Wastewater Inc	A-2023-3041695
Aqua Virginia - Alpha Water Corporation	Pue-2009-00059
Aqua Virginia - Blue Ridge Utility Company, Inc.	Pue-2009-00059
Aqua Virginia - Caroline Utilities, Inc. (Wastewater)	Pue-2009-00059
Aqua Virginia - Caroline Utilities, Inc. (Water)	Pue-2009-00059
Aqua Virginia - Earlysville Forest Water Company	Pue-2009-00059
Aqua Virginia - Heritage Homes of Virginia	Pue-2009-00059

Aqua Virginia - Indian River Water Company	Pue-2009-00059
Aqua Virginia - James River Service Corp.	Pue-2009-00059
Aqua Virginia - Lake Holiday Utilities, Inc. (Wastewater)	Pue-2009-00059
Aqua Virginia - Lake Holiday Utilities, Inc. (Water)	Pue-2009-00059
Aqua Virginia - Lake Monticello Services Co. (Wastewater)	Pue-2009-00059
Aqua Virginia - Lake Monticello Services Co. (Water)	Pue-2009-00059
Aqua Virginia - Lake Shawnee	Pue-2009-00059
Aqua Virginia - Land'or Utility Company (Wastewater)	Pue-2009-00059
Aqua Virginia - Land'or Utility Company (Water)	Pue-2009-00059
Aqua Virginia - Mountainview Water Company, Inc.	Pue-2009-00059
Aqua Virginia - Powhatan Water Works, Inc.	Pue-2009-00059
Aqua Virginia - Rainbow Forest Water Corporation	Pue-2009-00059
Aqua Virginia - Shawnee Land	Pue-2009-00059
Aqua Virginia - Sydnor Water Corporation	Pue-2009-00059
Aqua Virginia - Water Distributors, Inc.	Pue-2009-00059
Atlantic City Sewerage Company	WR21071006
Berkshire Gas Company	18-40
Berkshire Gas Company	22-20
Bermuda Water Company, Inc	W-01812A-22-0256
Borough of Brentwood	A-2021-3024058
Borough of Hanover	R-2009-2106908
Borough of Hanover	R-2012-2311725
Borough of Hanover	R-2014-242830
Borough of Hanover	R-2021-3026116
Borough of Hanover	P-2021-3026854
Borough of Royersford	A-2020-3019634
Butler Area Sewer Authority	A-2020-3019634
Chaparral City Water Company	W 02113a 04 0616
California-American Water Company	CIVCV156413
Citizens Utilities Company Colorado Gas Division	-
Citizens Utilities Company Vermont Electric Division	5426
Citizens Utilities Home Water Company	R 901664

Citizens Utilities Water Company of Pennsylvania	R 901663
City of Beaver Falls	A-2022-3033138
City of Bethlehem - Bureau of Water	R-00984375
City of Bethlehem - Bureau of Water	R 00072492
City of Bethlehem - Bureau of Water	R-2013-2390244
City of Bethlehem - Bureau of Water	R-2020-3020256
City of Dubois - Bureau of Water	R-2013-2350509
City of Dubois - Bureau of Water	R-2016-2554150
City of Lancaster Sewer Fund	R-00005109
City of Lancaster Sewer Fund	R-00049862
City of Lancaster Sewer Fund	R-2012-2310366
City of Lancaster Sewer Fund	R-2019-3010955
City of Lancaster Water Fund	R-00984567
City of Lancaster Water Fund	R-00016114
City of Lancaster Water Fund	R 00051167
City of Lancaster Water Fund	R-2010-2179103
City of Lancaster Water Fund	R-2014-2418872
City of Lancaster Water Fund	R-2021-3026682
City of Lancaster Water Fund	P-2022-3035591
Coastland Corporation	15-cvs-216
Commonwealth Edison Company	23-0728
Commonwealth Edison Company	24-0087
Commonwealth Edison Company	23-0064
Commonwealth Edison Company	24-0795
Community Utilities of Pennsylvania-Water	R-2023-3042804
Community Utilities of Pennsylvania-Wastewater	R-2023-3042805
Connecticut-American Water Company	99-08-32
Connecticut Water Company	06 07 08
Consumers Pennsylvania Water Company Roaring Creek Division	R-00973869
Consumers Pennsylvania Water Company Shenango Valley Division	R-00973972
Country Knolls Water Works, Inc.	90 W 0458
East Resources, Inc. - West Virginia Utility	06 0445 G 42T
Elizabeth Borough Municipal Authority	A-2023-3038717
Elizabethtown Water Company	WR06030257

ENSTAR Natural Gas Company	U-22-081
Falls Water Company, Inc.	FLS-W-23-01
Forest Park, Inc.	19-W-0168 & 19-W-0269
Hampton Water Works Company	DW 99-057
Hidden Valley Utility Services, LP	R-2018-3001306
Hidden Valley Utility Services, LP	R-2018-3001307
Illinois American Water Company	16-0093
Illinois American Water Company	22-0210
Illinois American Water Company	24-0097
Indian Rock Water Company	R-911971
Indiana Natural Gas Corporation	38891
Iowa American Water Company	RPU-2024-0002
Jamaica Water Supply Company	-
Kane Borough Authority	A-2019-3014248
Kentucky American Water Company, Inc.	2007 00134
Kentucky American Water Company, Inc.	2023-00191
Middlesex Water Company	WR 89030266J
Millcreek Township Water Authority	55 198 Y 00021 11
Missouri-American Water Company	WR 2000-281
Missouri-American Water Company	SR 2000-282
Missouri-American Water Company	WR-2022-0303
Missouri-American Water Company	SR-2022-0304
Missouri-American Water Company	WR-2024-0320
Missouri-American Water Company	SR-2024-0321
Mount Holly Water Company	WR06030257
Nevada Power Company d/b/a NV Energy	20-06003
Nevada Power Company d/b/a NV Energy	23-06007
New Jersey American Water Company	WR 89080702J
New Jersey American Water Company	WR 90090950J
New Jersey American Water Company	WR 03070511
New Jersey American Water Company	WR-06030257
New Jersey American Water Company	WR08010020
New Jersey American Water Company	WR10040260
New Jersey American Water Company	WR11070460
New Jersey American Water Company	WR15010035
New Jersey American Water Company	WR17090985
New Jersey American Water Company	WR19121516

New Jersey American Water Company	WR22010019
New Jersey American Water Company	WR24010056
New Jersey Natural Gas Company	GR19030420
New Jersey Natural Gas Company	GR21030679
New Jersey Natural Gas Company	GR24010071
Newtown Artesian Water Company	R-911977
Newtown Artesian Water Company	R-00943157
Newtown Artesian Water Company	R-2009-2117550
Newtown Artesian Water Company	R-2011-2230259
Newtown Artesian Water Company	R-2017-2624240
Newtown Artesian Water Company	R-2019-3006904
Newtown Artesian Water Company	R-2024-3050208
North Maine Utilities	14-0396
Northern Indiana Fuel & Light Company	38770
Oklahoma Natural Gas Company	PUD-940000477
Palmetto Utilities, Inc.	2020-281-S
Palmetto Wastewater Reclamation, LLC	2018-82-S
Pennichuck Water Works, Inc.	DW 04 048
Pennichuck Water Works, Inc.	DW 06 073
Pennichuck Water Works, Inc.	DW 08 073
Pennsylvania-American Water Company	A-2023-3039900
Pennsylvania Gas & Water Company (Gas)	R-891261
Pennsylvania Gas & Water Co. (Water)	R 901726
Pennsylvania Gas & Water Co. (Water)	R-911966
Pennsylvania Gas & Water Co. (Water)	R-22404
Pennsylvania Gas & Water Co. (Water)	R-00922482
Pennsylvania Gas & Water Co. (Water)	R-00932667
Philadelphia Gas Works	R-2020-3017206
Philadelphia Gas Works	R-2023-3037933
Public Service Company of North Carolina, Inc.	G-5, Sub 565
Public Service Electric and Gas Company	ER181010029
Public Service Electric and Gas Company	GR18010030
Presque Isle Harbor Water Company	U-9702
Sierra Pacific Power Company d/b/a NV Energy	19-06002
Sierra Pacific Power Company d/b/a NV Energy	22-06014
Sierra Pacific Power Company d/b/a NV Energy	24-02026
Sierra Pacific Power Company d/b/a NV Energy	24-02027

St. Louis County Water Company	WR-2000-844
Suez Water Delaware, Inc.	19-0615
Suez Water Idaho, Inc.	SUZ-W-20-02
Suez Water New Jersey, Inc.	WR18050593
Suez Water New Jersey, Inc.	WR20110729
Suez Water Owego-Nichols, Inc.	17-W-0528
Suez Water Pennsylvania, Inc.	R-2018-3000834
Suez Water Pennsylvania, Inc.	A-2018-3003519
Suez Water Pennsylvania, Inc.	A-2018-3003517
Suez Water Rhode Island, Inc.	Docket No. 4800
Suez Water Owego-Nichols, Inc.	19-W-0168 & 19-W-0269
Suez Water New York, Inc.	19-W-0168 & 19-W-0269
Suez Westchester, Inc.	19-W-0168 & 19-W-0269
Tennessee American Water Company	24-00032
Town of North East Water Fund	9190
Township of Exeter	A-2018-3004933
United Water New Rochelle	W-95-W-1168
United Water Toms River	WR-95050219
Upper Pottsgrove Township	A-2020-3021460
Valley Township (water)	A-2020-3019859
Valley Township (wastewater)	A-2020-3020178
Valley Water Systems, Inc.	06 10 07
Veolia Water Idaho, Inc.	VEO-W-22-02
Veolia Water Idaho, Inc.	VEO-W-24-01
Veolia Water Delaware, Inc.	23-0598
Veolia Water New Jersey, Inc.	WR23110790
Veolia Water New York, Inc.	23-W-0111
Veolia Water Pennsylvania, Inc.	R-2024-3045192
Veolia Water Pennsylvania, Inc.	R-2024-3045193
Virginia American Water Company	PUR-2018-00175
Virginia American Water Company	PUR-2021-00255
Virginia American Water Company	PUR-2023-00194
West Virginia-American Water Company	15-0676-W-42T
West Virginia-American Water Company	15-0675-S-42T
Wilmington Suburban Water Corporation	94-149
York Water Company	R-901813
York Water Company	R-922168

York Water Company	R-943053
York Water Company	R-963619
York Water Company	R-994605
York Water Company	R-00016236
Young Brothers, LLC	2019-0117

BEFORE THE
REGULATORY COMMISSION OF ALASKA

DOCKET NO. U-25_____

ENSTAR NATURAL GAS COMPANY,
A DIVISION OF TRISUMMIT UTILITIES, INC.

Lead-Lag Schedules

Schedule HW-1 Through Schedule HW-17

To Accompany the

Direct Testimony of Harold Walker, III

On Lead-Lag Study - Working Capital

ENSTAR Natural Gas Company

Calculation of Cash Working Capital Requirements
Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Index to Schedules

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Schedule HW-2, Page 4	Residential & Commercial Sales Billing Lag
Schedule HW-2, Page 5	Transport Revenue Billing Lag
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Schedule HW-4	Purchased Gas Cost Lead Days Lead Days
Schedule HW-5	Payroll Expenses Lead Days Lead Days
Schedule HW-6	Salary and Wage Expenses Lead Days Lead Days
Schedule HW-7	Salary and Wage Bonus Expenses Lead Days Lead Days
Schedule HW-8	401k Matching Expense Lead Days Lead Days
Schedule HW-9	FICA, Medicare Lead Days Lead Days
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Schedule HW-11	Affiliate Charges Lead Days Lead Days
Schedule HW-12	Other Third-Party O&M Expenses Lead Days Lead Days
Schedule HW-13	Current Federal Income Taxes Lead Days Lead Days
Schedule HW-14	Current State Income Taxes Lead Days Lead Days
Schedule HW-15	Property Taxes Lead Days Lead Days
Schedule HW-16	Local Sales Tax Lead Days Lead Days
Schedule HW-17	Regulatory Cost Charge Lead Days Lead Days

ENSTAR Natural Gas Company
Summary Calculation of Cash Working Capital Requirements
Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Line	Description	Test Year Amount	Average Daily Amount	Revenue Lag	Lag Ref.	Expense Lead	Lead Ref.	Net (Lead)/Lag Days	Working Capital Requirement
1	Operations and Maintenance Expenses								
2	Purchased Gas Costs	$ 338,327,971	$ 926,926	41.30	(1)	38.80	(3)	2.50	$ 2,317,315
3	Non-Gas Operation and Maintenance Expenses								
4	Payroll Expenses	26,247,136	71,910	41.30	(1)	30.90	(3)	10.40	747,864
5	Affiliate Charges	3,316,056	9,085	41.30	(1)	96.70	(3)	(55.40)	(503,314)
6	Other Third-Party O&M Expenses	17,470,641	47,865	41.30	(1)	(57.00)	(3)	98.30	4,705,107
7	Total O&M Expenses	$ 385,361,804	$ 1,055,786						$ 7,266,972
8	Income Taxes								
9	Current Federal Income Taxes	$ 6,255,033	$ 17,137	41.30	(1)	38.00	(3)	3.30	$ 56,552
10	Deferred Federal Income Taxes	(831,570)							
11	State Income Tax	3,501,212	9,592	41.30	(1)	38.00	(3)	3.30	31,655
12	Total Federal Income Taxes	$ 8,924,675	$ 26,729						$ 88,207
13	Taxes Other Than Income Taxes								
14	Ad Valorem Taxes	$ 4,493,232	$ 12,310	41.30	(1)	41.40	(3)	(0.10)	$ (1,231)
15	Total Taxes Other Than Income Taxes	$ 4,493,232	$ 12,310						$ (1,231)
16	Depreciation Expense	$ 20,731,921							
17	Utility Operating Income	$ 35,796,610							
18	Subtotal	$ 455,308,242							$ 7,353,948
19	Other Adjustments								
20	Local Sales Tax	$ 1,637,038	$ 4,485	21.00	(2)	73.60	(3)	(52.60)	$ (235,913)
21	Regulatory Charge	1,244,255	3,409	21.00	(2)	70.10	(3)	(49.10)	(167,378)
22	Total Other Adjustments	$ 2,881,293	$ 7,894						$ (403,291)
23	Total Cash Working Capital Requirement								$ 6,950,657

Notes: (1) See page 1 of Schedule HW-2 for total revenue lag days.
(2) See page 3 of Schedule HW-2 for total revenue collection lag days.
(3) See page 1 of Schedule HW-3 for lead days.

ENSTAR Natural Gas Company

Calculation of Total Revenue Lag Days

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Description		Sales Revenue Customers	Transportation Revenue Customers		Total
Service Period & Billing Lag Days:					
(From mid-point of service period to A/R Posting Date. See page 2 of this Schedule)		20.3	21.7		20.3
Collection Lag:					
(Sum of daily accounts receivable balance divided by the sum of daily receipts. See page 3 of this Schedule)	+	20.9	23.6	+	21.0
Total Revenue Lag Days		41.2	45.3		41.3

ENSTAR Natural Gas Company

Calculation of Service Period and Billing Lag Days

Description		Sales Revenue Customers	Transportation Revenue Customers		Total
Annual Service Days		365.0	365.0		365.0
Months	÷	12	12	÷	12
Average Monthly Service Days		30.4	30.4		30.4
Mid-point Service Conversion	÷	2	2	÷	2
Service Lag Days		15.2	15.2		15.2
Billing Lag Days (1)	+	5.1	6.5	+	5.1
Total Service Period & Billing Lag Days		20.3	21.7		20.3
Test Year Revenues		$ 390,210,421	$ 8,291,851		$ 398,502,272

Note: (1) Developed on pages 4 and 5 of this schedule.

ENSTAR Natural Gas Company

Calculation of Collection Lag Days

Description		Sales Revenue Customers		Transportation Revenue Customers		Total
Sum of Net Daily Accounts Receivable Balance in a Year (1)		$ 8,168,003,872		$ 195,453,256		$ 8,363,457,128
Divided By the Sum of Daily Test Year Revenues	÷	390,210,421		8,291,851	÷	398,502,272
Total Service Period Collection Lag Days		20.9		23.6		21.0

Note: (1) Developed on pages 6 and 7 of this schedule.

ENSTAR Natural Gas Company

Calculation of Residential & Commercial Sales Billing Lag

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Cycles	Weighted Amount
(1)	(2)	(3)	(4)
January-24	6.0	16.00	96.00
February-24	5.1	16.00	81.00
March-24	5.1	16.00	82.00
April-24	5.1	16.00	82.00
May-24	5.2	16.00	83.00
June-24	4.8	16.00	77.00
July-24	4.1	16.00	66.00
August-24	5.1	16.00	82.00
September-24	5.5	16.00	88.00
October-24	5.0	16.00	80.00
November-24	5.0	16.00	80.00
December-24	4.8	16.00	77.00
Total Residential & Commercial Sales Billing Lag	5.1	192.00	974.00

ENSTAR Natural Gas Company

Calculation of Transport Revenue Billing Lag

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-24	5.0	$791,442.29	$3,957,211.45
February-24	5.0	716,292.34	3,581,461.70
March-24	8.0	735,131.52	5,881,052.16
April-24	7.0	701,109.50	4,906,690.50
May-24	6.0	702,134.67	4,211,732.02
June-24	5.0	682,614.95	3,409,846.75
July-24	8.0	650,409.64	5,196,821.12
August-24	9.0	667,484.63	6,007,361.67
September-24	8.0	609,862.47	4,872,443.76
October-24	6.0	656,729.80	3,939,302.80
November-24	5.0	681,901.82	3,409,509.10
December-24	7.0	696,737.17	4,872,877.93
Total Transport Revenue Billing Lag	6.5	$8,291,850.80	$54,246,310.96

ENSTAR Natural Gas Company

Calculation of Residential & Commercial Sales Sum of the Daily Accounts Receivable Balance

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Day	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
1	32,036,284	34,796,772	33,211,102	38,932,898	25,730,496	18,291,478	16,612,605	9,378,767	8,994,966	9,800,415	15,072,341	19,326,010
2	27,888,020	39,703,204	33,211,102	34,767,952	27,701,283	18,291,478	13,807,257	10,405,588	7,586,228	9,394,676	15,072,341	15,048,787
3	26,291,220	39,703,204	33,211,102	33,690,224	30,165,011	14,882,454	14,534,968	10,405,588	5,728,327	10,939,131	15,072,341	8,156,007
4	29,887,455	39,703,204	26,960,000	36,354,646	30,165,011	13,127,106	14,443,823	10,405,588	1,666,986	12,711,773	15,660,748	7,637,531
5	31,648,707	34,280,757	23,501,686	39,616,385	30,165,011	12,721,610	15,763,345	8,491,141	2,928,684	12,711,773	10,253,117	17,585,809
6	31,648,707	30,668,226	22,063,269	39,616,385	25,816,842	14,632,303	15,763,345	6,793,354	4,469,696	12,711,773	10,789,313	23,130,582
7	31,648,707	29,410,355	27,492,714	39,616,385	23,478,792	17,041,634	15,763,345	9,970,514	4,469,696	6,678,854	20,023,441	23,130,582
8	29,601,986	38,260,085	32,781,543	33,237,154	22,871,922	17,041,634	12,943,135	12,161,731	4,469,696	8,969,669	23,249,381	23,130,582
9	26,445,839	44,901,022	32,781,543	29,890,579	27,014,504	17,041,634	11,221,076	13,253,413	6,215,340	8,432,354	23,249,381	20,401,225
10	25,334,723	44,901,022	32,781,543	29,142,651	29,606,478	14,745,933	11,383,844	13,253,413	4,962,591	12,100,113	23,249,381	17,779,513
11	33,736,380	44,901,022	28,917,343	34,434,197	29,606,478	13,126,245	13,704,407	13,253,413	4,730,296	13,927,187	21,186,881	17,284,568
12	36,266,623	40,059,388	25,728,365	36,946,252	29,606,478	12,649,859	14,923,360	11,936,126	7,929,833	13,927,187	19,137,118	26,460,334
13	36,266,623	36,472,603	24,474,659	36,946,252	25,948,699	16,590,380	14,923,360	10,929,655	10,006,787	13,927,187	18,477,811	32,788,234
14	36,266,623	35,401,587	30,472,305	36,946,252	23,722,196	19,091,530	14,923,360	10,637,113	10,006,787	12,295,669	21,266,348	32,788,234
15	34,369,772	41,429,432	36,612,257	32,182,081	22,900,080	19,091,530	12,858,001	11,907,786	10,006,787	10,697,733	24,758,936	32,788,234
16	32,613,279	44,960,550	36,612,257	28,229,948	25,214,602	19,091,530	11,256,464	12,795,889	8,594,604	10,071,977	24,758,936	29,253,739
17	31,045,035	44,960,550	36,612,257	27,227,002	25,582,645	16,519,578	10,762,997	12,795,889	8,114,590	12,604,838	24,758,936	28,031,423
18	36,167,585	44,960,550	32,987,041	30,399,478	25,582,645	15,631,464	11,641,531	12,795,889	7,711,155	14,749,790	21,299,727	27,631,287
19	40,418,398	41,659,789	31,205,040	33,067,965	25,582,645	15,440,330	12,483,590	11,383,523	9,807,107	14,749,790	20,327,100	33,763,119
20	40,418,398	39,558,752	30,383,762	33,067,965	22,669,356	17,639,956	12,483,590	10,533,983	11,369,368	14,749,790	19,189,163	38,778,665
21	40,418,398	38,610,473	35,649,626	33,067,965	21,574,096	19,055,363	12,483,590	10,297,925	11,369,368	12,694,251	22,813,663	38,778,665
22	35,879,849	43,367,497	40,064,192	29,053,264	20,935,300	19,055,363	10,346,031	11,618,208	11,369,368	12,005,020	24,865,945	38,778,665
23	34,706,278	42,832,430	40,064,192	27,482,984	22,553,771	19,055,363	9,816,838	11,624,811	10,716,926	11,588,671	24,865,945	37,199,491
24	33,778,632	42,832,430	40,064,192	26,865,808	22,451,202	17,614,356	9,309,561	11,624,811	9,909,639	13,845,290	24,865,945	36,583,540
25	38,488,011	42,832,430	38,941,320	31,442,413	22,451,202	18,217,782	10,287,816	11,624,811	11,145,064	16,197,163	24,801,928	36,507,728
26	41,519,578	41,065,348	40,389,682	32,188,685	22,451,202	17,613,020	11,338,687	9,368,403	13,145,978	16,197,163	22,029,956	44,011,466
27	41,519,578	38,601,233	39,940,261	32,188,685	20,777,622	19,122,654	11,338,687	9,999,335	13,304,155	16,197,163	21,396,926	44,770,531
28	41,519,578	37,541,214	43,912,311	32,188,685	19,948,811	19,050,843	11,338,687	9,828,925	13,304,155	14,339,635	21,312,118	44,770,531
29	38,641,698	35,684,888	43,983,828	29,136,523	19,745,704	19,050,843	9,995,880	9,486,919	13,304,155	13,515,728	19,326,010	44,770,531
30	34,819,325		43,983,828	26,534,028	19,074,623	19,050,843	8,780,445	8,994,966	11,368,666	12,991,134	19,326,010	40,195,193
31	33,808,925		43,983,828		18,291,478		8,510,350	8,994,966		12,221,525		31,559,824
Total	1,033,063,931	1,119,263,241	1,029,767,045	945,528,789	733,655,693	491,284,618	369,131,366	327,573,679	249,712,033	378,144,011	597,384,847	893,494,618

Sum of A/R Daily Balances 8,168,003,872

ENSTAR Natural Gas Company

Calculation of Transport Revenue Sum of the Daily Accounts Receivable Balance

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-24	24.7	$791,442.29	$19,570,500.81
February-24	23.3	716,292.34	16,675,977.12
March-24	22.4	735,131.52	16,459,022.00
April-24	23.4	701,109.50	16,378,540.62
May-24	22.9	702,134.67	16,062,103.67
June-24	21.9	682,614.95	14,954,953.91
July-24	21.0	650,409.64	13,651,634.84
August-24	23.0	667,484.63	15,348,797.57
September-24	26.3	609,862.47	16,031,443.38
October-24	23.9	656,729.80	15,686,439.78
November-24	23.2	681,901.82	15,830,503.35
December-24	27.0	696,737.17	18,803,339.07
Total Transport Revenue Sum of the Daily Accounts Receivable Balance	23.6	$8,291,850.80	$195,453,256.12
		Sum of A/R Daily Balances	$195,453,256.12

ENSTAR Natural Gas Company
Summary of Operating Expenses and Taxes Lead Days
Determined in the Lead-Lag Study For the Twelve Months Ended December 31, 2024

Description	Schedule Reference	Amount	Weighted Amount	(Lead)/ Lag Days
(1)	(2)	(3)	(4)	(5)=(4)/(3)
Operating Expenses & Taxes*				
Purchased Gas Cost	Schedule HW-4	346,495,220	13,428,099,531	38.8
Payroll Expenses	Schedule HW-5	26,247,136	811,657,959	30.9
Salary and Wage Expenses	Schedule HW-6	22,067,336	708,616,794	32.1
Salary and Wage Bonus Expenses	Schedule HW-7	2,004,594	477,894,734	238.4
401k Matching Expense	Schedule HW-8	2,455,186	77,752,503	31.7
Federal Payroll Taxes - FICA, Medicare & FUTA	Schedule HW-9	2,326,460	26,411,772	11.4
FICA, Medicare	Schedule HW-9	2,312,841	25,141,310	10.9
FUTA	Schedule HW-9	13,619	1,270,462	93.3
State Payroll Taxes - SUTA	Schedule HW-10	132,311	9,507,201	71.9
Affiliate Charges	Schedule HW-11	12,233,723	1,182,723,231	96.7
Other Third-Party O&M Expenses	Schedule HW-12	22,401,998	(1,276,391,455)	(57.0)
Current Federal Income Taxes	Schedule HW-13			38.0
Current State Income Taxes	Schedule HW-14			38.0
Property Taxes	Schedule HW-15	4,468,181	184,882,454	41.4
Local Sales Tax	Schedule HW-16	1,637,038	120,561,637	73.6
Regulatory Cost Charge	Schedule HW-17	948,148	66,432,991	70.1

* Lead days for expenses are calculated from the mid-point of the service period to the payment date. (See Schedules 4 - 17.)

ENSTAR Natural Gas Company
Operating Expenses & Taxes Sample Sizes Used In the
Lead-Lag Study For the Twelve Months Ended December 31, 2024

Description	Per Books	Sample Size	Percentage Sampled	
(1)	(2)	(3)	(4)=(3)/(2)	
Expenses & Taxes				
1. Purchased Gas Cost	$338,327,971	$346,495,220	102%	(1)
2. Payroll Expenses	26,247,136	26,247,136	100%	(2)
3. Salary and Wage Expenses	20,711,502	22,067,336	107%	(3)
4. Salary and Wage Bonus Expenses	2,387,735	2,004,594	84%	
5. 401k Matching Expense	1,410,322	2,455,186	174%	(3)
6. FICA, Medicare	1,634,451	2,312,841	142%	(3)
7. FUTA	9,624	13,619	142%	(3)
8. Federal Payroll Taxes - FICA, Medicare & FUTA	1,644,075	2,326,460	142%	(3)(4)
9. State Payroll Taxes - SUTA	93,502	132,311	142%	(3)
10. Affiliate Charges	3,316,056	12,233,723	369%	(5)
11. Other Third-Party O&M Expenses	17,470,641	22,401,998	128%	(1)
12. Current Federal Income Taxes	6,255,033	6,255,033	100%	
13. Current State Income Taxes	3,501,212	3,501,212	100%	
14. Property Taxes	4,493,232	4,468,181	99%	
15. Local Sales Tax	1,637,038	1,637,038	100%	
16. Regulatory Cost Charge	1,244,255	948,148	76%	
	$402,492,574	$402,171,416 (6)	100%	(6)

Notes: (1) Sample amount is greater than 100% of expense because sampling based on cash payment, not accrual expense amount.
(2) Sampling amount weighted based on Test Year amount of line items 3,4,5, 8 and 9.
(3) Sample amount is greater than 100% of expense because it includes the capital portion, employee contributions, or deferred amounts.
(4) Based on the sampling for line items 6-7.
(5) Includes expenses that are have been reclassified into other expense line items.
(6) Totals exclude subline expense items and sampled amount adjusted to 100% if the actual sampled amount was greater than 100%.

ENSTAR Natural Gas Company

Calculation of Lead Days For Purchased Gas Cost

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-24	40.8	$45,189,473.28	$1,844,301,692.72
February-24	36.1	36,742,365.73	1,325,360,417.12
March-24	37.8	34,438,473.63	1,300,983,607.62
April-24	38.4	23,681,770.24	909,251,097.90
May-24	38.3	21,859,808.20	837,655,992.53
June-24	37.9	21,165,886.37	802,714,741.31
July-24	39.8	22,130,294.78	880,511,072.70
August-24	38.6	21,294,579.62	822,319,651.74
September-24	37.8	21,104,311.61	797,135,328.94
October-24	40.6	24,026,269.02	975,329,973.40
November-24	40.2	37,057,668.33	1,487,944,771.04
December-24	38.2	37,804,318.84	1,444,591,184.29
Total Purchased Gas Cost	38.8	$346,495,219.65	$13,428,099,531.30

ENSTAR Natural Gas Company

Calculation of Lead Days For Payroll Expenses

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Account	Test Year Amount	(Lead)/ Lag Days	Schedule Ref. For (Lead)/ Lag Days	Weighted Amount
(1)	(2)	(3)	(4)	(5)
Total Salary And Wage Expenses	$23,099,236.83	32.1	6	$741,485,502.39
Total 401k Matching Expense	1,410,321.66	31.7	8	44,707,196.73
Total Federal Payroll Taxes - FICA, Medicare & FUTA	1,644,075.00	11.4	9	18,742,455.00
Total State Payroll Taxes - SUTA	93,502.15	71.9	10	6,722,804.80
Total Payroll Expenses	$26,247,135.65	30.9		$811,657,958.92

ENSTAR Natural Gas Company

Calculation of Lead Days For Salary and Wage Expenses

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Facts	(Lead)/ Lag Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
All company employees are paid for a two week period (i.e., Days 1 through 14).			
Pay date is five days following the end of the payroll period (i.e., Day 19, where 19 = 14 + 5).			
LEAD [19 - 7.5 = 11.5; where 7.5 = (1 + 14 = 15 ÷ 2 = 7.5)]			

Account	Schedule Ref. For (Lead)/ Lag Days	(Lead)/ Lag Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)	(5)
Union Labor Wage & Non-Union Salaries (5 days)				
LEAD [19 - 7.5 = 11.5; where 7.5 = (1 + 14 = 15 ÷ 2 = 7.5)]		11.5	$20,062,742.10	$230,721,534.15
Non-Union Bonus	7	238.4	2,004,594	477,895,259.66
Total Salary And Wage Expenses		32.1	$22,067,336.31	$708,616,793.81

ENSTAR Natural Gas Company

Calculation of Lead Days For Salary and Wage Bonus Expenses

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
March-24	240.1	$1,991,871.73	$478,307,589.31
May-24	(45.5)	10,350.80	-470,961.40
July-24	24.5	2,371.68	58,106.16
Total Salary and Wage Bonus Expenses	238.4	$2,004,594.21	$477,894,734.07

ENSTAR Natural Gas Company

Calculation of Lead Days For 401k Matching Expense

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-24	99.7	$276,130.73	$27,543,376.04
February-24	11.5	155,475.30	1,787,965.95
March-24	110.6	255,543.39	28,268,354.51
April-24	11.5	156,521.74	1,800,000.01
May-24	11.5	251,998.24	2,897,643.82
June-24	11.5	181,667.45	2,089,175.68
July-24	11.5	185,225.03	2,130,087.85
August-24	11.5	184,532.91	2,122,128.47
September-24	11.5	187,563.06	2,156,975.19
October-24	11.5	187,498.16	2,156,228.84
November-24	10.8	266,748.83	2,888,335.31
December-24	11.5	166,281.02	1,912,231.73
Total 401k Matching Expense	31.7	$2,455,185.86	$77,752,503.38

ENSTAR Natural Gas Company

Calculation of Lead Days For Federal Payroll Taxes - FICA, Medicare & FUTA

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-24	11.6	$156,451.06	$1,821,302.95
February-24	11.5	157,032.09	1,803,736.71
March-24	6.2	287,146.07	1,773,130.72
April-24	16.9	163,210.29	2,763,247.66
May-24	11.5	258,495.47	2,961,123.27
June-24	11.5	191,074.68	2,197,358.82
July-24	12.3	190,089.05	2,343,773.52
August-24	11.5	181,136.27	2,080,323.55
September-24	11.5	182,749.23	2,098,480.86
October-24	11.7	181,541.14	2,120,924.92
November-24	10.9	236,937.81	2,572,693.14
December-24	13.3	140,597.24	1,875,676.12
Total Federal Payroll Taxes - FICA, Medicare & FUTA	11.4	$2,326,460.40	$26,411,772.22
Federal Payroll Tax Breakdown:			
FICA, Medicare	10.9	2,312,841.19	25,141,310.40
FUTA	93.3	13,619.21	1,270,461.83
Total	11.4	$2,326,460.40	$26,411,772.22

ENSTAR Natural Gas Company

Calculation of Lead Days For State Payroll Taxes - SUTA

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-24	63.5	$8,888.26	$564,404.51
April-24	71.0	60,661.16	4,306,942.36
July-24	74.0	45,811.00	3,390,014.00
October-24	73.5	16,950.21	1,245,840.44
Total State Payroll Taxes - SUTA	71.9	$132,310.63	$9,507,201.31

ENSTAR Natural Gas Company

Calculation of Lead Days For Affiliate Charges

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days*	Amount	Weighted Amount
(1)	(2)	(3)	(4)
February-24	238.7	$33,666.50	$8,037,207.00
March-24	91.9	5,429,814.86	498,907,509.94
April-24	26.0	36,661.50	953,199.00
May-24	(78.7)	77,134.46	-6,070,176.65
June-24	130.4	693,134.50	90,419,228.67
July-24	45.5	289.08	13,153.14
August-24	380.9	25,665.87	9,776,555.24
September-24	93.9	5,140,211.97	482,784,778.96
December-24	122.8	797,144.12	97,901,775.57
Total Affiliate Charges	96.7	$12,233,722.86	$1,182,723,230.85

ENSTAR Natural Gas Company

Calculation of Lead Days For Other Third-Party O&M Expenses

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-24	(6.3)	$985,565.26	-$6,212,862.50
February-24	(8.7)	1,267,203.05	-11,059,891.99
March-24	(76.8)	1,595,138.93	-122,532,993.11
April-24	(132.8)	4,514,751.59	-599,747,420.78
May-24	(110.2)	3,681,624.23	-405,800,152.50
June-24	(5.6)	1,071,035.10	-5,988,287.81
July-24	7.5	1,033,170.54	7,789,569.34
August-24	10.2	977,125.87	9,940,229.84
September-24	6.8	1,470,296.34	10,005,606.45
October-24	(21.8)	1,267,884.60	-27,619,295.93
November-24	(11.6)	1,905,587.79	-22,182,661.96
December-24	(39.1)	2,632,614.93	-102,983,293.56
Total Other Third-Party O&M Expenses	(57.0)	$22,401,998.23	-$1,276,391,454.51

ENSTAR Natural Gas Company

Calculation of Lead Days For Current Federal Income Taxes

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Service Period		Payment	(Lead)/		Weighted
From	To	Date	Lag Days	Amount	Amount
(1)	(2)	(3)	(4)	(5)	(6)
Federal Income Taxes (Current)					
1/1/24	12/31/24	4/15/24	(77.5)	25%	(19.4)
1/1/24	12/31/24	6/17/24	(14.5)	25%	(3.6)
1/1/24	12/31/24	9/16/24	76.5	25%	19.1
1/1/24	12/31/24	12/16/24	167.5	25%	41.9
Total Current Federal Income Taxes			38.0	100%	38.0

ENSTAR Natural Gas Company

Calculation of Lead Days For Current State Income Taxes

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Service Period		Payment	(Lead)/		Weighted
From	To	Date	Lag Days	Amount	Amount
(1)	(2)	(3)	(4)	(5)	(6)
State Income Taxes (Current)					
1/1/24	12/31/24	4/15/24	(77.5)	25%	(19.4)
1/1/24	12/31/24	6/17/24	(14.5)	25%	(3.6)
1/1/24	12/31/24	9/16/24	76.5	25%	19.1
1/1/24	12/31/24	12/16/24	167.5	25%	41.9
Total Current State Income Taxes			38.0	100%	38.0

ENSTAR Natural Gas Company

Calculation of Lead Days For Property Taxes

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
February-24	44.5	$442,284.42	$19,681,656.69
June-24	(4.5)	151,654.08	-682,443.36
August-24	(82.7)	619,510.36	-51,227,161.23
September-24	(102.8)	595,567.84	-61,227,564.12
October-24	107.5	3,082.50	331,368.75
November-24	104.7	2,656,081.79	278,006,597.42
Total Property Taxes	41.4	$4,468,180.99	$184,882,454.15

ENSTAR Natural Gas Company

Calculation of Lead Days For Local Sales Tax

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-24	46.0	$686.26	$31,567.96
February-24	73.1	430,349.81	31,441,000.53
March-24	42.0	38,329.55	1,609,841.10
May-24	74.9	553,520.50	41,449,522.88
June-24	46.0	44,205.38	2,035,264.59
July-24	72.5	309,753.10	22,452,223.24
August-24	51.7	13,612.83	704,239.41
September-24	40.0	10,126.66	404,880.85
October-24	42.2	16,513.90	696,882.29
November-24	96.4	193,570.54	18,653,351.95
December-24	41.1	26,369.87	1,082,861.86
Total Local Sales Tax	73.6	$1,637,038.40	$120,561,636.65

ENSTAR Natural Gas Company

Calculation of Lead Days For Regulatory Cost Charge

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2024

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
April-24	70.0	$528,851.55	$37,019,608.50
July-24	70.0	294,102.50	20,587,175.00
October-24	70.5	125,194.43	8,826,207.32
Total Regulatory Cost Charge	70.1	$948,148.48	$66,432,990.82