STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Keith Kurber II, Chair Robert A. Doyle Robert M. Pickett Daniel A. Sullivan Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-____

PREFILED DIRECT TESTIMONY
OF
BRUCE H. FAIRCHILD

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I. POSITION AND QUALIFICATIONS

Q. State your name, business address, and present position.

A. My name is Bruce H. Fairchild. My business address is 3907 Red River, Austin, Texas 78751. 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. Briefly describe your professional experience and educational background.

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.

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.

Q. Briefly describe your current professional responsibilities.

A. 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. A resume that contains the details of my experience and qualifications is attached as Exhibit BHF-1.

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

A. Yes. As mentioned above, I have previously testified before a number of regulatory authorities, including the RCA. Exhibit BHF-1 includes a listing of my prior testimony before regulatory agencies since leaving the PUCT.

II. PURPOSE OF TESTIMONY AND BACKGROUND

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony on behalf of ENSTAR Natural Gas Company, a division of SEMCO Energy, Inc., and Alaska Pipeline Company (collectively, "ENSTAR") is to address four items in its 275(a) filing[1] (Attachment B to TA334-4) and 275(h) filing[2] (Attachment C to TA334-4). First, I opine on the reasonableness of the calculation of the weather adjustments to normalize gas usage during the 2021 test year by selected customer classes. Second, I sponsor the calculation of the income tax expense included

[1] 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.

[2] 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…"

in the revenue requirement on Schedule G to ENSTAR's 275(a) filing, which includes an adjustment to amortize excess accumulate deferred income taxes ("ADIT") resulting from the Tax Cut and Jobs Act of 2017 ("TCJA"). Third, I present 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. Fourth, I develop specific rates for each of ENSTAR's proposed 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, a listing of which is 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 for the unusually cold weather experienced during the test year?

A. Yes. The methodology, sponsored by ENSTAR witness Mr. Daniel M. Dieckgraeff, used to weather normalize test year usage 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 the test year is then reduced by the base usage to calculate per customer test year heating load. This test year heating load is then increased or decreased based on the fewer or greater, respectively, heating degree days ("HDD")[3] in the test year versus an average year. The resulting adjusted HDD are then added to or subtracted from base usage to calculate normalized usage per customer. The normalized usage serves as the basis for adjusting certain test year operating expenses and revenues to develop the revenue requirement, 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 test year usage by customers in its general service customer classes is a standard method of weather normalization. It is the same methodology that I used to normalize usage to develop the revenue requirement, allocate costs in a COS study, and design rates in Docket Nos. U-00-088 and U-09-069/U-09-070.[4]

B. <u>Income Tax Expense</u>

Q. Do you sponsor the Income Tax pro forma found on Schedule G of the 275(a) filing?

A. Yes.

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[3] 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.

[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 test year rate case was settled, and the Commission accepted the stipulation in Order U-09-069(10)/U-09-070(10). The weather normalized volumes per customer proposed by ENSTAR were used to derive the tariff rates that were approved in that Order.

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, is developed on Schedule G of the 275(a) filing (Attachment B). Beginning with ENSTAR's requested after-tax return on equity of $20,543,671 from page 3 of the 275(a) filing, the amortization of excess ADIT is subtracted to arrive at a net after-tax return of $19,848,602. This amount is then multiplied by a combined state/federal income tax factor of 0.397155[5] to calculate state and federal income tax expenses of $7,882,979.

Q. What portion of this total is state income taxes?

A. Combining ENSTAR's requested net after-tax return on equity of $19,848,602 with the total combined state/federal income tax expenses of $7,882,979 produces state taxable income of $27,731,581. Multiplying this amount by Alaska's 9.4% corporate income tax rate results in state income tax expense of $2,606,769, which is $79,965 greater than the $2,526,804 recorded on ENSTAR's books during 2021. These values are shown on page 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 of $2,606,769 from state taxable income of $27,731,581 leaves federal taxable income of $25,124,813. Multiplying this amount

[5] The combined state/federal income tax factor may be calculated as: (1/((1-state tax rate) x (1-federal income tax rate)))-1.

by the U.S. corporate income tax rate of 21% produces federal income tax expense of $5,276,211.

Q. Is this the federal income tax included in ENSTAR's requested revenue requirement?

A. No, this federal income 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 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. The excess ADIT related to the timing differences between accelerated (including bonus) depreciation expense used for tax purposes versus the straight-line depreciation expense used for book purposes is classified as "protected." Per Internal Revenue Service ("IRS") normalization rules, protected ADIT can be only amortized using either the average rate assumption method ("ARAM") or the reverse South Georgia method ("remaining life"). All other excess ADIT is classified as "unprotected," and may be amortized over an appropriate period.

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. What is the amount of ENSTAR's excess ADIT?

A. On January 1, 2018, ENSTAR's excess ADIT was a net balance of $14,940,519, which it continued to carry on its books for resolution in this case. This total consists of a credit balance of $18,419,491 in protected excess ADIT and a debit balance of $3,478,972 in unprotected excess ADIT, although as discussed by Mr. Dieckgraeff, these balances are under review and may be adjusted. Please also note that whereas these excess ADIT balances have not been grossed-up for income taxes, the excess ADIT included in rate base has.

Q. What method is ENSTAR using to amortize protected excess ADIT?

A. ENSTAR does not have the data to use the ARAM, which is based on the deferred tax reversal pattern calculated by comparing the book depreciation versus tax depreciation of assets. For accounting purposes, ENSTAR's plant data are maintained on a J. D. Edwards software system, while for tax purposes, plant data are maintained on software called PowerTax. These systems were implemented at different times and there is no direct mapping of assets between them. Because a review concluded that it was impractical to map the records between the two systems, ENSTAR is using the remaining life method to amortize protected excess ADIT.

Q. Over what period is ENSTAR proposing to amortize excess ADIT?

A. In its correspondence with the Commission in I-18-002 and TA303-4 (attached as Exhibits DMD-2 and DMD-3 to Mr. Dieckgraeff's testimony), ENSTAR proposed to amortize the protected excess ADIT over the remaining book life of the underlying assets beginning with its next rate case. Based on a study by Dane Watson of the Alliance Consulting Group, ENSTAR's assets as of December 31, 2017, had a remaining life of 23.87 years. Because four years have passed since the excess ADIT arose, ENSTAR proposes to amortize the protected excess ADIT over the remaining life at the end of the test year of 19.87 years, which complies with the IRS normalization rules. Meanwhile, ENSTAR proposes to amortize unprotected excess ADIT over 15 years. This amortization period recognizes that the majority of the unprotected ADIT is related to contributions in aid of construction for plant, and is the same period approved for Cook Inlet Natural Gas Storage Alaska, LLC in Docket U-18-043.

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 G of the 275(a) filing, amortizing the protected and unprotected excess ADIT balances over 19.87 and 15 years, respectively, results in a net amortization of $695,069. This amortization of excess ADIT is deducted from the federal income tax expense of $5,276,211 developed earlier to calculate federal income tax expense included in ENSTAR's requested revenue requirement of $4,581,142. As shown on page 4 of the 275(a) filing, this amount is $533,216 less than the $5,114,358 in federal income tax expense recorded on ENSTAR's books during 2021. Please note that the $695,069 amortization of excess

ADIT 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.

IV. <u>3 AAC 48.275(h) FILING</u>

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 "if a proposed tariff revision includes a rate redesign, other than an across-the-board increase, a COS study and a narrative explaining the methodology used in the study must be submitted."

Q. Does this tariff revision include a rate redesign other than an across-the-board increase?

A. Yes.

Q. Are you sponsoring a COS study?

A. Yes. I present a COS study attached to TA334-4 as Attachment C, that allocates ENSTAR's revenue requirement among its customer classes. The results of the COS study provide a basis for developing the rate design, which then establishes the rates for ENSTAR's various customer classes.

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 ENSTAR's present COS study?

A. The present COS study follows the methodology approved by the Commission in Order U-16-066(19) in ENSTAR's last rate case.

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 revenue requirement and rate base to Federal Energy Regulatory Commission 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. However, these amounts are adjusted for two items. First, the cost of gas is recovered through ENSTAR's gas cost adjustment ("GCA"). Accordingly, the GCA is excluded and the COS study only allocates amounts that are incorporated into base rates. Second, ENSTAR transports gas to Homer Electric Association's Bernice Lake plant under a special non-cost-based "bypass" rate designed to retain this load on the system (approved in Letter Order L1300590, TA247-4). The $43,200 in bypass revenues, as well as $1,904,686 in miscellaneous service revenues, received during the test year are used to offset the cost of providing service to other customers. Thus, a net revenue requirement of $91,844,132 and rate base of $293,177,574 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 seven rate classes, which are the same as approved in Order U-16-066(19):

- General Service 1 (“G1”);
- General Service 2 (“G2”);
- General Service 3 (“G3”);
- General Service 4 (“G4”);
- Very Large Firm Transportation (“VLFT”);
- Mid-sized Firm Transportation (“MSFT”); 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 its 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, uncollectible accounts expenses are borne solely by the General Service customer classes, and no measuring and regulating expenses or related plant are allocated to the MSFT class.

Q. What are the results of the COS study?

A. The following table 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 itself):

Class	Customer	Capacity	Commodity	Total
G-1	30,962,776	26,188,420	114,953	57,266,149
G-2	1,747,096	2,704,844	12,014	4,463,953
G-3	3,776,962	5,476,864	24,622	9,278,448
G-4	2,605,846	9,571,633	44,907	12,222,386
VLFT	100,061	7,618,663	113,992	7,832,715
MSFT	10,833	494,838	8,147	513,818
IIT/ITS	40,024	220,704	5,935	266,663
Total	39,243,597	52,275,965	324,570	91,844,132

Q. How do the results of this COS study compare with the normalized revenues being produced under existing rates?

A. The following table compares the results of the COS study with normalized test year revenues (excluding gas costs) by customer class:

Class	Cost-of-Service	Current Base Revenues	Base Revenue Shortfall	Percent Increase
G-1	57,266,149	54,716,431	2,549,718	4.66%
G-2	4,463,953	4,254,484	209,469	4.92%
G-3	9,278,448	8,592,094	686,354	7.99%
G-4	12,222,386	11,206,316	1,016,071	9.07%
VLFT	7,832,715	7,387,469	445,246	6.03%
MSFT	513,818	444,106	69,712	15.70%
IIT/ITS	266,663	202,382	64,281	31.76%
Total	91,844,132	86,803,281	5,040,851	5.81%

As shown above, the rates currently being charged to each customer class are below ENSTAR's cost of providing service, especially those of the MSFT and IIT/ITS classes.

Q. What rate design is ENSTAR proposing for its General Service classes?

A. Rates for ENSTAR's General Service classes are based on the costs allocated to each in the COS study. As described earlier, the COS study classifies these costs between those that are primarily customer-related, capacity-related, or commodity-related. Virtually all of the customer- and capacity-related costs comprising ENSTAR's revenue requirement are fixed, and ENSTAR incurs these costs regardless of how much gas is sold. Historically, ENSTAR's gas rates have been designed to include only customer-related costs in the monthly customer charge, with capacity- and commodity-related costs being included in the volumetric charges. However, increasingly throughout the U.S., gas rates are being designed to recover fixed costs through a monthly service charge and variable costs through a volumetric charge, which is often referred to as the Straight Fixed-Variable ("SFV") method. SFV rates are being adopted because they best match and recover how costs are incurred by the utility, encourage conservation by decoupling the utility's earnings from sales, reduce the volatility of customers' bills, and are easy for customers to understand.

For the General Service classes of customers, ENSTAR is proposing rates in this case that include more fixed costs in the monthly service charge than in the past, but not a full SFV rate design where all fixed costs are included in the monthly service charge. Specifically, ENSTAR proposes to calculate the monthly service charge for each of the General Service classes as the sum of customer-related costs plus 50% of capacity-related costs. This may be viewed as including the portion of the capacity-related costs incurred to meet peak demand in the monthly service charge, with the remainder, which is related to average demand, being included in the volumetric charge. The end-result of this rate redesign is that customers' monthly service charge will increase, but their volumetric charges will decrease. This rate redesign produces the following monthly customer charges (rounded up to the nearest dollar) and volumetric charges for each of the General Service classes:

Class	**G1**	**G2**	**G3**	**G4**
Monthly Service Charge	$27.00	$46.00	$150.00	$620.00
Volumetric Rate (Mcf)[6]	$0.6555	$0.6797	$0.6728	$0.6361

Q. Are there benefits to ENSTAR's General Service customers of this rate redesign?

A. Yes. By including a greater portion of fixed costs in the monthly service charge and reducing the portion included in the volumetric charge (*i.e.*, moving closer to a SFV rate design), General Service customers' bills are more stable from month-to-month and season-to-season. ENSTAR believes this decreased volatility will aid customers in budgeting and paying their gas bills throughout the year.

Q. How are the rates for ENSTAR's VLFT customer class developed?

A. ENSTAR's proposed rates for the VLFT class are also based on the costs allocated to it in the COS study. Customer-related costs of $100,061 are divided by five customer delivery locations and twelve months to calculate a monthly customer charge (rounded to the nearest hundred) of $1,700. Similarly, $113,992 in commodity-related costs are divided by test year volumes to calculate a volumetric charge of $0.0057 per Mcf.

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

Finally, rates for the VLFT class include monthly demand charges for each Mcf of a customer's contracted maximum demand. Accordingly, capacity-related costs, adjusted for the rounding of the monthly customer charge, of $7,618,663 are divided by total contracted peak demand of 76,300 Mcf to calculate a monthly capacity charge of $8.32 per Mcf of contracted demand.

Q. What rates does ENSTAR propose for the MSFT class?

A. Consistent with the SFV rate design discussed earlier, ENSTAR proposes to calculate a monthly service charge for MSFT customers by dividing all of the customer- and capacity-related costs allocated to the MSFT class, which totals $505,671, by the two customers in the class and twelve months, and then rounding up to the next hundred dollars. The remaining costs of $7,418 are divided by test year throughput to calculate the volumetric charge. This produces a monthly service charge of $21,100 and a volumetric charge of $0.0052 per Mcf.

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. Because IIT/ITS service is interruptible, ENSTAR is proposing that rates for IIT and ITS customers continue to be entirely volumetric and that the existing flat rate structure be maintained. Accordingly, the IIT/ITS class revenue requirement of $266,663 is divided by test year billing units of 1,109,908 Mcf to produce a volumetric rate $0.2403 per Mcf. Again, in an effort to prevent the IIT tariff from being misused by customers that are not true large volume users, ENSTAR proposes to retain the minimum charge equal to 100,000 Mcf, which equates to $24,000, for any month gas is transported by an IIT customer and for any year gas is transported by an ITS customer.

Q. Do other ENSTAR witnesses also discuss the reasons for ENSTAR's proposed rate design?

A. Yes. ENSTAR witnesses Mr. John D. Sims, Mr. Dieckgraeff, and Ms. Inna B. Johansen also discuss support for why ENSTAR is proposing various changes to the rate design of certain rate classes.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

BRUCE H. FAIRCHILD

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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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Monographs

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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).

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BRUCE H. FAIRCHILD
SUMMARY OF TESTIMONY BEFORE REGULATORY AGENCIES

.	Utility Case	Agency	Docket	Date	Nature of Testimony
1.	Arkansas Electric Cooperative	Arkansas PSC	U-3071	Aug-80	Wholesale Rate Design
2.	East Central Oklahoma Electric Cooperative	Oklahoma CC	26925	Sep-80	Retail Rate Design
3.	Kansas Gas & Electric Company	Kansas CC	115379-U	Nov-80	PURPA Rate Design Standards
4.	Kansas Gas & Electric Company	Kansas CC	128139-U	May-81	Attrition
5.	City of Austin Electric Department	City of Austin	--	Jun-81	PURPA Rate Design Standards
6.	Tarrant County Water Control and Improvement District No. 1	Texas Water Commission	--	Oct-81	Wholesale Rate Design
7.	Owentown Gas Company	Texas RRC	2720	Jan-82	Revenue Requirements and Retail Rate Design
8.	Kansas Gas & Electric Company	Kansas CC	134792-U	Aug-82	Attrition
9.	Mississippi Power Company	Mississippi PSC	U-4190	Sep-82	Working Capital
10.	Lone Star Gas Company	Texas RRC	3757; 3794	Feb-83	Rate of Return on Equity
11.	Kansas Gas & Electric Company	Kansas CC	134792-U	Feb-83	Rate of Return on Equity
12.	Southwestern Bell Telephone Company	Oklahoma CC	28002	Oct-83	Rate of Return on Equity
13.	Morgas Company	Texas RRC	4063	Nov-83	Revenue Requirements
14.	Seagull Energy	Texas RRC	4541	Jul-84	Rate of Return
15.	Southwestern Bell Telephone Company	FCC	84-800	Nov-84	Rate of Return on Equity
16.	Kansas Gas & Electric Company, Kansas City Power & Light Company, and Kansas Electric Power Cooperatives	Kansas CC	142098-U; 142099-U; 142100-U	May-85	Nuclear Plant Capital Costs and Allowance for Funds Used During Construction
17.	Lone Star Gas Company	Texas RRC	5207	Oct-85	Overhead Cost Allocation
18.	Westar Transmission Company	Texas RRC	5787	Nov-85 Jan-86 Jul-86	Rate of Return, Rate Design, and Gas Processing Plant Economics
19.	City of Houston	Texas Water Commission	RC-022; RC-023	Nov-86	Line Losses and Known and Measurable Changes
20.	ENSTAR Natural Company	Alaska PUC	TA 50-4; R-87-2; U-87-2	Nov-86 May-87 May-87	Cost Allocation, Rate Design, and Tax Rate Changes
21.	Brazos River Authority	Texas Water Commission	RC-020	Jan-87	Revenue Requirements and Rate Design
22.	East Texas Industrial Gas Company	Texas RRC	5878	Feb-87	Revenue Requirements and Rate Design

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
23.	Seagull Energy	Texas RRC	6629	Jun-87	Revenue Requirements
24.	ENSTAR Natural Company	Alaska PUC	U-87-42	Jul-87 Sep-87 Sep-87	Cost Allocation, Rate Design, and Contracts
25.	High Plains Natural Gas Company	Texas RRC	6779	Sep-87	Rate of Return
26.	Hughes Texas Petroleum	Texas RRC	2-91,855	Jan-88	Interim Rates
27.	Cavallo Pipeline Company	Texas RRC	7086	Sep-88	Revenue Requirements
28.	Union Gas System, Inc.	Kansas CC	165591-U	Mar-89 Aug-89	Rate of Return
29.	ENSTAR Natural Gas Company	Alaska PUC	U-88-70	Mar-89	Cost Allocation and Bypass
30.	Morgas Co.	Texas RRC	7538	Aug-89	Rate of Return and Cost Allocation
31.	Corpus Christi Transmission Company	Texas RRC	7346	Sep-89	Revenue Requirements
32.	Amoco Gas Co.	Texas RRC	7550	Oct-89	Rate of Return and Cost Allocation
33.	Iowa Southern Utilities	Iowa Utilities Board	RPU-89-7	Nov-89 Mar-90	Rate of Return on Equity
34.	Southwestern Bell Telephone Company	FCC	89-624	Feb-90 Apr-90	Rate of Return on Equity
35.	Lower Colorado River Authority	Texas PUC	9427	Mar-90 Aug-90 Aug-90	Revenue Requirements
36.	Rio Grande Valley Gas Company	Texas RRC	7604	May-90	Consolidated FIT and Depreciation
37.	Southern Union Gas Company	El Paso PURB	--	Oct-90	Disallowed Expenses and FIT
38.	Iowa Southern Utilities	Iowa Utilities Board	RPU-90-8	Nov-90 Feb-91	Rate of Return on Equity
39.	East Texas Gas Systems	Texas RRC	7863	Dec-90	Revenue Requirements
40.	San Jacinto Gas Transmission	Texas RRC	7865	Dec-90	Revenue Requirements
41.	Southern Union Gas Company	Austin; Texas RRC	-- 7878	Feb-91 Feb-91	Rate of Return and Acquisition Adjustment
42.	Southern Union Gas Company	Port Arthur; Texas RRC	-- 8033	Mar-91 Aug-91 Oct-91	Rate of Return and Acquisition Adjustment
43.	Cavallo Pipeline Company	Texas RRC	8016	Jun-91	Revenue Requirements
No.	**Utility Case**	**Agency**	**Docket**	**Date**	**Nature of Testimony**

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
44.	New Orleans Public Service Inc.	New Orleans City Council	CD-91-1	Jun-91 Mar-92	Rate of Return on Equity
45.	Houston Pipe Line Company	Texas RRC	8017	Jul-91	Rate of Return
46.	Southern Union Gas Company	El Paso PURB	--	Aug-91 Sep-91	Acquisition Adjustment
47.	Southwestern Gas Pipeline, Inc.	Texas RRC	8040	Jan-92 Feb-92	Rate Design and Settlement
48.	City of Fort Worth	Texas Water Commission	8748-A 9261-A	Mar-92 Aug-92 Dec-92 Oct-94 Nov-94	Interim Rates, Revenue Requirements, and Public Interest
49.	Southern Union Gas Company	Oklahoma Corp. Com.	--	Jun-92	Rate of Return
50.	Minnegasco	Minnesota PUC	G-008/GR-92-400	Jul-92 Dec-92	Rate of Return
51.	Guadalupe-Blanco River Authority	Texas PUC	11266	Sep-92	Cost Allocation and Bond Funds
52.	Dorchester Intra-State Gas System	Texas RRC	8111	Oct-92 Nov-92	Rate Impact of System Upgrade
53.	Corpus Christi Transmission Company GP and GPII	Texas RRC	8300 8301	Oct-92 Oct-92	Revenue Requirements
54.	East Texas Industrial Gas Company	Texas RRC	8326	Mar-93	Revenue Requirements
55.	Arkansas Louisiana Gas Company	Arkansas PSC	93-081-U	Apr-93 Oct-93	Rate of Return on Equity
56.	Texas Utilities Electric Company	Texas PUC	11735	Jun-93 Jul-93	Impact of Nuclear Plant Construction Delay
57.	Minnegasco	Minnesota PUC	G-008/GR-93-1090	Nov-93 Apr-94	Rate of Return
58.	Gulf States Utilities Company	Municipalities	--	May-94 Oct-94 Nov-94	Rate of Return on Equity
59.	Louisiana Power & Light Company	Louisiana PSC	U-20925	Aug-94 Feb-95	Rate of Return on Equity
60.	San Jacinto Gas Transmission	Texas RRC	8429	Sep-94	Revenue Requirements
61.	Cavallo Pipeline Company	Texas RRC	8465	Sep-94	Revenue Requirements
62.	Eastrans Limited Partnership	Texas RRC	8385	Oct-94	Revenue Requirements
63.	Gulf States Utilities Company	Louisiana PSC	U-19904	Oct-94	Rate of Return on Equity
No.	**Utility Case**	**Agency**	**Docket**	**Date**	**Nature of Testimony**

64.	Entergy Services, Inc.	FERC	ER95-112- 000	Mar-95 Nov-95	Rate of Return on Equity
65.	East Texas Gas Systems	Texas RRC	8435	Apr-95	Revenue Requirements
66.	System Energy Resources, Inc.	FERC	ER95-1042- 000	May-95 Dec-95 Jan-96	Rate of Return on Equity
67.	Minnegasco	Minnesota PUC	G-008/GR- 95-700	Aug-95 Dec-95	Rate of Return
68.	Entex	Louisiana PSC	U-21586	Aug-95	Rate of Return
69.	City of Fort Worth	Texas NRCC	SOAH 582- 95-1084	Nov-95	Public Interest of Contract
70.	Seagull Energy Corporation	Texas RRC	8589	Nov-95	Revenue Requirements
71.	Corpus Christi Transmission Company LP	Texas RRC	8449	Feb-96	Revenue Requirements
72.	Missouri Gas Energy	Missouri PSC	GR-96-285	Apr-96 Sep-96 Oct-96	Rate of Return
73.	Entex	Mississippi PSC	96-UA-202	May-96	Rate of Return
74.	Entergy Gulf States, Inc.	Louisiana PSC	U-22084	May-96	Rate of Return on Equity (Gas)
75.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-96 Oct-96	Rate of Return on Equity
76.	American Gas Storage, L.P.	Texas RRC	8591	Sep-96	Revenue Requirements
77.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	Sep-96 Oct-96	Rate of Return on Equity
78.	Lone Star Pipeline and Gas Company	Texas RRC	8664	Oct-96 Jan-97	Rate of Return
79.	Entergy Arkansas, Inc.	Arkansas PSC	96-360-U	Oct-96 Sep-97	Rate of Return on Equity
80.	East Texas Gas Systems	Texas RRC	8658	Nov-96	Revenue Requirements
81.	Entergy Gulf States, Inc.	Texas PUC	16705	Nov-96 Jul-97	Rate of Return on Equity
82.	Eastrans Limited Partnership	Texas RRC	8657	Nov-96	Revenue Requirements
83.	Enserch Processing, Inc.	Texas RRC	8763	Nov-96	Interim Rates
84.	Entergy New Orleans, Inc.	City of New Orleans	UD-97-1	Feb-97 Mar-97 May-98	Rate of Return on Equity
No.	**Utility Case**	**Agency**	**Docket**	**Date**	**Nature of Testimony**

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

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85.	ENSTAR Natural Gas Company	Alaska PUC	U-96-108	Mar-97 Apr-97	Service Area Certificate
86.	San Jacinto Gas Transmission	Texas RRC	8741	Sep-97	Revenue Requirements
87.	Missouri Gas Energy	Missouri PSC	GR-98-140	Nov-97 Apr-98 May-98	Rate of Return
88.	Corpus Christi Transmission Company LP	Texas RRC	8762	Dec-97	Revenue Requirements
89.	Texas-New Mexico Power Company	Texas PUC	17751	Feb-98	Excess Cost Over Market
90.	Southern Union Gas Company	Texas RRC	8878	May-98	Rate of Return
91.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	May-98 Jul-98	Financial Integrity
92.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-98 Jul-98	Financial Integrity
93.	ACGC Gathering Company, LLC	Texas RRC	8896	Sep-98	Cost-based Rates
94.	American Gas Storage, L.P.	Texas RRC	8855	Oct-98	Revenue Requirements
95.	Duke Energy Intrastate Network	Texas RRC	8940	Jun-99	Rate of Return
96.	Aquila Energy Corporation	Texas RRC	8970	Aug-99	Revenue Requirements
97.	San Jacinto Gas Transmission	Texas RRC	8974	Sep-99	Revenue Requirements
98.	Southern Union Gas Company	El Paso PURB	--	Oct-99	Rate of Return
99.	TXU Lone Star Pipeline	Texas RRC	8976	Oct-99 Feb-00	Rate of Return
100.	Sharyland Utilities, L.P.	Texas PUC	21591	Nov-99	Rate of Return
101.	TXU Lone Star Gas Distribution	Texas RRC	9145	Apr-00 Aug-00	Rate of Return
102.	Rotherwood Eastex Gas Storage	Texas RRC	9136	May-00	Revenue Requirements
103.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9137	May-00	Revenue Requirements
104.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9138	Jul-00	Revenue Requirements
105.	East Texas Gas Systems	Texas RRC	9139	Jul-00	Revenue Requirements
106.	Eastrans Limited Partnership	Texas RRC	9140	Aug-00	Revenue Requirements
107.	Reliant Energy – Entex	City of Tyler	--	Oct-00	Rate of Return
108.	City of Fort Worth	Texas NRCC	SOAH 582-00-1092	Dec-00	CCN – Rates and Financial Ability
109.	Entergy Services, Inc.	FERC	RTO1-75	Dec-00	Rate of Return on Equity
No.	**Utility Case**	**Agency**	**Docket**	**Date**	**Nature of Testimony**

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
110	ENSTAR Natural Gas Company	Alaska PUC	U-00-88	Jun-01 Aug-01 Nov-01 Sep-02 Dec-02	Revenue Requirements, Cost Allocation, and Rate Design
111.	TXU Gas Distribution	Texas RRC	9225	Jul-01	Rate of Return
112.	Centana Intrastate Pipeline LLC	Texas RRC	9243	Aug-01	Rate of Return
113.	Maxwell Water Supply Corp.	Texas NRCC	SOAH-582-01-0802	Oct-01 Mar-02 Apr-02	Reasonableness of Rates
114.	Reliant Energy Arkla	Arkansas PSC	01-243-U	Dec-01 Jun-01	Rate of Return
115.	Entergy Services, Inc.	FERC	ER01-2214-000	Mar-02	Rate of Return on Equity
116.	TXU Lone Star Pipeline	Texas RRC	9292	Apr-02	Rate of Return
117.	Southern Union Gas Company	El Paso PURB	--	Apr-02	Rate of Return
118.	San Jacinto Gas Transmission Co.	Texas RRC	9301	May-02	Rate of Return
119.	Duke Energy Intrastate Network	Texas RRC	9302	May-02	Rate of Return
120.	Reliant Energy Arkla	Oklahoma CC	200200166	May-02	Rate of Return
121.	TXU Gas Distribution	Texas RRC	9313	Jul-02 Sep-02	Rate of Return
122.	Entergy Mississippi, Inc.	Mississippi PSC	2002-UN-256	Aug-02	Rate of Return on Equity
123.	Aquila Storage & Transportation LP	Texas RRC	9323	Sep-02	Revenue Requirements
124.	Panther Pipeline Ltd.	Texas RRC	9291	Oct-02	Revenue Requirements
125.	SEMCO Energy	Michigan PSC	U-13575	Nov-02	Revenue Requirements
126.	CenterPoint Energy Entex	Louisiana PSC	U-26720	Jan-03	Rate of Return
127.	Crosstex CCNG Transmission Ltd.	Texas RRC	9363	May-03	Revenue Requirements
128.	TXU Gas Company	Texas RRC	9400	May-03 Jan-04	Rate of Return
129.	Eastrans Limited Partnership	Texas RRC	9386	May-03	Rate of Return
130.	CenterPoint Energy Entex	City of Houston		Jun-03	Rate of Return
131.	East Texas Gas Systems, L.P.	Texas RRC	9385	Jun-03	Rate of Return
132.	ENSTAR Natural Gas Company	Alaska RCA	U-03-084	Aug-03 Nov-03	Line Extension Surcharge
133.	CenterPoint Energy Arkla	Louisiana PSC		Nov-03	Rate of Return
134.	ENSTAR Natural Gas Company	Alaska RCA	U-03-091	Feb-04	Cost Separation and Taxes

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
135.	Sid Richardson Pipeline, Ltd.	Texas RRC	9532	Jun-04 Nov-04	Revenue Requirements
136.	ETC Katy Pipeline, Ltd.	Texas RRC	9524	Sep-04	Revenue Requirements
137.	CenterPoint Energy Entex	Mississippi PSC	03-UN-0831	Sep-04	Rate Formula
138.	Centana Intrastate Pipeline LLC	Texas RRC	9527	Sep-04	Rate of Return
139.	SEMCO Energy	Michigan PSC	U-14338	Dec-04	Revenue Requirements
140.	Atmos Energy – Energas	Texas RRC	9539	Feb-05	Regulatory Policy
141.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9613	Sep-05	Revenue Requirements
142.	SiEnergy, L.P.	Texas RRC	9604	Dec-05	Rate of Return, Income Taxes, and Cost Allocation
143.	ENSTAR Natural Gas Company	Alaska RCA	TA-140-4	Feb-06	Connection Fees
144.	SEMCO Energy	Michigan PSC	U-14984	May-06 Dec-06	Revenue Requirements
145.	Atmos Energy – Mid-Tex	Texas RRC	9676	May-06 Oct-06	Revenue Requirements
146.	EasTrans Limited Partnership	Texas RRC	9659	Jun-06	Rate of Return
147.	Kinder Morgan Texas Pipeline, L.P.	Texas RRC	9688	Jul-06	Rate of Return
148.	Crosstex CCNG Transmission Ltd.	Texas RRC	9660	Aug-06	Revenue Requirements
149.	Enbridge Pipelines (North Texas), LP	Texas RRC	9691	Oct-06	Rate of Return
150.	Panther Interstate Pipeline Energy	FERC	CP03-338-00	Mar-07	Revenue Requirements
151.	El Paso Electric Company	Texas PUC	34494	Jul-07	CCN
152.	El Paso Electric Company	NM PRC	07-00301-UT	Jul-07	CCN
153.	Atmos Energy	Kansas CC	08-ATMG-280-RTS	Sep-07 Feb-08	Rate of Return on Equity
154.	Centana Intrastate Pipeline LLC	Texas RRC	9759	Sep-07	Rate of Return
155.	Texas Gas Service Company	Texas RRC	9770	Nov-07	Rate of Return
156.	ENSTAR Natural Gas Company	Alaska RCA	U-08-25	Jun-08	Rate Class Switching
157.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-131-301	Oct-08	Rate of Return
158.	ExxonMobil Pipeline Co.	Alaska RCA	TL-140-304	Nov-08	Rate of Return
159.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9843	Dec-08	Revenue Requirements
160.	Koch Alaska Pipeline Company	Alaska RCA	TL 128-308	Dec-08	Rate of Return
161.	Unocal Pipeline Company	Alaska RCA	TL 118-312	Dec-08	Rate of Return

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
162.	ETC Katy Pipeline, Ltd.	Texas RRC	9841	Dec-08	Revenue Requirements
163.	Oklahoma Natural Gas	Oklahoma CC	200800348	Jan-09	Rate of Return on Equity
164.	Entergy Mississippi, Inc.	Mississippi PSC	EC-123-0082	Mar 09	Rate of Return on Equity
165.	ENSTAR Natural Gas Company	Alaska RCA	U-09-69 U-09-70	Jun-09 Jul-09 Oct-09	Revenue Requirements, Cost Allocation, and Rate Design
166.	EasTrans, LLC	Texas RRC	9857	Jun-09	Rate of Return
167.	Oklahoma Natural Gas	Oklahoma CC	200900110	Jun-09	Rate of Return
168.	Crosstex CCNG Transmission Ltd.	Texas RRC	9858	Jun-09	Revenue Requirements
169.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul-09	Rate of Return
170.	ENSTAR Natural Gas Company	Alaska RCA	U-08-142	Jul-09	Gas Cost Adjustment
171.	Kinder Morgan Texas Pipeline, LLC	Texas RRC	9889	Jul-09	Rate of Return
172.	Koch Alaska Pipeline Company	Alaska RCA	TL 133-308	Aug-09	Rate of Return
173.	ExxonMobil Pipeline Co.	Alaska RCA	TL-147-304	Nov-09	Rate of Return
174.	Texas Gas Service Company	El Paso PURB	--	Dec-09	Rate of Return
175.	Unocal Pipeline Company	Alaska RCA	TL126-312	Dec-09	Rate of Return
176.	Kuparuk Transportation Company	Alaska RCA	P-08-05	Apr-10	Rate of Return
177.	Trans-Alaska Pipeline System	FERC	ISO9-348-000	Apr 10 Oct 10	Rate of Return
178.	Texas Gas Service	Texas RRC	9988	May 10 Aug 10	Rate of Return
179.	SEMCO Energy Gas Company	Michigan PSC	U-16169	Jun 10 Dec 10	Revenue Requirements
180.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul 10	Rate of Return
181.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-308	Aug 10	Rate of Return
182.	CPS Energy	Texas PUC	36633	Sep 10 Apr 11	Rate of Return for MOU
183.	ExxonMobil Pipeline Co.	Alaska RCA	TL-151-304	Dec 10	Rate of Return
184.	Unocal Pipeline Company	Alaska RCA	TL132-312	Feb 11	Rate of Return
185.	New Mexico Gas Company	NM PRC	11-00042-UT	Mar 11	Rate of Return
186.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-143-301	May 11	Rate of Return

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
187.	Enbridge Pipelines (Southern Lights)	FERC	IS11-146-000	Jun 11 Nov 11	Rate of Return
188.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-___	Jul 11	Rate of Return
189.	Unocal Pipeline Company	Alaska RCA	TL126-___	Dec 11	Rate of Return
190.	Kansas Gas Service	Kansas CC	12-KGSC-835-RTS	May 12 Oct 12	Rate of Return
191.	ExxonMobil Pipeline Co.	Alaska RCA	TL-157-304	Jun 12	Rate of Return
192.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-149-301	Jul 12	Rate of Return
193.	Seaway Crude Pipeline Company	FERC	IS12-226-000	Aug 12 Feb 13	Rate of Return
194.	Cross Texas Transmission, LLC	Texas PUC	40604	Aug 12 Oct 12 Nov 12	Revenue Requirements
195.	Wind Energy Transmission Texas	Texas PUC	40606	Aug 12 Nov 12	Revenue Requirements
196.	Lone Star Transmission LLC	Texas PUC	40798	Nov 12	Revenue Requirements
197.	West Texas Gas Company	Texas RRC	10235	Jan 13	Rate of Return
198.	Cross Texas Transmission, LLC	Texas PUC	41190	Feb 13	Revenue Requirements
199.	ExxonMobil Pipeline Co.	Alaska RCA	TL-162-304	Apr 13	Rate of Return
200.	EasTrans,LLC	Texas RRC	10276	Jul 13	Rate of Return
201.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-152-301	Jul 13	Rate of Return
202.	BP Pipelines (Alaska) Inc.	Alaska RCA	TL-143-311	Sep 13	Rate of Return
203.	Wind Energy Transmission Texas	Texas PUC	41923	Oct 13	Revenue Requirements
204.	Oliktok Pipeline Company	Alaska RCA	P-13-013	Nov 13	Rate of Return
205.	Aqua Texas Southeast Region-Gray	Texas CEQ	2013-2007-UCR	Apr 14	Revenue Requirements
206.	Entergy Mississippi	Mississippi PSC	EC-123-0082	Jun 14	Rate of Return on Equity
207.	Westlake Ethylene Pipeline	Texas RRC	10358	Jul 14 Aug 15	Rates
208.	ExxonMobil Pipeline Co.	Alaska RCA	TL-164-304	Jul 14	Rate of Return
209.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-154-301	Aug 14	Rate of Return
210.	Enstar Natural Gas Company	Alaska RCA	TA-262-4	Sep 14 Jun 15	Revenue Requirements, Cost Allocation, and Rate Design

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
211.	Oliktok Pipeline Company	Alaska RCA	TL-44-334	Mar 15	Rate of Return
212.	Entergy Arkansas, Inc.	Arkansas PSC	15-0150U	Apr 15 Oct 15 Dec 15	Rate of Return on Equity
213.	Wind Energy Transmission Texas	Texas PUC	44746	Jun 15	Revenue Requirements
214.	Texas City	Texas RRC	10408	Jun 15 Nov 15	Pipeline Annual Assessment
215.	Oklahoma Natural Gas	Oklahoma CC	201500213	Jul 15 Nov 15	Rate of Return
216.	PTE Pipeline LLC	Alaska RCA	P-12-015	Sep 15	Rate of Return
217.	Northeast Transmission Development, LLC	FERC	ER16-453	Dec 15	Formula Rates
218.	Oncor Electric Delivery	Texas PUC	45188	Dec 15	Public Interest of Acquisition
219.	Corix Utilities (Texas)	Texas PUC	45418	Dec 15 Oct 16	Rate of Return
220.	Texas Gas Service	Texas RRC	10488	Dec 15	Rate of Return
221.	Texas Gas Service	Texas RRC	10506	Mar 16 Jun 16	Rate of Return
222.	Kansas Gas Service	Kansas CC	16-KGSG-491-RTS	May 16 Sep 16	Rate of Return on Equity
223.	Enstar Natural Gas Company	Alaska RCA	TA-285-4	Jun 16 Apr 17	Revenue Requirements, Cost Allocation, and Rate Design
224.	Texas Gas Service	Texas RRC	10526	Jun 16	Rate of Return
225.	West Texas LPG Pipeline	Texas RRC	10455	Aug 16 Jan 17	Rates and Rate of Return
226.	Liberty Utilities	Texas PUC	46356	Sep 16 Feb 17 Jun 17	Revenue Requirements and Rate of Return
227.	DesertLink LLC	FERC	ER17-135	Oct 16	Formula Rates
228.	Houston Pipe Line Co.	Texas RRC	10559	Nov 16	Revenue Requirements
229.	Texas Gas Service	Texas RRC	10656	Jun 17	Rate of Return
230.	Trans-Pecos Pipeline	Texas RRC	10646	Sep 17 Feb 18	Revenue Requirements
231.	Comanche Trail Pipeline	Texas RRC	10647	Sep 17 Feb 18	Revenue Requirements
232.	Alpine High Pipeline	Texas RRC	10665	Oct 17 Feb 18	Revenue Requirements
No.	**Utility Case**	**Agency**	**Docket**	**Date**	**Nature of Testimony**

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

233.	SiEnergy, LP	Texas RRC	10679	Jan 18	Rate of Return
234.	Targa Midland Gas Pipeline LLC	Texas RRC	10690	Jan 18	Revenue Requirements
235.	ET Fuel, LP	Texas RRC	10706	Apr 18	Revenue Requirements
236.	Texas Gas Service	Texas RRC	10739	Jun 18	Rate of Return
237.	Kansas Gas Service	Kansas CC	18-KGSG-560-RTS	Jun 18 Nov 18	Rate of Return on Equity
238.	Oliktok Pipeline Company	Alaska RCA	TL46-334	Jul 18	Rate of Return
239.	Red Bluff Express, LLC	Texas RRC	10752	Jul 18	Revenue Requirements
240.	PTE Pipeline LLC	Alaska RCA	P-18-0__	Jul 18	Rate of Return
241.	Agua Blanca, LLC	Texas RRC	10761	Aug 18	Revenue Requirements
242.	Texas Gas Service	Texas RRC	10766	Aug 18	Rate of Return
243.	Republic Transmission LLC	FERC	ER19-___	Dec 18	Formula Rates
244.	Gulf Coast Express Pipeline LLC	Texas RRC	10825	Feb 19	Revenue Requirements
245.	Cook Inlet Natural Gas Storage Alaska, LLC	Alaska RCA	U-18-043	Mar 19 Apr 19	Accumulated Deferred Income Taxes and Working Capital
246.	Impulsora Pipeline LLC	Texas RRC	10829	Mar 19	Revenue Requirements
247.	SEMCO Energy Gas Co.	Michigan PSC	U-20479	May 19 Oct 19	Revenue Requirements
248.	Liberty Utilities (Fox River) LLC	AAA	01-18-0002-2510	Jul 19 Oct 19	Revenue Requirements
249.	AMP Intrastate Pipeline LLC	Texas RRC	10887	Aug 19	Revenue Requirements
250.	Corix Utilities (Texas) Inc.	Texas PUC	49923	Aug 19 Jul 20 Aug 20	TCJA Tax Expense Reduction
251.	Colonial Pipeline Company	FERC	OR18-7-002	Nov 19 Feb 20 May 20 Jul 20	Rate of Return
252.	Texas Gas Service	Texas RRC	10928	Dec 19 Apr 20	Rate of Return
253.	Mississippi Power Company	Mississippi PSC	2019-UN-219	Feb 20	Rate of Return on Equity
254.	Corix Utilities (Texas)	Texas PUC	50557	Mar 20 Mar 21	Rate of Return and Excess ADFIT
255.	SouthCross CCNG Transmission	Texas RRC	10967	May 20	Revenue Requirements
256.	Kinder Morgan Border Pipeline LLC	Texas RRC	10980	Jun 20	Revenue Requirements
257.	Monarch Utilities I LP	Texas PUC	50944	Jul 20 Nov 20	Rate of Return

258.	West Texas Gas, Inc.	Texas RRC	10998	Aug 20	Revenue Requirements, Rate of Return, and Cost of Service Study
259.	Centric Gas Services, LLC	Texas RRC		Oct 20	Rate of Return
260.	CoServ Gas, Ltd	Texas RRC	00005136	Nov 20	Rate of Return
261.	Permian Highway Pipeline LLC	Texas RRC	00005306	Dec 20	Revenue Requirements
262.	Whistler Pipeline LLC	Texas RRC	00005675	Feb 21	Revenue Requirements
263.	Oklahoma Natural Gas	Oklahoma CC	202100063	May 21 Oct 21	Rate of Return
264.	Oliktok Pipeline Company	Alaska RCA	TL47-334	Jul 21	Rate of Return
265.	Participating Gas Utilities	Texas RRC	00007061	Jul 21 Oct 21	Excess Gas Cost Securitization
266.	Texas Pipeline Webb County Lean System, LLC	Texas RRC	00008188	Nov 21	Revenue Requirements
267.	Legend Gas Pipeline LLC	Texas RRC	00008714	Jan 22	Revenue Requirements
268.	Oliktok Pipeline Company	Alaska RCA	TL48-334	Mar 22	Rate of Return
269.	Texas Gas Service	Texas RRC	00009896	Jun 22	Rate of Return

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Keith Kurber II, Chair Robert A. Doyle Robert M. Pickett Daniel A. Sullivan Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-____

PREFILED DIRECT TESTIMONY
OF
CHELSEA N. GUINTU

PREFILED DIRECT TESTIMONY
OF
CHELSEA N. GUINTU

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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 Supervisor of Rates and Regulatory Affairs for ENSTAR Natural Gas Company ("ENSTAR") and Alaska Pipeline Company ("APC"). For convenience, I will refer to ENSTAR and APC together as "ENSTAR." ENSTAR is a division of SEMCO Energy, Inc. ("SEMCO").

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 Supervisor of Rates and Regulatory Affairs, I oversee the preparation of financial analyses and reports for both ENSTAR and for Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA").[1] I am also responsible for the preparation of testimony, tariff revisions, and filings with the Regulatory Commission of Alaska ("Commission" or

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

"RCA"). Additionally, I act as a liaison for ENSTAR and CINGSA with Commission staff.

Q. Have you previously testified before the RCA?

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

II. <u>PURPOSE OF DIRECT TESTIMONY</u>

Q. What is the purpose of your direct testimony?

A. In compliance with 3 AAC 48.275(a), I am sponsoring ENSTAR's revenue requirement and comparative financial schedules, which are included in Attachment B to TA334-4. I also will describe various pro forma adjustments made to test year data used in ENSTAR's 275(a) filing.

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, 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; and
- Depreciation Expense.

These schedules are required by 3 AAC 48.275(a)(1)-(3), 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, 2021.

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 and supervision reviewed the data contained in ENSTAR's accounting books and records and identified unusual and 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.

III. 3 AAC 48.275(a) FILING

Q. Please summarize how the revenue requirement study was prepared.

A. The revenue requirement study was prepared in conformity with applicable Commission precedent and regulations and was based on a pro forma test year ending December 31, 2021. Test year revenues and operating expenses were revised as necessary, with pro forma adjustments, to make the normalized amounts representative of the period in which the rates will be in effect. Test year rate base was calculated using a 13-month average based on historical 2021 data with the addition of normalizing and regulatory adjustments. ENSTAR's weighted cost of capital was applied to the normalized rate base amount to determine the total return on investment. The normalized net income amount was used to calculate the amount for state and federal income taxes, less the annual amortization of the excess accumulated deferred income taxes resulting from the 2017 Tax Cuts and Jobs Act as further described in the prefiled testimony of Dr. Bruce H. Fairchi.

Q. Please identify the schedules in the filing.

A. ENSTAR's 275(a) filing is contained in Attachment B to TA334-4 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 through U, 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 Mr. Daniel M. Dieckgraeff, Dr. Bruce H. Fairchild, and Mr. Mark A. Moses;

- the computation of the pro forma adjustment for state and federal taxes for the normalized test year is shown on Schedule G and contained in the testimony of Dr. Fairchild;
- the computation of rate base using a 13-month average 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 U and is derived based upon the lead-lag study sponsored by ENSTAR witness Mr. Harold Walker, III;
- the computation of ENSTAR's requested weighted cost of capital is shown on page 3 and sponsored by the testimony of Mr. Dieckgraeff;
- the Comparative Statement of Assets, Liabilities and Other Credits for 2021 and 2020 is shown on page 30;
- the Comparative Statement of Income and Operating Expenses for 2021 and 2020 is shown on page 31;
- the Comparative Statement of Changes in Equity Position for 2021 and 2020 is shown on page 32;
- Plant in Service and Accumulated Depreciation balances for 2021 and 2020 are shown on pages 33 and 34;
- Depreciation Expense for 2021 and 2020 is shown on pages 35 and 36; and
- Long-Term Debt Outstanding for 2021 and 2020 is shown on page 37.

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, 2021 (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 test-year balances (column 1), 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). The 13-month averages for use in the calculation of rate base are computed on page 5.

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 Mr. Dieckgraeff. ENSTAR's return on equity and capital structure are sponsored by and discussed in the testimony of ENSTAR witness Mr. Dylan W. D'Ascendis.

Page 4 of the filing reconfigures the information on pages 1, 2, and 3 into a revenue requirement format. Pages 9 through 29 of the filing provide supporting schedules that detail the various adjustments made on pages 1 through 4 (Schedules A – U). Pages 30 through 37 provide the required historical comparative information.

Q. What types of adjustments were made to ENSTAR's historical results of operations for the year ended December 31, 2021?

A. The historical test year serves only as the starting point for evaluating the adequacy of base rates. Routinely, various adjustments are required to convert actual test-year revenues, expenses, and rate base to a representative set of test-period data reflective of normalized, ongoing operations.

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. How are the adjustments shown in ENSTAR's filing?

A. As discussed above, the second column of pages 1, 2 and 4 of Attachment B shows the summary of adjustments for each main category on the respective schedule. Each adjustment is shown on pages 6-8, Summary of Pro Forma Adjustments, with reference to the schedule where the adjustment is described and the witness who sponsors the adjustment in their testimony.

Q. What is ENSTAR's adjusted rate base in this case?

A. As shown at the bottom of column 3 ("Normalized"), page 2 of the 275(a) filing, after making the various adjustments discussed further in the testimony of Mr. Dieckgraeff, Dr. Fairchild, Mr. Moses, and myself, ENSTAR's rate base totals $293,177,574.

Q. Please describe page 4 of ENSTAR's 275(a) filing.

A. Page 4 reconfigures pages 1-3 into a revenue requirement format. It calculates the total revenues ENSTAR needs to earn its requested overall rate of return of 8.32%.

Q. Based on the changes in O&M expenses and taxes and ENSTAR's requested rate of return, what is ENSTAR's total revenue requirement?

A. As shown at the bottom of column 3 ("Normalized") on page 4, after taking into account the adjustments to operating expenses, state and federal taxes, and return on investment, ENSTAR's revenue requirement is $365,487,320. Comparing this with current adjusted normalized revenues of $360,446,470 developed on page 1 of the 275(a) filing, ENSTAR is proposing that its current rates increase by $5,040,851, or 1.40%.[2]

IV. 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 of the largest four international 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. As a division of SEMCO, ENSTAR

[2] 1.40% includes the cost of gas, without the cost of gas the rate increase is 5.68%.

also adheres to accounting policies and procedures prescribed by SEMCO. Finally, ENSTAR adheres to the Cost Allocation Manual ("CAM") applicable to ENSTAR and CINGSA, which includes policies and procedures for allocating costs between the companies, among other things. Attached to my testimony as Exhibit CNG-2 is the CAM.

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. It was updated in 2018 to address guidelines of the National Association of Regulatory Utility Commissioners and to incorporate recommendations made by Commission personnel. The CAM is updated on an as-needed basis to reflect changes to accounting policies and procedures. It was most recently updated in 2021 primarily to reflect changes as to which entity performs certain accounting functions.

Q. Please describe the eligible cost allocations transferred to CINGSA during ENSTAR's test year.

A. ENSTAR incurred a total of $26,817,680 of administrative and general ("A&G") expenses on its financial statements during the test year. Of this amount, $8,292,892 was allocated to ENSTAR (including APC) construction, CINGSA, and reimbursable construction (referred to below as "RC jobs"). Therefore, a total of approximately

$8.3 million of A&G expenses are not included in ENSTAR's operating expenses. Below is a table detailing the A&G costs allocated during the test year.

Total A&G Expenses (Gross)	$ 26,817,680
A&G Allocated:	
To ENSTAR Construction	$ (5,896,770)
To APC Construction	$ (1,257,012)
Allocated to CINGSA	$ (819,506)
Allocated to RC jobs	$ (319,604)
Net A&G per Financials	$ 18,524,788

V. ADJUSTMENTS TO 275(a) FILING

Q. Which adjustments included in ENSTAR's 275(a) filing do you sponsor?

A. I sponsor several adjustments to expenses and rate base that are included in the 275(a) filing, including the following:

- 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 F);
- Earthquake Deferral (Schedule J);
- Amortization of Bad Debts from COVID-19 (Schedule K);
- Rate Case Expense (Schedule L);
- Removal of ROU Lease (Schedule N);
- Year End Plant Adjustment (Schedule P);
- Payroll Adjustment (Schedule R);
- Critical Position Additions (Schedule S);
- Maintenance Contracts (Schedule T); and

- Cash Working Capital (Schedule U).

A. <u>Removal of Disallowed Reg Assets (Schedule A)</u>

Q. Please describe the Removal of Disallowed Regulatory Assets adjustment shown on Schedule A of the 275(a) filing.

A. This pro forma 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 the costs incurred on the proposed Bullet Line pipeline from the North Slope in future ENSTAR rate proceedings. To adjust out these costs, Pro Forma A removes the regulatory asset ("reg asset") of $1,630,249 from rate base and the associated amortization expense of $465,786 from test year expenses.

B. <u>Removal of Misc. Revenues and Expenses (Schedule B)</u>

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 increases 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 $573,234.

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. Additionally, ENSTAR is removing the costs associated with the disposal of unamortized software.

Q. How did ENSTAR arrive at the amount for the adjustment found on Schedule B?

A. My team and I reviewed all 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.

C. <u>Removal of Other Assets (Schedule C)</u>

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. This adjustment removed 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 $3,910,668.

D. <u>Removal of CWIP (Schedule F)</u>

Q. Please describe the Removal of CWIP adjustment shown on Schedule F of the 275(a) filing.

A. This adjustment reduces ENSTAR's rate base. In keeping with Commission precedent, ENSTAR has removed the 13-month average of construction work-in-progress ("CWIP") from the rate base calculation. The adjustment decreases rate base by $5,809,690.

E. <u>Earthquake Deferral (Schedule J)</u>

Q. Please describe the Earthquake Deferral adjustment shown on Schedule J of the 275(a) filing.

A. In Docket U-19-101, ENSTAR sought the creation of a regulatory asset for the earthquake costs incurred to respond to the November 30, 2018 earthquake. In Order

U-19-101(5), the Commission approved the regulatory asset in the amount of $1,016,184. The Commission authorized ENSTAR to earn "a return on the regulatory asset" and stated that ENSTAR "may apply the rate of return determined in its next rate case to the regulatory asset for that intervening time period."[3] Accordingly, ENSTAR is amortizing the earthquake costs over a three-year period.

Q. Why is ENSTAR using a three-year amortization period for the earthquake costs?

A. ENSTAR began incurring the earthquake costs included in this adjustment slightly less than four years ago. During this time, ENSTAR has not applied any carrying costs on the balance. ENSTAR is now proposing to amortize the remaining balance over three years. Using a three-year amortization will allow ENSTAR to recover the costs within seven years of when the event took place.

Q. Does the Commission discuss amortization of regulatory assets in relation to matching between cost and rate payer benefit?

A. Yes, Order U-01-108(14) states that a "cost may be capitalized and ratably expensed over the period in which the cost is expected to provide benefit."[4] By requesting a three-year, as opposed to a five-year amortization period, ENSTAR seeks to ensure recovery of these costs as close to the time they were incurred (and the benefit was rendered) as possible.

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[3] Order U-19-101(5) at page 9.

[4] Order U-01-108(14) at page 8.

F. Amortization of Bad Debts from COVID-19 (Schedule K)

Q. Please describe the Amortization of Bad Debts from COVID-19 shown on Schedule K of the 275(a) filing.

A. As discussed in Mr. John D. Sims' testimony, ENSTAR has incurred $262,979, as of June 30, 2022, in bad debt expenses associated with the COVID-19 pandemic. This adjustment shown on Schedule K reduces the test year 13-month average balance to $262,979 (from $314,257) and amortizes this amount over a three-year period.

Q. Why did ENSTAR reduce the COVID bad debt regulatory asset from the 13-month average balance in the test year?

A. ENSTAR thought it was appropriate to reduce the asset balance to the lowest amount, which was the amount as of June 30, 2022. ENSTAR ceased making adjustments to that regulatory asset as of June 30, 2022.

Q. Why is ENSTAR proposing a three-year amortization for bad debts resulting from COVID-19?

A. Similar to the earthquake costs discussed above, the COVID-19 pandemic began in March 2020. Many of these incurred costs are over two years old; therefore, a longer amortization period could inappropriately shift costs to future ratepayers. Using a three-year amortization will allow ENSTAR to recover the costs within six years of when the pandemic began.

Q. Does ENSTAR believe it is reasonable to earn a return on the bad debt resulting from the COVID-19 pandemic?

A. Yes. As described by Mr. Sims, the Alaska Legislature worked quickly to enact SB 241 following declaration of an emergency in March 2020. The legislation specifically permitted utilities to create regulatory assets associated with COVID-19 related bad debt, and left the question of whether the costs in the bad debt account were COVID-19 related, as well as the time period over which it should be amortized, to the Commission. ENSTAR effectively provided funding to cover the abnormal amount of uncollectible revenues that have resulted from the pandemic. The funds that were used to cover the increase in uncollectible revenue could have been used for other items – including system improvements that might have earned a return throughout their depreciable life. As discussed above, these costs will take a minimum of six years for ENSTAR to recover; therefore, it is reasonable for ENSTAR to earn a return on this asset.

G. Rate Case Expense (Schedule L)

Q. Please describe the Rate Case Expense adjustment shown on Schedule L in the 275(a) filing.

A. The 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 2021 test year from Docket U-16-066. 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 U-16-066 Rate Case Expense on the test year books?

A. ENSTAR's amortized test-year rate case expense was $414,408.

Q. How does this amount compare with the amount authorized by the Commission to be included in rates in Order U-16-066(19)?

A. In Docket U-16-066, ENSTAR made three rate case expense-related requests: first, to recover $1.8 million in rate case expense for U-16-066; second, to amortize that $1.8 million over three years; and third, to be permitted to include unamortized Docket U-

14-111 rate case expenses in its ongoing revenue requirement. The Commission approved ENSTAR's requested recovery of $1.8 million in rate case expense but instructed ENSTAR to recover it over five years instead of three. This would have resulted in an annual recovery of $360,000 (as included in rates). However, ENSTAR's actual rate case expense for Docket U-16-066 was $2,071,447.95. As such, the annual amortization amount in the rate case regulatory asset was $414,408.

Q. Is ENSTAR seeking to recover the remaining balance in this regulatory asset?

A. No. The Commission denied ENSTAR's third rate case expense-related request (related to ongoing recovery of U-14-111 rate case expenses) in Docket U-16-066, stating 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."[5] As such, Pro Forma L requests an adjustment to omit this unamortized balance.

Q. What amount is ENSTAR estimating for rate case expenses for this case?

A. ENSTAR is estimating it will incur $2.1 million in rate case expenses for this case. This estimate is based on the actual costs ENSTAR incurred five years ago in U-16-066, while also reflecting the professional support services ENSTAR has enlisted to prepare this case and attempting to account for inflation in costs since that case. This is consistent with the Commission's statement in Order U-16-066(19) at 92 that "[c]urrent experience is relevant and may indicate trends that costs will differ from past experience."

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5 Order U-16-066(19) at 92, citing Order U-00-088(12) at 24.

Q. What is ENSTAR's proposed amortization period for rate case expenses incurred in this case?

A. ENSTAR proposes a three-year amortization period.

Q. Why did ENSTAR select this amortization period?

A. ENSTAR believes it is highly likely it will file another rate case in a short period of time following the conclusion of this case. ENSTAR is facing significant gas supply challenges. As discussed in the prefiled testimony of Ms. Inna B. Johansen, we are working collaboratively with other Cook Inlet utilities on solutions and substantial investments in Cook Inlet storage or LNG import facilities will likely be required in the very near future. ENSTAR would then need to file another rate case. A three-year amortization period is reasonable.

H. Removal of ROU Lease (Schedule N)

Q. Please describe the Removal of ROU Lease Contracts adjustment shown on Schedule N of the 275(a) filing.

A. This adjustment reduces rate base by $2,805,821 and increases operating expenses by $33,817. 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. 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 includes the lease payments in A&G expenses.

Q. Did ENSTAR have similar regulatory treatment of operating leases in Docket U-16-066?

A. Yes. ENSTAR included the lease payments in A&G expenses, as opposed to including the leases in rate base.

I. Year-End Plant Adjustment (Schedule P)

Q. Please describe the Year-End Plant adjustment shown on Schedule P of the 275(a) filing.

A. As discussed by Mr. Sims, 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-3.

Q. Please describe Exhibit CNG-3 in more detail.

A. The first column of CNG-3 ("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. These pro forma amounts from this exhibit are included in Pro Forma P and summarized by FERC account number.

J. Payroll Adjustment (Schedule R)

Q. Please describe the Payroll adjustment shown on Schedule R of the 275(a) filing.

A. The purpose of the payroll adjustment shown on Schedule R 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 R?

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 August 1, 2022. For union-represented clerical and operations employees, wage rates were adjusted to reflect scheduled grade changes along with increases of (1) a 2.4% inflation adjustment and (2) a 1.5% cost of living increase specified by union contract that became effective on April 1, 2022, as discussed in Mr. Sims' testimony. This adjustment increases ENSTAR's revenue requirement by $592,946.

Q. 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.

K. Critical Position Additions (Schedule S)

Q. Please describe the Critical Position Additions adjustment shown on Schedule S of the 275(a) filing.

A. As discussed in Mr. Sims' testimony, ENSTAR added two new critical positions in 2022: a Safety Assistant and the Operation Technology Systems & Compliance

Engineer. This pro forma adjusts for costs associated with the salary, benefits, and payroll taxes for these two positions. Additionally, the pro forma removes the temporary Safety Assistant salary, benefits, and payroll taxes as this position is being replaced by the full-time Safety Assistant. The net impact of these adjustments is an increase in A&G expense of $35,247 and an increase in transmission expense of $188,251.

L. Maintenance Contracts (Schedule T)

Q. Please describe the Maintenance Contract adjustment shown on Schedule T of the 275(a) filing.

A. This pro forma adjusts for a new contract and a contract revision that ENSTAR entered into following the test year. First, the ACS Circuit Lease begins August 1, 2022, and covers a three-year term. This new contract that provides ENSTAR's pipeline system connection between ENSTAR's facilities in Wasilla and CINGSA's facilities in Kenai. The circuit lease increases the reliability and safety of ENSTAR's system when responding to a disaster recovery scenario. This connection will allow ENSTAR's pipeline system to be fully controlled from one of two disaster recovery points (ENSTAR's Wasilla Operations office or CINGSA) if ENSTAR were to experience significant damage to the Anchorage operations facility. This contract is a known and measurable change and increases test year expenses by an annual amount of $35,016.

Second, ENSTAR has been operating with the same janitorial contract and pricing since 1998. The contract was revised on July 7, 2022 to increase prices by $1,300 a month. Schedule T adjusts test year expenses for this increase at an annual amount of $15,600.

M. <u>Cash Working Capital (Schedule U)</u>

Q. Please describe the Cash Working Capital adjustment shown on Schedule U of the 275(a) filing.

A. ENSTAR was required to file a lead-lag study pursuant to Order U-16-066(19) and Order U-16-066(22) with its next revenue requirement. ENSTAR witness Mr. Walker performed and sponsors the lead-lag study in this matter. Based on Mr. Walker's testimony and the lead-lag study, ENSTAR is proposing a cash working capital adjustment of $9,834,683.

VI. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes.

Chelsea N. Guintu

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, AK: 2015 - Present

Supervisor of Rates and Regulatory Affairs: 2019 - Present

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

Friends of Pets, volunteer

ENSTAR NATURAL GAS CO.
COST ALLOCATION MANUAL

Guidelines for Cost Allocations to/from ENSTAR Natural Gas Co. to Construction Projects and Related Companies

Updated: 04/20/2021

Table of Contents

Introduction

This Cost Allocation Manual (CAM) was developed to specify the procedures that ENSTAR Natural Gas Company (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 SEMCO Energy, Inc. is a 65% member. ENSTAR is a division of SEMCO Energy, Inc., 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 formulae 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.

AltaGas Ltd (AltaGas), a Canadian corporation located in Calgary, AB, is a North American diversified energy infrastructure company with a focus on owning and operating assets to provide clean and affordable energy to its customers. As part of its infrastructure, AltaGas owns and operates utility assets that store and deliver natural gas to end-users in Alaska, Michigan, Virginia, Maryland and the District of Columbia. AltaGas is not regulated at this level, but owns utilities that are regulated.

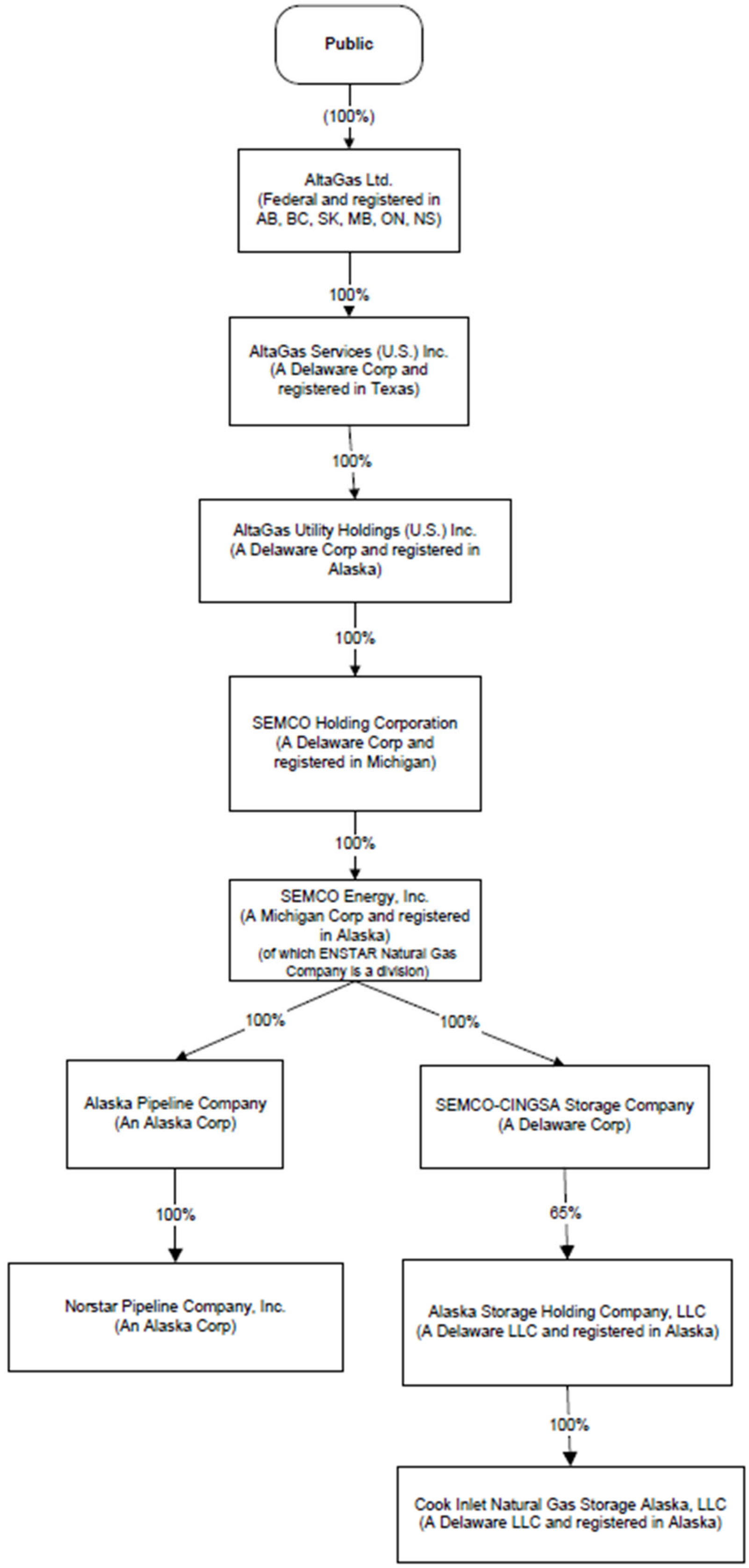
SEMCO Energy, Inc. (SEMCO), located in Port Huron, MI, is an indirect wholly-owned subsidiary of AltaGas Ltd. SEMCO owns regulated natural gas distribution utilities in Michigan and in Alaska. SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas) and its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR).

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 Alaska Pipeline Company (APC) transmission system. APC is a wholly owned subsidiary of SEMCO Energy, Inc.   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 Alaska Pipeline Company. Norstar provides utility-related contractual services in the Cook Inlet area. Norstar is a non-regulated company.

SEMCO-CINGSA Storage Company (SCSC), headquartered in Port Huron, MI, is a wholly-owned subsidiary of SEMCO Energy, Inc. SCSC 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. SCSC and ASHC are non-regulated companies, while CINGSA is regulated by the Regulatory Commission of Alaska.

Ownership structure of ENSTAR and CINGSA



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 administrative, management, accounting, and other support services from SEMCO, WGL and AltaGas. ENSTAR is not billed directly for these services from SEMCO and AltaGas, but is charged a shared services allocation. The allocations are calculated using the Modified Massachusetts Formula (MMF), which has been approved by the regulatory commissions in both Alaska and Michigan. WGL charges shared services directly to the SEMCO, and SEMCO passes on any direct charges to ENSTAR.

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:

AltaGas, Ltd.

Executive Management Services: Executive management and services, including, but not limited to, officers of AltaGas.

Investor Relations: Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.

Internal Audit: Reviews and audits internal audit controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded.

Legal: Provides legal services and corporate governance.

Corporate Communications: Provides corporate communications and coordinates media services. Provides safety campaigns and public awareness for companies within the AltaGas system.

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.

Finance & Treasury: Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.

Accounting/Financial Reporting: Consolidates financial and statistical reports. Ensures compliance with applicable laws, regulations and GAAP.

Budgeting: Provides financial analysis, budget coordination and support.

WGL

Executive Management Services: Executive management and services, including, but not limited to, officers of AltaGas Services (US).

Internal Audit: Reviews and audits internal audit controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded.

SEMCO Energy, Inc.

Executive Management Services: Executive management and services, including, but not limited to, officers of SEMCO.

Investor Relations: Provides communications to investors and the financial community.

Finance & Treasury: Coordinates activities related to maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.

Accounting/Financial Reporting/Taxes: Consolidates financial and statistical reports. Prepares tax filings. Ensures compliance with applicable laws and regulations. Maintains the accounting systems.

Budgeting: Provides financial analysis, consolidates budgets and coordinates the budget process.

Procurement: Manages purchase requisition and purchase order processing.

Payment Processing: Processes payments to vendors and related reporting.

Human Resources: Establishes and administers policies related to employment, compensation and benefits. Maintains HR computer system.

Business Systems: Provides basic information technology services such as application management and systems management.

Risk Management: Maintains relationships with insurance brokers, obtains policies for all types of liability insurance.

Payroll: Processes payroll including, but not limited to, time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports. Payroll services are related to ENSTAR employees who work on CINGSA projects.

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 12. 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 SEMCO 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.

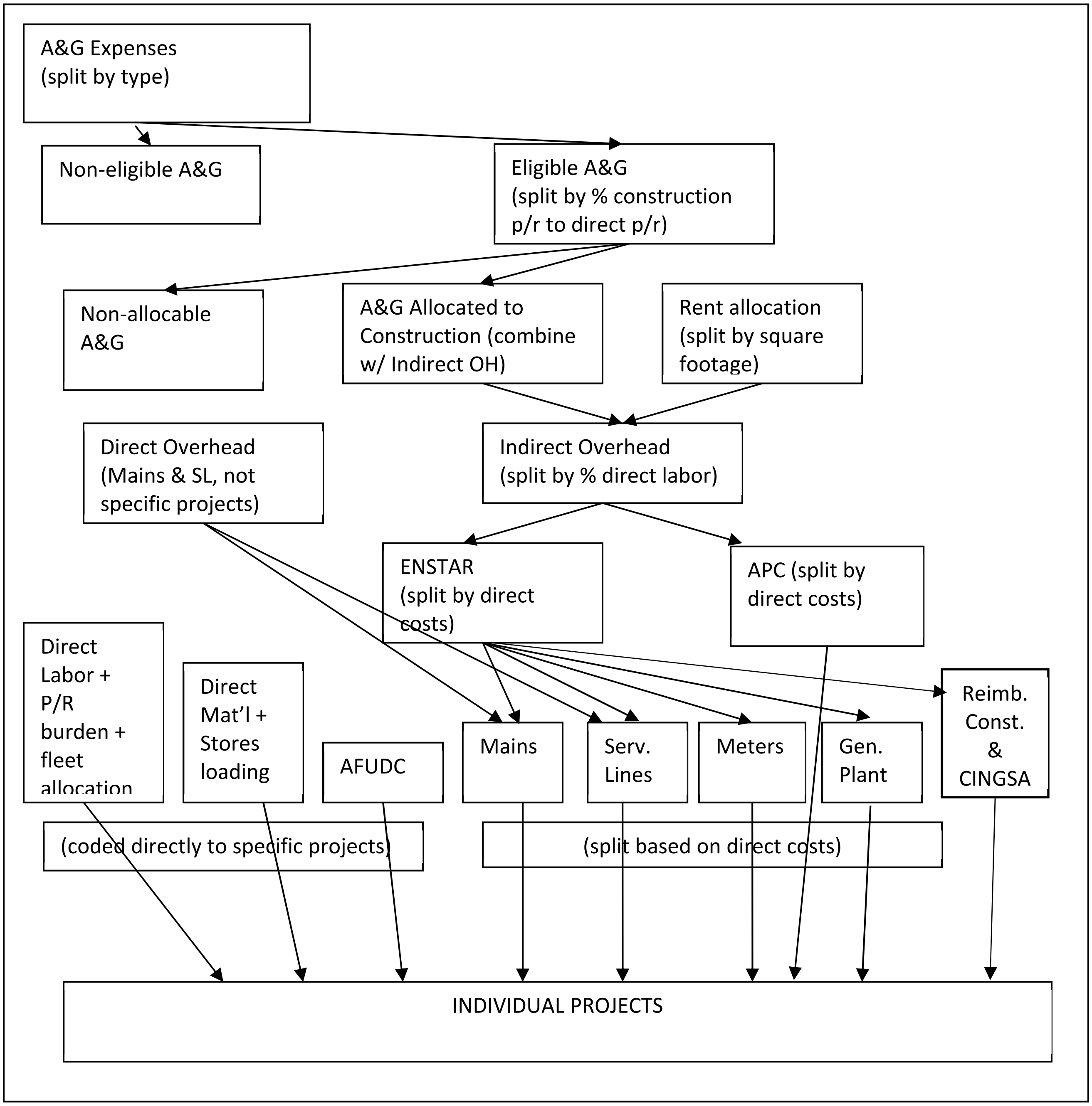
COST ASSIGNMENT AND ALLOCATION PRINCIPLES

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:

Payroll Vac-Sick-Holida	Eligible - Labor
Benefits	Eligible - Benefits
Employee Relations	Not eligible
Employee Awards	Eligible - Benefits
Relocation Expenses	Eligible - Benefits
Community Relations	Not eligible
Employee Other Benefits	Split
Office Supplies	Split
Telephone	Eligible - Expense
Postage & Shipping	Eligible - Expense
Computer Expenses	Eligible - Data Processing
Office - Contract Labor	Split
Building Maintenance	Eligible - Expense
Ground Travel	Eligible - Expense
Air Travel	Eligible - Expense
Lodging	Eligible - Expense
Meals & Ent-Out of Town	Eligible - Expense
Meals & Ent-Other	Not eligible
Meetings	Split
Training	Split
Conferences	Split
Dues & Subscriptions	Eligible - Expense
Membership Dues - Other	Eligible - Expense
Parent Allocations	Not eligible
Shared Services	Eligible
WGL direct charges	Not eligible
Legal	Split
Accounting	Eligible - Audit
Other Professional Svs	Eligible - Expense
General Liability Insur	Split
Property Insurance	Split
Auto Liab - TPA Fees	Not eligible
Bonds	Not eligible
Regulatory Expenses	Eligible - Expense
Advertising	Split
Job Advertising-Recruitment	Eligible - Expense
Corporate & Securities	Not eligible
Safety Expenses	Eligible - Expense
Injuries & Damages	Not eligible
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

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

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
41699900200.26570	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
4.15280	Non Stock Inventory

The stores loading rate is developed using a ratio of stores expense loaded out divided by the total dollar value of inventory issues to compute a rate which can be applied to material charged to each project.

For CINGSA and 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 a specific object account (18932), 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
18932-18934	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 21-UA-07

June 11, 2021

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:
Lee R. Ellenburg, CIA, CMA
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). 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 2020 actual financial data.

The scope of the audit was limited to the company's calendar year 2020 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, Highways 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 with the exception of GAGAS 3.31 Auditor Independence, as due to the reorganized structure of the Department the AKDOT Office of Internal Review did not meet the independence requirement as we report to the Division of Administrative Services as opposed to directly to the Department Commissioner; additionally GAGAS 3.75 as there is not a licensed Certified Public Accountant on staff (there is a Certified Internal Auditor and Certified Management Accountant on staff). We do not believe these exceptions have a significant effect on the audit conducted or assurance provided. 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 165.67% (as a percentage of direct gross wages)
   - Materials Handling Rate 15.96% (as a percentage of materials issued)
   - Transportation Rate 16.30% (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.

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.

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   ENSTAR has an acceptable work order accounting system, which is capable of identifying, segregating and accumulating costs to specific work orders.

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   - Transportation Rate 16.30% (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.

ENSTAR Natural Gas Company

Capital Projects for Test Year 2021

Jobs	FERC Account #	Depr. Rate	Gas Utility Plant: 2021 Year End Plant	Gas Utility Plant: Amount in 13-Month Average	Gas Utility Plant: Adjustment to Plant	Depreciation: Annual Depreciation Expense	Depreciation: Amount in Test Year	Depreciation: Adjustment to Depreciation	Accumulated Depreciation: 2021 Year End Accum Dept	Accumulated Depreciation: Amount in 13-Month Average	Accumulated Depreciation: Adjustment
Safety											
MP39 Station Rebuild (Meas & Reg Sta Equip)	369.00	2.42%	984,016	75,694	908,322	23,813	1,984	21,829	(11,907)	(153)	(11,754)
MP39 Station Rebuild (Lines)	367.00	1.76%	64,949	4,996	59,953	1,143	95	1,048	(572)	(7)	(564)
MP39 Station Rebuild (M&R Station Structures)	366.20	1.87%	5,013	386	4,627	94	8	86	(47)	(1)	(46)
Kenai B-Line MP 45.3 Repair (Lines)	367.00	1.76%	60,080	4,622	55,458	1,057	88	969	(529)	(7)	(522)
B-Line Cutout 2021 (Lines)	367.00	1.76%	90,340	6,949	83,391	1,590	132	1,457	(795)	(10)	(785)
Bernice Lake Station - Final Tie in Work (M&R Station Structures)	366.20	1.87%	210,691	68,781	141,910	3,940	1,393	2,547	(1,970)	(107)	(1,863)
Bernice Lake Station - Final Tie in Work (Meas & Reg Sta Equip)	369.00	2.42%	1,338,465	436,945	901,520	32,391	11,455	20,936	(16,195)	(881)	(15,314)
Bernice Lake Station - Final Tie in Work (Lines)	367.00	1.76%	126,093	41,163	84,930	2,219	785	1,434	(1,110)	(60)	(1,049)
Bernice Lake Site Work (M&R Station Structures)	366.20	1.87%	52,801	4,062	48,739	987	82	905	(494)	(6)	(487)
Fairview Elementary Steel Main Replacement (Shorted casing)	376.41	2.08%	37,969	14,135	23,834	790	319	471	(395)	(25)	(370)
Mains Sanya & Dolina Steel Replacement (Mains - Plastic)	376.41	2.08%	119,551	42,746	76,805	2,487	963	1,523	(1,243)	(74)	(1,169)
Upland Dr Steel Replacement (Mains - Plastic)	376.41	2.08%	16,608	6,290	10,318	345	142	204	(173)	(11)	(162)
Glacier Creek Reroute (Mains - Plastic)	376.41	2.08%	134,499	67,277	67,223	2,798	1,516	1,282	(1,399)	(117)	(1,282)
Dist-Svc AN Copper Renewal 5/8" PL (Services - Plastic)	380.41	3.64%	352,162	264,267	87,895	12,819	10,421	2,398	(6,409)	(802)	(5,608)
Dist-Svc AN Copper Renewal 7/8" PL (Services - Plastic)	380.41	3.64%	667	520	147	24	21	4	(12)	(2)	(11)
Dist-Svc AN Copper Renewal 1" PL (Services - Plastic)	380.41	3.64%	124	139	(14)	5	5	(1)	(2)	(0)	(2)
Dist-Svc AN Copper Renewal 1" Stubs (Services - Plastic)	380.41	3.64%	1,525	1,617	(92)	56	64	(8)	(28)	(5)	(23)
Dist-Svc AN X-trube Renewal 5/8" PL (Services - Plastic)	380.41	3.64%	44,407	36,666	7,741	1,616	1,446	171	(808)	(111)	(697)
Dist-Svc AN X-trube Renewal 7/8" PL (Services - Plastic)	380.41	3.64%	34,430	25,999	8,431	1,253	1,025	228	(627)	(79)	(548)
Dist-Svc SK Copper Renewal 5/8" PL (Services - Plastic)	380.41	3.64%	60	46	14	2	2	0	(1)	(0)	(1)
Dist-Svc SK X-trube Renewal 7/8" PL (Services - Plastic)	380.41	3.64%	1,323	789	534	48	31	17	(24)	(2)	(22)
Kusco Steel S/L Replacement 1" (Services - Plastic)	380.41	3.64%	87,212	75,960	11,252	3,175	2,995	179	(1,587)	(230)	(1,357)
Reliability											
EAG Valve Replacement (Meas & Reg Sta Eq CG)	379.00	2.09%	40,336	3,103	37,233	843	70	773	(422)	(5)	(416)
ERT Replacement (ERTS)	381.10	5.68%	58,863	4,528	54,335	3,343	279	3,065	(1,672)	(21)	(1,650)
A&B MP50.5 - Fencing (M&R Station Structures)	366.20	1.87%	14,136	1,087	13,048	264	22	242	(132)	(2)	(130)
SCADA Cybersecurity Improvements (Communication Equip)	397.00	11.71%	61,470	4,728	56,741	7,198	600	6,598	(3,599)	(46)	(3,553)
SCADA Cybersecurity Improvements (Computer Equipment)	391.10	14.25%	19,478	1,498	17,980	2,776	231	2,544	(1,388)	(18)	(1,370)
			Total Adjustment		2,762,277			70,901			(50,755)

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Keith Kurber II, Chair Robert A. Doyle Robert M. Pickett Daniel A. Sullivan Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-____

PREFILED DIRECT TESTIMONY
OF
DANIEL M. DIECKGRAEFF

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I. POSITION AND QUALIFICATIONS

Q. State your name, business address, and present position.

A. My name is Daniel M. Dieckgraeff. My business address is 3000 Spenard Road, Anchorage, Alaska 99503. I am the Director of Rates and Regulatory Affairs for ENSTAR Natural Gas Company, a division of SEMCO Energy, Inc. ("SEMCO"), and Alaska Pipeline Company, a subsidiary of SEMCO. For purposes of my testimony, I will refer to these two regulated entities collectively as "ENSTAR."

Q. Briefly describe your professional experience and educational background.

A. I have been employed by ENSTAR since July 1982, and have held various supervisory and managerial positions with responsibility for ENSTAR regulatory matters since then. From 2000 to early 2008, I also had primary responsibility for ENSTAR's gas supply contract negotiation and administration. Prior to joining ENSTAR, I spent three years with the Anchorage office of the accounting firm of Price Waterhouse (now known as PricewaterhouseCoopers). I received a Bachelor of Business Administration degree with a major in public accounting from Gonzaga University in 1979 and a Master of Business Administration with a concentration in Global Finance from Alaska Pacific University in 2007. My resume is attached as Exhibit DMD-1.

Q. Briefly describe your current professional responsibilities.

A. I am responsible for all regulatory matters before the Regulatory Commission of Alaska ("RCA" or "Commission") for ENSTAR and for Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA").[1]

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

Q. Have you previously testified before the RCA?

A. Yes, I have testified before the RCA and its predecessor agency numerous times, including in Docket U-16-066, which was ENSTAR's last rate case, and I most recently appeared before the Commission in Docket U-21-058 as a witness on behalf of CINGSA.

II. PURPOSE OF TESTIMONY AND BACKGROUND

Q. What is the purpose of your direct testimony?

A. My testimony has several primary functions. First, I will summarize ENSTAR's recent rate history beginning with its last rate case (U-16-066). Second, I am sponsoring the requested weighted cost of capital schedule in ENSTAR's revenue requirement, which is included as page 3 of Attachment B to ENSTAR's overall rate filing ("275(a) Filing" or "Filing"). Third, I am discussing and sponsoring the following pro forma adjustments and the corresponding schedules in the 275(a) filing:

- adjustment to reflect the current purchased gas cost (Schedule D);
- adjustment to uncollectible account expenses (Schedule H);
- weather normalization adjustment to test year gas sales volumes (Schedule O);
- adjustment to travel and conference expenses to normalize expenses for the impact of COVID-19 (Schedule Q); and
- adjustment to reflect the decommissioning of Chugach Electric Association Inc.'s ("Chugach") International Generation Turbine ("IGT") (Schedule I).

Fourth, I will discuss components of the income tax adjustment sponsored by ENSTAR witness Dr. Bruce H. Fairchild (Schedule G). Fifth, I will discuss:

- the directions given to Dr. Fairchild concerning cost of service (and rate design);
- ENSTAR's rate design proposals for its General Service, medium-sized firm service and very large firm transportation service customers;
- ENSTAR's proposal for a rate schedule to accommodate the power pool between Chugach and Matanuska Electric Association, Inc. ("MEA"); and
- ENSTAR's request for interim rate relief effective October 1, 2022.

Finally, I am sponsoring the related tariff sheets that present the proposed interim and permanent rates, as well as ENSTAR's proposed tariff sheets to add its suggested power pool rate schedule to its tariff.

III. ENSTAR'S RECENT RATE HISTORY

Q. Briefly summarize ENSTAR's last rate case, U-16-066.

A. ENSTAR's last rate case was initiated with the filing of a revenue requirement and cost-of-service study based upon a 2015 test year as stipulated to in Docket U-14-111.[2] The filing requested an across-the-board interim increase of 1.6% of total revenues and an additional 2.3% upon final approval or acceptance.[3] The Commission approved the interim increase effective for billings on or after August 1, 2016, in Order U-16-066(1) dated July 18, 2016. 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 cost-of-service 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

[2] Docket U-14-111 was ENSTAR's 2013 test year rate case that was settled by a stipulation that was accepted by the Commission in Order U-14-111(18) dated September 29, 2015.

[3] TA285-4, dated June 1, 2016, at 2-3.

file revised revenue requirement schedules, and a revised cost-of-service study, and tariff sheets consistent with the Commission's decisions. The Order also required ENSTAR to file another rate case based upon calendar year 2020 by June 1, 2021. ENSTAR filed the revised revenue requirement schedules, cost-of-service 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.

Q. Have ENSTAR's general rates been revised since the approval of tariff sheets in Order U-16-066(20)?

A. Yes, ENSTAR lowered its rates in 2018 in response to the Tax Cut and Jobs Act of 2017 ("TCJA") that was enacted on December 22, 2017. In an April 4, 2018 letter to the Commission in Docket I-18-002 ("*In the Matter of the Consideration of the Impact of the Tax Cut and Jobs Act of 2017 on Alaskan Public Utilities*"),[4] ENSTAR stated that it anticipated "making a filing by the end of April 2018 to address the change in the corporate income tax rate on the income tax expense and related components of ENSTAR's recently decided 2015 test year revenue requirement, excluding deferred taxes." Because of the considerable work involved in determining the effect of the TCJA on accumulated deferred income taxes ("ADIT"), the uncertainty around the appropriate method of amortization and amortization life of excess ADIT created by the TCJA, ENSTAR proposed "including the excess ADIT amortization adjustment in its next rate case . . . ."[5] ENSTAR filed the rate revision as TA303-4 on April 26, 2018

[4] ENSTAR's letter is attached as Exhibit DMD-2.

[5] *Id.* at 3.

(see Exhibit DMD-3, attachments excluded), which represented "a 5.7% reduction of ENSTAR's non-gas revenue requirement."[6] TA303-4 also stated that "[a]s noted in ENSTAR's letter to the Commission in Docket I-18-002 dated April 6, 2018, ENSTAR will address any impact on its deferred taxes in its next rate case."[7]

Q. Did the Commission approve the rates filed in TA303-4?

A. Yes, there were no changes to the rates proposed in TA303-4 and the rates were approved in Letter Order L1800240 dated May 29, 2018, with an effective date of June 1, 2018 (Exhibit DMD-4). These are the rates that are currently in effect as of the filing of this rate case.

Q. Is the current (TA334-4) rate case filing the one required by the Commission in Order U-16-066(19) that you mentioned earlier?

A. Yes. In Order U-16-066(21), 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.

Q. Did ENSTAR request a subsequent stay of the filing deadline?

A. Yes. As discussed by ENSTAR witness Mr. John D. Sims, an acquisition was announced on May 26, 2022. That day, ENSTAR moved the Commission for a stay of the filing deadline for this rate case. 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.

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[6] TA303-4 at 1.

[7] *Id.* at 2, n. 2.

Q. Is there another docket open to address the proposed transaction for the sale of SEMCO's Alaska utility business interests, which include ENSTAR and APC, to a subsidiary of TriSummit Utilities Inc. ("TSU")?

A. Yes. On June 24, 2022, a joint application was filed with the RCA for approval of the transfer of ENSTAR's certificates of public convenience and necessity (Docket U-22-032).

Q. Does this instant filing (TA334-4) reflect that proposed transaction?

A. No, it does not. The proposed transaction is pending approvals, including those by this Commission mentioned above, and has not yet closed. The statutory timeline for the Commission to rule on the ENSTAR certificate transfer docket, U-22-032, is December 21, 2022. If the RCA grants the approvals and all other conditions are met, the proposed transaction is likely to close well before this rate case proceeding is concluded.

Q. Do you have personal experience with a situation where there was a change of a utility's ownership during the course of a rate case proceeding?

A. Yes. During the course of ENSTAR's 1984 rate case, U-84-059, ENSTAR was sold to Seagull Energy Corporation (Docket U-84-067) and Commission approval of the transaction was pending at the time ENSTAR filed its direct testimony. In that filing, ENSTAR noted that the ownership change would affect it, and "expressly reserve[d] its right to supplement its filing and to file rebuttal testimony. See 3 AAC 48.310(i)."[8] The Commission did approve the transaction and it closed. ENSTAR then made a

[8] Docket U-84-059, *Transmittal of Prefiled Testimony and Updated Test Year Information in Accordance with Order No.2 and Request that a Hearing Date be Set and a Procedural Order be Issued*, dated April 1, 1985 at 2.

supplemental filing to address the ownership change, which the Commission accepted.[9] If the proposed transaction closes, ENSTAR may supplement its testimony and rate filing if required.

IV. 3 AAC 48.275(a) FILING

A. Schedules Sponsored

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

A. As I noted above, I am sponsoring the computation of ENSTAR's requested weighted cost of capital, which is shown on page 3 of ENSTAR's 275(a) filing (Attachment B to TA334-4) and the related schedule of Long-Term Debt Outstanding (page 37 of Attachment B).

Q. What capital structure is ENSTAR using in the 275(a) filing?

A. ENSTAR is using its actual capital structure as of December 31, 2021, which is 45.89% debt and 54.11% common equity.

Q. Please explain ENSTAR's requested weighted cost of capital on page 3 of the 275(a) filing.

A. The schedule shows the calculation of the cost of long-term debt and the cost of common equity. It then weights these costs based on ENSTAR's capital structure. The result is a weighted cost of capital of 8.32%.

Q. What is the cost of common equity proposed by ENSTAR in this rate case?

A. ENSTAR is using a 12.95% return on common equity as recommended and discussed by ENSTAR witness Mr. Dylan W. D'Ascendis in his prefiled direct testimony.

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[9] The Commission ordered ENSTAR to supplement its testimony with respect to "matters affected by the change in ownership" in Order U-84-059(3) at 4, dated June 24, 1985.

Q. What is the cost of long-term debt used by ENSTAR?

A. To calculate the cost of long-term debt, ENSTAR performs the following steps:

- first, ENSTAR calculates the outstanding debt costs. This calculation nets the December 31, 2021 balance of outstanding notes and unamortized debt expense on required debt to arrive at a balance of $152,642,347;
- second, ENSTAR calculates the interest expense for both tranches of its debt for the test year by taking the debt interest rates of 2.45% and 3.15% respectively and applying them to the December 31, 2021 outstanding balance of the tranches, $76,753,000 for each. Next, ENSTAR adds the test-year amortization cost of the debt expense to arrive at an interest expense of $4,363,306; and
- third, the total interest expense ($4,363,306) is divided by the December 31, 2021 outstanding debt ($152,642,347), which results in an overall embedded cost of debt of 2.86%.

Please also see the direct testimony of ENSTAR witness Mr. Mark A. Moses for a discussion of ENSTAR's long-term debt.

B. Pro Forma Adjustments Sponsored

1. Normalize 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 Mr. Sims explains in his 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 is not representative of the updated GCA. Gas cost revenues in the test year were removed and replaced with the weighted average cost of gas that was effective July 1, 2022, $8.3771 per Mcf[10] (proposed in ENSTAR's annual GCA revision filing, TA331-4, filed on May 13, 2022, and approved in Letter Order L2200193 dated June 17, 2022). The adjustment to remove the test year gas cost and to add the new gas cost is developed in Schedule D to Attachment B, and the new gas cost is applied to the weather normalized volumes. Weather normalization is discussed in Section IV.B.3.

2. <u>Uncollectible Account Pro Forma</u>

Q. Please discuss the uncollectible account pro forma adjustment shown on Schedule H of the 275(a) filing.

A. As shown on Schedule H to Attachment B, ENSTAR is adjusting its test year uncollectible (bad debts) expense to reflect the weather normalized revenues (including the updated gas cost discussed above). In reviewing the account, ENSTAR also noticed an item that had been miscoded to the account, and we are removing it from the test year balance. The net result of the adjustment is a decrease to the uncollectible expense account.

3. <u>Weather Normalization</u>

Q. Why is ENSTAR proposing a weather normalization adjustment to test year gas sales volumes?

A. The 2021 test year weather, as measured in heating degree days ("HDD"),[11] was unusually cold for recent years and departed significantly from the normal range of

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10 Mcf is one thousand cubic feet. Ccf is one hundred cubic feet.

11 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

temperature fluctuations in a way that was highly correlated with gas usage. Thus, it was not representative of a "normal" year as defined by ENSTAR witness Inna B. Johansen in her testimony. At 10,544 HDD, 2021 was 15.6% colder than the average for the previous five years, colder than any year since 2012, the third coldest year in the last 20 years, and 10.8% colder than average for the previous ten years.

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 the graphs 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 2011[12] through 2021.

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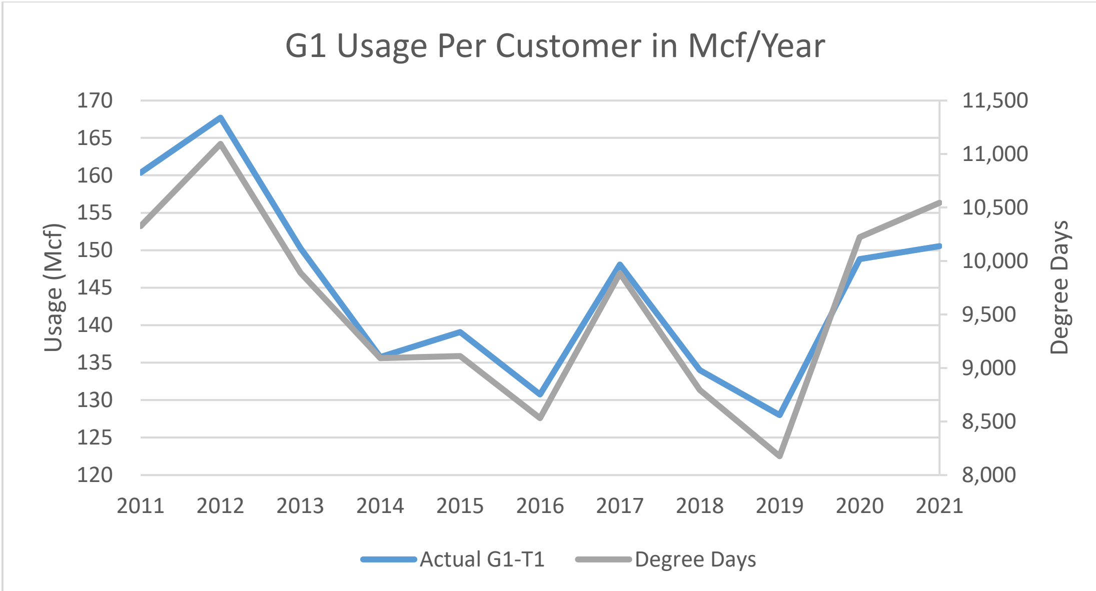
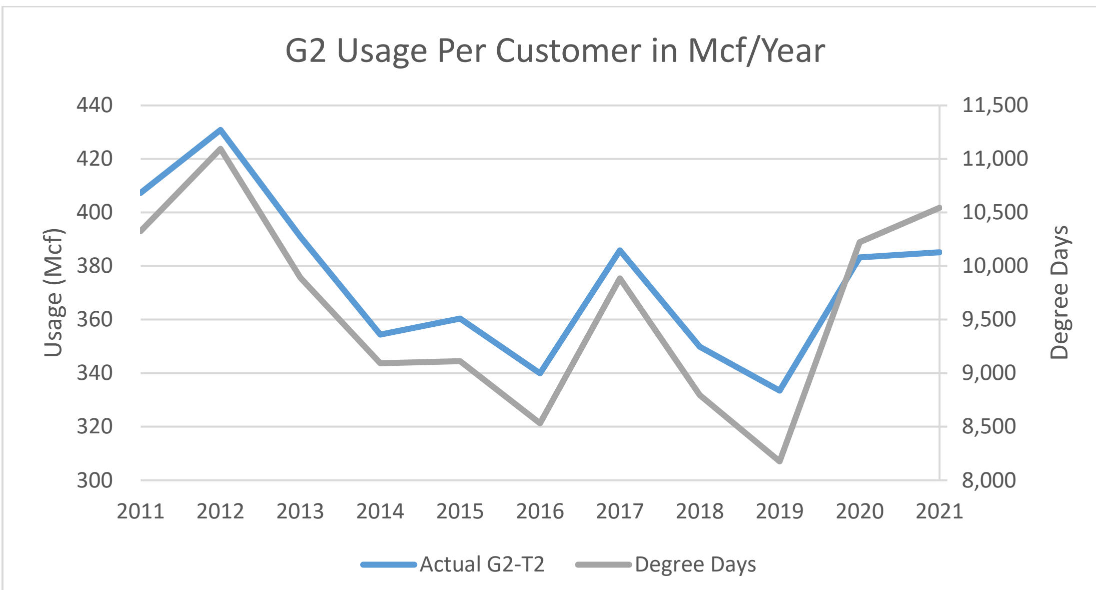
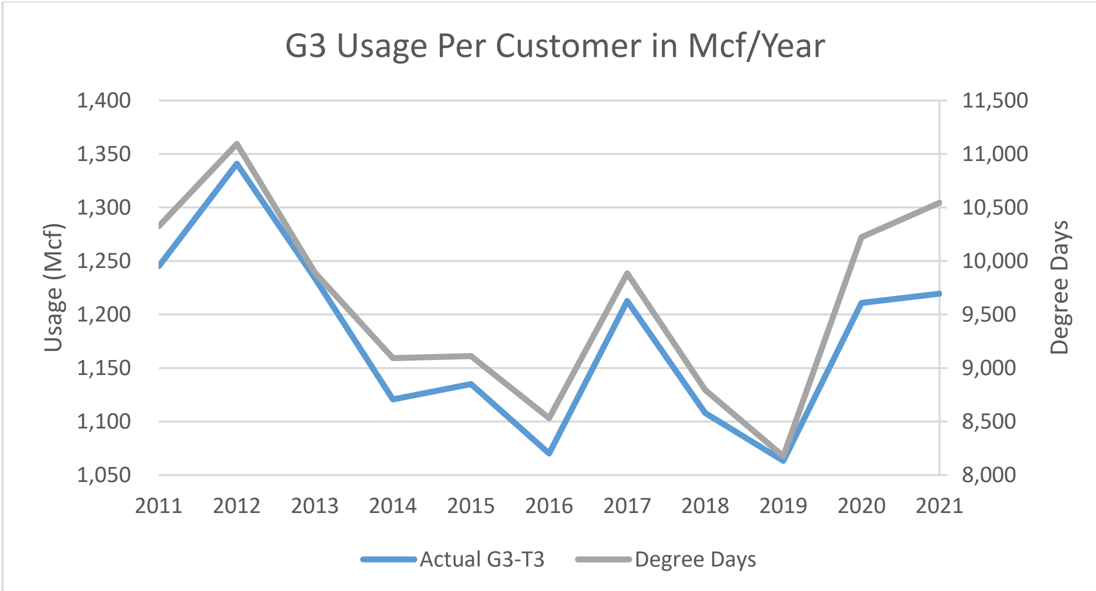
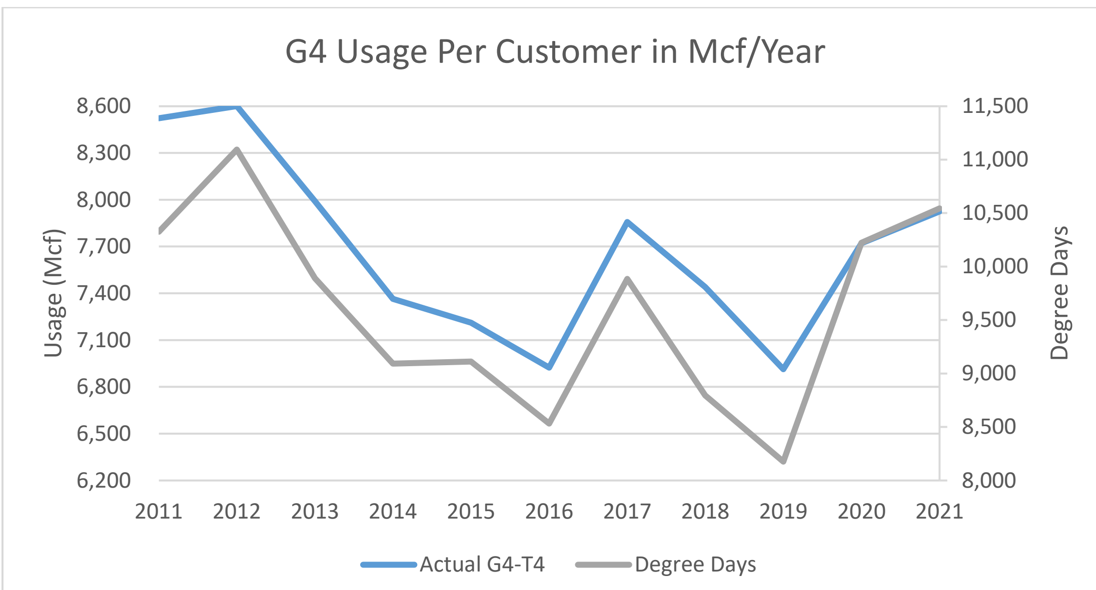
entities may use a different base such as 55°F). For example, on a day where the average of the high and low temperature is 35°F, there would be 30 HDD. The more extreme the outside temperature, the higher the number of HDD. The U.S. Energy Information Administration notes that a high number of HDD generally 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.

[12] ENSTAR's General Service rate classes were changed to the G1-G4 rate categories beginning in 2011 as a result of Docket U-99-069/U-99-070. ENSTAR had three General Service rate categories prior to that.


G1 Usage Per Customer in Mcf/Year
Usage (Mcf)
Degree Days
170
165
160
155
150
145
140
135
130
125
120
11,500
11,000
10,500
10,000
9,500
9,000
8,500
8,000
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
Actual G1-T1
Degree Days


G2 Usage Per Customer in Mcf/Year
Usage (Mcf)
Degree Days
440
420
400
380
360
340
320
300
11,500
11,000
10,500
10,000
9,500
9,000
8,500
8,000
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
Actual G2-T2
Degree Days





I have observed this strong correlation between ENSTAR's General Service customer usage and HDD throughout my career at ENSTAR.

Q. What guidance has the Commission set out for weather normalization adjustments?

A. Starting at page 94 of Order U-16-066(19), the Commission stated the following:

> We provided guidance for proposed weather normalization adjustments in Order U-01-108(26). In that proceeding, we denied intervenor proposed weather normalization adjustments to Chugach test year loads. We stated:
>
> > Any proposed adjustment to normalize historical weather data must be reasonable, measurable, and must adequately address the following two issues. First, it must clearly demonstrate that the test year was a climatic anomaly where temperature departed significantly from the normal range of temperature fluctuations. Second, it must clearly demonstrate how this anomaly correlates to the power sales.

Q. Does ENSTAR's proposed weather normalization adjustment meet this standard?

A. Yes. ENSTAR's adjustment methodology is reasonable, measurable, and has been accepted by the Commission before. The 2021 test year weather departed significantly from the normal range of temperature fluctuations, with more HDD than any of the previous five years and 15.6% more than the average of the previous five years. The graphs above clearly show how weather correlates to ENSTAR's General Service customer usage. Finally, with the global warming trends that were recognized and discussed in ENSTAR's last rate case, it is appropriate to weather normalize the test year HDD aberration.

Q. How did ENSTAR calculate its proposed weather normalization adjustment?

A. The detailed calculation of the weather normalization adjustment is shown on Exhibit DMD-5. The methodology used is almost identical to the weather normalization adjustment that was part of ENSTAR's approved revenue requirement in its 2000 test year rate case (U-00-088) and that ENSTAR proposed in its 2009 test year rate case (U-09-069/U-09-070).[13] For each of the General Service customer classes, the test year

[13] 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 test year rate case was settled, and the Commission accepted the

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.[14] 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:

Rate Class	Test Year Actual Mcf/Customer	Normalized Mcf/Customer
G1	150.54	137.13
G2	385.10	351.26
G3	1,219.44	1,117.79
G4	7,925.05	7,345.54

The full volume and revenue impacts are shown on Schedule O to Attachment B. The overall impact is a reduction of 3,000,535 Mcf and $3,641,825 in gas sales margins (revenues excluding gas cost).

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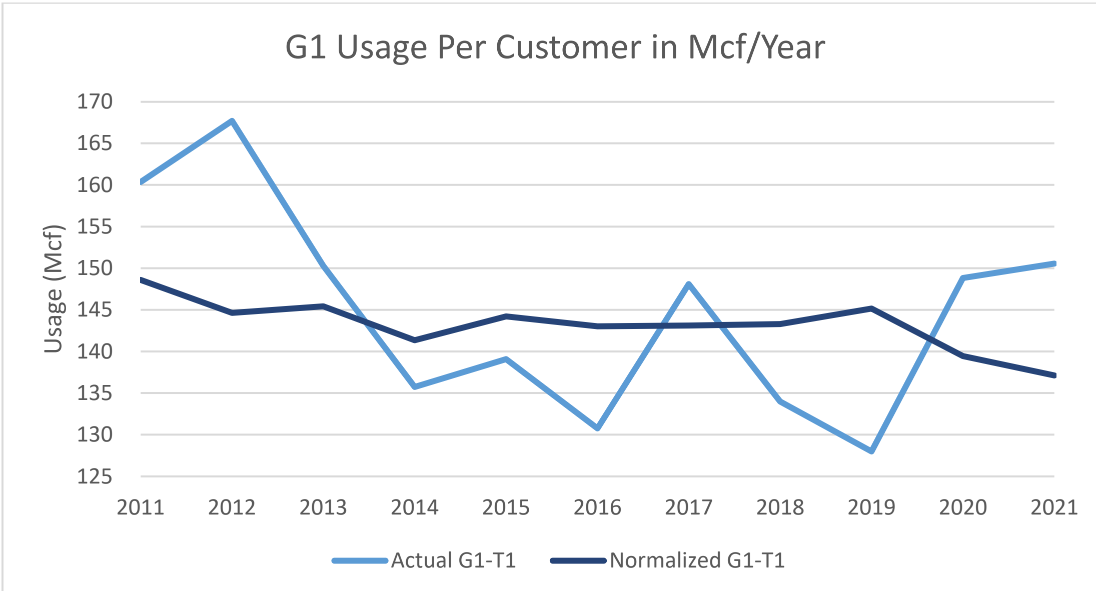
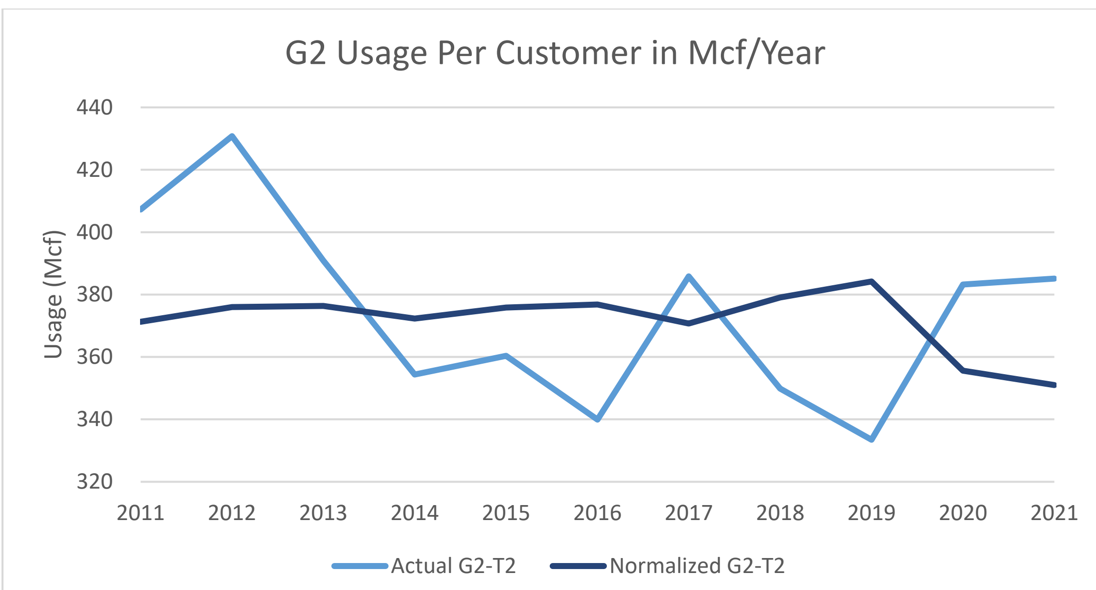
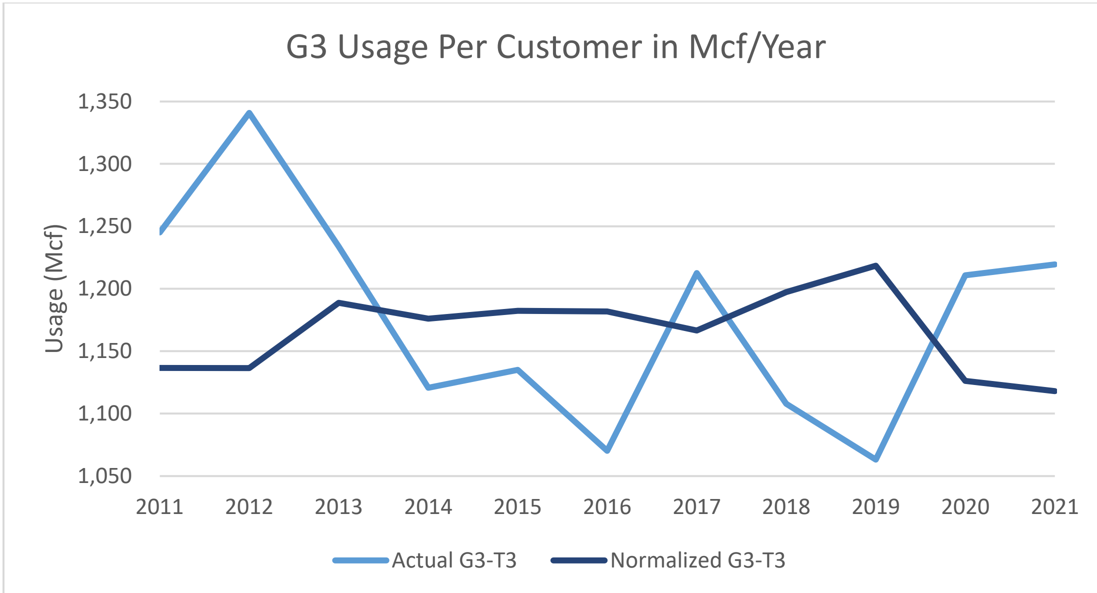
stipulation in Order U-09-069(10)/U-09-070(10). The weather normalized volumes per customer proposed by ENSTAR were used to derive the tariff rates that were approved in that order.

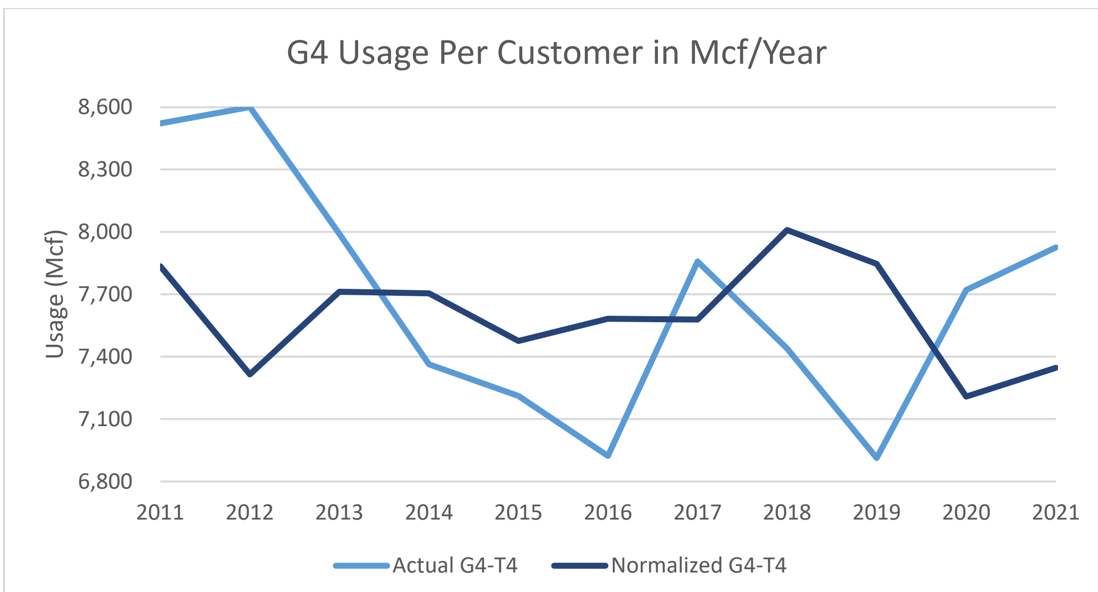
[14] In both U-00-088 and U-09-069/U-09-070, only two summer base months were used in the calculation. Here, ENSTAR uses the three summer months (June-August) as is commonly used elsewhere.

The graphs below depict the weather-normalized General Service rate class usage for 2011 through 2021 using the same ten-year average HDD (9,512) used in the weather normalization adjustment.









This analysis shows that ENSTAR continues to see erosion in its per-customer usage,[15] particularly in the G1 and G2 rate classes, which make up 97% of its customers and 65% of its gas sales volumes. It also shows that the test year weather-normalized per customer usage for each customer class is higher than the actual per customer usage in

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[15] As I discussed in testimony in Dockets U-09-069 and U-14-111, ENSTAR has seen a consistent trend of declining average use per customer on a weather-normalized basis.

three of the five years prior to the test year and is not significantly different from the last test year (2015).

Q. Is ENSTAR proposing to weather normalize its medium transportation, large transportation, and power plant customer volumes?

A. No. Other than the adjustment to remove the revenues relating to the decommissioning of the IGT that I discuss later, ENSTAR is not proposing any pro forma adjustments to the medium transportation, large transportation, and power plant volumes and revenues.

4. Travel and Conferences Expenses

Q. Please discuss the pro forma adjustment to travel and conferences expenses to normalize the test year for expenses that were impacted by the COVID-19 pandemic shown on Schedule Q of the 275(a) filing.

A. ENSTAR regularly sends its personnel to conferences and training to learn new methods, review new equipment, exchange ideas with others in the gas and utility industry, and obtain professional development. Given the specialized nature of the utility and gas industries, most of these opportunities involve out-of-state travel. As Mr. Sims states in his direct testimony, with the first reporting of COVID-19 cases in Alaska in March 2020, ENSTAR ceased all business-related travel, which included costs related to conferences and training. Restrictions on ENSTAR business travel extended through the test year. Exhibit DMD-6 shows the history of the accounts used for conferences, training and business travel, and the development of the adjustment. It is clear from Exhibit DMD-6 that the COVID-19 pandemic impacted 2020 and 2021, resulting in a substantial decrease in these expenses (some 44% of the average level of the previous five years). ENSTAR has eased its restrictions on business travel and out-of-state training. As shown on Schedule Q, ENSTAR is proposing a $204,887 pro forma adjustment to these expenses to bring them back to the average level for the five years preceding the COVID-19 pandemic, which is a level of expense ENSTAR expects to incur in the rate-effective period.

5. Adjustment to Remove Chugach IGT Revenues

Q. Why is ENSTAR removing the revenues for the Chugach IGT in pro forma Schedule I?

A. Chugach is decommissioning its IGT power plant and formally requested termination of the transportation service agreement ("TSA") for the plant on March 2, 2022. There were no volumes delivered to IGT during the test year[16] and the $34,800 in revenues recorded in the test year were solely from the monthly customer charge. While the TSA requires a twelve-month notice period to terminate, ENSTAR has decided to waive the last six months of the notice period for operational and administrative efficiency, making termination of the agreement effective following the billing for July 2022 service. As a result of the termination of service at Chugach's request, ENSTAR is also revising the Transportation Service to Power Plants rate schedule (Tariff Section 2101, Sheet 211) to remove the listing for IGT concurrent with the requested effective date of the interim rates in this proceeding. ENSTAR began removing its metering facilities at IGT on July 20, 2022.

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[16] ENSTAR last delivered gas to IGT in November 2020.

6. <u>Income Tax Adjustment</u>

Q. What components of the income tax adjustment sponsored by Dr. Fairchild are you addressing?

A. I am not sponsoring anything related to Dr. Fairchild's income tax adjustment, but I do want to address a change that we anticipate will occur during this rate case related to the division of excess ADIT between protected and unprotected. While the total amount of ENSTAR's excess ADIT is correct and will not change, ENSTAR will need to revise the protected/unprotected components to comply with recently-issued Internal Revenue Service ("IRS") private letter rulings. The private letter rulings offer guidance on the application of the normalization rules of the Internal Revenue Code and the normalization rules specific to the accounting for excess deferred taxes under the TCJA with respect to costs of plant removal. ENSTAR's accounting for cost of removals is being reviewed and ENSTAR will be proposing an adjustment to its excess ADIT split between protected and unprotected to comply with the private letter rulings. ENSTAR expects this review and any necessary revisions to the protected/unprotected excess ADIT split to be completed during the course of this proceeding. If utilities correct any inadvertent normalization deviations at the next available rate case opportunity, the IRS offers "safe harbor relief." As I stated above, this possible revision would not change the total amount of excess ADIT, just the protected/unprotected classification.

V. <u>COST OF SERVICE AND RATE DESIGN</u>

Q. How does the structure and composition of ENSTAR's system impact its cost-of-service ("COS") study and rate design?

A. ENSTAR's system has been, and continues to be, functionally designed and operated as an integrated delivery network. As such, a customer need not be directly or physically connected to a specific item of plant in order to benefit from its existence. The Commission acknowledged this on page 102 of Order U-16-066(19) in ENSTAR's last rate case when it stated:

> The record in this docket demonstrates that the ENSTAR system is functionally designed and operated as an integrated system. Customers need not be directly or physically connected to a unit of plant in order to benefit from its existence. The integrated nature of the ENSTAR system results in a superior overall system from the standpoint of reliability and economic efficiency. All classes of customers benefit from the integrated system and, therefore, must share in the costs.

Q. Historically, why has ENSTAR extended its transmission system?

A. The primary driver for ENSTAR's largest transmission system extensions has been access to gas supply. That was true for the construction of the 100-mile Beluga to Anchorage pipeline in the 1980s, and it was true for the construction of the Anchor Point Pipeline (also referred to as the South Peninsula Pipeline). Capacity is obviously a consideration, but the largest single cost of a pipeline is digging a trench to install a pipe of any size. Sizing of pipe is incremental, meaning that the costs are driven less by peak capacity needs than by the need to extend pipelines to the sources of gas that all of our customers, including the transportation customers, demand.

Q. Does ENSTAR build pipelines exclusively for use in serving its gas supply customers?

A. While ENSTAR's original pipelines (and even its Beluga to Anchorage pipeline) were constructed in an era when ENSTAR supplied the gas to every customer it served, including the power plants, ENSTAR has had transportation-only customers on its system since 1989. Virtually every pipeline and gas field it is connected to can (and often does) provide gas for ENSTAR's gas sales customers, as well as the gas that ENSTAR transports for others.

Q. In past rate cases, some of ENSTAR's customers have argued for cost allocations and rate designs that exclude significant portions of ENSTAR's plant for them. What is ENSTAR's view on that approach to cost allocation and rate design?

A. ENSTAR continues to believe that a "postage stamp" rate principle is appropriate and reflects its integrated system. ENSTAR notes that this is the type of cost allocation and rate design that the Commission has traditionally approved and encouraged, not just for ENSTAR, but for most utilities in Alaska. As an example, every one of the power customers ENSTAR serves has postage stamp rates for its utility operations, as does Interior Alaska Natural Gas Utility (Interior Gas Utility or IGU), which also receives its gas for its liquefaction plant from ENSTAR's system. As the Commission reiterated in Order U-16-066(19) at 108, "[a]ll classes of customers benefit from the integrated system and must share in its costs, regardless of whether they are directly or physically connected to a unit of plant." On page 116 of the Order, the Commission further discussed postage stamp rates, citing to its decision in Order U-14-001(9) (quoting Order U-71-021(4)), where it stated that it explicitly rejected the argument that a transmission customer who alleges it only uses a small portion of the transmission facilities should receive a reduced rate. The Commission stated that it reached this decision based on precedent, stating:

> The adoption of "postage stamp" rates in a local interconnected area has long been in use by electric, gas and water utilities. The mere proximity of a customer to a utility's generating plant, substation, transmission line, transformer bank, pressure station, well, water treatment plant, main water line, etc. has long been rejected as the prime consideration in establishing rates.

The Commission's findings in past orders are still relevant and applicable to the manner in which ENSTAR operates its system today.

Q. Did ENSTAR prepare a COS study to support its requested rates?

A. Yes. Dr. Fairchild prepared a fully-allocated COS study for ENSTAR, in compliance with 3 AAC 48.275(h), using the revenue requirement developed in the test year 2021 275(a) filing (Attachment B). The COS is included as Attachment C to TA334-4. Dr. Fairchild has followed the COS methodology and specific allocations approved by the RCA in ENSTAR's last rate case, U-16-066, including using the method to allocate transmission-related costs among customer classes approved in that case. He has also used the four General Service customer classes, as well as the large firm and mid-sized firm transportation classes, and interruptible transportation classes that were used in U-16-066.

Q. What allocation method was used to apportion transmission-related costs among customer classes?

A. An allocation factor based on an equal weighting of each customer class contribution to coincident system peak demand and average day demand (sometimes referred to as the "Seaboard" method) was used to allocate transmission-related costs among

ENSTAR's various customer classes. The Commission reaffirmed its use by ENSTAR in Order U-16-066(19) at 105 when it stated "[w]e believe that use of the Seaboard allocation method best recognizes the unique nature of the ENSTAR system and the fact that it is designed and operated to meet both peak-demand and also provide access to gas supplies."

Q. What is rate design?

A. Rate design is the way in which base rates are calculated to collect the revenue requirement assigned to a utility's various customer classes.

Q. Is ENSTAR proposing rates based on each customer class' full cost of service?

A. Yes.

Q. What factors, other than cost of service, did ENSTAR consider in designing rates?

A. The other factors considered in designing rates were:

- value of service;
- promoting the wise use of energy;
- matching costs and revenues;
- lessening the impact of high winter bills; and
- public acceptability and understandability.

Q. Why should value of service be considered?

A. Conceptually, utility base rates should not be set higher than the value of service to a particular group of customers, unless the cost of providing service exceeds the value by a significant amount. If the base rate charged to a class of customers is higher than the value of service to that class, those customers may seek alternative supplies. As a result, the fixed costs of operating the utility would be spread over a smaller base and increased costs would be borne by other future customers. ENSTAR aims to ensure that its rates reflect the value of its service to its customers. If base rates are set significantly below the value of service, wasteful use of a premium fuel will be encouraged.

Q. Why should conservation be encouraged?

A. As a matter of state policy, waste of any natural resource is discouraged. Furthermore, the wise use of natural gas results in more gas availability for future consumption. The Company has always encouraged the use of natural gas, but has no interest in seeing this premium fuel wasted.

Q. Why is the matching of costs and revenues important in the rate design?

A. Except for the cost of gas, the vast majority of the costs incurred to provide service to customers are essentially fixed. Capital-related costs (*i.e.*, depreciation, return, and income taxes) do not vary with usage, nor do most operating expenses. For efficient use of resources and capital, a utility needs a revenue stream that matches its expense outflow as closely as possible. Base rates should be designed to match cost incurrence.

Q. Why should the effect of high winter bills on customers be considered in designing rates?

A. There are a number of reasons. ENSTAR's customers use more energy to heat their homes in the winter than they do in the summer, by a factor of at least five. The difference between winter and summer bills can be significant, especially for customers on limited or fixed incomes. Most people do not see seasonal increases in their income. In fact, those who do have seasonal jobs tend to enjoy seasonal income in the summer, not in the winter when they face the higher bills for home heating. For these reasons, the effect of rate design on winter bills should be taken into account.

Q. Is ENSTAR proposing a change in the way its General Service rate classes are defined?

A. No.

Q. What is ENSTAR's current rate design structure for its General Service rate classes?

A. All four General Service rate classes have the same basic rate structure, a fixed monthly "Customer Charge" and a "Service Change (Base)" that is applied volumetrically. Additionally, General Service gas sales customers are separately charged for the cost of purchased gas. ENSTAR is not proposing to change this basic rate structure, which has been in place for decades.

Q. How does ENSTAR allocate each General Service rate class' non-gas cost of service (or revenue requirement) between the two types of rate structure, the fixed charge and the volumetric rate?

A. The COS allocates costs to each customer class in three cost categories: customer costs, capacity costs and commodity costs. The total costs allocated to those three categories for each customer class is that customer class' revenue requirement. In reality, only commodity costs are variable costs. The other two cost categories (customer costs and capacity costs) do not change with volumes delivered and are considered fixed. They are there regardless of the volumes moved or delivered. In ENSTAR's 2008 test year rate case (Docket U-09-069/U-09-070), the parties stipulated to rates that allocated approximately 50% of each customer class' total revenue requirement to be recovered by the fixed monthly charge and 50% to be recovered by the volumetric charge, without regard to what is a truly fixed or variable cost. Because of the application of across-the-board interim increases and overall rate changes in ENSTAR's last two rate cases (U-14-111 and U-16-066) and the application of rate reduction for the TCJA (TA303-4) that I discussed earlier, the fixed monthly charges for the General Service rate classes in the current rate design recover the following percentages of the class' revenue requirement: G1 49%, G2 55%, G3 57% and G4 57%.

Q. How is ENSTAR proposing to allocate the General Service rate class revenue requirements in this proceeding?

A. ENSTAR believes that it is time to take another step toward matching fixed costs with fixed revenues. Taking this step spreads the cost to the customers more evenly throughout the year and moderates customer bills in the high-usage winter season. Dr Fairchild describes ENSTAR's proposed allocation to General Service customers in his testimony.

Q. Is ENSTAR unique in moving to a rate design that recovers more of the fixed costs with fixed charges to customers?

A. No. As Dr. Fairchild discusses in his direct testimony, increasingly throughout the U.S., gas rates are being designed to recover fixed costs through a monthly service charge, or to use some other rate mechanism to "decouple" rates from customer usage, reducing the volatility of customer's bills. As of July 2022, the American Gas Association reports that 109 gas utility company tariffs in 41 jurisdictions had either full or partial decoupled rates. That's up from 75 utilities in 32 jurisdictions in July 2011.

Q. What percentage of each General Service rate class' revenue requirement is recovered via a fixed monthly charge under ENSTAR's proposed rate design?

A. 77% of the G1 revenue requirement, 69% of the G2 revenue requirement, 70% of the G3 revenue requirement and 60% of the G4 revenue requirement is recovered via fixed monthly charges in ENSTAR's proposal.

Q. What other rates is ENSTAR proposing to change?

A. ENSTAR is proposing to change its rate schedules for the mid-sized firm transportation and large transportation customers, including the power plant and interruptible customers. While all of these rate categories continue from the rate classes that were approved in the last case, ENSTAR has made some changes to the design and offerings based upon changes that are occurring with its customers. For the mid-sized and large firm transportation customer classes, ENSTAR is proposing to employ the Straight Fixed-Variable method ("SFV") utilized by the Federal Energy Regulatory Commission since 1993. This method is described in further detail in the direct testimony of Dr. Fairchild.

Q. Why is ENSTAR proposing to shift to the SFV method?

A. As discussed in the direct testimony of ENSTAR witnesses Mr. Sims and Ms. Johansen, there are changes occurring in the energy industry in Alaska that are likely to result in reductions in the annual usage of ENSTAR's system, but not its requirement to have the facilities, and investment, to serve the peaks it currently sees. An SFV rate design allows full recovery of the fixed costs incurred via fixed charges, allowing

ENSTAR the opportunity to earn its full revenue requirement in times of changing annual power load.

Q. Besides the revisions for the rates proposed in this filing, is ENSTAR proposing any other revisions to Schedule VLFT (Very Large Firm Transportation) service?

A. Yes. In 2020, Chugach purchased and merged with Anchorage Municipal Light and Power ("ML&P"). ENSTAR is updating Section 2150a(3) to remove the references to ML&P, and to indicate that Contracted Peak Demand and demand charges for Chugach delivery points (which include the former ML&P plants) will be aggregated. The revision also states that Chugach will be assessed a monthly customer charge for each of its four power plant delivery points served under Schedule VLFT.[17] ENSTAR is also deleting Section 2150c(4) on Sheet 214.1 in Attachment D as the provision is no longer relevant after the Chugach/ML&P merger.

Q. Is ENSTAR proposing anything else in response to ongoing changes in the power plant market?

A. Yes. At the direction of the Commission in Order U-18-102(44)/U-19-020(39)/U-19-021(39), Chugach and MEA have formed a tight power pool and entered into an agreement for it (the "Power Pool Agreement").[18] As recited in Order U-22-010(1) at 3, tight power pool energy transactions were reported to the Commission beginning April 30, 2021. ENSTAR has developed a rate schedule and classification for members of the tight power pool that would allow them to: (1) move gas to the major pool

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[17] As noted on Chugach's TSA, those four points are Southcentral Power Project, and the former ML&P Plant 1, Plant 2 and Plant 2A. ENSTAR has metering facilities it has to maintain at each of these locations.

[18] The Power Pool Agreement, *Amended and Restated Operations Agreement for Power Pooling and Joint Dispatch,* was filed as TA491-8 and approved by the Commission in Letter Order No. L2000392, dated November 2, 2020.

member power plants for the same marginal transportation rate; and (2) effectively share the contracted demand between the members of the pool so that they can move loads among the most efficient units available without incurring penalties for exceeding contracted demands.

Q. Please describe the proposed rate schedule.

A. ENSTAR is proposing a new South Central Power Pool Firm Transportation Service rate schedule ("Schedule SCPPFT").[19] The schedule is identical to ENSTAR's VLFT rate schedule with the following exceptions: (1) it is only available to locations that are part of the power pool; (2) locations that elect to take service must enter into a new transportation service agreement that specifically references the SCPPFT rate schedule; (3) an SCPPFT customer will not be subject to excess demand penalty on a given day so long as the combined volumes for all SCPPFT customers on that given day do not exceed the combined contracted peak demand for all SCPPFT customers (effectively combining and sharing the contracted peak demand among power pool members); and (4) as with ENSTAR's other rate schedules, service to a SCPPFT location is exclusive (it cannot also be served at the same time under a different rate schedule).

Q. Would Schedule SCPPFT only be available to Chugach and MEA?

A. Schedule SCPPFT as it is proposed now is only available to Chugach and MEA as they are the only members of the Power Pool Agreement. If other electric utilities joined the Power Pool Agreement and agreed to the terms of Schedule SCPPFT, ENSTAR would propose amending the schedule to include them.

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[19] Attachment E to TA334-4.

Q. Why is a separate schedule from ENSTAR's existing Schedule VLFT necessary?

A. Schedule VLFT does not provide the sharing of contracted peak demand between different shippers. ENSTAR has already experienced situations since the power pool transactions began in April 2021 where Schedule VLFT shippers exceeded their contracted peak demand while providing power to the other power pool member who had sufficient unused contracted peak demand at the time. These situations created potential penalty conditions under ENSTAR's VLFT tariff.

Q. Did ENSTAR propose a power pool rate schedule in its last rate case?

A. Yes, ENSTAR proposed a similar power pool rate schedule in Docket U-16-066. In Order U-16-066(19) at page 122, the Commission noted that the power pool being discussed at the time was "still being developed by the pool members and the specifics on how it will operate are not known" and declined to consider the proposed rate schedule until the power pool was finalized. The power pool has been formed and the Commission has approved the agreement. The time is ripe for the addition of this new rate schedule.

Q. Is ENSTAR proposing to delete Schedule VLFT if the Commission approves Schedule SCPPFT?

A. No. While ENSTAR envisions the two current Schedule VLFT shippers moving to Schedule SCPPFT if approved, ENSTAR wants Schedule VLFT to remain available for other shippers that may qualify for service and are not part of the power pool. In the more than 15 years that Schedule VLFT has been in existence, ENSTAR has had several entities approach it with projects that would have qualified for Schedule VLFT.

I will also note that there were no shippers under Schedule VLFT when it was first approved by the Commission in Order U-00-088(40).

Q. Is ENSTAR revising any other tariff sheets as a result of adding Schedule SCPPFT?

A. Yes, ENSTAR is revising its Tariff table of contents at Tariff Sheet 5 and Section 1640b(1) on Tariff Sheet 165 to reflect the new Schedule SCPPFT in Attachment E of TA334-4. Section 1640b(1) on Sheet 165 is also being updated to reflect the renaming of Schedule MSFT that occurred in Docket U-14-111.

Q. Are you sponsoring tariff sheets showing the rate structures and rates ENSTAR is proposing?

A. Yes. The revised tariff sheets for the interim rates are included as Attachment D to TA334-4 and the revised tariff sheets for the permanent rates are included as Attachment E to TA334-4. The revision to Tariff Sheet 211 to delete the Chugach IGT and the revision to Tariff Sheet 214.1 deleting Section 2150c(4) that I discussed earlier are included with the revised tariff sheets for the interim rates in Attachment D. The tariff sheets for the proposed Schedule SCPPFT and the revisions to Tariff Sheets 5 and 165 discussed above are included with the revised tariff sheets for the permanent rates in Attachment E.

VI. INTERIM RATES

Q. Is ENSTAR asking for interim rate relief?

A. Yes. ENSTAR's TA 334-4 filing includes a request for an interim and refundable base rate increase of 1.5% (approximately 0.4% on total revenues including gas cost), which is expected to generate about $1.3 million more in annual base rate revenues for billings on or after October 1, 2022. ENSTAR is not seeking interim recovery of the full revenue deficiency that the 275(a) filing in Attachment B demonstrates.

Q. Is ENSTAR currently earning its previously authorized return on equity?

A. No. As shown on Exhibit DMD-7, ENSTAR's current rates result in an effective rate of return on equity of 10.68% and therefore, ENSTAR is not earning the approved return on equity of 11.875%. 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 15 months, or longer, as provided by Commission statute. Assuming the Commission will later approve some or all of ENSTAR's proposed permanent increase, interim rates protect ENSTAR from irreparable harm. Historically, the Commission has preferred that rate increases be implemented incrementally to mitigate the impact on customers. Therefore, it is desirable to have ENSTAR's proposed base rate increase implemented in two smaller steps (interim and permanent) rather than one larger increase.

Q. How did ENSTAR calculate the 1.5% interim rate increase?

A. In keeping with Commission policy on interim increases, the interim base rate increase of 1.5% was developed using the requested revenue requirement (Attachment B to the TA Letter) and using the currently-approved rate of return of 11.875% from Order 16-066(19). For the interim increase, ENSTAR is requesting rates sufficient to recover approximately one-half of the deficiency that calculation produces.

Q. Is ENSTAR providing a schedule showing how the interim rates were calculated and tariff sheets for the interim rates?

A. Yes. Exhibit DMD-8 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 TA334-4.

Q. Why is ENSTAR requesting this interim increase to be effective October 1, 2022?

A. As set out in TA334-4, ENSTAR is requesting that the additional interim increase be effective as of October 1, 2022, which is the beginning of the first month following the statutory 45-day review period.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

Daniel M. Dieckgraeff

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, Alaska: 1982 – Present.

Director of Rates and Regulatory Affairs: 2012 – Present

Manager, Rates and Regulatory Affairs: 2008 – 2012

Manager, Regulatory and Gas Supply: 2006 – 2008

Manager, Finance and Rates: 2000 – 2006

Manager, Rates and Planning: 1989 – 2000

Rates and Planning Supervisor: 1982 – 1988

Price Waterhouse, Anchorage, Alaska: 1979 – 1982

Senior Accountant: 1981 – 1982

Staff Accountant: 1979 – 1981

EDUCATION

Gonzaga University, Spokane, Washington: Bachelor Business Administration, Major in Public Accounting. 1979

Alaska Pacific University, Anchorage, Alaska: Master of Business Administration, Concentration in Global Finance. 2007

OTHER

Certified Public Accountant (AK), 1982 – present

American Institute of Certified Public Accountants, Member

Alaska Society of Certified Public Accountants, Member

Institute of Management Accountants, Member

Commonwealth North, Member

Spirit of Youth, Board Member

American Gas Association, State Affairs Committee

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RECEIVED
By the Regulatory Commission of Alaska on Apr 04, 2018

April 4, 2018

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

Subject: TCJA of 2017 Impact on Rates – I-18-002

Dear Commissioners:

ENSTAR Natural Gas Company, a division of SEMCO Energy, Inc. ("ENSTAR") is in receipt of your letter of March 23, 2018, and appreciates the opportunity to respond to the Commission's questions. While this is an extremely complicated issue, with a number of implications from a regulated utility perspective, ENSTAR has worked diligently since the passage of the Tax Cuts and Jobs Act of 2017 ("TCJA") to understand the impacts of the tax changes, and proposes this course of action to provide the intended tax savings to customers. At this time, ENSTAR anticipates that the reduction in the corporate income tax rate will result in a reduction to its annual revenue requirement of $4.5 to $5.5 million dollars.

I. Impact on Income Tax Expense

ENSTAR anticipates making a filing by the end of April 2018 to address the change in the corporate income tax rate on the income tax expense and related components of ENSTAR's recently decided 2015 test year revenue requirement, excluding deferred taxes. ENSTAR plans to include a revised 275(a) to reflect U-16-066(19) Normalized Test Year Revenue Requirement and Revenue Deficiency Adjusted for 2017 TCJA Tax Rate. This revised 275(a) would include Revised Schedule O, State and Federal Income Tax Adjustments; Revised Schedule G, Uncollectible Accounts Expense Adjustment; and Revised Schedule LL, Lead-Lag Study-Cash Working Capital Requirement. The filing will also include a revised 275(h), a Cost-of-Service Study Adjusted for 2017 TCJA Tax Rate. Finally, ENSTAR will submit for Commission review and approval revised tariff sheets reflecting the reduced customer rates resulting from adjustments to the corporate tax rate.

II. Impact of Deferred Taxes

As noted by Commissioner Pickett during the Public Meeting held on March 14, 2018, "this is a little more complicated in some cases than is generally portrayed in the press." (Transcript at 75.) The TCJA of 2017 includes normalization provisions for regulated utilities, which require a specific treatment of accumulated deferred income taxes ("ADIT") resulting from the corporate income tax rate reduction.

Excess ADIT is defined in the TCJA as the excess of: (1) the reserve for deferred taxes as of the day before the corporate rate reductions take effect, over (2) the amount which would be the balance in the reserve if the amount of the reserve were determined by assuming that the corporate

rate reductions provided in the TCJA were in effect for all prior periods. The excess ADIT normalization requirements apply only to accelerated federal tax method/life depreciation differences on public utility property.

The normalization provision requires that excess deferred income taxes be used to reduce revenue requirements no sooner than would occur as the book/tax difference reverses. The utility must identify the deferred tax reversal pattern (comparing book depreciation versus tax depreciation) and start to reverse the excess ADIT when book depreciation exceeds tax depreciation. This method is referred to as the Average Rate Assumption Method ("ARAM"). An alternative approach allowed in the TCJA is the Reverse South Georgia Method ("RSG"), which is allowed only if the utility is unable to identify when book/tax differences originate and reverse. RSG is not permitted if the utility has the records to calculate the reversal using ARAM. The RSG spreads the excess ADIT evenly over the estimated book life of the utility assets that created the ADIT.

Both approaches reduce rates over the estimated remaining book life of the related assets. The difference between the two is that under RSG, the reduction begins immediately, while under ARAM the reduction does not occur until the book/tax difference begins to reverse. Further, a normalization violation occurs if the excess ADIT is used to reduce rates more rapidly than would occur under either of these approaches, resulting in severe penalties from the IRS.

In order to illustrate this difference, the following simplified example was prepared by the audit and accounting firm PricewaterhouseCoopers ("PwC") and presented in a Power & Utilities Technical Update on March 22, 2018 (page 9). (The full presentation is attached for reference.)

ARAM vs RSG comparison

				DR/(CR) ARAM					DR/(CR) RSGM			
Year	Book Depreciation	Tax Depreciation	Book/Tax Difference	Tax Rate	Deferred Tax Expense	EDIT amort	ADIT		Tax Rate	Deferred Tax Expense	[2] EDIT Amort	ADIT
2016	100,000	200,000	100,000	35%	35,000	-	(35,000)		35%	35,000	-	(35,000)
2017	100,000	320,000	220,000	35%	77,000	-	(112,000)		35%	77,000	-	(112,000)
2018	100,000	192,000	92,000	20%	18,400	-	(130,400)		20%	18,400	(6,000)	(124,400)
2019	100,000	115,200	15,200	20%	3,040	-	(133,440)		20%	3,040	(6,000)	(121,440)
2020	100,000	115,200	15,200	20%	3,040	-	(136,480)		20%	3,040	(6,000)	(118,480)
2021	100,000	57,600	(42,400)	30.85%	(8,480)	(4,600)	(123,400)	[1]	20%	(8,480)	(6,000)	(104,000)
2022	100,000	-	(100,000)	30.85%	(20,000)	(10,850)	(92,550)	[1]	20%	(20,000)	(6,000)	(78,000)
2023	100,000	-	(100,000)	30.85%	(20,000)	(10,850)	(61,700)	[1]	20%	(20,000)	(6,000)	(52,000)
2024	100,000	-	(100,000)	30.85%	(20,000)	(10,850)	(30,850)	[1]	20%	(20,000)	(6,000)	(26,000)
2025	100,000	-	(100,000)	30.85%	(20,000)	(10,850)	0	[1]	20%	(20,000)	(6,000)	-
	1,000,000	1,000,000	-		48,000	(48,000)				48,000	(48,000)	

PwC | Power & Utilities Technical Update 9

As this example shows, under ARAM, the excess ADIT begins to reverse in 2021, which is when the book depreciation overtakes the tax depreciation and the ADIT begins to reverse. Using RSG, the excess ADIT is amortized beginning in 2018 using a straight-line method over the remaining book life of the asset. The end result, over the book life of the hypothetical asset, is the same under either method.

In order to determine the impact of excess ADIT on its revenue requirement, and thus on customers' rates, ENSTAR must take the following steps:

- Determine whether the historical records available are sufficient to use ARAM.
    - If yes, then calculate the book/tax depreciation differences and resulting ADIT to determine when the book depreciation starts to exceed the tax depreciation.
    - Calculate the excess ADIT for each year and apply it to the appropriate revenue requirement.
- If ARAM cannot be used, calculate the estimated remaining book life for all underlying assets and amortize the excess ADIT over this period.

Because of the considerable work involved in these steps, and the uncertainty around the results of the analysis, ENSTAR proposes including the excess ADIT amortization adjustment in its next rate case, which as required by U-16-066(19), will be filed using a test year of 2020 or sooner. This gives ENSTAR's tax department the time it needs to do the thorough analysis demanded in the TCJA.

In conclusion, ENSTAR has proactively and diligently worked to understand the implications associated with the TCJA and understands the potential savings our customers can realize by acting expeditiously. Our proposal is the best solution to realize those savings for customers while staying within the applicable regulations.

Sincerely,

ENSTAR Natural Gas Company

John Sims
President

Phone: 907-334-7625
Fax: 907-334-7671
John.Sims@enstarnaturalgas.com

Attachments as stated

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RECEIVED
By the Regulatory Commission of Alaska on Apr 26, 2018

April 26, 2018

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

Subject: Tariff Advice Letter TA 303-4

Dear Commissioners:

The tariff filing described below is transmitted to you for filing in compliance with Section 3 AAC 48.200 - 3 AAC 48.430 of the Alaska Administrative Code:

Tariff Sheet		Cancels Sheet		
Number	Revision	Number	Revision	Schedule or Rule Number
201	15th	201	14th	Rates – Section 2001 G1
202	14th	202	13th	Rates – Section 2002 G2
203	14th	203	13th	Rates – Section 2003 G3
204	Ninth	204	Eighth	Rates – Section 2004 G4
211	13th	211	12th	Rates – Section 2101 PPT
212	Seventh	212	Sixth	Rates – Section 2145 MSFT
213	Seventh	213	Sixth	Rates – Section 2150 VLFT
214	Sixth	214	Fifth	Rates – Section 2150 VLFT
216	11th	216	Tenth	Rates – Section 2201 IIT
218	Eighth	218	Seventh	Rates – Section 2251 ITS

On December 22, 2017, President Trump enacted P.L. 115-97, commonly known as the Tax Cut and Jobs Act of 2017 ("TCJA"). This major tax reform is a complex piece of legislation that is still being researched to understand the full ramifications for corporations across the country. While this is an extremely complicated issue, with a number of implications from a regulated utility perspective, ENSTAR Natural Gas Company ("ENSTAR") has worked diligently since the passage of the TCJA to understand its effect on customers' rates.

The TCJA reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. This tariff filing, which applies that tax rate change, represents a decrease of $5.1 million for ENSTAR's customers from the revenue requirement approved in U-16-066(20).[1] This represents a 5.7% reduction of ENSTAR's non-gas revenue requirement.

[1] As of March 31, 2018, ENSTAR has 144,691 General Service customers, as well as 11 power

ENSTAR recognizes that the Commission has not yet specified the treatment utilities should take. ENSTAR nonetheless proposes the attached filing because it believes this methodology is the most expeditious way for customers to realize savings on their monthly bills.[2]

ENSTAR estimates that, with its proposed rate change, all gas sales customer categories (G1 through G4) will see an approximately 1.3% decrease in their total bill on an annualized basis from the rates currently in effect.

Recomputed Revenue Requirement

ENSTAR's last revenue requirement was established by the Commission in Order No. U-16-066(19) and accepted in U-16-066(20). The authorized revenue requirement is recomputed in Attachment A to reflect the reduction in federal corporate income tax rate from 35% to 21%. In calculating the revised revenue requirement, ENSTAR took into account the following items:

- Decreased working capital requirements due to the lower income tax payments which will be made under the TCJA. This resulted in a decrease of $57,700 in the working capital component of rate base. Using the approved rate of return of 8.59%, this equates to a reduction of $4,956 in return on investment.
- Decreased bad debt expense due to the decrease in revenue requirement. This resulted in a decrease of $14,307 to customer accounting expenses.
- Decreased state income tax expense due to the decrease in revenue requirement. This lead to a decrease of $477,607 in state income tax expense.
- Decreased the federal income tax expense due to the reduction in tax rates from 35% to 21%, as well as the reductions in expenses listed above. This resulted in a decrease in $4,599,769 in federal income tax expense.

Cost of Service Study and Rate Design

Attachment B is the recalculated cost-of-service study utilizing the revised revenue requirement shown in Attachment A. ENSTAR has utilized the same allocation methodologies ordered by the Commission in U-16-066(19), and accepted in U-16-066(20).

ENSTAR has maintained the same rate design for all customer classes adopted in U-16-066(20). For each rate category, the proposed new rates also preserve the same rate class revenue requirement split between the monthly fixed charge and the variable charge that was used the final permanent rates.

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and industrial transportation customer locations.

[2] As noted in ENSTAR's letter to the Commission in Docket I-18-002 dated April 6, 2018, ENSTAR will address any impact on its deferred taxes in its next rate case.

Revised Rate Schedules

Included in Attachment C to this filing is a schedule showing the proposed new rate by rate class compared to the current rates. The proposed tariff sheets are included in Attachment D.

ENSTAR requests that the revisions be effective on a permanent basis on the first day of the month following Commission approval. Please feel free to contact me at 334-7661 if you have any questions.

Sincerely,

ENSTAR Natural Gas Company

Daniel M. Dieckgraeff
Director of Rates and Regulatory Affairs

Phone: 907-334-7661
Fax: 907-334-7657
Dan.dieckgraeff@enstarnaturalgas.com

Attachments as stated

STATE OF ALASKA
DEPARTMENT OF
COMMERCE
COMMUNITY AND
ECONOMIC DEVELOPMENT

Bill Walker, Governor
Mike Navarre, Commissioner
Stephen McAlpine, Chairman

Regulatory Commission of Alaska

May 29, 2018

In reply refer to: Tariff Section
File: TA303-4
LO#: L1800240

Daniel M. Dieckgraeff
Director of Rates and Regulatory Affairs
ENSTAR Natural Gas Company
P.O. Box 190288
Anchorage, AK 99519-0288

Dear Mr. Dieckgraeff:

ENSTAR Natural Gas Company (ENSTAR) filed TA303-4 on April 26, 2018, seeking to revise its rates in response to the passage of new federal tax legislation. TA303-4 proposes to decrease ENSTAR's non-gas revenue requirement by 5.7%. ENSTAR, in TA303-4, estimates that all of their gas sales customers will collectively realize a savings of 1.3% on their bills on an annualized basis with the approval of TA303-4.

On May 29, 2018, the Regulatory Commission of Alaska approved Tariff Sheet Nos. 201, 202, 203, 204, 211, 212, 213, 214, 216, and 218, filed on April 26, 2018, by ENSTAR in TA303-4. The Commission, on its own motion, waived the statutory notice period and specified an early effective date for the tariff sheets of June 1, 2018.

Enclosed are validated copies of the approved tariff sheets. Please note the effective date of June 1, 2018, has been added to the bottom right corner of each tariff sheet.

BY DIRECTION OF THE COMMISSION (Commissioner Stephen McAlpine dissenting)

Sincerely,

REGULATORY COMMISSION OF ALASKA

Stephen McAlpine
Chairman

Enclosures

701 West 8th Avenue, Suite 300, Anchorage, Alaska 99501-3469
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§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):	$0.14759 per hundred cubic feet (Ccf)	**R**
Customer Charge:	$16.00	**R**

§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.

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§2002 <u>**Schedule G2 - General Service 2**</u>

§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):	$0.09459 per hundred cubic feet (Ccf)	**R**
Customer Charge:	$35.00	**R**

§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 the Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

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§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):	$0.09308 per hundred cubic feet (Ccf)	R
Customer Charge:	$110.00	R

§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 the Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

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§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):	$0.06483 per hundred cubic feet (Ccf)	**R**
Customer Charge:	$530.00	**R**

§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 the Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

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ENSTAR Natural Gas Company

§2101 **Transportation Service to Power Plants**

§2101a **Rates**

		(Volumetric) Rate Per Mcf	Monthly Customer Charge	
§2101a(1)	Chugach International	$0.7671	$ 2,900	**R**

§2101b The power plant named above is subject to varying interruptions of service as provided under Section 1200 above.

§2101c **Transportation Service**
The Customer at the location listed above in Section 2101a 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.

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

§2145a **Application**

§2145a(1) This rate schedule applies to firm transportation service to:

§2145a(1)(a) Titan Alaska LNG, LLC (formerly Fairbanks Natural Gas Company (FNG)) 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:
$0.1605 per thousand cubic feet (Mcf) **R**

Customer charge:
$9,000 per Month **R**

§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.

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§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 rate, customer charge and demand charge applies to each individual Delivery Point receiving service under Schedule VLFT except for Anchorage Municipal Light and Power ("ML&P") Plants 1, 2 and 2A. The volumes, load factor, Contracted Peak Demand, and demand charge for these three locations will be aggregated, and ML&P will only be charged one customer charge. 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:	$0.1736 per Mcf	**R**
Customer Charge:	$2,500 per Delivery Point	**R**
Demand Charge:	$4.20 per Month per Mcf of Contracted Peak Demand	**R**

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ENSTAR Natural Gas Company

§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 $4.20 X 12 X 2] = [2,000 X $4.20 X 12 X 2] = $201,600 **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 are sales of energy sold on a non-firm basis. 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:

(The next page is Sheet 214.1)

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§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	$17,400	R
Remaining Volumes		$0.1744 Per Mcf	R

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.

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§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: $0.1744 per Mcf **R**

There is no charge for any month which volumes are not transported, however there is a minimum charge of $15,900 for each Year in which gas is transported under this rate schedule. **R**

§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.

WEATHER NORMALIZATION ADJUSTMENTS

Purpose: To adjust for abnormal weather during 2021.

G1 Class:

Test Year Use per Consuming Customer (Mcf)			150.54	150.54
Base Use per Customer				
Jun Use per Customer		4.28		
Jul Use per Customer		3.77		
Aug Use per Customer		4.20		
Total		12.25		
No. of Days - Jul & Aug		92		
Base Use per Day		0.1331		
Annual Days		365		
Base Use per Customer			48.58	
Heating Load per Customer			101.96	
Heating Degree Days				
Actual Degree Days		10,544		
Base Degree Days:				
Jun	248			
Jul	189			
Aug	243			
Total	680			
No. of Days - Jul & Aug	92			
Average Daily	7.39			
Annual Days	365			
Annual Base Degree Days		2,698		
Heating Degree Days			7,846	
Heating Load per Degree Day			0.01299	
Excess Degree Days				
10-Year Normal		9,512		
Actual Degree Days		10,544		
Excess Degree Days			(1,032)	
Adjustment per Customer (Mcf)				(13.41)
Normalized Use per Customer (Mcf)				137.13
Test Year Customers				138,360
Normalized Volumes (Mcf)				18,973,894
Test Year Volumes (Mcf)				20,829,042
Excess Weather-related Volumes				(1,855,148)
G1 Volumetric Rate per Mcf				$ 1.4759
G1 Weather Normalization Adjustment				**$ (2,738,012)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G2 Class:

Test Year Use per Consuming Customer (Mcf)			385.10	385.10
Base Use per Customer				
Jun Use per Customer		10.86		
Jul Use per Customer		9.98		
Aug Use per Customer		11.36		
Total		32.20		
No. of Days - Jul & Aug		92		
Base Use per Day		0.3500		
Annual Days		365		
Base Use per Customer			127.77	
Heating Load per Customer			257.33	
Heating Degree Days				
Actual Degree Days		10,544		
Base Degree Days:				
Jun	248			
Jul	189			
Aug	243			
Total	680			
No. of Days - Jul & Aug	92			
Average Daily	7.39			
Annual Days	365			
Annual Base Degree Days		2,698		
Heating Degree Days			7,846	
Heating Load per Degree Day			0.03280	
Excess Degree Days				
10-Year Normal		9,512		
Actual Degree Days		10,544		
Excess Degree Days			(1,032)	
Adjustment per Customer (Mcf)				(33.84)
Normalized Use per Customer (Mcf)				351.26
Test Year Customers				5,645
Normalized Volumes (Mcf)				1,982,935
Test Year Volumes (Mcf)				2,173,969
Excess Weather-related Volumes				(191,034)
G2 volumetric per Mcf				$ 0.9459
G2 Weather Normalization Adjustment				**$ (180,699)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G3 Class:

Test Year Use per Consuming Customer (Mcf)			1,219.44	1,219.44
Base Use per Customer				
Jun Use per Customer		36.44		
Jul Use per Customer		35.60		
Aug Use per Customer		40.49		
Total		112.53		
No. of Days - Jul & Aug		92		
Base Use per Day		1.2232		
Annual Days		365		
Base Use per Customer			446.45	
Heating Load per Customer			772.99	
Heating Degree Days				
Actual Degree Days		10,544		
Base Degree Days:				
Jun	248			
Jul	189			
Aug	243			
Total	680			
No. of Days - Jul & Aug	92			
Average Daily	7.39			
Annual Days	365			
Annual Base Degree Days		2,698		
Heating Degree Days			7,846	
Heating Load per Degree Day			0.09852	
Excess Degree Days				
10-Year Normal		9,512		
Actual Degree Days		10,544		
Excess Degree Days			(1,032)	
Adjustment per Customer (Mcf)				(101.65)
Normalized Use per Customer (Mcf)				1,117.79
Test Year Customers				3,636
Normalized Volumes (Mcf)				4,064,009
Test Year Volumes (Mcf)				4,433,588
Excess Weather-related Volumes				(369,579)
G3 Volumetric Rate per Mcf				$ 0.9308
G3 Weather Normalization Adjustment				**$ (344,004)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G4 Class:

Test Year Use per Consuming Customer (Mcf)			7,925.05	7,925.05
Base Use per Customer				
Jun Use per Customer		293.66		
Jul Use per Customer		248.85		
Aug Use per Customer		344.28		
Total		886.79		
No. of Days - Jul & Aug		92		
Base Use per Day		9.6390		
Annual Days		365		
Base Use per Customer			3,518.25	
Heating Load per Customer			4,406.80	
Heating Degree Days				
Actual Degree Days		10,544		
Base Degree Days:				
Jun	248			
Jul	189			
Aug	243			
Total	680			
No. of Days - Jul & Aug	92			
Average Daily	7.39			
Annual Days	365			
Annual Base Degree Days		2,698		
Heating Degree Days			7,846	
Heating Load per Degree Day			0.56165	
Excess Degree Days				
10-Year Normal		9,512		
Actual Degree Days		10,544		
Excess Degree Days			(1,032)	
Adjustment per Customer (Mcf)				(579.51)
Normalized Use per Customer (Mcf)				7,345.54
Test Year Customers				1,009
Normalized Volumes (Mcf)				7,412,260
Test Year Volumes (Mcf)				7,997,034
Excess Weather-related Volumes				(584,774)
G4 Volumetric Rate per Mcf				$ 0.6483
G4 Weather Normalization Adjustment				**$ (379,109)**

		Travel and Training Normalization Adjustment								
							COVID Impact			
		2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	Norm. 5Y Average (2017-2019)	5 Y Norm. vs 2021 (Adjust. to 2021 Test Year)
76510	Ground Travel	20,087	20,640	25,298	25,484	28,264	10,882	17,178	23,954	6,776
76520	Air Travel	86,029	96,445	110,802	96,320	127,709	25,259	20,092	103,461	83,369
76530	Lodging	109,531	94,891	117,063	48,697	75,361	29,456	20,561	89,109	68,548
76540	Meals & Ent-Out of Tow	13,166	12,770	26,701	19,045	26,277	15,738	15,369	19,592	4,223
76560	Meetings	4,886	4,831	9,012	1,584	2,170	455	-	4,497	4,497
76570	Training	88,846	113,216	76,652	63,913	59,103	60,213	72,647	80,346	7,700
76580	Conferences	49,167	33,270	41,517	44,393	31,770	23,981	10,237	40,023	29,786
		371,711	376,062	407,045	299,436	350,654	165,984	156,083	360,982	204,899

ENSTAR NATURAL GAS COMPANY

CALCULATION OF NORMALIZED RATE OF RETURN AT CURRENT RATES
For the Year Ended December 31, 2021

Calculation of Taxes at Current Rates	
Normalized Revenues at Current Rates	360,446,470
Normalized Operating Expenses	(329,398,539)
Normalized Taxes Other Than Income	(4,511,377)
Earnings Before Interest and Taxes	26,536,554
Less: Return on Long Term Debt	(3,845,824)
Taxable State Income	22,690,730.52
State Income Tax Rate	9.4%
State Income Tax	2,132,929
Taxable Federal Income	20,557,802
Federal Income Tax Rate	21.0%
Amount At Tax Rate	4,317,138
Amortization of Excess Deferred Taxes	(695,069)
Federal Income Tax	3,622,069
Calculation of Effective Rate of Return	
Normalized Earnings Before Taxes	26,536,554
Net Income Taxes at Current Rates	5,754,998
Net Utility Operating Income	20,781,556
Less: Interest Expense	(3,845,824)
Normalized Net Income Available for Member's Equity	16,935,732
Rate of Return on Equity	**10.68%**

Calculation of Interim and Proposed Increase

	Current Rates	Interim at 1.50%	Proposed Permanent Rates
General Service			
G1			
Monthly Customer Charge	$ 16.00	$ 16.25	$ 27.00
Base Rate (per Ccf)	$ 0.14759	$ 0.14980	$ 0.06555
G2			
Monthly Customer Charge	$ 35.00	$ 35.50	$ 46.00
Base Rate (per Ccf)	$ 0.09459	$ 0.09600	$ 0.06797
G3			
Monthly Customer Charge	$ 110.00	$ 112.00	$ 150.00
Base Rate (per Ccf)	$ 0.09308	$ 0.09448	$ 0.06728
G4			
Monthly Customer Charge	$ 530.00	$ 538.00	$ 620.00
Base Rate (per Ccf)	$ 0.06483	$ 0.06580	$ 0.06361
Large Transportation Firms			
Chugach International			
Monthly Customer Charge	$ 2,900	*	*
Base Rate (per Mcf)	$ 0.7671	*	*
* The Chugach Int. Power Plant is decommissioned and metering facilities removed in July 2022			
Mid-Sized Firm Transportation			
Monthly Customer Charge	$ 9,000	$ 9,140	$ 21,100
Base Rate (per Mcf)	$ 0.1605	$ 0.1629	$ 0.0052
Very Large Firm Transportation			
Base Rate (per Mcf)	$ 0.1736	$ 0.1762	$ 0.0057
Customer Charge per Delivery Point	$ 2,500	$ 2,540	$ 1,700
Demand Charge per Mcf of Contracted Peak Demand per Month	$ 4.20	$ 4.26	$ 8.32
Interruptible Industrial Transportation			
Mcf/Mo.			
< 100,000	$ 17,400	$ 17,660	$ 24,000
Remaining Volumes	$ 0.1744	$ 0.1770	$ 0.2403
There is no charge for any month which volumes are not transported.			
Interruptible Storage Transportation			
Mcf/Mo.			
All Volumes	$ 0.17439	$ 0.17701	$ 0.2403
Minimum charge for each Year in which gas is transported under this rate schedule.	$ 15,900	$ 16,100	$ 24,000
There is no charge for any month which volumes are not transported.			

Daniel M. Dieckgraeff

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, Alaska: 1982 – Present.

- Director of Rates and Regulatory Affairs: 2012 – Present
- Manager, Rates and Regulatory Affairs: 2008 – 2012
- Manager, Regulatory and Gas Supply: 2006 – 2008
- Manager, Finance and Rates: 2000 – 2006
- Manager, Rates and Planning: 1989 – 2000
- Rates and Planning Supervisor: 1982 – 1988

Price Waterhouse, Anchorage, Alaska: 1979 – 1982

- Senior Accountant: 1981 – 1982
- Staff Accountant: 1979 – 1981

EDUCATION

Gonzaga University, Spokane, Washington: Bachelor Business Administration, Major in Public Accounting. 1979

Alaska Pacific University, Anchorage, Alaska: Master of Business Administration, Concentration in Global Finance. 2007

OTHER

Certified Public Accountant (AK), 1982 – present

American Institute of Certified Public Accountants, Member

Alaska Society of Certified Public Accountants, Member

Institute of Management Accountants, Member

Commonwealth North, Member

Spirit of Youth, Board Member

American Gas Association, State Affairs Committee

ENSTAR Natural Gas Company

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www.enstarnaturalgas.com

RECEIVED
By the Regulatory Commission of Alaska on Apr 04, 2018

April 4, 2018

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

Subject: TCJA of 2017 Impact on Rates – I-18-002

Dear Commissioners:

ENSTAR Natural Gas Company, a division of SEMCO Energy, Inc. ("ENSTAR") is in receipt of your letter of March 23, 2018, and appreciates the opportunity to respond to the Commission's questions. While this is an extremely complicated issue, with a number of implications from a regulated utility perspective, ENSTAR has worked diligently since the passage of the Tax Cuts and Jobs Act of 2017 ("TCJA") to understand the impacts of the tax changes, and proposes this course of action to provide the intended tax savings to customers. At this time, ENSTAR anticipates that the reduction in the corporate income tax rate will result in a reduction to its annual revenue requirement of $4.5 to $5.5 million dollars.

I. Impact on Income Tax Expense

ENSTAR anticipates making a filing by the end of April 2018 to address the change in the corporate income tax rate on the income tax expense and related components of ENSTAR's recently decided 2015 test year revenue requirement, excluding deferred taxes. ENSTAR plans to include a revised 275(a) to reflect U-16-066(19) Normalized Test Year Revenue Requirement and Revenue Deficiency Adjusted for 2017 TCJA Tax Rate. This revised 275(a) would include Revised Schedule O, State and Federal Income Tax Adjustments; Revised Schedule G, Uncollectible Accounts Expense Adjustment; and Revised Schedule LL, Lead-Lag Study-Cash Working Capital Requirement. The filing will also include a revised 275(h), a Cost-of-Service Study Adjusted for 2017 TCJA Tax Rate. Finally, ENSTAR will submit for Commission review and approval revised tariff sheets reflecting the reduced customer rates resulting from adjustments to the corporate tax rate.

II. Impact of Deferred Taxes

As noted by Commissioner Pickett during the Public Meeting held on March 14, 2018, "this is a little more complicated in some cases than is generally portrayed in the press." (Transcript at 75.) The TCJA of 2017 includes normalization provisions for regulated utilities, which require a specific treatment of accumulated deferred income taxes ("ADIT") resulting from the corporate income tax rate reduction.

Excess ADIT is defined in the TCJA as the excess of: (1) the reserve for deferred taxes as of the day before the corporate rate reductions take effect, over (2) the amount which would be the balance in the reserve if the amount of the reserve were determined by assuming that the corporate

rate reductions provided in the TCJA were in effect for all prior periods. The excess ADIT normalization requirements apply only to accelerated federal tax method/life depreciation differences on public utility property.

The normalization provision requires that excess deferred income taxes be used to reduce revenue requirements no sooner than would occur as the book/tax difference reverses. The utility must identify the deferred tax reversal pattern (comparing book depreciation versus tax depreciation) and start to reverse the excess ADIT when book depreciation exceeds tax depreciation. This method is referred to as the Average Rate Assumption Method ("ARAM"). An alternative approach allowed in the TCJA is the Reverse South Georgia Method ("RSG"), which is allowed only if the utility is unable to identify when book/tax differences originate and reverse. RSG is not permitted if the utility has the records to calculate the reversal using ARAM. The RSG spreads the excess ADIT evenly over the estimated book life of the utility assets that created the ADIT.

Both approaches reduce rates over the estimated remaining book life of the related assets. The difference between the two is that under RSG, the reduction begins immediately, while under ARAM the reduction does not occur until the book/tax difference begins to reverse. Further, a normalization violation occurs if the excess ADIT is used to reduce rates more rapidly than would occur under either of these approaches, resulting in severe penalties from the IRS.

In order to illustrate this difference, the following simplified example was prepared by the audit and accounting firm PricewaterhouseCoopers ("PwC") and presented in a Power & Utilities Technical Update on March 22, 2018 (page 9). (The full presentation is attached for reference.)

ARAM vs RSG comparison

				DR/(CR) ARAM				DR/(CR) RSGM			
Year	Book Depreciation	Tax Depreciation	Book/Tax Difference	Tax Rate	Deferred Tax Expense	EDIT amort	ADIT	Tax Rate	Deferred Tax Expense	[2] EDIT Amort	ADIT
2016	100,000	200,000	100,000	35%	35,000	-	(35,000)	35%	35,000	-	(35,000)
2017	100,000	320,000	220,000	35%	77,000	-	(112,000)	35%	77,000	-	(112,000)
2018	100,000	192,000	92,000	20%	18,400	-	(130,400)	20%	18,400	(6,000)	(124,400)
2019	100,000	115,200	15,200	20%	3,040	-	(133,440)	20%	3,040	(6,000)	(121,440)
2020	100,000	115,200	15,200	20%	3,040	-	(136,480)	20%	3,040	(6,000)	(118,480)
2021	100,000	57,600	(42,400)	30.85%	(8,480)	(4,600)	(123,400) [1]	20%	(8,480)	(6,000)	(104,000)
2022	100,000	-	(100,000)	30.85%	(20,000)	(10,850)	(92,550) [1]	20%	(20,000)	(6,000)	(78,000)
2023	100,000	-	(100,000)	30.85%	(20,000)	(10,850)	(61,700) [1]	20%	(20,000)	(6,000)	(52,000)
2024	100,000	-	(100,000)	30.85%	(20,000)	(10,850)	(30,850) [1]	20%	(20,000)	(6,000)	(26,000)
2025	100,000	-	(100,000)	30.85%	(20,000)	(10,850)	0 [1]	20%	(20,000)	(6,000)	-
	1,000,000	1,000,000	-		48,000	(48,000)			48,000	(48,000)	

PwC | Power & Utilities Technical Update 9

As this example shows, under ARAM, the excess ADIT begins to reverse in 2021, which is when the book depreciation overtakes the tax depreciation and the ADIT begins to reverse. Using RSG, the excess ADIT is amortized beginning in 2018 using a straight-line method over the remaining book life of the asset. The end result, over the book life of the hypothetical asset, is the same under either method.

In order to determine the impact of excess ADIT on its revenue requirement, and thus on customers' rates, ENSTAR must take the following steps:

- Determine whether the historical records available are sufficient to use ARAM.
  - If yes, then calculate the book/tax depreciation differences and resulting ADIT to determine when the book depreciation starts to exceed the tax depreciation.
  - Calculate the excess ADIT for each year and apply it to the appropriate revenue requirement.
- If ARAM cannot be used, calculate the estimated remaining book life for all underlying assets and amortize the excess ADIT over this period.

Because of the considerable work involved in these steps, and the uncertainty around the results of the analysis, ENSTAR proposes including the excess ADIT amortization adjustment in its next rate case, which as required by U-16-066(19), will be filed using a test year of 2020 or sooner. This gives ENSTAR's tax department the time it needs to do the thorough analysis demanded in the TCJA.

In conclusion, ENSTAR has proactively and diligently worked to understand the implications associated with the TCJA and understands the potential savings our customers can realize by acting expeditiously. Our proposal is the best solution to realize those savings for customers while staying within the applicable regulations.

Sincerely,

ENSTAR Natural Gas Company

John Sims
President

Phone: 907-334-7625
Fax: 907-334-7671
John.Sims@enstarnaturalgas.com

Attachments as stated

ENSTAR
Natural Gas Company

3000 Spenard Road
PO Box 190288
Anchorage, AK 99519-0288
www.enstarnaturalgas.com

RECEIVED
By the Regulatory Commission of Alaska on Apr 26, 2018

April 26, 2018

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

Subject: Tariff Advice Letter TA 303-4

Dear Commissioners:

The tariff filing described below is transmitted to you for filing in compliance with Section 3 AAC 48.200 - 3 AAC 48.430 of the Alaska Administrative Code:

Tariff Sheet		Cancels Sheet		
Number	Revision	Number	Revision	Schedule or Rule Number
201	15th	201	14th	Rates – Section 2001 G1
202	14th	202	13th	Rates – Section 2002 G2
203	14th	203	13th	Rates – Section 2003 G3
204	Ninth	204	Eighth	Rates – Section 2004 G4
211	13th	211	12th	Rates – Section 2101 PPT
212	Seventh	212	Sixth	Rates – Section 2145 MSFT
213	Seventh	213	Sixth	Rates – Section 2150 VLFT
214	Sixth	214	Fifth	Rates – Section 2150 VLFT
216	11th	216	Tenth	Rates – Section 2201 IIT
218	Eighth	218	Seventh	Rates – Section 2251 ITS

On December 22, 2017, President Trump enacted P.L. 115-97, commonly known as the Tax Cut and Jobs Act of 2017 ("TCJA"). This major tax reform is a complex piece of legislation that is still being researched to understand the full ramifications for corporations across the country. While this is an extremely complicated issue, with a number of implications from a regulated utility perspective, ENSTAR Natural Gas Company ("ENSTAR") has worked diligently since the passage of the TCJA to understand its effect on customers' rates.

The TCJA reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. This tariff filing, which applies that tax rate change, represents a decrease of $5.1 million for ENSTAR's customers from the revenue requirement approved in U-16-066(20).[1] This represents a 5.7% reduction of ENSTAR's non-gas revenue requirement.

[1] As of March 31, 2018, ENSTAR has 144,691 General Service customers, as well as 11 power

ENSTAR recognizes that the Commission has not yet specified the treatment utilities should take. ENSTAR nonetheless proposes the attached filing because it believes this methodology is the most expeditious way for customers to realize savings on their monthly bills.[2]

ENSTAR estimates that, with its proposed rate change, all gas sales customer categories (G1 through G4) will see an approximately 1.3% decrease in their total bill on an annualized basis from the rates currently in effect.

Recomputed Revenue Requirement

ENSTAR's last revenue requirement was established by the Commission in Order No. U-16-066(19) and accepted in U-16-066(20). The authorized revenue requirement is recomputed in Attachment A to reflect the reduction in federal corporate income tax rate from 35% to 21%. In calculating the revised revenue requirement, ENSTAR took into account the following items:

- Decreased working capital requirements due to the lower income tax payments which will be made under the TCJA. This resulted in a decrease of $57,700 in the working capital component of rate base. Using the approved rate of return of 8.59%, this equates to a reduction of $4,956 in return on investment.
- Decreased bad debt expense due to the decrease in revenue requirement. This resulted in a decrease of $14,307 to customer accounting expenses.
- Decreased state income tax expense due to the decrease in revenue requirement. This lead to a decrease of $477,607 in state income tax expense.
- Decreased the federal income tax expense due to the reduction in tax rates from 35% to 21%, as well as the reductions in expenses listed above. This resulted in a decrease in $4,599,769 in federal income tax expense.

Cost of Service Study and Rate Design

Attachment B is the recalculated cost-of-service study utilizing the revised revenue requirement shown in Attachment A. ENSTAR has utilized the same allocation methodologies ordered by the Commission in U-16-066(19), and accepted in U-16-066(20).

ENSTAR has maintained the same rate design for all customer classes adopted in U-16-066(20). For each rate category, the proposed new rates also preserve the same rate class revenue requirement split between the monthly fixed charge and the variable charge that was used the final permanent rates.

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and industrial transportation customer locations.

[2] As noted in ENSTAR's letter to the Commission in Docket I-18-002 dated April 6, 2018, ENSTAR will address any impact on its deferred taxes in its next rate case.

Revised Rate Schedules

Included in Attachment C to this filing is a schedule showing the proposed new rate by rate class compared to the current rates. The proposed tariff sheets are included in Attachment D.

ENSTAR requests that the revisions be effective on a permanent basis on the first day of the month following Commission approval. Please feel free to contact me at 334-7661 if you have any questions.

Sincerely,

ENSTAR Natural Gas Company

Daniel M. Dieckgraeff
Director of Rates and Regulatory Affairs

Phone: 907-334-7661
Fax: 907-334-7657
Dan.dieckgraeff@enstarnaturalgas.com

Attachments as stated

STATE OF ALASKA
DEPARTMENT OF
COMMERCE
COMMUNITY AND
ECONOMIC DEVELOPMENT

Bill Walker, Governor
Mike Navarre, Commissioner
Stephen McAlpine, Chairman

Regulatory Commission of Alaska

May 29, 2018

In reply refer to: Tariff Section
File: TA303-4
LO#: L1800240

Daniel M. Dieckgraeff
Director of Rates and Regulatory Affairs
ENSTAR Natural Gas Company
P.O. Box 190288
Anchorage, AK 99519-0288

Dear Mr. Dieckgraeff:

ENSTAR Natural Gas Company (ENSTAR) filed TA303-4 on April 26, 2018, seeking to revise its rates in response to the passage of new federal tax legislation. TA303-4 proposes to decrease ENSTAR's non-gas revenue requirement by 5.7%. ENSTAR, in TA303-4, estimates that all of their gas sales customers will collectively realize a savings of 1.3% on their bills on an annualized basis with the approval of TA303-4.

On May 29, 2018, the Regulatory Commission of Alaska approved Tariff Sheet Nos. 201, 202, 203, 204, 211, 212, 213, 214, 216, and 218, filed on April 26, 2018, by ENSTAR in TA303-4. The Commission, on its own motion, waived the statutory notice period and specified an early effective date for the tariff sheets of June 1, 2018.

Enclosed are validated copies of the approved tariff sheets. Please note the effective date of June 1, 2018, has been added to the bottom right corner of each tariff sheet.

BY DIRECTION OF THE COMMISSION (Commissioner Stephen McAlpine dissenting)

Sincerely,

REGULATORY COMMISSION OF ALASKA

Stephen McAlpine
Chairman

Enclosures

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§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):	$0.14759 per hundred cubic feet (Ccf)	**R**
Customer Charge:	$16.00	**R**

§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.

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§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):	$0.09459 per hundred cubic feet (Ccf)	**R**
Customer Charge:	$35.00	**R**

§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 the Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

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§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):	$0.09308 per hundred cubic feet (Ccf)	R
Customer Charge:	$110.00	R

§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 the Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

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§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):	$0.06483 per hundred cubic feet (Ccf)	R
Customer Charge:	$530.00	R

§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 the Sections 1605 and 1640, and may be subject to the additional fees set out in Section 2561.

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ENSTAR

ENSTAR Natural Gas Company

§2101 **Transportation Service to Power Plants**

§2101a **Rates**

		(Volumetric) Rate Per Mcf	Monthly Customer Charge	
§2101a(1)	Chugach International	$0.7671	$ 2,900	R

§2101b The power plant named above is subject to varying interruptions of service as provided under Section 1200 above.

§2101c **Transportation Service**
The Customer at the location listed above in Section 2101a 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.

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§2145 Schedule MSFT – Mid-Sized Firm Transportation Service

§2145a Application

§2145a(1) This rate schedule applies to firm transportation service to:

§2145a(1)(a) Titan Alaska LNG, LLC (formerly Fairbanks Natural Gas Company (FNG)) 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:
$0.1605 per thousand cubic feet (Mcf) R

Customer charge:
$9,000 per Month R

§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.

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§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 rate, customer charge and demand charge applies to each individual Delivery Point receiving service under Schedule VLFT except for Anchorage Municipal Light and Power ("ML&P") Plants 1, 2 and 2A. The volumes, load factor, Contracted Peak Demand, and demand charge for these three locations will be aggregated, and ML&P will only be charged one customer charge. 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:	$0.1736 per Mcf	R
Customer Charge:	$2,500 per Delivery Point	R
Demand Charge:	$4.20 per Month per Mcf of Contracted Peak Demand	R

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§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 $4.20 X 12 X 2] = [2,000 X $4.20 X 12 X 2] = $201,600 **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 are sales of energy sold on a non-firm basis. 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:

(The next page is Sheet 214.1)

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§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	$17,400	**R**
Remaining Volumes		$0.1744 Per Mcf	**R**

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.

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§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: $0.1744 per Mcf **R**

There is no charge for any month which volumes are not transported, however there is a minimum charge of $15,900 for each Year in which gas is transported under this rate schedule. **R**

§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.

WEATHER NORMALIZATION ADJUSTMENTS

Purpose: To adjust for abnormal weather during 2021.

G1 Class:

Test Year Use per Consuming Customer (Mcf)			150.54	150.54
Base Use per Customer				
Jun Use per Customer		4.28		
Jul Use per Customer		3.77		
Aug Use per Customer		4.20		
Total		12.25		
No. of Days - Jul & Aug		92		
Base Use per Day		0.1331		
Annual Days		365		
Base Use per Customer			48.58	
Heating Load per Customer			101.96	
Heating Degree Days				
Actual Degree Days		10,544		
Base Degree Days:				
Jun	248			
Jul	189			
Aug	243			
Total	680			
No. of Days - Jul & Aug	92			
Average Daily	7.39			
Annual Days	365			
Annual Base Degree Days		2,698		
Heating Degree Days			7,846	
Heating Load per Degree Day			0.01299	
Excess Degree Days				
10-Year Normal		9,512		
Actual Degree Days		10,544		
Excess Degree Days			(1,032)	
Adjustment per Customer (Mcf)				(13.41)
Normalized Use per Customer (Mcf)				137.13
Test Year Customers				138,360
Normalized Volumes (Mcf)				18,973,894
Test Year Volumes (Mcf)				20,829,042
Excess Weather-related Volumes				(1,855,148)
G1 Volumetric Rate per Mcf				$ 1.4759
G1 Weather Normalization Adjustment				**$ (2,738,012)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G2 Class:

Test Year Use per Consuming Customer (Mcf)			385.10	385.10
Base Use per Customer				
Jun Use per Customer		10.86		
Jul Use per Customer		9.98		
Aug Use per Customer		11.36		
Total		32.20		
No. of Days - Jul & Aug		92		
Base Use per Day		0.3500		
Annual Days		365		
Base Use per Customer			127.77	
Heating Load per Customer			257.33	
Heating Degree Days				
Actual Degree Days		10,544		
Base Degree Days:				
Jun	248			
Jul	189			
Aug	243			
Total	680			
No. of Days - Jul & Aug	92			
Average Daily	7.39			
Annual Days	365			
Annual Base Degree Days		2,698		
Heating Degree Days			7,846	
Heating Load per Degree Day			0.03280	
Excess Degree Days				
10-Year Normal		9,512		
Actual Degree Days		10,544		
Excess Degree Days			(1,032)	
Adjustment per Customer (Mcf)				(33.84)
Normalized Use per Customer (Mcf)				351.26
Test Year Customers				5,645
Normalized Volumes (Mcf)				1,982,935
Test Year Volumes (Mcf)				2,173,969
Excess Weather-related Volumes				(191,034)
G2 volumetric per Mcf				$ 0.9459
G2 Weather Normalization Adjustment				**$ (180,699)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G3 Class:

Test Year Use per Consuming Customer (Mcf)			1,219.44	1,219.44
Base Use per Customer				
Jun Use per Customer		36.44		
Jul Use per Customer		35.60		
Aug Use per Customer		40.49		
Total		112.53		
No. of Days - Jul & Aug		92		
Base Use per Day		1.2232		
Annual Days		365		
Base Use per Customer			446.45	
Heating Load per Customer			772.99	
Heating Degree Days				
Actual Degree Days		10,544		
Base Degree Days:				
Jun	248			
Jul	189			
Aug	243			
Total	680			
No. of Days - Jul & Aug	92			
Average Daily	7.39			
Annual Days	365			
Annual Base Degree Days		2,698		
Heating Degree Days			7,846	
Heating Load per Degree Day			0.09852	
Excess Degree Days				
10-Year Normal		9,512		
Actual Degree Days		10,544		
Excess Degree Days			(1,032)	
Adjustment per Customer (Mcf)				(101.65)
Normalized Use per Customer (Mcf)				1,117.79
Test Year Customers				3,636
Normalized Volumes (Mcf)				4,064,009
Test Year Volumes (Mcf)				4,433,588
Excess Weather-related Volumes				(369,579)
G3 Volumetric Rate per Mcf				$ 0.9308
G3 Weather Normalization Adjustment				**$ (344,004)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G4 Class:

Test Year Use per Consuming Customer (Mcf)			7,925.05	7,925.05
Base Use per Customer				
Jun Use per Customer		293.66		
Jul Use per Customer		248.85		
Aug Use per Customer		344.28		
Total		886.79		
No. of Days - Jul & Aug		92		
Base Use per Day		9.6390		
Annual Days		365		
Base Use per Customer			3,518.25	
Heating Load per Customer			4,406.80	
Heating Degree Days				
Actual Degree Days		10,544		
Base Degree Days:				
Jun	248			
Jul	189			
Aug	243			
Total	680			
No. of Days - Jul & Aug	92			
Average Daily	7.39			
Annual Days	365			
Annual Base Degree Days		2,698		
Heating Degree Days			7,846	
Heating Load per Degree Day			0.56165	
Excess Degree Days				
10-Year Normal		9,512		
Actual Degree Days		10,544		
Excess Degree Days			(1,032)	
Adjustment per Customer (Mcf)				(579.51)
Normalized Use per Customer (Mcf)				7,345.54
Test Year Customers				1,009
Normalized Volumes (Mcf)				7,412,260
Test Year Volumes (Mcf)				7,997,034
Excess Weather-related Volumes				(584,774)
G4 Volumetric Rate per Mcf				$ 0.6483
G4 Weather Normalization Adjustment				**$ (379,109)**

		Travel and Training Normalization Adjustment								
							COVID Impact			
		2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	Norm. 5Y Average (2017-2019)	5 Y Norm. vs 2021 (Adjust. to 2021 Test Year)
76510	Ground Travel	20,087	20,640	25,298	25,484	28,264	10,882	17,178	23,954	6,776
76520	Air Travel	86,029	96,445	110,802	96,320	127,709	25,259	20,092	103,461	83,369
76530	Lodging	109,531	94,891	117,063	48,697	75,361	29,456	20,561	89,109	68,548
76540	Meals & Ent-Out of Tow	13,166	12,770	26,701	19,045	26,277	15,738	15,369	19,592	4,223
76560	Meetings	4,886	4,831	9,012	1,584	2,170	455	-	4,497	4,497
76570	Training	88,846	113,216	76,652	63,913	59,103	60,213	72,647	80,346	7,700
76580	Conferences	49,167	33,270	41,517	44,393	31,770	23,981	10,237	40,023	29,786
		371,711	376,062	407,045	299,436	350,654	165,984	156,083	360,982	204,899

ENSTAR NATURAL GAS COMPANY

CALCULATION OF NORMALIZED RATE OF RETURN AT CURRENT RATES
For the Year Ended December 31, 2021

Calculation of Taxes at Current Rates	
Normalized Revenues at Current Rates	360,446,470
Normalized Operating Expenses	(329,398,539)
Normalized Taxes Other Than Income	(4,511,377)
Earnings Before Interest and Taxes	26,536,554
Less: Return on Long Term Debt	(3,845,824)
Taxable State Income	22,690,730.52
State Income Tax Rate	9.4%
State Income Tax	2,132,929
Taxable Federal Income	20,557,802
Federal Income Tax Rate	21.0%
Amount At Tax Rate	4,317,138
Amortization of Excess Deferred Taxes	(695,069)
Federal Income Tax	3,622,069
Calculation of Effective Rate of Return	
Normalized Earnings Before Taxes	26,536,554
Net Income Taxes at Current Rates	5,754,998
Net Utility Operating Income	20,781,556
Less: Interest Expense	(3,845,824)
Normalized Net Income Available for Member's Equity	16,935,732
Rate of Return on Equity	**10.68%**

Calculation of Interim and Proposed Increase

	Current Rates	Interim at 1.50%	Proposed Permanent Rates
General Service			
G1			
Monthly Customer Charge	$ 16.00	$ 16.25	$ 27.00
Base Rate (per Ccf)	$ 0.14759	$ 0.14980	$ 0.06555
G2			
Monthly Customer Charge	$ 35.00	$ 35.50	$ 46.00
Base Rate (per Ccf)	$ 0.09459	$ 0.09600	$ 0.06797
G3			
Monthly Customer Charge	$ 110.00	$ 112.00	$ 150.00
Base Rate (per Ccf)	$ 0.09308	$ 0.09448	$ 0.06728
G4			
Monthly Customer Charge	$ 530.00	$ 538.00	$ 620.00
Base Rate (per Ccf)	$ 0.06483	$ 0.06580	$ 0.06361
Large Transportation Firms			
Chugach International			
Monthly Customer Charge	$ 2,900	*	*
Base Rate (per Mcf)	$ 0.7671	*	*
* The Chugach Int. Power Plant is decommissioned and metering facilities removed in July 2022			
Mid-Sized Firm Transportation			
Monthly Customer Charge	$ 9,000	$ 9,140	$ 21,100
Base Rate (per Mcf)	$ 0.1605	$ 0.1629	$ 0.0052
Very Large Firm Transportation			
Base Rate (per Mcf)	$ 0.1736	$ 0.1762	$ 0.0057
Customer Charge per Delivery Point	$ 2,500	$ 2,540	$ 1,700
Demand Charge per Mcf of Contracted Peak Demand per Month	$ 4.20	$ 4.26	$ 8.32
Interruptible Industrial Transportation			
Mcf/Mo.			
< 100,000	$ 17,400	$ 17,660	$ 24,000
Remaining Volumes	$ 0.1744	$ 0.1770	$ 0.2403
There is no charge for any month which volumes are not transported.			
Interruptible Storage Transportation			
Mcf/Mo.			
All Volumes	$ 0.17439	$ 0.17701	$ 0.2403
Minimum charge for each Year in which gas is transported under this rate schedule.	$ 15,900	$ 16,100	$ 24,000
There is no charge for any month which volumes are not transported.			

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Keith Kurber II, Chair Robert A. Doyle Robert M. Pickett Daniel A. Sullivan Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-____

PREFILED DIRECT TESTIMONY
OF
DYLAN W. D'ASCENDIS

PREFILED DIRECT TESTIMONY
OF
DYLAN W. D'ASCENDIS

TABLE OF CONTENTS

I. POSITION AND QUALIFICATIONS

Q. State your name, business address, and present position.

A. My name is Dylan W. D'Ascendis. I am a Partner of ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 240, Mount Laurel, NJ 08054.

Q. Briefly describe your professional experience and educational background.

A. I have offered expert testimony on behalf of investor-owned utilities in 35 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, one American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization-weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances, including those before the Regulatory Commission of Alaska ("RCA"), are included in Exhibit DWD-1.

II. PURPOSE OF TESTIMONY AND BACKGROUND

Q. What is the purpose of your testimony?

A. The purpose is to present evidence and provide testimony on behalf of ENSTAR Natural Gas Company and Alaska Pipeline Company (collectively "ENSTAR" or the "Company"), relative to the appropriate capital structure and corresponding cost rates which the Company should be afforded the opportunity to earn on their jurisdictional rate base.

Q. Have you prepared any exhibits in support of your recommendation?

A. Yes. As stated above, my curriculum vitae is attached as Exhibit DWD-1. In addition, attached as Exhibit DWD-2 are schedules that support my recommendation on the appropriate rate of return for ENSTAR. There are eight "Schedules" included in Exhibit DWD-2 that I refer to throughout my testimony.

III. SUMMARY

Q. What is your recommended cost of capital for ENSTAR?

A. I recommend that the Regulatory Commission of Alaska (the "Commission") authorize ENSTAR the opportunity to earn an overall rate of return of 8.32% based on the

Company's actual capital structure at December 31, 2021, which consists of 45.89% long-term debt at an embedded debt cost rate of 2.86%, and 54.11% common equity at my recommended common equity cost rate of 12.95%. The overall rate of return is summarized on page 1 of Schedule 1 and in Table 1 below:

Table 1: Summary of Overall Rate of Return for ENSTAR

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.89%	2.86%	1.31%
Common Equity	54.11%	12.95%	7.01%
Total	100.00%		8.32%

Q. Please summarize your recommended common equity cost rate for the Company.

A. My recommended common equity cost rate of 12.95% for ENSTAR is summarized on page 2 of Schedule 1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to the Company. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] cases. No proxy group can be identical in risk to any single company, so there must be an evaluation of relative risk between the Company and the proxy group to see if it is appropriate to make adjustments to the proxy group's indicated rate of return.

My recommendation results from the application of several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the

[1] *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944).

[2] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922).

market data of a proxy group of twelve gas transmission and distribution utilities ("Utility Proxy Group"). The selection of the Utility Proxy Group is discussed below. In addition, I also applied the DCF, RPM, and CAPM to a proxy group of 53 domestic, non-price regulated companies comparable in total risk to the Utility Proxy Group ("Non-Price Regulated Proxy Group").

The results derived from each are as follows:

Table 2: Summary of Common Equity Cost Rate

Discounted Cash Flow Model	11.29%
Risk Premium Model	12.58%
Capital Asset Pricing Model	11.97%
Market Models Applied to Comparable Risk, Non-Price Regulated Companies	13.11%
Indicated Range of Common Equity Cost Rates Before Adjustments for Company-Specific Risk	11.70% - 12.70%
Business Risk Adjustment	0.75%
Indicated Range of Common Equity Cost Rates after Adjustment	12.45% – 13.45%
Recommended Cost of Common Equity	12.95%

After analyzing the cost rates based on these models, I conclude that a range of common equity cost rates between 11.70% and 12.70% for ENSTAR would be indicated before any adjustment resulting from a relative risk analysis between the Company and the Utility Proxy Group. I then adjusted the indicated common equity cost rate upward by 0.75% to reflect the Company's greater business risk, reflecting its unique risks of providing a natural gas transmission and distribution service in Alaska's Cook Inlet region, and smaller relative size compared with the members of the Utility

Proxy Group which results in a Company-specific indicated range of common equity cost rates between 12.45% and 13.45%. Based on these results, I recommend the Commission consider a common equity cost rate of 12.95% for use in setting rates for ENSTAR.

IV. CAPITAL MARKET OBSERVATIONS

Q. Do economic conditions influence the required cost of capital and required return on common equity?

A. Yes. The models used to estimate the cost of equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. Therefore, it is important to assess the reasonableness of any financial model's results in the context of observable market data.

Q. Does your recommended ROE consider the current capital market environment?

A. Yes, it does. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken.

Q. Please summarize the current capital market environment.

A. The economy is currently in an inflationary environment, as evidenced by increased levels of the Consumer Price Index ("CPI") as compared to the Federal Reserve's ("Fed") traditional inflation target of 2.00%. Inflation can be characterized as an imbalance of supply and demand in the economy, specifically, when demand is in excess of supply. When demand is in excess of supply, the cost of goods and services increase.

Part of the Fed's Congressional mandate is to mitigate inflation and they have two main tools to achieve their mandate: (1) raising the Fed Funds Rate;[3] or decreasing the size of their balance sheet. In Fed Chairman Jerome H. Powell's Press Conference on June 15, 2022, he indicated that the Fed has the resolve to use both tools to restore price stability on behalf of American families and businesses.[4]

Overall, the current market environment can be summarized as one with increasing inflation, and expectations that the Fed will implement both of its tools in an attempt to limit inflation.

Q. Has the CPI risen recently?

A. Yes, it has. As shown on Chart 1, the CPI has increased exponentially since the beginning of the pandemic and more recently has experienced year-over-year increases not seen since the early 1980s.[5]

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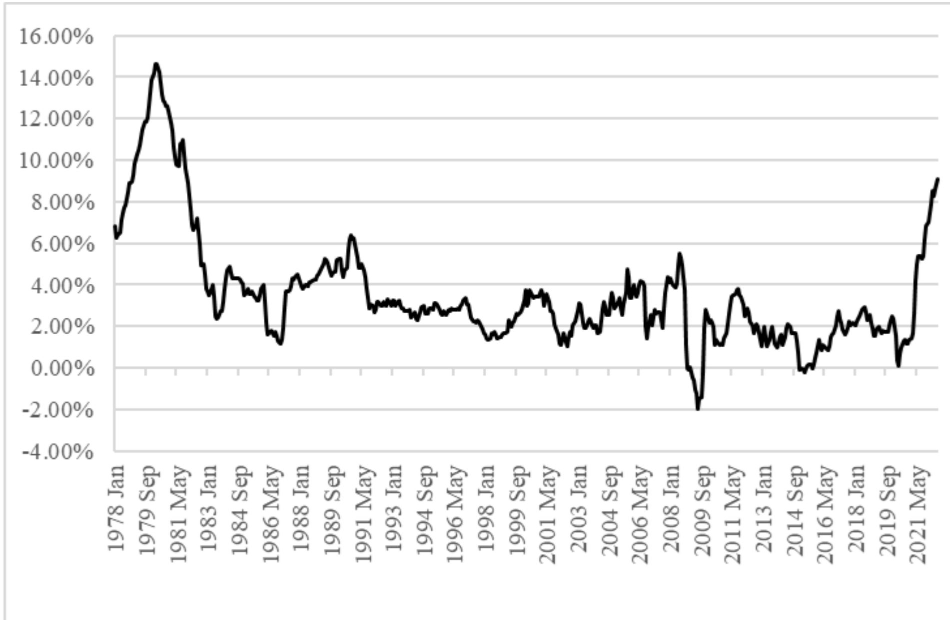
[3] The Fed Funds Rate is the rate in which the Fed suggests commercial banks borrow and lend their excess reserves to each other overnight.

[4] Transcript of Chair Powell's Press Conference, June 15, 2022.

[5] Source: Bureau of Labor Statistics, Series Title: All items in U.S. city average, all urban consumers, seasonally adjusted, Series ID: CUSR0000SA0 (https://data.bls.gov/timeseries/CUSR0000SA0?output_view=pct_1mth).

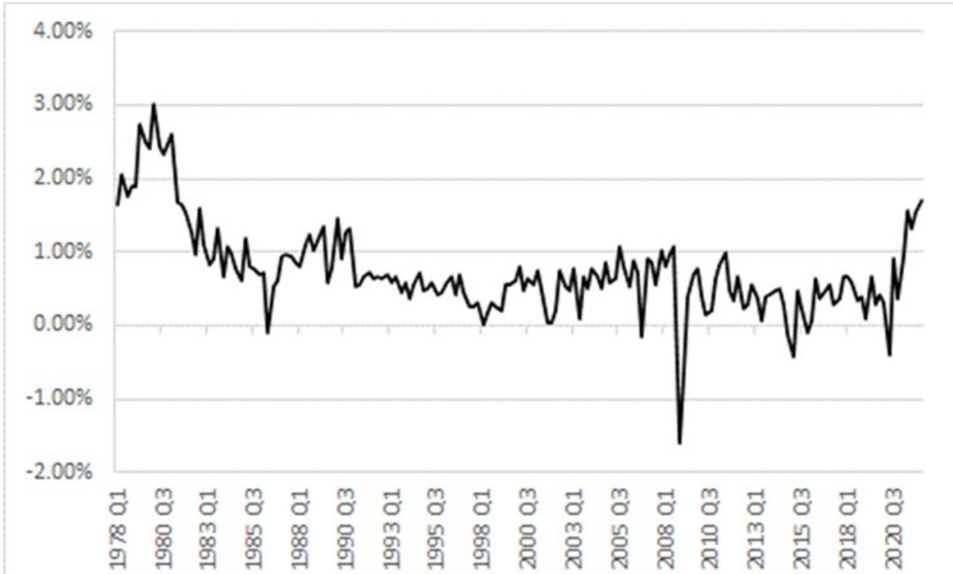
Chart 1: Consumer Price Index Change, 1978-Current[6]



Given the rise in the CPI as shown in Chart 1, even if inflation were to moderate to a degree, it would still remain significantly elevated compared to the last several years and the Fed's inflation target of 2.00%. Further, other measures of inflation such as the Personal Consumption Expenditures Index, which is considered by the Fed to be a better indicator of inflation than the CPI, show quarterly increases higher they have been since the 1980s.

6 Source: Bureau of Labor Statistics, Series Title: All items in U.S. city average, all urban consumers, seasonally adjusted, Series ID: CUSR0000SA0 (https://data.bls.gov/timeseries/CUSR0000SA0?output_view=pct_1mth).

Chart 2: Personal Consumption Expenditures Index Change, 1978-Current[7]



Q. Is inflation expected to be elevated from historical levels moving forward?

A. Yes, it is. The 10-year and 30-year breakeven inflation rates[8] have steadily increased since August 27, 2020, when Fed Chairman Jerome H. Powell released a statement noting that the Federal Open Market Committee ("FOMC") will adopt an approach towards inflation that, "could be viewed as a flexible form of average inflation targeting," meaning that following periods in which inflation has run below 2.00%, "appropriate monetary policy will likely aim to achieve inflation moderately above 2 percent for some time."[9] More recently, Mr. Powell has noted that, "the risk is rising that an extended period of high inflation could push longer-term expectations

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[7] Bureau of Economic Analysis. Table 2.3.4. Price Indexes for Personal Consumption Expenditures by Major Type of Product (https://apps.bea.gov/iTable/iTable.cfm?reqid=19&step=2#reqid=19&step=2&isuri=1&1921=survey).

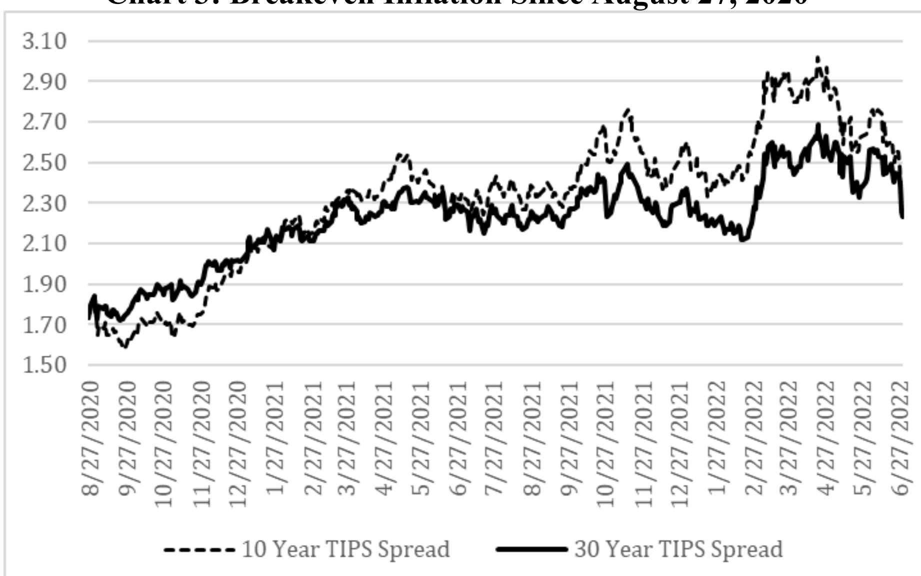
[8] The breakeven inflation rate is the market's determination of the level of inflation during the period it measures. For example, the ten-year breakeven inflation rate is the market's expectation of inflation over the next ten years.

[9] New Economic Challenges and the Fed's Monetary Policy Review, Remarks by Jerome H. Powell, Chair Board of Governors of the Federal Reserve System, August 27, 2020.

uncomfortably higher, which underscores the need for the Committee to move expeditiously as I have described."[10]

In response to market conditions and Fed action, the breakeven inflation rate, represented as the 10-year and 30-year Treasury Inflation-Protected Securities spreads, has increased from 1.73% and 1.76% on August 27, 2020, respectively, to 2.33% and 2.23% respectively, as of June 30, 2022. Further, as shown in Chart 3 below, breakeven inflation has trended upward since the Fed's policy change at a relatively consistent pace.

Chart 3: Breakeven Inflation Since August 27, 2020[11]



Market-based inflation expectations like the breakeven inflation rate are important benchmarks for the Fed. Michelle W. Bowman, Member of the Board of Governors of the Federal Reserve System noted that:

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10 Restoring Price Stability, Chair Pro Tempore Jerome H. Powell, at "Policy Options for Sustainable and Inclusive Growth" 38th Annual Economic Policy Conference National Association for Business Economics, Washington, D.C., March 21, 2022.

11 Source: Federal Reserve (https://www.federalreserve.gov/datadownload/); downloaded on March 18, 2022.

> One important factor that we often point to in driving today's spending decisions and inflation outlook are expectations of future inflation. Near-term expectations tend to rise as current inflation increases, but when inflation expectations over the longer term – the next 5 to 10 years – begin to rise, it may indicate that consumers and businesses have less confidence in the Fed's ability to address higher inflation and return it to the Federal Open Market Committee's (FMOC) goal of 2 percent. If expectations move significantly above our 2 percent goal, it would make it more difficult to change people's perceptions about the duration of high inflation and potentially more difficult to get inflation under control.[12]

Q. Has Chairman Powell made additional comments concerning inflation?

A. Yes, he did. In a statement before the U.S. Senate Committee on Banking, Housing and Urban Affairs, Mr. Powell stated:

> The Fed's monetary policy actions are guided by our mandate to promote maximum employment and stable prices for the American people. My colleagues and I are acutely aware that high inflation imposes significant hardship, especially on those least able to meet the higher costs of essentials like food, housing, and transportation. We are highly attentive to the risks high inflation poses to both sides of our mandate, and we are strongly committed to returning inflation to our 2 percent objective.

> Against the backdrop of the rapidly evolving economic environment, our policy has been adapting, and it will continue to do so. With inflation well above our longer-run goal of 2 percent and an extremely tight labor market, we raised the target range for the federal funds rate at each of our last three meetings, resulting in a 1-1/2 percentage point increase in the target range so far this year. The Committee reiterated that it anticipates that ongoing increases in the target range will be appropriate. In May, we announced plans for reducing the size of our balance sheet and, shortly thereafter, began the process of significantly reducing our securities holdings. Financial conditions have been tightening since last fall and have now tightened significantly, reflecting both policy actions that we have already taken and anticipated actions.

> Over coming months, we will be looking for compelling evidence that inflation is moving down, consistent with inflation returning to 2 percent. We anticipate that ongoing rate increases will be appropriate;

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[12] Michelle W. Bowman, "The Outlook for Inflation and Monetary Policy", At "Executive Officers Conference Massachusetts Bankers Association", Harwich, Massachusetts, June 23, 2022.

> the pace of those changes will continue to depend on the incoming data and the evolving outlook for the economy. We will make our decisions meeting by meeting, and we will continue to communicate our thinking as clearly as possible. Our overarching focus is using our tools to bring inflation back down to our 2 percent goal and to keep longer-term inflation expectations well anchored.[13]

As can be gleaned from statements by members of the Fed, they expect inflation to continue well into next year and that they will continue to use the tools at their disposal to support the economy and the labor market, including accelerating the pace of rate increases of the Fed Funds Rate and the roll off of assets from its balance sheet.

Q. Is the market currently pricing in expectations of significant future Fed Funds Rate increases in line with Chairman Powell's statements?

A. Yes. The CME FedWatch Tool, as presented in Chart 4 below, indicates that a majority of investors are pricing in at least a Fed Funds Rate of 3.50% by the Fed's February 1, 2023 meeting, as compared to the level of the Fed Funds Rate of between 1.50% and 1.75% as of July 25, 2022.

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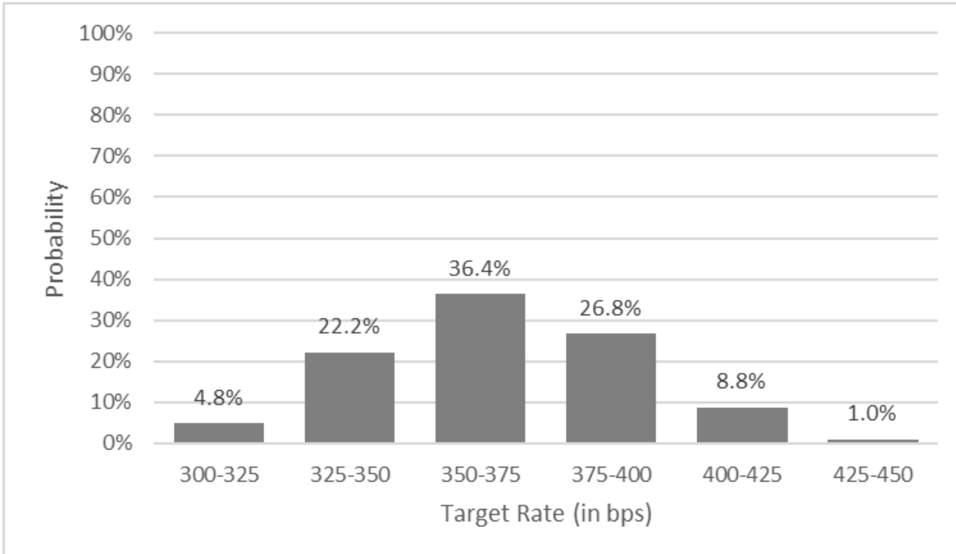
[13] Jerome H. Powell, Statement Before the Committee on Banking, Housing, and Urban Affairs, U.S. Senate, Washington, D.C., June 22, 2022.

Chart 4: CME FedWatch Tool – February 1, 2023 FOMC Meeting[14]



Q. Please summarize your observations of the current market environment.

A. In response to the current inflationary environment, the Fed recently raised the Fed Funds Rate and anticipates additional increases over the next year in addition to rolling off of assets from their balance sheet. Investors have already priced in these actions and prospective actions into market prices. Regardless of current and future actions of the Fed, however, they have acknowledged that inflation is higher than its target average level of 2.00% and will continue to run higher than that target well into 2022 and possibly beyond.

Increasing inflation drives all costs higher (*e.g.*, prices for materials, labor, capital). This is an economic reality that affects companies across the board and ENSTAR is not immune to such increases. As a result, higher inflation increases risk, and the investor-required return for utility investors. In addition, some of the business

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[14] Source: https://www.cmegroup.com/trading/interest-rates/countdown-to-fomc.html, accessed July 25, 2022.

risks (such as ENSTAR's isolated geographic location and operating environment) as discussed later in my testimony and in the direct testimony of ENSTAR witness Mr. John D. Sims may be exacerbated in an inflationary period.

V. GENERAL PRINCIPLES

Q. What general principles have you considered in arriving at your recommended common equity cost rate?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, *i.e.,* the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. 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 the stock. *Cf. Chicago & Grand Trunk R. Co. v. Wellman*, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. 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.[15]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this proceeding, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure their financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, *i.e.*, for the utility operating company at issue in a rate case. Parent entities, 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. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of the source of the funding, public funding or corporate 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

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15 *Hope*, 320 U.S. 591 (1944), at 603.

than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all 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 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, as measured by their combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (*i.e.*, business risk) and financing (*i.e.*, financial risk) of ENSTAR's utility operations on a stand-alone basis.

Q. Within that broad framework, how is the cost of capital estimated in regulatory proceedings?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (*i.e.*, rate base). The fair rate of return for a regulated utility is based on its Weighted Average Cost of Capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in 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 providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. Is the authorized return set in regulatory proceedings guaranteed?

A. No, it is not. The *Hope* and *Bluefield* standards, and the regulatory compact upon which the ratemaking process is based, only require that the utility be afforded a reasonable <u>opportunity</u> to recover its return of, and return on, its prudently incurred investments. It does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (*e.g.*, management performance, operating and maintenance expenses, etc.), there are several factors beyond a utility's control that affect its ability to earn its authorized return.

A. <u>Business Risk</u>

Q. Please define business risk and explain why it is important to the determination of a fair rate of return.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks <u>generally</u> faced by utilities include, but are not limited to: the regulatory environment; mandatory environmental and safety compliance requirements; customer mix and concentration of customers; service territory economic growth; market demand; risks and uncertainties of supply; operations; capital intensity; size; the degree of operating leverage; emerging technologies including distributed energy resources; and the vagaries of weather. All of these business risks have a direct bearing on earnings. Although analysts, including ratings agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. Therefore, it is difficult to specifically and numerically quantify the effect of any individual risk on investors' required return, *i.e.*, the cost of capital. For determining an appropriate return on common equity, the relevant issue is where investors see the subject company as falling within a spectrum of risk. To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. Please define financial risk and explain why it is important in determining a fair rate of return.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (*i.e.*, failure to receive dividends due to default or other covenants). Consequently, as the degree of financial leverage increases, the risk of financial distress (*i.e.*, financial risk) also increases. In essence, even if two firms face the same business risks, a company with meaningfully higher levels of debt in its capital structure is likely to have a higher cost of both debt and equity. Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. Can bond and credit ratings be a proxy for the combined business and financial risks (*i.e.*, investment risk of an enterprise)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (*i.e.*, total risk) faced by bond investors.[16] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a

[16] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, *i.e.*, within the A category, an S&P rating can be at A+, A, or A-. Similarly, risk distinctions for Moody's ratings are distinguished by numerical rating gradations, *i.e.*, within the A category, a Moody's rating can be A1, A2 and A3.

debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

Q. Do rating agencies account for company size in their bond ratings?

A. No. Neither Standard & Poor's ("S&P") nor Moody's Investors Service ("Moody's") have minimum company size requirements for any given rating level. This means, all else equal, a relative size analysis would still need to be performed on companies with similar bond ratings.

VI. CAPITAL STRUCTURE

Q. What capital structure ratios do you recommend be employed in developing an overall fair rate of return appropriate for the Company?

A. I recommend the use of ENSTAR's actual capital structure at December 31, 2021, which consists of 45.89% long-term debt and 54.11% common equity for the Company as shown on page 1 of Schedule 1.

Q. What are the typical sources of capital commonly considered in establishing a utility's capital structure?

A. Common equity and long-term debt are commonly considered in establishing a utility's capital structure because they are the typical sources of capital financing a utility's rate base.

Q. Please explain.

A. Long-lived assets are typically financed with long-lived securities, so that the overall term structure of the utility's long-term liabilities (both debt and equity) closely match the life of the assets being financed. As stated by Brigham and Houston:

> In practice, firms don't finance each specific asset with a type of capital that has a maturity equal to the asset's life. However, academic studies do show that most firms tend to finance short-term assets from short-term sources and long-term assets from long-term sources.[17]

Whereas short-term debt has a maturity of one year or less, long-term debt may have maturities of 30 years or longer. Although there are practical financing constraints, such as the need to "stagger" long-term debt maturities, the general objective is to extend the average life of long-term debt. Still, long-term debt has a finite life, which is likely to be less than the life of the assets included in rate base. Common equity, on the other hand is outstanding into perpetuity. Thus, common equity more accurately matches the life of the going concern of the utility, which is also assumed to operate in perpetuity. Consequently, it is both typical and important for utilities to have significant proportions of common equity in their capital structures.

Q. Why is it important for ENSTAR's actual capital structure, consisting of 45.89% long-term debt and 54.11% common equity, be authorized in this proceeding?

A. In order to provide safe, reliable, and affordable service to its customers, ENSTAR must meet the needs and serve the interests of its various stakeholders, including customers, shareholders, and bondholders. The interests of these stakeholder groups are aligned with maintaining a healthy balance sheet, strong credit ratings, and a supportive regulatory environment, so that the Company has access to capital on reasonable terms in order to make necessary investments.

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[17] Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, Concise 4th Ed., Thomson South-Western, 2004, at 574.

Safe and reliable service cannot be maintained at a reasonable cost if utilities do not have the financial flexibility and strength to access the competitive markets on reasonable terms. The authorization of a capital structure other than the Company's actual capital structure will weaken its financial condition and adversely impact the Company's ability to address expenses and investment, to the detriment of customers and shareholders. Safe and reliable service for customers cannot be sustained over the long term if the interests of shareholders and bondholders are minimized such that the public interest is not optimized.

Q. How does the regulatory environment in which a utility operates affect its access to, and cost of, capital?

A. The regulatory environment can significantly affect both the access to, and cost of, capital in several ways. The proportion and cost of debt capital available to utility companies are both influenced, in large part, by the rating agencies' assessment of the regulatory environment. In other words, the Company's credit rating and outlook depend substantially on the extent to which rating agencies view the regulatory environment as credit supportive, or not. In fact, Moody's finds the regulatory environment to be so important that 50.00% of the factors that weigh in the Company's ratings determination are dependent on the nature of regulation.[18] Similarly, S&P has noted that:

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[18] Moody's Investors Service, *Rating Methodology; Regulated Gas and Electric Utilities*, June 23, 2017, at 4.

> The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most.[19] (emphasis added)

The regulatory environment is thus one of the most important factors considered by both debt and equity investors in assessing the risks and prospects of utility companies. From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow necessary to meet its near-term financial obligations, make the capital investments needed to maintain and expand its system, and maintain sufficient levels of liquidity to fund unexpected events.

Moreover, because fixed income investors have many investment alternatives, even within a given market sector, 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. From the perspective of equity investors, the authorized return must be sufficient to provide a risk-comparable return on the equity portion financing the Company's capital investments. Authorization of a capital structure that is not representative of ENSTAR's actual capital structure could be a signal to the investment community that the Commission is not constructive from an investor standpoint, which could lead to increased borrowing costs in the future.

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[19] Standard & Poor's, *Utilities: Assessing U.S. Utility Regulatory Environments*, November 15, 2011, at 1.

Q. How does your proposed ratemaking common equity ratio of 54.11% for ENSTAR compare with the common equity ratios maintained by the Utility Proxy Groups?

A. In order to assess the reasonableness of the Company's requested ratemaking common equity ratio, I reviewed the actual common equity ratios maintained by the comparable companies within the Utility Proxy Group. The Company's requested ratemaking common equity ratio of 54.11% is reasonable and consistent with the range of common equity ratios maintained by the Utility Proxy Group. As shown on Schedule 2, the range of five-quarter average common equity ratios of the utilities that comprise my Utility Proxy Group range from 29.81% to 60.05%.[20] The Company's actual capital structure demonstrates both the reasonableness of using it to set rates and the Company's relative financial health. Setting the WACC as requested by the Company will continue to support the long-term financial health of the Company for the benefit of all of its stakeholders, including its customers.

VII. ENSTAR AND THE UTILITY PROXY GROUP

Q. Are you familiar with ENSTAR's operations?

A. Yes. ENSTAR functions as a natural gas transmission utility, which serves large users such as power generation facilities, natural gas producers, and the Fairbanks distribution utility, and as a natural gas local distribution utility, providing service to more than 150,000 customers in Southcentral Alaska. Because ENSTAR is a hybrid transmission and distribution utility operating in a unique environment, it is difficult to

[20] Excluding securitized debt relating to Winter Storm Uri.

find comparable gas utilities with a similar risk profile. In establishing my proxy group, I have considered the hybrid nature of ENSTAR and have developed a proxy group that, on balance, is indicative of ENSTAR's diverse operational characteristics. It is important to note, however, that even the hybrid proxy group does not fully encompass the risk factors unique to ENSTAR, all of which must be considered.

Q. Why is it necessary to develop a proxy group when estimating the ROE for ENSTAR?

A. Because ENSTAR is not publicly traded and does not have publicly-traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for ENSTAR. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, share key fundamental risks with ENSTAR: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.[21]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses and

[21] The development of the Non-Price Regulated Proxy Group is explained in more detail below.

necessarily must consider the sort of quantitative and qualitative information discussed throughout my direct testimony. Additionally, a relative risk analysis between ENSTAR and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group's indicated results.

My analyses are based on the Utility Proxy Group containing U.S. gas transmission and natural gas distribution companies. As discussed earlier, utilities must compete for capital with other companies with commensurate risk (including non-utilities) and, to do so, must be provided the opportunity to earn a fair and reasonable return. Consequently, it is appropriate to consider the Utility Proxy Group's market data in determining ENSTAR's ROE.

Q. Please explain how you chose your Utility Proxy Group of comparable companies for ENSTAR.

A. As discussed above, ENSTAR operates as both a gas transmission and a gas distribution utility, the risks of which are materially different from a typical natural gas local distribution company. Because of this, a proxy group containing some regulated transmission operations is appropriate for calculating ENSTAR's cost of capital. Because of this reason, I determined the Utility Proxy Group as discussed below.

The basis of selection for the Utility Proxy Group was to select those companies that meet the following criteria:

1) they are included in one of the following groups as reported by *Value Line Standard Edition* ("*Value Line*"): Natural Gas Utility, Natural Gas Diversified, Oil and Gas Distribution, or Pipeline MLPs;

2) they have 40% or greater of 2021 total operating income derived from, <u>or</u> 40% or greater of 2021 total assets devoted to, regulated operations;

3) At the time of the preparation of this direct testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (*i.e.*, one publicly-traded utility merging with or acquiring another);

4) they have not cut or omitted their common dividends during the past five years through the time of the preparation of this direct testimony;

5) they have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Beta coefficients;

6) they have a positive *Value Line* five-year dividends per share ("DPS") growth rate projection; and

7) they have *Value Line*, Zacks, Bloomberg, or Yahoo! Finance, consensus five-year earnings per share ("EPS") growth rate projections.

The following twelve companies met these criteria: Atmos Energy Corporation, Kinder Morgan, Inc., MDU Resources Group, Inc., National Fuel Gas Company, New Jersey Resources Corporation, NiSource, Inc., Northwest Natural Holding Company, ONE Gas, Inc., ONEOK, Inc., Spire Inc., TC Energy Corporation, and The Williams Companies, Inc.

VIII. COMMON EQUITY COST RATE MODELS

Q. Is it important that cost of common equity models be market-based?

A. Yes. As discussed previously, regulated public utilities, like the Company, must compete for equity in capital markets along with all other companies with commensurate risk, including non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies with comparable risk, they will choose the company providing a higher return over a company providing a lower return.

Q. Are your cost of common equity models market-based models?

A. Yes. The DCF model is market-based because market prices are used in developing the dividend yield component of the model. The RPM is market-based because the bond ratings and expected bond yields used in the application of the RPM reflect the market's assessment of bond/credit risk. In addition, the use of Beta coefficients to determine the equity risk premium reflects the market's assessment of market/systematic risk since Beta coefficients are derived from regression analyses of market prices. The Predictive Risk Premium Model ("PRPM") uses monthly market returns in addition to expectations of the risk-free rate. The CAPM is market-based for many of the same reasons that the RPM is market-based (*i.e.*, the use of expected bond yields and Beta coefficients). Selection of the comparable risk non-price regulated companies is market-based because it is based on statistics which result from regression analyses of market prices and reflect the market's assessment of total risk.

Q. What analytical approaches did you use to determine the Company's ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I applied to the Utility Proxy Group described above. I also applied these same models to Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while risk premium-based methods (*i.e.*, the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Groups adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

The use of multiple models also makes intuitive sense when we consider that market prices are set by the buying and selling behavior of multiple investors, whose circumstances, objectives, and constraints vary over time and across market conditions. We cannot assume a single method is the best measure of the factors motivating those decisions for all investors at all times. Giving undue weight to a single method runs the very real risk of ignoring important information provided by other methods.

In other words, no single model is more reliable than all others under all market conditions. Intuition suggests it is more appropriate to use as many methods as we reasonably can, and to reflect the many factors motivating investment decisions as best we can. In this instance, intuition, financial theory,[22] and financial practice reach a common conclusion: we should apply and reasonably consider multiple methods when estimating the ROE.

A. Discounted Cash Flow Model

Q. What is the theoretical basis of the DCF model?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from cash flows received in the form of dividends plus appreciation in market price (the expected growth rate). Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate, *i.e.*, the total common equity return rate expected by investors, as shown in Equation [1] below:

$$K_e = (D_0\,(1+g))/P + g$$

Where: K_e = the required Return on Common Equity;

D_0 = the annualized Dividend Per Share;

P = the current stock price; and

G = the growth rate.

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[22] As Brigham and Gapenski explain: "Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate [the ROE]. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive – no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand." Eugene F. Brigham, Louis C. Gapenski, *Financial Management, Theory and Practice*, 7th ed., The Dryden Press, 1994, at 341.

Q. Which version of the DCF model did you use?

A. I used the single-stage constant growth DCF model in my analyses.

Q. Please describe the dividend yield you used in your application of the DCF model.

A. The unadjusted dividend yields are based on the proxy company's dividend as of June 30, 2022, divided by the average of closing market prices for the 60 trading days ending June 30, 2022.[23]

Q. Please explain your adjustment to the dividend yield.

A. Because dividends are paid periodically (*e.g.*, quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for the use of the full growth rate, or D_1, in calculating the dividend yield component of the model. Since the companies in the Utility and Non-Price Regulated Proxy Groups increase their quarterly dividend at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, my adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1 on page 1 of Schedule 3 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 5.

Q. Please explain the basis of the growth rates you applied to your Utility Proxy Group in your DCF model.

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[23] Schedule 3, page 1, Column 1.

A. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations and ever changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, the use of earnings growth rates in a DCF analysis provides a better matching between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. Please summarize the DCF model results.

A. As shown on page 1 of Schedule 3, the mean result of the application of the single-stage DCF model is 11.85%, the median result is 10.73%, and the average of the two is 11.29% for the Utility Proxy Group. In arriving at a conclusion for the DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF. This approach takes into consideration all the proxy companies' results while mitigating the high and low outliers of those individual results.

B. The Risk Premium Model

Q. Please describe the theoretical basis of the RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from investment in bonds, to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity return cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings in the event of a liquidation.

Q. Please explain how you derived your indicated cost of common equity based on the RPM.

A. To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the PRPM and the second method was a risk premium model using a total market approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

C. <u>The Predictive Risk Premium Model</u>

Q. Please explain the PRPM.

A. The PRPM, published in the *Journal of Regulatory Economics*,[24] was developed from the work of Robert F. Engle who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility ("ARCH")[25]". Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that the volatility in prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by the prediction of volatility or risk. The PRPM is not based on an <u>estimate</u> of investor behavior, but rather on the evaluation of the results of that behavior (*i.e.*, the variance of historical equity risk premiums).

The inputs to the model are the historical returns on the common shares of each company in the Utility Proxy Groups minus the historical monthly yield on long-term U.S. Treasury securities through June 2022. Using a generalized form of ARCH, known as GARCH, I calculated each of the Utility Proxy Groups' company's projected equity risk premium using Eviews© statistical software. When the GARCH Model is applied to the historical return data, it produces a predicted GARCH variance series[26]

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24 Autoregressive conditional heteroscedasticity. *See*, *A New Approach for Estimating the Equity Risk Premium for Public Utilities*, Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, Ph.D. *The Journal of Regulatory Economics* (December 2011), 40:261-278.

25 www.nobelprize.org

26 Illustrated on Columns 1 and 2 of page 2 of Schedule 4.

and a GARCH coefficient.[27] Multiplying the predicted monthly variance by the GARCH coefficient and annualizing it[28] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury Bond yield, 3.74%,[29] to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury yield is a consensus forecast derived from the *Blue Chip Financial Forecasts* ("*Blue Chip*").[30]

Q. What are the results of the PRPM?

A. As shown on page 2 of Schedule 4, the mean PRPM indicated common equity cost rate for the Utility Proxy Group is 13.63%, the median is 13.94%, and the average of the two is 13.79%. Consistent with my reliance on the average of the median and mean results of the DCF, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 13.79%.

D. <u>The Total Market Approach RPM</u>

Q. Please explain the total market approach RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: 1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium; and 2) an equity risk premium based on the S&P Utilities Index.

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27 Illustrated on Column 4 of page 2 of Schedule 4.

28 Annualized Return = (1+Monthly Return)^12 - 1

29 *See,* Column 6 of page 2 of Schedule 4.

30 *Blue Chip Financial Forecasts*, July 1, 2022, at 2 and June 1, 2022 at 14.

Q. Please explain the basis of the expected bond yield of 5.77% applicable to the Utility Proxy Group.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital (including common equity cost rate), are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the fourth calendar quarter of 2023, and the long-term projections for 2024 to 2028 and 2029 to 2033. As shown on line 1 of page 3 of Schedule 4, the average expected yield on Moody's Aaa-rated corporate bonds is 5.00%. To derive an expected yield on Moody's A2-rated public utility bonds, I made an upward adjustment of 0.60%, which represents the recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds, and converts the expected Aaa-rated corporate bond yield to an equivalent Moody's A2-rated public utility bond.[31] Adding the recent 0.60% spread between Aaa-rated corporate and A2-rated public utility bond yields to the expected Aaa-rated corporate bond yield of 5.00% results in an expected A2-rated public utility bond of 5.60%. Since the Utility Proxy Group's average Moody's long-term issuer ratings is A3/Baa1, another adjustment to the expected A2-rated public utility bond yield is needed to reflect the difference in bond ratings. An upward adjustment of 0.17%, which represent one-half of a recent spread between A2 and Baa2 public utility bond yields, respectively, are necessary to make the A2 prospective bond yield applicable to

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[31] As shown on line 2 and explained in note 2 on page 3 of Schedule 4.

A3/Baa1 public utility bonds.[32] Adding the 0.17% to the 5.60% prospective A2 public utility bond yield results in a 5.77% expected bond yield for the Utility Proxy Group.

Table 3: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[33]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip)*	5.00%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.60%
Adjustment to Reflect A3/Baa1 Average Rating of Utility Proxy Group	0.17%
Prospective Bond Yield Applicable to the Utility Proxy Group	5.77%

Q. Please explain the derivation of the Beta-derived equity risk premium.

A. The components of the beta-derived risk premium model are: 1) an expected market equity risk premium over corporate bonds and 2) the Beta coefficient. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Groups is shown on lines 1 through 9 of page 8 of Schedule 4. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

Q. How did you derive a market equity risk premium based on long-term historical data?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the *Stocks, Bonds, Bills, & Inflation*

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32 As shown on line 4 and explained in note 3 on page 3 of Schedule 4.

33 As shown on page 3 of Schedule 4.

("SBBI") Yearbook 2022 ("*SBBI – 2022*")[34] less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2021. Using holding period returns over a very long period of time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, *i.e.*, a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks is 12.11% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds is 5.98%.[35] As shown on line 1 on page 8 of Schedule 4, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 6.13%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa-rated corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in *SBBI – 2022*.[36] Using arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of

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[34] Morningstar SBBI Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2021.

[35] As explained in note 1 on page 8 of Schedule 4.

[36] *SBBI – 2021*, at 200-201.

change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. Please explain the derivation of the regression-based market equity risk premium.

A. To derive the regression-based market equity risk premium of 7.32% shown on line 2, page 8 of Schedule 4, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

where:

RP = the market equity risk premium;

α = the regression intercept coefficient;

β = the regression slope coefficient; and

$R_{Aaa/Aa}$ = the Moody's Aaa/Aa rated corporate bond yield.

Using the equation generated by the regression, an expected equity risk premium of 7.32% is calculated using the average forecast of Aaa corporate bond yield of 5.00%, as discussed above.

Q. Please explain the derivation of the PRPM market equity risk premium.

A. I used the same PRPM approach described previously to develop the PRPM equity risk premium estimate. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Aaa/Aa-rated corporate bonds during the period from January 1928 through June 2022. Using the previously discussed generalized form of ARCH, known as GARCH, the market's projected equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 8.22%.[37]

Q. Please explain the derivation of a projected equity risk premium based on *Value Line* Summary & Index data for your RPM analysis.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is essential. The derivation of the forecasted or prospective market equity risk premium can be found in note 4 on page 8 of Schedule 4. Consistent with the premise that income returns plus capital appreciation equals total returns, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* Summary & Index for the 13 weeks ended July 1, 2022, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line*.[38]

The average median expected price appreciation is 62%, which translates to a 12.82% annual appreciation, and, when added to the average of *Value Line's* median

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37 Shown on line 3 on page 8 of Schedule 4.

38 As explained in detail in note 1 of Schedule 5.

expected dividend yields of 2.04%, equates to a forecasted annual total return rate on the market as a whole of 14.86%. The forecasted Aaa-rated corporate bond yield of 5.00% is deducted from the total market return of 14.86%, resulting in an equity risk premium of 9.86%, shown on page 8 line 4 of Schedule 4.

Q. Please explain the derivation of an equity risk premium based on the S&P 500 companies.

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 16.54%. Subtracting the prospective yield on Aaa-rated corporate bonds of 5.00% results in an 11.54% projected equity risk premium.

Q. Please explain the derivation of an equity risk premium based on Bloomberg data.

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for capital appreciation, identical to the method described above. The expected total return for the S&P 500 is 12.64%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.00% results in a 7.64% projected equity risk premium.

Q. What is your conclusion of a Beta-derived equity risk premium for use in your RPM analysis?

A. I gave equal weight to all six equity risk premiums based on each source – historical, *Value Line*, and Bloomberg – in arriving at an 8.45% equity risk premium.

Table 4: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[39]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2021)	6.13%
Regression Analysis on Historical Data	7.32%
PRPM Analysis on Historical Data	8.22%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	9.86%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected Aaa Corporate Bond Yields	11.54%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields	7.64%
Average	8.45%

After calculating the average market equity risk premium of 8.45%, I adjusted it by beta to account for the risk of the Utility Proxy Group. As discussed below, the Beta coefficient is a meaningful measure of prospective relative risk to the market as a whole and is a logical way to allocate a company's or proxy group's share of the market's total equity risk premium relative to corporate bond yields. As shown on Schedule 5, the average of the mean and median Beta coefficients for the Utility Proxy Group is 0.83. Multiplying the Beta coefficient of 0.83 by the market equity risk premium of 8.45% results in a beta-adjusted equity risk premium of 7.01%.

[39] As shown on page 8 of Schedule 4.

Q. How did you derive the equity risk premium based on the S&P Utility Index and Moody's A2-rated public utility bonds?

A. I estimated three equity risk premiums based on the S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utility Index. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.74% and monthly A-rated public utility bond yields of 6.46% from 1928 to 2021 to arrive at an equity risk premium of 4.28%[40]. I then used the same historical data to derive an equity risk premium of 5.03% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to June 2022 to arrive at a PRPM-derived equity risk premium of 5.55% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 11.04% and 9.93% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 5.60%[41], which resulted in equity risk premiums of 5.44% and 4.33%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source (*i.e.*, historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 4.93%.

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[40] As shown on line 1, page 11 of Schedule 4.

[41] Derived on line 3, page 3 of Schedule 4.

Table 5: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[42]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2021)	4.28%
Regression Analysis on Historical Data	5.03%
PRPM Analysis on Historical Data	5.55%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P Utilities Index less Projected A2 Utility Bond Yields	5.44%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields	4.33%
Average	4.93%

Q. How did you derive an equity risk premium of 4.86% based on authorized ROEs for gas distribution utilities?

A. The equity risk premium of 4.86% shown on line 3, page 7 of Schedule 4 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A-rated public utility bonds. That analysis is shown on page 12 of Schedule 4 which contains the graphical results of a regression analysis of 810 rate cases for gas distribution utilities which were fully litigated during the period from January 1, 1980 through June 30, 2022. It shows the implicit equity risk premium relative to the yields on A-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with

[42] As shown on page 11 of Schedule 4.

financial literature on the subject.[43] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds of 5.60%. Given the expected A-rated utility bond yield of 5.60%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.86%.

Q. What is your conclusion of an equity risk premium for use in your total market approach RPM analysis?

A. The equity risk premium I applied to the Utility Proxy Group is 5.60% which is the average of the beta-derived equity risk premium, S&P Utility Index equity risk premium, and the authorized return equity risk premium of 7.01%, 4.93%, and 4.86%, respectively.[44]

Q. What is the indicated RPM common equity cost rate based on the total market approach?

A. As shown on line 7, page 3, of Schedule 4, I calculated a common equity cost rate of 11.37% for the Utility Proxy Group.

Table 6: Summary of the Total Market Return Risk Premium Model[45]

Prospective Moody's Utility Bond Applicable to the Utility Proxy Group	5.77%
Prospective Equity Risk Premium	5.60%
Indicated Cost of Common Equity	11.37%

[43] *See*, *e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, *Journal of Applied Finance*, Vol. 11, No. 1, 2001, at pages 11 to 12; 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.

[44] As shown on page 7 of Schedule 4.

[45] As shown on page 3 of Schedule 4.

Q. What are the results of your application of the PRPM and the total market approach RPM?

A. As shown on page 1 of Schedule 4, the indicated RPM-derived common equity cost rate for the Utility Proxy Group is 12.58%,[46] which gives equal weight to the PRPM (13.79%) and the adjusted market approach results (11.37%).

E. The Capital Asset Pricing Model

Q. Please explain the theoretical basis of the CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the Beta coefficient ("β"). A Beta coefficient less than 1.0 indicates lower variability than the market as a whole, while a Beta coefficient greater than 1.0 indicates greater variability than the market.

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. In addition, the CAPM presumes that investors require compensation only for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the Beta coefficient. The traditional CAPM model is expressed as:

---

46 12.58% = (13.79%+11.37%)/2.

$$R_s = R_f + \beta(R_m - R_f)$$

Where: R_s = Return rate on the common stock;

R_f = Risk-free rate of return;

R_m = Return rate on the market as a whole; and

β = Adjusted Beta coefficient (volatility of the security relative to the market as a whole).

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the Beta coefficient is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[47]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low." [48]

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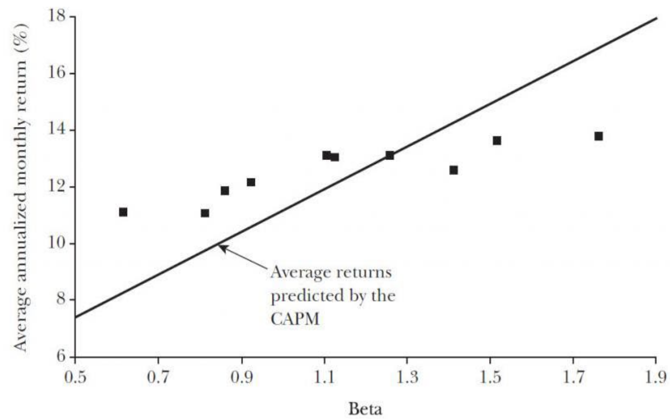
[47] Roger A. Morin, *Modern Regulatory Finance* (Public Utility Reports, Inc., 2021) 205-209. ("Morin")

[48] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004 at 33. ("Fama & French")

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. 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.[49]
>
> * * *
>
> 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 [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [50]

Fama and French provide similar support for the ECAPM when they state:

[49] Morin, at 207.

[50] Morin, at 221.

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[51]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[52]

Clearly, the justification from Morin, Fama, and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Groups and averaged the results.

Q. What Beta coefficients did you use in your CAPM analysis?

A. For the Beta coefficients in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg. While both of those services adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00, *Value Line* calculates the Beta coefficient over a five-year period, while Bloomberg calculates it over a two-year period.

Q. Please describe your selection of a risk-free rate of return.

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[51] Fama & French, at 32.

[52] Fama & French, at 33.

A. As shown in column 5 on page 1 of Schedule 5, the risk-free rate adopted for both applications of the CAPM is 3.74%. This risk-free rate of 3.74% is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the fourth calendar quarter of 2023 and long-term projections for the years 2024 to 2028 and 2029 to 2033.

Q. Why is the yield on long-term U.S. Treasury Bonds appropriate for use as the risk-free rate?

A. The yield on long-term U.S. Treasury Bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A-rated public utility bonds, the long-term investment horizon inherent in utilities' common stocks, and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (*i.e.*, cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

More specifically, the term of the risk-free rate used for cost of capital purposes should match the life (or duration) of the underlying investment (*i.e.*, perpetuity). As noted by Morningstar:

> The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year

> Treasury note would not be appropriate since the company will continue to exist beyond those five years.[53]

Morin also confirms this when he states:

> [b]ecause common stock is a long-term investment and because the cash flows to investors in the form of dividends last indefinitely, the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM (footnote omitted)… The expected common stock return is based on long-term cash flows, regardless of an individual's holding time period.[54]

Pratt and Grabowski recommend a similar approach to selecting the risk-free rate: "[i]n theory, when determining the risk-free rate and the matching ERP you should be matching the risk-free security and the ERP with the period in which the investment cash flows are expected."[55] As a practical matter, equity securities represent a perpetual claim on cash flows; 30-year Treasury bonds are the longest-maturity securities available to approximate that perpetual claim.

Q. Please explain the estimation of the expected equity risk premium for the market used in your CAPM analyses.

A. The basis of the market risk premium is explained in detail in note 1 on page 2 of Schedule 5. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

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53 Morningstar, Inc., *2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook*, at 44.

54 Morin, at 169.

55 Shannon Pratt and Roger Grabowski, *Cost of Capital: Applications and Examples*, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. "ERP" is the Equity Risk Premium.

The long-term income return on U.S. Government securities of 5.02% was deducted from the *SBBI - 2022* monthly historical total market return of 12.37%, which results in an historical market equity risk premium of 7.35%.[56] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from *SBBI – 2022*. That regression analysis yielded a market equity risk premium of 8.89%. The PRPM market equity risk premium is 9.21% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through June 2022.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 3.74%, discussed above, from the *Value Line* Summary & Index projected total annual market return of 14.86%, resulting in a forecasted total market equity risk premium of 11.12%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the projected risk-free rate of 3.74% from the projected total return of the S&P 500 of 16.54%. The resulting market equity risk premium is 12.80%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 3.74% from the projected total return of the S&P 500 of 12.64%. The resulting market equity risk premium is 8.90%.

These six measures, when averaged, result in an average total market equity risk premium of 9.71%.

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56 *SBBI - 2022*, at 256-258, 274-276.

Table 7: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[57]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2021)	7.35%
Regression Analysis on Historical Data	8.89%
PRPM Analysis on Historical Data	9.21%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	11.12%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected 30-Year Treasury Bond Yields	12.80%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields	8.90%
Average	9.71%

Q. What are the results of your application of the traditional and empirical CAPM to the Utility Proxy Group?

A. As shown on page 1 of Schedule 5, the mean result of the Utility Proxy Group CAPM/ECAPM analyses is 12.14%, the median is 11.80% and the average of the two is 11.97%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate for the Utility Proxy Group using the CAPM/ECAPM is 11.97%.

F. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM and CAPM

Q. Why did you also consider a proxy group of domestic, non-price regulated companies?

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[57] As shown on page 2 of Schedule 5.

A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for the competition of the marketplace, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. I believe that the basis of the selection of such domestic, non-price regulated competitive firms theoretically and empirically results in proxy groups which are comparable in total risk to the Utility Proxy Group.

Q. How did you select non-price regulated companies that are comparable in total risk to the utility proxy group?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the Beta coefficients and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (*i.e.*, five years). Using these selection criteria results in a proxy group of 53 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in the selection of the domestic, non-price regulated firms were:

1) They must be covered by *Value Line*;
2) They must be domestic, non-price regulated companies, *i.e.*, non-utilities;
3) Their Beta coefficients must lie within plus or minus two standard deviations of the average unadjusted Beta coefficient of the Utility Proxy; and

4) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted Beta coefficients must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Beta coefficients are a measure of market, or systematic, risk which is not diversifiable. The residual standard errors of the regressions were used to measure each firm's company-specific, diversifiable risk. Companies that have similar Beta coefficients <u>and</u> similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. Have you prepared a schedule which shows the data from which you selected the domestic, non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. Yes, the basis of my selection and my proxy group's regression statistics are shown in Schedule 6.

Q. Did you calculate common equity cost rates using the DCF, RPM, and CAPM for the Non-Price Regulated Proxy Group?

A. Yes. Because the DCF, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM where I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual companies.

Page 2 of Schedule 7 contains the derivation of the DCF cost rates. As shown, the indicated common equity cost rate using the DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group is 12.45%.

Pages 3 through 5 of Schedule 7 contain the data and calculations that support the 14.06% RPM cost rate for the Non-Price Regulated Proxy Group. As shown on line 1, page 3 of Schedule 7, the consensus prospective yield on Moody's Baa2-rated corporate bonds for the six quarters ending in the fourth quarter of 2022, and for the years 2024 to 2028 and 2029 to 2033, is 6.03%.[58] Since the Non-Price Regulated Proxy Groups have average Moody's long-term issuer ratings of Baa2, no adjustment to the projected Baa2-rated corporate bond yield is necessary.

When the beta-adjusted risk premium of 8.03%[59] relative to the Non-Price Regulated Proxy Group is added to the prospective Baa2-rated corporate bond yield of 6.03%, results in an indicated RPM cost rate of 14.06%.

Page 6 of Schedule 7 contains the inputs and calculation that support my indicated CAPM/ECAPM cost rate of 13.03% for the Non-Price Regulated Proxy Group.

Q. What is the cost rate of common equity based on the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group?

A. As shown on page 1 of Schedule 7, the results of the DCF, RPM, and CAPM applied to the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group are 12.45%, 14.06% and 13.03%, respectively. The average of the mean and median of these models is 13.11%, which I used as the indicated common equity cost rate for the Non-Price Regulated Proxy Group.

58 *Blue Chip Financial Forecasts*, June 1, 2022, at 14, and July 1, 2022 at 2.

59 Derived on page 5 of Schedule 7.

IX. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

Q. What is the indicated common equity cost rate range before adjustments?

A. By applying multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, the indicated range for the cost of common equity before any relative risk adjustments is from 11.70% to 12.70% for ENSTAR. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate range, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

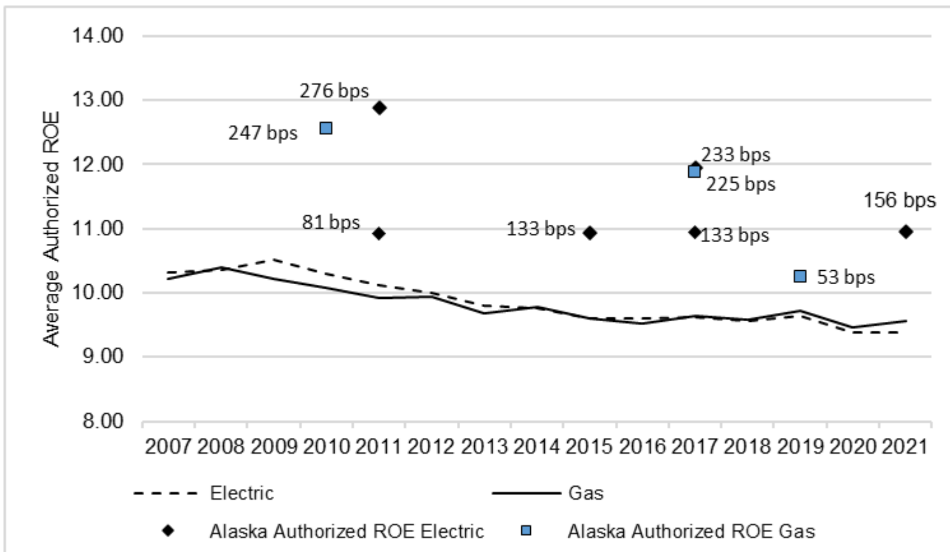
As discussed previously, after determining the indicated range of ROEs attributable to a comparable group, there must be an evaluation of relative risk between that group and the target company to determine whether it is appropriate to apply adjustments to the comparable group's indicated ROE to better reflect the target company's specific risks.

X. ADJUSTMENTS TO THE COST OF COMMON EQUITY

Q. Has the Commission routinely authorized ROEs in Alaska that are higher than those awarded in other states?

A. Yes. Given certain business risks faced by utilities in the state, an "Alaska Premium" is routinely applied by the Commission as compared to utilities operating in the Lower 48. For example, in U-16-066, ENSTAR's last rate case, the Commission stated in Order U-16-066(19) that ENSTAR faced unique business risks, including but not limited to, ENSTAR's operations that include both transmission and distribution assets, operating in an isolated geographic environment under relatively harsh conditions, significant gas supply risk, and ENSTAR's smaller size relative to the proxy group companies.[60] As shown in Chart 5 below, since 2007, authorized ROEs in Alaska have been between 53 basis points to 276 basis points higher than the average for the U.S., for both electric and natural gas utilities.

Chart 5: Alaska Authorized ROEs vs Average U.S. Authorized ROEs[61]



That being said, the Company is not requesting the addition of a blanket "Alaska Premium," but rather to be fairly evaluated on the specific risks facing ENSTAR that are mentioned above and discussed in Mr. Sims' direct testimony.

Q. Does ENSTAR still face the unique business risks as described by the Commission in Order U-16-066?

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60 Order U-16-066(19) at 50-52, dated Sept. 22, 2017.

61 Source: Regulatory Research Associates.

A. Yes. Based on my understanding of the Company's operations and the testimony of ENSTAR witnesses Mr. Sims, Ms. Inna B. Johansen, and Mr. Daniel M. Dieckgraeff, ENSTAR faces the same business risks that it faced in its last rate case making it incrementally riskier from an investor standpoint as compared to the other companies in the Utility Proxy Group.

Q. Please summarize the business risks faced by ENSTAR.

A. There are three primary business risks faced by ENSTAR when compared to the Utility Proxy Group. They are as follows:

- Remote Geographic Location & Harsh Operating Environment – as compared to the companies in the Utility Proxy Group, ENSTAR operates in a location that results in geographical isolation from the supply chains found in the rest of the country. Specialized materials required for capital and maintenance projects take significantly longer to acquire. Further, ENSTAR's isolation results in a shortage of qualified personnel to operate its facilities. As described in further detail in Mr. Sims' direct testimony, this risk has been amplified by both COVID-19 and the geopolitical instability in the world.
- Lack of Diversity in Gas Supply - the gas supply required for ENSTAR's operations is entirely dependent on supply from the Cook Inlet, and there are no alternative pipeline systems to transport natural gas to its facilities. This isolation is particularly risky because there is a risk that supply will not be available as needed. If this occurs, the Company's remote location becomes a compounding factor if gas needs to be imported from an outside

source or if ENSTAR constructs a pipeline to a new source. As described in the direct testimony of Mr. Sims and Ms. Johansen, the risk is even more relevant now than it was in ENSTAR's last rate case given the largest producer in the Cook Inlet has cast further uncertainty on the availability of natural gas in the future.

- Small Size - as discussed in my qualitative and quantitative analysis below, ENSTAR's small size relative to the Utility Proxy Group presents increased risk.

For the reasons stated above, and other reasons such as weather fluctuations, declining use per customer, and operations consisting of both transmission and distribution operations, it is my opinion that ENSTAR faces unique risks relative to my Utility Proxy Group at this time.

Q. Does the Company's smaller size relative to the Utility Proxy Group companies increase its business risk?

A. Yes. As a preliminary matter, because I have developed my cost of common equity recommendation for ENSTAR's operations based on market data applied to the Utility Proxy Group of risk-comparable companies, in order to assess ENSTAR's risk associated with the relatively small size of its operations, it is necessary to compare ENSTAR's size relative to the Utility Proxy Group. ENSTAR's smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for ENSTAR because, all else being equal, size has a material bearing on risk.

At a high level, size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings.

For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a smaller company than on a bigger company with a larger, more diverse, customer base.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll's *Cost of Capital Navigator: U.S. Cost of Capital Module* ("Kroll") 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 Premiums," Kroll 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.[62]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 38, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[63]

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[62] Kroll, *Cost of Capital Navigator: U.S. Cost of Capital Module*, Size as a Predictor of Returns, at 1 (footnote omitted) (emphasis in original).

[63] Fama & French, at 25-43.

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[64] As Eugene Brigham states in another well-known treatise:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms**.[65]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of the Company, including its small relative size, which is justified and supported above by evidence in the financial literature.

Q. Is there a way to quantify a relative risk adjustment due to the Company's increased business risk relative to the Utility Proxy Group?

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[64] Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance* (McGraw-Hill Book Company, 1996), at 204-205, 229.

[65] Eugene F. Brigham, *Fundamentals of Financial Management, Fifth Edition* (The Dryden Press, 1989), at 623 (emphasis added).

A. Yes, there is a method that can be used to quantify the relative risk of ENSTAR to the companies in the Utility Proxy Group as to size. In the absence of other empirical methods, I compared ENSTAR's and the Utility Proxy Group's relative size, as measured by an estimated market capitalization for ENSTAR.

Table 8: Size as Measured by Market Capitalization for the Company and the Utility Proxy Groups

	Market Capitalization (1) ($ Millions)	Times Greater than the Company
ENSTAR	$387.204	
Utility Proxy Group	$18,316.567	47.3x
(1) From page 1 of Schedule 8		

ENSTAR's estimated market capitalization was $387.204 million based on the assumed market-to-book ratio of the Utility Proxy Group, respectively, as of June 30, 2022, compared with the market capitalization of the average company in the Utility Proxy Group of $18.3 billion on June 30, 2022, or 47.3 times the size of ENSTAR's estimated market capitalization, respectively.

As a result, it is necessary to upwardly adjust the ranges of indicated common equity cost rates to reflect the Company's greater risk due to its smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2021 period. The size decile applicable to the Utility Proxy Group is the second decile, while ENSTAR's market capitalizations place the Company in the ninth decile. The size premium spread between the second and ninth deciles is 1.67% and an associated adjustment of 167 basis points could be made to my indicated range of cost of common equity for size risk alone.

Q. Based on your analysis, what is the indicated cost of common equity after adjustments for financial and business risks?

A. After taking into consideration the Commission precedent regarding ROE as compared to utilities in the Lower 48 and applying a conservative 0.75% business risk adjustment (*i.e.*, taking into consideration all business risks I describe above) to ENSTAR's indicated range of cost of common equity between 11.70% and 12.70%, a Company-specific range of common equity cost rates between 12.45% and 13.45% results.

XI. CONCLUSION

Q. What is your recommended cost of common equity for the Company?

A. Given the results of the ROE models discussed above, Commission precedent, and the relative riskiness of the Company compared with the Utility Proxy Group based on its business risk, I conclude that an appropriate cost of common equity is 12.95% for ENSTAR. A common equity cost rate of 12.95% is both reasonable and conservative, providing ENSTAR with sufficient earnings to enable it to attract necessary new capital.

Q. In your opinion, is ENSTAR's actual capital structure consisting of 45.89% long-term debt and 54.11% common equity fair and reasonable?

A. Yes, it is.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Dylan W. D'Ascendis, CRRA, CVA
Partner

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and has become a leading expert witness with respect to cost of capital and capital structure. He has served as a consultant for investor-owned and municipal utilities and authorities for 14 years. Dylan has testified as an expert witness on over 100 occasions regarding rate of return, cost of service, rate design, and valuation before more than 30 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Regulation and Rates
- Rate of Return
- Valuation
- Mutual Fund Benchmarking
- Capital Market Risk
- Regulatory Strategy
- Cost of Service

Recent Expert Testimony Submission/Appearance

- Regulatory Commission of Alaska – Capital Structure
- Federal Energy Regulatory Commission – Rate of Return
- Public Utility Commission of Texas – Return on Equity
- Hawaii Public Utilities Commission – Cost of Service / Rate Design
- Pennsylvania Public Utility Commission - Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Articles and Speeches

- Co-Author of: "Decoupling, Risk Impacts and the Cost of Capital", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020
- Co-Author of: "Decoupling Impact and Public Utility Conservation Investment", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319
- "Establishing Alternative Proxy Groups", before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA
- "Past is Prologue: Future Test Year", Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
Colorado Public Utilities Commission				
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Delaware Public Service Commission				
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System	09/20	Peoples Gas System	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy	07/19	Atmos Energy	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy	04/20	Atmos Energy	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Maryland Public Service Commission				
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	Docket No. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation

Sponsor	Date	Case/Applicant	Docket No.	Subject
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
Tennessee Public Utility Commission				
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Virginia State Corporation Commission				

Sponsor	Date	Case/Applicant	Docket No.	Subject
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
Monongahela Power Company and The Potomac Edison Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
Monongahela Power Company and The Potomac Edison Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

ENSTAR Natural Gas Company and Alaska Pipeline Company
Table of Contents
to Exhibit DWD-2

ENSTAR Natural Gas Company and Alaska Pipeline Company
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes
at December 31, 2021

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	45.89%	2.86%	(1)	1.31%
Common Equity	54.11%	12.95%	(2)	7.01%
Total	100.00%			8.32%

Notes:

(1) Company-provided.
(2) From page 2 of this Schedule.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Twelve Companies
1.	Discounted Cash Flow Model (DCF) (1)	11.29%
2.	Risk Premium Model (RPM) (2)	12.58%
3.	Capital Asset Pricing Model (CAPM) (3)	11.97%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	13.11%
5.	Indicated Range of Common Equity Cost Rates	11.70% - 12.70%
6.	Business Risk Adjustment (5)	0.75%
7.	Indicated Range of Common Equity Cost Rates after Adjustment	12.45% - 13.45%
8.	Recommended Common Equity Cost Rate	12.95%

Notes:
(1) From page 1 of Schedule 3.
(2) From page 1 of Schedule 4.
(3) From page 1 of Schedule 5.
(4) From page 1 of Schedule 7.
(5) Adjustment to reflect the Company's greater business risk relative to the Utility Proxy Group as detailed in Mr. D'Ascendis' direct testimony.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Five-Quarter Average Equity Ratios (1) of the
Proxy Group of Twelve Companies

Proxy Group of Twelve Companies	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Average
Atmos Energy Corporation	60.94%	59.02%	59.58%	60.25%	60.45%	60.05%
Kinder Morgan, Inc.	49.06%	47.82%	48.33%	48.01%	49.20%	48.48%
MDU Resources Group, Inc.	53.95%	54.13%	57.75%	56.63%	56.67%	55.83%
National Fuel Gas Company	41.32%	44.52%	40.24%	43.35%	44.41%	42.77%
New Jersey Resources Corp.	41.76%	40.77%	40.65%	41.62%	43.12%	41.58%
Nisource, Inc.	34.40%	33.29%	30.34%	30.18%	33.15%	32.27%
Northwest Natural Holding Co.	47.35%	45.98%	47.88%	47.25%	48.09%	47.31%
ONE Gas, Inc.	59.26%	57.81%	57.90%	52.66%	52.44%	56.02%
ONEOK, Inc.	30.38%	30.42%	29.04%	29.29%	29.92%	29.81%
Spire, Inc.	42.75%	41.09%	42.29%	42.72%	44.98%	42.77%
TC Energy Corp.	36.24%	36.63%	34.49%	34.53%	33.64%	35.11%
The Williams Companies, Inc.	33.43%	32.30%	33.26%	33.03%	33.40%	33.08%
Minimum	30.38%	30.42%	29.04%	29.29%	29.92%	29.81%
Maximum	60.94%	59.02%	59.58%	60.25%	60.45%	60.05%

Notes:
(1) Excludes securitized debt attributable to Winter Storm Uri.

Source of Information:
S&P Capital IQ

ENSTAR Natural Gas Company and Alaska Pipeline Company
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Twelve Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Twelve Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.38 %	7.50 %	7.30 %	8.61 %	7.80 %	2.47 %	10.27 %
Kinder Morgan, Inc.	5.93	19.00	3.00	(2.66)	11.00	6.26	17.26
MDU Resources Group, Inc.	3.25	10.50	6.90	7.80	8.40	3.39	11.79
National Fuel Gas Company	2.71	24.50	10.00	10.00	14.83	2.91	17.74
New Jersey Resources Corp.	3.23	5.00	6.00	6.00	5.67	3.32	8.99
Nisource, Inc.	3.11	9.50	7.20	7.18	7.96	3.23	11.19
Northwest Natural Holding Co.	3.74	6.50	4.70	4.60	5.27	3.84	9.11
ONE Gas, Inc.	2.90	6.50	5.00	5.00	5.50	2.98	8.48
ONEOK, Inc.	5.79	11.50	7.90	10.87	10.09	6.08	16.17
Spire, Inc.	3.64	9.00	5.00	4.30	6.10	3.75	9.85
TC Energy Corp.	6.45	4.50	4.00	1.70	3.40	6.56	9.96
The Williams Companies, Inc.	4.92	8.50	3.50	7.09	6.36	5.08	11.44
						Average	11.85 %
						Median	10.73 %
						Average of Mean and Median	11.29 %

NA= Not Available
NMF= Not Meaningful Figure

Notes:
(1) Indicated dividend at 07/01/2022 divided by the average closing price of the last 60 trading days ending 07/01/2022 for each company.
(2) From pages 2 through 13 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 6) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.38% x (1+(1/2 x 7.80%)) = 2.47%.
(5) Column 5 + column 6.

Source of Information:
Value Line Investment Survey
www.zacks.com Downloaded on 07/01/2022
www.yahoo.com Downloaded on 07/01/2022

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE **113.16** | P/E RATIO **20.0** (Trailing: 21.0 / Median: 20.0) | RELATIVE P/E RATIO **1.23** | DIV'D YLD **2.5%** | VALUE LINE

TIMELINESS	3	Raised 2/18/22
SAFETY	1	Raised 6/6/14
TECHNICAL	1	Raised 5/20/22
BETA .80 (1.00 = Market)		

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	35.6	37.3	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	
Low:	28.5	30.4	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	99.8	

18-Month Target Price Range

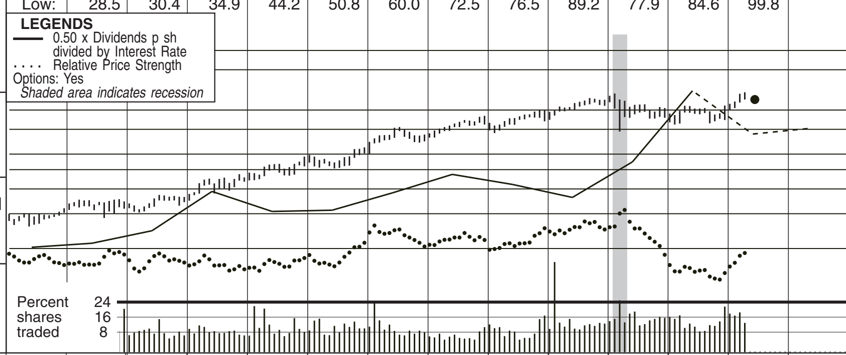
Low-High	Midpoint (% to Mid)
$83-$128	$106 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+40%)	11%
Low	130	(+15%)	6%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	256	247	262
to Sell	258	223	217
Hld's(000)	107920	109549	114371



Target Price Range
2025 | 2026 | 2027

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.1	-7.2
3 yr.	20.2	37.2
5 yr.	58.6	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
75.27	66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	**27.45**	**28.75**	Revenues per sh A	**35.50**
4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	**9.05**	**9.75**	"Cash Flow" per sh	**11.95**
2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	**5.50**	**5.90**	Earnings per sh AB	**7.30**
1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	**2.72**	**2.92**	Div'ds Decl'd per sh C■	**3.50**
5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	**17.25**	**17.10**	Cap'l Spending per sh	**18.00**
20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	**64.25**	**68.20**	Book Value per sh	**82.85**
81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	**142.00**	**146.00**	Common Shs Outst'g D	**155.00**
13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**20.0**
.73	.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.00			Relative P/E Ratio	**1.10**
4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%			Avg Ann'l Div'd Yield	**2.4%**
						3438.5	3886.3	4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	**3900**	**4200**	Revenues ($mill) A	**6000**
						192.2	230.7	289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	**760**	**860**	Net Profit ($mill)	**1130**
						33.8%	38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	**8.5%**	**17.5%**	Income Tax Rate	**25.0%**
						5.6%	5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	**19.5%**	**20.5%**	Net Profit Margin	**18.8%**
						45.3%	48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	**40.0%**	**40.0%**	Long-Term Debt Ratio	**40.0%**
						54.7%	51.2%	55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	**60.0%**	**60.0%**	Common Equity Ratio	**60.0%**
						4315.5	5036.1	5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	**15200**	**16600**	Total Capital ($mill)	**21400**
						5475.6	6030.7	6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	**16500**	**18000**	Net Plant ($mill)	**23000**
						6.1%	5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	**6.0%**	**6.5%**	Return on Total Cap'l	**6.5%**
						8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	**8.5%**	**8.5%**	Return on Shr. Equity	**9.0%**
						8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	**8.5%**	**8.5%**	Return on Com Equity	**9.0%**
						2.8%	4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	**4.0%**	**4.5%**	Retained to Com Eq	**4.5%**
						65%	56%	50%	51%	50%	50%	48%	48%	49%	49%	**51%**	**50%**	All Div'ds to Net Prof	**48%**

CAPITAL STRUCTURE as of 3/31/22
Total Debt $7959.0 mill. **Due in 5 Yrs** $2410.0 mill.
LT Debt $5757.6 mill. **LT Interest** $85.0 mill.
(LT interest earned: 10.8x; total interest coverage: 10.8x)
Leases, Uncapitalized Annual rentals $41.8 mill.

Pfd Stock None

Pension Assets-9/21 $596.8 mill. **Oblig.** $596.0 mill.

Common Stock 139,015,012 shs. **as of 4/29/22**

MARKET CAP: $15.7 billion (Large Cap)

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	20.8	116.7	582.5
Other	450.5	2722.0	2946.5
Current Assets	471.3	2838.7	3529.0
Accts Payable	235.8	423.2	354.0
Debt Due	.2	2400.5	2201.4
Other	546.4	686.7	653.0
Current Liab.	782.4	3510.4	3208.4
Fix. Chg. Cov.	1306%	1457%	1445%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-7.5%	-10.0%	6.5%
"Cash Flow"	6.0%	7.0%	7.0%
Earnings	8.5%	8.5%	7.5%
Dividends	5.5%	8.0%	7.0%
Book Value	8.5%	11.0%	7.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	877.8	1094.6	485.7	443.7	2901.8
2020	875.6	977.6	493.0	474.9	2821.1
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	**640**	**597.4**	**3900**
2023	**1060**	**1720**	**730**	**690**	**4200**

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	1.38	1.82	.68	.49	4.35
2020	1.47	1.95	.79	.53	4.72
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	**.82**	**.45**	**5.50**
2023	**2.02**	**2.43**	**.91**	**.54**	**5.90**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.485	.485	.485	.525	1.98
2019	.525	.525	.525	.575	2.15
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2021: 67.9%, residential; 26.8%, commercial; 3.6%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .9% of common stock (12/21 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy had a decent showing through the first half of fiscal 2022 (which ended last March 31st). Share net rose 5.5%, to $4.23, compared to $4.01 for the same period in fiscal 2021. That was brought about partly by the distribution unit, helped by favorable rate case outcomes and an expanded customer base. A substantially diminished effective income tax rate also benefited the company. But the performance of the pipeline and storage division was held back a bit by heightened operating expenses. Nevertheless, assuming that the second half goes fairly well for Atmos, full-year earnings stand to increase around 7%, to $5.50 a share, relative to fiscal 2021's $5.12 total. Regarding next year, share net might grow at a similar percentage rate, to $5.90, as operating margins widen further.

The Financial Strength rating is A+. When the second quarter concluded, cash and equivalents resided at $582.5 million. Also, long-term debt was manageable (roughly 40% of total capital) and short-term commitments did not appear to be a major obstacle. Furthermore, $2.2 billion in common stock and/or debt securities remained available for issuance (out of $5 billion) under a shelf registration statement expiring in June, 2024. Lastly, Atmos can access four revolving credit facilities aggregating $2.5 billion plus a $1.5 billion commercial paper program. So, there seems to be ample liquidity to satisfy working capital needs, capital expenditures, and other obligations for some time.

Prospects out to 2025-2027 appear encouraging. The company ranks as one of the nation's largest natural gas-only distributors, with more than three million customers across several states, including Texas, Louisiana, and Mississippi. Moreover, we think the pipeline and storage segment has promising overall growth opportunities, given that it operates in one of the most-active drilling regions in the world. The healthy balance sheet is another positive.

That said, these top-quality shares hold unimpressive long-term total return potential. Capital appreciation possibilities aren't exciting. Also, the dividend yield is below the average of *Value Line's* Natural Gas Utility group.

Frederick L. Harris, III *May 27, 2022*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next egs. rpt. due early Aug.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	100

KINDER MORGAN, INC. NYSE-KMI

RECENT PRICE 19.39 | P/E RATIO 16.2 (Trailing: 43.1 Median: 53.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 5.7% | VALUE LINE

TIMELINESS 3 Lowered 2/18/22
SAFETY 3 Lowered 6/5/15
TECHNICAL 3 Raised 2/25/22
BETA 1.15 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$14-$25	$20 (0%)

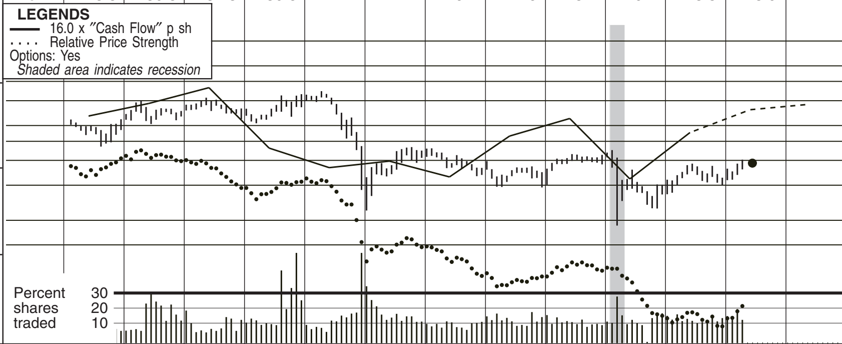
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+185%)	*33%*
Low	40	(+105%)	*24%*

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	596	612	611
to Sell	464	458	457
Hld's(000)	1350369	1354925	1338458

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	32.3	40.3	41.5	43.2	44.7	23.4	23.0	19.8	21.5	22.6	19.3	20.2
Low:	23.5	30.5	32.3	30.8	14.2	11.2	16.7	14.6	15.1	9.4	13.5	15.9



Target Price Range 2025 2026 2027

80 60 50 40 30 25 20 15 10 7.5

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.5	-7.2
3 yr.	10.4	37.2
5 yr.	15.0	58.7

Kinder Morgan, Inc. was formed in 2006, principally for the purpose of acquiring all of the common stock of Kinder Morgan Kansas. It completed its initial public offering on February 10, 2011. At that time, 109.79 million shares were sold to the public at an average price of $30 per share. The underwriting syndicate included Barclays and Goldman Sachs.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
9.63	13.65	7.64	6.46	5.86	6.18	6.25	5.83	5.17	7.33	***7.85***	***8.40***	Revenues per sh	***9.75***
2.42	2.91	1.44	1.15	1.24	1.03	1.66	2.03	1.01	1.73	***2.25***	***2.40***	"Cash Flow" per sh	***3.05***
.56	1.15	.89	.10	.25	.01	.66	.96	.05	.78	***1.20***	***1.30***	Earnings per sh A	***1.70***
1.34	1.56	1.70	1.93	.50	.50	.73	.95	1.04	1.07	***1.11***	***1.15***	Div'ds Decl'd per sh C	***1.50***
1.95	3.27	1.70	1.75	1.29	1.44	1.29	.95	.75	.57	***1.20***	***1.20***	Cap'l Spending per sh	***1.40***
13.39	12.70	16.03	15.04	14.72	14.45	14.89	14.90	13.88	13.59	***14.35***	***14.95***	Book Value per sh B	***16.75***
1035.7	1030.7	2125.1	2229.2	2230.1	2217.1	2262.2	2264.9	2264.3	2267.4	***2240.0***	***2220.0***	Common Shs Outst'g D	***2160.0***
NMF	32.4	40.7	NMF	NMF	NMF	25.9	20.8	NMF	21.4	***Bold figures are***		Avg Ann'l P/E Ratio	***28.0***
NMF	1.82	2.14	NMF	NMF	NMF	1.40	1.11	NMF	1.14	***Value Line***		Relative P/E Ratio	***1.55***
3.9%	4.2%	4.7%	5.5%	2.6%	2.5%	4.2%	4.8%	6.8%	6.4%	***estimates***		Avg Ann'l Div'd Yield	***3.3%***
9973.0	14070	16226	14403	13058	13705	14144	13209	11700	16610	***17800***	***18700***	Revenues ($mill)	***21100***
40.2%	41.2%	40.0%	33.0%	42.1%	42.4%	44.2%	48.0%	48.3%	40.1%	***40.0%***	***43.5%***	Operating Margin	***46.5%***
1419.0	1806.0	2040.0	2309.0	2209.0	2261.0	2297.0	2411.0	2164.0	2135.0	***2315***	***2430***	Depreciation ($mill)	***2955***
1092.0	1197.0	1026.0	253.0	708.0	183.0	1609.0	2190.0	119.0	1784.0	***2695***	***2880***	Net Profit ($mill)	***3670***
10.4%	21.6%	21.0%	73.1%	56.0%	NMF	23.4%	29.3%	72.8%	16.6%	***21.0%***	***21.0%***	Income Tax Rate	***21.0%***
10.9%	8.5%	6.3%	1.8%	5.4%	1.3%	11.4%	16.6%	1.0%	10.7%	***15.2%***	***15.4%***	Net Profit Margin	***17.4%***
d1535	d2207	d2610	d1241	d2695	d3466	d1835	d1862	d1871	d1992	***d1780***	***d1830***	Working Cap'l ($mill)	***d2115***
32000	33887	40246	42406	37354	35015	33936	31915	32131	30674	***29755***	***28860***	Long-Term Debt ($mill)	***26340***
13865	13093	34076	35119	34431	33636	33678	33742	31436	30823	***32145***	***33185***	Shr. Equity ($mill)	***36070***
3.9%	4.3%	2.6%	1.6%	2.2%	1.6%	3.8%	4.7%	1.4%	4.1%	***6.0%***	***6.5%***	Return on Total Cap'l	***8.0%***
7.9%	9.1%	3.0%	.7%	2.1%	.5%	4.8%	6.5%	.4%	5.8%	***8.5%***	***8.5%***	Return on Shr. Equity	***10.0%***
NMF	NMF	NMF	NMF	NMF	NMF	NMF	.1%	NMF	NMF	***.5%***	***1.0%***	Retained to Com Eq	***1.0%***
108%	NMF	NMF	NMF	NMF	NMF	110%	99%	NMF	NMF	***92%***	***89%***	All Div'ds to Net Prof	***89%***

CAPITAL STRUCTURE as of 3/31/22
Total Debt $32.1 bill. **Due in 5 Yrs** $12.6 bill.
LT Debt $28.8 bill. **LT Interest** $1.6 bill
(50% of Cap'l)
Leases, Uncapitalized: Annual rentals $156 mill.

Pension Assets-12/21 $2231 mill.
Oblig. $2658 mill.
Preferred Stock None

Common Stock 2,267,472,525 shares out.
as of 4/21/22

MARKET CAP: $44.0 billion (Large Cap)

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	1209	1140	84
Receivables	1293	1611	1661
Inventory	348	562	591
Other	353	516	697
Current Assets	3203	3829	3033
Accts Payable	837	1259	1204
Debt Due	2558	2646	3324
Other	1659	1916	1922
Current Liab.	5074	5821	6450

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-5.0%	-1.5%	*8.0%*
"Cash Flow"	-2.5%	4.5%	*11.5%*
Earnings	-2.0%	7.5%	*19.0%*
Dividends	3.5%	-6.0%	*6.5%*
Book Value	13.0%	-1.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3429	3214	3214	3352	13209
2020	3106	2560	2919	3115	11700
2021	5211	3150	3824	4425	16610
2022	4293	***4400***	***4500***	***4607***	***17800***
2023	***4600***	***4650***	***4700***	***4750***	***18700***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.24	.23	.22	.27	.96
2020	d.14	d.28	.20	.27	.05
2021	.62	d.34	.22	.28	.78
2022	.29	***.30***	***.30***	***.31***	***1.20***
2023	***.30***	***.32***	***.33***	***.35***	***1.30***

Cal-endar	QUARTERLY DIVIDENDS PAID C Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.125	.20	.20	.20	.73
2019	.20	.25	.25	.25	.95
2020	.25	.2625	.2625	.2625	1.04
2021	.2625	.27	.27	.27	1.07
2022	.27	.2775			

BUSINESS: Kinder Morgan, Inc. is one of the largest energy infrastructure companies in North America. It transports natural gas, refined petroleum products, crude oil, condensate and carbon dioxide among other products using its more than 83,000 miles of pipelines. Its 147 terminals handle various commodities, including gasoline, diesel fuel, chemicals, ethanol, metals and petroleum coke. The company employs more than 11,000 individuals. Sold Kinder Morgan Canada, 12/18. Chairman: Richard D. Kinder. CEO: Steven J. Kean. Officers/directors own 12.5% of the common stock; The Vanguard Group, 7.6% (4/22 proxy). Incorporated: Delaware. Address: 1001 Louisiana Street, Suite 1000, Houston, TX 77002. Telephone: 713-369-9000. Internet: www.kindermorgan.com.

Kinder Morgan's first-quarter comparisons were tough. Revenues dipped to around $4.3 billion as last year's high gas and throughput related to Winter Storm Uri in Texas exceeded the increased throughput to power plants and LNG facilities. Additionally, the pipeline to Mexico faced increased competition. Gross margins declined in the quarter, and inflationary pressures and additional contributions from recent purchases caused administrative costs to increase. However, interest costs decreased due to a reduced debt load. Overall, these factors netted to earnings of $0.29 per share during the quarter.

The company ought to have sequentially better performance over the coming quarters. Revenues will likely expand at a decent clip as more natural gas is put through its pipelines to be sent abroad. Kinder currently transports about 50% of natural gas in the United States to liquefaction facilities. Moreover, we think demand will continue to pick up as the economy recovers from the coronavirus pandemic. Overall, we believe earnings will reach $1.20 per share this year.

The company should benefit from a few positives over the long haul. We expect that demand for natural gas will continue to increase both domestically and abroad. Europe will likely continue to call for more LNG to offset declining amounts coming from Russia. Additionally, cash flows may benefit from a decline in capital expansion projects in the United States due to a tougher regulatory environment. We expect the debt load to decline, allowing interest costs to drop. We think earnings will expand to $1.30 per share in 2023 and $1.70 per share by 2025-2027.

The quarterly dividend was raised 3% to $0.2775 per share. This is a modest increase, but the dividend yield is among the highest in the *Survey*. Too, the company should opportunistically buy back stock in the years ahead.

Shares of Kinder Morgan are neutrally ranked for Timeliness. Still, this equity holds ample 3- to 5-year appreciation potential based on the stronger earnings we project and a higher price-to-earnings multiple. We think this stock should appeal to long-term total return investors.

John E. Seibert III *May 27, 2022*

(A) Diluted P Class earnings. Next earnings report due mid-July. Earnings may not sum due to rounding.
(B) Includes intangibles. In 2021, $21.6 billion or $9.52 per share.
(C) Dividends historically paid mid-February, May, August, and November.
(D) In millions.

Company's Financial Strength	B
Stock's Price Stability	75
Price Growth Persistence	5
Earnings Predictability	25

MDU RESOURCES NYSE-MDU

RECENT PRICE **26.50** | P/E RATIO **13.3** (Trailing: 15.1; Median: 19.0) | RELATIVE P/E RATIO **0.82** | DIV'D YLD **3.3%** | VALUE LINE

TIMELINESS 5 Lowered 3/11/22
SAFETY 3 Lowered 3/19/21
TECHNICAL 5 Lowered 4/29/22
BETA 1.10 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$22-$39	$31 (15%)

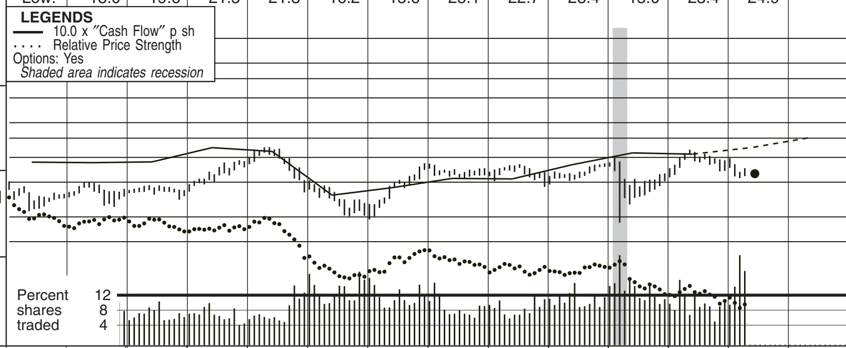
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+125%)	24%
Low	40	(+50%)	13%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	198	179	175
to Sell	162	178	165
Hld's(000)	138257	138401	139696

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	24.0	23.2	31.0	36.1	24.5	29.9	29.7	29.6	29.8	32.2	35.0	31.7
Low:	18.0	19.6	21.5	21.3	16.2	15.6	25.1	22.7	23.4	15.0	25.4	24.9



Target Price Range 2025 2026 2027: 128, 96, 80, 64, 48, 40, 32, 24, 16, 12

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-21.1	-7.2
3 yr.	6.6	37.2
5 yr.	9.9	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
22.49	23.22	27.24	22.23	20.71	21.45	21.52	23.63	24.05	21.47	21.08	22.69	23.05	26.56	27.59	27.94	**31.20**	**31.70**	Revenues per sh	**35.65**
3.25	3.41	4.04	3.15	3.03	3.01	3.04	3.58	3.43	2.06	2.25	2.51	2.49	2.94	3.37	3.33	**3.60**	**4.05**	"Cash Flow" per sh	**5.30**
1.75	1.76	2.05	1.41	1.29	1.19	1.15	1.53	1.40	.90	1.15	1.45	1.37	1.69	1.95	1.87	**2.00**	**2.30**	Earnings per sh A	**3.35**
.52	.56	.60	.62	.64	.66	.68	.52	.72	.74	.76	.78	.80	.82	.84	.86	**.87**	**.89**	Div'ds Decl'd per sh B■†	**.95**
2.81	3.05	4.06	2.39	2.38	2.63	4.61	4.82	5.01	3.20	1.98	1.74	2.89	2.87	2.78	3.24	**3.05**	**2.95**	Cap'l Spending per sh	**3.45**
11.88	13.75	14.95	13.61	14.19	14.62	13.91	15.04	16.66	12.20	11.75	12.40	13.06	14.17	15.36	16.64	**17.50**	**18.65**	Book Value per sh C	**24.75**
181.02	182.95	183.67	187.85	188.76	188.82	189.37	188.83	194.22	195.27	195.84	195.84	196.57	200.92	200.52	203.35	**203.40**	**203.40**	Common Shs Outst'g D	**203.40**
13.7	15.7	13.2	13.7	15.8	18.0	19.0	17.4	22.1	22.0	19.6	18.6	19.8	15.8	12.4	16.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**16.0**
.74	.83	.79	.91	1.01	1.13	1.21	.98	1.16	1.11	1.03	.94	1.07	.84	.64	.89			Relative P/E Ratio	**.90**
2.2%	2.0%	2.2%	3.2%	3.1%	3.1%	3.1%	2.0%	2.3%	3.7%	3.3%	2.9%	2.9%	3.1%	3.5%	2.8%			Avg Ann'l Div'd Yield	**1.9%**

CAPITAL STRUCTURE as of 3/31/22
Total Debt $2847.7 mill. **Due in 5 Yrs** $1183.2 mill.
LT Debt $2599.8 mill. **LT Interest** $93.0 mill.
(LT interest earned: 6.0x) (43% of Cap'l)
Leases, Uncapitalized Annual rentals $46.6 mill.
Pension Assets-12/21 $473.3 mill. **Oblig.** $485.0 mill.

Common Stock 203,889,613 shs.

MARKET CAP: $5.4 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
4075.4	4462.4	4670.6	4191.5	4128.8	4443.4	4531.6	5336.8	5532.8	5680.7	**6350**	**6450**	Revenues ($mill)	**7250**
18.9%	20.0%	19.0%	14.9%	18.8%	18.1%	17.4%	17.5%	20.1%	19.7%	**19.0%**	**19.0%**	Operating Margin	**19.0%**
359.2	386.8	401.4	227.7	216.3	207.5	220.2	256.0	285.1	299.2	**330**	**355**	Depreciation ($mill)	**390**
217.5	290.6	266.1	175.5	225.3	284.2	269.4	335.2	390.5	377.7	**400**	**465**	Net Profit ($mill)	**685**
37.2%	32.0%	29.2%	31.9%	49.9%	18.6%	15.0%	15.9%	17.8%	19.1%	**21.0%**	**25.0%**	Income Tax Rate	**25.0%**
5.3%	6.5%	5.7%	4.2%	5.5%	6.4%	5.9%	6.3%	7.1%	6.6%	**6.3%**	**7.2%**	Net Profit Margin	**9.5%**
278.0	331.8	226.3	73.4	307.8	257.1	198.0	411.3	373.9	458.7	**335**	**325**	Working Cap'l ($mill)	**580**
1610.9	1842.3	1825.3	1627.4	1746.6	1566.4	1856.8	2226.6	2211.6	2593.8	**2500**	**2350**	Long-Term Debt ($mill)	**2000**
2648.2	2855.9	3249.8	2396.5	2316.2	2429.0	2566.8	2847.2	3079.1	3382.9	**3555**	**3790**	Shr. Equity ($mill)	**5035**
6.0%	7.1%	6.1%	5.5%	6.6%	8.1%	7.0%	7.6%	8.3%	7.1%	**7.5%**	**8.5%**	Return on Total Cap'l	**10.5%**
8.2%	10.2%	8.2%	7.3%	9.7%	11.7%	10.5%	11.8%	12.7%	11.2%	**11.5%**	**12.5%**	Return on Shr. Equity	**13.5%**
2.2%	6.7%	4.0%	1.3%	3.4%	5.5%	4.5%	6.1%	7.3%	6.1%	**6.5%**	**7.5%**	Retained to Com Eq	**10.0%**
74%	34%	52%	82%	65%	53%	57%	48%	43%	45%	**44%**	**39%**	All Div'ds to Net Prof	**28%**

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	59.5	54.2	64.9
Receivables	874.0	946.7	948.0
Inventory (Avg. Cst)	291.2	335.6	380.3
Other	112.6	214.4	178.7
Current Assets	1337.3	1550.9	1571.9
Accts Payable	426.3	478.9	449.7
Debt Due	51.6	148.1	247.9
Other	485.6	465.2	469.1
Current Liab.	963.5	1092.2	1166.7

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	2.5%	4.5%	4.5%
"Cash Flow"	.5%	4.5%	8.5%
Earnings	3.5%	10.0%	10.5%
Dividends	2.5%	2.5%	2.0%
Book Value	1.0%	2.5%	8.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1091.2	1303.6	1563.8	1378.2	5336.8
2020	1197.4	1362.9	1587.3	1385.2	5532.8
2021	1227.9	1423.7	1586.0	1443.1	5680.7
2022	1416.6	**1550**	**1780**	**1603.4**	**6350**
2023	**1430**	**1580**	**1820**	**1620**	**6450**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.21	.32	.69	.47	1.69
2020	.13	.50	.76	.56	1.95
2021	.26	.50	.68	.42	1.87
2022	.16	**.50**	**.75**	**.59**	**2.00**
2023	**.30**	**.55**	**.85**	**.60**	**2.30**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.1975	.1975	.1975	.1975	.79
2019	.2025	.2025	.2025	.2025	.81
2020	.2075	.2075	.2075	.2075	.83
2021	.2125	.2125	.2125	.2125	.85
2022	.2175	.2175			

BUSINESS: MDU Resources Group, Inc. is a regulated energy delivery and construction materials and services company. Segments: construction materials and contracting (39% of '21 revs; 36% of '21 op. inc.), construction services (36%, 27%), natural gas distribution (17%, 17%); electric (6%, 12%) and pipeline (2%, 8%). Utilities sell gas & electricity in northwest and upper midwest U.S. Construction materials has 1.1 billion tons of construction reserves. Has about 12,826 employees. Off./dir. own less than 1.0% of common stock; The Vanguard Group, 11.1% (3/22 Proxy). Chrmn.: Thomas Everist. Pres./CEO: David L. Goodin. Inc.: DE. Address.: 1200 W. Century Ave., P.O. Box 5650, Bismarck, ND 58506-5650. Tel.: 701-530-1000. Internet: www.mdu.com.

MDU Resources produced mixed first-quarter results. The diversified company registered roughly a 15% year-over-year revenue increase, to approximately $1.42 billion, thanks in large part to a record performance by the construction businesses (combined for $862.6 million). However, operating expenses rose at an even faster pace of 18%, to $1.35 billion. Greater-than-expected increases in operating and maintenance expenses, as well as manufacturing costs, accounted for the disappointing bottom-line showing of $0.16 per share, compared to our target of $0.25.

In all likelihood, significant sequential improvement is probable. Major reasons for our outlook include a record construction backlog and various growth opportunities within the regulated businesses. The Construction Services unit is experiencing strong demand for utility-related projects, as efforts to improve the U.S. electric grid continue. This, along with elevated interest from the renewable sector, enabled the business to close the March period with a record backlog of $1.67 billion, up more than 30% year over year. Meanwhile, the Construction Materials segment is gaining from recent acquisitions and increased product pricing. While price hikes had a modest impact in the first quarter, the benefits are apt to be more significant during the remainder of the year. The segment reported a backlog of $940 million. MDU Resources utility expects to grow the customer base 1%-2% annually over the next five years, and is looking for the rate base to expand at 5% per annum during the same time period. Its pipeline business recently placed the expanded North Bakken project into service and should benefit from forecasted natural gas production growth. Elsewhere, the unit has various expansion projects coming up, including the Wahpeton that should enter service in 2024, assuming regulatory approval. In all, these initiatives ought to add an incremental 300 million cubic feet of natural gas transport capacity to the system.

Though untimely, our projections (supported by the likelihood of added business from the Infrastructure Investment and Jobs Act) lead to solid total return potential out to 2025-2027.

Dominic B. Silva *May 27, 2022*

(A) Diluted EPS. Excludes nonrecurring gains/(losses): '08, (46¢); '09, ($2.08); '12, ($1.16); '13, (6¢);'14, 13¢; '15, 14¢; '16, 72¢. Gain (loss) on disc. ops.: '14, 2¢; '15, ($3.96); '16, ($1.54); '17, (2¢); '18, 1¢; '19, 1¢. Next egs. report due early August. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder investment plan available. (C) Includes intangibles: In 2021: $788.0 million, $3.88/sh. (D) In millions.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	25
Earnings Predictability	85

NATIONAL FUEL GAS NYSE-NFG

RECENT PRICE 67.79 | P/E RATIO 11.5 (Trailing: 13.2, Median: 19.0) | RELATIVE P/E RATIO 0.71 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 3 Raised 10/15/21
SAFETY 3 Lowered 12/6/13
TECHNICAL 3 Lowered 3/18/22
BETA .80 (1.00 = Market)

High:	76.0	57.0	72.5	78.8	70.2	59.6	61.3	59.2	61.7	46.7	64.7	74.3
Low:	44.5	41.6	48.5	64.3	37.0	39.8	53.0	48.3	43.0	31.6	39.8	58.1

Target Price Range
2025 2026 2027

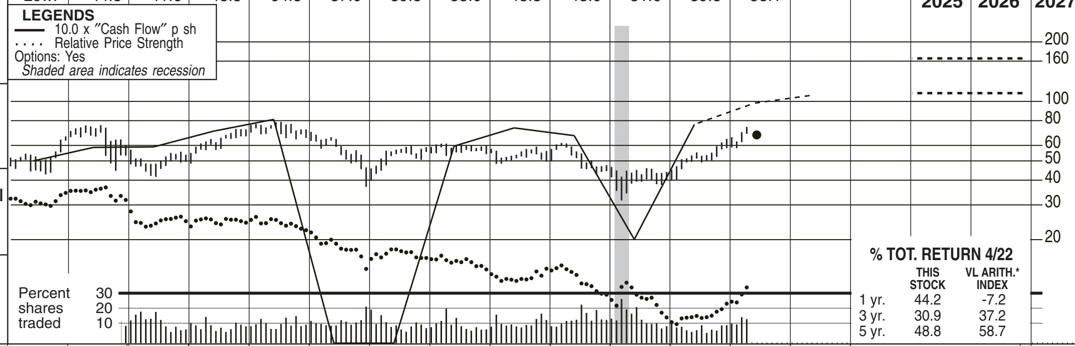
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$52-$93 $73 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	165	(+145%)	26%
Low	110	(+60%)	15%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	154	146	158
to Sell	152	156	149
Hld's(000)	64402	65713	64671



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	44.2	-7.2
3 yr.	30.9	37.2
5 yr.	48.8	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
27.72	24.44	30.34	25.56	21.45	21.47	19.52	21.87	25.11	20.82	17.06	18.47	18.53	19.62	17.00	19.11	24.20	27.70	Revenues per sh A	30.00
4.59	4.31	5.55	4.77	5.00	5.85	5.90	7.07	8.12	d.51	d.49	5.93	7.36	6.72	2.01	7.67	9.80	10.80	"Cash Flow" per sh	11.80
2.40	2.37	3.18	2.60	2.65	3.09	2.63	3.14	3.52	d4.50	d3.43	3.30	4.53	3.51	d1.41	3.97	5.85	6.75	Earnings per sh B	7.60
1.18	1.22	1.27	1.32	1.36	1.40	1.44	1.48	1.52	1.56	1.60	1.64	1.68	1.72	1.76	1.80	1.85	1.90	Div'ds Decl'd per sh C■	2.25
3.53	3.32	5.03	3.85	5.55	10.11	12.44	8.41	10.87	12.04	6.83	5.26	6.79	9.14	7.87	8.24	8.50	8.50	Cap'l Spending per sh	8.50
17.31	19.53	20.27	19.74	21.27	22.84	23.52	26.23	28.65	23.94	17.94	19.92	22.54	24.78	21.68	19.59	24.80	28.55	Book Value per sh	44.20
83.40	83.46	79.12	80.50	82.08	82.85	83.33	83.66	84.16	84.59	85.12	85.54	85.96	86.32	90.95	91.18	92.00	92.50	Common Shs Outst'g D	95.00
14.1	17.8	15.5	13.4	18.5	21.4	19.3	18.6	20.6	- -	- -	17.2	12.0	15.6	15.6	12.0	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	18.0
.76	.94	.93	.89	1.18	1.34	1.23	1.05	1.08	- -	- -	.87	.65	.83	.83	.64			Relative P/E Ratio	1.00
3.5%	2.9%	2.6%	3.8%	2.8%	2.1%	2.8%	2.5%	2.1%	2.5%	3.1%	2.9%	3.1%	3.1%	4.1%	3.8%			Avg Ann'l Div'd Yield	1.6%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $2848.0 mill. **Due in 5 Yrs** $1700.0 mill.
LT Debt $2081.5 mill. **LT Interest** $100.0 mill.
(Total interest coverage: 4.4x)
(53% of Cap'l)
Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-9/21 $1095.7 mill.
Oblig. $1098.5 mill.
Pfd Stock None

Common Stock 91,455,696 shs.
as of 4/30/22

MARKET CAP: $5.6 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1626.9	1829.6	2113.1	1760.9	1452.4	1579.9	1592.7	1693.3	1546.3	1742.7	2225	2560	Revenues ($mill) A	2850
44.2%	46.6%	45.1%	48.3%	53.8%	49.2%	45.7%	46.5%	50.8%	57.4%	58.0%	58.5%	Operating Margin	60.0%
271.5	326.8	383.8	336.2	249.4	224.2	241.0	275.7	306.2	335.3	350	360	Depreciation ($mill)	400
220.1	264.7	299.4	d379.4	d291.0	283.5	391.5	304.3	d123.8	363.6	550	640	Net Profit ($mill)	720
40.6%	39.9%	38.8%	- -	- -	36.2%	- -	21.9%	21.9%	24.0%	24.0%	24.0%	Income Tax Rate	22.0%
13.5%	14.5%	14.2%	NMF	NMF	17.9%	24.6%	18.0%	NMF	20.9%	24.7%	25.0%	Net Profit Margin	25.3%
d378.9	146.5	d113.3	66.9	109.3	172.3	104.5	d59.3	d145.4	d713.6	85.0	180	Working Cap'l ($mill)	300
1149.0	1649.0	1649.0	2084.0	2086.3	2083.7	2131.4	2133.7	2629.6	2628.7	2000	2000	Long-Term Debt ($mill)	2000
1960.1	2194.7	2410.7	2025.4	1527.0	1703.7	1937.3	2139.0	1972.0	1786.2	2280	2640	Shr. Equity ($mill)	4200
8.4%	8.1%	8.5%	NMF	NMF	9.0%	11.0%	8.2%	NMF	9.8%	13.0%	14.0%	Return on Total Cap'l	11.5%
11.2%	12.1%	12.4%	NMF	NMF	16.6%	20.2%	14.2%	NMF	20.4%	24.0%	24.0%	Return on Shr. Equity	17.0%
5.2%	6.5%	7.2%	NMF	NMF	8.5%	12.8%	7.3%	NMF	11.2%	16.5%	17.5%	Retained to Com Eq	12.0%
54%	46%	42%	NMF	NMF	49%	37%	48%	NMF	45%	31%	27%	All Div'ds to Net Prof	30%

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	20.5	31.5	52.6
Receivables	143.6	205.3	339.4
Inventory (LIFO)	50.6	53.6	48.9
Other	99.5	232.0	230.2
Current Assets	314.2	522.4	671.1
Accts Payable	134.1	171.7	135.8
Debt Due	30.0	158.5	767.0
Other	295.5	905.9	1103.4
Current Liab.	459.6	1236.1	2006.2

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	-2.5%	8.5%
"Cash Flow"	.5%	- -	13.5%
Earnings	-3.0%	- -	24.5%
Dividends	2.5%	2.5%	4.0%
Book Value	.5%	-1.5%	12.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	490.3	552.5	357.2	293.3	1693.3
2020	444.2	491.1	323.0	288.0	1546.3
2021	441.2	551.1	394.4	356.0	1742.7
2022	546.6	701.7	485	491.7	2225
2023	600	725	625	610	2560

Fiscal Year Ends	EARNINGS PER SHARE ABE Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	1.18	1.04	.73	.54	3.51
2020	1.00	d1.23	.47	d1.60	d1.41
2021	.85	1.23	.94	.95	3.97
2022	1.44	1.82	1.34	1.25	5.85
2023	1.50	2.00	1.65	1.60	6.75

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.415	.415	.425	.425	1.68
2019	.425	.425	.435	.435	1.72
2020	.435	.435	.445	.445	1.76
2021	.445	.445	.455	.455	1.80
2022	.455	.455			

BUSINESS: National Fuel Gas Company is engaged in the production, gathering, transportation, distribution, and marketing of natural gas & oil. Exploration/Production and other (48% of fiscal 2021 sales); Utility and Energy Marketing Revenues (38%), and Pipeline, Storage & Gathering (14%). NFG has a large position in the Marcellus Shale basin in western NY & PA and oil reserves in CA. Proved reserves as of 9/30/21: 21,537 MMcf of natural gas. Employs 2,188. Off./dir. own 1.9% of stock; Vanguard, 12.6%; BlackRock, 8.8%; State Street, 7.5%; JPMorgan, 5.6%; Gabelli, 5.0% (1/22 proxy). Chairman: David F. Smith. President/CEO: David P. Bauer. Inc.: NJ. Addr.: 6363 Main St., Williamsville, NY 14221. Tel.: 716-857-7000. Internet: www.nationalfuelgas.com.

National Fuel continued to build momentum in the fiscal second quarter. (Fiscal year ends September 30th.) Share earnings jumped 48% during the March period, on a 24% sales gain. The recent performance was driven by robust Exploration & Production numbers, especially from the Appalachian natural gas properties, combined with higher commodity prices. Moreover, Supply Corporation's FM100 project went into service during the interim, which benefits results.

The company is well positioned for near-term growth. We are optimistic that National Fuel's strategic investments in the Appalachian region, as well as other improvements to transportation infrastructure, will bear fruit in the near future. Management has implemented rate hikes due to rising energy valuations and higher operating costs, and we envision this will aid profit margins moving forward. As such, the company issued earnings guidance of $5.70-$6.00 a share, and we have raised our estimates accordingly. We look for share net to expand between 45% and 50% this year, and for sales to increase 25%-30%. The top and bottom lines ought to grow at a mid- to upper-teen clip through 2023.

National Fuel has been adjusting its portfolio. In early May, the company announced plans to divest Seneca's California oil and gas properties to Sentinel Peak Resources for a total consideration of $280 million-$310 million, depending on energy valuations. The deal is expected to close by June 30th. National Fuel will probably use the proceeds from the divestiture to continue to deleverage the balance sheet and add to its overall financial flexibility. Meanwhile, the company has been shoring up other operations, including holdings in the Appalachian Basin, which should boost production and more than offset for output lost as a result of the asset sale.

These shares offer good long-term appeal. NFG holds robust capital appreciation potential over the coming 3 to 5 years. What's more, it has an above-average dividend yield, and we believe further hikes to the payout will enhance its long-term total return possibilities. For now, this issue is ranked 3 (Average) for year-ahead relative price performance.

Orly Seidman *May 27, 2022*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Excl. nonrecurring gains/(losses):'06, (79¢); '09, ($1.32); '13, (6¢); '14, (3¢). Excl. disc. operations gain/(loss): '07, $1.56. Next earnings report due in early Aug.
(C) Div'd. hist. paid in mid-Jan., Apr., July, and Oct. ■ Div'd. reinvestment plan available.
(D) In millions.
(E) Quarterly EPS may not sum due to rounding.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	10
Earnings Predictability	5

NEW JERSEY RES. NYSE-NJR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
44.63	19.1	(Trailing: 22.7) (Median: 17.0)	1.18	3.2%	VALUE LINE

TIMELINESS 4 Lowered 5/20/22
SAFETY 2 Lowered 4/17/20
TECHNICAL 3 Lowered 5/27/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$29-$55	$42 (-5%)

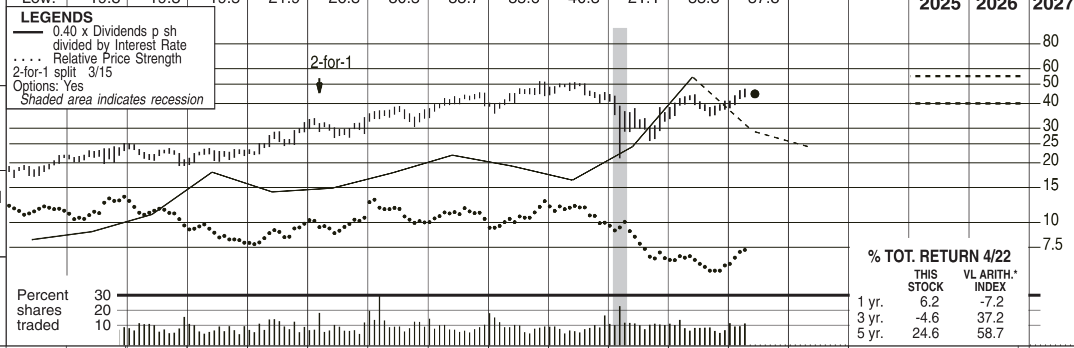
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	8%
Low	40	(-10%)	1%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	105	102	109
to Sell	139	130	121
Hld's(000)	68468	68609	66131

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	25.2	25.1	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	47.5
Low:	19.8	19.3	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8



Target Price Range
2025 | 2026 | 2027

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.2	-7.2
3 yr.	-4.6	37.2
5 yr.	24.6	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	**25.50**	**25.95**	Revenues per sh A	**28.10**
1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	**3.65**	**3.75**	"Cash Flow" per sh	**4.25**
.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	**2.30**	**2.40**	Earnings per sh B	**2.80**
.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	**1.45**	**1.49**	Div'ds Decl'd per sh C■	**1.70**
.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	**5.35**	**5.30**	Cap'l Spending per sh	**5.50**
7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	**18.70**	**19.85**	Book Value per sh D	**23.15**
82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	**98.00**	**99.00**	Common Shs Outst'g E	**100.00**
16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**17.0**
.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94			Relative P/E Ratio	**.95**
3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%			Avg Ann'l Div'd Yield	**4.0%**

CAPITAL STRUCTURE as of 3/31/22
Total Debt $2646.1 mill. **Due in 5 Yrs** $442.8 mill.
LT Debt $2319.4 mill. **LT Interest** $78.6 mill.
Incl. $6.0 mill. capitalized leases.
(LT interest earned: 5.0x; total interest coverage: 5.0x)
Pension Assets-9/21 $469.5 mill. **Oblig.** $640.2 mill.
Pfd Stock None

Common Stock 96,152,712 shs.
as of 5/2/22
MARKET CAP: $4.3 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
2248.9	3198.1	3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	**2500**	**2570**	Revenues ($mill) A	**2810**
112.4	113.7	176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	**225**	**240**	Net Profit ($mill)	**280**
7.1%	25.4%	30.2%	26.3%	15.5%	17.2%	- -	- -	NMF	10.3%	**10.5%**	**10.5%**	Income Tax Rate	**10.5%**
5.0%	3.6%	4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	**9.1%**	**10.0%**	Net Profit Margin	**10.0%**
39.2%	36.6%	38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	**57.5%**	**57.0%**	Long-Term Debt Ratio	**56.5%**
60.8%	63.4%	61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	**42.5%**	**43.0%**	Common Equity Ratio	**43.5%**
1339.0	1400.3	1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	**4335**	**4565**	Total Capital ($mill)	**5310**
1484.9	1643.1	1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	**4145**	**4225**	Net Plant ($mill)	**4485**
9.2%	9.0%	12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	**6.5%**	**6.5%**	Return on Total Cap'l	**6.5%**
13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	**12.5%**	**12.0%**	Return on Shr. Equity	**12.0%**
13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	**12.5%**	**12.0%**	Return on Com Equity	**12.0%**
6.2%	5.2%	11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	**4.5%**	**4.5%**	Retained to Com Eq	**4.5%**
55%	59%	40%	50%	60%	59%	40%	59%	60%	56%	**63%**	**62%**	All Div'ds to Net Prof	**61%**

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	117.0	4.7	13.9
Other	505.3	629.6	542.1
Current Assets	622.3	634.3	556.0
Accts Payable	270.1	429.6	301.6
Debt Due	152.6	450.1	326.7
Other	111.0	171.7	253.8
Current Liab.	533.7	1051.4	882.1
Fix. Chg. Cov.	545%	545%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.0%	-6.0%	*2.5%*
"Cash Flow"	7.0%	4.5%	*5.0%*
Earnings	5.0%	2.5%	*5.0%*
Dividends	6.5%	6.5%	*5.0%*
Book Value	7.5%	7.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	811.8	866.2	434.9	479.1	2592.0
2020	615.0	639.6	299.0	400.1	1953.7
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	***430***	***481.9***	***2500***
2023	***695***	***930***	***450***	***495***	***2570***

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	.61	1.27	d.20	.29	1.96
2020	.44	1.12	d.06	.57	2.07
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	***d.10***	***.35***	***2.30***
2023	***.73***	***1.38***	***d.08***	***.37***	***2.40***

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.273	.273	.273	.2925	1.11
2019	.2925	.2925	.2925	.3125	1.19
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 564,000 cust. at 9/30/21. Fiscal 2021 volume: 112 bill. cu. ft. (20% interruptible, 61% residential, commercial & firm transportation, 19% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2021 dep. rate: 2.4%. Has 1,251 empls. Off./dir. own less than 1% of common; BlackRock, 15.3%; Vanguard, 10.6% (12/21 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

Since our February review, shares of New Jersey Resources have continued to trend higher. In fact, the stock's price advanced another 9.5%. In comparison, the S&P 500 Index registered a downturn of nearly 10% for this same period.

Meanwhile, the retail and wholesale energy provider posted mixed March-quarter results. To that point, revenues advanced 13.7%, to $912.3 million, besting our call for $855 million. This reflected an impressive 49% spike in utility volumes, partially offset by a 9% downturn in non-utility volumes. On the margin front, total expenses increased 990 basis points, as a percentage of the top line. That margin compression completely offset the top-line growth, and after factoring in the dilutive effects of stock issuances, NJR's fiscal second-quarter (ended March 31, 2022) earnings declined 23%, to $1.36 a share. This fell short of our outlook of $1.70.

We have left our fiscal 2022 (ends September 30th) bottom-line estimate unchanged at this time. Despite the lower-than-expected second-quarter earnings, management recently raised its guidance range from $2.20-$2.30, to $2.30-$2.40 per share. Our call of $2.30 represents a year-over-year advance of about 6.5%. Share net should be driven by an estimated uptick in the top line of approximately 16%. This ought to be supported by the addition of more than 3,575 new customer accounts over the first half of the year. At the same time, steady contributions from the Storage & Transportation arm will likely be nicely complementary this year. Alternatively, the Energy Services segment has been hurt by the increased volatility in energy prices over the past year. This will likely present some headwinds for the company as the year progresses.

At the recent quotation, these untimely shares have already realized the bulk of the earnings growth potential that we envision for the pull to 2025-2027. Due to this, the stock offers below-average capital appreciation potential over that time frame. That said, conservative investors will likely find the Above-Average Safety rank and high Price Stability mark attractive features, given the recent market volatility. The attractive dividend yield is also a plus.

Bryan J. Fong *May 27, 2022*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early Aug.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2021: $522.1 million, $5.49/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	55

NISOURCE INC. NYSE-NI

RECENT PRICE **30.43** | P/E RATIO **21.0** (Trailing: 22.1 / Median: 21.0) | RELATIVE P/E RATIO **1.30** | DIV'D YLD **3.1%** | **VALUE LINE**

TIMELINESS 4 Raised 3/11/22
SAFETY 3 Lowered 3/19/21
TECHNICAL 2 Raised 5/13/22
BETA .85 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	24.0	26.2	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6
Low:	17.7	22.3	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	26.4

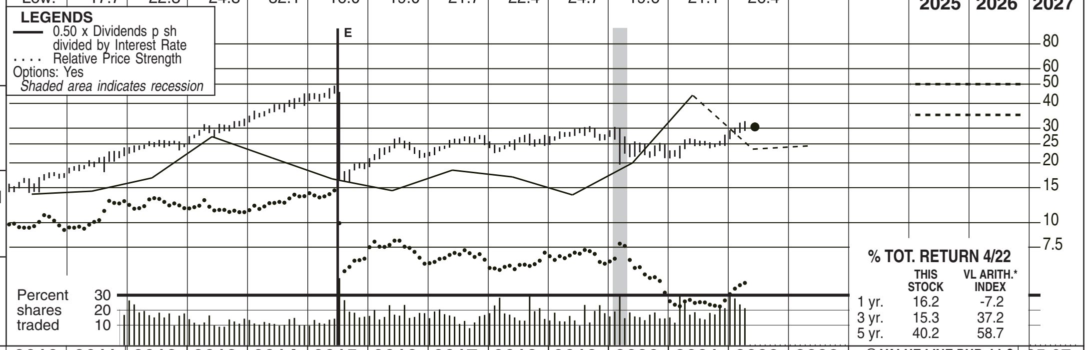
18-Month Target Price Range
Low-High $28-$39 | Midpoint (% to Mid) $34 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+65%)	16%
Low	35	(+15%)	7%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	252	256	230
to Sell	188	197	208
Hld's(000)	361696	367884	376481



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.2	-7.2
3 yr.	15.3	37.2
5 yr.	40.2	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
27.37	28.96	32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	**13.85**	**14.70**	Revenues per sh	**17.55**
3.18	3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	**3.20**	**3.50**	"Cash Flow" per sh	**4.35**
1.14	1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	**1.45**	**1.60**	Earnings per sh A	**2.30**
.92	.92	.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	**.94**	**.98**	Div'd Decl'd per sh B ■	**1.08**
2.33	2.88	3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	**4.45**	**4.45**	Cap'l Spending per sh	**4.35**
18.32	18.52	17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.66	13.33	**13.80**	**14.35**	Book Value per sh C	**17.40**
273.65	274.18	274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	**405.00**	**405.00**	Common Shs Outst'g D	**415.00**
19.2	18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	64.4	19.3	21.3	18.7	18.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**19.0**
1.04	1.00	.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	3.24	1.04	1.13	.96	.99	*estimates*		Relative P/E Ratio	**1.05**
4.2%	4.3%	5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%			Avg Ann'l Div'd Yield	**2.5%**
						5061.2	5657.3	6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	**5600**	**5950**	Revenues ($mill)	**7290**
						410.6	490.9	530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	**605**	**670**	Net Profit ($mill)	**990**
						34.4%	34.8%	36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	**19.0%**	**19.0%**	Income Tax Rate	**19.0%**
						- -	- -	- -	- -	- -	- -	- -	- -	2.9%	2.0%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
						55.1%	56.3%	56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.2%	56.9%	**56.5%**	**56.0%**	Long-Term Debt Ratio	**52.0%**
						44.9%	43.7%	43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.9%	33.5%	**34.0%**	**35.0%**	Common Equity Ratio	**39.5%**
						12373	13480	14331	9792.0	10129	11832	12856	13843	15058	16131	**16435**	**16700**	Total Capital ($mill)	**18225**
						12916	14365	16017	12112	13068	14360	15543	16912	16620	17882	**18000**	**19000**	Net Plant ($mill)	**22000**
						5.0%	5.2%	5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	**3.5%**	**4.0%**	Return on Total Cap'l	**5.5%**
						7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.6%	9.0%	**8.5%**	**9.0%**	Return on Shr. Equity	**11.5%**
						7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.2%	10.6%	**8.5%**	**9.0%**	Return on Com Equity	**11.5%**
						2.5%	3.1%	3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.7%	4.2%	**2.5%**	**3.0%**	Retained to Com Eq	**5.5%**
						67%	62%	61%	NMF	63%	NMF	60%	64%	67%	64%	**72%**	**68%**	All Div'ds to Net Prof	**51%**

CAPITAL STRUCTURE as of 3/31/22
Total Debt $9757.7 mill. **Due in 5 Yrs** $1318 mill.
LT Debt $9179.8 mill. **LT Interest** $341 mill.
(Interest cov. earned: 2.2x) (58% of Cap'l)

Leases, Uncapitalized Annual rentals $32.7 mill.
Pension Assets-12/21 $1.9 bill. **Oblig.** $2.0 bill.

Pfd Stock $1547 mill. **Pfd Div'd** $55.1 mill.

Common Stock 407,798,111 shs.
as of 4/26/22
MARKET CAP: $12.4 billion (Large Cap)

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	116.5	85.2	114.5
Other	1542.9	1835.6	1757.4
Current Assets	1659.4	1920.8	1871.9
Accts Payable	589.0	697.8	628.5
Debt Due	526.3	618.1	577.9
Other	1164.1	1430.3	1388.2
Current Liab.	2279.4	2746.2	2594.6
Fix. Chg. Cov.	250%	250%	255%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-6.0%	-5.0%	5.5%
"Cash Flow"	.5%	2.0%	5.5%
Earnings	3.0%	4.0%	9.5%
Dividends	-1.0%	- -	4.5%
Book Value	-3.0%	-2.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1869.8	1010.4	931.5	1397.2	5208.9
2020	1605.5	962.7	902.5	1211.0	4681.7
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	**1085**	**1035**	**1606.7**	**5600**
2023	**1960**	**1170**	**1120**	**1700**	**5950**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.82	.05	- -	.45	1.31
2020	.76	.13	.09	.34	1.32
2021	.77	.13	.11	.39	1.37
2022	.75	**.17**	**.15**	**.38**	**1.45**
2023	**.80**	**.20**	**.20**	**.40**	**1.60**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.195	.195	.195	.195	.78
2019	.200	.200	.200	.200	.80
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 479,185 electric in Indiana, 3,200,000 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2021: electrical, 31%; gas, 69%; other, less than 1%. Generating sources, coal, 69.4%; purchased & other, 30.6%. 2021 reported depreciation rates: 2.9% electric, 2.2% gas. Has 7,304 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

Since our February review, shares of NiSource have continued on their upward trajectory. In fact, over that time frame, the stock's price advanced another roughly 7%. In comparison, the S&P 500 Index underwent a correction of approximately 10% over that same period.

Meantime, the supplier of electricity and gas to northern Indiana is off to a mixed start this year. To that point, revenues advanced 21.2%, to $1.873 billion, thanks to a solid, double-digit increase in customer revenues, partially offset by a modest decline in other volumes. This handily bested our call for $1.645 billion. On the profitability front, total expenses declined 402 basis points, as a percentage of the top line. After accounting for the dilutive effects of a 13.3 million spike in the number of shares outstanding, NI's first-quarter share net fell 2.6%, to $0.75. This was modestly below our call for $0.80.

As a result, we have sliced a nickel off our 2022 and 2023 earnings estimates, bringing those figures to $1.45 and $1.60, respectively. In the current year, our revised call would still represent a roughly 6% annual increase. This figure also coincides with management's recently reiterated guidance range of $1.42 to $1.48. This ought to reflect an estimated revenue advance of more than 14%, to $5.6 billion. NiSource has roughly $10 billion in capital growth projects on deck and planned to come into service through 2024. It is also transitioning away from coal-fired generation and toward greener alternatives. Finally, the company has filed for roughly $475 million in proposed rate-case increases across its various service territories. Those efforts ought to help the company recoup some of its already invested capital and offset growth costs.

This stock offers an above-average dividend yield when viewed against the Value Line median, which may appeal to income-oriented investors. That said, the stock's upside potential for the pull to 2025-2027 is below the *Value Line* median. What's more, momentum accounts would probably be better served elsewhere. Our Timeliness Ranking System has NiSource pegged to lag the broader market averages in the coming six to 12 months (Timeliness: 4).

Bryan J. Fong *May 27, 2022*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '06, (11¢); '07, 3¢; '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due late July. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '21: $1485.9 million, $3.68/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	20
Earnings Predictability	50

N.W. NATURAL NYSE-NWN

RECENT PRICE **50.78** | P/E RATIO **19.9** (Trailing: 21.0 Median: 24.0) | RELATIVE P/E RATIO **1.23** | DIV'D YLD **3.8%** | **VALUE LINE**

TIMELINESS	4	Raised 4/29/22
SAFETY	3	Lowered 3/19/21
TECHNICAL	4	Lowered 5/27/22

BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$41-$67	$54 (5%)

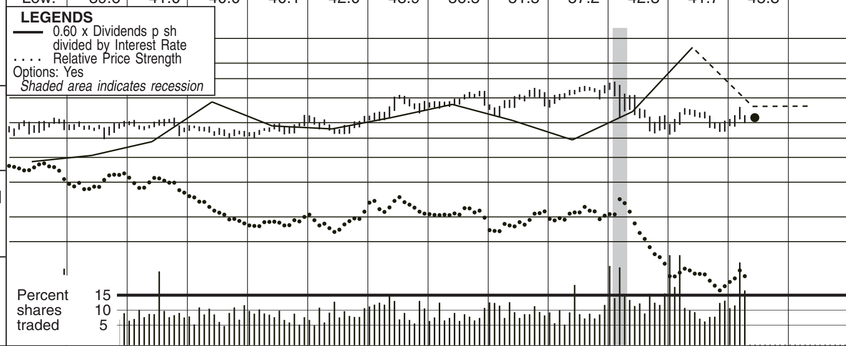
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+65%)	16%
Low	55	(+10%)	6%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	103	114	95
to Sell	89	81	95
Hld's(000)	21451	21444	21597

High:	49.0	50.8	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6
Low:	39.6	41.0	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	45.8



Target Price Range

2025	2026	2027

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.2	-7.2
3 yr.	-20.6	37.2
5 yr.	-5.4	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	**28.50**	**29.45**	Revenues per sh	**33.55**
4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	**6.20**	**6.65**	"Cash Flow" per sh	**7.65**
2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	**2.55**	**2.85**	Earnings per sh A	**3.45**
1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	**1.93**	**1.94**	Div'ds Decl'd per sh B■	**1.96**
3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	**8.65**	**8.90**	Cap'l Spending per sh	**9.40**
22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	**29.25**	**30.25**	Book Value per sh D	**37.20**
27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	**31.25**	**31.50**	Common Shs Outst'g C	**32.00**
15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	Bold figures are		Avg Ann'l P/E Ratio	**20.0**
.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.06	Value Line		Relative P/E Ratio	**1.10**
3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	estimates		Avg Ann'l Div'd Yield	**2.6%**

CAPITAL STRUCTURE as of 3/31/22
Total Debt $1434.4 mill. **Due in 5 Yrs** $175.3 mill.
LT Debt $1044.6 mill. **LT Interest** $44.5 mill.

(Total interest coverage: 3.1x)

Pension Assets-12/21 $399.2 mill.
Oblig. $569.8 mill.

Pfd Stock None

Common Stock 30,730,274 shares
as of 10/27/21

MARKET CAP $1.6 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
730.6	758.5	754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	**890**	**925**	Revenues ($mill)	**1075**
59.9	60.5	58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	**80.0**	**90.0**	Net Profit ($mill)	**135**
42.4%	40.8%	41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
8.2%	8.0%	7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	**8.9%**	**9.7%**	Net Profit Margin	**10.3%**
48.5%	47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	**52.0%**	**51.0%**	Long-Term Debt Ratio	**48.0%**
51.5%	52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	**48.0%**	**49.5%**	Common Equity Ratio	**52.0%**
1424.7	1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	**1915**	**1955**	Total Capital ($mill)	**2290**
1973.6	2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	**3105**	**3360**	Net Plant ($mill)	**4250**
5.7%	5.8%	5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	**4.0%**	**4.5%**	Return on Total Cap'l	**5.0%**
8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	**8.5%**	**9.5%**	Return on Shr. Equity	**9.5%**
8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	**8.5%**	**9.5%**	Return on Com Equity	**9.5%**
1.6%	1.5%	1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	**2.0%**	**3.0%**	Retained to Com Eq	**4.0%**
80%	81%	85%	92%	87%	NMF	76%	82%	79%	71%	**76%**	**68%**	All Div'ds to Net Prof	**57%**

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	30.2	18.6	24.3
Other	293.0	418.7	367.1
Current Assets	323.2	437.3	391.4
Accts Payable	97.9	133.5	130.6
Debt Due	399.9	389.8	332.8
Other	129.3	201.5	194.9
Current Liab.	627.1	724.8	658.3
Fix. Chg. Cov.	335%	335%	312%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	- -	4.5%
"Cash Flow"	1.0%	2.5%	5.0%
Earnings	-1.0%	2.5%	6.5%
Dividends	1.5%	.5%	.5%
Book Value	1.0%	.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	285.4	123.4	90.3	247.3	746.4
2020	285.2	135.0	93.3	260.2	773.7
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	**150**	**110**	**279.7**	**890**
2023	**355**	**160**	**120**	**290**	**925**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.50	.07	d.61	1.26	2.19
2020	1.58	d.17	d.61	1.50	2.30
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	**.01**	**d.56**	**1.30**	**2.55**
2023	**2.00**	**.05**	**d.55**	**1.35**	**2.85**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.4725	.4725	.4725	.475	1.89
2019	.475	.475	.475	.4775	1.90
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 775,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,167. BlackRock Inc. owns 17.2% of shares; Vanguard, 11.8%; Off./Dir., .92% (4/22 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Since our February review, shares of Northwest Natural Holding Co. have ticked modestly higher. In fact, the stock's price advanced nearly 7%. In comparison, the S&P 500 Index logged a correction of nearly 10% for that same period.

Meantime, the distributor of natural gas posted mixed financial results for the March quarter. On the upside, revenues increased 10.9%, to $350.3 million, thanks to incremental volumes associated with the 10,800 natural gas meters added over the past 12 months. Additional benefits stemmed from a rate increase in Washington state. On the profitability front, total costs rose 498 basis points, as a percentage of the top line. After accounting for a drop in other expenses and an increase in common stock outstanding, NWN's share net declined about 7%, to $1.80, versus the prior year. This was well below our call for $1.96 per share.

Consequently, we have sliced $0.15 off our bottom-line outlook for this year, to $2.55 a share. Our revised figure would represent a less-than-1% year-over-year earnings decline. This ought to reflect an estimated revenue advance of about 3.5%, to $890 million, as Northwest Natural continues to focus its efforts on growing its renewal operations, and moving its existing rate cases forward. In mid-December, it filed for a more-than-$365 million hike with the Oregon Public Utility Commission, which is anticipated to go into effect around November 1st. The purpose of the higher rate is to support long-term investments in safety, reliability, and technology upgrades. That said, we look for costs to remain elevated as the year progresses. This will likely offset the top-line gains and keep a lid on bottom-line growth until next year.

These shares have improved one notch in Timeliness since our last report. Still, they are ranked a 4, suggesting NWN will lag the broader market averages in the year ahead. Meanwhile, the stock offers worthwhile capital appreciation potential for the pull to 2025-2027, even after reducing our 3- to 5-year P/E multiple to 20 from 24. Additionally, NWN offers a dividend yield that is well above the *Value Line* median, which may appeal to yield-seeking investors.

Bryan J. Fong *May 27, 2022*

(A) Diluted earnings per share. Excludes non-recurring items: '06, ($0.06); '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early Aug.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2021: $70.6 million, $2.27/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	10

ONE GAS, INC. NYSE-OGS

RECENT PRICE 85.96 | P/E RATIO 21.2 (Trailing: 22.1 Median: NMF) | RELATIVE P/E RATIO 1.31 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Raised 5/13/22
SAFETY 2 New 6/2/17
TECHNICAL 1 Raised 5/20/22
BETA .80 (1.00 = Market)

	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	73.4

Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range

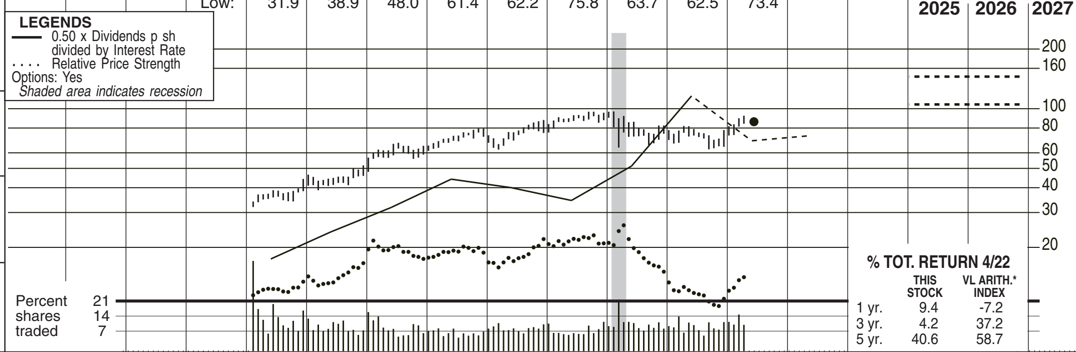
Low-High	Midpoint (% to Mid)
$69-$110	$90 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+70%)	16%
Low	105	(+20%)	8%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	127	111	135
to Sell	144	140	122
Hld's(000)	42395	43179	42681



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.4	-7.2
3 yr.	4.2	37.2
5 yr.	40.6	58.7

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	**42.80**	**45.35**	Revenues per sh	**57.45**
--	--	4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	**8.25**	**8.70**	"Cash Flow" per sh	**10.55**
--	--	2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	**4.05**	**4.25**	Earnings per sh A	**5.30**
--	--	.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	**2.48**	**2.64**	Div'ds Decl'd per sh B■	**3.12**
--	--	5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	**9.40**	**9.55**	Cap'l Spending per sh	**9.85**
--	--	34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	**59.70**	**60.65**	Book Value per sh	**71.60**
--	--	52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	**54.00**	**54.00**	Common Shs Outst'g C	**57.00**
--	--	17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	**Bold figures are**		Avg Ann'l P/E Ratio	**23.5**
--	--	.94	1.00	1.19	1.18	1.25	1.35	1.11	1.03	**Value Line**		Relative P/E Ratio	**1.30**
--	--	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	**estimates**		Avg Ann'l Div'd Yield	**2.5%**
--	--	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	**2310**	**2450**	Revenues ($mill)	**3275**
--	--	109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	**218**	**230**	Net Profit ($mill)	**300**
--	--	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	**18.0%**	**18.5%**	Income Tax Rate	**22.0%**
--	--	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	**9.4%**	**9.4%**	Net Profit Margin	**9.2%**
--	--	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.0%	**48.0%**	**49.0%**	Long-Term Debt Ratio	**52.0%**
--	--	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	39.0%	**52.0%**	**51.0%**	Common Equity Ratio	**48.0%**
--	--	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	**6200**	**6420**	Total Capital ($mill)	**8500**
--	--	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	**5500**	**5800**	Net Plant ($mill)	**6750**
--	--	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	**5.0%**	**5.0%**	Return on Total Cap'l	**5.0%**
--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	**7.0%**	**7.0%**	Return on Shr. Equity	**7.5%**
--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	**7.0%**	**7.0%**	Return on Com Equity	**7.5%**
--	--	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	**2.5%**	**2.5%**	Retained to Com Eq	**3.0%**
--	--	40%	53%	52%	55%	56%	56%	58%	60%	**61%**	**62%**	All Div'ds to Net Prof	**59%**

CAPITAL STRUCTURE as of 3/31/22
Total Debt $4188.8 mill. **Due in 5 Yrs** $2900.0 mill.
LT Debt $2283.6 mill. **LT Interest** $140.0 mill.
(LT interest earned: 5.1x; total interest coverage: 5.1x)
Leases, Uncapitalized Annual rentals $7.5 mill.
Pfd Stock None
Pension Assets-12/21 $1245.2 mill. **Oblig.** $1272.8 mill.
Common Stock 54,089,905 shs. **as of 4/25/22**
MARKET CAP: $4.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	8.0	8.9	12.4
Other	531.9	2215.7	2262.1
Current Assets	539.9	2224.6	2274.5
Accts Payable	152.3	258.6	209.8
Debt Due	418.2	494.0	1905.2
Other	226.6	227.9	253.8
Current Liab.	797.1	980.5	2368.8
Fix. Chg. Cov.	587%	625%	632%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	.5%	10.5%
"Cash Flow"	--	8.5%	6.5%
Earnings	--	9.5%	6.5%
Dividends	--	13.5%	6.5%
Book Value	--	3.5%	9.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	661.0	290.6	248.6	452.5	1652.7
2020	528.2	273.3	244.6	484.2	1530.3
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	**400**	**323.5**	**615**	**2310**
2023	**1009**	**450**	**346**	**645**	**2450**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.76	.46	.33	.96	3.51
2020	1.72	.48	.39	1.09	3.68
2021	1.79	.56	.38	1.12	3.85
2022	1.83	**.62**	**.45**	**1.15**	**4.05**
2023	**1.90**	**.67**	**.50**	**1.18**	**4.25**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.46	.46	.46	.46	1.84
2019	.50	.50	.50	.50	2.00
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62			

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 164 Bcf of natural gas supply in 2021, compared to 153 Bcf in 2020. Total volumes delivered by customer (fiscal 2021): transportation, 59.3%; residential, 30.4%; commercial & industrial, 9.7%; other, .6%. ONE Gas has around 3,600 employees. BlackRock owns 12.2% of common stock; The Vanguard Group, 10.9%; American Century Investment, 8.0%; officers and directors, 1.5% (4/22 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas' first-quarter 2022 results showed some improvement. Share net of $1.83 was several pennies higher than last year's $1.79 figure. That stemmed partially from benefits from new rates. Also, there was a rise in residential sales due to net customer growth. Bad-debt expense decreased, too. So, assuming that the business climate continues to be generally favorable over the course of the year, we believe that 2022 share net will increase around 5%, to $4.05, compared to the 2021 tally of $3.85. Regarding next year, the company's bottom line might advance at a similar percentage rate, to $4.25 a share, as operating margins expand further.

Prospects over the 2025-2027 period appear promising. ONE Gas remains the top natural gas distributor (as measured by customer count) in both Oklahoma and Kansas, and holds the number-three position in Texas. Moreover, we think these markets have decent growth possibilities and are located in one of the most active drilling regions in the United States. Too, thanks to healthy finances, the company should continue to satisfy its working capital requirements, capital expenditures, and other commitments with little difficulty.

There are risks to bear in mind, though. ONE Gas' lack of geographic diversification leaves it somewhat more vulnerable to regional economic downturns and regulations. Also, there's competition from other energy suppliers, which include electric companies and propane dealers. Lastly, pipeline ruptures, leaks, and other unfortunate occurrences can take a big bite out of corporate profits if not adequately covered by insurance.

The good-quality stock has climbed roughly 15% in value since our last full-page report in February. It seems that can be traced, to some extent, to expectations of decent earnings for the energy provider in 2022. But the price action has dampened 3- to 5-year capital appreciation potential. Too, the dividend yield does not stand out from the average yield in *Value Line's* Natural Gas Utility group. Lastly, these shares are ranked to just approximate the market over the coming six to 12 months.

Frederick L. Harris, III *May 27, 2022*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Aug.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

ONEOK, INC. NYSE-OKE

RECENT PRICE 65.19 | P/E RATIO 17.2 (Trailing: 19.3; Median: 25.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 5.7-3.0% | VALUE LINE

TIMELINESS 3 Raised 6/11/21
SAFETY 3 New 7/27/90
TECHNICAL 2 Raised 5/13/22
BETA 1.50 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$55-$108	$82 (25%)

2025-27 PROJECTIONS

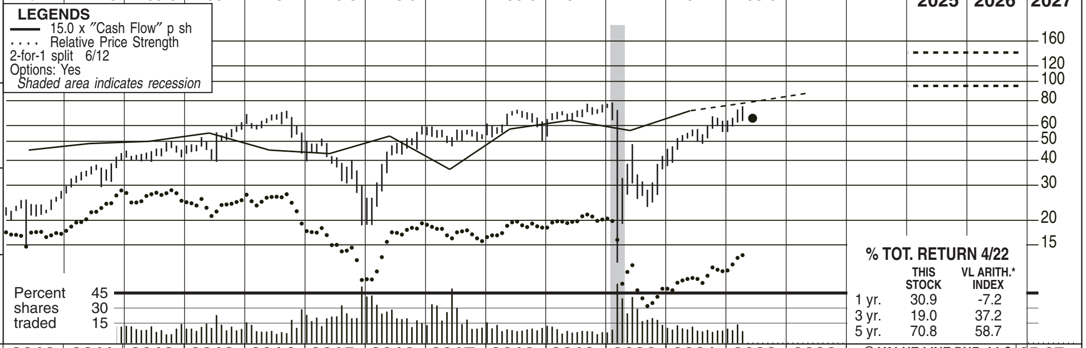
	Price	Gain	Ann'l Total Return
High	140	(+115%)	25%
Low	95	(+45%)	15%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	374	466	422
to Sell	358	293	336
Hld's(000)	285852	288208	287045

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	43.6	49.8	62.2	71.2	51.5	59.5	59.3	72.0	77.2	78.5	66.8	75.1
Low:	27.3	39.3	39.4	43.4	18.8	18.9	47.1	50.3	52.7	12.2	37.4	55.6

LEGENDS
— 15.0 x "Cash Flow" p sh
.... Relative Price Strength
2-for-1 split 6/12
Options: Yes
Shaded area indicates recession



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.9	-7.2
3 yr.	19.0	37.2
5 yr.	70.8	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
53.71	64.85	77.05	52.46	60.99	71.70	61.64	70.67	58.54	37.02	42.34	31.32	30.60	24.60	19.20	37.07	**50.00**	**51.75**	Revenues per sh	**60.65**
2.32	2.56	2.65	2.81	3.01	3.25	3.33	3.67	3.00	2.89	3.54	2.41	3.84	4.25	3.77	4.76	**5.25**	**5.85**	"Cash Flow" per sh	**7.80**
1.22	1.40	1.48	1.44	1.55	1.67	1.64	1.78	1.52	1.19	1.67	1.76	2.78	3.07	2.59	3.35	**3.80**	**4.25**	Earnings per sh A	**5.80**
.61	.70	.78	.82	.91	1.08	1.27	1.48	2.13	2.43	2.46	2.72	3.25	3.53	3.74	3.74	**3.74**	**4.05**	Div'ds Decl'd per sh B■	**4.75**
1.70	4.25	7.03	3.74	2.73	6.47	9.11	10.92	8.54	5.67	2.96	1.32	5.20	9.31	4.93	1.56	**2.20**	**2.75**	Cap'l Spending per sh	**4.25**
10.01	9.47	9.96	10.42	11.46	10.84	10.39	11.31	2.84	1.60	.90	14.22	15.99	15.07	13.58	13.48	**14.00**	**14.65**	Book Value per sh D	**19.15**
221.36	207.98	209.69	211.81	213.63	206.51	204.94	206.62	208.32	209.73	210.68	388.70	411.53	413.24	444.87	446.14	**450.00**	**454.00**	Common Shs Outst'g C	**470.00**
14.6	16.9	14.1	11.0	15.1	20.8	26.6	28.2	40.5	32.7	24.5	30.4	22.6	22.4	14.9	16.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**20.0**
.79	.90	.85	.73	.96	1.30	1.69	1.58	2.13	1.65	1.29	1.53	1.22	1.19	.77	.88	*estimates*		Relative P/E Ratio	**1.10**
3.4%	3.0%	3.7%	5.2%	3.9%	3.1%	2.9%	2.9%	3.5%	6.2%	6.0%	5.1%	5.2%	5.1%	9.7%	7.0%			Avg Ann'l Div'd Yield	**4.1%**

CAPITAL STRUCTURE as of 3/31/22
Total Debt $13724.3 mill. **Due in 5 Yrs** $3808 mill.
LT Debt $12750.5 mill. **LT Interest** $725.0 mill.
(Total interest coverage: 3.8x) (68% of Cap'l)

Leases, Uncapitalized: Annual rentals $16.4 mill.
Pension Assets-12/21 $413.2 mill. **Oblig.** $567.0 mill.
Pfd Stock None

Common Stock 446,616,031 shs.
as of 4/25/22

MARKET CAP: $29.1 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
12633	14603	12195	7763.2	8920.9	12174	12593	10164	8542.2	16540	**22500**	**23500**	Revenues ($mill)	**28500**
11.4%	8.9%	11.8%	18.4%	18.7%	14.8%	18.0%	23.5%	29.8%	19.4%	**18.5%**	**19.5%**	Operating Margin	**21.0%**
335.8	384.4	306.0	354.6	391.6	406.3	428.6	476.5	578.7	621.7	**650**	**725**	Depreciation ($mill)	**950**
346.3	373.3	319.7	251.1	354.1	529.1	1151.7	1278.6	1098.5	1499.7	**1710**	**1930**	Net Profit ($mill)	**2725**
38.3%	13.2%	32.1%	35.2%	37.5%	36.6%	24.0%	22.6%	22.6%	24.4%	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
2.7%	2.6%	2.6%	3.2%	4.0%	4.3%	9.1%	12.6%	12.9%	9.1%	**7.6%**	**8.2%**	Net Profit Margin	**9.6%**
d48.3	d325.6	d1085	d663.1	d1407	d902.8	d709.8	d550.0	525.2	d810.2	**d750**	**d250**	Working Cap'l ($mill)	**500**
6515.4	7755.0	7192.9	8323.6	7920.0	8091.6	8873.3	12504	14228	12748	**13250**	**14000**	Long-Term Debt ($mill)	**16000**
2129.6	2337.9	592.1	335.8	188.7	5527.9	6579.5	6226.0	6042.4	6015.2	**6300**	**6650**	Shr. Equity ($mill) D	**9000**
5.6%	4.7%	6.4%	5.1%	6.9%	5.5%	9.0%	8.1%	7.4%	9.9%	**10.5%**	**11.0%**	Return on Total Cap'l	**12.5%**
16.3%	16.0%	54.0%	74.8%	NMF	9.6%	17.5%	20.5%	18.2%	24.9%	**27.0%**	**29.0%**	Return on Shr. Equity	**30.5%**
4.0%	2.9%	NMF	NMF	NMF	NMF	NMF	NMF	NMF	NMF	**NMF**	**1.5%**	Retained to Com Eq	**5.5%**
76%	82%	NMF	NMF	NMF	NMF	116%	114%	NMF	NMF	**NMF**	**95%**	All Div'ds to Net Prof	**82%**

CURRENT POSITION ($MILL.)

	2020	2021	3/31/22
Cash Assets	524.5	146.4	14.6
Receivables	829.8	1441.8	1682.5
Inventory (LIFO)	371.0	581.0	732.4
Other	144.5	205.2	211.8
Current Assets	1869.8	2374.4	2641.3
Accts Payable	719.3	1332.4	1729.9
Debt Due	7.7	895.8	973.8
Other	617.5	956.4	778.9
Current Liab.	1344.5	3184.6	3482.6

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-8.0%	-10.0%	14.5%
"Cash Flow"	3.5%	6.5%	10.5%
Earnings	7.0%	15.5%	11.5%
Dividends	14.5%	9.5%	4.5%
Book Value	2.5%	51.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2780.0	2457.6	2263.2	2663.6	10164.4
2020	2136.7	1660.7	2174.3	2570.5	8542.2
2021	3194.7	3389.0	4536.2	5420.4	16540.3
2022	5105.2	**5800**	**6200**	**5394.8**	**22500**
2023	**5350**	**6150**	**6400**	**5600**	**23500**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.81	.75	.74	.77	3.07
2020	.83	.32	.70	.69	2.59
2021	.86	.77	.88	.85	3.35
2022	.87	**.90**	**1.00**	**1.03**	**3.80**
2023	**1.00**	**1.00**	**1.10**	**1.15**	**4.25**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.77	.795	.825	.855	3.25
2019	.86	.865	.89	.915	3.53
2020	.935	.935	.935	.935	3.74
2021	.935	.935	.935	.935	3.74
2022	.935	.935			

BUSINESS: ONEOK, Inc. is a leading midstream service provider. It owns premier natural gas liquids systems connecting supply in the Mid-Continent, Permian, and Rocky Mountain regions with key market centers. Has three operating segments: natural gas liquids, natural gas gathering and processing, and natural gas pipelines. Completed separation of natural gas distribution business in February of 2014. Has 2,847 employees. The Vanguard Group, Inc. owns 11.4% of common stock; BlackRock, Inc., 10.2%; State Street Corporation, 7.0%; officers and directors, less than 1.0% (4/22 Proxy). Chair: Julie H. Edwards. President & Chief Executive Officer: Pierce H. Norton II. Inc.: OK. Address: 100 West Fifth Street, Tulsa, Oklahoma 74103. Telephone: 918-588-7000. Internet: www.oneok.com.

Shares of ONEOK have pulled back in price in recent weeks, in conjunction with a selloff in the broader equity market. The company reported mixed results for the March quarter. The top line increased roughly 60%, on a year-over-year basis. ONEOK benefited from greater natural gas and natural gas liquids volumes. However, cost of sales and fuel more than doubled, and earnings per share of $0.87 only marked a slight increase over the prior-year tally. Top-line comparisons will likely remain quite favorable for the second and third quarters, and we expect growth in earnings per share will pick up. For full-year 2022, we look for revenues and share net to advance 36% and 13%, respectively.

Capacity expansions ought to benefit results going forward. The company has recently completed the 1.1 billion cubic feet expansion of its Texas storage facilities. ONEOK is expanding its Oklahoma storage capabilities by four billion cubic feet. This is expected to be completed in the second quarter of 2023.

The healthy operating performance will likely continue. This assumes that the company's business climate remains favorable. ONEOK is a leading midstream service provider, and owns premier natural gas liquids systems, connecting NGL supply from several producing regions with important market centers and an extensive network of gathering, processing, transportation, and storage assets.

This stock is ranked to track the broader market averages for the coming six to 12 months. Looking further out, we anticipate solid growth in revenues and earnings per share here over the pull to mid-decade. From the recent quotation, this stock offers attractive long-term total return potential. This is supported by a generous dividend yield. Aggressive accounts may want to take a closer look. Nevertheless, conservative subscribers can probably find more-suitable choices elsewhere. Leverage is somewhat greater than we would prefer. The payout was not covered by earnings last year, and we are showing a split dividend to indicate the possibility of a reduction in the dividend. ONEOK earns unfavorable marks for Price Stability and Growth Persistence.

Michael Napoli, CFA *May 27, 2022*

(A) Diluted earnings. Excl. nonrecur. items: '06, 13¢; '11, 1¢; '12, 6¢; '13, (51¢); '14, (3¢); '15, (3¢); '16, (1¢); '17, (47¢); '20, ($1.17). Earnings may not sum due to rounding. Next egs. report due late August.
(B) Dividends historically paid mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail.
(C) In mill., adj. for split. (D) Includes intangibles. In 2021: $797.6 mill., $1.79/sh.

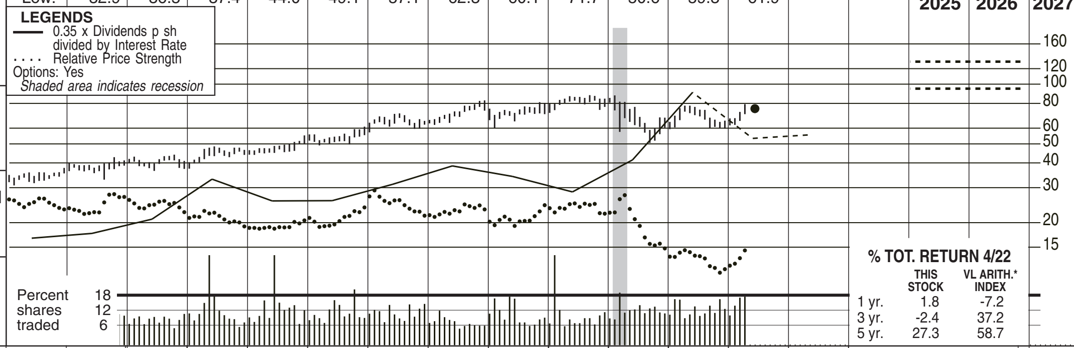
Company's Financial Strength	B+
Stock's Price Stability	25
Price Growth Persistence	30
Earnings Predictability	75

SPIRE INC. NYSE-SR

RECENT PRICE 75.39 | P/E RATIO 17.6 (Trailing: 18.6; Median: 19.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 4 Lowered 8/20/21
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Raised 5/20/22
BETA .80 (1.00 = Market)

High:	42.8	44.0	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2	
Low:	32.9	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.9	



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$51-$84	$68 (-10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+70%)	17%
Low	95	(+25%)	10%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	124	112	125
to Sell	139	126	113
Hld's(000)	42475	42992	42729

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.8	-7.2
3 yr.	-2.4	37.2
5 yr.	27.3	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	***38.95***	***40.75***	Revenues per sh A	***63.65***
3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	***8.40***	***9.10***	"Cash Flow" per sh	***10.90***
2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	***3.90***	***4.35***	Earnings per sh A B	***5.50***
1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	***2.74***	***2.86***	Div'ds Decl'd per sh C■	***3.30***
2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	***10.40***	***11.10***	Cap'l Spending per sh	***11.50***
18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	***51.90***	***56.55***	Book Value per sh D	***67.10***
21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	***52.00***	***52.50***	Common Shs Outst'g E	***55.00***
13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	NMF	13.6	*Bold figures are*		Avg Ann'l P/E Ratio	***20.5***
.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	NMF	.73	*Value Line*		Relative P/E Ratio	***1.15***
4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	*estimates*		Avg Ann'l Div'd Yield	***3.0%***

CAPITAL STRUCTURE as of 3/31/22
Total Debt $3845.6 mill. **Due in 5 Yrs** $1520.0 mill.
LT Debt $3207.3 mill. **LT Interest** $145.0 mill.
(Total interest coverage: 4.2x)

Leases, Uncapitalized Annual rentals $8.8 mill.
Pension Assets-9/21 $945.7 mill. **Oblig.** $1318.0 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 52,121,977 shs.
as of 5/1/22

MARKET CAP: $3.9 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1125.5	1017.0	1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	***2025***	***2140***	Revenues ($mill) A	***3500***
62.6	52.8	84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	***205***	***230***	Net Profit ($mill)	***300***
29.6%	25.0%	27.6%	31.2%	32.5%	32.4%	NMF	15.7%	12.3%	20.1%	***21.0%***	***22.0%***	Income Tax Rate	***25.0%***
5.6%	5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	***10.1%***	***10.7%***	Net Profit Margin	***8.6%***
36.1%	46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	***53.0%***	***52.0%***	Long-Term Debt Ratio	***51.0%***
63.9%	53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	***43.0%***	***44.0%***	Common Equity Ratio	***45.0%***
941.0	1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	***6275***	***6750***	Total Capital ($mill)	***8200***
1019.3	1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	***5400***	***5715***	Net Plant ($mill)	***7100***
7.9%	3.3%	3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	***5.0%***	***5.0%***	Return on Total Cap'l	***5.0%***
10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	***7.5%***	***7.5%***	Return on Shr. Equity	***8.0%***
10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	***7.5%***	***7.5%***	Return on Com Equity	***8.0%***
4.3%	1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	***2.0%***	***2.0%***	Retained to Com Eq	***3.0%***
59%	81%	73%	58%	59%	60%	51%	66%	NMF	54%	***77%***	***72%***	All Div'ds to Net Prof	***65%***

CURRENT POSITION ($MILL.)

	2020	2021	3/31/22
Cash Assets	4.1	4.3	8.3
Other	586.5	1312.2	1081.0
Current Assets	590.6	1316.5	1089.3
Accts Payable	243.3	409.9	367.5
Debt Due	708.4	727.8	638.3
Other	497.5	470.6	390.0
Current Liab.	1449.2	1608.3	1395.8
Fix. Chg. Cov.	373%	448%	435%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-6.5%	- -	*8.5%*
"Cash Flow"	5.0%	6.0%	*7.5%*
Earnings	2.0%	2.5%	*9.0%*
Dividends	4.5%	6.0%	*5.0%*
Book Value	6.5%	4.5%	*7.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	602.0	803.5	321.3	225.6	1952.4
2020	566.9	715.5	321.1	251.9	1855.4
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	***330***	***258.7***	***2025***
2023	***580***	***950***	***340***	***270***	***2140***

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	1.32	3.04	d.09	d.74	3.52
2020	1.24	2.54	d1.87	d.45	1.44
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	***.06***	***d.44***	***3.90***
2023	***1.40***	***3.36***	***.07***	***d.48***	***4.35***

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.5625	.5625	.5625	.5625	2.25
2019	.5925	.5925	.5925	.5925	2.37
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685			

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2021: 3.3 bill. Revenue mix for regulated operations: residential, 58%; commercial and industrial, 28%; transportation, 6%; other, 8%. Has about 3,710 employees. Officers and directors own 3.0% of common shares; BlackRock, 11.5% (1/22 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

It's been a difficult year, thus far, for Spire Inc. (Fiscal 2022 ends on September 30th.) In fact, first-half share net of $4.28 plummeted about 18%, compared to the prior-year tally of $5.20. This stemmed partially from substantially lower profits from the Gas Marketing unit, as fiscal 2021's results enjoyed very favorable market conditions created by extreme weather associated with Winter Storm Uri. Moreover, the Gas Utility division was held back, to a certain extent, by higher operating expenses. So, right now, it seems that full-year share net will plunge more than 20%, to $3.90, relative to fiscal 2021's $4.96 figure. Please be aware that our fiscal 2023 estimate of $4.35 a share is a bit tentative, in part, because of a pending rate case in Missouri. Too, the company is authorized by the Federal Energy Regulatory Commission to operate the key Spire STL Pipeline, temporarily, while it reviews whether permanent approval should be granted. (Leadership expects the process to continue into calendar 2023.)

The Financial Strength rating is B++. When the March period concluded, cash and equivalents resided at $8.3 million. Furthermore, there was $975 million available through a revolving credit facility maturing in October, 2023. Elsewhere, long-term debt was a manageable 53% of total capital, and short-term borrowings were not a major stumbling block. So, Spire ought to be able to meet its various obligations for a while.

We are optimistic about the company's performance out to 2025-2027. The gas utilities boast 1.7 million customers in Mississippi, Alabama, and Missouri, providing a measure of regional diversity. Also, the other businesses, especially pipelines, hold promise. Additional expansionary projects and technological enhancements in customer service and elsewhere should aid Spire, as well. Finally, acquisitions are plausible, supported by the decent balance sheet.

These good-quality shares offer a solid dividend yield. Steady hikes in the payout appear to be in store during the 3- to 5-year period, too. But recent price strength has diminished long-term capital appreciation potential. Meanwhile, the stock is untimely.

Frederick L. Harris, III *May 27, 2022*

(A) Fiscal year ends Sept. 30th. **(B)** Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. **(C)** Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. **(D)** Incl. deferred charges. In '21: $1,171.6 mill., $22.66/sh. **(E)** In millions. **(F)** Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	45

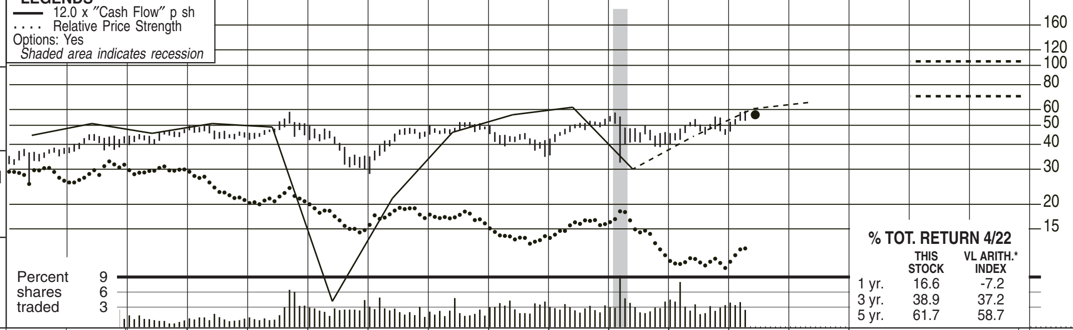
TC ENERGY CORP. NYSE-TRP

RECENT PRICE 56.39 | P/E RATIO 18.8 (Trailing: 21.7 Median: 22.0) | RELATIVE P/E RATIO 1.16 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 4 Lowered 6/4/21
SAFETY 3 Lowered 3/3/17
TECHNICAL 2 Raised 5/13/22
BETA 1.05 (1.00 = Market)

High:	45.1	47.8	49.7	58.4	49.6	48.5	51.8	49.9	53.9	57.9	55.3	59.1	
Low:	36.1	39.7	42.4	42.2	29.9	28.4	44.9	34.6	35.2	32.4	40.2	46.4	

LEGENDS
— 12.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2025 2026 2027

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$36-$61	$49 (-15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+85%)	20%
Low	70	(+25%)	10%

U.S. Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	311	220	203
to Sell	189	230	226
Hld's(000)	681273	682593	686062

Percent shares traded 9 6 3

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.6	-7.2
3 yr.	38.9	37.2
5 yr.	61.7	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
.86	1.01	.82	.95	1.00	.98	1.00	.94	.86	.72	.74	.79	.73	.77	.78	.79	*.75*	*.75*	Trans. Rate (US$/Cdn.$) A	*.75*
13.23	16.36	11.46	12.47	11.58	12.71	11.36	11.70	12.38	11.59	10.77	12.13	10.92	10.85	10.85	10.78	*11.20*	*11.60*	Revenues per sh	*13.20*
3.36	4.29	3.50	3.83	3.71	4.25	3.79	4.25	4.08	.54	1.78	3.84	4.71	5.14	2.50	*3.65*	*5.05*	*5.45*	"Cash Flow" per sh	*6.80*
1.63	2.30	2.07	2.01	1.77	2.12	1.84	2.28	2.12	d1.26	.12	2.00	2.87	3.28	3.72	1.48	*3.00*	*3.75*	Earnings per sh B	*4.50*
1.10	1.36	1.18	1.45	1.60	1.65	1.76	1.73	1.66	1.50	1.68	1.99	2.02	2.30	2.54	2.67	*2.84*	*2.90*	Div'ds Decl'd per sh C■	*3.25*
2.76	3.06	4.17	7.54	7.23	4.55	3.68	5.93	5.30	4.02	4.31	6.66	7.52	6.12	6.69	4.75	*6.00*	*6.00*	Cap'l Spending per sh	*6.00*
13.54	18.13	17.16	21.17	22.27	22.39	22.25	22.22	20.44	14.30	17.47	19.00	20.25	21.86	22.84	21.51	*25.60*	*27.15*	Book Value per sh	*30.45*
488.98	539.77	616.47	684.36	696.20	704.00	705.00	707.00	709.00	702.61	863.76	881.38	918.00	938.40	940.06	981.00	*982.00*	*982.50*	Common Shs Outst'g D	*985.00*
19.0	15.6	17.2	14.1	20.1	19.4	23.9	20.2	22.5	- -	NMF	24.2	14.8	14.7	12.3	32.5	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
1.03	.83	1.04	.94	1.28	1.22	1.52	1.13	1.18	- -	NMF	1.22	.80	.78	.63	1.75	*Value Line*		Relative P/E Ratio	*1.05*
3.6%	3.8%	3.3%	5.1%	4.5%	4.0%	4.0%	3.8%	3.5%	3.8%	4.0%	4.1%	4.8%	4.8%	5.6%	5.6%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $42827.9 mill. **Due in 5 Yrs** $8067 mill.
LT Debt $37418.3 mill. **LT Int.** $1650.0 mill.
(Tot. int. coverage: 2.8x)
(59% of Cap'l)
Leases, Uncapitalized Annual rentals $49.5 mill.

Pension Assets-12/21 $3253.8 mill.
Oblig. $3161.2 mill.

Pfd Stock $2787.5 mill. **Pfd Div'd** $100 million
Common Stock 983,000,000 shs.

MARKET CAP: $55.4 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
8007.0	8269.2	8779.5	8146.2	9303.7	10692	10027	10180	10204	10575.7	*11000*	*11375*	Revenues ($mill)	*13000*
1354.0	1678.8	1586.1	d826.2	173.4	1870.6	2713.6	3053.6	3623.6	1616.3	*2945*	*3685*	Net Profit ($mill)	*4435*
24.0%	24.2%	29.4%	- -	42.1%	21.6%	10.9%	14.5%	3.8%	*5.5%*	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
16.9%	20.3%	18.1%	NMF	1.9%	17.5%	27.1%	30.0%	35.5%	15.3%	*26.8%*	*32.4%*	Net Profit Margin	*34.1%*
51.6%	54.2%	54.6%	65.7%	61.2%	56.0%	60.0%	58.2%	58.0%	58.3%	*52.0%*	*53.0%*	Long-Term Debt Ratio	*55.0%*
44.9%	41.3%	40.0%	29.1%	32.4%	37.0%	34.6%	36.3%	36.6%	41.7%	*40.0%*	*42.0%*	Common Equity Ratio	*40.0%*
34930	37992	36230	34529	46551	45247	53769	56569	58725	50605	*62800*	*65000*	Total Capital ($mill)	*75000*
33713	35350	36009	32309	40529	45535	48747	50296	54773	*55100*	*57000*	*59000*	Net Plant ($mill)	*65000*
5.2%	5.6%	5.7%	NMF	1.9%	5.9%	6.6%	7.0%	7.7%	3.0%	*4.5%*	*5.5%*	Return on Total Cap'l	*7.0%*
8.0%	9.6%	9.6%	NMF	1.0%	9.4%	12.6%	12.9%	14.7%	7.5%	*10.0%*	*11.0%*	Return on Shr. Equity	*12.5%*
8.3%	10.2%	10.4%	NMF	.7%	10.4%	14.0%	14.3%	1.5%	NMF	*10.0%*	*11.0%*	Return on Com Equity	*12.5%*
.5%	2.6%	2.4%	NMF	NMF	4.1%	7.8%	7.6%	NMF	NMF	*.5%*	*2.5%*	Retained to Com Eq	*3.5%*
95%	76%	78%	NMF	NMF	63%	47%	49%	68%	68%	*95%*	*77%*	All Div'ds to Net Prof	*72%*

CURRENT POSITION ($MILL.)

	2020	2021	3/31/22
Cash Assets	1201.1	531.7	857.8
Other	2881.7	5332.5	5913.1
Current Assets	4082.8	5864.2	6770.9
Accts Payable	2995.6	4028.2	4541.4
Debt Due	4826.2	5123.9	5409.5
Other	1588.0	1150.3	1179.1
Current Liab.	9409.8	10302.4	11130.0

ANNUAL RATES

of change (per ADR)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-2.0%	*3.0%*
"Cash Flow"	1.0%	7.0%	*7.5%*
Earnings	5.5%	26.0%	*4.5%*
Dividends	5.0%	7.0%	*5.0%*
Book Value	.5%	2.5%	*5.0%*

QUARTERLY REVENUES ($ mill.) E

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2679	2589	2406	2506	10179.8
2020	2683	2425	2508	2588	10204.2
2021	2671	2514	2560	2831	10575.7
2022	2798	*2725*	*2640*	*2837*	*11000*
2023	*2875*	*2850*	*2750*	*2900*	*11375*

EARNINGS PER SHARE BE

Cal-endar	Mar. 31	Jun.30	Sep.30	Dec.31	Full Year
2019	.84	.93	.61	.91	3.28
2020	.96	1.07	.75	.94	3.72
2021	d.87	.79	.63	.90	1.48
2022	.29	*1.00*	*.76*	*.95*	*3.00*
2023	*.50*	*1.15*	*1.00*	*1.10*	*3.75*

QUARTERLY DIVIDENDS PAID AC■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.506	.506	.506	.506	1.99
2019	.576	.576	.576	.576	2.31
2020	.636	.636	.636	.636	2.37
2021	.608	.653	.705	.705	2.67
2022	.687	.720			

BUSINESS: TC Energy Corp, formerly known as TransCanada Corp., operates the most extensive natural gas pipeline system in North America. The company's 57,969 mi. of natural gas pipelines supply more than 25% of clean burning natural gas consumed in North America, and it has gas storage facilities with a 653 bill. cubic capacity. It has 3,019 mi. of liquids pipelines. Its three major segments are natural gas pipelines (78% of '21 revenues), oil pipelines (17%), and power/storage (5%). Has 7,017 employees. Off./dir. own less than 1% of stock (2021 40-F). Chairman: Siim Vanaselja. President/CEO: Francois Poirier. Incorporated: Canada. Address: 450 1 Street S.W., Calgary, Alberta, T2P 5H1. Telephone: 403-920-2000. Internet: www.tcenergy.com.

Shares of TC Energy have edged higher in price in recent months. The company reported moderate top-line growth for the March period. Earnings per share of $0.29 compared favorably with the prior-year deficit. Strong demand for energy in North America supported operating performance here during the recent quarter. Solid results ought to continue in the coming quarters, and we look for top-line growth of roughly 4% for full-year 2022. Earnings comparisons will likely remain much more favorable, and we project that share net will improve dramatically from the last year's depressed level.

Prospects for the long haul appear to be relatively healthy. With a diversified portfolio of essential energy infrastructure assets, the company remains well positioned in the markets that it serves, and ought to further capitalize on rising demand for energy in North America in the coming years. Investment in operations is expected to support growth in revenues and earnings in the years ahead. Much of the company's infrastructure expansion projects are underwritten by long-term contracts and regulated business models. A greater emphasis on renewable energy and sustainable projects should also pay off. We expect that this will better diversify the company's asset roster and support returns down the road. Efforts by TC to pursue greater operating efficiency are also encouraging. The cost savings resulting from these measures can then be reinvested.

These shares are unfavorably ranked for year-ahead relative price performance. We anticipate solid growth in revenues and earnings per share for the company over the pull to mid-decade. From the recent quotation, this stock offers worthwhile long-term total return potential. This is supported by a generous dividend yield, and we believe that the payout will continue to increase going forward. Thus, venturesome subscribers with a long time horizon might find something to like here. That said, conservative investors can probably find more-suitable choices elsewhere. TC Energy earns unfavorable marks for Price Growth Persistence and Earnings Predictability.

Michael Napoli, CFA *May 27, 2022*

(A) At yearend. In US$.
(B) Diluted EPS. Excl. nonrecurring gains/(losses): '06, 22¢; '07, 5¢; '08, 22¢; '10, (18¢). Next earnings report due late July.
(C) Dividends subject to 15% Canadian non-resident tax. Dividends historically paid: late January, April, July, and October. ■Div'd reinvestment plan available.
(D) In millions.
(E) Quarterlies may not sum due to translation.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	20
Earnings Predictability	15

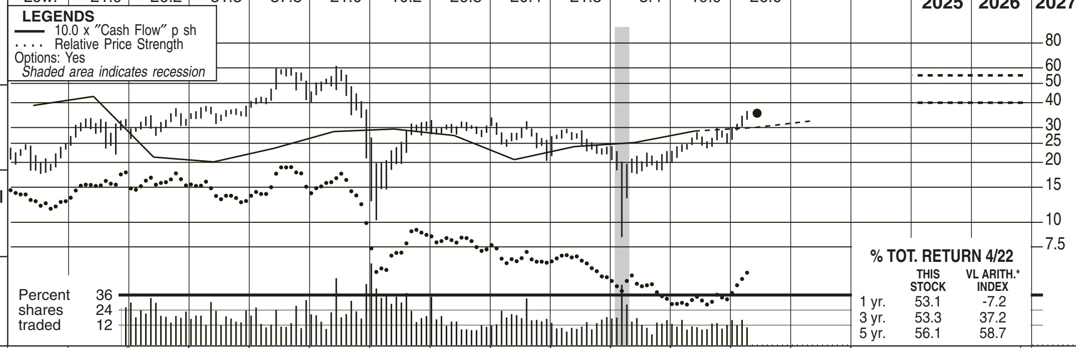
WILLIAMS COS. NYSE-WMB

RECENT PRICE 35.44 | P/E RATIO 23.6 (Trailing: 25.0; Median: 36.0) | RELATIVE P/E RATIO 1.46 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 3 Raised 5/14/21
SAFETY 3 Raised 2/26/21
TECHNICAL 3 Raised 2/25/22
BETA 1.20 (1.00 = Market)

High:	33.5	37.6	38.7	59.8	61.4	32.2	32.7	33.7	29.5	24.2	29.9	37.1
Low:	21.9	26.2	31.3	37.8	21.0	10.2	26.8	20.4	21.5	8.4	19.9	26.0

Target Price Range 2025 2026 2027



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$21-$41	$31 (-15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+55%)	16%
Low	40	(+15%)	8%

Institutional Decisions

	2Q2021	3Q2021	4Q2021
to Buy	522	477	543
to Sell	333	361	387
Hld's(000)	1021408	1024391	1025606

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	53.1	-7.2
3 yr.	53.3	37.2
5 yr.	56.1	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
19.78	18.02	21.37	14.16	16.44	13.42	10.99	10.04	10.22	9.83	10.00	9.72	7.18	6.77	6.36	8.75	***8.65***	***9.10***	Revenues per sh	***10.85***
2.32	3.34	4.55	3.27	3.88	4.30	2.13	2.01	2.35	2.86	2.95	2.73	2.07	2.41	2.52	2.88	***3.25***	***3.45***	"Cash Flow" per sh	***4.15***
.86	1.44	2.23	.75	1.30	1.55	1.11	.81	.80	.54	.60	.63	.79	.99	1.10	1.36	***1.45***	***1.55***	Earnings per sh A	***1.90***
.35	.39	.43	.44	.49	.78	1.20	1.44	1.96	2.45	1.68	1.20	1.36	1.52	1.60	1.64	***1.70***	***1.76***	Div'ds Decl'd per sh B	***2.10***
4.20	4.81	6.01	4.09	4.77	4.73	3.71	5.23	5.40	4.23	2.73	2.95	2.70	1.77	1.05	1.03	***2.45***	***2.50***	Cap'l Spending per sh	***2.40***
10.17	10.88	14.60	14.49	12.46	3.03	6.98	7.12	11.75	8.21	6.19	11.69	12.09	11.00	9.67	9.37	***10.10***	***10.15***	Book Value per sh	***11.25***
597.10	586.00	578.00	583.00	585.00	591.00	681.00	683.00	747.00	749.00	750.00	826.00	1210.0	1212.0	1213.0	1215.0	***1215.00***	***1212.00***	Common Shs Outst'g C	***1200.00***
27.4	21.7	13.2	21.6	16.4	18.8	28.4	43.9	61.3	84.3	39.0	46.9	34.6	26.0	17.8	18.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	***25.0***
1.48	1.15	.79	1.44	1.04	1.18	1.81	2.47	3.23	4.24	2.05	2.36	1.87	1.39	.91	1.01	*estimates*		Relative P/E Ratio	***1.40***
1.5%	1.2%	1.5%	2.7%	2.3%	2.7%	3.8%	4.0%	4.0%	5.4%	7.2%	4.1%	5.0%	5.9%	8.2%	6.5%			Avg Ann'l Div'd Yield	***4.4%***

CAPITAL STRUCTURE as of 3/31/22
Total Debt $22426 mill. **Due in 5 Yrs** $8292 mill.
LT Debt $20801 mill. **LT Interest** $1300.0 mill.
(66% of Cap'l)
Annual Rentals $32.0 mill.

Pension Assets-12/21 $1336.0 mill.
Oblig. $1133.0 mill.
Pfd Stock None

Common Stock 1,218,011,601 shares
as of 4/28/22
MARKET CAP: $36.5 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
7486.0	6860.0	7637.0	7360.0	7499.0	8031.0	8686.0	8201.0	7719.0	10627	***10500***	***11000***	Revenues ($mill)	***13000***
32.0%	32.4%	32.3%	43.3%	46.3%	44.1%	43.4%	50.1%	56.1%	43.9%	***52.8%***	***53.1%***	Operating Margin	***53.5%***
756.0	815.0	1176.0	1738.0	1763.0	1736.0	1725.0	1714.0	1721.0	1842.0	***2205***	***2310***	Depreciation ($mill)	***2730***
695.0	559.0	582.0	405.0	450.0	521.0	776.0	1203.0	1336.0	1661.0	***1765***	***1880***	Net Profit ($mill)	***2275***
30.1%	26.2%	31.4%	- -	29.5%	27.0%	21.2%	29.5%	25.5%	24.7%	***23.0%***	***23.0%***	Income Tax Rate	***23.0%***
9.3%	8.1%	7.6%	5.5%	6.0%	6.5%	8.9%	14.7%	17.3%	15.6%	***16.8%***	***17.1%***	Net Profit Margin	***17.5%***
375.0	d300.0	d677.0	d970.0	d1487	d467.0	d347.0	d2388	d890.0	d423.0	***295***	***220***	Working Cap'l ($mill)	***d380***
10735	11353	20888	23812	22624	20434	22367	20148	21451	21650	***22300***	***22970***	Long-Term Debt ($mill)	***25610***
4752.0	4864.0	8777.0	6148.0	4643.0	9656.0	14660	13363	11769	11423	***12285***	***12365***	Shr. Equity ($mill)	***13525***
6.3%	5.3%	3.5%	3.2%	3.9%	3.6%	3.7%	5.4%	5.8%	6.8%	***6.5%***	***7.0%***	Return on Total Cap'l	***8.0%***
14.6%	11.5%	6.6%	6.6%	9.7%	5.4%	5.3%	9.0%	11.4%	14.5%	***14.5%***	***15.0%***	Return on Shr. Equity	***16.5%***
NMF	NMF	NMF	NMF	NMF	NMF	NMF	NMF	NMF	NMF	***NMF***	***NMF***	Retained to Com Eq	***NMF***
107%	NMF	NMF	NMF	NMF	NMF	NMF	NMF	NMF	120%	***NMF***	***NMF***	All Div'ds to Net Prof	***NMF***

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	142	1680	604
Receivables	999	1978	1973
Inventory	136	379	201
Other	152	512	376
Current Assets	1429	4549	3154
Accts Payable	482	1746	1584
Debt Due	893	2025	1625
Other	944	1201	1099
Current Liab.	2319	4972	4308

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-7.0%	-6.0%	*7.0%*
"Cash Flow"	-4.0%	-1.0%	*8.0%*
Earnings	-.5%	12.0%	*8.5%*
Dividends	11.0%	-5.0%	*5.0%*
Book Value	- -	3.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2054	2041	1999	2107	8201
2020	1913	1781	1933	2092	7719
2021	2612	2283	2475	3257	10627
2022	2524	***2550***	***2650***	***2765***	***10500***
2023	***2600***	***2700***	***2800***	***2900***	***11000***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.22	.26	.26	.24	.99
2020	.26	.25	.27	.31	1.10
2021	.35	.27	.35	.39	1.36
2022	.41	***.35***	***.36***	***.38***	***1.45***
2023	***.37***	***.38***	***.40***	***.40***	***1.55***

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.34	.34	.34	.34	1.36
2019	.38	.38	.38	.38	1.52
2020	.40	.40	.40	.40	1.60
2021	.41	.41	.41	.41	1.64
2022	.425	.425			

BUSINESS: The Williams Companies, Inc., gathers, processes, and transports natural gas throughout the United States. It also performs gas marketing services. Business segments include Transmission & Gulf of Mexico, Northeast G&P, West, and other. Acquired Access Midstream Partners, 7/14; WPX Energy, 1/12. I.P.O. for Williams Partners L.P., 8/05; Williams Pipeline Partners L.P., 1/08. Reaquired Williams Pipeline Partners L.P. 10/18. Has about 5,425 employees. Officers/directors own less than 1.0% of common shares; State Street, 6.9%; The Vanguard Group, 9.5%; BlackRock, Inc., 8.9% (4/22 Proxy). President and CEO: Alan S. Armstrong. Inc.: Delaware. Addrress: One Williams Center, Tulsa, Oklahoma 74172. Tel.: 918-573-2000. Internet:www.williams.com.

The Williams Cos. recorded a decent first-quarter performance. Revenues slipped slightly to $2.5 billion, as the nonrecurrence of income related to Winter Storm Uri more than offset growth across all business segments. Additionally, the company incurred some losses related to commodity derivatives during the quarter. Still, volumes expanded across the western U.S., and its upstream joint venture operations recorded a good quarter. Costs grew at a decent clip, including operation and maintenance, due to a broader production footprint. Moreover, administrative costs faced inflationary pressures. Overall, adjusted earnings rose to $0.41 per share during the quarter. The company will likely have strong operating results over the coming quarters as drilling increases due to higher commodity prices. This should help volumes across the Transco pipeline system, while a few expansion projects will probably boost top-line growth. Overall, we project adjusted earnings will rise to $1.45 per share this year.

The Williams Cos. has agreed to purchase Trace Midstream's assets for $950 million. This purchase will enlarge Williams' operations in the Haynesville Shale region, while increasing its gathering capacity to more than four billion cubic feet per day. As part of the agreement, Trace's customer, Rockcliff Energy, agreed to a long-term capacity assurance agreement to help keep volumes steady. The company ought to benefit from higher demand for natural gas liquefaction facilities, and Williams will send more gas to the Gulf of Mexico through its pipelines. Too, we think inflationary pressures will ease, allowing for a steady rise in profits. This should allow long-term adjusted earnings to reach $1.55 per share in 2023 and $1.90 in 2025-2027.

The dividend remains a top draw. The yield is above the *Value Line* median, remains well covered by cash flows, and the payout will likely grow steadily. The company has a $1.5 billion stock-repurchase authorization outstanding.

Shares of The Williams Cos. are neutrally ranked for Timeliness. Still, this equity offers below-average 3- to 5-year appreciation potential. This stock is best suited for income-oriented accounts.

John E. Seibert III *May 27, 2022*

(A) Diluted egs. Excl. nonrec. gains (losses): '06, (31¢); '07, (4¢); '08, 3¢; '09, (47¢); '10, ($3.17); '11, (21¢); '12, 4¢; '13, (17¢). Excl. gains (losses) from disc. op.: '06, (4¢); '07, 23¢; '08, 14¢; '09, (45¢); '10, (1¢); '11, (71¢); '12, 22¢; '13, (2¢); '14, $2.11; '15, ($1.28), '16, ($1.17) '17, $1.99; '18, (95¢); '19, (28¢); '20, (93¢) '21 (23¢), '22 (10¢). Egs. may not sum due to rounding. Next egs. report due in late July. (B) Div'ds paid in Mar., June, Sep., and Dec. (C) In mill.

Company's Financial Strength	B
Stock's Price Stability	65
Price Growth Persistence	10
Earnings Predictability	75

ENSTAR Natural Gas Company and Alaska Pipeline Company
Summary of Risk Premium Models for the
Proxy Group of Twelve Companies

	Proxy Group of Twelve Companies
Predictive Risk Premium Model (PRPM) (1)	13.79 %
Risk Premium Using an Adjusted Total Market Approach (2)	11.37
Average	12.58 %

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Indicated ROE
Derived by the Predictive Risk Premium Model (1)

Proxy Group of Twelve Companies	[1] LT Average Predicted Variance	[2] Spot Predicted Variance	[3] Recommended Variance (2)	[4] GARCH Coefficient	[5] Predicted Risk Premium (3)	[6] Risk-Free Rate (4)	[7] Indicated ROE (5)
Atmos Energy Corporation	0.34%	0.39%	0.36%	2.31	10.61%	3.74%	14.35%
Kinder Morgan, Inc.	0.67%	0.62%	0.64%	1.41	11.50%	3.74%	15.24%
MDU Resources Group, Inc.	0.37%	0.43%	0.40%	1.66	8.31%	3.74%	12.05%
National Fuel Gas Company	0.33%	0.36%	0.34%	1.50	6.39%	3.74%	10.13%
New Jersey Resources Corp.	0.38%	0.37%	0.38%	2.08	9.79%	3.74%	13.53%
Nisource, Inc.	0.49%	0.60%	0.54%	0.83	5.49%	3.74%	9.23%
Northwest Natural Holding Co.	0.33%	0.54%	0.44%	1.55	8.43%	3.74%	12.17%
ONE Gas, Inc.	0.33%	0.36%	0.34%	2.66	11.57%	3.74%	15.31%
ONEOK, Inc.	0.71%	0.54%	0.63%	1.72	13.74%	3.74%	17.48%
Spire, Inc.	0.70%	0.38%	0.54%	0.96	6.42%	3.74%	10.16%
TC Energy Corp.	0.36%	0.50%	0.43%	2.22	12.01%	3.74%	15.75%
The Williams Companies, Inc.	1.62%	0.80%	1.21%	0.93	14.38%	3.74%	18.12%
						Average	13.63%
						Median	13.94%
						Average of Mean and Median	13.79%

Notes:
(1) The Predictive Risk Premium Model uses historical data to generate a predicted variance and a GARCH coefficient. The historical data used are the equity risk premiums for the first available trading month as reported by Bloomberg Professional Service.
(2) Average of Column [1] and Column [2].
(3) (1+(Column [3] * Column [4])^12) - 1.
(4) From note 2 on page 2 of Schedule 5.
(5) Column [5] + Column [6].

ENSTAR Natural Gas Company and Alaska Pipeline Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Twelve Companies	
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.00	%
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds	0.60	(2)
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.60	%
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group	0.17	(3)
5.	Adjusted Prospective Bond Yield	5.77	%
6.	Equity Risk Premium (4)	5.60	
7.	Risk Premium Derived Common Equity Cost Rate	11.37	%

Notes:
(1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 9 and 10 of this Schedule).
(2) The average yield spread of A rated public utility bonds over Aaa rated corporate bonds of 0.60% from page 4 of this Schedule.
(3) Adjustment to reflect the A3/Baa1 Moody's LT issuer rating of the Utility Proxy Group as shown on page 5 of this Schedule. The 0.17% upward adjustment is derived by taking 1/2 of the spread between A2 and Baa2 Public Utility Bonds (1/2 * 0.33% = 0.17%) as derived from page 4 of this Schedule.
(4) From page 7 of this Schedule.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1]	[2]	[3]
	Aaa Rated Corporate Bond	A2 Rated Public Utility Bond	Baa2 Rated Public Utility Bond
Jun-2022	4.24 %	4.86 %	5.22 %
May-2022	4.13	4.75	5.07
Apr-2022	3.76	4.32	4.61
Average	4.04 %	4.64 %	4.97 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.60 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:
0.33 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Service

ENSTAR Natural Gas Company and Alaska Pipeline Company
Comparison of Long-Term Issuer Ratings for
Proxy Group of Twelve Companies

	Moody's Long-Term Issuer Rating July 2022		Standard & Poor's Long-Term Issuer Rating July 2022	
Proxy Group of Twelve Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
Atmos Energy Corporation	A1	5.0	A-	7.0
Kinder Morgan, Inc.	Baa2	9.0	BBB	9.0
MDU Resources Group, Inc.	NR	- -	BBB+	8.0
National Fuel Gas Company	Baa3	10.0	BBB-	10.0
New Jersey Resources Corp.	A1	5.0	NR	- -
Nisource, Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Co.	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	BBB+	8.0
ONEOK, Inc.	Baa3	10.0	BBB+	8.0
Spire, Inc.	A1/A2	5.5	A-	7.0
TC Energy Corp.	A3/Baa1	7.5	BBB+	8.0
The Williams Companies, Inc.	Baa1	8.0	BBB	9.0
Average	A3/Baa1	7.5	BBB+	7.9

Notes:

(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 6 of this Schedule.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

ENSTAR Natural Gas Company and Alaska Pipeline Company
Judgment of Equity Risk Premium for
Proxy Group of Twelve Companies

Line No.		Proxy Group of Twelve Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	7.01 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	4.93
3.	Predicted Equity Risk Premium Based on Regression Analysis of 810 Fully-Litigated Gas Utility Rate Cases (3)	4.86
4.	Average equity risk premium	5.60 %

Notes: (1) From page 8 of this Schedule.
(2) From page 11 of this Schedule.
(3) From page 12 of this Schedule.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Twelve Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Twelve Companies	
1.	Ibbotson Equity Risk Premium (1)	6.13	%
2.	Regression on Ibbotson Risk Premium Data (2)	7.32	
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.22	
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	9.86	
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	11.54	
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	7.64	
7.	Conclusion of Equity Risk Premium	8.45	%
8.	Adjusted Beta (7)	0.83	
9.	Forecasted Equity Risk Premium	7.01	%

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Ibbotson® SBBI® 2021 Market Report minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1926-2021.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa rated corporate bond yields from 1928-2021 referenced in note 1 above.

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through June 2022.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.00% (from page 3 of this Schedule) from the projected 3-5 year total annual market return of 14.86% (described fully in note 1 on page 2 of Schedule 5).

(5) Using data from Value Line for the S&P 500, an expected total return of 16.54% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.00% results in an expected equity risk premium of 11.54%.

(6) Using data from Bloomberg Professional Service for the S&P 500, an expected total return of 12.64% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.00% results in an expected equity risk premium of 7.64%.

(7) Average of mean and median beta from page 1 of Schedule 5.

Sources of Information:

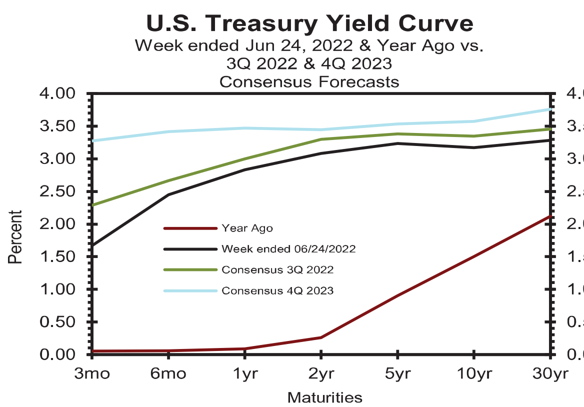
Stocks, Bonds, Bills, and Inflation - 2022 SBBI Yearbook, John Wiley & Sons, Inc.
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, July 1, 2022 and June 1, 2022
Bloomberg Professional Service

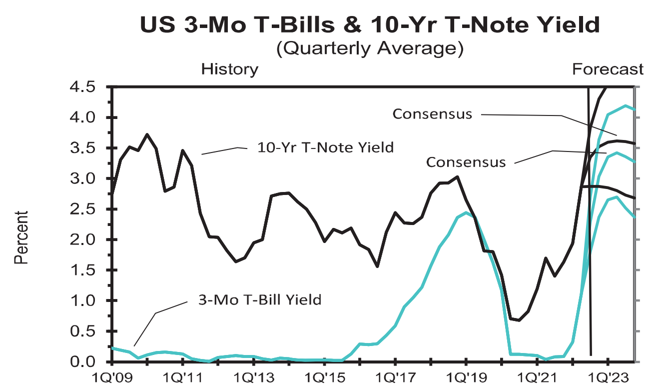
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

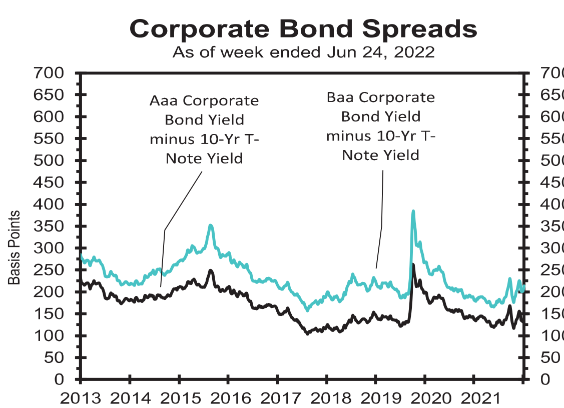
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Qtr	3Q	4Q	1Q	2Q	3Q	4Q
Interest Rates	Jun 24	Jun 17	Jun 10	Jun 3	May	Apr	Mar	2Q 2022*	2022	2022	2023	2023	2023	2023
Federal Funds Rate	1.58	0.83	0.83	0.83	0.77	0.33	0.20	0.73	2.4	3.1	3.5	3.5	3.5	3.4
Prime Rate	4.75	4.00	4.00	4.00	3.94	3.50	3.37	3.90	5.4	6.2	6.6	6.7	6.6	6.5
SOFR	1.45	1.00	0.76	0.79	0.72	0.29	0.16	0.69	2.1	2.9	3.4	3.5	3.4	3.3
Commercial Paper, 1-mo.	1.60	1.40	1.00	0.87	0.80	0.44	0.32	0.80	2.2	3.0	3.4	3.4	3.4	3.3
Treasury bill, 3-mo.	1.67	1.70	1.30	1.17	0.99	0.76	0.45	1.08	2.3	3.0	3.4	3.4	3.4	3.3
Treasury bill, 6-mo.	2.45	2.30	1.81	1.65	1.49	1.26	0.86	1.62	2.7	3.3	3.5	3.6	3.5	3.4
Treasury bill, 1 yr.	2.83	2.94	2.34	2.14	2.06	1.89	1.34	2.18	3.0	3.5	3.7	3.7	3.6	3.5
Treasury note, 2 yr.	3.08	3.27	2.83	2.63	2.62	2.54	1.91	2.71	3.3	3.6	3.7	3.6	3.6	3.4
Treasury note, 5 yr.	3.23	3.45	3.07	2.91	2.87	2.78	2.11	2.95	3.4	3.6	3.6	3.6	3.6	3.5
Treasury note, 10 yr.	3.17	3.36	3.05	2.92	2.90	2.75	2.13	2.93	3.3	3.5	3.6	3.6	3.6	3.6
Treasury note, 30 yr.	3.28	3.38	3.18	3.09	3.07	2.81	2.41	3.04	3.5	3.6	3.7	3.8	3.8	3.8
Corporate Aaa bond	4.58	4.68	4.39	4.27	4.37	4.01	3.63	4.30	4.7	5.0	5.1	5.1	5.1	5.1
Corporate Baa bond	5.30	5.38	5.05	4.94	5.05	4.63	4.23	4.97	5.6	6.0	6.2	6.2	6.2	6.2
State & Local bonds	4.05	4.08	3.77	3.73	3.96	3.70	3.30	3.87	4.0	4.3	4.4	4.5	4.5	4.4
Home mortgage rate	5.81	5.78	5.23	5.09	5.23	4.98	4.17	5.23	5.7	5.9	6.0	5.9	5.8	5.7

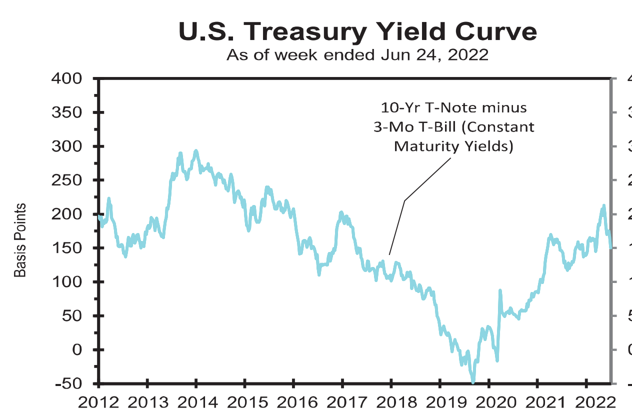
	History								Consensus Forecasts-Quarterly					
	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q
Key Assumptions	2020	2020	2021	2021	2021	2021	2022	2022**	2022	2022	2023	2023	2023	2023
Fed's AFE $ Index	107.2	105.1	103.4	102.9	105.0	107.0	108.4	113.6	115.3	115.4	115.1	114.6	114.0	113.8
Real GDP	33.8	4.5	6.3	6.7	2.3	6.9	-1.6	2.9	2.1	1.6	1.2	1.0	1.3	1.6
GDP Price Index	3.6	2.2	4.3	6.1	6.0	7.1	8.2	5.9	5.2	3.9	3.4	2.8	2.7	2.6
Consumer Price Index	4.8	2.2	4.1	8.2	6.7	7.9	9.2	7.6	6.0	3.8	3.3	2.7	2.5	2.5
PCE Price Index	3.7	1.5	3.8	6.5	5.3	6.4	7.1	5.8	5.2	3.6	3.1	2.5	2.4	2.3

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. *Interest rate data for 2Q 2022 based on historical data through the week ended June 24. **Data for 2Q 2022 for the Fed's AFE $ Index based on data through the week ended June 24. Figures for 2Q 2022 Real GDP, GDP Chained Price Index, Consumer Price Index, and PCE Price Index are consensus forecasts from the June 2022 survey.









Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2023 through 2028 and averages for the five-year periods 2024-2028 and 2029-2033. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year						Five-Year Averages	
		2023	2024	2025	2026	2027	2028	2024-2028	2029-2033
1. Federal Funds Rate	**CONSENSUS**	**3.0**	**2.7**	**2.5**	**2.5**	**2.5**	**2.5**	**2.6**	**2.5**
	Top 10 Average	3.5	3.3	3.0	2.8	2.8	2.8	3.0	2.8
	Bottom 10 Average	2.6	2.1	2.0	2.2	2.2	2.2	2.2	2.1
2. Prime Rate	**CONSENSUS**	**6.1**	**5.9**	**5.7**	**5.6**	**5.6**	**5.6**	**5.7**	**5.6**
	Top 10 Average	6.6	6.4	6.1	6.0	6.0	6.0	6.1	5.9
	Bottom 10 Average	5.6	5.3	5.2	5.3	5.3	5.3	5.3	5.2
3. SOFR	**CONSENSUS**	**3.0**	**2.8**	**2.5**	**2.5**	**2.5**	**2.5**	**2.6**	**2.5**
	Top 10 Average	3.4	3.3	3.0	2.9	2.8	2.8	3.0	2.8
	Bottom 10 Average	2.7	2.2	2.0	2.2	2.2	2.2	2.2	2.1
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.2**	**2.9**	**2.6**	**2.6**	**2.6**	**2.6**	**2.7**	**2.6**
	Top 10 Average	3.5	3.4	3.1	2.9	2.9	2.9	3.0	2.9
	Bottom 10 Average	2.8	2.5	2.3	2.4	2.4	2.3	2.3	2.3
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.0**	**2.8**	**2.6**	**2.6**	**2.6**	**2.5**	**2.6**	**2.5**
	Top 10 Average	3.6	3.4	3.1	3.1	3.0	2.9	3.1	2.9
	Bottom 10 Average	2.5	2.2	2.0	2.1	2.2	2.2	2.1	2.2
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.2**	**2.9**	**2.7**	**2.7**	**2.7**	**2.6**	**2.7**	**2.6**
	Top 10 Average	3.8	3.6	3.2	3.2	3.1	3.0	3.2	3.0
	Bottom 10 Average	2.6	2.2	2.1	2.2	2.3	2.3	2.2	2.3
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.2**	**3.0**	**2.9**	**2.9**	**2.8**	**2.8**	**2.9**	**2.8**
	Top 10 Average	3.9	3.8	3.5	3.4	3.3	3.2	3.4	3.2
	Bottom 10 Average	2.6	2.4	2.2	2.4	2.4	2.4	2.3	2.4
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.4**	**3.2**	**3.1**	**3.1**	**3.0**	**3.0**	**3.1**	**3.0**
	Top 10 Average	4.3	4.1	3.8	3.6	3.5	3.5	3.7	3.5
	Bottom 10 Average	2.7	2.4	2.3	2.5	2.6	2.5	2.4	2.5
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.5**	**3.4**	**3.3**	**3.3**	**3.3**	**3.2**	**3.3**	**3.3**
	Top 10 Average	4.3	4.2	4.1	3.9	3.8	3.8	3.9	3.8
	Bottom 10 Average	2.8	2.6	2.5	2.7	2.7	2.7	2.6	2.8
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**3.5**	**3.5**	**3.4**	**3.5**	**3.5**	**3.4**	**3.5**	**3.5**
	Top 10 Average	4.4	4.4	4.2	4.2	4.1	4.1	4.2	4.1
	Bottom 10 Average	2.8	2.5	2.6	2.9	2.9	2.8	2.7	2.8
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**3.8**	**3.8**	**3.8**	**3.9**	**3.8**	**3.8**	**3.8**	**3.9**
	Top 10 Average	4.6	4.7	4.5	4.5	4.4	4.5	4.5	4.5
	Bottom 10 Average	3.0	2.9	3.0	3.3	3.2	3.2	3.1	3.2
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.0**	**5.0**	**4.9**	**5.0**	**5.0**	**4.9**	**4.9**	**5.0**
	Top 10 Average	5.7	5.7	5.6	5.5	5.5	5.5	5.5	5.6
	Bottom 10 Average	4.4	4.2	4.3	4.4	4.4	4.4	4.3	4.4
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**5.9**	**5.8**	**5.9**	**5.9**	**5.9**	**5.9**	**5.9**
	Top 10 Average	6.6	6.6	6.4	6.3	6.3	6.3	6.4	6.4
	Bottom 10 Average	5.4	5.3	5.2	5.4	5.4	5.4	5.3	5.4
14. State & Local Bonds Yield	**CONSENSUS**	**4.3**	**4.3**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**
	Top 10 Average	5.0	5.0	4.8	4.8	4.7	4.7	4.8	4.8
	Bottom 10 Average	3.7	3.7	3.7	3.9	3.9	3.9	3.8	3.9
15. Home Mortgage Rate	**CONSENSUS**	**5.7**	**5.5**	**5.4**	**5.4**	**5.4**	**5.4**	**5.4**	**5.4**
	Top 10 Average	6.4	6.4	6.1	6.0	6.0	6.0	6.1	6.0
	Bottom 10 Average	4.9	4.7	4.6	4.8	4.8	4.8	4.7	4.8
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**113.8**	**112.8**	**111.9**	**111.0**	**110.6**	**110.4**	**111.3**	**109.8**
	Top 10 Average	115.6	114.7	114.0	113.4	113.1	112.8	113.6	112.7
	Bottom 10 Average	112.2	111.0	109.9	108.8	108.2	107.9	109.2	107.4

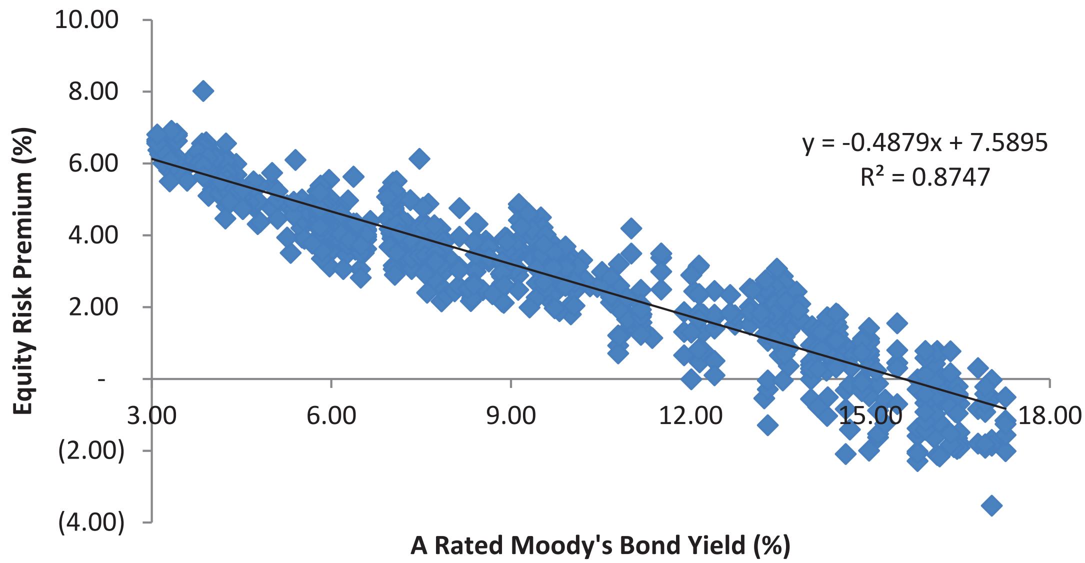
		Year-Over-Year, % Change						Five-Year Averages	
		2023	2024	2025	2026	2027	2028	2024-2028	2029-2033
B. Real GDP	**CONSENSUS**	**2.0**	**2.0**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.0**
	Top 10 Average	2.6	2.4	2.4	2.4	2.4	2.4	2.4	2.3
	Bottom 10 Average	1.5	1.5	1.8	1.8	1.8	1.8	1.7	1.8
C. GDP Chained Price Index	**CONSENSUS**	**3.0**	**2.4**	**2.3**	**2.3**	**2.2**	**2.2**	**2.3**	**2.2**
	Top 10 Average	3.7	2.8	2.7	2.6	2.6	2.6	2.7	2.6
	Bottom 10 Average	2.3	2.0	1.9	1.9	1.9	1.9	1.9	1.9
D. Consumer Price Index	**CONSENSUS**	**3.2**	**2.4**	**2.4**	**2.4**	**2.3**	**2.3**	**2.4**	**2.3**
	Top 10 Average	4.1	3.0	2.9	2.8	2.7	2.7	2.8	2.7
	Bottom 10 Average	2.3	1.8	2.0	2.0	1.9	1.9	1.9	1.9
E. PCE Price Index	**CONSENSUS**	**3.0**	**2.3**	**2.3**	**2.3**	**2.3**	**2.2**	**2.3**	**2.3**
	Top 10 Average	3.8	2.8	2.8	2.7	2.7	2.6	2.7	2.7
	Bottom 10 Average	2.2	1.8	1.9	1.9	1.9	1.8	1.9	1.9

ENSTAR Natural Gas Company and Alaska Pipeline Company
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium
	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):	
1.	Historical Equity Risk Premium	4.28 %
2.	Regression of Historical Equity Risk Premium (2)	5.03
3.	Forecasted Equity Risk Premium Based on PRPM (3)	5.55
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	5.44
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	4.33
6.	Average Equity Risk Premium (6)	4.93 %

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2021. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2021 referenced in note 1 above.
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - June 2022.
(4) Using data from Value Line for the S&P Utilities Index, an expected total return of 11.04% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the expected A2 rated public utility bond yield of 5.60% results in an expected equity risk premium of 5.44%. (11.04% - 5.60 = 5.44%)
(5) Using data from the Bloomberg Professional Service for the S&P Utilities Index, an expected total return of 9.93% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the expected A2 rated public utility bond yield of 5.60% results in an expected equity risk premium of 4.33%. (9.93% - 5.60 = 4.33%)
(6) Average of lines 1 through 5.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5895 %	-0.4879	5.60 %	4.86 %

Notes:
(1) From line 3 of page 3 of this Schedule.

Source of Information: Regulatory Research Associates

ENSTAR Natural Gas Company and Alaska Pipeline Company
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Twelve Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.80	0.71	0.76	9.71 %	3.74 %	11.12 %	11.70 %	11.41 %
Kinder Morgan, Inc.	1.15	0.77	0.96	9.71	3.74	13.06	13.16	13.11
MDU Resources Group, Inc.	1.10	0.70	0.90	9.71	3.74	12.48	12.72	12.60
National Fuel Gas Company	0.80	0.71	0.75	9.71	3.74	11.02	11.63	11.33
New Jersey Resources Corp.	0.95	0.72	0.83	9.71	3.74	11.80	12.21	12.01
Nisource, Inc.	0.85	0.70	0.78	9.71	3.74	11.32	11.85	11.58
Northwest Natural Holding Co.	0.80	0.56	0.68	9.71	3.74	10.34	11.12	10.73
ONE Gas, Inc.	0.80	0.68	0.74	9.71	3.74	10.93	11.56	11.24
ONEOK, Inc.	1.50	0.95	1.23	9.71	3.74	15.69	15.13	15.41
Spire, Inc.	0.80	0.66	0.73	9.71	3.74	10.83	11.49	11.16
TC Energy Corp.	1.05	0.65	0.85	9.71	3.74	12.00	12.36	12.18
The Williams Companies, Inc.	1.20	0.67	0.93	9.71	3.74	12.77	12.94	12.86
Mean			0.85			11.95 %	12.32 %	12.14 %
Median			0.81			11.56 %	12.03 %	11.80 %
Average of Mean and Median			0.83			11.76 %	12.18 %	11.97 %

Notes on page 2 of this Schedule.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Ibbotson, Value Line, and Bloomberg as illustrated below:

Historical Data MRP Estimates:

Measure 1: Ibbotson Arithmetic Mean MRP (1926-2021)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2021:	12.37	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.02	
MRP based on Ibbotson Historical Data:	7.35	%

Measure 2: Application of a Regression Analysis to Ibbotson Historical Data (1926-2021)	8.89	%

Measure 3: Application of the PRPM to Ibbotson Historical Data: (January 1926 - June 2022)	9.21	%

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending July 01, 2022)

Total projected return on the market 3-5 years hence*:	14.86	%
Projected Risk-Free Rate (see note 2):	3.74	
MRP based on Value Line Summary & Index:	11.12	%

*Forecasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	16.54	%
Projected Risk-Free Rate (see note 2):	3.74	
MRP based on Value Line data	12.80	%

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	12.64	%
Projected Risk-Free Rate (see note 2):	3.74	
MRP based on Bloomberg data	8.90	%
Average of Value Line, Ibbotson, and Bloomberg MRP:	9.71	%

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 9 and 10 of Schedule 4.) The projection of the risk-free rate is illustrated below:

Third Quarter 2022	3.50	%
Fourth Quarter 2022	3.60	
First Quarter 2023	3.70	
Second Quarter 2023	3.80	
Third Quarter 2023	3.80	
Fourth Quarter 2023	3.80	
2024-2028	3.80	
2029-2033	3.90	
	3.74	%

(3) Average of Column 6 and Column 7.

Sources of Information:

Value Line Summary and Index
Blue Chip Financial Forecasts, July 1, 2022 and June 1, 2022
Stocks, Bonds, Bills, and Inflation - 2022 SBBI Yearbook, John Wiley & Sons, Inc.
Bloomberg Professional Services

ENSTAR Natural Gas Company and Alaska Pipeline Company
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Utility Proxy Group

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the Utility Proxy Group were that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

One proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.78 – 1.08 and residual standard error of the regression range of 2.8331 – 3.3791 of the Utility Proxy Group

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard errors of the regression is 0.1365. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus, } 0.1365 = \frac{3.1061}{\sqrt{518}} = \frac{3.1061}{22.7596}$$

Source of Information: Value Line, Inc., June 2022
Value Line Investment Survey (Standard Edition)

ENSTAR Natural Gas Company and Alaska Pipeline Company
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Twelve Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.80	0.67	2.7945	0.0677
Kinder Morgan, Inc.	1.15	1.17	2.7674	0.0670
MDU Resources Group, Inc.	1.10	1.09	2.8384	0.0687
National Fuel Gas Company	0.80	0.68	2.8929	0.0701
New Jersey Resources Corp.	0.95	0.88	3.0417	0.0737
Nisource, Inc.	0.85	0.70	2.5272	0.0612
Northwest Natural Holding Co.	0.80	0.65	3.2952	0.0798
ONE Gas, Inc.	0.80	0.63	2.8702	0.0695
ONEOK, Inc.	1.50	1.69	5.4111	0.1311
Spire, Inc.	0.80	0.68	3.0039	0.0728
TC Energy Corp.	1.05	1.03	2.5892	0.0627
The Williams Companies, Inc.	1.20	1.24	3.2412	0.0785
Average	0.98	0.93	3.1061	0.0752

Beta Range (+/- 2 std. Devs. of Beta)	0.78	1.08
2 std. Devs. of Beta	0.15	
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.8331	3.3791
Std. dev. of the Res. Std. Err.	0.1365	
2 std. devs. of the Res. Std. Err.	0.2730	

Source of Information: Valueline Proprietary Database, June 2022

ENSTAR Natural Gas Company and Alaska Pipeline Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Twelve Companies

	[1]	[2]	[3]	[4]
Proxy Group of Fifty-Three Non-Price Regulated Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Apple Inc.	0.95	0.89	3.3430	0.0810
AmerisourceBergen	0.90	0.78	3.3410	0.0809
Abbott Labs.	0.90	0.82	2.8507	0.0690
Analog Devices	0.95	0.92	2.8804	0.0698
Allison Transmission	1.10	1.08	3.1506	0.0763
Ball Corp.	0.95	0.91	2.9306	0.0710
Bunge Ltd.	0.95	0.91	3.3456	0.0810
CACI Int'l	0.90	0.78	3.0598	0.0741
Casey's Gen'l Stores	0.90	0.78	3.1603	0.0765
CDK Global Inc.	1.00	0.96	2.9231	0.0708
Copart, Inc.	1.05	1.03	3.2654	0.0791
Encompass Health	1.05	1.07	3.0358	0.0735
Lauder (Estee)	1.05	1.00	3.0636	0.0742
Edwards Lifesciences	1.05	1.06	3.3229	0.0805
Exponent, Inc.	0.90	0.79	3.1641	0.0766
Fastenal Co.	0.90	0.83	3.0771	0.0745
Franklin Electric	0.90	0.82	2.9924	0.0725
F5, Inc.	0.95	0.85	3.3779	0.0818
FLEETCOR Technologie	1.05	1.06	3.1082	0.0753
Federal Signal	1.00	0.98	3.0376	0.0736
Forward Air	1.00	0.99	3.1557	0.0764
GATX Corp.	0.95	0.86	3.0817	0.0746
Graphic Packaging	1.00	0.98	2.9854	0.0723
Grainger (W.W.)	1.00	0.99	3.2372	0.0784
Huntington Ingalls	1.05	1.00	3.3474	0.0811
IDEXX Labs.	1.00	1.00	3.3290	0.0806
Int'l Flavors & Frag	0.95	0.91	3.3602	0.0814
Intuit Inc.	1.05	1.04	3.2005	0.0775
Iron Mountain	0.90	0.78	3.2912	0.0797
Hunt (J.B.)	0.95	0.89	3.1818	0.0771
J&J Snack Foods	0.90	0.82	3.0428	0.0737
Leidos Hldgs.	1.05	1.06	3.2032	0.0776
Laboratory Corp.	1.05	1.06	3.1773	0.0770
L3Harris Technologie	0.95	0.85	3.2265	0.0851
Lennox Int'l	1.00	0.92	2.8633	0.0693
McKesson Corp.	0.95	0.88	3.2915	0.0797
Altria Group	0.90	0.83	3.0813	0.0746
MSA Safety	1.00	0.93	2.9536	0.0715
MSC Industrial Direc	0.90	0.83	3.2047	0.0776
Old Dominion Freight	0.95	0.86	3.1748	0.0769
Omnicom Group	1.00	0.97	2.9704	0.0719
OSI Systems	0.90	0.80	3.3623	0.0814
PotlatchDeltic Corp.	1.05	1.05	3.1277	0.0757
Packaging Corp.	0.95	0.87	2.9010	0.0703
PerkinElmer Inc.	0.90	0.82	3.2948	0.0798
Philip Morris Int'l	0.95	0.92	3.3123	0.0802
RPM Int'l	1.05	1.03	2.9205	0.0707
Selective Ins. Group	0.90	0.79	2.9203	0.0707
Synopsys, Inc.	1.00	0.97	3.2702	0.0792
Tennant Co.	1.05	1.06	3.2122	0.0778
UnitedHealth Group	1.05	1.04	2.8416	0.0688
Valmont Inds.	1.05	1.04	2.8898	0.0700
Waters Corp.	0.95	0.87	2.8676	0.0694
Average	0.98	0.93	3.1266	0.0758
Proxy Group of Twelve Companies	0.98	0.93	3.1061	0.0752

Source of Information: Valueline Proprietary Database, June 2022

ENSTAR Natural Gas Company and Alaska Pipeline Company
Summary of Cost of Equity Models Applied to
Proxy Group of Fifty-Three Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Twelve Companies

Principal Methods	Proxy Group of Fifty-Three Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	12.45 %
Risk Premium Model (RPM) (2)	14.06
Capital Asset Pricing Model (CAPM) (3)	13.03
Mean	13.18 %
Median	13.03 %
Average of Mean and Median	13.11 %

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.
(3) From page 6 of this Schedule.

ENSTAR Natural Gas Company and Alaska Pipeline Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Twelve Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Fifty-Three Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
Apple Inc.	0.61 %	14.00 %	12.50 %	9.91 %	12.14 %	0.65 %	12.79 %
AmerisourceBergen	1.20	8.50	8.10	9.85	8.82	1.25	10.07
Abbott Labs.	1.66	8.00	5.70	12.60	8.77	1.73	10.50
Analog Devices	1.93	14.00	12.30	18.71	15.00	2.07	17.07
Allison Transmission	2.20	11.00	7.00	8.58	8.86	2.30	11.16
Ball Corp.	1.06	21.50	5.00	12.10	12.87	1.13	14.00
Bunge Ltd.	2.25	2.50	6.70	15.00	8.07	2.34	10.41
CACI Int'l	-	7.00	4.10	2.40	4.50	-	NA
Casey's Gen'l Stores	0.76	7.00	NA	8.24	7.62	0.79	8.41
CDK Global Inc.	1.11	14.50	NA	10.00	12.25	1.18	13.43
Copart, Inc.	-	12.00	NA	22.30	17.15	-	NA
Encompass Health	2.19	10.50	7.30	10.35	9.38	2.29	11.67
Lauder (Estee)	0.95	14.00	10.80	12.40	12.40	1.01	13.41
Edwards Lifesciences	-	12.50	13.90	13.64	13.35	-	NA
Exponent, Inc.	1.02	9.50	NA	15.00	12.25	1.08	13.33
Fastenal Co.	2.31	8.50	9.00	6.33	7.94	2.40	10.34
Franklin Electric	1.06	12.00	NA	13.40	12.70	1.13	13.83
F5, Inc.	-	10.00	5.50	8.70	8.07	-	NA
FLEETCOR Technologie	-	10.50	15.80	16.45	14.25	-	NA
Federal Signal	1.05	10.50	NA	16.00	13.25	1.12	14.37
Forward Air	1.04	18.00	NA	13.16	15.58	1.12	16.70
GATX Corp.	1.96	5.50	NA	12.00	8.75	2.05	10.80
Graphic Packaging	1.42	20.50	25.00	28.50	24.67	1.60	26.27
Grainger (W.W.)	1.42	7.00	13.00	15.38	11.79	1.50	13.29
Huntington Ingalls	2.23	10.00	NA	13.60	11.80	2.36	14.16
IDEXX Labs.	-	12.00	19.00	10.20	13.73	-	NA
Int'l Flavors & Frag	2.53	7.50	10.20	4.82	7.51	2.63	10.14
Intuit Inc.	0.66	18.50	15.70	17.47	17.22	0.72	17.94
Iron Mountain	4.71	11.00	4.00	6.44	7.15	4.88	12.03
Hunt (J.B.)	0.95	11.50	15.00	22.97	16.49	1.03	17.52
J&J Snack Foods	1.86	8.50	NA	73.10	8.50	1.94	10.44
Leidos Hldgs.	1.39	9.00	6.90	6.60	7.50	1.44	8.94
Laboratory Corp.	-	1.50	NA	(12.81)	1.50	-	NA
L3Harris Technologie	1.86	18.50	4.40	41.80	11.45	1.97	13.42
Lennox Int'l	1.95	13.50	13.20	12.35	13.02	2.08	15.10
McKesson Corp.	0.59	10.00	9.40	13.59	11.00	0.62	11.62
Altria Group	6.96	5.50	4.00	5.51	5.00	7.13	12.13
MSA Safety	1.49	7.00	NA	18.00	12.50	1.58	14.08
MSC Industrial Direc	3.66	6.00	NA	9.12	7.56	3.80	11.36
Old Dominion Freight	0.46	10.50	18.00	25.91	18.14	0.50	18.64
Omnicom Group	3.80	6.50	3.30	10.60	6.80	3.93	10.73
OSI Systems	-	10.00	11.00	8.00	9.67	-	NA
PotlatchDeltic Corp.	3.42	(3.00)	NA	5.00	5.00	3.51	8.51
Packaging Corp.	3.24	11.00	5.00	9.71	8.57	3.38	11.95
PerkinElmer Inc.	0.19	5.00	46.50	44.80	5.00	0.19	5.19
Philip Morris Int'l	4.90	7.00	5.10	3.05	5.05	5.02	10.07
RPM Int'l	1.90	10.50	5.20	6.41	7.37	1.97	9.34
Selective Ins. Group	1.38	9.00	3.00	13.40	8.47	1.44	9.91
Synopsys, Inc.	-	12.50	19.60	19.60	17.23	-	NA
Tennant Co.	1.56	13.50	NA	15.00	14.25	1.67	15.92
UnitedHealth Group	1.32	12.00	14.80	14.62	13.81	1.41	15.22
Valmont Inds.	0.90	13.50	NA	10.00	11.75	0.95	12.70
Waters Corp.	-	6.00	9.00	11.30	8.77	-	NA
						Mean	12.77 %
						Median	12.13 %
						Average of Mean and Median	12.45 %

NA= Not Available
NMF= Not Meaningful Figure

(1) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Group. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of June 30, 2022. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Source of Information: Value Line Investment Survey
www.zacks.com Downloaded on 07/01/2022
www.yahoo.com Downloaded on 07/01/2022

ENSTAR Natural Gas Company and Alaska Pipeline Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Fifty-Three Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.03 %
2.	Equity Risk Premium (2)	8.03
3.	Risk Premium Derived Common Equity Cost Rate	14.06 %

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated July 1, 2022 and June 1, 2022 (see pages 9 and 10 of Schedule 4). The estimates are detailed below.

Third Quarter 2022	5.60 %
Fourth Quarter 2022	6.00
First Quarter 2023	6.20
Second Quarter 2023	6.20
Third Quarter 2023	6.20
Fourth Quarter 2023	6.20
2024-2028	5.90
2029-2033	5.90
Average	6.03 %

(2) From page 5 of this Schedule.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Fifty-Three Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Twelve Companies

		Moody's Long-Term Issuer Rating July 2022		Standard & Poor's Long-Term Issuer Rating July 2022	
	Proxy Group of Fifty-Three Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
AAPL	Apple Inc.	Aaa	1.0	AA+	2.0
ABC	AmerisourceBergen	Baa2	9.0	BBB+	8.0
ABT	Abbott Labs.	A1	5.0	AA-	4.0
ADI	Analog Devices	A3	7.0	A-	7.0
ALSN	Allison Transmission	NR	--	NR	--
BALL	Ball Corp.	Ba1	11.0	BB+	11.0
BG	Bunge Ltd.	NR	--	BBB	9.0
CACI	CACI Int'l	NR	--	BB+	11.0
CASY	Casey's Gen'l Stores	NR	--	NR	--
CDK	CDK Global Inc.	NR	--	B+	14.0
CPRT	Copart, Inc.	NR	--	NR	--
EHC	Encompass Health	B1	14.0	BB-	13.0
EL	Lauder (Estee)	A1	5.0	A+	5.0
EW	Edwards Lifesciences	Baa2	9.0	BBB	9.0
EXPO	Exponent, Inc.	NR	--	NR	--
FAST	Fastenal Co.	NR	--	NR	--
FELE	Franklin Electric	NR	--	NR	--
FFIV	F5, Inc.	NR	--	NR	--
FLT	FLEETCOR Technologie	NR	--	BB+	11.0
FSS	Federal Signal	NR	--	NR	--
FWRD	Forward Air	NR	--	NR	--
GATX	GATX Corp.	Baa2	9.0	BBB	9.0
GPK	Graphic Packaging	NR	--	NR	--
GWW	Grainger (W.W.)	A3	7.0	A+	5.0
HII	Huntington Ingalls	Baa3	10.0	BBB-	10.0
IDXX	IDEXX Labs.	NR	--	NR	--
IFF	Int'l Flavors & Frag	Baa3	10.0	BBB	9.0
INTU	Intuit Inc.	A3	7.0	A-	7.0
IRM	Iron Mountain	Ba3	13.0	BB-	13.0
JBHT	Hunt (J.B.)	Baa1	8.0	BBB+	8.0
JJSF	J&J Snack Foods	NR	--	NR	--
LDOS	Leidos Hldgs.	Baa3	10.0	BBB-	10.0
LH	Laboratory Corp.	Baa2	9.0	BBB	9.0
LHX	L3Harris Technologie	Baa2	9.0	BBB	9.0
LII	Lennox Int'l	Baa2	9.0	BBB	9.0
MCK	McKesson Corp.	Baa2	9.0	BBB+	8.0
MO	Altria Group	A3	7.0	BBB	9.0
MSA	MSA Safety	NR	--	NR	--
MSM	MSC Industrial Direc	NR	--	NR	--
ODFL	Old Dominion Freight	NR	--	NR	--
OMC	Omnicom Group	Baa1	8.0	BBB+	8.0
OSIS	OSI Systems	NR	--	NR	--
PCH	PotlatchDeltic Corp.	Baa3	10.0	BBB-	10.0
PKG	Packaging Corp.	Baa2	9.0	BBB	9.0
PKI	PerkinElmer Inc.	Baa3	10.0	BBB	9.0
PM	Philip Morris Int'l	A2	--	A	6.0
RPM	RPM Int'l	Baa3	10.0	BBB	9.0
SIGI	Selective Ins. Group	Baa2	9.0	BBB	9.0
SNPS	Synopsys, Inc.	NR	--	NR	--
TNC	Tennant Co.	WR	--	BB	12.0
UNH	UnitedHealth Group	A3	7.0	A+	5.0
VMI	Valmont Inds.	Baa3	10.0	BBB+	8.0
WAT	Waters Corp.	NR	--	NR	--
	Average	Baa2	8.7	BBB	8.7

Notes:
(1) From page 6 of Schedule 4.

Source of Information:
Bloomberg Professional Services

ENSTAR Natural Gas Company and Alaska Pipeline Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Proxy Group of Fifty-Three Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Twelve Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Fifty-Three Non-Price Regulated Companies	
1.	Ibbotson Equity Risk Premium (1)	6.13	%
2.	Regression on Ibbotson Risk Premium Data (2)	7.32	
3.	Ibbotson Equity Risk Premium based on PRPM (3)	8.22	
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	9.86	
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	11.54	
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	7.64	
7.	Conclusion of Equity Risk Premium	8.45	%
8.	Adjusted Beta (7)	0.95	
9.	Forecasted Equity Risk Premium	8.03	%

Notes:
(1) From note 1 of page 9 of Schedule 4.
(2) From note 2 of page 9 of Schedule 4.
(3) From note 3 of page 9 of Schedule 4.
(4) From note 4 of page 9 of Schedule 4.
(5) From note 5 of page 9 of Schedule 4.
(6) From note 6 of page 9 of Schedule 4.
(7) Average of mean and median beta from page 6 of this Schedule.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2022 SBBI Yearbook, John Wiley & Sons, Inc.
Value Line Summary and Index
Blue Chip Financial Forecasts, July 1, 2022 and June 1, 2022
Bloomberg Professional Services

ENSTAR Natural Gas Company and Alaska Pipeline Company
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Twelve Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Fifty-Three Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Apple Inc.	0.95	1.18	1.06	9.71 %	3.74 %	14.03 %	13.89 %	13.96 %
AmerisourceBergen	0.90	0.86	0.88	9.71	3.74	12.29	12.58	12.43
Abbott Labs.	0.90	0.82	0.86	9.71	3.74	12.09	12.43	12.26
Analog Devices	0.95	1.03	0.99	9.71	3.74	13.35	13.38	13.37
Allison Transmission	1.10	0.84	0.97	9.71	3.74	13.16	13.23	13.20
Ball Corp.	0.95	0.94	0.94	9.71	3.74	12.87	13.01	12.94
Bunge Ltd.	1.00	0.69	0.85	9.71	3.74	12.00	12.36	12.18
CACI Int'l	0.90	0.74	0.82	9.71	3.74	11.70	12.14	11.92
Casey's Gen'l Stores	0.90	0.94	0.92	9.71	3.74	12.67	12.87	12.77
CDK Global Inc.	1.05	0.58	0.81	9.71	3.74	11.61	12.07	11.84
Copart, Inc.	1.05	1.09	1.07	9.71	3.74	14.13	13.96	14.05
Encompass Health	1.05	0.80	0.92	9.71	3.74	12.67	12.87	12.77
Lauder (Estee)	1.05	1.18	1.11	9.71	3.74	14.52	14.25	14.39
Edwards Lifesciences	1.05	1.18	1.12	9.71	3.74	14.62	14.33	14.47
Exponent, Inc.	0.90	1.05	0.98	9.71	3.74	13.26	13.31	13.28
Fastenal Co.	0.90	0.94	0.92	9.71	3.74	12.67	12.87	12.77
Franklin Electric	0.90	0.98	0.94	9.71	3.74	12.87	13.01	12.94
F5, Inc.	0.95	0.96	0.95	9.71	3.74	12.97	13.09	13.03
FLEETCOR Technologie	1.05	0.98	1.02	9.71	3.74	13.65	13.60	13.62
Federal Signal	1.00	0.91	0.96	9.71	3.74	13.06	13.16	13.11
Forward Air	1.00	1.01	1.00	9.71	3.74	13.45	13.45	13.45
GATX Corp.	0.95	0.88	0.92	9.71	3.74	12.67	12.87	12.77
Graphic Packaging	1.00	0.93	0.97	9.71	3.74	13.16	13.23	13.20
Grainger (W.W.)	1.00	0.90	0.95	9.71	3.74	12.97	13.09	13.03
Huntington Ingalls	1.05	0.71	0.88	9.71	3.74	12.29	12.58	12.43
IDEXX Labs.	1.00	1.14	1.07	9.71	3.74	14.13	13.96	14.05
Int'l Flavors & Frag	0.95	1.03	0.99	9.71	3.74	13.35	13.38	13.37
Intuit Inc.	1.05	1.32	1.18	9.71	3.74	15.20	14.76	14.98
Iron Mountain	0.90	0.78	0.84	9.71	3.74	11.90	12.29	12.09
Hunt (J.B.)	0.95	0.98	0.97	9.71	3.74	13.16	13.23	13.20
J&J Snack Foods	0.95	0.60	0.77	9.71	3.74	11.22	11.78	11.50
Leidos Hldgs.	1.05	0.80	0.92	9.71	3.74	12.67	12.87	12.77
Laboratory Corp.	1.05	0.69	0.87	9.71	3.74	12.19	12.51	12.35
L3Harris Technologie	0.95	0.82	0.89	9.71	3.74	12.38	12.65	12.52
Lennox Int'l	1.00	1.05	1.02	9.71	3.74	13.65	13.60	13.62
McKesson Corp.	0.95	0.97	0.96	9.71	3.74	13.06	13.16	13.11
Altria Group	0.95	0.76	0.85	9.71	3.74	12.00	12.36	12.18
MSA Safety	1.00	0.97	0.99	9.71	3.74	13.35	13.38	13.37
MSC Industrial Direc	0.95	0.84	0.89	9.71	3.74	12.38	12.65	12.52
Old Dominion Freight	0.95	1.11	1.03	9.71	3.74	13.74	13.67	13.71
Omnicom Group	1.00	0.84	0.92	9.71	3.74	12.67	12.87	12.77
OSI Systems	0.90	0.75	0.82	9.71	3.74	11.70	12.14	11.92
PotlatchDeltic Corp.	1.05	1.06	1.05	9.71	3.74	13.94	13.82	13.88
Packaging Corp.	0.95	0.73	0.84	9.71	3.74	11.90	12.29	12.09
PerkinElmer Inc.	0.90	0.93	0.91	9.71	3.74	12.58	12.80	12.69
Philip Morris Int'l	0.95	0.70	0.82	9.71	3.74	11.70	12.14	11.92
RPM Int'l	1.05	0.99	1.02	9.71	3.74	13.65	13.60	13.62
Selective Ins. Group	0.90	0.87	0.88	9.71	3.74	12.29	12.58	12.43
Synopsys, Inc.	1.00	1.13	1.07	9.71	3.74	14.13	13.96	14.05
Tennant Co.	1.10	0.89	1.00	9.71	3.74	13.45	13.45	13.45
UnitedHealth Group	1.05	0.94	0.99	9.71	3.74	13.35	13.38	13.37
Valmont Inds.	1.05	1.02	1.03	9.71	3.74	13.74	13.67	13.71
Waters Corp.	0.95	0.86	0.90	9.71	3.74	12.48	12.72	12.60
Mean			0.95			12.96 %	13.08 %	13.02 %
Median			0.95			12.97 %	13.09 %	13.03 %
Average of Mean and Median			0.95			12.97 %	13.09 %	13.03 %

Notes:
(1) From note 1 of page 2 of Schedule 5.
(2) From note 2 of page 2 of Schedule 5.
(3) Average of CAPM and ECAPM cost rates.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		Market Capitalization on July 01, 2022 (1) (millions) [1]	(times larger)	Applicable Decile of the NYSE/AMEX/ NASDAQ (2) [2]	Applicable Size Premium (3) [3]	Spread from Applicable Size Premium (4) [4]
1.	ENSTAR Natural Gas Company and Alaska Pipeline Company	$ 357.888		9	2.10%	
2.	Proxy Group of Twelve Companies	$ 18,316.567	51.2 x	2	0.43%	1.67%

	Decile [A]	Market Capitalization of Smallest Company (millions) [B]	Market Capitalization of Largest Company (millions) [C]	Size Premium (Return in Excess of CAPM)* [D]
Largest	1	$ 36,160.584	$ 2,324,390.219	-0.22%
	2	16,759.390	36,099.221	0.43%
	3	8,216.356	16,738.364	0.55%
	4	5,019.883	8,212.638	0.54%
	5	3,281.009	5,003.747	0.89%
	6	2,170.315	3,276.553	1.18%
	7	1,306.402	2,164.524	1.34%
	8	629.118	1,306.038	1.21%
	9	290.002	627.803	2.10%
Smallest	10	10.588	289.007	4.80%

*From 2022 Duff & Phelps Cost of Capital Navigator

Notes:
(1) From page 2 of this Schedule.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 1.67% in Column [4], Line No. 2 is derived as follows 1.67% = 2.1% - 0.43%.

ENSTAR Natural Gas Company and Alaska Pipeline Company
Market Capitalization of ENSTAR Natural Gas Company and Alaska Pipeline Company and the
Proxy Group of Twelve Companies

Company	Exchange	[1] Total Common Equity at Fiscal Year End 2021 (millions)		[2] Market-to-Book Ratio on July 01, 2022 (1)			[3] Market Capitalization on July 01, 2022 (2) (millions)	
ENSTAR Natural Gas Company and Alaska Pipeline Company		158.64	(3)					
Based upon Proxy Group of Twelve Companies				225.6	(4)	$	357.888	(5)
Proxy Group of Twelve Companies								
Atmos Energy Corporation	NYSE			173.5	%	$	15,583.583	
Kinder Morgan, Inc.	NYSE			124.1			38,002.840	
MDU Resources Group, Inc.	NYSE			163.3			5,488.436	
National Fuel Gas Company	NYSE			324.1			6,040.649	
New Jersey Resources Corp.	NYSE			239.8			4,281.680	
Nisource, Inc.	NYSE			211.6			11,966.986	
Northwest Natural Holding Co.	NYSE			168.7			1,818.990	
ONE Gas, Inc.	NYSE			179.3			4,391.559	
ONEOK, Inc.	NYSE			413.5			24,787.190	
Spire, Inc.	NYSE			149.1			3,876.311	
TC Energy Corp.	NYSE			223.5			65,546.440	
The Williams Companies, Inc.	NYSE			336.7			38,014.142	
Average				225.6	%	$	18,316.567	

Notes: (1) Source: Bloomberg Professional Services.
(2) Source: Bloomberg Professional Services.
(3) Requested rate base multiplied by equity ratio.
(4) The market-to-book ratio of ENSTAR Natural Gas Company and Alaska Pipeline Company on July 01, 2022 is assumed to be equal to the market-to-book ratio of Proxy Group of Twelve Companies on July 01, 2022 as appropriate.

(5) Column [1] multiplied by Column [2].

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

Keith Kurber II, Chair
Robert A. Doyle
Robert M. Pickett
Daniel A. Sullivan
Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-____

PREFILED DIRECT TESTIMONY
OF
HAROLD WALKER, III

PREFILED DIRECT TESTIMONY
OF
HAROLD WALKER, III

TABLE OF CONTENTS

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 hereto 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 the rate base of ENSTAR Natural Gas Company, a division of SEMCO Energy, Inc. and Alaska Pipeline Company (collectively, "ENSTAR" or "Company"). My recommendation is based upon 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 16 supporting schedules, identified as Schedule HW-1 through Schedule HW-16, summarizing the Company's 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*.[1] Among the many benchmarks established in the case was the "property devoted to public use" doctrine as a basis for establishing 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."[2] 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 bridges the gap between the time when funds are provided to the Company by investors

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[1] *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."

[2] *Id*. at 547.

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 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. Was ENSTAR required to conduct a lead-lag analysis in support of its cash working capital requirement?

A. Yes, Order U-16-066(19) in ENSTAR's last rate case ordered it to conduct a lead-lag study in support of its next rate case.

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 four 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, 2021, 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 – 10 days).

Q. Why are midpoints used in the cash working capital analysis?

A. Midpoints are used to determine the weighted 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 ENSTAR's overall cost of service in your lead-lag study?

A. Yes, I considered ENSTAR's overall cost of service in my lead-lag study to determine its cash working capital requirement. A lead-lag study based on the entire revenue requirement and cost of service provides 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, data validation was performed 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 twelve months ended December 31, 2021. 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 twelve months ended December 31, 2021 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 97% of the Company's total expense and tax dollars.[3]

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 twelve months ended December 31, 2021, 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 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 requirement of each cost-of-service line item were totaled

[3] As shown on page 2 of Schedule HW-3, the sampling for the total expense and tax dollars paid totaled 97% and reflected a range of sampling from 33% 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.

(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-16 provided in my Exhibit HW-2. Schedule HW-1 summarizes ENSTAR's cash working capital requirements. The cash working capital requirement for ENSTAR is $9,834,683.

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-16, 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 shown. 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.[4]

The purchased gas costs line item amount of $271,695,303 was divided by 365 to determine the average daily amount, $744,371. This average daily amount was then multiplied by the 3.5 net lag days to produce the cash working capital requirement of $2,605,297 for purchased gas costs ($271,695,303 ÷ 365 days = $744,371 × 3.5 net lag days = $2,605,297). The 3.5-day net lag for purchased gas costs was determined by subtracting the purchased gas costs 39.3-day expense lead from the 42.8-day revenue lag (42.8 lag days – 39.3 lead days = 3.5 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 $9,834,683 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 42.8-day lag for the Company's revenue requirement. The Company's 42.8-day revenue lag is developed on page 1 of Schedule HW-2. The revenue requirement lag reflects the Company's service, billings, and 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

[4] All cost-of-service expense 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.

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.[5] ENSTAR's bills are prepared, mailed, and recorded to accounts receivable 4.3 days after meters are read. Adding the service period lag to the billing lag produces a combined 19.5-day service period and billing lag (15.2 days + 4.3 days = 19.5 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 23.3 days as shown on page 3 of Schedule HW-2.

Q. Please summarize the total revenue lag.

A. The total revenue lag of 42.8 lag days is the result of adding the 19.5-day service period and billing lag and an average collection lag of 23.3 days as shown on page 1 of 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

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[5] 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.

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 39.3-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), 401k matching expense (see Schedule HW-7), federal payroll taxes - FICA, Medicare & FUTA (see Schedule HW-8), 50% FICA (see Schedule HW-8), FICA, Medicare (see Schedule HW-8), FUTA (see Schedule HW-8), state payroll taxes - SUTA (see Schedule HW-9), affiliate charges (see Schedule HW-10), and other third-party O&M expenses (see Schedule HW-11). As shown on Schedule HW-1, line 7, and on Schedule HW-3, a zero lead has been assigned for uncollectable accounts expense to recognize the full revenue lag related to this expense.

Q. How were the lead days determined for the income taxes sub-account line items shown on Schedule HW-1?

A. 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) 36.5 lead days is shown on Schedule HW-12, and the derivation of the state taxes (current) 36.5 lead days is shown on Schedule HW-13. As shown on Schedule HW-1, line 11 and Schedule HW-3, a zero lead has been assigned for deferred taxes because they are deducted from rate base, as they are recorded as part of accumulated deferred taxes.

Q. Please explain in more detail why zero expense lead days should be assigned to the deferred taxes line item.

A. A zero lead has been assigned to the current year's deferred tax expense because accumulated deferred taxes have been deducted from rate base as a source of cost-free funds. However, the deferred taxes account balance (balance sheet) always includes an uncollected amount of deferred tax expense that is equal to the revenue requirement lag days (*i.e.*, 42.8 days). Therefore, the recorded amount of accumulated deferred taxes deducted from rate base overstates the actual amount of available cost-free capital by an amount equal to the revenue requirement lag days.

Assigning a zero lead recognizes that a portion of these cost-free funds have not been collected from customers. That is, ENSTAR collects cash associated with its deferred tax liability from customers in the same way it collects all other revenues – with a revenue lag of 42.8 days. Mathematically, the recorded amount of deferred taxes that is subtracted from rate base is overstated by a portion of the uncollected revenue requirement related to the current year's deferred tax expense, because, like all other revenues, the current year's deferred tax expense is uncollected from customers for

42.8 days.

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-14.

Q. How were the lead days determined for the depreciation expense sub-account line items shown on Schedule HW-1?

A. For the depreciation expense line item, a zero lead has been assigned because the full amount of the depreciation expense is deducted from rate base when the expense is recorded.

Q. Please explain in more detail why zero expense lead days should be assigned to the depreciation expense line item.

A. A zero lead has been assigned because accumulated depreciation, the contra account for the depreciation expense, has been deducted from rate base. The accumulated depreciation account balance always includes an uncollected amount of the current year's depreciation expense that is equal to the revenue requirement lag days (*i.e.,* 42.8 days). Assigning a zero lag recognizes that investor funding occurred but has not yet been recovered from customers.

Q. How were the lead days determined for the operating income sub-account line item shown on Schedule HW-1?

A. I assigned a zero lead day to utility operating income, or return on invested capital, because operating income is the property of investors when it is earned.[6] Further, operating income is earned when service is provided. However, when service is provided, the operating income is not collected simultaneously as is evidenced by the existence of the revenue requirement lag days. This situation is remedied by assigning a zero lead day to operating income in recognition that these earnings have not been recovered from customers.

Q. What is 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 57.6 lead days is shown on Schedule HW-15, and the derivation of the regulatory cost charge 70.8 lead days is shown on Schedule HW-16.

VII. CONCLUSION

Q. What are the results of the lead-lag study?

A. The results of the lead-lag study are shown on Schedule HW-1. The results of the lead-lag study shown on Schedule HW-1 show that the Company requires $9,834,683 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

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[6] *See Smyth v. Ames*, 169 U.S. 466.

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 is also a licensed 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. Currently, he also serves on the Pennsylvania Municipal Authorities Association, Electric Deregulation Committee.

EXPERT TESTIMONY

Mr. Walker has submitted testimony or been deposed on several topics before regulatory commissions and courts in 26 states including: Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Idaho, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Hampshire, Nevada, New Jersey, New York, North Carolina, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia, and West Virginia. His testimonies covered various subjects including 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, cash working capital, 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 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 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
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
Chaparral City Water Company	W 02113a 04 0616
California-American Water Company	CIVCV156413
Connecticut-American Water Company	99-08-32
Connecticut Water Company	06 07 08
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 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 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
Coastland Corporation	15-cvs-216
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
Elizabethtown Water Company	WR06030257
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
Indian Rock Water Company	R-911971
Indiana Natural Gas Corporation	38891
Jamaica Water Supply Company	-
Kane Borough Authority	A-2019-3014248
Kentucky American Water Company, Inc.	2007 00134
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
Mount Holly Water Company	WR06030257
Nevada Power Company d/b/a NV Energy	20-06003

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 Natural Gas Company	GR19030420
New Jersey Natural Gas Company	GR21030679
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
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 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
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
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
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
Virginia American Water Company	PUR-2018-00175
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

ENSTAR Natural Gas Company

Calculation of Cash Working Capital Requirements
Based on Lead-Lag Study For the Twelve Months Ended December 31, 2021

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Schedule HW-8	FICA, Medicare Lead Days Lead Days
Schedule HW-8	FUTA Lead Days Lead Days
Schedule HW-9	State Payroll Taxes - SUTA Lead Days Lead Days
Schedule HW-10	Affiliate Charges Lead Days Lead Days
Schedule HW-11	Other Third-Party O&M Expenses Lead Days Lead Days
Schedule HW-12	Current Federal Income Taxes Lead Days Lead Days
Schedule HW-13	Current State Income Taxes Lead Days Lead Days
Schedule HW-14	Property Taxes Lead Days Lead Days
Schedule HW-15	Local Sales Tax Lead Days Lead Days
Schedule HW-16	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, 2021

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	$ 271,695,303	$ 744,371	42.80	(1)	39.30	(3)	3.50	$ 2,605,297
3	Non-Gas Operation and Maintenance Expenses								
4	Payroll Expenses	17,602,827	48,227	42.80	(1)	34.00	(3)	8.80	424,397
5	Affiliate Charges	4,597,389	12,596	42.80	(1)	35.00	(3)	7.80	98,246
6	Other Third-Party O&M Expenses	15,942,528	43,678	42.80	(1)	21.30	(3)	21.50	939,080
7	Uncollectible Accounts Expense	947,883	2,597	42.80	(1)	0.00	(3)	42.80	111,149
8	Total O&M Expenses	$ 310,785,930	$ 851,468						$ 4,178,169
9	Income Taxes								
10	Current Federal Income Taxes	$ 4,581,142	$ 12,551	42.80	(1)	36.50	(3)	6.30	$ 79,072
11	Deferred Federal Income Taxes	(992,935)	(2,720)	42.80	(1)	0.00	(3)	42.80	(116,432)
12	State Income Tax	2,606,769	7,142	42.80	(1)	36.50	(3)	6.30	44,994
13	Total Federal Income Taxes	$ 6,194,976	$ 16,973						$ 7,633
14	Taxes Other Than Income Taxes								
15	Ad Valorem Taxes	$ 4,511,377	$ 12,360	42.80	(1)	(21.50)	(3)	64.30	$ 794,744
16	Total Taxes Other Than Income Taxes	$ 4,511,377	$ 12,360						$ 794,744
17	Depreciation Expense	$ 18,612,610	$ 50,993	42.80	(1)	0.00	(3)	42.80	$ 2,182,520
18	Utility Operating Income	$ 24,389,495	$ 66,821	42.80	(1)	0.00	(3)	42.80	$ 2,859,919
19	Subtotal	$ 364,494,388							$ 10,022,985
20	Other Adjustments								
21	Local Sales Tax	$ 1,499,362	$ 4,108	23.30	(2)	57.60	(3)	(34.30)	$ (140,899)
22	Regulatory Charge	364,259	998	23.30	(2)	70.80	(3)	(47.50)	(47,404)
23	Total Other Adjustments	$ 1,863,621	$ 5,106						$ (188,303)
24	Total Cash Working Capital Requirement								$ 9,834,683

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, 2021

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)		19.5	20.5		19.5
Collection Lag:					
(Sum of daily accounts receivable balance divided by the sum of daily receipts. See page 3 of this Schedule)	+	23.3	22.2	+	23.3
Total Revenue Lag Days		42.8	42.7		42.8

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)	+	4.3	5.3	+	4.3
Total Service Period & Billing Lag Days		19.5	20.5		19.5
Test Year Revenues		$ 374,007,996	$ 8,124,677		$ 382,132,673

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)		$ 8,708,612,519	$ 180,294,897		$ 8,888,907,416
Divided By the Sum of Daily Test Year Revenues	÷	374,007,996	8,124,677	÷	382,132,673
Total Service Period Collection Lag Days		23.3	22.2		23.3

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, 2021

Month of Payment	Lead/ (Lag) Days	Cycles	Weighted Amount
(1)	(2)	(3)	(4)
January-21	5.4	16.00	86.00
February-21	4.4	16.00	70.00
March-21	4.1	16.00	66.00
April-21	4.1	16.00	66.00
May-21	4.2	16.00	67.00
June-21	4.1	16.00	66.00
July-21	4.0	16.00	64.00
August-21	4.0	16.00	64.00
September-21	4.3	16.00	68.00
October-21	4.1	16.00	66.00
November-21	4.3	16.00	68.00
December-21	4.1	16.00	66.00
Total Residential & Commercial Sales Billing Lag	4.3	192.00	817.00

ENSTAR Natural Gas Company

Calculation of Transport Revenue Billing Lag

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-21	5.0	$710,440.73	$3,552,203.65
February-21	4.0	701,186.75	2,805,807.00
March-21	5.0	702,998.63	3,514,993.15
April-21	4.0	695,679.96	2,783,779.84
May-21	1.0	693,118.42	696,298.42
June-21	7.0	638,930.58	4,471,454.06
July-21	6.0	633,943.05	3,803,658.30
August-21	13.0	639,836.97	8,326,587.60
September-21	6.0	633,409.36	3,801,516.16
October-21	4.0	653,739.19	2,613,896.76
November-21	3.0	697,585.65	2,096,466.95
December-21	6.0	723,807.72	4,342,846.32
Total Transport Revenue Billing Lag	5.3	$8,124,677.01	$42,809,508.21

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, 2021

Day	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
1	28,250,276	38,227,412	42,216,485	33,562,272	41,642,066	27,050,527	16,488,290	14,525,015	10,283,192	9,667,753	16,888,659	21,665,828
2	28,250,276	34,863,014	39,011,125	29,807,666	41,642,066	25,805,043	16,305,694	15,076,759	9,546,665	9,667,753	15,017,742	20,955,839
3	28,250,276	33,572,928	36,926,373	29,807,666	42,924,867	25,191,392	16,305,694	13,877,503	7,513,794	9,667,753	14,239,674	24,334,933
4	28,850,402	32,653,086	35,867,476	29,807,666	39,262,080	25,091,756	16,305,694	13,427,638	7,513,794	10,963,070	13,558,517	24,334,933
5	26,181,533	34,751,129	38,369,608	32,935,307	37,975,804	25,091,756	16,028,192	12,906,180	7,513,794	9,481,304	14,924,747	24,334,933
6	25,119,422	34,751,129	38,369,608	29,950,523	36,952,217	25,091,756	14,681,472	12,804,429	7,254,615	8,920,686	14,924,747	32,222,725
7	24,182,412	34,751,129	38,369,608	29,051,001	36,647,292	27,171,072	14,046,765	12,804,429	6,255,001	8,562,484	14,924,747	30,531,829
8	27,751,349	40,516,806	44,488,290	28,283,718	36,647,292	24,807,557	13,465,342	12,804,429	5,559,079	9,805,929	19,103,436	29,593,147
9	27,751,349	37,579,074	42,067,970	31,782,477	36,647,292	24,240,421	13,738,919	14,090,023	5,287,473	9,805,929	17,308,043	28,641,722
10	27,751,349	36,403,275	40,878,972	31,782,477	39,618,338	23,733,110	13,738,919	12,849,468	6,039,141	9,805,929	16,476,772	32,343,780
11	32,279,448	35,339,294	39,962,238	31,782,477	36,808,180	24,057,935	13,738,919	12,541,585	6,039,141	13,389,939	16,143,562	32,343,780
12	28,849,335	39,479,133	44,342,003	39,087,568	35,537,531	24,057,935	15,176,290	12,321,153	6,039,141	12,419,019	17,945,230	32,343,780
13	26,987,413	39,479,133	44,342,003	35,224,753	34,946,927	24,057,935	14,032,265	12,688,072	8,401,379	11,830,218	17,945,230	35,838,931
14	26,423,242	39,479,133	44,342,003	34,885,419	34,539,549	24,182,493	13,782,458	12,688,072	6,660,684	11,080,309	17,945,230	33,314,263
15	30,098,719	37,045,191	46,292,618	34,201,588	34,539,549	22,637,884	13,314,411	12,688,072	6,403,325	12,573,674	20,912,625	32,468,688
16	30,098,719	38,959,504	43,144,243	36,729,341	34,539,549	22,040,497	13,656,469	13,526,527	5,983,048	12,573,674	18,780,607	30,509,511
17	30,098,719	37,032,896	41,108,775	36,729,341	34,230,936	21,560,930	13,656,469	11,945,650	6,955,897	12,573,674	17,527,183	33,140,753
18	28,538,576	36,269,215	39,923,948	36,729,341	31,489,083	21,572,986	13,656,469	11,370,406	6,955,897	14,516,837	16,926,928	33,140,753
19	32,696,503	38,476,501	39,613,492	41,162,015	30,674,792	21,572,986	14,682,094	11,018,181	6,955,897	12,847,204	18,664,358	33,140,753
20	31,505,676	38,476,501	39,613,492	39,529,402	29,822,902	21,572,986	14,124,835	11,061,299	8,292,341	12,151,326	18,664,358	36,858,304
21	30,658,759	38,476,501	39,613,492	38,771,934	29,282,104	21,505,168	13,782,047	11,061,299	7,636,995	11,686,033	18,664,358	35,711,261
22	33,572,968	39,759,464	41,597,449	38,060,593	29,282,104	20,721,419	13,483,751	11,061,299	7,452,884	12,982,688	21,192,679	34,084,461
23	33,572,968	38,160,665	40,538,704	41,594,603	29,282,104	20,285,617	14,543,519	11,684,369	6,965,486	12,982,688	20,315,882	37,299,050
24	33,572,968	40,385,324	39,710,882	41,594,603	30,046,026	19,817,762	14,543,519	11,249,718	8,577,364	12,982,688	22,401,479	36,330,028
25	36,439,917	41,389,860	38,467,988	41,594,603	28,754,770	20,837,833	14,543,519	10,928,713	8,577,364	14,895,392	22,347,434	36,330,028
26	34,750,013	38,716,448	37,088,722	44,134,368	29,069,624	20,837,833	15,524,936	10,407,354	8,577,364	14,211,824	20,870,122	36,330,028
27	36,769,395	38,716,448	37,088,722	42,489,960	29,663,791	20,837,833	15,253,119	11,207,327	9,318,176	15,318,696	20,870,122	34,120,129
28	38,323,152	38,703,557	37,088,722	43,475,542	27,785,105	19,490,214	14,981,301	11,207,327	9,684,807	16,528,718	20,870,122	31,694,582
29	35,487,563		38,405,268	44,475,292	27,785,105	17,936,578	14,962,280	11,207,327	10,559,911	14,944,082	20,426,953	30,145,765
30	35,487,563		36,043,200	41,642,066	27,785,105	17,429,393	14,497,589	10,727,757	10,125,133	14,944,082	17,810,964	28,634,657
31	35,490,111		34,793,256		27,299,779		14,525,015	9,357,291		14,947,406		25,191,156
Total	925,790,093	1,014,186,338	1,197,470,249	1,057,103,309	1,001,481,861	653,238,083	435,077,965	362,589,658	218,645,594	369,061,012	527,703,852	946,264,505

Sum of A/R Daily Balances 8,708,612,519

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, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-21	22.2	$710,440.73	$15,806,265.85
February-21	22.9	701,186.75	16,044,997.80
March-21	21.0	702,998.63	14,780,720.48
April-21	20.9	695,679.96	14,515,784.43
May-21	24.9	693,118.42	17,256,425.98
June-21	21.2	638,930.58	13,534,587.20
July-21	24.4	633,943.05	15,470,244.96
August-21	15.3	639,836.97	9,783,621.70
September-21	19.4	633,409.36	12,280,919.01
October-21	22.6	653,739.19	14,795,628.20
November-21	32.1	697,585.65	22,363,644.17
December-21	18.9	723,807.72	13,662,057.70
Total Transport Revenue Sum of the Daily Accounts Receivable Balance	22.2	$8,124,677.01	$180,294,897.48
		Sum of A/R Daily Balances	$180,294,897.48

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, 2021

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	283,653,338	11,158,814,072	39.3
Payroll Expenses	Schedule HW-5	17,602,827	598,917,465	34.0
Salary and Wage Expenses	Schedule HW-6	26,024,775	751,370,163	28.9
401k Matching Expense	Schedule HW-7	1,668,378	19,128,570	11.5
Federal Payroll Taxes - FICA, Medicare & FUTA	Schedule HW-8	4,260,372	307,959,113	72.3
50% FICA	Schedule HW-8	503,455	252,482,853	501.5
FICA, Medicare	Schedule HW-8	3,745,011	54,508,968	14.6
FUTA	Schedule HW-8	11,906	967,292	81.2
State Payroll Taxes - SUTA	Schedule HW-9	242,694	16,121,861	66.4
Affiliate Charges	Schedule HW-10	4,597,389	160,896,204	35.0
Other Third-Party O&M Expenses	Schedule HW-11	5,313,960	113,311,236	21.3
Uncollectible Accounts Expense**				0.0
Current Federal Income Taxes	Schedule HW-12			36.5
Deferred Federal Income Taxes**				0.0
Current State Income Taxes	Schedule HW-13			36.5
Property Taxes	Schedule HW-14	4,413,034	(94,823,584)	(21.5)
Depreciation Expense**				0.0
Local Sales Tax	Schedule HW-15	1,499,362	86,387,556	57.6
Regulatory Cost Charge	Schedule HW-16	364,259	25,797,830	70.8

* Lead days for expenses are calculated from the mid-point of the service period to the payment date. (See Schedules 4 - 16.)

** Lead days are assumed to be 0.

ENSTAR Natural Gas Company
Operating Expenses & Taxes Sample Sizes Used In the
Lead-Lag Study For the Twelve Months Ended December 31, 2021

Description	Per Books	Sample Size	Percentage Sampled	
(1)	(2)	(3)	(4)=(3)/(2)	
Expenses & Taxes				
1. Purchased Gas Cost	$271,695,303	$283,653,338	104%	
2. Payroll Expenses	17,602,827	17,602,827	100%	(1)
3. Salary and Wage Expenses	14,228,677	26,024,775	183%	(2)
4. 401k Matching Expense	912,162	1,668,378	183%	(2)
5. Federal Payroll Taxes - FICA, Medicare & FUTA	2,329,298	4,260,372	183%	(2)(3)
6. 50% FICA	275,257	503,455	183%	(2)
7. FICA, Medicare	2,047,532	3,745,011	183%	(2)
8. FUTA	6,509	11,906	183%	(2)
9. State Payroll Taxes - SUTA	132,689	242,694	183%	(2)
10. Affiliate Charges	4,597,389	4,597,389	100%	
11. Other Third-Party O&M Expenses	15,942,528	5,313,960	33%	
12. Current Federal Income Taxes	4,581,142	4,581,142	100%	
13. Current State Income Taxes	2,606,769	2,606,769	100%	
14. Property Taxes	4,511,377	4,413,034	98%	
15. Local Sales Tax	1,499,362	1,499,362	100%	
16. Regulatory Cost Charge	364,259	364,259	100%	
	$323,400,956	$312,674,045	97%	(4)

Notes: (1) Based on the sampling for line items 3,4,5 and 9.
(2) Sample amount is greater than 100% of expense because it includes the capital portion, employee contributions, or deferred amounts.
(3) Based on the sampling for line items 6-8.
(4) 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, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-21	38.0	$33,369,906.09	$1,268,469,117.53
February-21	35.3	34,387,552.37	1,215,245,608.00
March-21	40.3	30,139,766.96	1,215,690,666.20
April-21	40.8	15,808,488.90	644,836,458.15
May-21	38.4	15,883,732.17	610,425,136.28
June-21	39.5	16,204,927.02	639,403,822.51
July-21	39.8	16,548,251.15	657,937,582.74
August-21	40.2	16,761,714.93	673,995,107.32
September-21	39.9	14,183,497.96	566,353,485.40
October-21	38.5	19,535,192.73	752,471,791.26
November-21	41.8	31,462,497.88	1,313,805,229.97
December-21	40.6	39,367,809.85	1,600,180,066.83
Total Purchased Gas Cost	39.3	$283,653,338.01	$11,158,814,072.19

ENSTAR Natural Gas Company

Calculation of Lead Days For Payroll Expenses

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2021

Account	Amount	(Lead)/ Lag Days	Schedule Ref. For (Lead)/ Lag Days	Weighted Amount
(1)	(2)	(3)	(4)	(5)
Total Salary And Wage Expenses	$14,228,677.00	28.9	6	$411,208,765.30
Total 401k Matching Expense	912,162.22	11.5	7	10,489,865.48
Total Federal Payroll Taxes - FICA, Medicare & FUTA	2,329,298.21	72.3	8	168,408,260.37
Total State Payroll Taxes - SUTA	132,689.37	66.4	9	8,810,574.03
Total Payroll Expenses	$17,602,826.79	34.0		$598,917,465.18

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, 2021

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).

Non-Union bonus paid in March 2021 for the year 2020.

Facts	(Lead)/ Lag Days	Amount	Weighted Amount
Non-Union Salaries (5 days)			
LEAD [19 - 7.5 = 11.5; where 7.5 = (1 + 14 = 15 ÷ 2 = 7.5)]	11.5	$8,214,549.08	$94,467,314.42
Non-Union Bonus			
LEAD [2/26/21 - 7/1/20 = 267.5; where 7/1/20 = ([1/1/20 + 12/31/20] ÷ 2 = 7/1/20)]	267.5	1,765,958	472,393,765.00
Union Labor (5 days)			
LEAD [19 - 7.5 = 11.5; where 7.5 = (1 + 14 = 15 ÷ 2 = 7.5)]	11.5	16,044,268.18	184,509,084.07
Total Salary And Wage Expenses	28.9	$26,024,775.26	$751,370,163.49

ENSTAR Natural Gas Company

Calculation of Lead Days For 401k Matching Expense

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-21	11.5	$116,750.20	$1,342,627.30
February-21	11.5	111,722.16	1,284,804.84
March-21	11.5	191,432.90	2,201,478.35
April-21	11.5	113,428.01	1,304,422.12
May-21	11.5	112,169.82	1,289,952.93
June-21	11.5	121,483.25	1,397,057.38
July-21	11.5	203,225.29	2,336,997.63
August-21	11.5	133,194.45	1,531,736.18
September-21	11.5	130,945.11	1,505,868.77
October-21	11.5	134,328.58	1,544,778.67
November-21	11.5	124,644.99	1,433,417.39
December-21	11.2	175,053.59	1,955,428.68
Total 401k Matching Expense	11.5	$1,668,378.35	$19,128,570.21

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, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-21	15.2	$193,871.48	$2,948,433.37
February-21	15.0	256,058.84	3,837,568.18
March-21	14.5	595,331.51	8,632,306.90
April-21	17.0	258,718.32	4,393,977.16
May-21	14.5	260,546.07	3,777,035.00
June-21	14.5	285,902.36	4,143,978.62
July-21	15.3	303,697.33	4,657,706.27
August-21	14.5	444,494.43	6,445,169.24
September-21	14.5	275,500.70	3,991,174.55
October-21	15.1	276,797.38	4,192,264.44
November-21	14.5	258,666.01	3,750,657.15
December-21	302.3	850,787.94	257,188,842.20
Total Federal Payroll Taxes - FICA, Medicare & FUTA	72.3	$4,260,372.37	$307,959,113.05

Federal Payroll Tax Breakdown:

50% FICA	501.5	$503,455.34	$252,482,853.01
FICA, Medicare	14.6	3,745,011.13	54,508,968.24
FUTA	81.2	11,905.90	967,291.81
Total	72.3	$4,260,372.37	$307,959,113.05

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, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-21	72.5	$10,562.94	$765,813.15
April-21	73.5	115,869.38	8,516,399.43
July-21	59.0	76,709.18	4,525,841.62
October-21	58.5	39,552.25	2,313,806.63
Total State Payroll Taxes - SUTA	66.4	$242,693.75	$16,121,860.83

ENSTAR Natural Gas Company

Calculation of Lead Days For Affiliate Charges

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2021

Month of Payment	Lead/ (Lag) Days*	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-21	29.3	$343,824.50	$10,074,057.85
February-21	27.2	$354,460.14	$9,641,315.81
March-21	54.8	468,780.18	25,689,153.86
April-21	31.5	292,824.45	9,223,970.18
May-21	29.0	404,881.14	11,741,553.06
June-21	42.4	403,656.51	17,115,036.02
July-21	34.2	310,234.53	10,610,020.93
August-21	29.5	360,122.99	10,623,628.21
September-21	30.9	465,995.30	14,399,254.77
October-21	31.9	496,077.94	15,824,886.29
November-21	44.3	220,512.11	9,768,686.47
December-21	34.0	476,018.84	16,184,640.56
Total Affiliate Charges	35.0	$4,597,388.63	$160,896,204.00

* The affiliate charges are paid on the day the charge is issued. The lead days shown reflect an assumption that affiliate charges experience the same monthly payment lead as other third-party O&M expense invoices do.

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, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-21	7.7	$185,614.02	$1,435,497.58
February-21	31.6	323,959.69	10,241,916.86
March-21	60.3	409,846.30	24,713,337.47
April-21	28.4	410,844.18	11,650,149.36
May-21	25.2	322,798.01	8,135,493.07
June-21	36.1	452,556.43	16,338,125.12
July-21	26.4	609,429.98	16,097,732.62
August-21	28.3	345,243.76	9,758,564.49
September-21	12.0	375,878.01	4,496,624.39
October-21	(13.5)	668,920.66	-9,001,750.77
November-21	21.2	608,845.96	12,911,690.19
December-21	10.9	600,022.81	6,533,855.58
Total Other Third-Party O&M Expenses	21.3	$5,313,959.81	$113,311,235.94

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, 2021

Service Period		Payment	(Lead)/		Weighted
From	To	Date	Lag Days	Amount	Amount
(1)	(2)	(3)	(4)	(5)	(6)
Federal Income Taxes (Current)					
1/1/21	12/31/21	4/15/21	(78.0)	25%	(19.5)
1/1/21	12/31/21	6/15/21	(17.0)	25%	(4.3)
1/1/21	12/31/21	9/15/21	75.0	25%	18.8
1/1/21	12/31/21	12/15/21	166.0	25%	41.5
Total Current Federal Income Taxes			36.5	100%	36.5

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, 2021

Service Period From	Service Period To	Payment Date	(Lead)/ Lag Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)	(5)	(6)
State Income Taxes (Current)					
1/1/21	12/31/21	4/15/21	(78.0)	25%	(19.5)
1/1/21	12/31/21	6/15/21	(17.0)	25%	(4.3)
1/1/21	12/31/21	9/15/21	75.0	25%	18.8
1/1/21	12/31/21	12/15/21	166.0	25%	41.5
Total Current State Income Taxes			36.5	100%	36.5

ENSTAR Natural Gas Company

Calculation of Lead Days For Property Taxes

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
February-21	37.0	$472,811.74	$17,494,034.38
June-21	(18.0)	1,041,738.56	-18,751,294.08
August-21	(8.5)	1,614,563.25	-13,695,697.43
September-21	(108.0)	586,842.52	-63,378,992.16
October-21	116.6	110,235.80	12,850,491.75
November-21	(50.0)	586,842.52	-29,342,126.00
Total Property Taxes	(21.5)	$4,413,034.39	-$94,823,583.54

ENSTAR Natural Gas Company
Calculation of Lead Days For Local Sales Tax
Based on Lead-Lag Study For the Twelve Months Ended December 31, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
January-21	63.7	$361,704.86	$23,046,991.23
February-21	33.0	34,002.16	1,122,071.28
March-21	31.5	30,892.84	973,124.46
April-21	57.4	461,441.96	26,492,006.09
May-21	34.5	33,337.11	1,150,130.30
June-21	23.0	17,455.43	401,474.89
July-21	63.8	313,830.14	20,017,646.58
August-21	39.0	11,322.99	441,596.61
September-21	31.0	9,384.43	290,917.33
October-21	62.2	184,090.49	11,457,617.28
November-21	24.0	18,674.56	448,189.44
December-21	23.5	23,225.13	545,790.56
Total Local Sales Tax	57.6	$1,499,362.10	$86,387,556.03

ENSTAR Natural Gas Company

Calculation of Lead Days For Regulatory Cost Charge

Based on Lead-Lag Study For the Twelve Months Ended December 31, 2021

Month of Payment	Lead/ (Lag) Days	Amount	Weighted Amount
(1)	(2)	(3)	(4)
April-21	70.5	$187,267.66	$13,202,370.03
July-21	71.0	118,899.62	8,441,873.02
October-21	71.5	58,092.12	4,153,586.58
Total Regulatory Cost Charge	70.8	$364,259.40	$25,797,829.63

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

Keith Kurber II, Chair
Robert A. Doyle
Robert M. Pickett
Daniel A. Sullivan
Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-____

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	2021-2022 Winter Update to the Regulatory Commission of Alaska, presented at the January 12, 2022 Public Meeting

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 Director of Gas Supply Operations for ENSTAR Natural Gas Company, a division of SEMCO Energy, Inc. ("ENSTAR") and Alaska Pipeline Company ("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."

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. I have been leading the Gas Supply and Budget & Strategic Planning departments since 2015. I assumed responsibilities for Gas Control operations in 2020 and management of transport customers in January 2022. Prior to assuming my current position, I managed and worked in various individual departments within ENSTAR, including Finance, Marketing, Operations, and Regulatory. From 2013-2014, I held the position of Asset Manager at Southern Power Company ("SPC"), a subsidiary of Southern Company. While at SPC, I worked with multiple electric utilities and wholesale power buyers by managing the physical, financial, contractual, and operational activities associated with power purchase agreements across multiple states. 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.

Q. Have you previously testified before the Regulatory Commission of Alaska?

A. Yes. I testified before the Regulatory Commission of Alaska ("Commission") in Dockets U-07-084, U-18-004, and U-18-024 on behalf of ENSTAR. I also provided the 2021-2022 Winter Update on ENSTAR's gas supply management to the Commission during its January 2022 Public Meeting.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to identify operational risks faced by ENSTAR associated with its current and long-term gas supply challenges and to discuss the ways in which transportation volumes have changed and may change in the future on ENSTAR's system.

III. NATURAL GAS SUPPLY RISK

Q. Why is 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 when they need it, 24 hours a day, 365 days per year. As part of this mission, the vast majority of the Company's customers also rely on ENSTAR to not only deliver gas to their premises, but to procure the gas that is delivered. Quite simply, if ENSTAR is unable to procure the gas that needs to be delivered, it cannot meet its mandate as a public utility. In addition, ENSTAR relies on maintaining adequate pressure of natural gas in its transmission pipelines in order to not only deliver gas to its gas sales customers, but to provide service to its transport customers as well.

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 60-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.

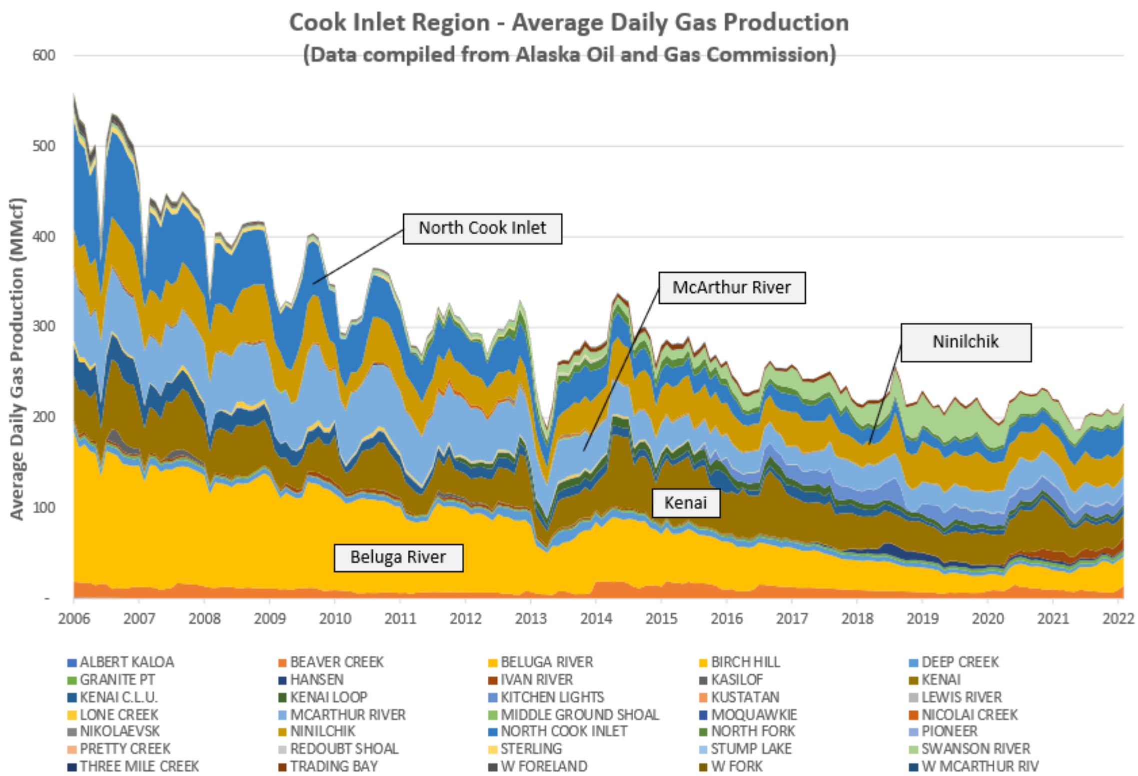
Currently, Hilcorp is the predominant producer in the region, supplying roughly 90% of production in the Cook Inlet, and is the only producer with multiple gas producing fields and storage capabilities. In 2021, Hilcorp provided 85% of ENSTAR's natural gas requirements. As to storage, the only entity 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.

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 market is shifting. Projected future demand is beginning to exceed the available future supply, but producers are only drilling enough to fulfill current contractual obligations and are reluctant to add new gas contracts. In addition, no new commercial storage is currently being developed in the region. As a result, ENSTAR has a significant supply issue to address in the very near term.

Chart 1 below demonstrates current Cook Inlet production deliverability, which has decreased by one-third over the last ten years, down from approximately 300,000

Mcf per day in 2012 to approximately 200,000 Mcf per day in 2022.[1] 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,[2] and the gap continues to increase going forward.

Chart 1



Q. Are there any other challenges in the Cook Inlet gas supply market?

A. Yes. There is a potential shortage in overall produced gas volumes that is facing gas

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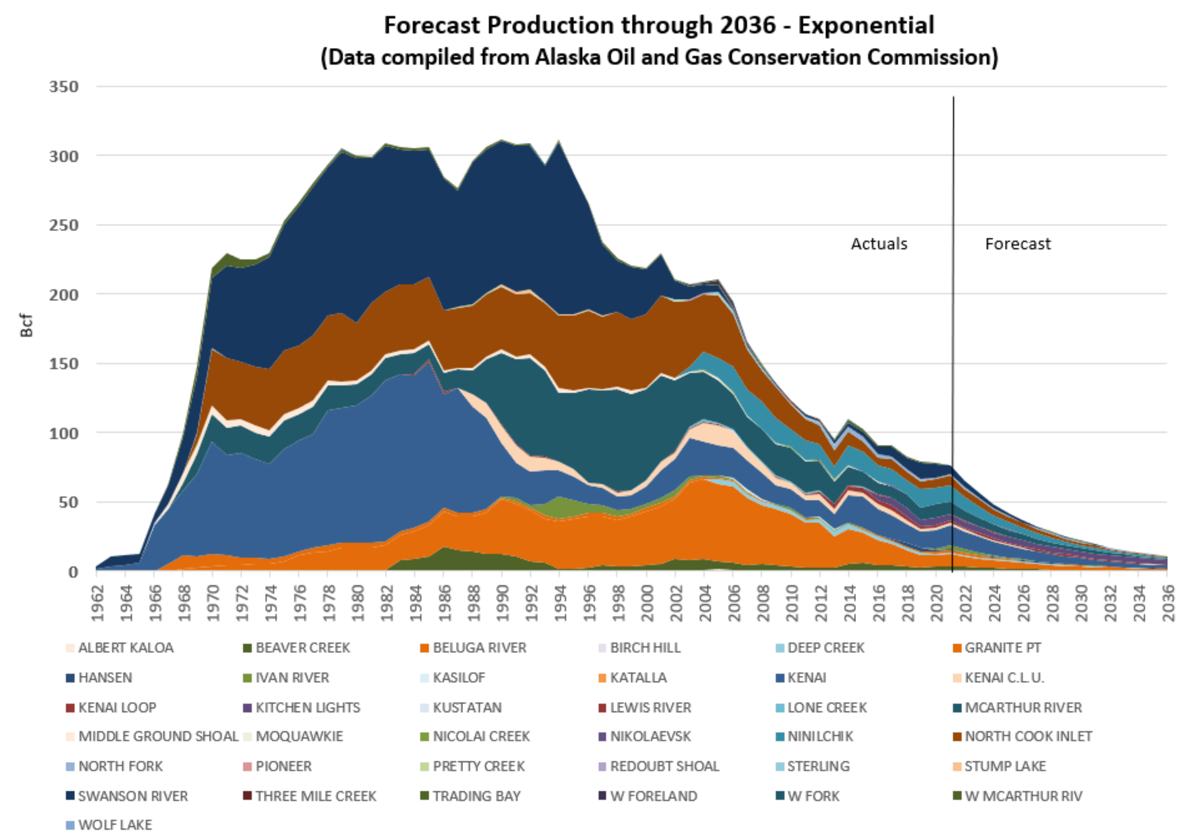
[1] Mcf is one thousand cubic feet. Bcf is 1,000,000 Mcf or 1 billion cubic feet.

[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 heating degree days. The Design Day estimate for the 2021-2022 season is 295,000 Mcf per day. ENSTAR has experienced temperatures of -22.0° F multiple times over the last 40 years.

users in the region. The chart below depicts the annual gas volumes produced in the Cook Inlet through 2021 as well as forecasted produced volumes through 2036.[3]

Chart 2



Q. How is ENSTAR responding to the issue of declining production?

A. Over the last three years, ENSTAR has engaged in continuous negotiations with producers Hilcorp, Furie, AIX, BlueCrest, Cook Inlet Energy, and Vision to secure new gas supply for 2022 and beyond, but with limited success. Recognizing the future forecasted imbalance between supply and demand, the solutions will likely have to come from a variety of sources. ENSTAR is participating in the recently formed

[3] The forecast applies decline rates to each production unit using the actual decline rate observed over the 2005-2021 period.

working group made up of several Alaska utilities, with the support and involvement of the State of Alaska. The group is currently evaluating options including development of known, non-producing gas reserves, increased exploration, increased gas storage development, in-state and imported gas options, and renewables. All potential solutions are on the table.

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 it did not have firm supplies available beyond existing contracts and encouraged utilities to seek other sources.[4] 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.[5]

Hilcorp also stated that no new contracts will be signed until it sees the results of this year's drilling season.[6] We are already seeing utilities encounter challenges with securing gas supply beyond current contract terms.[7] And, while ENSTAR might have a longer-term supply under contract in the Cook Inlet basin (through March 31,

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[4] *See* https://www.adn.com/business-economy/energy/2022/05/17/hilcorp-warns-alaska-utilities-about-uncertain-cook-inlet-natural-gas-supplies/, last accessed on Jul. 25, 2022; *see also* https://www.homerelectric.com/2022/05/monthly-managers-report-5/, last accessed on Jul. 25, 2022.

[5] https://alaskabeacon.com/2022/05/27/cook-inlet-teeming-with-renewables/, last accessed on Jul. 25, 2022.

[6] *See* https://www.homerelectric.com/2022/05/monthly-managers-report-5/, last accessed on Jul. 25, 2022.

[7] *See* https://www.kbbi.org/local-news/2022-05-16/natural-gas-from-cook-inlet, last accessed on Jul. 25, 2022.

2033), ENSTAR's requirements for firm supply far exceed the volumes that electric utilities require in order to provide service. This fact requires ENSTAR to act with equal or greater urgency in securing additional or alternative gas sources and creates significant operational risk to our utility.

Moreover, the federal government recently cancelled a Cook Inlet lease sale.[8] Regardless of whether this was a reflection of the current administration's position on natural resource development, or of low incentives or prospects for producers, the message is clear: we need alternate natural gas resources in the near future, and currently, there is no definitive solution.

Q. Has ENSTAR's operating experience contributed to its concern with the gas supply situation?

A. Yes. Our operating experience during the 2021 test year was a prime example of how cold weather taxed ENSTAR's overall gas supply portfolio and gas delivery system.

Q. Was 2021 a normal weather year?

A. No. The observed temperatures in 2021 were colder than normal during several months. A "normal weather year" is a year that exhibits an average of the actual observed annual temperatures over the last ten years. In 2021, however, heating degree days were 11% above average, and ENSTAR's service territory saw significantly colder than normal temperatures in March, April, November, and December.[9] ENSTAR delivered a record 35.4 Bcf to gas sales customers in 2021.

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[8] *See* https://www.adn.com/business-economy/energy/2022/05/12/biden-administration-cites-lackluster-industry-interest-in-canceling-cook-inlet-oil-and-gas-lease-sale/, last accessed on Jul. 25, 2022.

[9] 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

The abnormally cold temperatures observed in November and December were the focus of a presentation to the Commission in January 2022. During the presentation, ENSTAR provided an overview of two cold weather events it experienced during 2021 and the direct impact of the cold temperatures on customer demand. The presentation to the Commission is attached as Exhibit IBJ-2 to this testimony.

Q. Can you describe the cold weather events in further detail?

A. Yes. In March and April 2021, temperatures were notably below normal, especially during the first part of April, when ENSTAR's service territory experienced record cold temperatures for that time of the year. On April 8, 2021, Anchorage set a record daily low of 9 degrees, breaking the previous record set in 1986.[10] On April 9, 2021, ENSTAR customer demand increased to 163,000 Mcf per day, nearly doubling April's average demand of 87,000 Mcf per day. This weather event coincided with ENSTAR's seasonal change in gas supply purchases when gas purchases step down from large volumes delivered during winter months to summer purchase levels. In response, ENSTAR withdrew a significant amount of gas from CINGSA over this period, reaching a daily withdrawal rate of 108,000 Mcf per day on April 9. In April 2021, ENSTAR withdrew almost 1 Bcf of gas from CINGSA's storage facility, or one-third of ENSTAR's typical annual withdrawals.

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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.

[10] https://news.yahoo.com/time-april-low-could-fall-123000076.html, last accessed on Jul. 25, 2022; *see* https://alaskapublic.org/2021/04/08/arctic-air-hitting-anchorage-like-a-freight-train/, last accessed on Jul. 25, 2022.

The second event occurred in November and the first half of December 2021, when our service territory experienced persistent and intense cold temperatures triggering gas demand to peak at abnormally high levels. The average observed demand for November is about 100,000 Mcf per day. During November 2021, customer average demand for the month increased to 160,000 Mcf per day. By the second week of November, that demand increased to over 200,000 Mcf per day. Typically, ENSTAR does not withdraw large amounts of gas from its storage inventory during the earlier part of the heating season. However, this past November, ENSTAR withdrew 1.3 Bcf of gas from storage.

Q. How do the challenges described in this section impact ENSTAR's operating environment and ability to serve customers?

A. Since 2015, ENSTAR's operating environment has become increasingly challenging. Our customer base has grown by 10,000 customers, and the cold weather events I describe above resulted in increased demand variability for natural gas. At the same time, supplies in Cook Inlet are declining, making it more challenging each year to secure required volumes.

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 which rely on the Company to procure and supply natural gas to their premises for heating and other personal needs. If gas is not available to be procured, then the Company cannot meet its mandate as a public utility. Given the current lack of gas availability, ENSTAR will likely have to make substantial investments in infrastructure in the near future to ensure ongoing gas supply. As stated above, all options are on the table. Any investments to bring gas into the Cook Inlet will be costly and will almost certainly require investment above and beyond the existing costs to provide service to customers. In addition, and 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.

Q. From ENSTAR's perspective, and your personal perspective as someone who has managed ENSTAR's gas supply since 2015, is the gas supply situation worse than it was in 2015?

A. Yes, it is significantly worse. When ENSTAR negotiated its current contract with Hilcorp in 2015 and the contract amendment in 2020, we were careful to contract for the flexibility that would allow ENSTAR to purchase volumes from other producers. ENSTAR has been in constant contact with other producers and has done its best to enter into agreements with them for additional gas supply. We are proud of these efforts, but despite our best efforts, Hilcorp continues to supply 85% of ENSTAR's annual gas demand, and now Hilcorp says it does not have line of sight on additional contractual commitments. Reliance and dependence on one producer for such a large percentage of the Company's gas demand is risky for several reasons, and when we look at the activity in the Cook Inlet, we don't have confidence that another producer will take over a substantial portion of ENSTAR's supply needs (and in turn our customers' needs) any time soon.

IV. TRANSPORTATION CUSTOMERS

Q. Provide an overview of ENSTAR's transportation customers.

A. Currently, ENSTAR provides gas transportation service to seven customers. These customers consist of electric utilities that generate power through thermal generation, producers that deliver gas to their buyers and gas storage fields, and the Interior Gas Utility, which liquefies gas in Cook Inlet and trucks it to Fairbanks. These customers work directly with third-party producers to procure natural gas and have it delivered to ENSTAR for transport to various delivery points on our system.

Q. Please describe recent renewable energy legislation.

A. On February 4, 2022, Governor Dunleavy introduced a bill "setting renewable energy standards" for "Railbelt energy independence."[11] The bill as introduced would require 30% renewable power by 2030 and 80% by 2040.[12] While the legislature adjourned without passing the bill, it is an indication of where state policy may be headed.

Q. Have ENSTAR's transportation customers made public statements supporting the governor's proposed Renewable Portfolio Standard?

A. Yes. The Railbelt electric utilities, including ENSTAR's transportation customers Chugach Electric Association, Inc. ("Chugach"), Matanuska Electric Association, Inc. ("MEA"), and Homer Electric Association, Inc. ("HEA"), presented comments to the House Special Committee on Energy on May 17, 2022, stating their support for the

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[11] https://gov.alaska.gov/newsroom/2022/02/04/governor-dunleavy-introduces-legislation-setting-renewable-energy-standards-benchmarks-will-prepare-railbelt-for-energy-independence/, last accessed on Jul. 25, 2022.

[12] *Id*.

governor's vision, the importance of a more diverse energy mix for Alaska, and their support for the intent of the proposed legislation.[13]

Q. Have these customers made commitments or investments related to renewable energy generation?

A. Yes. ENSTAR's major transportation customers have all indicated support for near-term plans to add renewables into their energy mix, as follows:

- in its press release issued on October 4, 2021, Chugach stated that it has a goal of adding a project or projects that will produce 100,000 megawatt hours per year of additional renewable generation by the end of Q1 2025;[14]
- more than 75% of MEA members expressed support for the co-op to develop a carbon reduction goal in their 2019 and 2020 membership surveys.[15] In April 2021, MEA's Board of Directors passed a carbon reduction plan that includes a carbon reduction goal of 28% by year 2030, compared to 2012 as the baseline year;[16]
- HEA's Board has stated that HEA is working toward "50% renewable energy by 2026."[17] Currently, HEA relies on natural gas for more than 85% of its energy. To move towards renewable generation, HEA is working with a private

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[13] Railbelt Utilities: Comments to the House Special Committee on Energy, HB 301, March 17, 2022 at Slide 3.

[14] https://www.chugachelectric.com/media/press-releases/2022/3/2/companies-respond-to-renewable-energy-rfp, last accessed on Jul. 25, 2022.

[15] https://www.mea.coop/innovation#Renewable-Energy, last accessed on Jul. 25, 2022.

[16] MEA's April 2021 Regular Board Meeting Minutes, https://drive.google.com/drive/folders/1TvDmgKErLV7W7tNP0bMYpFeV8KonUJtx, last accessed on Jul. 26, 2022.

[17] https://www.homerelectric.com/2022/05/aea-railbelt-utilities-unveil-more-than-200-million-in-transmission-upgrades-projects-will-modernize-alaskas-largest-electric-grid-and-allow-for-more-renewable-energy/, last accessed on Jul. 25, 2022.

company to install a solar farm anticipated to generate 20 megawatts. HEA is also applying for grant funding to assess the feasibility of wind power in Kenai. HEA estimates that natural gas consumed will decline 28% in 2031 versus 2022;[18] and

- on May 25, 2022, during the Alaska Sustainable Energy Conference, the Alaska Energy Authority and the Railbelt utilities announced plans to spend more than $200 million on transmission line upgrades. According to the press release, these enhancements will reduce line losses, increase capacity, and improve the delivery of power from the Bradley Lake Hydroelectric Project to Railbelt consumers.[19]

Q. Based on the electric utilities' publicly-stated goals to transition some of their thermal generation to renewable sources, do you anticipate an impact on ENSTAR's transportation volumes?

A. Yes. I anticipate the volumes transported for thermal generation to decrease as these entities continue to transition to renewable generation.

Q. Are there any other foreseeable changes in the power generation market that could result in a reduction of ENSTAR's transportation volumes?

A. Yes. During the hearing in Docket U-19-020/U-19-021, Brian Hickey, then-Chief Operating Officer of Chugach, in response to a question from Commissioner Pickett,

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[18] Docket I-15-001, *In the Matter of the Evaluation of the Operation and Regulation of the Alaska Railbelt Electric Transmission System*, RE: I-15-001 In the Matter of the Evaluation of the Operation and Regulation of the Alaska Railbelt Electric Transmission System, Orders I-15-001(14) and I-15-001(15) and I-16-002 In the Matter of the Reliability and Security Standards and Practices of Alaska Electric Utilities, Orders I-16-002(14) and I-16-002(15) at 2, dated January 31, 2022.

[19] https://www.homerelectric.com/2022/05/aea-railbelt-utilities-unveil-more-than-200-million-in-transmission-upgrades-projects-will-modernize-alaskas-largest-electric-grid-and-allow-for-more-renewable-energy/, last accessed Jul. 26, 2022.

testified that power pool participants anticipate realizing 1.5 Bcf in annual fuel savings.[20] This translates to a corresponding annual reduction in ENSTAR transportation volumes of 1.5 Bcf of gas deliveries to power plants once the power pool is fully functional.

Q. Will the reduction in transportation volumes result in a reduction of required pipeline and gas delivery infrastructure to deliver gas to power plants?

A. No. Regardless of the annual gas volumes transported for thermal generation, the same gas infrastructure is required to provide safe and reliable service to transportation customers. As electric utilities continue to focus on the development of renewable generation, these customers also recognize that the performance of renewable energy can be extremely variable in Alaska. The availability of reliable gas-fired generation used as backup generation, along with the infrastructure to deliver gas to it, are necessary for uninterrupted service for electric customers.

Q. How have transportation volumes changed since 2015?

A. While the gas sales volumes fluctuated to some degree, largely in response to weather-related demand, ENSTAR saw an 11% reduction in transport volumes from 2015 to 2021. Transport volumes have been impacted by several developments in power generation. The first reduction in volumes was observed in 2018 when Municipal Light & Power ("ML&P") and Chugach established loose power pooling operations. In 2020 and 2021, transportation volumes decreased by 12% and 11% respectively, down to a combined 22 Bcf, compared to the adjusted 2015 test year volumes of 25 Bcf in ENSTAR's last rate case. The main drivers of these additional reductions were reduced

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[20] U-19-020/U-19-021 Tr. 3264.

economy energy sales, Chugach's acquisition of ML&P, and the establishment of a power pool between Chugach and MEA. The table below demonstrates total transportation volumes for 2015-2021.

Year	Transport Volumes, Mcf	Difference between 2015, Mcf		
		Mcf	%	
2015 *	25,067,484	0		Test year
2016	27,779,583	2,712,099	11%	
2017	27,020,013	1,952,529	8%	
2018	24,611,313	(456,171)	-2%	
2019	24,289,655	(777,829)	-3%	
2020	22,046,445	(3,021,039)	-12%	
2021	22,385,237	(2,682,247)	-11%	Test Year

*The actual volumes for 2015 were adjusted based on Order U-16-066(19)

Q. When transport volumes are reduced, what is the impact on ENSTAR's systems and operations?

A. While ENSTAR's revenues are reduced, there is no appreciable corresponding reduction in system requirements, the level of necessary infrastructure, or operating costs. ENSTAR designed and maintains 388 miles of transmission pipelines and related facilities to transport gas for its customers. As indicated above, these facilities must be maintained to the same standards and operated so as to provide the same reliable and safe service regardless of how much gas is moved on a transport customer's behalf on any given day. To address this issue, ENSTAR is proposing a revised rate design for its transportation service that is described in ENSTAR witnesses Mr. Daniel M. Dieckgraeff's and Dr. Bruce H. Fairchild's prefiled direct testimonies.

V. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Inna B. Johansen

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, Alaska: 2016 – Present.

Director, Gas Supply Operations: 2019 – Present

Senior Manager, Gas Supply and Financial Planning: 2016 – 2019

Gas Supply Manager: 2015 – 2016

Manger 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

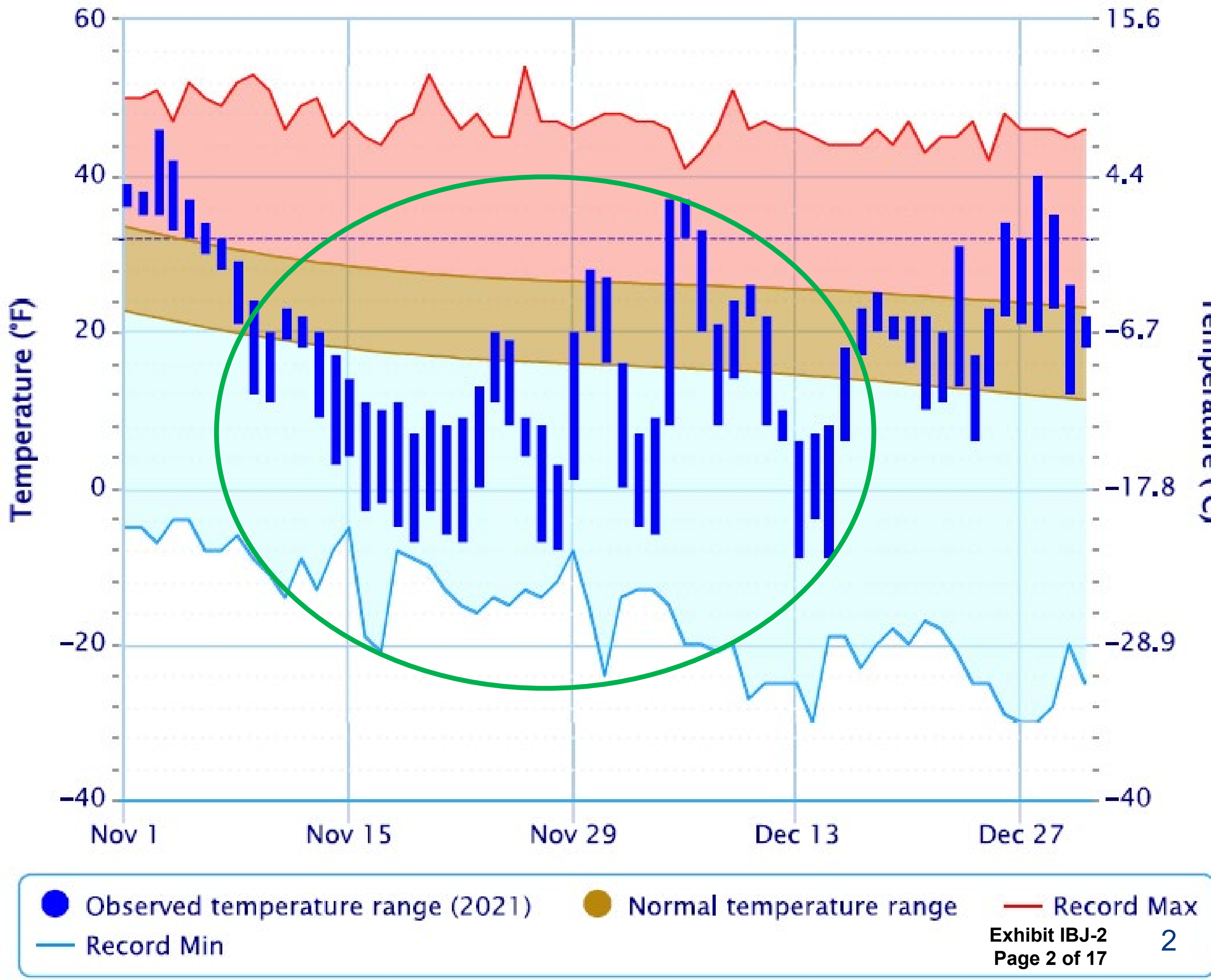
Habitat for Humanity, Board Member, 2011 – 2012

2021-2022 Winter Update

January 12, 2022

ENSTAR Natural Gas Company

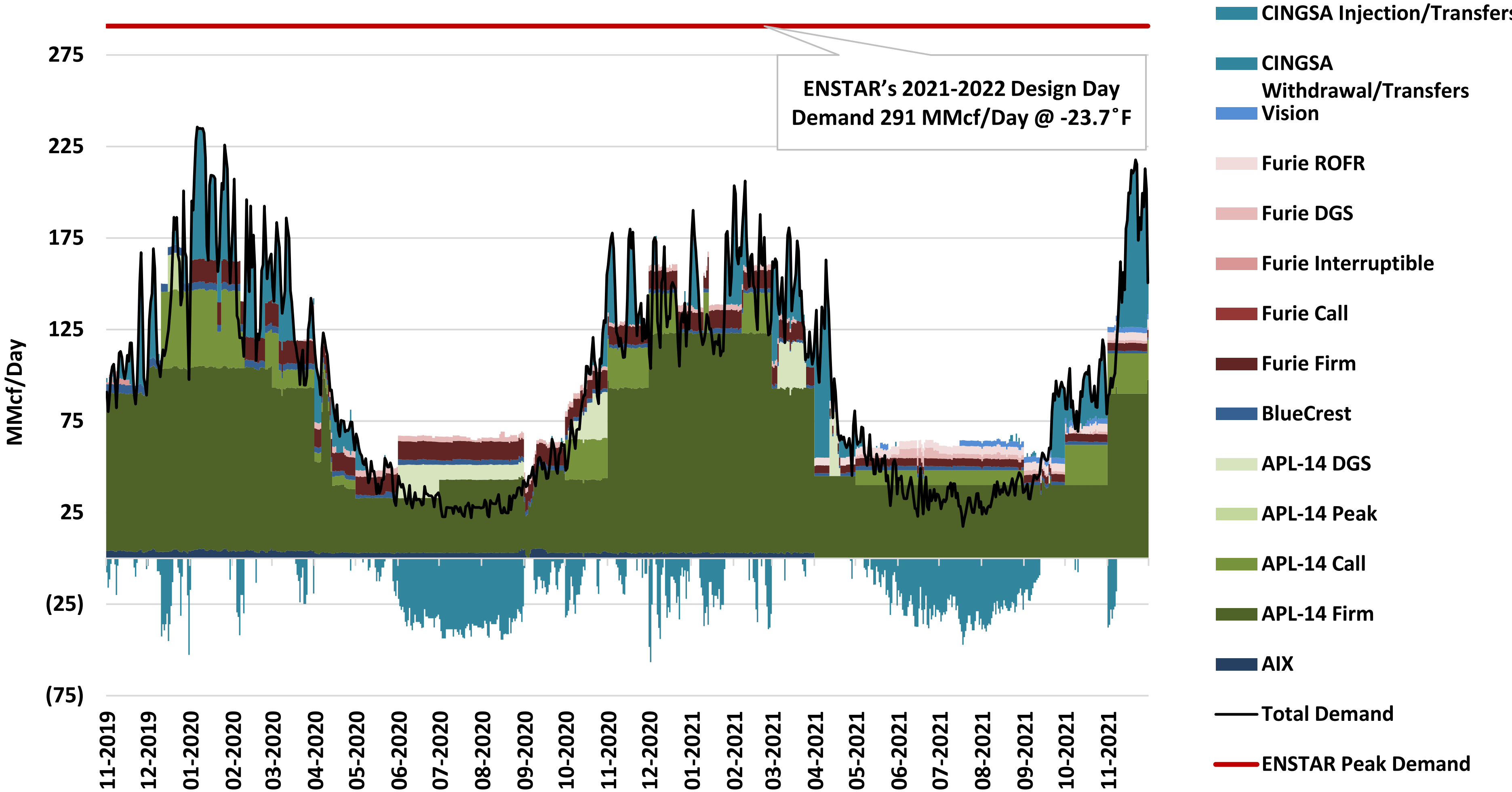
Early Cold Spell (11/09/2021-12/16/2021)



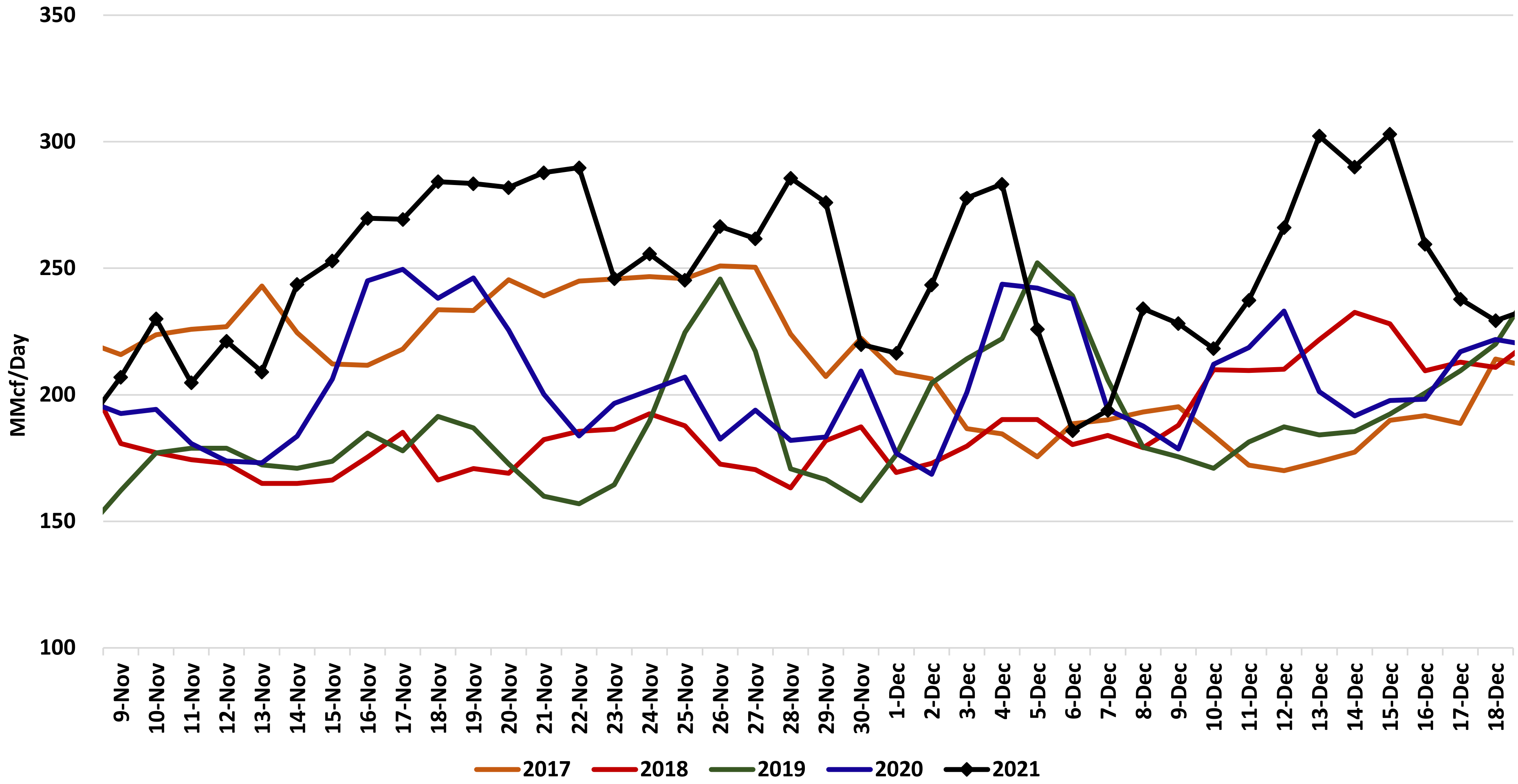
Climate (weather.gov)

ENSTAR

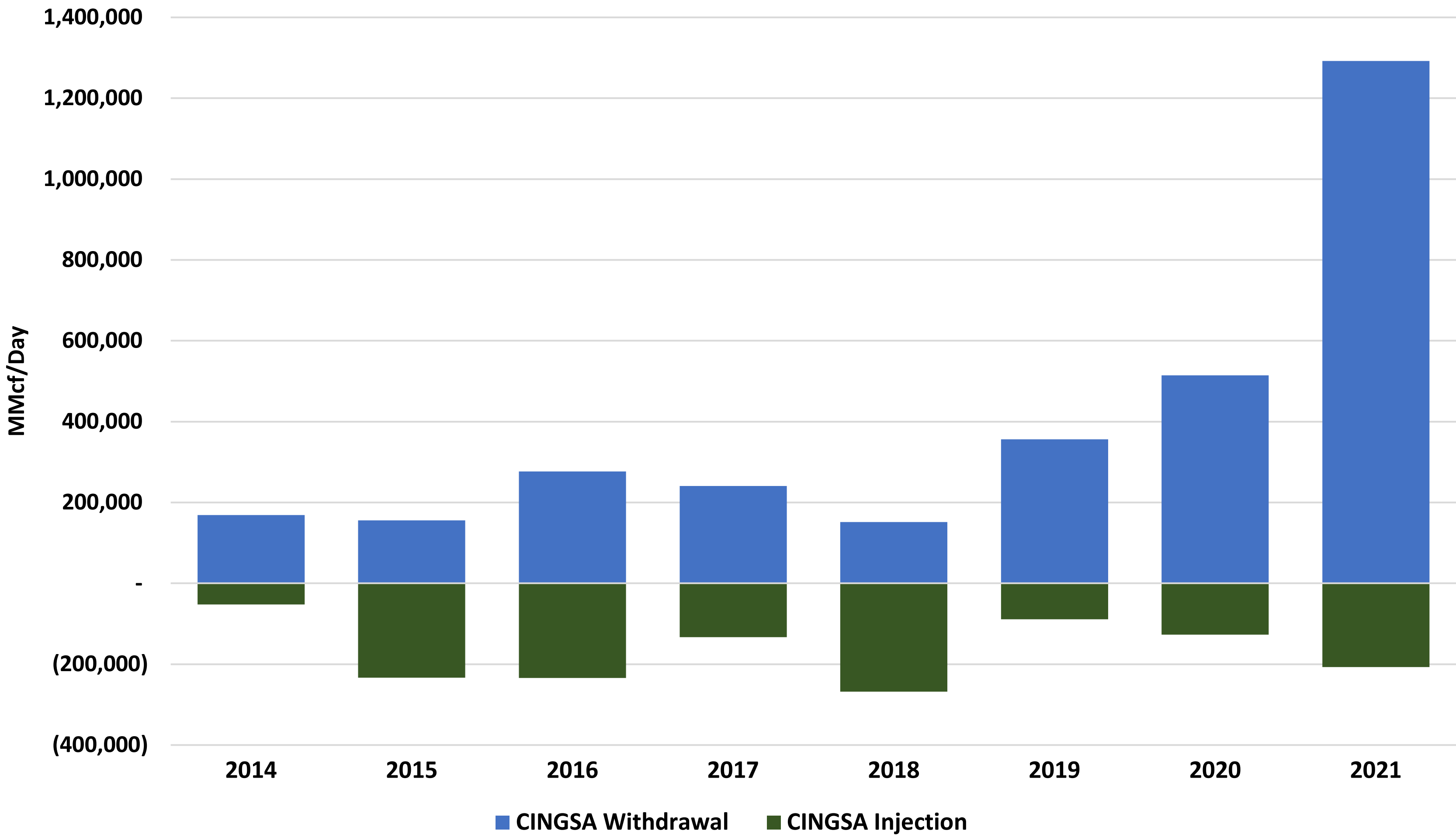
Supply vs Demand (11/2019-11/2021)



2017-2021 Total Transport and Deliveries



November: History of ENSTAR Storage Use



Statistical Summary of Cold Spell (11/11-12/16)

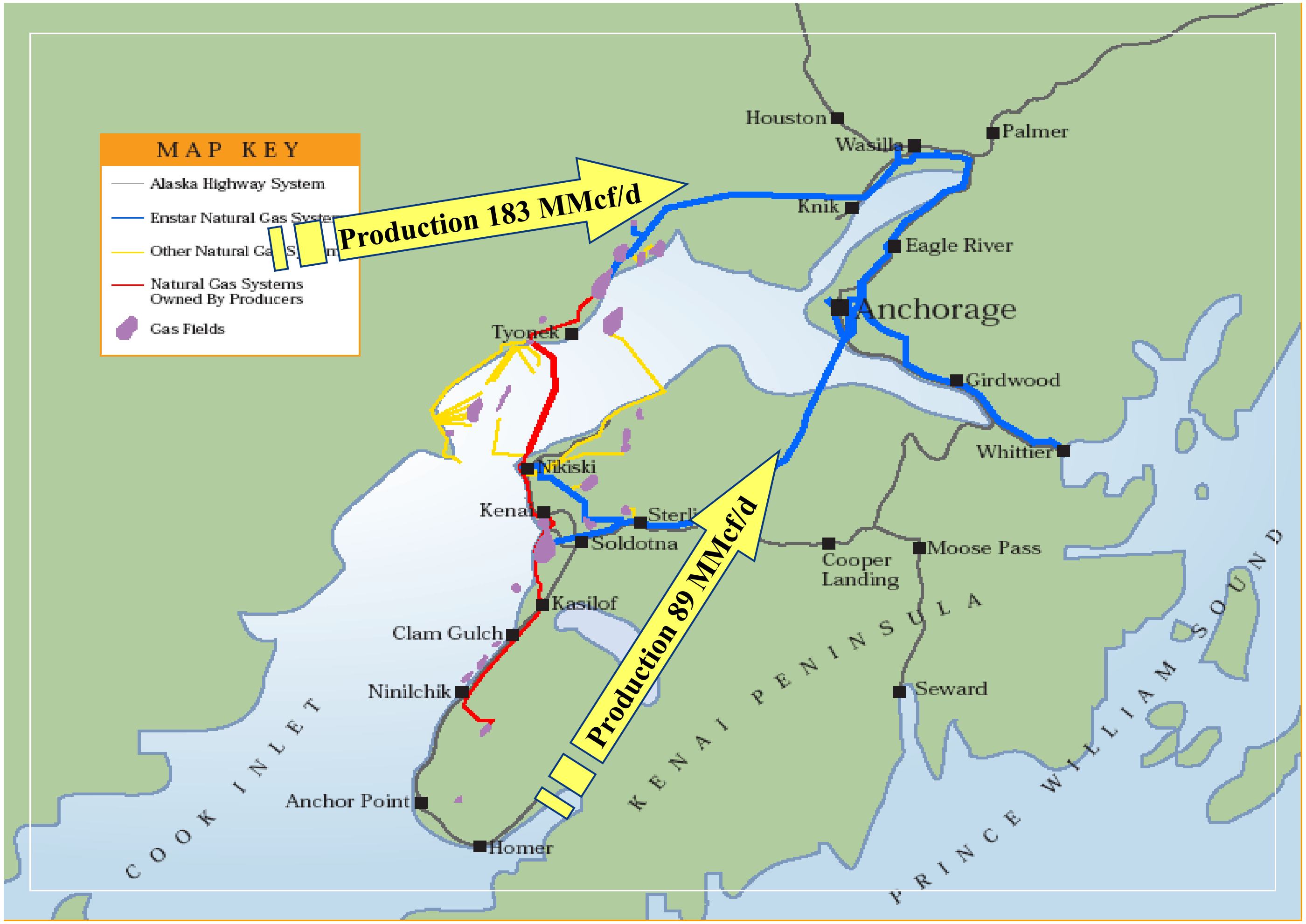
- 3 Days of Average Temp. Below 0º F (11/28, 12/13, and 12/15)
- 17 Consecutive Days of Average Temp. Below Normal Temperature (11/13/2021 - 11/29/2021)
- 22 Consecutive Days of ENSTAR Customer Demand in Excess of 138 MMcf (November typical daily demand)
- 8 Days of ENSTAR Customer Demand in Excess of 161 MMcf (December typical daily demand)

Overall Performance

- Daily Operational Update
  - Two compressors were needed at Gudenrath to maintain system pressures
  - At times, CINGSA supplied up to 45% of demand
  - Peak withdrawal November 19th 95.4 MMcf
- ENSTAR Gas Purchases at close to Maximum Availability

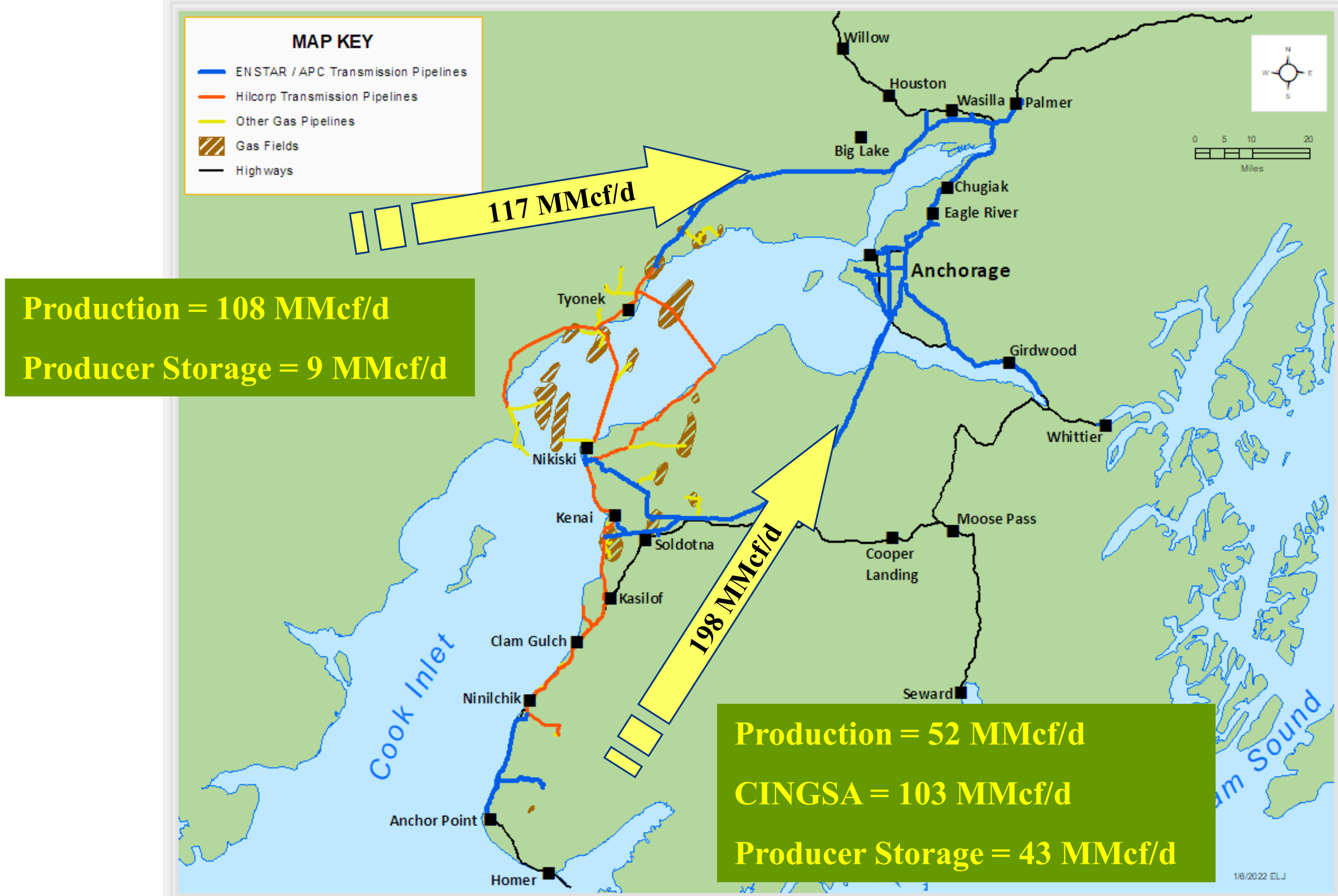
February 3, 1999

272 MMcf/d (-19º F)



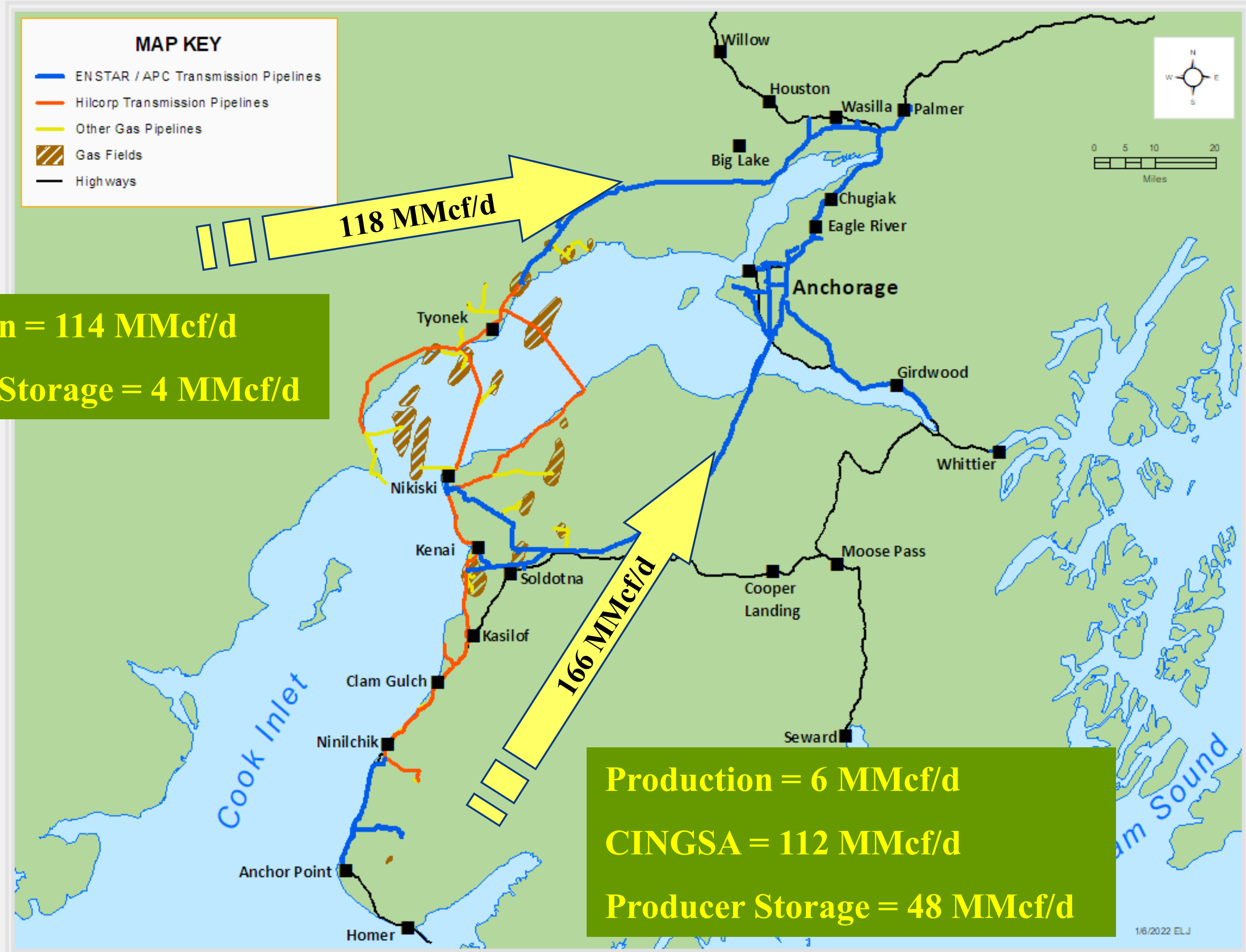
January 19, 2017

341 MMcf/d (-7° F)



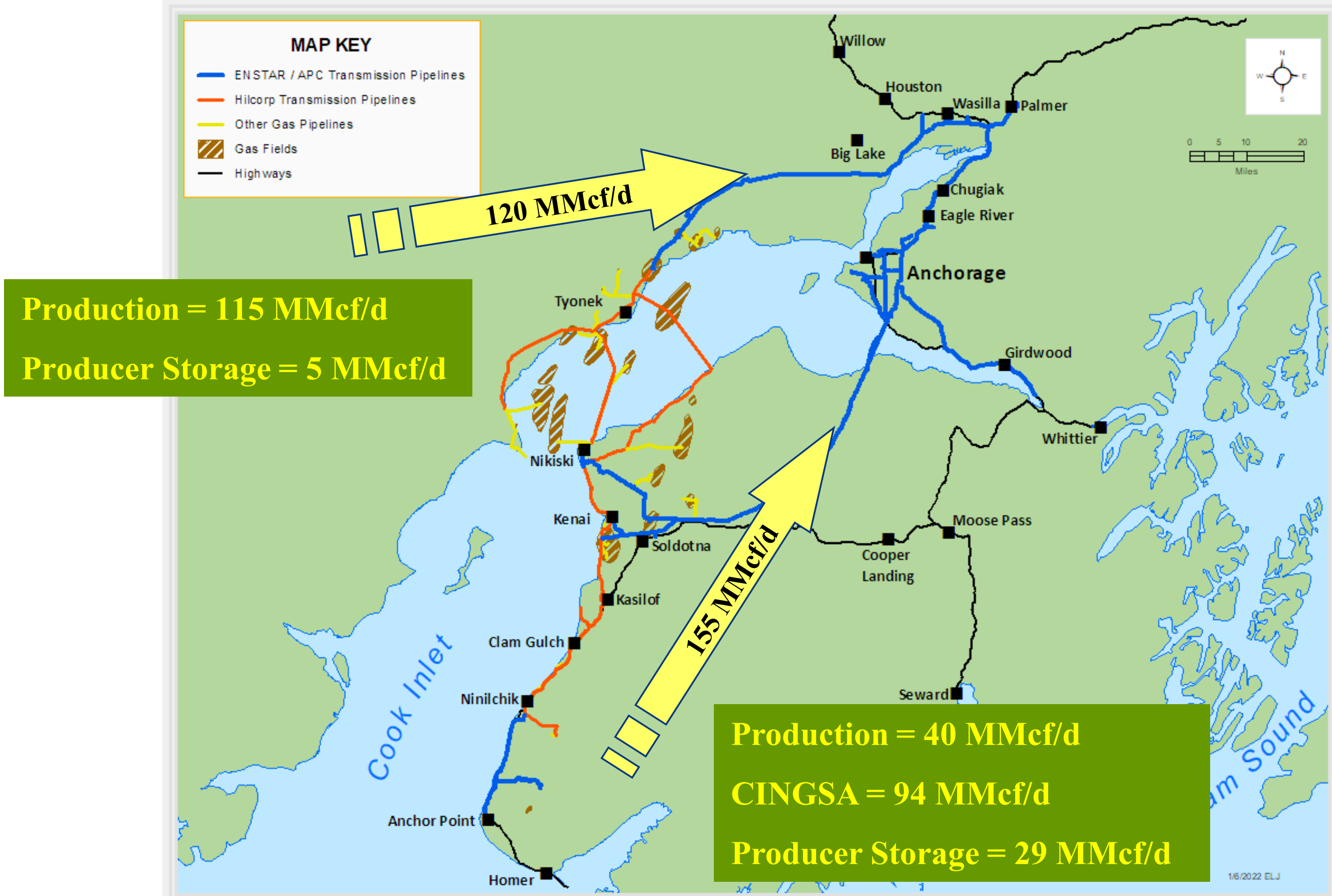
January 7, 2019

306 MMcf/d (1º F)



November 21, 2021

288 MMcf/d (1º F)



ENSTAR

ENSTAR System Peak Day Comparison

	2/3/99	1/19/17	1/7/19	11/21/21
Average Temp	-19º F	-7º F	1º F	1º F
ENSTAR Throughput	272	341	306	288
ENSTAR Gas Sales	187	254	232	218
Commercial Transport	29	0	1	0
Power Transport	56	77	65	66
Industrial Transport	0	10	8	4
CINGSA Withdrawals	0	103	112	94
ENSTAR CINGSA	0	107	103	91

Volumes in MMcf

ENSTAR

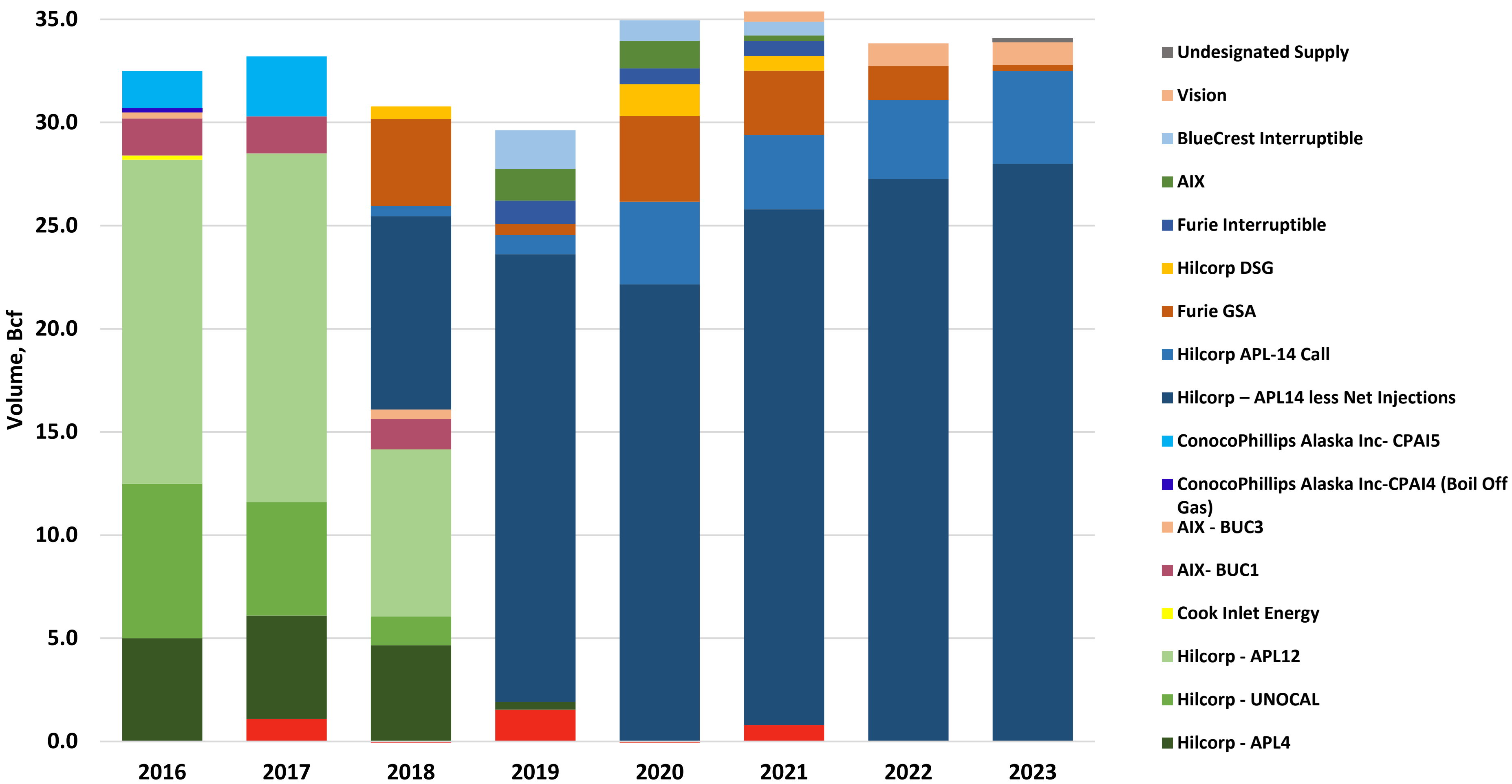
Cook Inlet Peak Day Comparison

	2/3/99	1/19/17	1/7/19	11/21/21
Average Temp	-19º F	-7º F	1º F	1º F
On ENSTAR System	272	341	306	288
CINGSA Remaining Withdrawal Capacity	0	47	38	56
Off ENSTAR System:				
CEA Beluga	83	0	0	0
HEA Nikiski	14	14	12	13
Nikiski LNG	224	0	0	0
Fertilizer Plant	157	0	0	0
Other Industrials	13	13	13	13
Total Cook Inlet Deliverability Est.	763	415	369	370

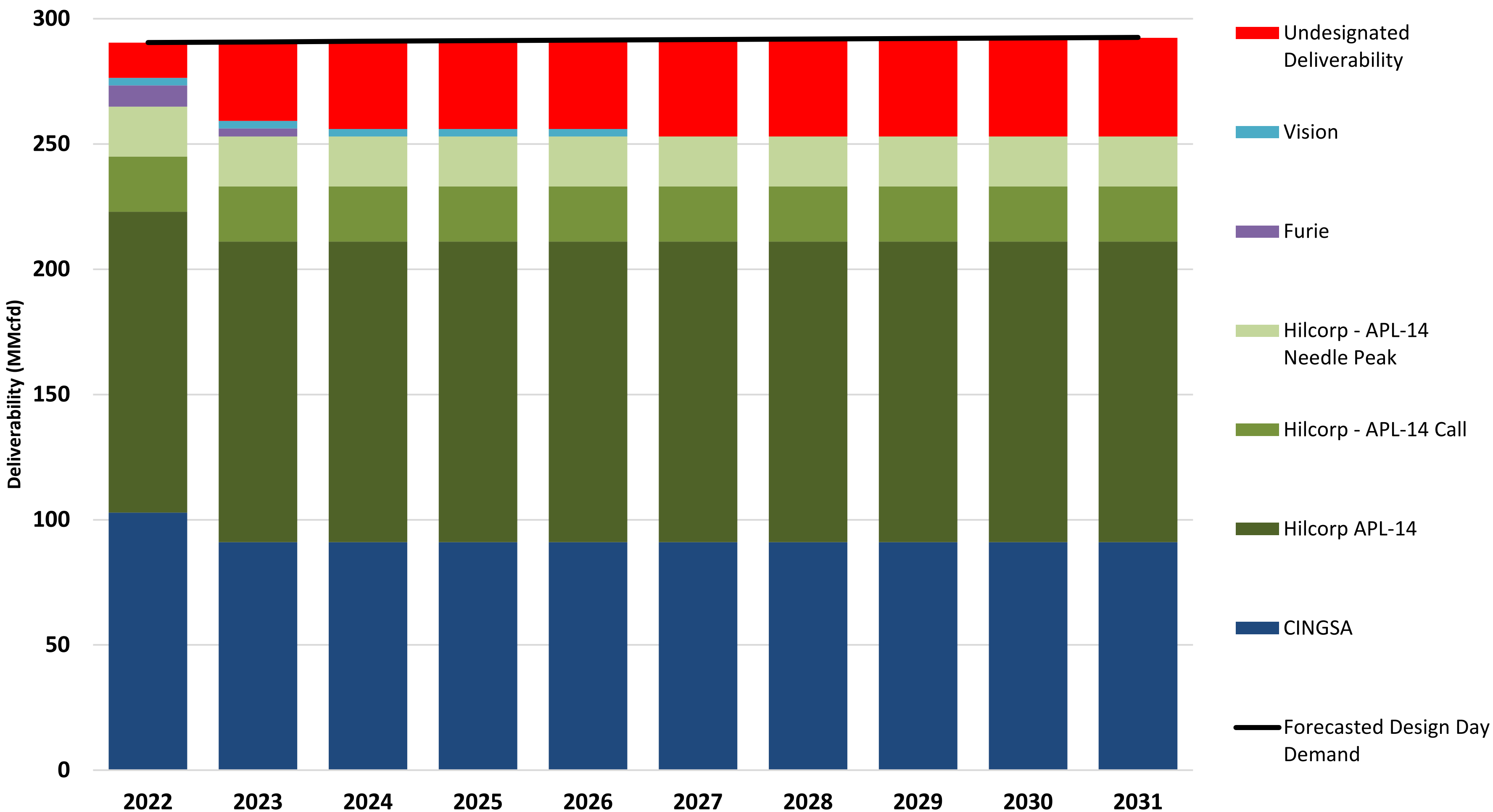
Volumes in MMcf

ENSTAR

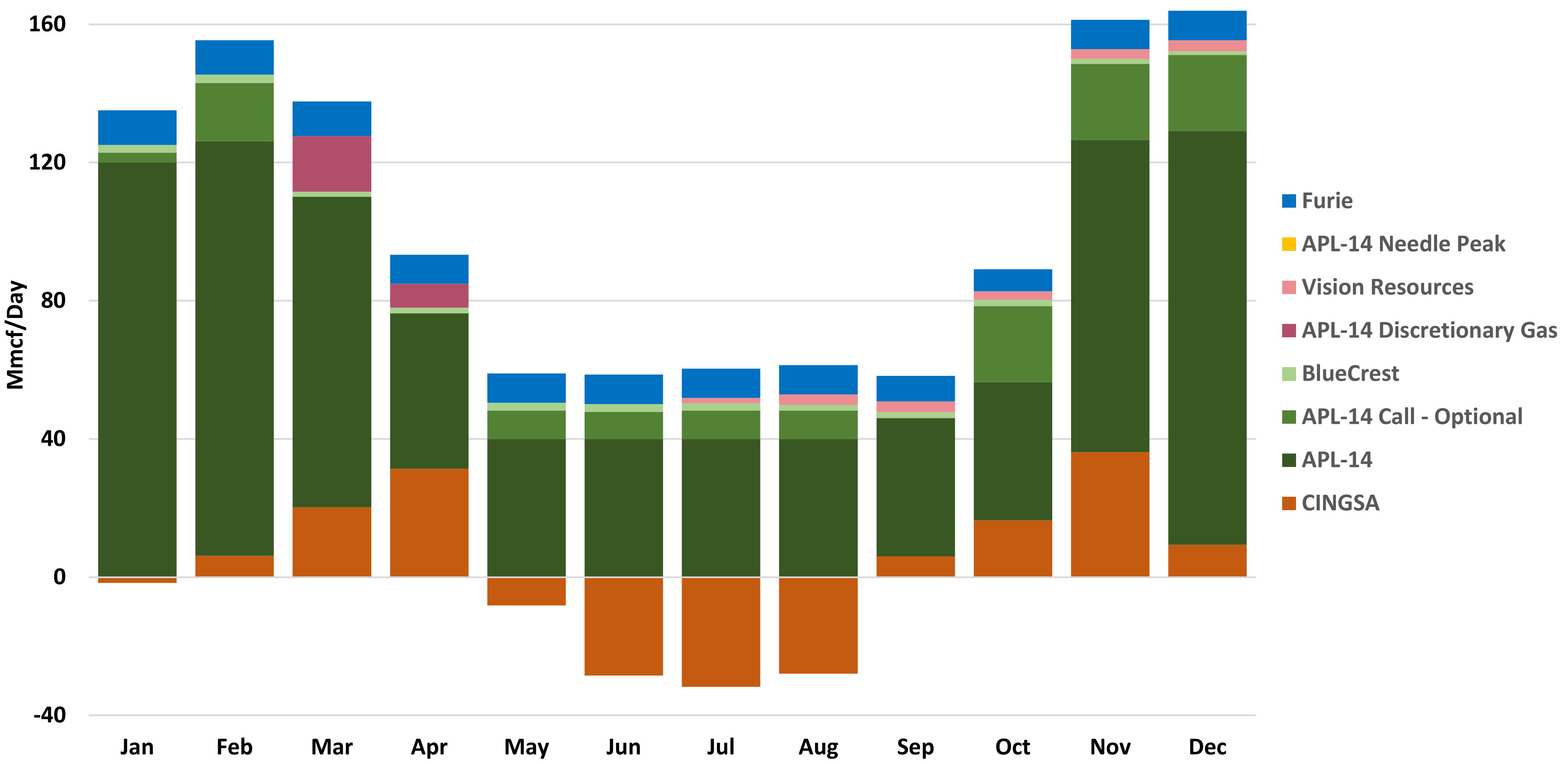
ENSTAR Supply Diversification 2016-2023



ENSTAR Deliverability 2022-2031



ENSTAR's 2021 Average Daily Deliverability



Questions

ENSTAR
Natural Gas Company

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Keith Kurber II, Chair Robert A. Doyle Robert M. Pickett Daniel A. Sullivan Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-____

PREFILED DIRECT TESTIMONY
OF
JILLIAN FAN

PREFILED DIRECT TESTIMONY
OF
JILLIAN FAN

TABLE OF CONTENTS

I. POSITION AND QUALIFICATIONS

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

A. My name is Jillian Fan. My business address is Suite 1700, 355 4th Avenue S.W., Calgary, Alberta T2P 0J1, Canada. I am the Director, Regulatory Policy for AltaGas Ltd. ("AltaGas"). I am appearing in this proceeding on behalf of ENSTAR Natural Gas Company ("ENSTAR") and Alaska Pipeline Company ("APC"). ENSTAR is a division of SEMCO Energy, Inc. ("SEMCO"), and APC is a subsidiary of SEMCO. For convenience, I will refer to ENSTAR and APC together as "ENSTAR" or the "Company."

Q. Briefly describe your professional experience and educational background.

A. I have been employed with AltaGas since 2008. I hold a Bachelor of Commerce degree in Accounting from the University of Calgary. I completed the Chartered Financial Analyst ("CFA") program and the Certified Management Accountants of Alberta professional program. I am an active member of both the CFA Institute and Chartered Professional Accountants of Alberta.

I have 29 years of experience in the energy and finance industries, including 25 years in energy infrastructure financing, investment, and management. My resume is attached as Exhibit JF-1.

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

A. Yes. I provided testimony in ENSTAR's last rate case, Docket U-16-066. I have also provided testimony on behalf of SEMCO Energy Gas Company, the other gas distribution division of SEMCO, located in Michigan and regulated by the Michigan

Public Service Commission ("MPSC"), in MPSC Case No. U-20479; and I have testified before the Alberta Utilities Commission.

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 AltaGas to ENSTAR, describe the nature of certain corporate support services provided by AltaGas to ENSTAR, describe how these services are charged through SEMCO to ENSTAR, and support the associated costs of those services to ENSTAR to satisfy the applicable statutes under which such expenses are reviewed by the RCA. In his prefiled direct testimony, ENSTAR witness Mr. Mark A. Moses discusses how these AltaGas costs are charged by SEMCO to ENSTAR, as well as shared services (and associated costs) that are provided by SEMCO on behalf of ENSTAR.

Q. Please describe the relationship between AltaGas and ENSTAR.

A. AltaGas is an energy infrastructure business with a focus on midstream and regulated public utilities. AltaGas is a public company that is traded on the Toronto Stock Exchange. AltaGas has business operations in Canada and the United States. AltaGas Services (U.S.) Inc. ("ASUS") is AltaGas' holding company in the U.S. and is a direct, wholly owned subsidiary of AltaGas. SEMCO is an indirect, wholly owned subsidiary of ASUS, and ENSTAR is a division of SEMCO. Therefore, AltaGas is the indirect parent company of SEMCO of which ENSTAR is a division. A simplified version of the AltaGas corporate organization is depicted in Exhibit JF-2.

Q. Are AltaGas and ENSTAR "affiliates" under Alaska statutes?

A. Yes, AltaGas considers ENSTAR an affiliate for ratemaking purposes. A true and correct copy of the relevant statutes is attached as Exhibit JF-3.

Q. During the test year, did ENSTAR receive services from AltaGas?

A. Yes, ENSTAR relied on AltaGas to provide support for ENSTAR's overall operations during the test year. These services have been provided since 2012, when AltaGas purchased SEMCO. These corporate support services ("Corporate Services") are provided pursuant to written services agreements between ASUS and AltaGas, and between SEMCO and ASUS, of which ENSTAR is a beneficiary.

Q. Why are these activities performed by AltaGas instead of by ENSTAR?

A. By centralizing these Corporate Services, AltaGas is able to share overhead costs and specific expertise across its businesses and achieve economies of scale and other efficiencies that could not be achieved by its business units or subsidiaries on a stand-alone basis. In many cases, AltaGas 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 AltaGas 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 simply cannot reasonably be outsourced by ENSTAR to third parties, such as services provided by AltaGas' Board of Directors and its executive management team and officers.

Q. Does ENSTAR incur costs associated with the Corporate Services provided by AltaGas?

A. Yes. Pursuant to the service agreements described above, SEMCO, on behalf of ENSTAR, is periodically invoiced for its allocated portion of the costs incurred by AltaGas 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 AltaGas to ENSTAR?

A. There are two applicable statutory requirements that must be satisfied for ENSTAR to be able to include costs associated with affiliate transactions in rates, specifically, AS 42.05.511(c) and 42.05.441(c). Attached as Exhibit JF-3 are true and correct copies of these statutes.

Pursuant to AS 42.05.511(c), ENSTAR has the burden to prove: (1) that services provided by AltaGas are necessary and consistent with the public interest; (2) payment made for those services is reasonably based, in part, on the cost incurred by AltaGas to provide those services; and (3) the payment is reasonably based, in part, on the estimated cost for ENSTAR 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), ENSTAR also has the burden to prove: (1) that payments made for the services provided by AltaGas were for services that were reasonably necessary for the operation of ENSTAR; and (2) the services were provided 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 ALTAGAS TO ENSTAR

A. Description of Corporate Services

Q. What types of Corporate Services are provided by AltaGas on behalf, or for the benefit, of ENSTAR?

A. As stated above, AltaGas provides various Corporate Services to ENSTAR. The services provided 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. Specifically, AltaGas engages in activities in the following broad categories:

- Board of Directors;
- Executive Committee;
- Finance;
- Accounting and Tax;
- Legal and Compliance;
- Information Technology and Procurement; and
- Office Services and Corporate Resources.

Each category of service provided by AltaGas to ENSTAR is briefly described below.

Q. Please describe the Corporate Services provided by the AltaGas Board of Directors for the benefit of ENSTAR.

A. The AltaGas Board of Directors (the "Board") is ultimately responsible for the stewardship of AltaGas and all its business units and subsidiaries, including ENSTAR. The Board oversees the business affairs of AltaGas and through periodic review of the strategic environment with management, is responsible for developing the strategic direction of AltaGas. The Board ensures the operations of AltaGas meet a high standard of governance and approves AltaGas' consolidated financial statements and quarterly and annual securities disclosure submissions. It also appoints its Chief Executive Officer ("CEO") and other senior officers and engages in succession planning. The Board also reviews and monitors principal business risks.

Q. Please describe the activities performed by the Executive Committee.

A. The AltaGas Executive Committee provides strategic management oversight to ensure corporate goals and objectives are met for all AltaGas business units. The Executive Committee provides strategic direction on matters including financial planning, capital access, business and capital risk management, and organization structure to achieve corporate objectives. It establishes effective company-wide governance models, establishes internal control standards and procedures to drive efficiencies and cost effectiveness, formulates strategy, and provides guidance to operational leadership to optimize AltaGas' lines of business. The executive management team also serves as the principal representatives and spokespersons of AltaGas.

Q. Please describe the Corporate Services provided for ENSTAR by the Finance group.

A. The services provided by the Finance group include those associated with treasury, corporate insurance services, commodity and credit risk management, and investor relations. The Finance group is charged with managing equity and debt financing for AltaGas, maintaining AltaGas' capital structure, providing consolidated cash flow forecasts and liquidity management, and monitoring financial market intelligence. The Finance group implements risk management strategies developed by the Executive

Committee and approved by the Board. Furthermore, the Finance group is responsible for investor relations activities, including managing analyst, investor, and shareholder communications, coordinating AltaGas' annual general meeting and quarterly conference calls, and preparing press releases and investor presentation materials.

Q. Please describe the Accounting and Tax services provided to ENSTAR.

A. The Accounting and Tax group prepares monthly, quarterly, and annual consolidated financial statements, and coordinates with external auditors for annual audit and quarterly reviews of AltaGas' consolidated financial statements. This group is also responsible for the payroll function and assists in the preparation of the analysis of financial information as well as management discussion and analysis that accompanies quarterly and annual consolidated financial statements required for securities filing documents. To satisfy securities disclosure requirements as a public issuer, the Accounting and Tax group implements and maintains the framework for internal controls and procedures. In addition, this group assists AltaGas' business units in their annual planning and budget cycle and ensures that business units' forecasts are incorporated in strategic planning. The Accounting and Tax group is also responsible for the overall tax compliance and tax planning framework for AltaGas and its subsidiaries. It provides strategic tax perspectives into AltaGas' annual budgeting and strategic planning process, coordinates corporate tax audits, and develops and implements cross-border transfer pricing policies.

Q. Please describe the Legal and Compliance Services provided to ENSTAR.

A. The Legal and Compliance group provides legal service and advice to AltaGas' various business functions. It maintains regular communications with these business functions to ensure effective management of legal matters, including management of external legal counsel where appropriate. This group provides corporate secretarial services to AltaGas and its subsidiaries, and coordinates all communications to, and the meetings of, the Boards of Directors of AltaGas and its affiliates, and oversees disclosure and compliance matters related to AltaGas' status as a reporting issuer. On the compliance side, this group develops guidelines and policies regarding AltaGas' code of business ethics and related core policies including human rights, environment, health and safety, and it maintains oversight on compliance of such matters across the organization. In addition, this group is responsible for developing and preparing AltaGas' disclosure regarding its environmental, social, and governance ("ESG") initiatives.

Q. Please describe the Information Technology ("IT") and Procurement services provided to ENSTAR.

A. The IT group develops and maintains organization-wide IT strategy, standardization, policies and practices to ensure there is a common framework for compliance and business automation across AltaGas and its subsidiaries. The compliance framework includes policies and practices to ensure access to the company's information assets is safeguarded. The IT group also develops and implements company-wide cybersecurity policies and procedures, as well as heading the enterprise cybersecurity governance committee. Initiatives include awareness programs to provide employees with education, training, support and tools to encourage best practices for cybersecurity. It also conducts third-party vulnerability and cybersecurity tests, oversees corporate threat detection, and develops incident response protocols.

Regarding procurement, AltaGas establishes company-wide strategic procurement procedures and practices to effectively secure supply of goods and services with quality vendors, mitigate commercial risks, and utilize procurement strategies to drive competitive tension and reduce price. The procurement function also facilitates active collaboration among procurement leaders from across the organization on procurement activities where possible to leverage enterprise spend opportunities to realize more favorable terms and conditions.

Q. Please describe the Office Services and Corporate Resources services provided to ENSTAR.

A. This group maintains the corporate headquarters of AltaGas and provides a safe, secure workplace environment with the necessary facilities, policies, and programs for AltaGas employees to perform the various corporate functions as described above. In addition, this group provides support for executives' and employees' compensation plan design, pension (including retirement savings) and benefits management, and enhances best practices in the governance on these items. It is also responsible for the development and implementation of enterprise-wide talent and human capital management, to promote employee engagement and enable the development and retention of business knowledge and experience within the organization.

Q. Are these services provided by AltaGas specifically for, or directly to, ENSTAR?

A. No. AltaGas performs these services for the benefit of all its business units, including ENSTAR. None of these services are performed specifically for, or directly to, any particular business unit. Costs incurred by AltaGas in performing these services are allocated to all business units in the same manner. These are common services that AltaGas performs as a parent company and a publicly-traded organization for, and on behalf of, all its business units. In other words, if AltaGas were not to perform these services, each business unit would need to provide these services on its own.

Q. Does SEMCO also provide corporate support services for ENSTAR?

A. Yes.

Q. Is there any duplication of services provided by AltaGas and SEMCO?

A. No. There is no duplication in services or activities performed at the AltaGas level as compared with those performed at the SEMCO level. As a result, there is no duplication in costs associated with services performed by AltaGas. As defined and described in Mr. Moses' direct testimony, SEMCO performs certain "Shared Services" associated with various functions such as accounting, human resources, IT, procurement, and finance. Although these Shared Services have similar names as the Corporate Services provided by AltaGas, the nature and purpose of the SEMCO Shared Services are different than the Corporate Services performed by AltaGas, in the sense that the SEMCO Shared Services are more focused on the everyday administration and operations of ENSTAR, ensuring good business practices. On the other hand, the Corporate Services performed by AltaGas focus on corporate governance, management oversight, strategic advice, guidance and leadership, and providing capital access. The AltaGas Corporate Services are therefore complementary to SEMCO's Shared Services.

Q. Does ENSTAR also self-provide administrative services?

A. Yes, certain SEMCO employees who reside in and only work on assets located in Alaska also provide certain administrative services to ENSTAR. Consistent with the definition in Mr. Moses' direct testimony, I will refer to them as "ENSTAR employees." Since these employees are fully dedicated to ENSTAR, costs associated with these employees are not allocated, but rather are directly charged to ENSTAR.

Q. Is there any duplication of the Corporate Services provided by AltaGas and the services provided by ENSTAR employees?

A. No. There is no duplication in services or activities performed at the AltaGas level as compared with those performed by ENSTAR employees. As a result, there is no duplication in costs associated with services performed by AltaGas. The services provided by AltaGas to ENSTAR are complementary in nature to the services provided by ENSTAR employees directly.

B. <u>Necessity and Public Interest</u>

Q. Are the Corporate Services provided by AltaGas necessary?

A. Yes. The services are common activities that are required as part of the ongoing management of a diversified, publicly-traded 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. As previously stated, these services are necessary for AltaGas to maintain its public-issuer status to satisfy the capital needs of its business units, including ENSTAR, in a timely and efficient manner.

Q. In addition to the Corporate Services being necessary, how do the Corporate Services provided by AltaGas benefit customers?

A. The Corporate Services benefit customers in several ways. First, the AltaGas 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 where 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, ENSTAR has the benefit of access to energy infrastructure management experience and expertise across the entire organization. ENSTAR senior leadership participates in AltaGas' monthly governance meetings during which senior management of AltaGas and its businesses share business and operational updates to ensure we remain focused on our goals. ENSTAR's safety personnel also participate in AltaGas' safety meetings where lessons learned are shared across the organization.

Third, AltaGas has well-established track records in capital market issuances, access to bank credit facilities and the equity capital market. For example, its investor relations function, which is part of the Finance group discussed earlier, manages AltaGas' communications with the shareholders, investors, and other capital market participants. Such outreach efforts facilitate capital issuance activities undertaken by AltaGas' Finance group. In other words, ENSTAR can rely on AltaGas as, and when, it requires capital to deliver safe and reliable gas utility services. The various Corporate Services performed by AltaGas, as described above, are necessary to maintain AltaGas' status as a publicly traded company and to support its continual access to capital markets.

Fourth, by consolidating the Corporate Services at AltaGas, ENSTAR is able to enjoy the benefits of cost efficiencies that cannot be achieved if it were to source the Corporate Services from third parties or replicate these services on its own. Consolidation of Corporate Services enables sharing of costs so that each business unit bears only a portion of these costs.

Q. Can you provide examples of how costs to customers are reduced by ENSTAR receiving Corporate Services from AltaGas?

A. Yes. While not exhaustive, the following are examples that demonstrate how costs to customers are reduced.

To illustrate, if AltaGas did not perform the Corporate Services needed to maintain its public-issuer status, ENSTAR would need to satisfy its legal mandates, compliance requirements, and capital requirement with its own personnel and resources. At a minimum, it would need to incorporate as a separate entity, recruit its own board of directors, hire an executive management team, establish an independent board of directors, set up its own treasury and investor relations function, and expand its accounting function to satisfy securities disclosure requirements. Furthermore, in order to become a publicly-traded company and issue its own securities, there are numerous essential functions ENSTAR would need to perform. These include arranging for its own external audit, preparing its own quarterly and annual reports, maintaining communication with its 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. ENSTAR would need an expanded staff and additional overhead, including office space, enhancement of IT hardware and software systems, as well as additional HR employees, to support these incremental functions. It is not reasonable for ENSTAR to outsource its board, executive management, and associated governance functions to third parties on a long-term basis; a market for these services simply does not exist.

To further illustrate, the total costs of Corporate Services included in the AltaGas Corporate Cost pool in 2021 were approximately $42 million, of which about $18 million (or around 43%) were third-party costs. "Third-party costs" are costs that are paid at arm's-length to unaffiliated third parties for services performed by such parties for the benefit of AltaGas and its business units. ENSTAR's allocated portion of these third-party costs was only $0.9 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 $0.9 million if it were to source these services for itself. Furthermore, ENSTAR would need to employ additional personnel and incur more overhead costs in order to manage these additional functions. Thus, the prudent approach is for AltaGas to perform these Corporate Services on ENSTAR's behalf.

Q. Are the Corporate Services provided by AltaGas to, or for the benefit of, ENSTAR in the public interest?

A. Yes. The Corporate Services provided under the service agreements discussed above are not only necessary to the operation of ENSTAR but are also beneficial to customers. Economies of scale are realized by provision of Corporate Services by AltaGas that directly result in lower costs to ENSTAR's customers. For the reasons discussed above, this arrangement is in the public interest.

IV. COST ALLOCATION AND COMPETITIVENESS OF COSTS

Q. How are the costs of the Corporate Services charged to AltaGas' divisions and subsidiaries?

A. AltaGas allocates costs for Corporate Services to ENSTAR based on the Modified Massachusetts Formula ("MMF"). MMF is an industry standard methodology to allocate fixed and common costs.

First, costs for Corporate Services are combined into one common cost pool at AltaGas for allocation. This cost pool is then allocated to ASUS, the holding company of AltaGas' U.S. business, and AltaGas' Canadian business units and subsidiaries, using the AltaGas Modified Massachusetts Formula ("AltaGas MMF"). The AltaGas MMF uses a simple average of three different cost allocator-bases (the "AltaGas MMF Allocator") of each business of the AltaGas consolidated group. The three cost allocator-basis in the AltaGas MMF Allocator are the (1) relative earnings before interest, tax, and depreciation ("EBITDA"), (2) relative payroll costs, and (3) relative property (Plant, Property, and Equipment, including construction work-in-progress, plus Materials and Supplies Inventories and Gas Inventories) of each business unit or subsidiary. The following table illustrates the 2021 AltaGas MMF Allocator used by AltaGas to allocate Corporate Services costs to ASUS:

AltaGas Limited
2021 MMF Allocator

	Total AltaGas ($000s)	ASUS ($000s)
Total Property	9,534,477	6,347,569
Property factor		66.6%
Total Payroll	312,255	234,724
Payroll factor		75.2%
Total EBITDA	1,151,130	719,203
EBITDA factor		62.5%
2021 Average Factor		**68.1%**

In the second step, when ASUS receives the allocation from AltaGas, ASUS allocates such costs to the U.S. businesses, including SEMCO, using the Washington Gas Modified Massachusetts Formula ("Washington Gas MMF").

Similar to the AltaGas MMF, Washington Gas' MMF also includes three equally weighted factors, although the factors are slightly different than the AltaGas MMF Allocators and consist of average invested capital, labor dollars, and net revenue (collectively, the "Washington Gas MMF Allocator"). The principal reason for using the Washington Gas MMF for the allocation from ASUS to its U.S. subsidiaries is that, after the acquisition of WGL Holdings Ltd. ("WGLH") by AltaGas, certain administrative services formerly provided by ASUS (including accounting, general ledger maintenance, cash management, payroll administration, IT, procurement, etc.), are now performed by Washington Gas Light Company ("Washington Gas"), a subsidiary of WGLH. Administratively, it was both practical and efficient to adopt the Washington Gas MMF and its allocation methodology. The following table illustrates the 2021 Washington Gas MMF Allocator used by ASUS to allocate Corporate Services costs to SEMCO and its other U.S. businesses:

ASUS
2021 MMF Allocator

	Total ASUS ($000s)	SEMCO ($000s)
Average Invested Capital ("AIC")	5,562,614	1,239,902
AIC factor		22.3%
Labor	201,296	28,582
Labor factor		14.2%
Net Revenue	1,257,141	253,276
Net Revenue factor		20.1%
2021 Average Factor		18.9%

ENSTAR receives an allocation of these costs through SEMCO given that ENSTAR is a division of SEMCO. When SEMCO receives an allocation of the Corporate Services costs, it allocates those costs directly to its divisions and subsidiaries using the MMF Allocator and methodology. The allocation of costs for Shared Services from SEMCO to ENSTAR is further discussed in Mr. Moses' direct testimony.

Q. Why does AltaGas 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.

SEMCO has also been using the MMF to allocate shared costs between its utility divisions in Michigan (SEMCO Gas) and Alaska (ENSTAR) since 1999 and the methodology has consistently been deemed acceptable by the regulatory commission in Michigan and this Commission since that time. As further explained in the direct testimony of Mr. Moses, SEMCO has what is called an Affiliated Transactions Policy Manual ("ATM") that specifies how costs are charged to all SEMCO divisions. The MMF allocation is described in that manual. SEMCO and ENSTAR continue to use the ATM in accounting for the costs addressed here.

Similarly, the Washington Gas MMF has been used for allocation of fixed and common costs and has been reviewed by regulators in Washington, D.C., Maryland, and Virginia. Washington Gas has a Cost Allocation Manual ("CAM") similar to SEMCO Energy's ATM. The CAM is also filed with its utility regulators every year.

Q. Does AltaGas charge a mark-up or profit of any kind on the cost it incurs to provide these Corporate Services?

A. No. These Corporate Services are provided at cost. In other words, costs associated with the Corporate Services are allocated to business units with no mark-up or profit of any kind.

Q. What were the allocated costs of the Corporate Services from AltaGas to ENSTAR in 2021?

A. The entire AltaGas corporate allocation to ENSTAR (through ASUS and SEMCO) was $2.01 million in 2021, part of which was the $0.9 million allocation of third-party costs to provide the services. The table below depicts the various service functions and allocations of costs to ENSTAR in 2021.

	2021 Total ENSTAR Allocation ($000s)	Allocation of Third Party Costs ($000s)
Board of Directors	55	55
Executive Management	279	11
Finance	248	142
Accounting and Tax	404	98
Legal & Compliance	388	67
IT & Procurement	513	434
Office Services & Corp Resources	121	68
	2,008	876

Q. Has AltaGas incurred any costs for services that are not allocated to ENSTAR?

A. Yes. Costs incurred by AltaGas solely for its midstream businesses, corporate and business development costs, corporate donation and promotion, supplemental executive retirement plan expense, share-based incentive expenses, and certain travel expenses are not allocated to ENSTAR. These costs are carved out from the Corporate Services cost pool as they are generally perceived to be not necessary for utility operations.

Q. How do the costs of Corporate Services allocated from AltaGas to ENSTAR in 2021 compare to those costs allocated in the last ENSTAR rate case, which was based on a 2015 test year?

A. Allocated costs to ENSTAR associated with Corporate Services have decreased about 30% since 2015 even though the total cost of Corporate Services to AltaGas has increased. This is mainly attributable to the increase in size and scale of AltaGas' operations between 2015 and 2021 and the focus on keeping costs controlled at a reasonable level.

Q. Has ENSTAR analyzed what the cost would be if it performed the Corporate Services with its own personnel and capital?

A. Yes. In order to address AS 42.05.511(c), ENSTAR has undertaken an analysis to determine what it would cost to self-provide services currently provided by SEMCO and AltaGas, assuming ENSTAR is a stand-alone entity with no parent company. This hypothetical analysis demonstrates that the cost to self-provide the suite of services is much higher than the current methodology. In this analysis, ENSTAR has included some of the known third-party costs necessary to perform the services and additional employee compensation costs. Taking into consideration market data, as well as AltaGas and SEMCO practices with regard to employee benefits and compensation, ENSTAR estimates that it would cost approximately $7.3 million to employ just the people to perform the services performed by SEMCO and AltaGas. Additionally, ENSTAR conservatively estimates that it would also incur approximately $5.8 million in third-party costs to self-provide the services performed by AltaGas and SEMCO on behalf of ENSTAR.

This analysis focuses on additional O&M costs that would be borne by ENSTAR if it were to self-provide these services. These costs do not include additional, significant capital costs as well as the return on and depreciation of the capital that would be passed on to ratepayers. This analysis also does not take into consideration the significant years of management experience or the loss of industry knowledge that is gained by being a part of a diversified energy company if ENSTAR were to self-provide these services. While it may be hard to put a price on this advantage, there is no doubt the advantage would be lost if ENSTAR were a stand-alone company.

Attached to my testimony as Exhibit JF-4 is a summary of the analysis that I co-sponsor with ENSTAR witnesses Messrs. Sims and Moses, which depicts a hypothetical workforce and some of the associated third-party cost ENSTAR would incur if ENSTAR were to self-provide the services provided by SEMCO and AltaGas.

Q. Are the charges associated with the Corporate Services provided by AltaGas to ENSTAR competitive with costs that would be incurred if the services were provided by an unaffiliated third-party?

A. Yes. The charges for the Corporate Services are lower than the costs that would be incurred if the services were performed by an unaffiliated third-party. This is demonstrated in several ways.

First, the AltaGas corporate philosophy is to keep all costs for its entire corporate enterprise at a competitive level with its competitors and peers. AltaGas has obligations not only to its customers through its business units, but to its shareholders, to keep costs associated with all activities to a reasonable level and provision of Corporate Services is just one example of where that obligation applies. For example, all costs for Corporate Services are subject to strict budgeting and cost controls that are focused on keeping costs at reasonable levels as discussed above. As another example, the AltaGas hiring practices are designed to competitively compensate employees performing services, but are not designed to compensate employees above and beyond what market forces establish as fair and reasonable. The objective of AltaGas' compensation program is to offer competitive base salary compensation at approximately the median among its peer group.

Second, a large portion of the costs being allocated to ENSTAR (approximately 43%) are associated with services performed by third parties and are competitive by definition. For example, during 2021, AltaGas retained Ernst & Young ("EY") for auditing and other consulting work due to its experience and independence from AltaGas. EY provides these types of services in a very competitive market and was retained at arm's length. In 2021, the fees AltaGas paid to EY regarding consolidated audit and quarterly reviews was approximately $0.9 million; and ENSTAR's portion of these costs was less than $45,000. While the EY costs are allocated, they are costs actually billed by third parties.

Third, ENSTAR is only receiving a fraction of the costs incurred by AltaGas for the Corporate Services. While the total amount of costs may be less for an organization the size of ENSTAR as compared to an organization the size of AltaGas, a large portion of the costs would be necessary regardless of the size of the company. For example, AltaGas incurred close to $1.2 million in third-party costs during 2021 for securities listing registration, annual report preparation, annual general meetings, other forms of shareholder communications, and D&O insurance. ENSTAR's allocation of these costs was less than $60,000. If ENSTAR were to self-provide these services, ENSTAR would expect to pay close to $1.4 million. The main driver for the spike in ENSTAR's standalone cost is the significant D&O insurance premium associated with a U.S. listed company; and some of the other costs have no direct correlation to company size.

Also for example, a publicly traded company needs a board of directors, a CEO, and a chief financial officer ("CFO"). For illustrative purposes, the average bundled cost of a board of directors, a CEO, and a CFO of five Alaska Native corporations and four listed public utilities in the Northwestern part of the U.S.,[1] is approximately $4.9 million. In stark contrast, ENSTAR was only allocated approximately $334,000 of total costs (including both compensation and third-party costs) associated with AltaGas' Board and Executive Management in 2021. Also note that while the amount varies from company to company, on average over 30% of the amounts of board of directors and executive compensation for the four listed public utilities in the Northwestern part of the U.S. were share-based compensation that AltaGas excludes from the cost allocation to ENSTAR. If ENSTAR were to recruit its own CEO and CFO and establish its own board of directors, however, it would need to provide compensation consistent with customary market practice, which typically includes a share-based compensation component.

Fourth, any services provided by third parties to ENSTAR will likely contain profit margins that simply are not assessed by AltaGas. While profit margins may differ depending on the type of service provided, it is fair to say that all services would be provided by third parties at fully-loaded costs, plus a profit margin. For these, and other reasons, the cost at which ENSTAR receives the Corporate Services from

[1] The five Alaska Native corporations are (i) Bristol Bay Native Corporation, (ii) Doyon, Ltd., (iii) Cook Inlet Region, Inc., (iv) Calista Corporation, and (v) Northwest Arctic Native Association. The four public utilities in the Northwestern part of the U.S. are (i) ATN International, the parent company of Alaska Communications Systems Group, Inc., (ii) Avista Corporation, the parent company of Alaska Electric Light & Power, (iii) Northwest Natural Gas Company, and (iv) Puget Energy, Inc.

AltaGas are competitive with the cost at which such services could be received from a third party, if such services were even available.

Q. How should the Commission consider the costs of these Corporate Services in light of AltaGas' entry into a Purchase and Sale Agreement to sell its Alaska assets?

A. In the event the sale is approved by the Commission and closes during the pendency of this proceeding, ENSTAR may file supplemental testimony if required.

Q. Are the Corporate Services provided by AltaGas to ENSTAR, and the costs associated with those services reasonable and necessary?

A. Yes. The Corporate Services are necessary, not duplicative of other services provided to ENSTAR, are beneficial to customers, and are in the public interest. Furthermore, the costs associated with the Corporate Services are allocated using a widely-accepted methodology, are less than they would be if ENSTAR performed the services for itself, and are competitive with what they would be if the Corporate Services were provided by an unaffiliated third party, if they could be obtained externally. For these reasons, the costs are reasonable.

V. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Jillian Fan

EMPLOYMENT

AltaGas Ltd. 2013-Present

Director Regulatory Policy

AltaGas Utility Group Inc. 2008-2012

Director Strategic Development

Brookfield Asset Management 2005-2008

Vice President

Darby Asia Investors Limited 1999-2004

Vice President

Associate

CIBC World Markets 1997-1999

Associate

Canadian Imperial Bank of Commerce 1996-1997

Financial Analyst

Numac Energy Inc. 1993-1996

Treasury Analyst

Financial Accountant

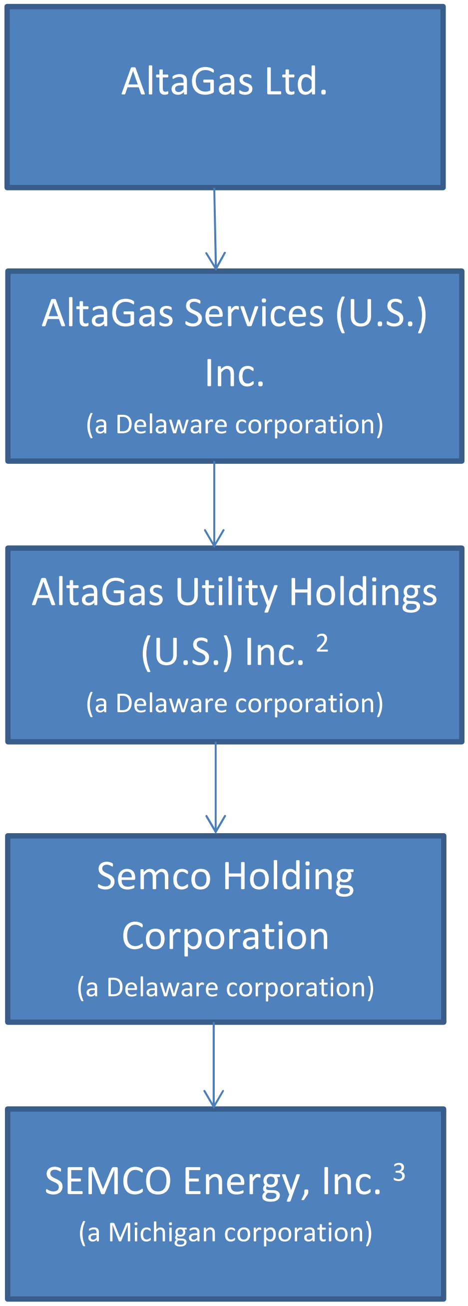
EDUCATION

University of Calgary: Bachelor of Commerce (distinction), Accounting, 1993

Certified Management Accountant / Chartered Professional Accountants of Alberta, 1996

Chartered Financial Analyst Institute, 1999

AltaGas Ltd. – U.S. Structure showing ownership of ENSTAR [1]



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[1] As at June 30, 2022.

[2] AltaGas Utility Holdings (U.S.) Inc. ("AUHUS") also indirectly owns 100% of WGL Holdings, Inc., which owns 100% of Washington Gas Light Company.

[3] SEMCO Energy, Inc. conducts its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company ("ENSTAR").

Select Alaska Statutes

AS 42.05.441(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 42.05.511(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 service 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, upon the submission of satisfactory proof as to the cost to the affiliated interest of furnishing the service or property and, in part, upon the estimated cost the utility would have incurred if it furnished the service or property with its own personnel and capital.

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.

Summary of Costs to ENSTAR to Perform All Corporate and Shared Services Activities

ENSTAR's Cost for AltaGas Corporate and SEMCO Energy Shared Services Expenses			
Shared Services Function	SALARIES & BENEFITS	THIRD PARTY & OTHER EXPENSE	TOTAL
Board of directors	$ -	$ 55,002	$ 55,002
Executive Management	267,676	10,863	278,539
Accounting / Tax	620,265	250,427	870,692
Corporate Compliance & Communications & Records Maintenance	965,122	119,445	1,084,567
Finance / Treasury	268,777	248,831	517,609
Information Technology / Procurement	428,854	994,751	1,423,605
Human Resources	52,815	97,859	150,674
Safety & Risk	30,384	5,520	35,904
Facilities	-	113,953	113,953
TOTAL	**$ 2,633,894**	**$ 1,896,652**	**$ 4,530,546**

Estimated ENSTAR Cost if AltaGas Corporate and SEMCO Energy Shared Services Activities Were Performed Directly by ENSTAR				
Shared Services Function	FTE REQUIRED	SALARIES & BENEFITS	THIRD PARTY & OTHER EXPENSE	TOTAL
Board of directors		$ -	$ 1,477,627	$ 1,477,627
Executive Management	2	3,460,058	140,419	3,600,477
Accounting / Tax	5	816,322	450,000	1,266,322
Corporate Compliance & Communications & Records Maintenance	2	439,118	332,281	771,399
Finance / Treasury	4	1,063,383	1,500,066	2,563,449
Information Technology / Procurement (1)	5	869,042	1,103,469	1,972,511
Human Resources	3	455,602	29,538	485,140
Safety & Risk	1	198,062	629,627	827,689
Facilities (2)		-	113,953	113,953
TOTAL (1), (2), (3)	**22**	**$ 7,301,587**	**$ 5,776,979**	**$ 13,078,566**

(1) In addition to the O&M items identified in the ENSTAR standalone costs, ENSTAR would be required to implement some systems/hardware (ERP, Cybersecurity, etc.) currently provided by SEMCO Energy, which would result in additional O&M expenses and/or capital expenditures necessary to provide the company with the support currently provided via shared solutions.

(2) This analysis does not include any requisite incremental capital or expense costs (O&M, depreciation and property taxes) specifically related to the additional 22 FTEs.

(3) Since ENSTAR is a division of SEMCO Energy, Inc. and not a legal entity, this analysis is hypothetical and represents a conservative estimate of the costs ENSTAR would bear to perform the activities currently provided by AltaGas Ltd. and SEMCO Energy Inc. on its behalf.

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Keith Kurber II, Chair Robert A. Doyle Robert M. Pickett Daniel A. Sullivan Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-____

PREFILED DIRECT TESTIMONY
OF
JOHN D. SIMS

PREFILED DIRECT TESTIMONY
OF
JOHN D. SIMS

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EXHIBITS

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 (a division of SEMCO Energy, Inc. ("SEMCO")) and Alaska Pipeline Company (a subsidiary of SEMCO) ("APC"), as well as President of Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"). ENSTAR Natural Gas Company 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 200+ 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, and U-19-014, and on behalf of CINGSA in Dockets U-18-005, U-18-024, U-18-043, U-19-025, and U-21-058.

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 provide a general overview of this rate filing and ENSTAR. Second, I provide an update on ENSTAR operations since its last rate case docketed as U-16-066. Finally, I discuss several key issues raised by this filing and detail the Company's proposals on these issues. These issues include the Company's return on equity ("ROE") and certain unique business risks of ENSTAR's operations, rate design, and requests for year-end rate base treatment of certain capital expenditures. Other witnesses in the case also testify on these topics and will provide their input based on their expertise and experience.

III. OVERVIEW OF ENSTAR'S FILING

Q. Why is ENSTAR making this rate filing?

A. ENSTAR was ordered by the Commission in Order U-16-066(22) to file a rate case based on a 2021 test year, including a lead-lag study, by August 1, 2022. This filing is being made in compliance with Order U-16-066(22). Additional discussion of ENSTAR's rate history is included in the direct testimony of Company witness Mr. Daniel M. Dieckgraeff.

Q. What is ENSTAR requesting in this rate filing?

A. ENSTAR is requesting an overall increase of 1.40% including the cost of gas and 5.68% 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 ROE to 12.95%, a capital structure using the actual structure at the end of the 2021 test year of 45.89% debt and 54.11% equity, and ENSTAR's current actual cost of debt of 2.86%. Cost 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 1.5%, to be effective October 1, 2022.

Q. Is ENSTAR proposing a change to its General Service Customers' rates?

A. It is. ENSTAR is proposing to increase the portion of costs that are recovered via the customer charge, thereby decreasing the volumetric charge.

Q. Why is ENSTAR making this proposal?

A. As Mr. Dieckgraeff discusses in his testimony, decoupling is becoming more and more common in the utility industry across the United States. While ENSTAR is not proposing to move to a completely decoupled rate, we do recognize the benefit for both the Company and ratepayers by moving slightly in this direction. From the ratepayers' perspective, it allows for more transparency on their monthly bill and greater predictability on utility costs. From ENSTAR's perspective, it helps to mitigate the losses experienced by the consistent trend of declining use per customer. Without this proposal being put in place, ENSTAR would be deprived of a fair opportunity to recover the costs of providing service.

Q. Is ENSTAR proposing a different rate design for its transportation customers in this case than the one approved by the Commission in Order U-16-066(19)?

A. Yes. ENSTAR is proposing straight fixed variable rates as discussed in the testimonies of Mr. Dieckgraeff and Dr. Bruce H. Fairchild. A majority of ENSTAR's transportation customers are going through an ideological metamorphosis. Electric utilities are being driven by local and state government, and their own boards, to reduce their dependency on fossil fuels. They will look to increase investments in wind, solar, hydro, and potentially tidal resources as well. At the same time these utilities are held to extremely high standards for reliability and continuity of service. ENSTAR has no doubt this will impact the volumes we transport on our system, however, just because volumes on the pipeline decrease, the costs do not.

Q. What do you mean by your statement above that decreases in volume do not relate to decreases in costs on our pipeline system?

A. ENSTAR transportation customers have relied on our transportation and distribution systems to bring them natural gas the exact moment they need it for decades. As renewable energy becomes more prevalent in our state, our system will become that much more important. Solar and wind powered generation is unpredictable, and we expect to continue to be called on in a moment's notice to bring the natural gas needed to generate power. This means that we need to reliably maintain the natural gas systems to meet their entire load.

Q. Why is ENSTAR proposing the move to straight fixed variable rates?

A. It is important that ENSTAR is allowed an opportunity to earn the appropriate and regulatorily approved costs. This removes the question, and ultimately the potential argument in this proceeding, about what the appropriate volumes transportation customers will need ENSTAR to deliver on its system. This topic is discussed in greater detail in Ms. Inna B. Johansen's direct testimony.

Q. Who are ENSTAR's witnesses in support of this filing?

A. ENSTAR's filing is supported by my direct testimony and by the direct testimony of the following witnesses:

- Ms. Johansen discusses the Cook Inlet gas supply challenges and ENSTAR's transport volumes;
- Ms. Jillian Fan will describe the various corporate services provided by AltaGas Ltd. ("AltaGas") as well as the manner in which certain costs of those services are allocated to ENSTAR;
- Mr. Mark A. Moses summarizes the shared services provided by SEMCO and explains the basis for an adjustment to pension expenses and removal of the acquisition adjustment;
- Mr. Harold Walker, III sponsors the required lead-lag study used to determine ENSTAR's cash working capital requirement;
- Mr. Dylan W. D'Ascendis sponsors testimony regarding the appropriate capital structure and corresponding cost of capital for ENSTAR;
- Ms. Chelsea N. Guintu sponsors the 275(a) filing, including the required comparative financial statements and historical financial schedules as well as

certain pro forma adjustments to the test year. Ms. Guintu also addresses certain aspects of ENSTAR's accounting policies, procedures, and records;

- Dr. Fairchild discusses the cost-of-service study, the adjusted rate design, and certain income tax adjustments; and
- Mr. Dieckgraeff summarizes ENSTAR's rate history and discusses the rate effect of certain pro forma adjustments, including an adjustment to normalize the unusual weather experienced during the 2021 test year. Mr. Dieckgraeff also sponsors the interim and permanent tariff sheets.

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

A. Although I am not an attorney, my understanding of 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 requirement to authorize just and reasonable rates, and the process to determine those rates, in Order U-18-043(15):

> We are required by statute to ensure that the rates charged by CINGSA are just and reasonable. 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]

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[1] Order U-18-043(15) at 9 (internal citations omitted).

To assist the Commission in determining "just and reasonable" rates and in compliance with Order U-16-066(22), ENSTAR has prepared revenue requirement and cost-of-service studies that follow 3 AAC 48.275(a) and (h), as well as a lead-lag study.

IV. OVERVIEW OF ENSTAR

Q. Please provide a brief overview of ENSTAR and its customers.

A. ENSTAR purchases, on average, 32.1 Bcf[2] of natural gas annually from various Cook Inlet producers and delivers the gas through its transmission and distribution system to residential, commercial, and industrial customers in the areas served by the Company. 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 the gas provided or transported by ENSTAR for the same purposes and for industrial purposes, such as generating power or running asphalt plants.

ENSTAR employs approximately 200 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

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

services from SEMCO and AltaGas, as further described in the testimony of ENSTAR witnesses Ms. Fan and Mr. Moses.

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, in terms of the rates it charges and the terms and conditions under which it provides service to customers, by the Commission. 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 is then resold 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 and what rate design should be used to collect the costs of providing service. Our proposed base rate charges in this request comprise about 20% of the typical gas sales customer's bill, and as you will see through this filing, are significantly lower than the average cost when compared to other utilities across the nation.

V. <u>ENSTAR UPDATE SINCE U-16-066</u>

Q. Please describe Docket U-16-066.

A. Docket U-16-066 was ENSTAR's last rate case, filed in June 2016 and based on a 2015 test year. This 2016 rate case was the first time the Commission had fully adjudicated ENSTAR's revenue requirement, cost of service, and rate design since 1987. The Commission's order resolving the case, Order U-16-066(19), set a ROE commensurate with the risks ENSTAR faced at that time; offered clear guidance to ENSTAR on what capital investments would qualify for year-end rate base treatment; adjudicated cost-of-service; addressed rate design; and definitively addressed several other proposals. ENSTAR was most proud of the Commission's observation in that case 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." The Company has sought to continue to live up to that observation since the last rate case and will demonstrate this fact in this filing.

Q. Have ENSTAR's costs to do business increased?

A. Yes. ENSTAR's total normalized operations and maintenance ("O&M") expenses, including administrative and general expenses, but not including depreciation or property taxes, in the last test year (2015), were approximately $34.5 million. Since then, O&M expenses have increased to $39.1 million in the 2021 normalized test year, mainly due to labor inflation, 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; and additional regulatory changes and compliance efforts. All of ENSTAR's O&M expenses as normalized are reasonable and necessary.

Q. Notwithstanding the modest 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 $3.02 per Mcf. This is well below the national average cost for natural gas distribution service during 2021 as reported by the Energy Information Administration of $6.13 per Mcf.

Q. Has ENSTAR done an analysis of the historical rate of increase in its gas sales base rates?

A. Yes. ENSTAR compared the rates proposed in this filing to 1985 rates using the following methodology:

- The actual customer charge per month for ENSTAR in 1985 was $4.50, and the actual non-gas base rate per CCF was $0.15896. For G1 customers, the Current

Monthly Average customer use is 114.2 CCF.[3] The "Current Monthly Average" refers to weather normalized volumes. The annual non-gas portion of a customer's bill using the Current Monthly Average would have been $281.38.

- In this case, ENSTAR's proposed customer charge is $27.00, and the base rate per CCF is $0.06555. Using the same Current Monthly Average customer use of 114.2 CCF, the current annual non-gas portion of a customer's bill is $413.80.
- The Current Monthly Average customer usage was used in both portions of the calculation in order to eliminate variations in customer consumption habits and weather.

This analysis equates to an average increase in residential non-gas base rates of 1.14% per year since 1985.

Q. How does that annual rate of increase compare to the overall inflation rate in Anchorage?

A. The average inflation rate over that same time period was 2.3% per year, using the Anchorage Consumer Price Index from 1986 to 2021. The Anchorage CPI for 1985 is not included, as that was the base year for this analysis.

Q. Please describe some key events that have occurred since Order U-16-066(19) through the end of the test year.

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[3] This amounts to ENSTAR's proposed G1 use per customer of 137 Mcf/year divided by 12 divided by 10 to arrive at ccf.

A. The most significant, and important event that occurred since ENSTAR's last rate case was that we celebrated our 60th year of serving customers in Alaska. We are proud of that fact and took time to honor those that came before us, and reflect on many proud moments we've experienced as a utility. Since that last rate case we have also dealt with some significant challenges, but have consistently met those challenges and provided safe and reliable service throughout this time period. This timeline highlights some of the key events since the Commission issued Order U-16-066(19):

- Sept. 2017 – Commission issues Order U-16-066(19).
- Dec. 2017 – Tax Cut and Jobs Act ("TCJA") of 2017 enacted.
- May 2018 – Commission issues Letter Order 1800240 approving ENSTAR's $5.1 million reduction in rates due to TCJA. ENSTAR was the first utility in Alaska to voluntarily file to reduce its rates.
- Nov. 2018 – Magnitude 7.1 earthquake rocks Alaska, damaging ENSTAR facilities, resulting in $1.016 million in extraordinary costs.
- Dec. 2019 – U-19-101 Earthquake recovery docket filed regarding ENSTAR's response to customer and system needs related to costs incurred.
- April 2020 – Filed amended and restated gas sales and purchase agreement with Hilcorp, which extended the existing contract to 2033 resulting in savings of millions of dollars for ENSTAR customers.
- May 2020 – New five-year union contract executed and ratified by union members. Contract provides a nine percent (9%) wage increase over the term of the contract, fairly compensating ENSTAR employees while maintaining competitive rates compared to ENSTAR's competitors.

- Oct. 2020 – Commission issues Order U-19-101(5) granting ENSTAR permission to create a regulatory asset to recover earthquake-related costs.
- May 2022 – Announcement made by AltaGas of its intention to sell Alaska assets, including ENSTAR, APC and CINGSA to a subsidiary of TriSummit Utilities Inc. ("TSU").

Q. Are there any items not listed above that you would like to communicate?

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 highlight not listed above: overall safety and reliability improvements, technological improvements, the impacts of COVID-19, and inflation. As demonstrated below, ENSTAR has faced some significant challenges and made some significant advances over the past six years. I am proud of the way we have reliably and safely met our customers' needs without significant increases in costs. 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 order in U-16-066?

A. No. Public, customer, and employee safety and the reliability of our service has remained the top priority for ENSTAR, and we continue to place high expectations on all our employees to consistently improve. ENSTAR conducts annual trainings for contractors, conducts a safe digging conference prior to the construction season, and spends thousands of dollars on communications and advertisements to educate individual homeowners and contractors of the danger of not calling for locates and following safe digging practices. Since the last rate case, our safety and reliability metrics have consistently improved from already high levels.

Q. Could you provide an example of a safety initiative undertaken by ENSTAR since the last rate case?

A. Yes. In May 2018, leaning on the experiences and best practices of others in the utility industry, we began to implement a new safety program called SafeStart. SafeStart focuses on critical error reduction techniques and simplifies training so that everyone can begin their day or task with the proper focus and mindset. 100 percent of ENSTAR employees were trained in various aspects of the SafeStart program in 2018 and continue to train with the program today.

Q. Have safety metrics improved since the SafeStart program was first implemented?

A. They have. First and foremost, there has been a culture shift in how we approach work safety. A valuable piece to the SafeStart approach is its focus on the individual employee and their "state" as they begin their day or task. The training focuses employees on self-awareness of the four states that give rise to most accidents: complacency, rushing, fatigue, and/or frustration. Identifying early, or self-triggering on the "state" you are currently in can allow you to refocus and proceed safely in executing your job or working throughout the day.

Department meetings prior to the work-day starting at ENSTAR begin with stories volunteered by employees who have recently experienced a close call at work, or at home. They reflect on the state they were in at the time of the incident, and what they could have done differently to recognize it and proceed safely. It is because of this new culture and focus that we have been able to reduce our Total Recordable Injury Frequency ("TRIF") rate[4] from 2.35 in 2018 to 0.94 in 2021. Another important metric when considering employee safety is the Days Away Restricted Transferred ("DART") rate.[5] The DART rate is a metric that quantifies the severity of incidents that happen while working and covers days that are spent away, restricted or transferred due to a work-related injury or illness. ENSTAR has been able to reduce this number from 1.88 in 2018 to 0.47 in 2021 and we received recognition from the American Gas Association in 2019, 2020, and 2021 for being an industry leader in accident prevention. Please see Exhibit JDS-2.

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

A. For decades, the ENSTAR pipeline system has experienced a significantly higher number of third-party damages by customers and contractors in our service territory than experienced in other states. In 2017, this number was 8.55 damages per thousand locate requests. Third-party damages are dangerous for the public, our customers, and our employees. They also result in fugitive emissions of methane from ENSTAR's pipelines until ENSTAR personnel can safely clamp the damage.

Q. What specifically has ENSTAR done to help reduce the threat of third-party damage to its facilities?

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[4] TRIF is calculated by taking the number of recordable injuries multiplied by total number of hours worked by all employees.

[5] DART is calculated by taking the number of DART incidents multiplied by 200,000 and then divided by the total number hours worked by all employees.

A. ENSTAR's approach has been multi-faceted and involves virtually every department in the company. In addition to the safety measures described above, ENSTAR has also sought federal support for enforcing federal fines on parties with particularly egregious third-party damages. In January 2018, ENSTAR representatives scheduled and met with the Deputy Administrator of PHMSA in Washington, D.C. The purpose of the meeting was to explain and highlight the challenges Alaska faces with third-party damages, to request PHMSA investigate a few specific examples, and to assess any warranted fines based on current regulations if applicable.

Q. What was the outcome of the meetings with PHMSA?

A. The Deputy Administrator agreed to send a team to investigate in Alaska, which ultimately found there was gross negligence in safe digging practices for three separate incidents in ENSTAR's service territory and levied the first fines ever in PHMSA's history for violating the regulations. Please see Exhibit JDS-3.

Q. Why is this outcome important for decreasing the third-party damage rate in Alaska?

A. For decades, contractors used dangerous digging practices either due to a lack of perceived consequences or significant bottom-line impact to their respective businesses. Word of those fines spread quickly across the State of Alaska, and businesses are now aware that there could be a hefty fine levied on them for conducting poor business practices while digging around our pipelines.

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

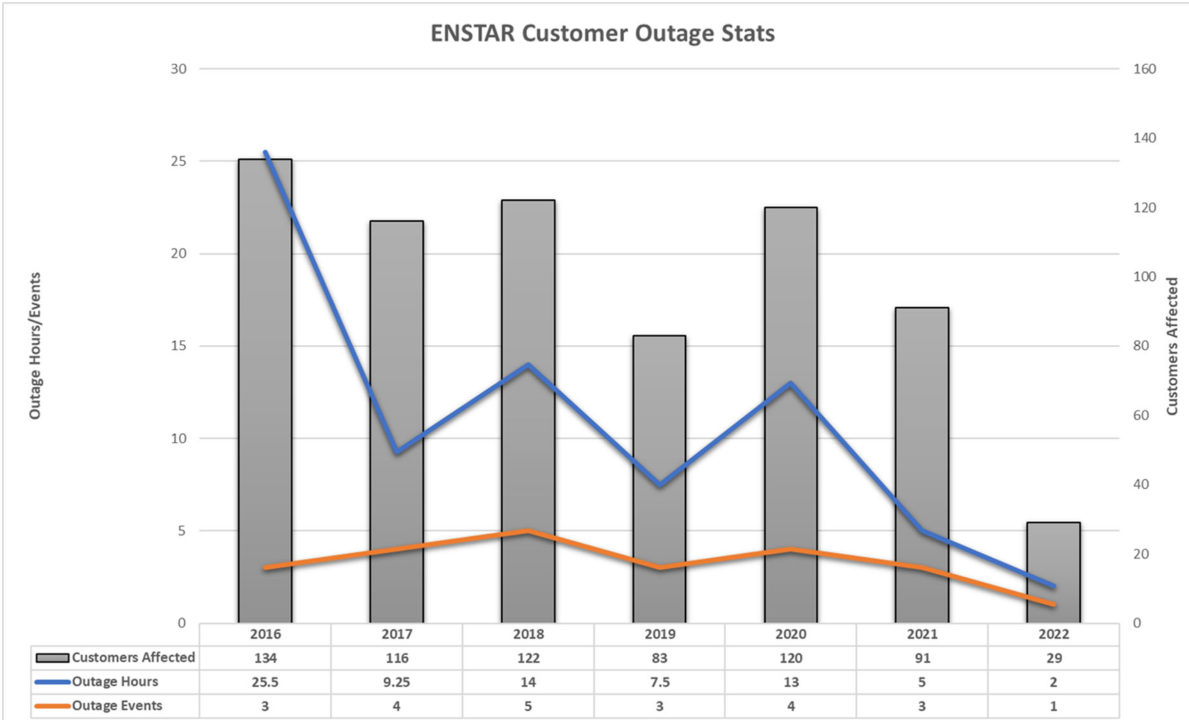
A. Yes. Through these initiatives and communications, we have been able to reduce this number over the past five years to 6.16 damages per thousand locate requests. This almost 40% decrease increases public safety and the reliability of our distribution system.

Q. Did ENSTAR add any employees tasked with assisting in ENSTAR's safety programs since the last rate case?

A. Yes. ENSTAR only had one full-time employee tasked with managing the administration, promotion, and documentation of our safety programs. In 2016, we brought on a temporary employee to assist the Safety Manager in her day-to-day responsibilities. Due to a high turnover rate at the temporary position and necessity of the position, we have hired a full-time Safety Assistant. This position is critical to assist in our safety efforts, ensure there is appropriate succession, and work to proactively maintain best-in-class safety performance.

Q. Have ENSTAR's overall reliability metrics improved since the last rate case?

A. Yes. Since the last rate case, ENSTAR's reliability metrics have improved, due in large part to the safety measures described above. As demonstrated in Figure 1 below, ENSTAR has seen a steady decline in outage events, the duration of hours our customers have been without service due to these events, and the number of customers impacted by outage events over the past six years.



These improvements are a testament to the Company's constant focus on providing service when customers need it 24 hours per day and 365 days of the year.

B. <u>Technological Improvements</u>

Q. What technological improvements has ENSTAR made since U-16-066?

A. ENSTAR has made a number of significant technological improvements since the last test year. These technological improvements relate to both customer service and Company operations. I'll begin with those that are customer-facing and provide for a better customer experience. In late 2016, ENSTAR installed self-service kiosks at our office locations to allow customers to make payments 24/7. While the number of transactions remained low for the first full year, they have increased significantly as we now see customers utilizing the kiosk even when our offices are open to walk-in customers.[6] Additionally, Chugach Electric Association Inc. ("Chugach") and

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[6] In 2021, over 26,000 transactions were made via ENSTAR kiosks.

ENSTAR are working together to install additional kiosks with the functionality to make a payment to either utility or both during the same visit.

Q. What other technological improvements have been made in customer service?

A. Two other important improvements of note are ones to the ENSTAR phone system and online platform. The phone system now has a virtual hold, which provides customers the option to receive a call back rather than having to wait on the phone for a customer service representative to be available during peak call volumes. Additionally, we moved to a new online platform in 2020 that allows customers to chat with customer service representatives, provides more options to manage accounts, and also introduced a mobile application so customers can access account information via their mobile devices.

Q. Have customer satisfaction scores increased since U-16-066?

A. Yes. ENSTAR surveys customers who interact with our staff via email or on the phone and request they fill out a short survey of their experience with the Company. In 2018, the surveys showed that 83% of those who completed the survey were satisfied with their experience with ENSTAR. In 2021, it increased to 95%.

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

A. ENSTAR has made significant improvements to our Geographical Information System ("GIS"), but the most important improvements made in the technology used by the Company were in the cybersecurity arena.

Q. What improvements were made to the GIS system?

A. In an attempt to streamline the "High Consequence Area" and "Moderate Consequence Area" delineation process, we have implemented an electronic field application process.

Q. What is a High Consequence Area ("HCA")?

A. HCAs are defined by PHMSA as those areas along a pipeline system that pose the greatest risk to human life, property, and the environment. Sections of the pipelines classified as HCAs meet one of the following criteria within and around a calculated potential impact radius along the pipeline:

- 20 or more structures intended for human occupancy;
- buildings that house populations of limited mobility;
- buildings that would be hard to evacuate (nursing homes, schools, etc.); or
- buildings and outside areas occupied by more than 20 persons on a specified number of days each year.

In 2003, ENSTAR was required by PHMSA regulation 49 CFR 192.710 (Subpart M) to identify, review, survey, and potentially adjust, HCAs. Identifying HCAs allows ENSTAR to prioritize mitigation efforts in such areas and reduce risk to our customers. Due to the ongoing development in Southcentral Alaska, the changing local economy, and expansion of the pipeline systems, this is required on an annual basis.

Q. What process did ENSTAR originally use to address HCA-related requirements?

A. The process originally developed by ENSTAR to identify HCAs was manual and cumbersome, using both field and office personnel. Office personnel would develop a spreadsheet of potential HCAs and previous HCAs, prepare paperwork forms, organize surveys, and make determinations. Field workers would visit sites based on the spreadsheet, fill out the paper form, and compare previous years' surveys. The paperwork was tracked in large binders.

Q. What are Moderate Consequence Areas ("MCAs")?

A. In 2019, PHMSA published the PHMSA Safety of Gas Gathering and Transmission Rule, also known as the "Mega Rule." Among the many increased provisions for data collection, management, and analysis, ENSTAR was required to identify additional segments of pipeline that pose the greatest risk to human life, property, and the environment. These segments are defined as MCAs and require additional focus, effort, and analysis. This rule became effective July 1, 2020. As a result, in 2020, ENSTAR added 126 MCAs (68.71 miles) to the existing 91 HCAs (40.056 miles), that had to be annually surveyed, assessed, tracked, and analyzed, representing a 138% increase in sites to be visited annually.

Q. What steps did ENSTAR take to handle the increase in workload?

A. There were really only two options to mitigate the impact of the new regulations and workload: hire additional personnel or look for technological improvements. ENSTAR chose the latter, and after making modifications to the GIS system in 2019 to allow for some data collection in the field, ENSTAR fully converted the manual process to an electronic platform in 2020. Moving to an electronic system has significantly reduced the time required for administration of the HCA/MCA process, has freed up Company resources, and provided better and faster access to data that can be used for current and future operations.

Q. What improvements have been made in cybersecurity protections at ENSTAR since the last rate case?

A. ENSTAR has significantly improved its cybersecurity protections since its last rate case. Following a vulnerability assessment in 2015, ENSTAR took action and over the next two years (2016-2017), implemented a universal multifactored authentication system, which includes internal and external authentication and is required at all remote access points. This significantly reduced ENSTAR's exposure to outside threats. Additionally, in 2018, ENSTAR established a security operations center ("SOC"). The SOC, which consists of key management personnel and dedicated IT staff, were charged with the following: establishing an action plan for mitigating identified vulnerabilities; creating and establishing policies and procedures to address specific cybersecurity issues; and establishing a communication plan to mitigate challenges related to change management as a result of the proposed changes.

Q. Have any additional full-time positions been created and hired to assist in this effort?

A. Yes, one so far. In response to needs identified by the SOC, in January 2022, ENSTAR hired an Operation Technology Systems and Compliance Engineer.

Q. What are the core responsibilities of this new position?

A. This position is focused on ensuring safe and reliable operation of ENSTAR's Supervisory Control and Data Acquisition ("SCADA") operations and instrumentation activities. Some of the essential functions of this position include:

- ensuring compliance with PHMSA regulations specifically related to SCADA, alarm management, and control room management;
- proper maintenance and monitoring of instrumentation systems and interfaces; and

- SCADA system reliability.

Q. What is the current state of cybersecurity at ENSTAR?

A. I am happy to report that all of the recommendations included in the vulnerability assessment have been implemented and completed. That being said, ENSTAR continues to make improvements and adhere to best practices for natural gas utilities.

Q. Is there still a 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, between April and June 2022, ENSTAR's IT systems successfully thwarted 226 attempts to hack our systems with malware via email. Additionally, the systems blocked 7,628 phishing attempts over the same timeframe. These phishing attempts are intended to trick ENSTAR users into clicking on a link or executing attached software. This is the same technique criminals used to access the Mat-Su Borough systems in 2018,[7] causing there to be an emergency declaration in that area and costing the Borough millions. Additionally, this is how Colonial Pipeline was shut down on May 7, 2021.[8] These threats are real and ever-present. We are in a constant state of defense and regularly combat against bad actors in our mission to maintain the safety and reliability of our utility.

Q. Have any new regulatory requirements associated with cybersecurity been implemented since the last rate case?

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[7] https://matsugov.us/news/mat-su-declares-disaster-from-cyber-attack, last accessed on Jul. 25, 2022; *see also* https://www.adn.com/alaska-news/mat-su/2018/10/11/price-tag-for-mat-su-cyberattack-now-tops-2-million/, last accessed on Jul. 25, 2022.

[8] https://www.engadget.com/pipeline-ransomware-010631984.html, last accessed on Jul. 25, 2022; *see also* https://www.wsj.com/articles/cyberattack-forces-closure-of-largest-u-s-refined-fuel-pipeline-11620479737?st=rqygmkq5qnkd1y9&reflink=desktopwebshare_permalink, last accessed on Jul. 25, 2022.

A. Regulations and requirements for pipelines and utilities are constantly evolving. The Transportation Security Administration ("TSA") has significantly increased its role and oversight in evaluating the preparedness of pipelines for dealing with cybersecurity threats.[9] ENSTAR expects to be designated as a "critical pipeline" in the very near future.

Q. What are the ramifications of being designated a "critical pipeline" by the TSA?

A. In response to the Colonial Pipeline malware attack in May of 2021, the TSA has issued a number of security directives related to cybersecurity for critical pipeline companies to follow.[10] While a necessary and important part of ensuring the reliability of ENSTAR's natural gas transmission and distribution systems, it will increase costs to the utility to implement these requirements.

C. Impact of COVID-19

Q. How has COVID-19 impacted ENSTAR operations?

A. On March 12, 2020, the Alaska Department of Health and Social Services announced the first recorded case of COVID-19 in the state. On March 13, 2020, ENSTAR, being concerned about the impact the virus may have on its workforce and reliability of service, closed its doors to walk-in traffic. ENSTAR also immediately ceased any business-related travel, meals, and company gatherings. Just a short two months later, as the virus began to exponentially spread throughout Alaska,[11] ENSTAR suspended disconnections for nonpayment as well as late fee assessments on May 8, 2020.

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[9] https://www.tsa.gov/about/employee-stories/tsa-support-pipeline-cybersecurity-grows-exponentially, last accessed on Jul. 25, 2022.

[10] https://www.tsa.gov/news/press/releases/2022/07/21/tsa-revises-and-reissues-cybersecurity-requirements-pipeline-owners, last accessed on Jul. 25, 2022.

[11] On May 21, 2020, there were 376 confirmed COVID-19 cases in the State of Alaska. By January 1, 2021, that number had increased to 58,398. Sum of weekly totals from March 8, 2020 – Jan 4, 2021

Q. Why did ENSTAR cease its collection and disconnection process for non-pay customers at that time?

A. There were a number of reasons ENSTAR made the decision to cease disconnecting customers and our collections processes. First and foremost, ENSTAR was concerned about the state of Alaska's economy. On March 16, 2020, then-Mayor Berkowitz signed an emergency order placing significant restrictions and closures on bars, breweries, restaurants, and entertainment facilities.[12] This significantly reduced the opportunity for wage earners to make their expected annual income and pay their utility bills. Additionally, around the same timeframe, the Centers for Disease Control and Prevention ("CDC") issued a 30-day "no-sail" order for ships carrying 250 passengers or more traveling to or from the United States. This order, along with the lack of tourism arriving to the State of Alaska via airplane, had a severe, detrimental impact on the tourism market in the state in 2020. ENSTAR became concerned about the long-term impact its collections and disconnection of service tariff provisions could have on the local economy. In an effort to assist its residential and commercial customers manage through those difficult times, we ceased disconnecting all customer types until September 2020, when we began disconnecting commercial customers again due to non-payment.

Q. Did the State of Alaska pass any legislation addressing challenges related to COVID?

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are available here: https://experience.arcgis.com/experience/af2efc8bffbf4cdc83c2d1a134354074/, last accessed on Jul. 25, 2022.

[12] https://www.muni.org/Departments/Mayor/PressReleases/Documents/EO-01_03162020_Signed.pdf, last accessed on Jul. 25, 2022.

A. Yes, among the various proposals, the most relevant to this proceeding is Senate Bill 241 ("SB 241"). On May 19, 2020, SB 241 was signed into law and, among other things, provided specific language to permit utilities to create regulatory assets for unpaid utility bills and extraordinary expenses related to COVID-19. Please see a relevant excerpt of SB 241 attached to my testimony as Exhibit JDS-4.

Q. Did ENSTAR create a regulatory asset for unpaid utility bills and extraordinary expenses related to COVID-19?

A. It did. On June 30, 2020, ENSTAR created a regulatory asset to recover extraordinary expenses related to bad debt. The initial entry was for $700,000, but over time it has been reduced to approximately $263,000. ENSTAR is asking for the Commission to allow recovery of this regulatory asset over a three-year amortization period.

Q. Was ENSTAR proactive in trying to reduce its bad debt expense over the time ENSTAR suspended its collections and disconnection processes?

A. It was. Understanding the impact this may have on rates, ENSTAR worked with local municipalities to secure and apply Coronavirus Aid, Relief, and Economic Security Act funding directly to customer accounts wherever possible. As a result, ENSTAR was able to apply over $1.25 million to 3,363 accounts through partnerships with the Municipality of Anchorage, the Mat-Su Borough, and the City of Wasilla. ENSTAR also worked with Alaska Housing Finance Corporation ("AHFC") to promote the heating assistance available to renters. AHFC has a program typically referred to as "HAP" (heating assistance program) that is paid for by the State of Alaska with the sole purpose to assist customers by making a one-time payment to their utilities. Through this program, ENSTAR has applied over $775,000 to 1,332 customer accounts.[13]

Further, ENSTAR was contacted by a customer who wanted to create a fund to help heat customer homes over the winter. This customer donated $10,000 (which ENSTAR matched with another $10,000) and created the Warm Hearts Warm Homes Fund in partnership with United Way of Anchorage. Together, ENSTAR and the United Way advertised the campaign through social media, email, local media interviews, and bill stuffers to encourage community members to donate or apply for assistance. By July 2021, the campaign had raised over $30,000 to benefit ENSTAR customer accounts, all of which has been disbursed.

Q. How has COVID-19 impacted the supply chain?

A. The worldwide supply chain has been dramatically impacted by the lockdowns in China due to COVID and other geopolitical events like the war in Ukraine. ENSTAR had already experienced challenges in the supply chain due to our geographic location, but these factors in addition to our existing concerns have forced ENSTAR to reevaluate our priorities, project timeframes and budgets, and inventory levels. The cost of doing business here continues to escalate.

Q. Do you have any specific examples of items ENSTAR is struggling to procure due to the strained supply chain?

A. Yes unfortunately, there are a number of examples that are making it more challenging to operate. The following is a small sample of issues we are currently experiencing:

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[13] https://www.ahfc.us/blog/posts/get-help-paying-your-utility-bills, last accessed on Jul. 25, 2022.

- AC250 meters – these are the most prevalent meters in our system. Prior to COVID, there was a two-to-three-month lead time for purchasing. Today, the lead time is almost a year and we are currently waiting on an order of 4,000 meters that we are hoping will arrive by year-end.
- Elster 1813 Regulators – over 90% of our current meter sets in operation today have this regulator on them. The Company placed an order for additional regulators in July 2021 and we still have not received them. In order to maintain operations, we have had to borrow regulators from other equipment and petition the factory for partial shipments.
- Flex risers – these are used to connect the service line and meter set in Alaska and are critical to mitigate damage caused by frost heaving and earthquakes. These normally take two to three months to procure, now a 52-week lead time is required.
- Commercial Encoder Receiver Transmitters ("ERT") – these are used on our larger meters to communicate the consumption to meter readers. ENSTAR placed an order in the latter part of 2021 for additional ERTs, and we are still waiting to hear back on a firm delivery date. The manufacturer is currently waiting for parts themselves and have projected a potential delivery date of September 2022.

Q. How has ENSTAR been able to manage through these challenges?

A. Historically, ENSTAR has attempted to carry higher inventory levels due to our geographic location when compared to other utilities in North America. Now, unfortunately, other utilities in the Lower 48 are increasing their inventories as well to help mitigate supply chain issues, which amplifies the challenges experienced here in Alaska.

D. Inflation

Q. During the test year, did the State of Alaska and residents in the ENSTAR service territory experience any challenges with inflation?

A. Yes, significant inflation. In fact, the State of Alaska's Department of Labor and Workforce Development concluded that "the average inflation rate for 2021 was 4.9 percent, the highest annual price increase since 1990. And that number was muted because the year-to-year increases began slowly. December's 7.2 percent inflation suggested 2022 would bring more of the same."[14]

Q. What challenges are experienced from the increase in prices?

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

Q. Can you provide an example of how inflation has affected Company operating costs?

A. Yes. The contract between ENSTAR and the Plumbers and Steamfitters, Local 367 ("Local 367") has specific provisions to address significant inflation experienced over the contract term. Specifically, Article 33.5 of the Operating Bargaining Unit ("OBU") and Article 29.2 of the Clerical Bargaining Unit ("CBU") contracts states:

> Beginning with the second half of 2020 Anchorage Consumer Price Index-Urban Wage Earners report issued by the Federal government and thereafter until April 1, 2025, should the Anchorage CPI-W for any two combined consecutive six month reporting periods be less than zero

[14] *See* Exhibit JDS-5 "Alaska Economic Trends, July 2022" at page 4.

> percent (0%) or more than five percent (5%) based on the percentage changes as reported by the official Anchorage CPI-W index, and not as may be calculated independently, the Company or the Union may request the other party to meet and confer regarding wages only.
>
> Should the parties not resolve their respective concerns through the meet and confer process, either party may demand in writing, within thirty (30) days of the publication of the CPI-W report that is the basis of the reopener demand, that the contract be opened for negotiations limited to the issue of wages, unless both parties mutually agree to open other terms and conditions of employment. If the Federal government materially alters the methodology by which it calculates the Anchorage CPI-W Index, the parties shall consider and discuss such changes should the above stated meet and confer or contract opener clause be initiated.

Q. Have the increases in inflation over the past twelve months caused this clause of the contract to be triggered?

A. They have. The Anchorage CPI-W for June 2021 – December 2021 increased 6.35% and the Anchorage CPI-W for January 2022 – June 2022 increased 9.1% for an average of 7.72%. Local 367 requested to meet and confer on wages, and ultimately the two parties settled for an increase of 2.4% for employees covered under the OBU and CBU retroactive to April 1, 2022.

Q. Could you provide any examples of increased costs for materials associated with inflation?

A. Yes. Effective March 31, 2022, ENSTAR's meter supplier, Honeywell, declared force majeure under the relevant contractual provision, which increased costs for materials by 19.6%. This was on top of a 13.6% increase in September 2021.

E. <u>TriSummit Acquisition</u>

Q. Can you please describe the pending transaction and filing before the Commission regarding the acquisition of ENSTAR?

A. Yes. Alaska Utility Holding, Inc., a United States subsidiary of TSU, submitted a joint application to the Commission with SEMCO on June 24, 2022 to acquire ENSTAR, APC, and 65% of the indirect interest in CINGSA.

Q. What is the current status of that filling?

A. It is currently pending before the Commission in Dockets U-22-032 and U-22-033.

Q. How might the acquisition impact ENSTAR?

A. It has yet to be seen if the transaction will close, and if it does, how new ownership will impact ENSTAR. But, pursuant to filings made with the Commission in that docket, I am encouraged by the representations made by the acquiring entity, including a pledge to continue the same levels of service historically provided by the Company and a desire to bring more jobs back to Alaska in support of ENSTAR's operations.

If this transaction closes while this rate case is pending, we may supplement our testimony and this rate filing if required.

VI. <u>ENSTAR'S REQUESTED ROE</u>

Q. What ROE is ENSTAR requesting in this proceeding?

A. ENSTAR is requesting a ROE of 12.95%, which is 107.5 basis points higher than our most recently adjudicated ROE. Our request is consistent with Mr. D'Ascendis' direct testimony, which provides for a range of ROE between 12.45% and 13.45%. His recommendation reflects the unique risks to the Company operations and the increased risks that have arisen since ENSTAR's last rate case. For a variety of reasons, which I will discuss, and which are also discussed in the direct testimony of Mr. D'Ascendis, Ms. Johansen, and Mr. Dieckgraeff, 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 a would-be investor. In addition to ENSTAR's inherent risk in providing not only distribution, but transmission services to customers as well, the Company's operations present unique, additional risk 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 unmitigated weather fluctuations, declining use per customer largely brought on by energy efficiency measures on its system, and volatility in local economic conditions.

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 has been a particular problem, as described in other portions of my testimony, in an inflationary environment. These issues have also been amplified by COVID-19, and the recent geopolitical concerns around the world. Please also see the direct testimony of Mr.

D'Ascendis for additional discussion of this risk and how it influences his recommendation.

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 been disconnected from 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. One hundred percent of the natural gas our customers consume comes from the Cook Inlet. That fact has not changed, and currently, there are no economically viable plans to bring gas from any other locations in the state to my knowledge. Second, as discussed in the direct testimony of Company witness Ms. Johansen, we continue to see a decline in deliverability from Cook Inlet wells. This fact increases the need for additional natural gas storage, and presents the need for enhancements on existing storage already in place. Finally, we are now hearing from producers in the region that they do not have line of sight on how they will be able to meet Cook Inlet uncontracted-for demand in the mid-term (next five years) with their existing reserves.[15] Despite ENSTAR's current contractual commitment through 2033, ENSTAR is deeply concerned about long-term energy security for all of the gas consumers in Cook Inlet. This fact has prompted the Railbelt

[15] https://www.alaskajournal.com/2022-05-17/hilcorp-warns-alaska-utilities-about-uncertain-cook-inlet-natural-gas-supplies, last accessed on Jul. 25, 2022.

Utilities (ENSTAR, Interior Gas Utility, Matanuska Electric Association, Inc., Chugach, Homer Electric Association, Inc., and Golden Valley Electric Association, Inc.) to create a working group, together with the Alaska Energy Authority and the State of Alaska Department of Natural Resources, to determine where future gas supplies may be available.

Q. How will ENSTAR meet future gas supply needs?

A. Currently, all options are on the table. 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 the utility and its investors in a situation where there is no gas supply is unquantifiable on its own, but the risk to its customers would certainly be bordering on, if not, catastrophic. Please also see the direct testimony of Mr. D'Ascendis for additional discussion of this risk and how it influences his recommendation.

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

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

Q. Has the Commission historically recognized these, and other, risks in adjudicating ENSTAR's previous rate cases?

A. Yes, as discussed in Mr. D'Ascendis' direct testimony, each time the Commission has adjudicated ENSTAR's ROE, it has granted an ROE that is higher than the national average because of risks posed by its operational attributes (substantial transmission assets), geographic isolation, natural gas supply challenges, and small size. This was most recently stated in ENSTAR's last rate case in Order U-16-066(19).

Q. What other comment has been made by the Commission regarding ENSTAR's allowed ROE?

A. In the October 6, 1982 Bench Order in Docket U-81-101,[16] the Commission stated:

> …this Commission is persuaded that when a utility succeeds in controlling the level of its rates in periods of extraordinarily high inflation with resultant savings to gas consumers and manages to do so while continuing to maintain a high quality of its service to customers (as evidenced by the noticeable absence of customer complaints regarding promptness of service connections, negligible outage occurrences, employee courtesy, minimal billing errors, and the overall positive corporate responsiveness to customer concerns, etc.), the utility's efforts justify a rate of return on equity at the upper end of the zone of reasonableness.

Q. Has ENSTAR met the Commission's standard set forth Order U-81-101(8) since the last rate case?

A. Yes. As demonstrated in the other portions of my testimony and the balance of the Company's filing, we have met this standard and should be granted our requested ROE of 12.95%, which is at the <u>midpoint</u> of Mr. D'Ascendis' recommended range of reasonableness.

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16 Appendix to Order U-81-101(8), *Order Affirming Bench Order of October 6, 1982; Establishing Revenue Requirement; and Requiring Production of Data*, dated March 15, 1983 at p. 6.

VII. NEW INVESTMENTS MADE SUPPORTING THE SAFE AND RELIABLE TRANSPORTATION AND DISTRIBUTION OF NATURAL GAS

Q. Has the Commission authorized pro forma adjustments to annualize plant additions in certain circumstances?

A. Yes. In U-16-066(19) the Commission stated the following, "[w]e have allowed annualizing pro forma adjustments for plant placed in service during the test year that provides a benefit to ratepayers, such as a reduction in costs or an increase in safety and reliability."

Q. Did ENSTAR make any investments during the test year that satisfy the criteria set forth above?

A. Yes. In total, ENSTAR invested approximately $4.0 million, or approximately 18% of its 2021 capital expenditures in facilities that meet this criteria. These investments include the following:

- MP39 Station Rebuild – this station is located on the 20-inch Beluga Pipeline on the West side of the Cook Inlet and all of the gas supplied to customers in the Mat-Su Valley and MEA's power plant flows through this station. The two main drivers for this project were (i) safety concerns associated with maintenance of the underground valves; and (ii) upgrade the pigging facilities on this section of the pipeline, which were addressed by installing above-ground valves and new facilities. This project, which was completed and placed in service on August 19, 2021, cost $1,053,977.
- Kenai B-Line MP 45.3 Repair – in December 2020, ENSTAR discovered a gas leak on the Kenai B-Line in a remote area of the Kenai National Wildlife Refuge. The B-Line is one of the two pipelines that deliver gas from Kenai to

Anchorage. Due to the criticality of this pipeline in winter operations, a temporary clamp was placed on the pipeline to keep it in service. The permanent repair required the pipeline to be shut down and 40 feet of pipeline was replaced in the summer of 2021. This project, which was completed and placed in service in 2021 and closed to plant effective December 30, 2021, cost $150,420.

- Bernice Lake Reg Station – this project was comprised of a variety of different components to ensure this critical station could reliably perform to ENSTAR standards and meet system needs. Included in this project was the installation of a new station building (replacing the one from 1966), elimination of buried valves, and installation of fencing to secure the site from vandals, a new water bath heater, separator, and a new odorization system. This project, which was completed and placed in service on August 30, 2021, cost $1,728,050.
- Glacier Creek Reroute – replaced a section of 6-inch plastic distribution pipeline running near Glacier Creek in Girdwood, protecting it from river bank erosion found in 2020. This project, which was completed and placed in service on September 27, 2021, cost $134,499.
- MP50.5 A & B Line Fencing Project – per PHSMA code requiring secured valves, and due to an increased volume of wildlife and recreational activities in the area, ENSTAR installed fencing around the block valve station to protect the only two lines that deliver gas to Anchorage from Kenai. This project,

which was placed in service in 2021 and closed to plant effective December 31, 2021, cost $14,136.

- Steel Mains Replacement – per ENSTAR's federally-mandated Distribution Integrity Management Program ("DIMP"), ENSTAR identifies segments of aged steel distribution main with a high frequency of leaks and corrosion issues. In 2021, ENSTAR replaced sections of distribution piping near Fairview Elementary, Upland Drive, and Sanya/Dolina Streets. Not only do these replacements improve safety, the new plastic main also reduces maintenance costs. These replacements cost $174,129.
- Copper and X-trube Service Line Replacement – joined by mechanical fittings, these lines were installed in the 1980s and are prone to corrosion and are also at risk of failure during a seismic event or as a result of frost heaving. This ongoing effort totaled $521,910 in replacements during the test year.
- East Anchorage Gate Valve Replacement – replaced the valve that controls flow and pressure from the 20-inch Beluga Pipeline into the Anchorage area transmission system. Parts for the old valve were no longer available as the control valve was obsolete. This project, which was placed in service in 2021 and closed to plant effective December 31, 2021, cost $40,336.
- SCADA Cybersecurity – Installed new switches on the microwave system to allow ENSTAR to separate network traffic that is deemed "safety sensitive" from other traffic. In the event of a failure on the enterprise system, this new configuration allows the safety sensitive data to continue to transmit

uninhibited. This project, which was placed in service in 2021 and closed to plant effective December 31, 2021, cost $80,948.

- ERTs – ENSTAR continued its program to replace ERTs that had reached the end of their 15-year battery design lives. These ERTs allow ENSTAR to continue to use vehicle-mounted equipment to read meters by driving through neighborhoods and receive signals from the meters without the need to physically visit and visually read each meter. This effort totaled $58,863 during the test year.

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 being used to provide natural gas transmission and distribution services to our customers.

VIII. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes.

John D. Sims

EMPLOYMENT

SEMCO Energy, Inc. 2005 – Present

ENSTAR Natural Gas Company/Alaska Pipeline Company

President, 2017 - Present

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

Executive Board Member, Alaska State Chamber of Commerce

Board Member, Junior Achievement Alaska

Board Member, Chugiak Eagle River Foundation

Advisory Board Member, Alaska Regional Hospital

AGA

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

U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF PROBABLE VIOLATION
and
PROPOSED CIVIL PENALTY

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

March 5, 2019

Mr. Terry Roberts
President
Sturgeon Electric, Inc.
1301 E. 64th Ave.
Anchorage, AK 99518

CPF 5-2019-0004E

Dear Mr. Roberts:

On April 23, 2018, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code (U.S.C.) investigated circumstances surrounding the August 9, 2017 damage to a natural gas pipeline located near 291 Sky Haven Circle in Anchorage, Alaska.

Background

On August 9, 2017, Sturgeon Electric Company Inc. (excavator) was installing electrical conduit underground by trenching with a tractor when they struck a 2-inch plastic main owned and operated by ENSTAR Natural Gas, causing a release of gas without ignition. Sturgeon did not request underground utility locates prior to the excavation. Sturgeon Electric was a subcontractor to Cruz Construction (Prime contractor). Sturgeon Electric did not request a locate ticket until after it damaged the 2-inch plastic main.

Based on excavation activities investigated, it is alleged that you have committed probable violations in Part 196 of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (C.F.R.). The items investigated and the probable violations are:

1. **§ 196.103 What must an excavator do to protect underground pipelines from excavation-related damage?**

Prior to and during excavation activity, the excavator must:
(a) Use an available one-call system before excavating to notify operators of underground pipeline facilities of the timing and location of the intended excavation;

Sturgeon Electric Company Inc. (Sturgeon) did not use the available one-call system (the Alaska Digline) before excavating on August 9, 2017. Sturgeon personnel stated in an interview with PHMSA that Sturgeon was excavating without a locate ticket when it struck a 2-inch underground natural gas line. Sturgeon notified ENSTAR of damage to the pipeline on August 9, 2017 at approximately 2:55 PM. Sturgeon requested a locate ticket with the Alaska Digline on August 9, 2017, at 3:30 PM.

2. **§ 196.109 What must an excavator do if damage to a pipeline from excavation activity causes a leak where product is released from the pipeline?**

If damage to a pipeline from excavation activity causes the release of any PHMSA regulated natural and other gas or hazardous liquid as defined in part 192, 193, or 195 of this chapter from the pipeline, the excavator must promptly report the release to appropriate emergency response authorities by calling the 911 emergency telephone number.

Sturgeon Electric failed to promptly report the release of natural gas by calling the 911 emergency telephone number. Sturgeon Electric called ENSTAR after hitting the line, and ENSTAR prompted Sturgeon to call 911.

Proposed Civil Penalty

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to exceed $213,268 per violation per day the violation persists, up to a maximum of $2,132,679 for a related series of violations. For violations occurring on or after November 2, 2015 and before November 27, 2018, the maximum penalty may not exceed $209,002 per violation per day, with a maximum penalty not to exceed $2,090,022. For violations occurring prior to November 2, 2015, the maximum penalty may not exceed $200,000 per violation per day, with a maximum penalty not to exceed $2,000,000 for a related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that you be preliminarily assessed a civil penalty of $12,100 as follows:

Item number	Proposed Penalty
1	$12,100

Response to this Notice

Enclosed as part of this Notice is a document entitled *Response Options for Third Party Excavators in Enforcement Proceedings*. Please refer to this document and note the response options. All material submit in response to this enforcement action may be made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. § 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

Following the receipt of this Notice, you have 30 days to submit written comments, or request a hearing under 49 C.F.R. § 190.211. If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order. If you are responding to this Notice, we propose that you submit your correspondence to my office within 30 days from the receipt of this Notice. This period may be extended by written request for good cause.

In your correspondence on this matter, please refer to **CPF 5-2019-0004E** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Acting Director, Western Region
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Third Party Excavators in Enforcement Proceedings*

cc: Bob Peters, Outside line Division Manager, Sturgeon Electric, Inc.
PHP-60 Compliance Registry
PHP-500 J. Gano (#163982)

U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF PROBABLE VIOLATION
and
PROPOSED CIVIL PENALTY

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

March 5, 2019

Mr. Jason Hodges
President
NPC Energy Services, LLC
7941 Sandlewood Place
Anchorage, AK 99507

CPF 5-2019-0005E

Dear Mr. Hodges:

On April 22 through May 3, 2018, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code (U.S.C.) investigated circumstances surrounding the June 22, 2017 damage to a natural gas pipeline located near 3802 Parks Highway in in Palmer, Alaska.

Background

On July 22, 2017, at 11:41 am, NPC Energy Services, LLC (NPC) contacted ENSTAR Natural Gas stating NPC hit an unmarked gas line with a mini excavator. After arriving onsite, ENSTAR observed 8-feet of exposed 2-inch plastic main natural gas line. NPC informed ENSTAR they thought the pipeline was abandoned and they proceeded to drill a hole in the pipeline to verify. When the pipeline began to release natural gas, the NPC placed a hose clamp with tape to cover the drill hole.

Underground utilities locate markings existed on the ground near the excavation, but not at the location being excavated. NPC Energy Services acting as the excavator did not have a one-call ticket for the excavation location at the time the damage occurred to the 2-inch pipeline. Work was being performed for an Alaska DOT project. NPC Energy Services was acting as a sub-contractor to Knik Construction performing excavations to install street light pole bases.

Based on excavation activities investigated, it is alleged that you have committed probable violations in Part 196 of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (C.F.R.). The items investigated and the probable violations are:

1. **§ 196.103 What must an excavator do to protect underground pipelines from excavation-related damage?**

Prior to and during excavation activity, the excavator must:

(a) Use an available one-call system before excavating to notify operators of underground pipeline facilities of the timing and location of the intended excavation;

NPC Energy Services (NPC) did not use the available one-call system (Alaska Digline (811 One-Call Center)) prior to excavating. NPC was conducting excavations at the time the underground pipeline facility was damaged on July 22, 2017. Underground utilities were marked nearby, but not at the excavation location where the damage to the pipeline occurred. PHMSA reviewed the one-call tickets opened in the year prior to the incident near the incident location. That review revealed that no one-call tickets were opened by NPC.

2. **§ 196.109 What must an excavator do if damage to a pipeline from excavation activity causes a leak where product is released from the pipeline?**

If damage to a pipeline from excavation activity causes the release of any PHMSA regulated natural and other gas or hazardous liquid as defined in part 192, 193, or 195 of this chapter from the pipeline, the excavator must promptly report the release to appropriate emergency response authorities by calling the 911 emergency telephone number.

NPC failed to report the release after its excavation activities damaged the pipeline resulting in a release of natural gas to appropriate emergency response authorities by calling the 911 emergency telephone number. After exposing a portion of a 2-inch underground natural gas pipeline during excavation activities performed on July 22, 2017, an NPC employee drilled a hole in the pipeline to determine if it was active. The drilled holed caused a release of natural gas. Upon the natural gas release, the excavation company representative contacted the operator of the pipeline, but did not call 911 as required by the regulation.

Proposed Civil Penalty

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to exceed $213,268 per violation per day the violation persists, up to a maximum of $2,132,679 for a related series of violations. For violations occurring on or after November 2, 2015 and before November 27, 2018, the maximum penalty may not exceed $209,002 per violation per day, with a maximum penalty not to exceed $2,090,022. For violations occurring prior to November 2, 2015, the maximum penalty may not exceed $200,000 per violation per day, with a maximum penalty not to exceed $2,000,000 for a related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that you be preliminarily assessed a civil penalty of $12,100 as follows:

Item number	Proposed Penalty
1	$12,100

Response to this Notice

Enclosed as part of this Notice is a document entitled *Response Options for Third Party Excavators in Enforcement Proceedings*. Please refer to this document and note the response options. All material submit in response to this enforcement action may be made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. § 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

Following the receipt of this Notice, you have 30 days to submit written comments, or request a hearing under 49 C.F.R. § 190.211. If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order. If you are responding to this Notice, we propose that you submit your correspondence to my office within 30 days from the receipt of this Notice. This period may be extended by written request for good cause.

In your correspondence on this matter, please refer to **CPF 5-2019-0005E** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Acting Director, Western Region
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Third Party Excavators in Enforcement Proceedings*

cc: Paul Lantz, General Manager, NPC Energy Services, LLC
PHP-60 Compliance Registry
PHP-500 J. Gano (#163983)

U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF PROBABLE VIOLATION
and
PROPOSED CIVIL PENALTY

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

March 5, 2019

Mr. Jerry Harman
Owner
Alaska Construction and Paving, Inc.
PO Box 874712
Wasilla, Alaska 99687

CPF 5-2019-0006E

Dear Mr. Harman:

On May 3, 2018, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code (U.S.C.), investigated circumstances surrounding the July 3, 2017 damage to a natural gas pipeline located near 8251 Harmany Ranch Road, Eagle River, Alaska.

Background

On July 3, 2017, Alaska Construction and Paving, Inc. (ACP) acting as the excavator, damaged a 1-inch plastic service line. The location of the damaged service line was near 8251 Harmony Ranch Road, Eagle River, Alaska. The damage resulted in a release of natural gas without ignition or property damage. At the time of the damage, ACP performed a temporary repair by folding back the plastic 1-inch pipeline and taping it. An ENSTAR Natural Gas representative arrived at the site to perform a locate request and discovered the damaged service line.

Based on excavation activities investigated, it is alleged that you have committed probable violations in Part 196 of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (C.F.R.). The items investigated and the probable violations are:

1. **§ 196.103 What must an excavator do to protect underground pipelines from excavation-related damage?**

Prior to and during excavation activity, the excavator must:
(a) ....
(b) If underground pipelines exist in the area, wait for the pipeline operator to arrive at the excavation site and establish and mark the location of its underground pipeline facilities before excavating;

Alaska Construction and Paving, Inc. (ACP) failed to wait for ENSTAR Natural Gas to arrive at the excavation site and establish and mark the location of its underground pipeline facilities before excavating. The excavator opened a ticket with Alaska Digline on Thursday, June 29, 2017 at 12:44 pm. The pipeline operator, ENSTAR, arrived on site on Monday July 3, 2017 at approximately 10AM to mark the location of the underground pipeline and discovered the 1-inch service line had already been excavated and damaged.

2. **§ 196.107 What must an excavator do if a pipeline is damaged by excavation activity?**

If a pipeline is damaged in any way by excavation activity, the excavator must promptly report such damage to the pipeline operator, whether or not a leak occurs, at the earliest practicable moment following discovery of the damage.

The excavator failed to report damage that they caused to the to the pipeline operator. ACP acknowledged to PHMSA in a May 3, 2018 telephone interview that ACP damaged the pipeline and attempted to crimp off and tape shut the 1-inch service line on July 3, 2017. However, ACP did not notify ENSTAR of the damage. ENSTAR's locator arrived on site later in the day on July 3, 2017 and discovered the damage.

3. **§ 196.109 What must an excavator do if damage to a pipeline from excavation activity causes a leak where product is released from the pipeline?**

If damage to a pipeline from excavation activity causes the release of any PHMSA regulated natural and other gas or hazardous liquid as defined in part 192, 193, or 195 of this chapter from the pipeline, the excavator must promptly report the release to appropriate emergency response authorities by calling the 911 emergency telephone number.

The excavator failed to call the 911 emergency telephone number after the 1-inch pipeline was damaged resulting in a release of natural gas. ACP was aware natural gas was released from the pipeline, and ACP admitted to making a temporary repair by folding the pipe and taping it to stem the release. However, ACP did not call 911 following the release.

Proposed Civil Penalty

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to exceed $213,268 per violation per day the violation persists, up to a maximum of $2,132,679 for a related series of violations. For violations occurring on or after November 2, 2015 and before November 27, 2018, the maximum penalty may not exceed $209,002 per violation per day, with a maximum penalty not to exceed $2,090,022. For violations occurring prior to November 2, 2015, the maximum penalty may not exceed $200,000 per violation per day, with a maximum penalty not to exceed $2,000,000 for a related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that you be preliminarily assessed a civil penalty of $12,100 as follows:

Item number	Proposed Penalty
1	$12,100

Response to this Notice

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In your correspondence on this matter, please refer to **CPF 5-2019-0006E** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Acting Director, Western Region
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Third Party Excavators in Enforcement Proceedings*

cc: PHP-60 Compliance Registry
PHP-500 J. Gano (#163984)

LAWS OF ALASKA

2020

Source
FCCS SB 241

Chapter No.
____

AN ACT

Extending the March 11, 2020, governor's declaration of a public health disaster emergency in response to the novel coronavirus disease (COVID-19) pandemic; providing for a financing plan; making temporary changes to state law in response to the COVID-19 outbreak in the following areas: standing orders of the chief medical officer; occupational and professional licensing, practice, and billing; telehealth; fingerprinting requirements for health care providers; elections in calendar year 2020; permanent fund dividend applications and eligibility; state tax filings, payments, and penalties; corporations; state and municipal government deadlines; the Alaska regional economic assistance program; Medicaid and public assistance; workers' compensation; sanitation standards for retail sellers; actions by the Regulatory Commission of Alaska; utilities and residential utility service; power cost equalization; forbearance of specified state loans; foreclosures; evictions; wills; repossessions; access to federal stabilization funds; seafood purchase and distribution; homelessness; administrative hearings; and liability for issuing, providing, or manufacturing personal protective equipment; and providing for an effective date.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

THE ACT FOLLOWS ON PAGE 1

DEPARTMENT OF HEALTH AND SOCIAL SERVICES; RETAIL SELLERS. Notwithstanding any other provision of law, for the duration of the novel coronavirus disease (COVID-19) public health disaster emergency declared by the governor under AS 26.23.020 on March 11, 2020, as extended by sec. 2 of this Act, the Department of Health and Social Services may, in coordination with the Department of Military and Veterans' Affairs, establish sanitation procedures for retail sellers. In this section, "retail seller" includes a market, grocery store, convenience store, drug store, or similar establishment that

(1) is located in a permanent building; and

(2) sells to consumers household supplies, perishable items, or food merchandise, including meat, produce, dairy products, or snack foods.

*** Sec. 18.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TOLLING DEADLINES FOR ACTION BY THE REGULATORY COMMISSION OF ALASKA. Notwithstanding a contrary provision of AS 42, including a provision of AS 42.05 or AS 42.08, during the novel coronavirus disease (COVID-19) public health disaster emergency declared by the governor on March 11, 2020, as extended by sec. 2 of this Act, all statutory and regulatory deadlines for action by the Regulatory Commission of Alaska are tolled and failure by the Regulatory Commission of Alaska to act on a filing does not constitute approval or dismissal by the commission. This section does not apply to a statutory or regulatory deadline extended by the commission before March 11, 2020, for good cause under AS 42.05.175(f).

*** Sec. 19.** The uncodified law of the State of Alaska is amended by adding a new section to read:

MORATORIUM ON DISCONNECTION OF RESIDENTIAL UTILITY SERVICE. (a) During the novel coronavirus disease (COVID-19) public health disaster emergency declared by the governor on March 11, 2020, as extended by sec. 2 of this Act, a public utility as defined in AS 42.05.990 may not disconnect for nonpayment the residential utility service of a person experiencing financial hardship related to the COVID-19 public health disaster emergency. A public utility shall make reasonable efforts to reconnect utility service to a dwelling that is occupied by a person experiencing financial hardship related to the COVID-19 public health disaster emergency and that is disconnected for nonpayment on or after

March 11, 2020.

(b) A person seeking protection under (a) of this section shall, before the date the governor determines, under sec. 2 of this Act, that the COVID-19 public health disaster emergency no longer exists, or before November 15, 2020, whichever is earlier,

(1) provide to the public utility a signed statement, sworn under penalty of perjury, that the person is experiencing financial hardship related to the COVID-19 public health disaster emergency; and

(2) negotiate and agree to a deferred payment agreement with the utility.

(c) This section does not relieve a public utility customer of the obligation to pay for utility service or restrict a public utility's ability to recover an amount due.

(d) A utility shall offer a person receiving protection under (a) of this section a deferred payment agreement allowing repayment over a period of time not shorter than the period of time of the public health disaster emergency declared by the governor on March 11, 2020, as extended by sec. 2 of this Act. The utility may not impose interest or late fees on a person receiving protection under (a) of this section who fulfills the terms of a deferred payment agreement.

(e) Notwithstanding any contrary provision of law, the Regulatory Commission of Alaska and the Alaska Energy Authority may not deny a utility otherwise eligible to receive power cost equalization payments on behalf of a utility customer power cost equalization payments for customers receiving protection under (a) of this section.

(f) In this section,

(1) "financial hardship" means that a person's liquid assets from any source, including payments from the state or federal government because of the COVID-19 public health disaster emergency or a state or national disaster declaration related to COVID-19, when combined, would be insufficient to pay the reasonable cost of food, housing, health care, and other goods and services vital to the health and wellness of the person and the person's spouse and dependents; in this paragraph, "dependent" has the meaning given in AS 23.20.350(g);

(2) "person" means a natural person.

* **Sec. 20.** The uncodified law of the State of Alaska is amended by adding a new section to read:

REGULATORY ASSETS FOR UNPAID UTILITY BILLS AND EXTRAORDINARY EXPENSES. A utility certificated under AS 42.05 may record regulatory assets, to be recovered through future rates, for uncollectable residential utility bills and extraordinary expenses that result from the novel coronavirus disease (COVID-19) public health disaster emergency declared by the governor on March 11, 2020, as extended by sec. 2 of this Act. The determination as to whether an extraordinary expense resulted from the COVID-19 public health disaster emergency and the amortization periods for the regulatory assets are subject to approval by the Regulatory Commission of Alaska before recovery occurs through future rates. In this section, an "uncollectable residential utility bill" does not include a debt paid under a deferred payment agreement under sec. 19 of this Act.

*** Sec. 21.** The uncodified law of the State of Alaska is amended by adding a new section to read:

MORATORIUM ON EVICTIONS FOR NONPAYMENT OF RENT. (a) Until the date the governor determines, under sec. 2 of this Act, that the novel coronavirus disease (COVID-19) public health disaster emergency no longer exists, or until June 30, 2020, whichever is earlier, the statutory cause of action for forcible entry and detainer for nonpayment of rent under AS 09.45 and any other statutory cause of action that could be used to evict or otherwise eject a person who is a residential tenant for nonpayment of rent, including for nonpayment of rent for a storage unit for personal property, is suspended as applied to a person experiencing financial hardship related to the COVID-19 public health disaster emergency.

(b) A person seeking protection under (a) of this section shall, before June 30, 2020, provide to the landlord a signed statement, sworn under penalty of perjury, that the person is experiencing financial hardship related to the COVID-19 public health disaster emergency.

(c) Nothing in this section

(1) prevents evictions for misconduct, violations of law, or violations of contracts outside of inability to pay rent;

(2) may be construed to increase civil liability of a landlord.

(d) This section does not relieve a person of the obligation to pay rent or restrict a landlord's ability to recover rent due.

(e) In this section,

ALASKA ECONOMIC TRENDS

JULY 2022

THE COST OF LIVING

ALASKA DEPARTMENT OF LABOR & WORKFORCE DEVELOPMENT • RESEARCH AND ANALYSIS

Program offers Alaskans state-of-the-art training for mining

By Dr. Tamika L. Ledbetter, Commissioner

One highlight of serving as commissioner of the Alaska Department of Labor and Workforce Development is supporting quality workforce training programs around the state. I get the chance to see first-hand the many opportunities Alaskans have to prepare for new careers or expand their professional skills.

Recently I traveled to the Delta Mine Training Center near Fairbanks and toured one of the country's top underground mine training facilities. Operated by the University of Alaska, this world-class training and research center features an underground mine, rock and gravel quarries, 100 acres of training area, an equipment fleet, and modern mining and construction machinery.

Under the leadership of director Bill Bieber, the center offers state-of-the-art surface and underground mine training as well as health, safety, and environmental skills development. Each year, more than 1,700 students earn the certifications they need to succeed in Alaska's high-paying hard rock mining and oil and gas sectors.

The training schedule mirrors real-life employment in an underground mine and surface operation. Students begin the program with mine safety compliance training, which is followed by an employability skills module. An important feature of the training develops and refines hand-eye coordination and muscle memory as the student completes tasks required of underground heavy equipment operators using heavy equipment simulation. The facility incorporates exemplary workforce safety standards into all aspects of the program.

The training is offered several times per year, and the schedule mirrors that of a typical mine worker:

I recently visited the Delta Mine Training Center near Fairbanks and am pictured here with Bill Bieber, the facility's director.

10-hour days over two 14-day shifts. The underground training totals 280 hours over six weeks, and the surface training is 140 hours over two weeks. Program graduates with these high-demand skills readily move into good jobs in Alaska's growing industries.

The department provides grant funding for this program and many others statewide to give Alaskans of all ages the training they need to work in Alaska's major industries. For young adults ages 18 to 24, we have also introduced career boot camps at our Alaska Vocational Technical Center in Seward (AVTEC). Whether you're interested in a maritime career or a job in health care, our Job Center staff can connect you to these opportunities and available funding.

For more information on this program, contact the Mine and Petroleum Training Services Office at (907) 262-0231 or email mapts@alaska.edu. For help getting started or exploring career and training options, call the Alaska Job Center network toll-free at (877) 723-2539.

Contact Dr. Tamika L. Ledbetter, Commissioner, at (907) 465-2700 or commissioner.labor@alaska.gov.

JULY
2022
Volume 42 Number 7
ISSN 0160-3345

ALASKA ECONOMIC TRENDS

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ON THE COVER:

Rosanna McInnes of Seldovia tests her soil nutrients with a pentrometer last summer. McInnes didn't consider herself a farmer until COVID-19 hit. "There was a shortage of food coming in," she said. "My neighbor said I should sell my garden produce, so I did. I couldn't sell it fast enough. So that's when I decided to expand my garden and help feed my community." Photo by Tracy Robillard, U.S. Department of Agriculture, Natural Resources Conservation Service

ALASKA
DEPARTMENT of LABOR and WORKFORCE DEVELOPMENT

Governor
Mike Dunleavy

Commissioner
Dr. Tamika L. Ledbetter

Trends is a nonpartisan, data-driven magazine that covers a variety of economic topics in Alaska.

ON THIS SPREAD: The background image for 2022 is a sparkly Alaska shoreline, taken by Flickr user Darren Hsu. License: creativecommons.org/licenses/by-nc-sa/2.0/

The costs of living in Alaska

Rising inflation hit in late 2021 and continued in 2022

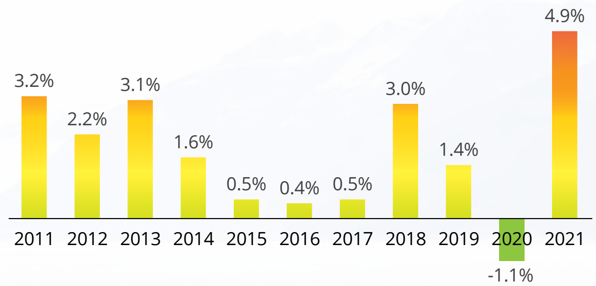
By NEAL FRIED

When COVID-19 hit, urban Alaska prices fell for the first time since at least 1961 as demand for many goods and services evaporated. But the deflation of 2020 was short-lived. As the economy began to rebound in 2021, consumers were flush with cash from savings, stimulus payments, and a job market rebound. Demand grew, but supply chain problems the pandemic caused continued to haunt the economy. This combination created the perfect environment for rising inflation: too many dollars chasing a limited number of goods and services.

Early 2021 showed only a hint of inflation as February's over-the-year cost increase came in at just 1.3 percent. (For context, Alaska's average inflation rate over the decade was 1.5 percent per year.) By April, the index climbed to 4.8 percent, then ballooned to 7.2 percent in December. Energy prices alone went from historic lows to near-highs in just a year.

The average inflation rate for 2021 was 4.9 percent, the highest annual price increase since 1990. And that number was muted because the year-to-year increases began slowly. December's 7.2 percent inflation suggested 2022 would bring more of the same.

High inflation followed 2020's drop

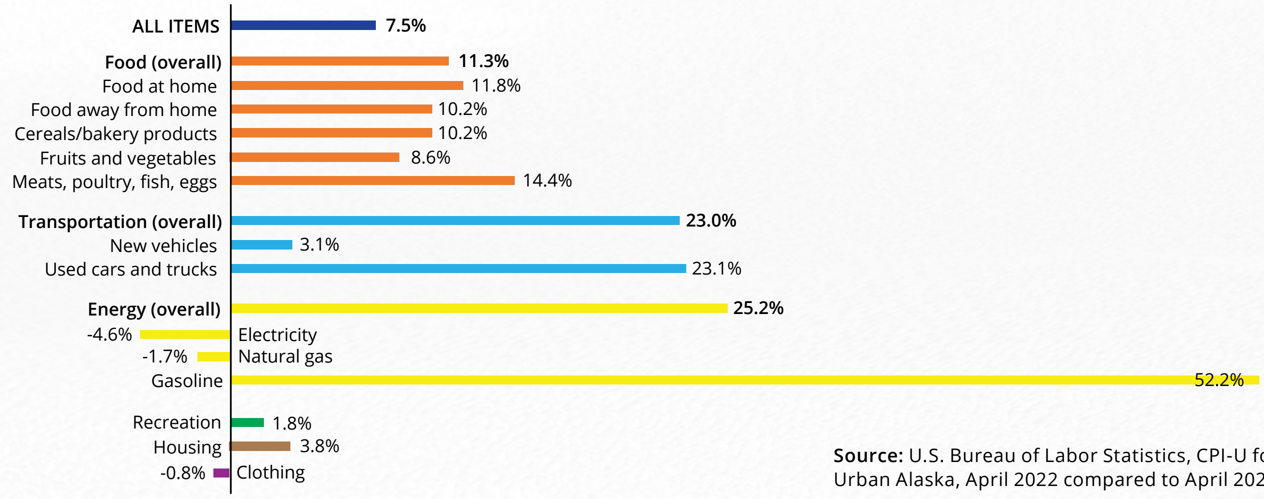


Source: U.S. Bureau of Labor Statistics, CPI-U for Urban Alaska

The trend has continued into 2022

The rise continued this year, with some cost categories' increases accelerating. Food is one example. Before 2020, food prices ticked up an average of 1.2 percent per year over the decade. In 2020, the rate

In early 2022, most urban Alaska prices continued their upward trend



Source: U.S. Bureau of Labor Statistics, CPI-U for Urban Alaska, April 2022 compared to April 2021

Two ways to measure the cost of living

1. In one place over time (inflation)

Alaska has a single measure to track inflation, or how much prices have changed: the Consumer Price Index for Urban Alaska.

Although there's a national consumer price index and CPIs for 31 cities and larger areas around the country, these only track costs over time in one area and can't be used to compare costs between places. For example, 2021's index for Alaska was 237.188, and the national index was 270.97. That doesn't mean the cost of living in the U.S. was higher; it just means prices have increased a bit faster nationally since the early 1980s than they have in Alaska cities.

The U.S. Bureau of Labor Statistics produces the CPI through elaborate surveys of consumer spending habits. These surveys cover a "market basket" of common items, to which BLS assigns location-specific weights to determine how people spend their money.

The categories include housing, food, transportation, medical care, and entertainment. In most categories, Alaska's weights resemble the national values.

The inflation rate is also used to adjust the value of the dollar over time. Workers, unions, and employers watch the CPI because bargaining agreements and other wage rate negotiations often incorporate an adjustment for inflation.

The CPI also plays a role in long-term real estate rental contracts, annual adjustments to the state's minimum wage, child support payments, and budgeting. The Alaska Permanent Fund Corporation uses the CPI to inflation-proof the fund. Senior citizens are affected nearly every year because Social Security payments are adjusted using the CPI.

The bureau produces the CPI for Urban Alaska bimonthly (in February, April, June, August, October, and December) as well as annually and semiannually.

2. In different places at the same time

The other way to assess the cost of living is to compare costs between two or more places, such as Alaska with other states and cities and Alaska communities with each other. These types of comparisons, which begin on page 8, play a role in relocation decisions and adjusting salaries and stipends by area.

While measuring inflation has a single source, a range of sources are available for cost comparisons between areas. Their reliability varies and they have different methods, so it's important to take their strengths and weaknesses into account. Some rely on random private individuals to enter prices for various goods and services in their communities, then automatically generate a cost-of-living index. Others use rigorous, broad-based, and transparent statistical methods. A good solution is to use multiple sources and look for patterns.

Other sources not marketed as cost-of-living measures can shed light on price differences, too. One is the U.S. Census Bureau's annual American Community Survey, which includes the median value of a home and median gross rental cost data for every community in the country. Because of the small sample sizes and large margins of error for many places, the five-year average is recommended when using the ACS.

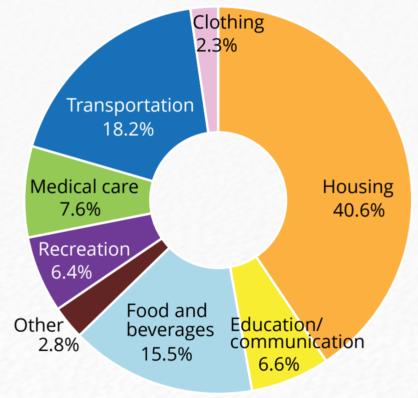
climbed above 4 percent, then hit 4.8 percent in 2021, the biggest jump in food costs since 1995.

By April 2022, food was 11.3 percent more expensive than the previous April, with meat and eggs the biggest culprits.

Transportation continued to register some of the largest cost increases among categories in 2022, running over 20 percent higher. After housing, transportation carries the second-largest weight in the overall index — 18.2 percent — meaning the typical household spends about 18 percent of its monthly income on transportation. Many expenses in transportation went up substantially: car rentals, airline tickets, used cars, and fuel. Gasoline prices jumped by over 50 percent.

The overall energy index, which gets a lot of

How urban Alaskans spend their consumer dollars

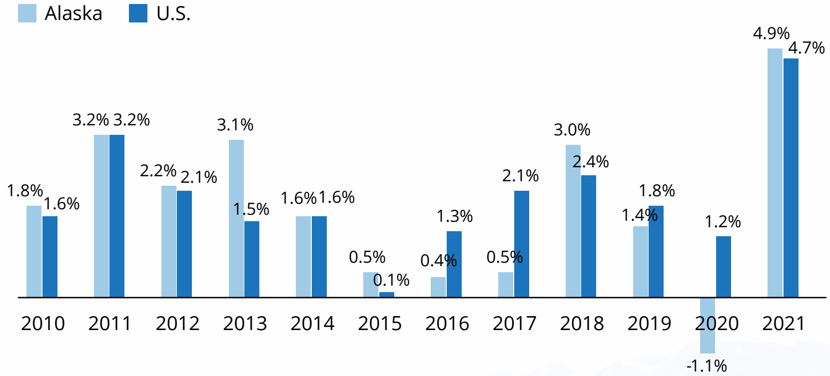


Source: U.S. Bureau of Labor Statistics, CPI-U for Urban Alaska, December 2021 attention and bleeds into many other categories, exceeded 25 percent. Energy is the most volatile part of the consumer price index. Since 2000, yearly energy costs have increased or decreased by double digits nine times.

Last year's 14.4 percent energy inflation was the second-largest in 21 years. It's still too early to know if the 2022 overall energy cost increase will top that number, but February and April did.

Housing costs escaped the eye-popping increases we saw in other categories. February registered 4.9 percent and April 3.8 percent, both relatively modest. But with housing the largest household expense, representing nearly 41 percent of the overall consumer price index, these numbers are consequential and well over the 10-year average of 1.6 percent.

Urban Alaska, U.S. inflation rates tend to track



Source: U.S. Bureau of Labor Statistics

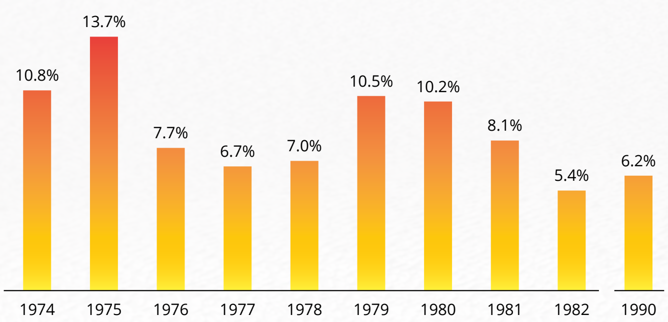
Clothing has a negligible effect on total costs, but even clothes prices have changed course. After dropping significantly in 2019 and 2020, clothes prices went up modestly in 2021 and early 2022. April 2022 showed a slight decrease.

National and global forces rather than local factors drive most price changes, but housing can be an exception.

Inflation has been high before

Only older Alaskans might remember past years of high inflation, but our rate hit double digits several times between 1974 and 1980.

Alaska's past years of high inflation



Source: U.S. Bureau of Labor Statistics, CPI-U for Urban Alaska

Coincidentally, these jumps came during some of Alaska's best economic growth years, which included the construction of the Trans-Alaska Pipeline System and the spectacular oil wealth that followed its completion in 1977.

High inflation doesn't typically lead to stronger economic growth, though. It's usually the opposite — high inflation creates uncertainty. Alaska's oil boom years were a notable exception.

Alaska's peak inflation rate was 13.7 percent in 1975, in the midst of pipeline construction and wild economic expansion. U.S. inflation was also notably high that year, at around 9 percent.

Alaska, U.S. inflation rates typically move together

Historically, Urban Alaska's consumer price index has followed the same pattern as the national index and most other cities' data, and that held true recently. Alaska's 2021 inflation was 4.9 percent overall and the nation's was 4.7 percent. (Alaska has just one consumer price index, and it's based mainly on costs in Anchorage and the Matanuska-Susitna Borough. See the sidebar on page 5 for more on the CPI.)

That's because national and international forces rather than local factors drive most price changes. Housing is sometimes an exception that can differentiate areas' cost changes. The differences are usually minor, though, which is the case right now.

There's no dominant view on where inflation is headed

Forecasting inflation has a poor track record even when circumstances are less volatile, so the rest of 2022 is an even bigger question mark than usual.

One group of national economic experts predicts supply chain problems will work themselves out this year and rising interest rates will dampen demand, slowing inflation.

Others worry we're entering a prolonged period of high inflation based on the assumptions that supply chain issues will persist, the war in Ukraine will keep food and energy prices high, and the mere expectation of high inflation could make it a reality.

Neal Fried is an economist in Anchorage. Reach him at (907) 269-4861 or neal.fried@alaska.gov.

Urban Alaska and national metro inflation by category, 2011 to 2021

ALL ITEMS

Year	Urban AK % chg from previous yr	U.S. % chg from previous yr
2011	3.2%	3.2%
2012	2.2%	2.1%
2013	3.1%	1.5%
2014	1.6%	1.6%
2015	0.5%	0.1%
2016	0.4%	1.3%
2017	0.5%	2.1%
2018	3.0%	2.4%
2019	1.4%	1.8%
2020	-1.1%	1.2%
2021	4.9%	4.7%

ALL ITEMS MINUS HOUSING

Year	Urban AK % chg from previous yr	U.S. % chg from previous yr
2011	3.4%	4.0%
2012	1.7%	2.0%
2013	3.0%	1.1%
2014	1.0%	1.1%
2015	-0.3%	-1.3%
2016	0.3%	0.2%
2017	1.1%	1.5%
2018	3.7%	2.0%
2019	1.9%	1.0%
2020	-0.4%	0.6%
2021	5.9%	5.7%

HOUSING

Year	Urban AK % chg from previous yr	U.S. % chg from previous yr
2011	2.9%	1.3%
2012	2.7%	1.6%
2013	3.1%	2.1%
2014	2.7%	2.6%
2015	2.4%	2.1%
2016	0.9%	2.5%
2017	0.3%	3.0%
2018	1.8%	2.9%
2019	1.2%	2.9%
2020	-1.9%	2.2%
2021	2.2%	3.3%

TRANSPORTATION

Year	Urban AK % chg from previous yr	U.S. % chg from previous yr
2011	4.7%	9.8%
2012	2.0%	2.3%
2013	7.0%	0%
2014	-0.6%	-0.7%
2015	-6.8%	-7.8%
2016	-1.7%	-2.1%
2017	2.4%	3.4%
2018	7.0%	4.5%
2019	0.2%	-0.3%
2020	-6.8%	-4.2%
2021	16.9%	14.6%

FOOD AND BEVERAGES

Year	Urban AK % chg from previous yr	U.S. % chg from previous yr
2011	3.6%	3.6
2012	2.4%	2.5
2013	0.4%	1.4
2014	1.3%	2.3
2015	1.7%	1.8
2016	-0.7%	0.3
2017	0%	0.9
2018	0.5%	1.4
2019	2.7%	1.8
2020	4.4%	3.3
2021	4.8%	3.8

MEDICAL CARE

Year	Urban AK % chg from previous yr	U.S. % chg from previous yr
2011	5.3%	3.0%
2012	4.3%	3.7%
2013	3.2%	2.5%
2014	3.2%	2.4%
2015	3.3%	2.6%
2016	4.5%	3.8%
2017	1.5%	2.5%
2018	7.6%	2.0%
2019	6.6%	2.8%
2020	5.2%	4.1%
2021	2.5%	1.2%

CLOTHING

Year	Urban AK % chg from previous yr	U.S. % chg from previous yr
2011	2.2%	2.2%
2012	4.3%	3.4%
2013	4.8%	0.9%
2014	1.5%	0.1%
2015	0.5%	-1.3%
2016	2.6%	0.1%
2017	0.3%	-0.3%
2018	2.0%	0%
2019	-8.3%	-1.3%
2020	-6.1%	-4.8%
2021	3.9%	2.5%

ENERGY

Year	Urban AK % chg from previous yr	U.S. % chg from previous yr
2011	10.8%	15.4%
2012	1.1%	0.9%
2013	-2.7%	-0.7%
2014	2.4%	-0.3%
2015	-10.3%	-16.7%
2016	-5.8%	-6.6%
2017	12.3%	7.9%
2018	8.0%	7.5%
2019	1.5%	-2.1%
2020	-10.6%	-8.5%
2021	14.4%	21.0%

Source: U.S. Department of Labor, Bureau of Labor Statistics

How Alaska's costs stack up nationally

By SARA TEEL

The Council for Community and Economic Research, or C2ER, publishes quarterly and annual surveys comparing the costs of everyday goods and services in more than 260 U.S. cities, including Anchorage, Fairbanks, and Juneau. It normally includes Kodiak, but Kodiak's numbers weren't reported for the first quarter of 2022.

This frequently used cost-of-living index covers 57 specific items in categories such as food, housing (rental and mortgage), medical care, utilities, and transportation. While the survey provides useful comparisons between cities, it has limitations. Actual consumption patterns vary by income and location, but the survey assumes a single consumption pattern: that of professionals with income in the top 20 percent. The survey doesn't take taxation into account, either. With no state sales or income tax, total taxation is typically lower in Alaska towns than other U.S. cities.

Where public health care premiums cost the most

	State	2022 premium
1	West Virginia	$752
2	Wyoming	$745
3	Vermont	$732
4	**Alaska**	**$672**
5	South Dakota	$592
6	Nebraska	$591
7	Alabama	$569
8	New York	$569
9	Connecticut	$540
10	Delaware	$538
	U.S. average	$428

Note: Lowest-cost monthly premium for a 40-year-old on the silver tier, Affordable Care Act coverage

Source: The Henry J. Kaiser Family Foundation

More cities surpass Alaska costs

Costs in Alaska's three surveyed cities always come in above the national average, and for the first quarter of 2022, Anchorage was highest at 130.1 — meaning its costs were 130 percent of the U.S. average — followed by Juneau at 127.5 and Fairbanks at 124.4. For comparison, the index ranged from a low of 74.1 for Kalamazoo, Mich., to 237.8 for Manhattan in New York City, which is usually No. 1.

The Price Is Right: Cost comparisons for common items in 2022

	Dozen eggs	Kraft parmesan	11.5 oz grnd coffee	Kleenex	Dental cleaning	Qtr Pounder with Cheese	Dry clean 2-pc suit	1-hour yoga class	6-pk of Heineken
U.S. average	**$1.78**	**$4.08**	**$4.63**	**$1.89**	**$104.87**	**$5.03**	**$14.58**	**$16.55**	**$9.88**
Anchorage	$1.99	$4.30	$5.79	$3.01	$150.00	$5.13	$16.63	$17.33	$10.49
Fairbanks	$1.99	$4.58	$6.29	$2.69	$151.15	$5.69	$20.00	$16.00	$10.49
Juneau	$2.19	$4.66	$5.89	$2.88	$160.00	$5.49	$16.00	$13.91	$9.99
Highest city	Honolulu, Hawaii	Mankato, Minnesota	Honolulu, Hawaii	Manhattan, New York	Juneau, Alaska	Pittsfield, Mass.	Marshfield, Wisconsin	Minneapolis, Minnesota	Salisbury, N. Carolina
Highest price	$3.97	$6.45	$9.29	$3.51	$160.00	$7.99	$24.80	$31.45	$15.49
Lowest city	Danville City, Virginia	Dublin-Laurens, Georgia	Providence, Rhode Island	Rapid City, S. Dakota	Little Rock, Arkansas	Ardmore, Oklahoma	Cedar Park, Texas	Bullhead City, Arizona	Temple, Texas
Lowest price	$0.99	$2.49	$2.90	$1.25	$48.50	$2.29	$7.18	$5.00	$7.79

Notes: This survey's prices, gathered by volunteers around the country, are for the first quarter of 2022. Food prices reflect the lowest-cost item in each category at a typical grocery store.

Source: The Council for Community and Economic Research

How Alaska cities compared to other U.S. cities in early 2022*

	Total index	Groceries	Housing	Utilities	Trans- portation	Health care	Misc
Category's weight in total index	100.0%	17.26%	30.90%	10.21%	7.54%	4.42%	29.67%
U.S. average	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Region and city							
West							
Anchorage	130.1	126.0	141.5	120.5	114.5	153.2	124.5
Fairbanks	124.4	122.1	103.2	209.2	109.2	152.7	118.4
Juneau	127.5	138.8	140.1	132.6	117.3	149.4	105.4
Honolulu, HI	192.7	152.7	320.7	144.6	124.2	120.1	127.6
San Francisco, CA	184.2	129.8	306.4	133.8	141.6	133.9	124.3
Los Angeles-Long Beach, CA	151.9	113.7	234.0	109.9	126.0	115.0	115.2
Seattle, WA	150.7	128.6	202.2	106.6	122.3	124.3	136.3
Portland, OR	127.4	109.4	165.8	93.0	120.9	103.5	115.0
Bozeman, MT	122.0	107.1	154.8	86.3	99.6	99.5	117.7
Salt Lake City, UT	110.5	106.3	126.3	93.0	105.9	94.3	106.0
Boise, ID	108.7	97.3	126.6	81.5	111.9	102.2	106.2
Spokane, WA	101.9	104.3	100.7	95.3	95.2	118.7	103.1
Las Vegas, NV	101.2	101.2	109.8	97.6	110.9	96.1	91.7
Casper, WY	92.2	103.2	84.3	88.1	83.1	99.2	96.8
Southwest/Mountain							
Denver, CO	110.0	93.3	129.0	86.5	98.2	100.7	112.3
Colorado Springs, CO	103.9	97.7	109.2	102.3	95.6	102.6	105.0
Phoenix, AZ	104.2	99.9	114.4	102.3	108.2	100.2	96.2
Dallas, TX	101.2	95.1	94.4	112.4	86.9	112.3	109.9
Houston, TX	91.7	96.7	81.5	97.7	90.6	100.4	96.5
Midland, TX	89.7	85.2	79.7	94.9	93.9	96.4	98.9
Oklahoma City, OK	83.9	92.2	69.6	93.5	89.9	101.1	86.5
Tulsa, OK	85.5	94.4	63.5	93.1	92.6	98.6	96.7
Midwest							
Chicago, IL	126.4	103.1	152.9	98.6	133.7	121.0	121.0
Minneapolis, MN	99.5	98.0	93.2	98.9	104.8	98.4	105.9
Cleveland, OH	92.9	103.4	79.8	98.6	92.5	103.1	97.0
Des Moines, IA	85.7	99.5	66.1	84.3	95.9	95.6	94.4
LOWEST ➡ Kalamazoo, MI	74.1	77.9	47.5	96.0	91.8	94.9	84.3
Southeast							
Washington, DC	158.8	111.0	260.5	111.0	111.1	98.5	118.3
Fort Lauderdale, FL	120.5	120.5	152.3	106.3	104.3	93.4	100.3
Miami-Dade County, FL	120.4	122.3	139.3	106.3	107.1	98.6	111.1
New Orleans, LA	111.2	96.1	141.2	80.8	98.3	117.4	101.6
Atlanta, GA	104.1	92.6	113.0	86.6	106.1	106.4	106.7
Birmingham, AL	92.9	91.0	82.8	102.8	93.5	101.1	99.8
Atlantic/New England							
HIGHEST ➡ New York (Manhattan), NY	237.8	144.4	482.7	103.3	117.6	107.9	133.1
Boston, MA	150.8	116.0	220.9	123.5	121.1	117.0	119.9
Hartford, CT	107.7	108.4	101.4	126.4	104.0	92.6	110.6
Philadelphia, PA	106.0	118.4	101.2	112.2	113.0	97.2	101.3

*Based on professional households with earnings in the top quintile, first quarter 2022

Source: The Council for Community and Economic Research

Over the last 20 years, Alaska cities have moved from being among the highest-cost cities in the United States to farther down in the rankings. In early 2022, Anchorage placed 18th, Juneau 19th, and Fairbanks 22nd.

The more expensive cities are mainly large metropolitan areas with high housing costs. Seattle is a good example. Seattle is the closest large city to Alaska and it used to rank lower on the list. Since the early 2010s, Seattle has consistently grown more expensive, mostly because of its housing. Its overall cost of living is now well above Alaska cities.

Alaska's housing costs are high and move the state's total index value more than any other category, but all spending categories in Alaska were above the national average this year.

Because food must arrive by barge or air, Juneau's grocery costs were 28 percent above the U.S. average and third-highest in the country. Only Honolulu and Manhattan groceries cost more.

Given Fairbanks' remoteness and climate, Fairbanks again topped the national list for utility costs. Fairbanks was indexed at 209, or more than double the national average.

Alaska's overall health care costs are the highest in the nation

Alaska's health care costs have ranked among the nation's highest for years, and in early 2022, our three cities had the most expensive health care in the country. Anchorage topped the list at 153.2 percent of the national average followed by Fairbanks at 152.7 and Juneau at 149.4. San Francisco came in fourth at 133.9.

One component of health care prices is public health insurance premiums under the Affordable Care Act. In 2020 and 2021, Alaska ranked second-highest for premiums after Wyoming. In 2022, Alaska fell to fourth place, but not because our premiums decreased. Alaska's premium was $672 per month, within a dollar of last year, but costs jumped for West Virginia ($752) and Vermont ($732) and remained high in Wyoming ($745). The national average was $428 per month. (See the table on page 8.)

Still, on average and in certain places, public health care premiums have declined somewhat in 2022. Most insurers who participate in the marketplace reported they don't anticipate COVID-19 will affect their premiums this year and they predict their costs will return to pre-pandemic levels.

Moving to Anchorage from cities in four 'neighbor' states

How far a dollar goes varies widely across the country. Someone living in a lower-cost community will need to earn more money to maintain the

Continued on page 18

What a mover to Anchorage would need to earn, Q1 2022

If you earned $50k in these cities, this is the amount required to live equally in Anchorage		
California	San Diego	$43,486
	San Francisco	$32,895
	Los Angeles	$42,275
Texas	Dallas	$61,005
	Houston	$67,747
	Austin	$62,870
Washington	Seattle	$41,423
	Spokane	$60,714
	Yakima	$64,394
Florida	Miami	$53,797
	Fort Lauderdale	$52,773
	Tallahassee	$66,684

Notes: These are the top four states that send movers to Alaska. Yearly earnings are after taxes. Living equally means you'll need the amount specified to purchase in Anchorage what you purchased in that city.

Sources: Internal Revenue Service Gross Migration to Alaska by State; and The Council for Community and Economic Research

Alaska drops to 6th highest-cost state

	State	2021 index
	U.S. average	**100.0**
1	Hawaii	193.3
2	New York	148.2
3	California	142.2
4	Massachusetts	135.0
5	Oregon	130.1
6	**Alaska**	**127.1**
7	Maryland	124.0
8	Connecticut	121.6
9	Rhode Island	117.2
10	Vermont	117.0

Source: Missouri Economic Research and Information Center

Comparing costs among Alaska towns

By SARA TEEL

Fuel costs rise across the state

Fuel is often a major expense for Alaska households and businesses, and costs vary widely by location and delivery method.

Focusing on rural fuel costs, the Alaska Department of Commerce, Community, and Economic Development conducts an annual survey of 100 communities across the state.

This year's survey was taken before the recent spike in fuel prices.

In the winter of 2022, a gallon of gasoline cost $5.31 on average and heating fuel was $4.83 a gallon — both up considerably from 2021 and especially from the lows of 2020. However, this year's survey was conducted before the recent spike in fuel prices.

At the time of the winter survey, fuel prices had only increased about 57 cents a gallon for gas and 75 cents for heating fuel, on average, from the year before. In May, the *Anchorage Daily News* reported that heating fuel in Noatak, north of Kotzebue, briefly hit $16 a gallon. Noatak isn't one of the surveyed communities but is a good proxy for how much more expensive fuel has become, since the survey was last conducted, in the small communities that fly it in.

Remote communities that fly in gasoline and heating fuel face the highest prices. Back to the winter survey, a gallon of gas in Atka was $8.35 and in Anaktuvuk Pass was $7.20 per gallon. A gallon of heating fuel cost $3.30 in Circle, which is on the road system, and $7.50 in Atka, which is on the Aleutian chain.

Towns that barge in fuel or are on the road system typically pay lower fuel prices. Healy, which is on the Railbelt, had the lowest-priced gas at $3.59 per gallon. A gallon of gasoline in Juneau was $3.60 and in Kodiak was $3.78.

North Slope communities are an exception to higher rural heating costs. Residential heating is subsidized, so these communities are listed in the results but excluded from the survey average. In Anaktuvuk Pass and Nuiqsut, for example, a gallon of home heating fuel was just $1.50 and $2.30 per gallon, respectively.

Gasoline and heating fuel costs in Alaska, winter '22

Community	Home heating fuel, gallon	Gasoline, gal regular
Akiak	$5.19	$4.92
Anaktuvuk Pass*	$1.50	$7.20
Atka	$7.50	$8.35
Bethel	$4.82	$4.33
Chenaga Bay	$5.52	$6.04
Chignik	$3.96	$3.92
Circle	$3.30	$4.70
Deering	$4.48	$4.79
Dillingham	$4.57	$5.06
Eagle	$4.00	$4.75
Emmonak	$5.12	$5.54
Fairbanks	$3.59	$3.85
Galena	$5.42	$6.90
Gambell	$4.69	$5.72
Glennallen	$3.29	$4.25
Golovin	$3.90	$4.00
Healy	$3.10	$3.59
Holy Cross	$6.05	$6.17
Homer	$3.55	$3.90
Hoonah	$4.71	$4.88
Hooper Bay	$6.62	$5.41
Juneau	$3.87	$3.60
King Cove	$3.22	$4.74
Kodiak	$3.68	$3.78
Kokhanok	$7.00	$7.00
Kotzebue	$6.23	$6.20
Mountain Village	$6.29	$6.61
Nenana	$3.81	$3.90
Noorvik	$5.64	$5.20
Nuiqsut*	$2.30	$5.00
Nulato	$5.00	$6.00
Pelican	$4.82	$5.12
Pilot Station	$7.20	$7.00
Port Lions	$5.35	$5.45
Ruby	$5.50	$5.50
Sand Point	$4.65	$3.97
Shishmaref	$3.91	$4.43
Unalaska	$4.37	$4.18
Wales	$4.64	$4.89
Wrangell	$3.91	$4.32

Note: This is a partial list of the 100 surveyed communities.

*North Slope communities' residential heating fuel costs are subsidized.

Source: Alaska Department of Commerce, Community, and Economic Development, *Current Community Conditions: Fuel Prices Across Alaska*

Rents and home sales prices across Alaska in early 2022

Median adjusted rent

Area	Rent
Sitka, City and Borough	$1,349
Anchorage, Municipality	$1,339
Fairbanks North Star Borough	$1,305
Survey total	**$1,279**
Kodiak Island Borough	$1,270
Chugach Census Area	$1,265
Juneau, City and Borough	$1,260
Ketchikan Gateway Borough	$1,153
Matanuska-Susitna Borough	$1,092
Kenai Peninsula Borough	$1,023
Wrangell-Petersburg Census Area	$929

Average house price

Area	Price
Ketchikan Gateway Borough	$503,200
Juneau, City and Borough	$481,451
Anchorage, Municipality	$445,408
Matanuska-Susitna Borough	$418,412
Bethel Census Area	$414,286
Statewide Total	**$402,976**
Kodiak Island Borough	$367,500
Kenai Peninsula Borough	$358,529
Rest of state	$330,491
Fairbanks North Star Borough	$326,659

Notes: Median adjusted rent is rent plus the cost of all utilities, whether they are included in the rent payment or paid separately by renters. Rents are for all unit types. All prices are for first quarter 2022.

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section and Alaska Housing Finance Corporation

How the military ranked Alaska towns' costs in 2022

City	Index
U.S. average	**100**
Bethel	150
Cordova	146
Valdez	144
Utqiagvik	142
Nome	142
Petersburg	142
Wainwright	142
Homer (incl Anchor Point)	140
Juneau	140
Kenai (incl Soldotna)	140
King Salmon (incl Bristol Bay Borough)	140
Seward	140
Sitka/Mt. Edgecumbe	140
Spruce Cape	140
Unalaska	140
Ketchikan	138
Kodiak	134
Clear Air Force Station	132
Tok	132
College (University of Alaska Fairbanks)	130
Eielson Air Force Base (Fairbanks)	130
Fort Wainwright (Fairbanks)	130
Delta Junction (incl Fort Greely)	128
Anchorage (incl Eagle River)	126
Wasilla	122

Source: OCONUS, effective May 16, 2022

Average house costs $403,000

Around 40 percent of an average household's income goes to housing, the largest expense. Housing prices depend on the available supply, the quality and type of housing, economic conditions, and the cost to build. Low interest rates, rising wages, building costs, and demand have all raised housing prices during the pandemic.

Our quarterly survey, conducted in partnership with the Alaska Housing Finance Corporation, found the average house in Alaska sold for $402,976 this year, up 8 percent from the year before.

The Fairbanks North Star Borough usually has the lowest-priced homes in the state and 2022 is no exception, but Fairbanks hasn't been immune to rising prices. The average home in Fairbanks in early 2022 was up 6 percent to $326,659.

Like Fairbanks, the Matanuska-Susitna Borough has lower-priced single-family homes. Most new homes in Alaska in recent years have been built there (48 percent of all new construction in the first quarter of 2022). A typical Mat-Su home sold for $418,412 this year, surpassing the statewide average for the first time in recent history.

On the other end of the spectrum, Juneau often tops the list for housing prices, but Ketchikan outpaced Juneau in early 2022 with the average Ketchikan Gateway Borough home coming in at $503,200, a whopping 35 percent higher than last year.

Like many small communities, the number of home sales in Ketchikan is small, so just a few higher-priced home sales can skew the average.

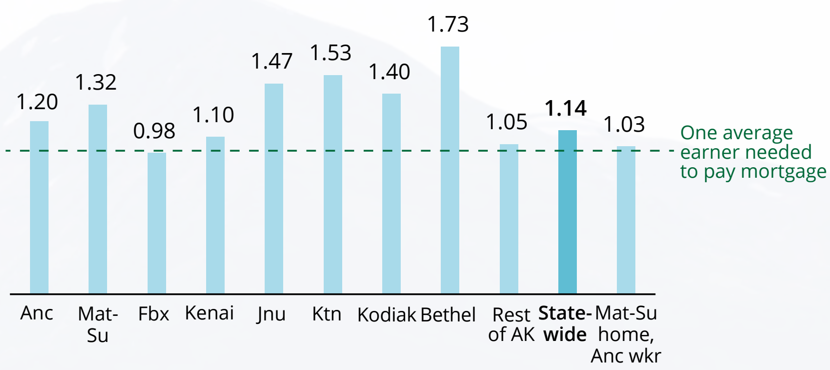
Homes become less affordable

Housing affordability depends on an area's average wage as well as its average home price. We've created an index that takes this into account, calculating how many average monthly paychecks are needed to afford a typical single-family home in that location.

Low interest rates and higher wages made homes more affordable in 2020, but by 2021, high demand drove sales prices to increase faster than average wages, and homes became slightly less affordable overall.

In the second half of 2021, It took 1.14 paychecks to afford the average Alaska house, as the chart on the right shows. However, with rising interest rates, this level of affordability won't last.

House affordability in the second half of 2021



Notes: The affordability index measures how many average monthly paychecks in a given area it would take to afford a 30-year mortgage on a typical house.

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section and Alaska Housing Finance Corporation

Fairbanks was Alaska's most affordable place in late 2021. At an index value of 0.98, it was the only area where a single average earner could afford a typical house.

It took 1.2 paychecks to afford a typical home in Anchorage and 1.32 in nearby Mat-Su. Mat-Su has less expensive housing but lower average wages. As a result, about 30 percent of Mat-Su residents work in Anchorage. Wages are higher there, but so are housing prices, which makes living in Mat-Su more affordable for Anchorage workers. (However, gas prices also play an important role, given the commute.) It took just 1.03 average monthly paychecks for an Anchorage worker living in Mat-Su to afford a typical house.

In a tiny market, just a few high-priced home sales can drive up the average.

For more on Alaska's home sales market over the last two years, [see the June issue of *Trends*].

Rents up in most places this year

Our rental survey uses median adjusted rent, which includes the cost of all utilities regardless of who pays them.

In March 2022, Alaska's median adjusted rent for all unit types was $1,279. That was an increase of $100 from the year before and largely due to rent increases in Anchorage. Rising costs, falling vacancy rates, and growing demand pushed rents up, especially in Anchorage but also in Fairbanks and Mat-Su.

Similar to 2021, Sitka rent topped the list at $1,349 per month. Anchorage was not far behind at $1,339, making it more expensive to rent there than in Kodiak ($1,270) or Fairbanks ($1,305).

Some renters face higher costs because the market has tightened. For example, Fairbanks' population increased recently because of the military, leading its vacancy rate to drop. The Fairbanks North Star Borough's vacancy rate dropped to 7.0 percent in March after peaking in March 2020 at 19.0 percent.

Military ranks Bethel costs No. 1

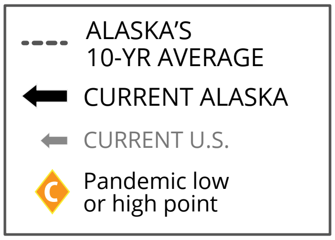
The U.S. Department of Defense tracks the costs in multiple small Alaska communities through its OCONUS index, or Outside the Continental United States (see the table on the previous page).

This frequently updated index compares costs across hundreds of locations and includes 25 in Alaska. It's calculated differently from other indexes because the military bases the index on spendable rather than total income and excludes housing, which it covers through a separate program.

OCONUS assigns a value of 100 for the average U.S. city. In May of this year, Bethel topped the list with costs at 150 percent of the national average. Wasilla, at 122, was ranked the least expensive place in Alaska.

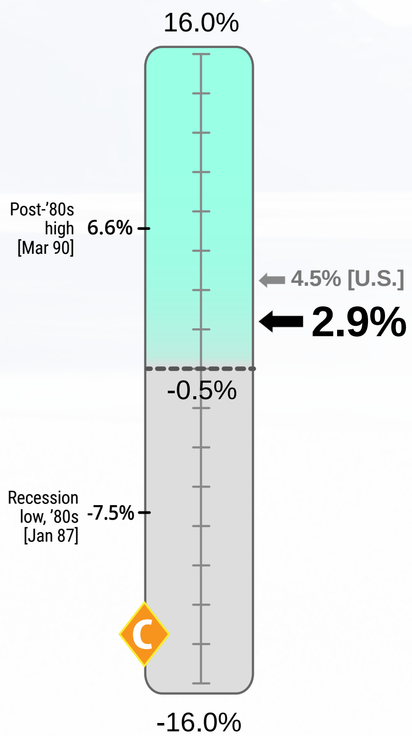
Sara Teel is an economist in Juneau. Reach her at (907) 465-6027 or sara.teel@alaska.gov.

Gauging The Economy



Job Growth

May 2022
Over-the-year percent change

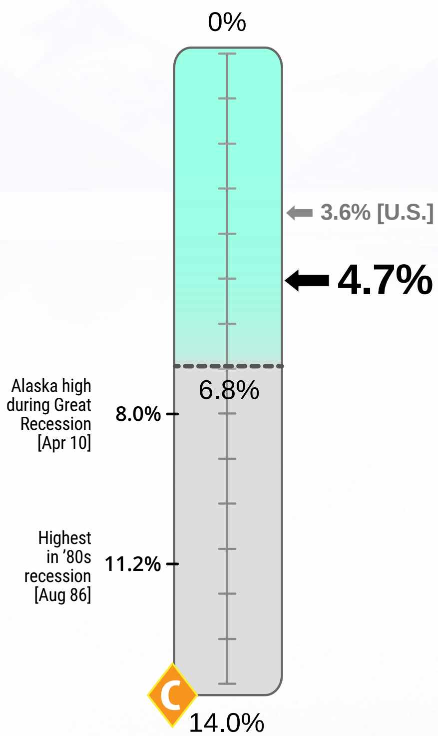


The spread of COVID-19 caused rapid job loss in early 2020. Although employment is up significantly from 2020, it is still 4.6 percent below May 2019.

U.S. employment, which was up 4.5 percent from May 2021, has now recovered to its May 2019 level.

Unemployment Rate

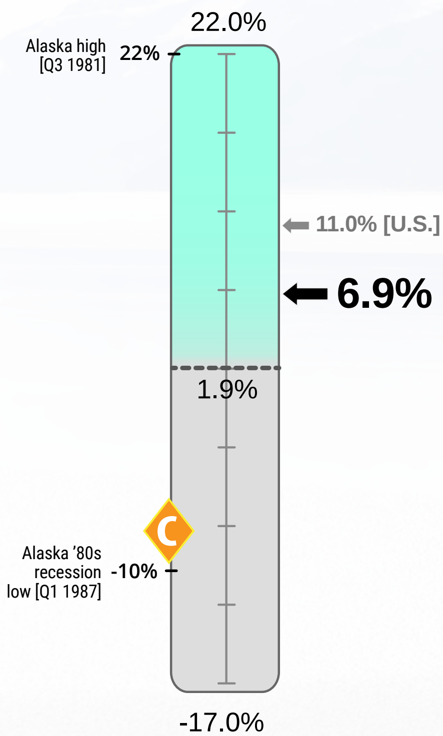
May 2022
Seasonally adjusted



Alaska's unemployment rate has been less useful as an economic measure during the pandemic because of data collection difficulties and an unusually large number of people leaving the labor market — that is, not working or looking for a job.

Wage Growth

4th Quarter 2021
Over-the-year percent change



After being well down during the second and third quarters of 2020, total wages paid by Alaska employers climbed above year-ago levels in the fourth quarter of 2020.

Wages were up 6.9 percent from year-ago levels in the fourth quarter of 2021 and 10.4 percent above fourth quarter 2019.

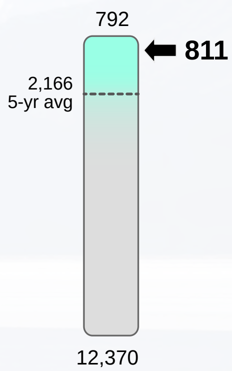
Gauging The Economy

ALASKA'S 10-YR AVERAGE

CURRENT ALASKA

Initial Claims

Unemployment, week ending May 7, 2022*

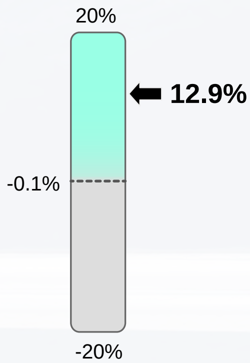


Unemployment claims jumped in the spring of 2020 with the pandemic as many businesses shut down or limited services. Pandemic-driven claims loads have fallen, and new claims for benefits are back below their long-term average.

*Four-week moving average ending with specified week

GDP Growth

4th Quarter 2021
Over-the-year percent change*

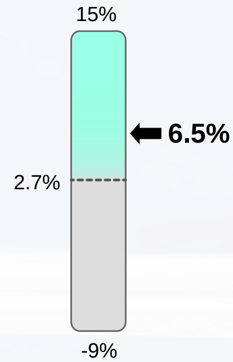


Gross domestic product is the value of the goods and services a state produces. Alaska's GDP fell hard in early 2020 but recovered most of those losses in 2021.

*In current dollars

Personal Income Growth

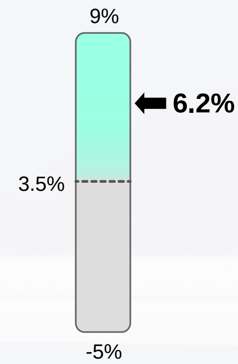
4th Quarter 2021
Over-the-year percent change



Personal income jumped early this year, largely because of federal COVID-19 relief funding, and has since fallen.

Change in Home Prices

Single-family, percent change from prior year, Q1 2022*

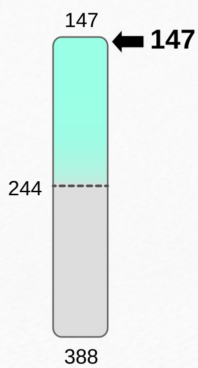


Home prices shown include only those for which a commercial loan was used. This indicator tends to be volatile from quarter to quarter.

*Four-quarter moving average ending with specified quarter

Foreclosures

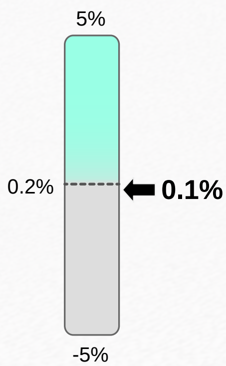
1st Quarter 2020



Foreclosure moratoriums have kept these numbers low during the pandemic.

Population Growth

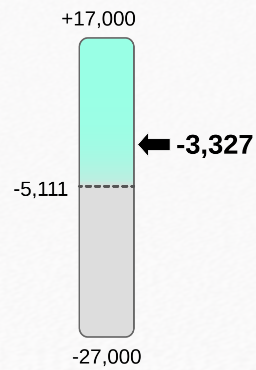
2020 to 2021



After four years of decline, Alaska's population grew slightly in 2021.

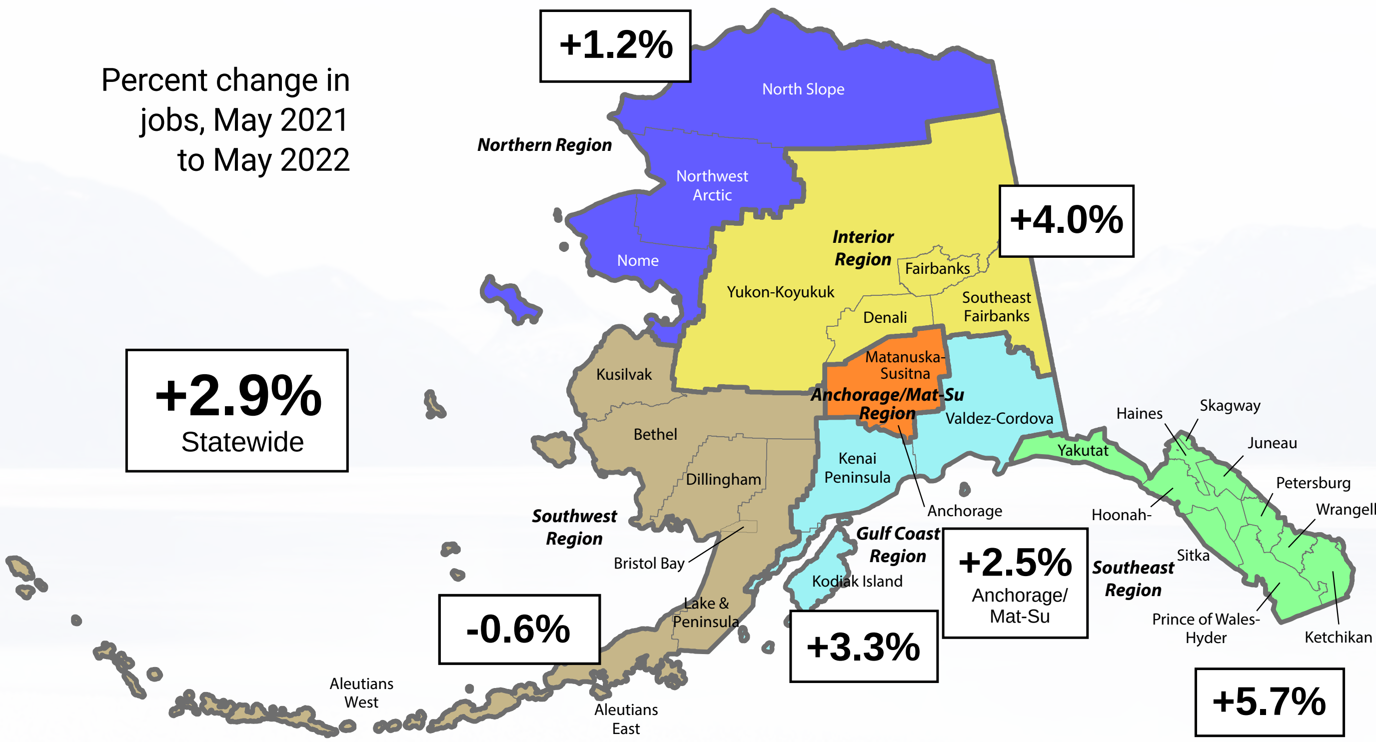
Net Migration

2020 to 2021



The state had net migration losses for the ninth consecutive year in 2021, although the loss was smaller. Net migration is the number who moved to Alaska minus the number who left.

Employment by Region



Seasonally adjusted

	Prelim. 5/22	Revised 4/22	5/21
United States	**3.6**	**3.6**	**5.8**
Alaska	**4.7**	**4.8**	**6.8**

Not seasonally adjusted

	Prelim. 5/22	Revised 4/22	5/21
United States	**3.4**	**3.3**	**5.5**
Alaska	**4.5**	**4.8**	**6.9**

Regional, not seasonally adjusted

	Prelim. 5/22	Revised 4/22	5/21
Interior Region	**4.3**	**4.6**	**5.9**
Denali Borough	7.2	11.3	8.9
Fairbanks N Star Borough	3.9	4.0	5.4
Southeast Fairbanks Census Area	5.4	6.4	6.5
Yukon-Koyukuk Census Area	9.6	10.9	12.5
Northern Region	**8.4**	**8.9**	**10.2**
Nome Census Area	8.8	9.8	10.9
North Slope Borough	5.7	5.6	6.5
Northwest Arctic Borough	10.5	10.9	12.7
Anchorage/Mat-Su Region	**4.1**	**4.3**	**6.6**
Anchorage, Municipality	3.7	3.9	6.4
Mat-Su Borough	5.0	5.4	7.3

	Prelim. 5/22	Revised 4/22	5/21
Southwest Region	**9.0**	**8.2**	**11.6**
Aleutians East Borough	2.2	1.4	3.0
Aleutians West Census Area	5.0	2.4	5.6
Bethel Census Area	11.7	12.0	14.5
Bristol Bay Borough	3.7	4.1	5.0
Dillingham Census Area	7.1	7.1	9.9
Kusilvak Census Area	16.1	16.6	21.4
Lake and Peninsula Borough	7.0	8.6	10.1
Gulf Coast Region	**5.0**	**5.7**	**7.6**
Kenai Peninsula Borough	4.9	5.7	7.6
Kodiak Island Borough	4.5	4.2	7.4
Chugach Census Area	3.9	4.7	7.2
Copper River Census Area	9.8	12.4	9.2

	Prelim. 5/22	Revised 4/22	5/21
Southeast Region	**3.9**	**4.3**	**6.6**
Haines Borough	7.0	8.3	11.2
Hoonah-Angoon Census Area	5.5	7.7	9.8
Juneau, City and Borough	3.0	3.0	5.3
Ketchikan Gateway Borough	4.6	5.2	8.2
Petersburg Borough	5.5	6.1	6.9
Prince of Wales-Hyder Census Area	5.8	6.3	8.0
Sitka, City and Borough	2.9	2.9	4.6
Skagway, Municipality	6.6	9.9	13.3
Wrangell, City and Borough	5.1	5.5	7.2
Yakutat, City and Borough	4.5	5.1	7.0

How Alaska Ranks

Unemployment Rate[1]

48th 4.7%

1st Nebraska 1.9%

50th New Mexico 5.1%

Job Growth[2]

29th* 2.9%

1st Nevada 7.4%

50th Kansas 1.4%

*Tied with Idaho

Job Growth, Private[2]

25th* 3.6%

1st Nevada 8.1%

50th Kansas 1.8%

*Tied with West Virginia

Job Growth, Government[2]

31st* 0.6%

1st West Virginia 5.5%

50th Louisiana -1.6%

*Tied with Rhode Island and S. Carolina

Job Growth, Leisure and Hospitality[2]

15th 12.4%

1st New York 22.9%

50th Kansas 2.8%

Note: Government employment includes federal, state, and local government plus public schools and universities.
[1]May seasonally adjusted unemployment rates
[2]May employment, over-the-year percent change

Sources: U.S. Bureau of Labor Statistics; and Alaska Department of Labor and Workforce Development, Research and Analysis Section

Other Economic Indicators

	Current		Year ago	Change
Urban Alaska Consumer Price Index (CPI-U, base yr 1982=100)	241.698	2nd half 2021	227.258	+6.4%
Commodity prices				
Crude oil, Alaska North Slope,* per barrel	$115.00	May 2022	$67.45	+70.50%
Natural gas, Henry Hub, per thousand cubic feet (mcf)	$8.16	May 2022	$2.96	+175.68%
Gold, per oz. COMEX	$1,849.90	6/17/2022	$1,769.00	4.57%
Silver, per oz. COMEX	$21.96	6/17/2022	$25.86	-15.08%
Copper, per lb. COMEX	$4.13	6/17/2022	$4.19	-1.43%
Zinc, per lb.	$1.62	6/17/2022	$1.30	+24.62%
Lead, per lb.	$0.94	6/17/2022	$0.97	-3.09%
Bankruptcies	29	Q1 2022	63	-53.97%
Business	0	Q1 2022	5	-100%
Personal	29	Q1 2022	58	-50.00%
Unemployment insurance claims				
Initial filings	4,299	Apr 2022	15,756	-72.72%
Continued filings	21,977	Apr 2022	56,046	-60.79%
Claimant count	6,331	Apr 2022	13,833	-54.23%

*Department of Revenue estimate

Sources for this page and the preceding three pages include Alaska Department of Labor and Workforce Development, Research and Analysis Section; U.S. Bureau of Labor Statistics; U.S. Bureau of Economic Analysis; U.S. Energy Information Administration; Kitco; U.S. Census Bureau; COMEX; NASDAQ; Alaska Department of Revenue; and U.S. Courts, 9th Circuit

STATE COMPARISONS

Continued from page 10

same lifestyle when moving to a higher-cost city. Housing and rental prices are the dominant factors, but transportation costs, grocery bills, health care costs, and utilities are also important.

For example, at the highest-cost end, if you earned $50,000 after taxes in San Francisco, you would only need to bring in about $33,000 after taxes in Anchorage to maintain the same spending patterns. Anchorage's housing costs in particular are significantly lower. (We chose $50,000 per year as the base for these comparisons because it's a roughly average wage for Alaska, but it's worth noting that in reality, $50,000 won't get you very far in San Francisco.)

At the other end, it costs less to live in Tallahassee, Fla., than in Anchorage. You would need to earn almost $67,000 after taxes in Anchorage to afford the same purchases you made while living in Tallahassee on $50,000 a year.

Related index places Alaska sixth-costliest among states

Another way to look at cost-of-living differences using the same data set is total costs by state, based on covered cities. The Missouri Economic Research and Information Center publishes its own annual state index using the same C2ER survey discussed previously. (See the table on page 10.) While this index does not account for city size, it can illuminate regional differences.

Basing the state's costs on Anchorage, Fairbanks, and Juneau placed Alaska sixth-highest in 2021 at 127.1, the same spot we held last year. Hawaii (193.3), New York (148.2), California (142.2), Massachusetts (135.0), and Oregon (130.1) costs of living outranked Alaska.

It's important to remember that the cost of living is far more specific to cities than states — coastal California is more expensive than inland, for example — so state comparisons should be taken with a grain of salt.

Sara Teel is an economist in Juneau. Reach her at (907) 465-6027 or sara.teel@alaska.gov.

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Keith Kurber II, Chair Robert A. Doyle Robert M. Pickett Daniel A. Sullivan Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-____

PREFILED DIRECT TESTIMONY
OF
MARK A. MOSES

PREFILED DIRECT TESTIMONY
OF
MARK A. MOSES

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I. POSITION AND QUALIFICATIONS

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

A. My name is Mark A. Moses. My business address is 1411 Third Street, Suite A, Port Huron, Michigan 48060. I am the Vice President, Chief Financial Officer and Treasurer of SEMCO Energy, Inc. ("SEMCO"). I am appearing in this proceeding on behalf of ENSTAR Natural Gas Company ("ENSTAR") and Alaska Pipeline Company ("APC") (which, for convenience, I will refer to collectively as "ENSTAR" or the "Company," unless the context clearly dictates otherwise). ENSTAR is a division of SEMCO, and APC is a subsidiary of SEMCO.

Q. Briefly describe your professional experience and educational background.

A. I graduated from Cedarville University in 1986 with a B.A. in Accounting and Business Administration. I have been employed by SEMCO since 1988. Prior to being named to my current position, I held various positions with increasing levels of responsibility in the finance, corporate development, and accounting departments within SEMCO. My years with SEMCO and the various positions that I have held have provided me with a comprehensive knowledge of SEMCO, its divisions and subsidiaries, and the regulated environment in which SEMCO operates. For example, my responsibilities in the budgeting and financial forecasting areas have provided me the opportunity to interact with SEMCO employees throughout the organization and required me to report the results to SEMCO's Board of Directors. Also, as the lead individual in the finance area, I am tasked with ensuring that SEMCO is adequately capitalized and has ample liquidity to meet both long- and short-term requirements. A copy of my resume is attached hereto as Exhibit MAM-1.

Q. Briefly describe your current professional responsibilities.

A. In my current role, my primary job responsibilities include: (1) overseeing the preparation of all SEMCO accounting records and systems, including various financial statements and reports prepared from those records; (2) monitoring SEMCO's borrowings and investments; (3) oversight of the income tax accounting and compliance team; (4) ensuring the filing of regulatory reports; (5) providing guidance in the development of accounting methods and procedures designed to provide adequate internal accounting controls; (6) ensuring that SEMCO (including ENSTAR) conducts its business in accordance with accounting standards prescribed by the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts and in conformity with Generally Accepted Accounting Principles ("GAAP"); (7) providing guidance and oversight in the preparation of financial budgets and forecasts; and (8) overseeing risk management.

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

A. Yes. I provided testimony in ENSTAR's last two rate cases, Dockets U-14-111 and U-16-066. I have provided testimony on behalf of SEMCO Energy Gas Company ("SEMCO Gas"), SEMCO's other gas distribution division located in Michigan and regulated by the Michigan Public Service Commission ("MPSC"), in MPSC Case Nos. U-16169, U-20311, U-20479, and U-21169.

II. PURPOSE OF TESTIMONY AND BACKGROUND

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to:

- describe the legal structure of SEMCO and its relationship to ENSTAR;
- describe the relationship between Washington Gas Light Company ("WGL") and ENSTAR;
- describe the nature of certain shared services SEMCO provides to ENSTAR;
- describe the nature of certain shared services provided by WGL to SEMCO and ENSTAR;
- describe how services provided by SEMCO are charged to ENSTAR;
- support the associated costs of those services to ENSTAR in satisfaction of the affiliate standards set out in statute, to the extent they apply;
- describe the methodology for allocating costs to ENSTAR for charges from WGL, AltaGas Ltd. ("AltaGas"), and AltaGas' intermediate holding company, AltaGas Services (U.S.) Inc. ("ASUS") to SEMCO for services provided for and on behalf of ENSTAR;
- sponsor the Pension Adjustment in Schedule M;
- sponsor the Removal of Acquisition Adjustment in Schedule E; and
- explain the current methodology for allocating long-term debt.

Q. Please describe the organizational and legal structure of SEMCO and its relationship to ENSTAR.

A. SEMCO is a regulated public utility company with geographically distinct divisions in both Alaska and Michigan and investments in other energy-related entities. The Alaska division of SEMCO operates as ENSTAR, and the Michigan division of SEMCO operates as SEMCO Gas. APC, as a subsidiary of SEMCO, also operates as a part of ENSTAR, but it is a separate legal entity. While SEMCO's divisions are organized as distinct parts of SEMCO's business, they are not stand-alone legal entities but a part of SEMCO, which is the legal entity under which the divisions operate. The Commission recognizes this in ENSTAR's Certificate of Public Convenience and Necessity, which is issued to "ENSTAR Natural Gas Company/A Division of SEMCO Energy, Inc." A true and correct copy is attached as Exhibit MAM-2.

Q. What is the relationship between WGL and ENSTAR?

A. WGL owns utilities serving customers in Maryland, Virginia, and the District of Columbia. WGL was acquired by AltaGas in 2018 and is indirectly owned through AltaGas' wholly-owned subsidiary, ASUS. ASUS is also the indirect owner of SEMCO, and therefore, ENSTAR.

Q. Are SEMCO and ENSTAR "affiliates" under Alaska statute?

A. No. 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 ENSTAR is a division of SEMCO, and not a distinct legal entity or person separate and apart from SEMCO, ENSTAR is not an affiliate of SEMCO under the statutory definition. As I discuss below, however, SEMCO and ENSTAR nevertheless treat the shared services provided by SEMCO in accordance with SEMCO's Affiliated Transactions Policy Manual ("ATM"), which the Commission (as well as the MPSC) has previously reviewed and approved with respect to ENSTAR's relationship with SEMCO.

Q. Are WGL and SEMCO (and therefore ENSTAR) "affiliates" under Alaska statute?

A. Yes, because of their common ownership by AltaGas indirectly through its subsidiary, ASUS.

Q. Are certain administrative functions performed by SEMCO and WGL on behalf of its divisions and subsidiaries?

A. Yes, there are certain functions that are centralized at SEMCO and WGL, and the cost of those functions is shared by all divisions and subsidiaries. At SEMCO, we refer to these centralized functions as "Shared Services." In addition, there were some de minimis costs billed from WGL in the test year to SEMCO for services related primarily to legal and consulting services. SEMCO then apportions its Shared Services costs and those from WGL using the Modified Massachusetts Formula ("MMF") to its subsidiaries and divisions.

Q. Why are these functions performed by SEMCO and WGL instead of separately by each of SEMCO's divisions or subsidiaries?

A. As a function of the corporate structure, SEMCO and WGL provide Shared Services where possible. By doing so, we can achieve economies of scale that accrue to the benefit of all customers.

Q. Does ENSTAR incur costs associated with SEMCO's and WGL's provision of these Shared Services?

A. Yes. ENSTAR receives an allocation of costs for the Shared Services provided by SEMCO and WGL.

Q. How much was the cost of the Shared Services provided by SEMCO and allocated to ENSTAR in 2021?

A. The amount of the cost allocated to ENSTAR for the Shared Services provided by SEMCO was approximately $2,522,406 during the 2021 test year.

Q. What was the cost of the Shared Services provided by WGL and allocated to ENSTAR in 2021?

A. The cost allocated to ENSTAR for the Shared Services provided by WGL was approximately $67,000 during the 2021 test year.

Q. What are the statutory requirements governing affiliate transactions in Alaska?

A. There are two statutory requirements that must be satisfied for a utility to include costs associated with affiliate transactions in rates, specifically, AS 42.05.511(c) and 42.05.441(c). True and correct copies of relevant portions of these statutes are attached hereto as Exhibit MAM-3.

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.

III. SHARED SERVICES PROVIDED BY SEMCO TO ENSTAR

A. Description of Shared Services

Q. What types of Shared Services were provided by SEMCO in the test year on behalf of, or for the benefit of, ENSTAR?

A. The Shared Services include certain functions or activities that any viable business needs, or is required, to perform. Generally, with companies of SEMCO's size, these required functions can be centralized in order to capture economies of scale and efficiencies.

Q. Can you delineate the centralized functions at SEMCO that make up the Shared Services?

A. Yes. The primary centralized functions that make up the Shared Services that SEMCO provides to ENSTAR as well as to its other divisions and subsidiaries are:

- Accounting and Tax;
- Corporate Compliance, Communications and Record Maintenance;
- Finance and Treasury;
- Information Technology ("IT") and Procurement;
- Human Resources ("HR");
- Safety and Risk Management; and
- Facilities.

Each category of service provided by SEMCO to ENSTAR is described below.

Q. Please describe the Accounting and Tax services provided to ENSTAR.

A. SEMCO prepares, on behalf of all its subsidiaries and divisions, quarterly and annual external financial reports and provides them to SEMCO's lenders and the Commission, among others. SEMCO employees also prepare and support the filing of federal, state, and local tax returns, federal payroll reporting, and federal accounts payable reporting for all its subsidiaries and divisions. It also reviews and performs analytics on the monthly financial results for all subsidiaries and divisions and prepares consolidated reports for management. These monthly financial results and consolidated reports are provided to AltaGas for preparation of AltaGas' consolidated financial statements. Further accounting services include calculating ENSTAR's asset retirement obligation, benefit plan accounting and compliance reporting, goodwill impairment testing, and income tax accounting. SEMCO also researches new accounting pronouncements and implements corresponding procedural changes. SEMCO coordinates annual external audits. SEMCO's accounting group provides application support for ENSTAR's accounting systems (accounts payable, payroll, fixed assets, general ledger, and financial reporting). Additionally, SEMCO provides Purchasing, Accounts Payable and Payroll services on behalf of ENSTAR.

Q. Please describe the Corporate Compliance, Communications and Record Maintenance services provided to ENSTAR.

A. This category includes the cost of providing corporate-wide compliance services such as corporate management, corporate filings, and costs associated with SEMCO's president, who provides oversight to all of SEMCO's divisions and subsidiaries.

Q. Please describe the Finance and Treasury services provided to ENSTAR.

A. This corporate function performs the daily cash management on a consolidated basis for SEMCO, which includes forecasting cash requirements, arranging for short-term borrowings from banks, and processing all wires and ACH payments. It also makes arrangements for and coordinates issuance of both short- and long-term debt. In addition, this function provides guidance and oversight in strategic planning and budgets and projections of revenue, costs, and profitability on a corporate-wide basis which provide management the tools to monitor financial performance. The budgets and forecasts prepared are provided to AltaGas for preparation of the consolidated annual operating and capital budgets and consolidated annual strategic plan for AltaGas. Finally, this function prepares material for and interacts with credit rating agencies.

Q. Please describe the IT and Procurement services provided to ENSTAR.

A. SEMCO provides overall support for the IT departments across all SEMCO divisions and subsidiaries. It procures computer server hardware, software licenses, and maintenance for the finance and accounting systems used by all SEMCO divisions and subsidiaries. These systems maintain electronic records and related reporting for ENSTAR's general ledger, accounts payable, fixed assets, HR, purchasing, inventory, payroll, budgeting, and reporting functions. Additionally, SEMCO provides Procurement Services to ENSTAR, ensuring that ENSTAR is getting a reasonable price on goods and services it uses in its business.

Q. Please describe the HR services provided to ENSTAR.

A. In 2021, SEMCO's HR Shared Services function administered all the benefit plans for SEMCO's employees, which include SEMCO's ENSTAR employees. These plans included health plans, flexible spending accounts, group life insurance, accidental death and dismemberment insurance, retiree medical insurance, pension plans and 401(k) plans. SEMCO also provided HR services related to audits of benefit plan changes, Affordable Care Act compliance, open enrollment services, compliance testing, and compensation reviews. Beginning in 2022, the administration of most benefit plans has been transitioned to WGL's Benefits Team on behalf of all AltaGas' employees in the U.S., but the services are still being provided and costs still being allocated to ENSTAR.

Q. Please describe the Risk Management services provided to ENSTAR.

A. This function, performed by SEMCO for all its divisions and subsidiaries, includes identifying, analyzing, and evaluating the potential loss exposures to SEMCO. The function also monitors risk control programs/procedures and financial risk transfer programs (*i.e.*, insurance) to mitigate the adverse effects of loss in the most economical way to the organization.

Q. Please describe the Facilities services provided to ENSTAR.

A. This function includes the operations and maintenance ("O&M") cost associated with SEMCO's facilities utilized by the Shared Services personnel in the performance of their functions.

Q. Are there other SEMCO-related costs that are allocated to ENSTAR besides the O&M costs associated with the Shared Services functions?

A. Yes. In addition to the O&M costs associated with the Shared Services functions, SEMCO allocates some depreciation and property and other taxes that relate to the Shared Services functions. In 2021, the amount of depreciation allocated to ENSTAR was $174,823 and the amount of property and other taxes was $105,187.

Q. Are the Shared Services provided by SEMCO consistent with the services provided by other service companies?

A. Yes. These services are common activities that are inherent in the ongoing management of a utility company and are relevant to more than a single project, division, or subsidiary within SEMCO.

Q. Has SEMCO consistently provided these Shared Services to ENSTAR over time?

A. Yes. SEMCO has consistently provided these Shared Services to ENSTAR since the Company's rate case in 2000.

Q. Does ENSTAR employ individuals directly?

A. No. Because ENSTAR is a division of SEMCO, all employees working in Alaska for ENSTAR are employees of SEMCO who are 100% dedicated to working on and for SEMCO's Alaska assets. I will refer to these individuals as "ENSTAR employees."

Q. Do ENSTAR employees also provide services similar to those provided by SEMCO?

A. Yes. ENSTAR employees provide services to support the operations of ENSTAR, but they are not the same types of services provided by SEMCO for the benefit of ENSTAR. For example, the accounting staff dedicated to ENSTAR perform day-to-day accounting tasks such as preparing financial reports for management and posting general ledger entries, while the accounting Shared Services staff maintain the general ledger itself and perform the consolidation function and financial reporting for SEMCO. The services provided by SEMCO to ENSTAR are complementary in nature to the services provided directly by ENSTAR employees and are not duplicative.

Q. Does AltaGas perform services on behalf of and for the benefit of ENSTAR?

A. Yes.

Q. Is there any duplication of costs or services provided to ENSTAR by SEMCO and those provided to ENSTAR by SEMCO's ultimate parent company, AltaGas or WGL?

A. No. There is no duplication of costs or services. As explained in the direct testimony of ENSTAR witness Ms. Jillian Fan, the Corporate Services performed for ENSTAR by

AltaGas are different in nature and purpose than the Shared Services performed by SEMCO.

B. Necessary and Consistent with the Public Interest

Q. Are the Shared Services provided by SEMCO necessary?

A. Yes. The Shared Services are common administrative services that are part of managing and operating a utility company. Many of these services focus on good business practices such as risk management, legal services, budgeting, financial and tax planning, and managing IT and HR.

Q. How do the Shared Services provided by SEMCO benefit customers?

A. ENSTAR and its customers benefit from the types of Shared Services that SEMCO provides in several ways. Consolidating these services enables cost-sharing so that each division and subsidiary of SEMCO only bears a portion of these costs and allows each division and subsidiary to leverage the experience of the Shared Services employees.

Q. Are costs to customers reduced by ENSTAR receiving Shared Services from SEMCO?

A. Yes. In particular, the consolidation of Risk Management and IT functions avoid costs that ENSTAR would bear on its own, and where there could well be cost increases.

Please refer to Section IV of my direct testimony for additional discussion of the hypothetical cost for ENSTAR to self-provide the Shared Services discussed above.

Q. Are the Shared Services provided by SEMCO to, or for the benefit of, ENSTAR in the public interest?

A. Yes. The Shared Services provided by SEMCO to ENSTAR are not only necessary for the operation of ENSTAR but the savings that result from the economies of scale derived from SEMCO's Shared Services accrue to the benefit of the customers in the form of lower rates.

IV. COST ALLOCATION AND COMPETITIVENESS

Q. How are the costs relating to the Shared Services that SEMCO provides on behalf, or for the benefit, of ENSTAR charged to ENSTAR?

A. SEMCO follows the ATM, which is regularly audited and submitted to regulators for review. The ATM is used to allocate both direct and indirect costs to SEMCO's divisions and subsidiaries for the services it provides on behalf of, and/or for the benefit of, its divisions and subsidiaries. The term "affiliate" is inapt when applied to ENSTAR because, as previously discussed, ENSTAR is not an affiliate under Alaska statute. The methodology delineated in the ATM for allocating costs associated with the Shared Services that are provided by SEMCO has been consistently accepted for many years in both Alaska and Michigan. In fact, as far back as 2000, the Commission has routinely approved SEMCO's use of the ATM as its guide for transactions with ENSTAR. Attached to my testimony as Exhibit MAM-4 is SEMCO's current ATM.

Q. Can you explain the method delineated in the ATM for the allocation of the Shared Services cost that SEMCO provides on behalf of, or for the benefit of, ENSTAR?

A. Yes. The ATM delineates a precise method of allocating both direct and indirect charges. To the extent that costs are specifically attributable to ENSTAR, those costs are charged directly to ENSTAR. For other costs that benefit ENSTAR, but which cannot be directly assigned to ENSTAR, those costs are apportioned using the MMF.

Q. Please describe the MMF.

A. The principle behind the MMF is to allocate shared expenses according to each division or subsidiary's relative share or consumption of the parent company's services. The purpose of the MMF is to assign an allocation factor ("MMF Factor") to each individual division or subsidiary, which represents their proportionate share of SEMCO's overall investment, revenue, and employees.

Q. Is this an accepted practice?

A. Yes. The MMF, or a variation thereof, is used by utilities to allocate costs before many state regulatory authorities across the country as well as before FERC. The MMF is one of the most commonly used multi-factor formulas approved by state and federal regulators.

Q. Does SEMCO charge a mark-up or profit of any kind on the cost it incurs to provide these Shared Services?

A. No. These Shared Services are provided at cost. In other words, costs associated with the Shared Services are allocated to divisions or subsidiaries with no mark-up or profit of any kind.

Q. Can you explain in more detail how the MMF was determined for ENSTAR in 2021?

A. Yes. The chart below depicts how the MMF was computed for 2021 for ENSTAR. As the chart demonstrates, ENSTAR's proportions of SEMCO's total property, gross margin, and payroll are 32.06%, 34.13%, and 43.07%, respectively. When weighted equally, ENSTAR's portion of the SEMCO Shared Services cost computes to 36.42%.

SEMCO ENERGY, INC.
2021 MMF ALLOCATION BASIS

Balances @ 12/31/20	**Total SEMCO**	**ENSTAR**
Property		
Utility Plant (Net of A/D)	$979,821,993	$283,469,806
Non-Utility Plant (Net)	$9,945,560	$2,137,836
Inventories		
Gas in Storage	$81,233,681	$52,305,718
Materials and Supplies	$16,799,485	$10,815,274
Total Property	$1,087,800,719	$348,728,634
Property Factor	100.00%	32.06%
Payroll		
2020 Wages	$63,203,192	$27,223,442
Payroll Factor	100.00%	43.07%
Gross Margin		
Gross Operating Revenue	$666,388,465	$383,414,777
Less Cost of Sales/O&M Expense	$504,820,519	$328,267,883
Total Gross Margin	$161,567,946	$55,146,894
Gross Margin Factor	100.00%	34.13%
2021 AVERAGE FACTOR	**100.00%**	**36.42%**

Q. What Shared Services costs were allocated to ENSTAR in 2021?

A. The table below identifies: (1) the total cost of the Shared Services that SEMCO provided in 2021 on behalf of and/or for the benefit of its divisions and subsidiaries; (2) the costs attributable to salaries and benefits; (3) the costs attributable to third-party vendors; (4) the costs allocated to ENSTAR; and (5) the percentage of those shared service costs allocated to ENSTAR for 2021. The table does not include certain costs from AltaGas or WGL that are allocated to ENSTAR through SEMCO.

SEMCO SHARED SERVICES COSTS ALLOCATED TO ENSTAR				
SHARED SERVICES FUNCTIONS	**2021 SEMCO TOTAL SHARED SERVICES O&M EXPENSE ($)**	**2021 SALARIES AND BENEFITS SHARED SERVICES O&M PORTION ENSTAR OF ALLOCATION ($)**	**2021 THIRD PARTY SHARED SERVICES O&M PORTION OF ENSTAR ALLOCATION ($)**	**2021 TOTAL SHARED SERVICES O&M ALLOCATION TO ENSTAR ($)**
Accounting/Tax	$1,282,281	$314,695	$152,174	$466,869
Corporate Compliance, Communications and Record Maintenance	$1,912,276	$644,052	$52,281	$696,332
Finance/Treasury	$740,723	$163,169	$106,532	$269,701
Information Technology/ Procurement	$2,499,480	$349,098	$561,010	$910,108
Human Resources	$81,105	-	$29,538	$29,538
Risk Management	$98,606	$30,384	$5,520	$35,904
Facilities	$312,928	-	$113,953	$113,953
TOTAL	$6,927,399	$1,501,397	$1,021,008	$2,522,406
AVERAGE ALLOCATION %				36.41%

Q. Has SEMCO incurred any costs for services that are not allocated to ENSTAR?

A. Yes. Some SEMCO Shared Services employees allocate some of their time directly to SEMCO's other divisions or subsidiaries based on work performed directly for that division or subsidiary. As a result, the amount of the salaries and benefits for some of SEMCO's Shared Services employees allocated through the MMF does not represent the full cost of those employees. Therefore, ENSTAR is not being allocated the full salary and benefit costs associated with some of SEMCO's Shared Services employees.

Q. Has there been any change to SEMCO's allocation methodology since the Commission approved use of the ATM in ENSTAR's rate case in 2015?

A. No. The methodology for allocating SEMCO's Shared Services is consistent with that used in 2015.

Q. What assurance does the Commission have that SEMCO is following the ATM appropriately with regard to intra-company and affiliate allocations?

A. As the Commission noted in 2000, the use of and methodology included in the ATM was approved by the MPSC. As part of that approval, the MPSC required SEMCO to conduct an internal audit of its affiliated transactions, which includes ENSTAR, every three years. Since that time, ENSTAR and SEMCO have triennially filed the internal audit report with both the MPSC and this Commission, most recently in April 2022, which covered the audit period 2019 through 2021. For reference, the most recent ATM audit report is attached as Exhibit MAM-5. These audit reports demonstrate that SEMCO's Shared Services costs are appropriately allocated pursuant to the Commission-approved mechanism.

Q. Are there other cost controls associated with the Shared Services provided by SEMCO to ENSTAR?

A. Yes. SEMCO uses the annual budgeting and monthly forecasting processes as tools to help control spending and hold local managers accountable. Additionally, employee incentive compensation is tied, in part, to meeting budgetary goals set by SEMCO. Additionally, internal auditors review controls and perform tests of transactions and balances on a periodic basis. There is also the external auditors' annual review of the books and records of SEMCO and its divisions and subsidiaries. Lastly, SEMCO, as part of a larger publicly traded company, is accountable to its ultimate parent company, AltaGas, in managing and controlling costs to meet the expectations of AltaGas' investors.

Q. How do the costs of Shared Services allocated to ENSTAR in 2021 compare to costs allocated from SEMCO to ENSTAR since 2015?

A. While costs have either increased or decreased since 2015 in the various functional areas, the costs in the aggregate have increased by approximately 4.9% on a compound average growth rate between 2015 and 2021.

Q. Has ENSTAR analyzed what the cost would be if it self-performed the Shared Services with its own personnel and capital?

A. Yes. In order to address AS 42.05.511(c) and in part AS 42.05.441(c), ENSTAR has undertaken a hypothetical analysis to determine what it would cost to self-provide the services currently provided by SEMCO, WGL, and AltaGas. This hypothetical analysis demonstrates that the cost to self-provide the suite of services is much higher than the current methodology. In this analysis, ENSTAR has included some of the known third-party costs necessary to perform the services, in addition to the additional employee compensation costs. Taking market data into consideration, as well as AltaGas and SEMCO practices with regard to employee benefits and compensation, ENSTAR estimates that it would cost approximately $7.3 million to hire additional employees to perform the services currently performed by SEMCO and AltaGas. Additionally, ENSTAR conservatively estimates that it would also incur approximately $5.8 million in third-party costs to self-provide the services currently performed by AltaGas and SEMCO on behalf of ENSTAR.

Further, this analysis only focuses on additional O&M costs that would be realized by ENSTAR if it were to self-provide these services. These costs do not include additional capital costs as well as any associated return and depreciation on the capital that would be passed on to ratepayers.

Attached to my testimony as Exhibit MAM-6 is a summary of the analysis that I co-sponsor with Ms. Fan, which depicts a hypothetical workforce and some of the associated third-party costs the Company would incur if ENSTAR were to self-provide the services currently provided by SEMCO and AltaGas.

Q. Are the charges associated with the Shared Services provided by SEMCO to ENSTAR competitive with costs that would be incurred if the services were provided by an unaffiliated third party?

A. Yes. The charges for the Shared Services are competitive with costs that would be incurred if the services were performed by an unaffiliated third party. This is demonstrated in several ways.

First, as a member of the AltaGas family of companies, SEMCO follows AltaGas' corporate philosophy of keeping all costs for its entire corporate enterprise at a competitive level with its competitors and peers. SEMCO has obligations not only to its customers, but to its ultimate parent, to keep costs associated with all activities to a reasonable level. Provision of Shared Services is just one example of where that obligation applies. As noted above, all costs for Shared Services are subject to strict budgeting processes and other cost controls that are focused on keeping costs at reasonable levels. For example, SEMCO's hiring practices are designed to competitively compensate employees performing services but are not designed to compensate employees above and beyond what market forces establish as fair and reasonable. SEMCO targets employee compensation at the 50th percentile of the industry based upon their experience and responsibilities compared to a consensus derived from multiple market data points. This ensures that SEMCO attracts, retains, and motivates a workforce that possesses the knowledge and expertise to satisfy the requirements of stakeholders, customers, and employees while keeping costs controlled.

Second, a large portion of the costs being allocated to ENSTAR are being performed by third parties and are competitive by definition. For example, SEMCO retains Gregory J. Schwartz & Co., Inc. to provide financial advice on SEMCO's defined benefit and 401(k) plans. These services are widely available and can be provided by other vendors in a competitive environment. A portion of those costs are then allocated to ENSTAR. While they are allocated through the invoicing process, they are actual costs billed by third parties.

Third, ENSTAR is only charged a fraction of the costs incurred by SEMCO for the Shared Services as described above. Recognizing that the total cost of a Shared Service could potentially be less for an organization the size of ENSTAR as compared to an organization the size of SEMCO, a large portion of the cost would be necessary regardless of the size of the company.

Fourth, any services provided by third parties to ENSTAR will likely contain profit margins, which are not charged by SEMCO. While profit margins may differ depending on the type of service provided, it is fair to say that all services would be provided by third parties at fully loaded costs, plus a profit margin.

For these and other reasons, the cost at which ENSTAR receives the Shared Services from SEMCO is competitive with the cost at which such services could be received from a third party, if such services were available.

Q. What were the costs of the services provided by AltaGas in 2021 and how were those costs allocated to ENSTAR?

A. SEMCO allocates the costs it is charged by AltaGas to its divisions and subsidiaries by utilizing the MMF methodology described above, consistent with the method SEMCO uses for allocating its Shared Services costs to its divisions and subsidiaries. In 2021, the total amount charged to SEMCO for the services provided to it by AltaGas was $5,515,803. Of that amount, ENSTAR was allocated $2,008,141 or 36.41%. This is in addition to the allocated costs from SEMCO to ENSTAR described above. These AltaGas services and resultant costs are described in greater detail in the direct testimony of Ms. Fan.

Q. Are the SEMCO Shared Services costs allocated to ENSTAR reasonable?

A. Yes. As stated earlier and as demonstrated in Exhibit MAM-6, consolidation of activities performed at SEMCO for ENSTAR and SEMCO Gas, among SEMCO's other divisions and subsidiaries, are necessary to the utility's operations and achieve economies of scale. Moreover, SEMCO provides services to ENSTAR at cost. Additionally, there have been no material changes to this methodology since the Commission approved the ATM in 2000.

V. ADJUSTMENTS

Q. Why are you proposing an adjustment for deferred taxes on Schedule E "Deferred Income Taxes" as part of ENSTAR's 275(a) filing?

A. This adjustment involves SEMCO's purchase of ENSTAR in 1999 and the purchase accounting adjustments as a result of that acquisition, specifically with regard to the treatment of deferred taxes. This adjustment removes the deferred tax impact of the purchase adjustments from the purchase in 1999.

Q. Please describe, in general, how deferred taxes are treated in setting rates.

A. Deferred tax liabilities would normally result in a reduction to rate base to pass on to customers the benefit of the utility's receipt of higher tax deductions than book deductions. Deferred tax assets would normally increase rate base.

Q. Can you summarize how ENSTAR has been accounting for certain deferred taxes that resulted from its acquisition in 1999?

A. When SEMCO acquired ENSTAR in 1999, ENSTAR recorded goodwill on its financial statements. For its tax filing, the goodwill was split into two pieces, tax goodwill and a step-up in basis on the assets acquired. SEMCO is allowed a tax deduction of this goodwill. Since 2001, under GAAP, book goodwill is no longer allowed to be amortized. The end result is a book/tax difference for which a deferred tax liability is recorded. ENSTAR was also allowed to step-up the basis of some of its assets as part of the acquisition for which a deferred tax asset was generated. For fixed assets, SEMCO identified this difference in fixed assets over the tax lives of the stepped-up assets. In this calculation, disposals were ignored, even though they would have increased the reduction of the deferred tax asset, to keep this calculation relatively simple. Deferred taxes were recognized for both state and federal purposes. The amount for the step-up in basis has been aggregated with the deferred tax liability generated by the book/tax difference for goodwill to come up with a total deferred tax adjustment for the purchase acquisitions of $13,001,077 as of December 31, 2021 as reflected on Schedule E of the 275(a) filing, Attachment B to TA334-4.

Q. How were these purchase accounting adjustments treated from a ratemaking perspective in ENSTAR's previous rate cases?

A. In those dockets, ENSTAR did not request and was not allowed to add the goodwill that was created as a result of the acquisition to rate base. The end result was that ENSTAR could not earn a return on that goodwill. Because ENSTAR could not earn a return on the goodwill, it removed the associated book/tax impact of these purchase accounting adjustments from its previous rate case filings. ENSTAR is making the same adjustment in this case. Specifically, it is making an adjustment to account for the deferred taxes that were generated as a result of the purchase adjustments.

Q. Are all of ENSTAR's deferred taxes being removed in this rate case filing?

A. No. Only the deferred taxes that remain from the acquisition adjustments recorded for ENSTAR's purchase in 1999 were removed from rate base. ENSTAR continues to record deferred taxes for various items unrelated to the goodwill recorded in 1999, and those deferred tax amounts remain on the books and are being used to determine ENSTAR's rates. ENSTAR also continues to record normal book versus tax differences on fixed assets that are not part of this acquisition-related calculation.

Q. Are you sponsoring any other adjustments?

A. Yes, I am proposing an adjustment for cost of pension expenses allocated to ENSTAR, which appears on Schedule M of ENSTAR's 275(a) filing. 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 expense as opposed to the 2021 expense. Therefore, based on the five-year average pension expense, I am proposing an adjustment in the pension expense of $1,125,775, of which $408,139 would be allocated to reimbursable construction and $717,637 would be allocated to administrative and general. This is available in Schedule M to the 275(a) filing.

Q. Why do you believe a five-year average for pension expense is more appropriate than using the test year expense?

A. As I noted above, the volatility in the underlying assumptions to compute the pension expense can have a significant impact on the expense and may not reflect what would be a normal cost associated with the pension. With the strong asset returns in 2020, the actual expense in 2021 was substantially below the average cost over the prior four years. I would also note that given the asset returns for the first half of 2022, the 2023 pension expense is likely to be much higher than the proposed average five-year adjustment. For these reasons, the five-year average is a more reasonable amount to use for the pension expense rather than the 2021 actual expense, which was an anomaly from past historical experience.

VI. LONG-TERM DEBT FINANCING

Q. Does ENSTAR finance its own long-term debt?

A. No. SEMCO finances debt on behalf of itself and all of its divisions and subsidiaries, and then allocates a portion of the debt proceeds to ENSTAR. SEMCO reviews the capital requirements of each of its divisions and subsidiaries to determine their capital requirements and the appropriate level of debt capital that should be used to finance the entity. For our regulated divisions, to a large extent, we allocate the debt based on the authorized debt in the division's approved capital structure.

Q. Has SEMCO refinanced any debt since ENSTAR's last rate case?

A. Yes. In April 2020, SEMCO refinanced $300 million of 5.15% Medium Term Notes ("MTNs") that were maturing with $450 million of First Mortgage Bonds ("FMBs") in a private placement transaction with a number of investors. The FMBs were issued in two tranches of $225 million each. SEMCO issued a 10-year tranche at 2.45% and a 30-year tranche at 3.15%, which was during a time when interest rates were at near-historic lows over the past thirty years.

Q. Why did SEMCO increase its debt by $150 million in the refinancing?

A. The increase in the debt from $300 million to the $450 million was due to the increase in plant since SEMCO issued the $300 million MTNs in April 2010, predominately in SEMCO's Michigan division.

Q. How much of the $450 million FMBs were allocated to ENSTAR?

A. For the 2021 test year, ENSTAR was allocated an amount of $153,506,000 of SEMCO debt partially for regulatory accounting purposes.

Q. What happens with the FMB debt allocated to ENSTAR if a change of control occurs?

A. ENSTAR would need to finance its own debt at current market rates, which are above the rates on the FMBs.

VII. CONCLUSION

Q. Are the costs associated with SEMCO's performance of the Shared Services for, or on behalf of, ENSTAR reasonable and necessary?

A. Yes. The Shared Services are necessary, not duplicative of other services provided to ENSTAR, beneficial to customers, and in the public interest. Further, the costs associated with the Shared Services are allocated using a widely-accepted methodology, this methodology and SEMCO activities have been audited, the costs are less than they would be if ENSTAR performed the services for itself, and the costs are competitive with what they would be if the Shared Services were provided by an unaffiliated third-party.

Q. Is ENSTAR's ratemaking adjustment for deferred taxes reasonable?

A. Yes. ENSTAR's deferred tax adjustment associated with goodwill realized from the acquisition of ENSTAR by SEMCO in 1999 should be accepted, consistent with past Commission precedent and GAAP.

Q. **Is ENSTAR's proposed pension expense adjustment reasonable?**

A**.** Yes, it is a more reasonable approach to use given the year-over-year volatility in the assumptions underlying the annual pension expense.

Q. **Is the manner in which ENSTAR receives debt financing reasonable?**

A**.** Yes, it is reasonable for ENSTAR, as a division of SEMCO, to be allocated proceeds from financing activity undertaken by SEMCO. The interest rates on the FMBs and that are included in the 2021 revenue requirement are reasonable and the bonds were issued in a low interest rate environment.

Q. Does this conclude your direct testimony?

A. Yes.

Mark A. Moses

EMPLOYMENT

SEMCO Energy, Inc. 1988 – Present

Vice President, Chief Financial Officer and Treasurer 2014 – Present

Treasurer 2009 – 2014

Director, Planning and Analysis 2001 – 2009

Director, Corporate Development 2000 - 2001

Manager, Corporate Development 1998 – 2000

Various Positions with increasing responsibility in the Finance, Treasury and Accounting departments 1988 - 1998

Women Life Issuance Company

Staff Accountant 1987

EDUCATION

Cedarville University: Bachelor of Arts, Accounting and Business Administration

OTHER

Energy Insurance Mutual – Member Representative

Regulatory Commission of Alaska

Certificate
of
Public Convenience and Necessity
No. 4

Having found that the grantee of this certificate is fit, willing, and able to provide the utility services applied for and that such services are required for the convenience and necessity of the public, the Regulatory Commission of Alaska, pursuant to the authority vested in it by AS 42.05, hereby issues this certificate of Public Convenience and Necessity to

ENSTAR NATURAL GAS COMPANY
A Division of SEMCO Energy, Inc.

authorizing it to operate a public utility, as defined by AS 42.05.990(4)(D) for the purpose of furnishing

NATURAL GAS SERVICE

This Certificate is issued under, and subject to, the provisions of AS 42.05 and all rules, regulations, and orders from time to time promulgated by the Commission governing the rates, charges, services, facilities, and practices of utility operations of the kind authorized herein.

The specific nature, scope, terms, conditions, and limitations of the authority granted by this Certificate, as amended to date, are set forth in the appendix hereto and in the following order(s) of the Commission which, by this reference, are incorporated in and made a part hereof as though fully set forth herein.

Docket No.	Date of Order
U-05-061(1)	January 13, 2006

(Chronology and service area description shown on the attached Appendix A)

*IN WITNESS THEREOF, the undersigned members of the Commission have executed this Certificate of Public Convenience and Necessity at Anchorage, Alaska on this **7th** day of **July, 2009**.*

Regulatory Commission of Alaska

(CHAIR)

(COMMISSIONER)

(COMMISSIONER)

(COMMISSIONER)

(COMMISSIONER)

Select Alaska Statutes

AS 42.05.441(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 42.05.511(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 service 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, upon the submission of satisfactory proof as to the cost to the affiliated interest of furnishing the service or property and, in part, upon the estimated cost the utility would have incurred if it furnished the service or property with its own personnel and capital.

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.

SEMCO ENERGY, INC.

AFFILIATED TRANSACTIONS POLICY MANUAL

Revised: April 30, 2007

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SECTION 1

INTRODUCTION

All companies, owned in full or in part, by **SEMCO ENERGY, INC.**, or by subsidiaries of companies owned by **SEMCO ENERGY, INC.**, or separate Utility Divisions of **SEMCO ENERGY, INC**. and including **SEMCO ENERGY, INC.**, itself, shall be called Affiliates. All Affiliates engaged in the business of local distribution of gas, as a gas utility, shall be called Utility Affiliates. All other Affiliates not directly engaged in the local distribution of gas shall be called Non-Utility Affiliates.

All transactions between and among Affiliates shall be guided by these policies. All Affiliates shall recognize the importance of these principles in protecting the customers of the Utility Affiliates from any and all disadvantages that could result from those subsidiaries affiliation with non-regulated Non-Utility Affiliates. This primary goal will be the responsibility of all Affiliates.

A. **<u>The Following General Guidelines Will Govern Transactions Among Affiliates:</u>**

1. Transactions among Affiliates will, to the extent possible, be specifically identified and directly billed.

2. To the extent that **SEMCO ENERGY, INC.** performs functions which benefit all Affiliates and which each subsidiary would have to perform individually, if not part of the **SEMCO ENERGY, INC.** system, the costs of such functions will be allocated among subsidiaries according to the Modified Massachusetts Formula. This Formula is later described in detail.

3. In all matters of transfer of services or property from a Utility Affiliate to any Non-Utility Affiliate, the transaction shall take place at the <u>greater of fair market value or fully loaded cost.</u>

4. In all matters of transfer of property from any Non-Utility Affiliate to a Utility Affiliate, that the transaction shall take place at the lower of cost or <u>fair market value.</u>

5. In all matters of transfer of services from any Non-Utility Affiliate to a Utility Affiliate, that the transaction shall take place at the lesser of fair market value or 10% over fully allocated cost.

6. In all matters of transfer of services or property from any Utility Affiliate to any other Utility Affiliate, that the transaction shall take place at the fully loaded cost or, in the case of property, net book value.

7. Each Affiliate shall recognize, subscribe to and uphold the policy set forth in Section VIII regarding Employee Transfers.

8. The Non-Utility Affiliates shall recognize that the Utility Affiliates are regulated by governmental authority that, from time to time, may request information related to Affiliate transactions. The Non-Utility Affiliates agree that they will provide, upon request, data necessary to support the transactions with the Utility Affiliates. The Utility Affiliates will similarly provide data to support transactions with other Utility Affiliates. Sufficient data will be provided to establish that all transactions were made in accordance with the above general guidelines and the specific guidelines as detailed later.

9. Nothing herein contained shall release the Officers and Directors of any of the Affiliates from the obligation to perform their respective duties, or to limit the exercise of their powers in accordance with the provisions of law or otherwise.

B. **Definitions**

Affiliate: An individual subsidiary company or division within the **SEMCO ENERGY, INC.** company structure, or **SEMCO ENERGY, INC.** itself.

Direct Cost: Direct Cost shall include the actual cost of goods and services paid. In the case of labor cost, direct cost shall be payroll cost based on the effective payroll rate.

Fair Market Value: The Consideration offered by a willing purchaser of a service or an asset in an arms length transaction, i.e. with a non-affiliated purchaser.

Fully Loaded Cost: The value at which a good or service is recorded in the transferor's accounting records. It includes all applicable direct charges, indirect charges and overheads.

Intangibles: An asset having no physical existence, its value being limited by the rights and anticipated benefits that possession confers upon the owner. Includes copyrights, patent rights, trade secrets, licenses, franchises, etc.

Net Book The original cost of an asset, reduced by applicable

Value:	valuation reserves and offsets (e.g., accumulated depreciation, deferred taxes and unamortized investment tax credits).
Non-Utility Affiliates:	**SEMCO ENERGY, INC.** and subsidiary companies that are established and operated wholly at the risk of the shareholders and not engaged in the local distribution of gas as a utility. Non-Utility Affiliate income or losses are assigned to the shareholders.
Personal Property:	Movable property or assets such as automobiles, equipment and furniture.
Real Property:	Land and land improvements, including buildings and appurtenances.
Transfers of Goods and Services:	Items of merchandise or useful work provided by one Affiliate to another.
Utility Affiliates:	Subsidiary companies or divisions that engage in local distribution of gas, perform a utility function and that may or may not be subject to regulation.

SECTION II

CORPORATE SUPPORT SERVICES - SEMCO ENERGY, INC. TO AFFILIATES

Corporate support services, provided by **SEMCO ENERGY, INC.** to Affiliates, constitute two categories: specific assignments and allocated services. To the extent possible, **SEMCO ENERGY, INC.** will specifically assign identifiable services. Those services and related expenses not specifically assignable will be allocated to Affiliates based on the Modified Massachusetts Formula (MMF).

A. **Direct Payroll and Related Expenses**

Compensation for services provided by **SEMCO ENERGY, INC.** to Affiliates shall be at the direct cost of such services. The cost of each such service shall be determined as follows:

1. Each employee of **SEMCO ENERGY, INC.** who in any month was involved in providing any service to an Affiliate, shall for that month, in accordance with Part D below, (Accounting), identify the service the Affiliate for which he or she provided such service and the time spent providing such service.

2. A payroll rate shall be computed for each such employee identified in Paragraph 1 above. The rate for salaried employees shall be based on their actual individual payroll rate. Direct cost for hourly employees will then be calculated as number of hours times the hourly payroll rate.

3. Costs associated with the items listed below will be accounted for in accordance with the provisions of Part C of this Section:

   a. All costs related to pensions, social security, vacations, absent time, unemployment compensation, health, dental and life insurance, and any other generally applicable employee benefits.

   b. All costs of office facilities and supplies which are not accounted for in Paragraph 4 below.

4. Direct Expenses

   Direct expenses associated with services provided to Affiliates shall be listed separately on the appropriate time sheet reports or fixed allocations.

B. **Direct Billed Expenses**

1. To the extent possible, all Expenses, which can be directly assignable to specific Affiliates, will be 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 **SEMCO ENERGY, INC.** and which identify specifically the cost responsibility of each Affiliate. Examples include certain outside accounting services and;

   b. Allocated direct billings are those which are received by **SEMCO ENERGY, INC.** and which are attributable to Affiliates on the basis of an allocation factor which relates to the incurring of the expense. Examples of such include incurred expenses related to property and employee benefits related to numbers of employees.

2. Billing of Direct Billed expenses as described above shall be performed in accordance to Part D, Paragraph 3, of this Section.

C. **Allocated Payroll and Expenses - Modified Massachusetts Formula**

SEMCO ENERGY, INC., as the parent company, will experience costs and expenses in performing certain activities, which would have been incurred independently by each Affiliate. Examples of such costs may include:

- Stockholder Relations and Related Services
- Financial and Accounting Services Including Statement and Tax Consolidation
- Risk Management
- Human Resources
- Purchasing
- Legal
- Corporate Communications
- Cash Management
- Corporate Strategic Management
- Internal Auditing
- External Auditing
- Board of Directors Fees
- Finance
- Planning

Payroll and expenses of this nature shall be allocated to Affiliates based on the Modified Massachusetts Formula (MMF). The MMF is comprised of an equal weighting of three components, a property factor, a payroll factor and a revenue factor.

1. Property Factor

   This factor is comprised of Net Utility Plant plus Construction Work in Progress plus Materials and Supplies Inventories and Gas Inventories for the Utility Affiliates. For the Non-Utility Affiliates, the property factor shall be composed of Net Plant plus Materials and Supplies Inventories. The property factor will be based upon year-end values.

2. Payroll Factor

   This factor is based on the most recent calendar year total salaries and wages including bonuses, if any.

3. Revenue Factor

   Net rather than Gross Revenues shall be used. For the Utility Affiliates, this is Total Gas Operating Revenue less cost of gas and operating and maintenance expenses. Cost of gas is as defined for each regulatory jurisdiction. Non-Utility Affiliates should determine net revenues as they would be calculated for income tax purposes, i.e. deducting cost of goods sold or direct operating costs.

The MMF allocation factors will be determined annually, based on the most recent calendar year's data available after books are officially closed. If new Affiliates join the **SEMCO ENERGY, INC.** system, allocation factors should be determined as if the Affiliate joining the system were in the system for the entire period covered by the calculation. These new allocation factors shall be applied on the effective date of the new Affiliate's acquisition or formation. If an Affiliate does not have operating results for any portion of the period, its share of indirect costs will be based upon financial analysis until such time as actual operating results are available.

At the time of a rate case filing by a Utility Affiliate, the then current MMF would be used.

D. **<u>Accounting for Expenditures Associated with Affiliates</u>**

The accounting for services provided by **SEMCO ENERGY, INC.** to an Affiliate are described below:

1. Reporting

Every Officer and employee of **SEMCO ENERGY, INC.** who performs a service for an Affiliate shall utilize a fixed allocation of time appropriate to the typical work performed for each Affiliate. For exceptions from the norm, each Officer and employee shall record such service on the appropriate time sheet. The time sheet shall indicate the date and the amount of time spent providing the service, a brief description of the service, the designation code identifying the Affiliate, and the Affiliate's account number to be charged.

Non-payroll charges are to be charged directly to the respective designation code and account on the appropriate source documents such as company expense bills, purchase orders, automobile allowance reports, material requisitions, invoices of third-party suppliers, etc.

2. Accounting Operations

Each month a computer-generated report will summarize the costs charged to the particular Affiliate. This report will detail both direct and allocated MMF charges.

3. Billing

Billing for the services described are to be rendered to the Utility Affiliate on a monthly basis in sufficient detail that the Utility Affiliate can fully audit the basis for and calculation of the charges.

E. Allocation of Headquarter Office Expenses

SEMCO Energy Inc. has a headquarters building which houses corporate shared services activities and Utility Affiliate activities. The Company will specifically assign identifiable expenses based on the type of activity as discussed below.

General Guidelines Governing the Allocation of Headquarters Office Expenses

1. The Company will review and determine the total square footage of the Headquarters building.

2. The Company will determine which departments are using the Headquarters and the space they are using and directly assign the square footage.

3. The square footage of the unassigned space and the common space will be assigned based on the percentages for which groups are using the assigned footage.

4. For the square footage assigned to the Utility Affiliates, it will be allocated to those affiliates based on the Modified Massachusetts formula for the particular utility, divided by the total Modified Massachusetts percentage of the Utility groups using the Headquarters combined.

5. For the floor space identified as corporate support services, it will be allocated to Affiliates by the use of the Modified Massachusetts formula.

6. Once the total percentages are calculated by items 2 through 5 above, the expenses associated with the Headquarters will be charged based on those percentages.

SECTION III

SERVICES PROVIDED - BY NON-UTILITY TO UTILITY AFFILIATES

A. **General**

There may be occasions when Non-Utility Affiliates, upon request, provide services to a Utility Affiliates. The policy for transaction price to the utility is that such services shall be recorded at the lessor of fair market value or 10% over fully allocated cost. Fair market value should be determined in accordance with the market prices for comparable services.

B. **Billing**

Each Non-Utility Affiliate providing services to a Utility Affiliate shall render a bill for these services monthly. The bill should provide sufficient detail so that the Utility Affiliate may audit the basis for the calculation of the charges in addition to the validity of the charges themselves. Bills should be sent to the Utility Affiliate's Accounting Department. Terms shall be generally consistent with those contained in Section VII of this Manual, except that there be no charge for late payment.

SECTION IV

SERVICES PROVIDED - BY UTILITY TO NON-UTILITY AFFILIATES

A. **General**

Services directly requested by a Non-Utility Affiliate are those services provided by a Utility Affiliate employee, which are performed exclusively for the benefit of the requesting Non-Utility Affiliate. These direct services differ from those identified in Section II.

Labor and expenses are identified and charged through the existing departmental function by adding a specific expense project number on the employee's bi-weekly time sheet or other payment and disbursement documents.

The Utility Affiliate's Accounting Department will bill the cost of these services to the Non-Utility Affiliates monthly.

Services provided by a Utility Affiliate to a Non-Utility Affiliate shall be at the greater of fair market value or the Utility Affiliate's fully loaded cost. Components of fully loaded cost are shown in D., below.

B. **Accounting on Time Sheets**

Labor hours for utility subsidiary activities are charged to the existing departmental function. Labor hours for services performed exclusively for the benefit of a Non-Utility Affiliate are charged to the appropriate expense project.

C. **Billing**

Billings shall be rendered by the Utility Affiliate in accordance with Section VII.

D. **Components of Fully Loaded Labor Cost**

- Wages and Salaries
- Paid Time Off
- Legally Required Payments
    - Social Security (FICA)
    - Unemployment Tax (FUTA & SUI)
    - Worker's Compensation

- Pensions and Benefits
    - Retirement Plan
    - Sick Leave
    - Stock Ownership Plan
    - Group Life Insurance
    - Health Care Plan
    - Dental Plan
    - Long-Term Disability Payments
- Vehicle Expense
- Five Percent Labor Overhead*

* The overhead of five percent on fully loaded labor cost ensures that all unidentified costs, if any, which are related to Non-Utility operations, are charged to the Non-Utility Affiliates.

SECTION V

PROPERTY SOLD - BY UTILITY TO NON-UTILITY AFFILIATES

A. **General**

The purpose of this Section is to assign a monetary value (price) and record all property, including materials and supplies, sold by Utility to Non-Utility Affiliates. These types of transactions should be considered exceptions and are expected to be kept to a minimum.

Sale of property includes tangible and intangible property used in a trade or business (Refer to Part B, Identification of Property).

Where product rights, patents, copyrights, or similar legal rights are transferred from a utility subsidiary to a Non-Utility Affiliate, a royalty payment may be required. The need for a royalty payment will be considered on a case-by-case basis.

For property sales to Non-Utility Affiliates, the following must be reported to any regulatory body, if required:

- The basis on which the cost and sale price was established for any property sold between the utility subsidiary and Non-Utility Affiliates. This is reported annually.

- Written notice within thirty (30) days prior to any sale of property between a utility subsidiary and the Non-Utility Affiliates with a value in excess of $100,000.

All property sold requires the following information:

- Identification: Identify asset as either tangible (real or personal) or intangible property.

- Valuation - The selling price of property must be at the greater of fair market value or cost.

- Recording - Each subsidiary is responsible for maintaining asset acquisition and disposition control within its own individual accounting system.

B. **Identification of Property**

1. Tangible real property includes the following: land and land improvements, including building.

2. Tangible personal property includes the following: automobiles, computer hardware, computer software or application software, furniture, materials and supplies, and power operated equipment.

3. Intangible property includes the following: copyrights, licenses, patent rights, franchises, trade secrets, mineral rights, and royalty interests.

C. **Valuation of Property**

Examples of methods that may be used to value property at current fair market value include:

- Appraisals from qualified, independent appraisers.
- Averaging bid and ask prices as published in newspapers or trade journals.
- Conducting Market Surveys.

The determination of fair market value must be adequately documented to ensure that a proper audit trail exists.

SECTION VI

PROPERTY SOLD- BY NON-UTILITY TO UTILITY AFFILIATES

A. **General**

The purpose of this Section is to define the procedures by which property which is transferred from Non-Utility Affiliates to a Utility Affiliate should be recorded on the books and records of the Utility Affiliate. Such property shall be transferred at the lesser of cost or fair market value.

B. **Procedures**

The procedures to be followed, with respect to such transfers should be identical to those found in Section V, Property Sold to Non-Utility Affiliates, with two exceptions.

1. Property transfers from a Non-Utility Affiliate to a Utility Affiliate shall not carry the MPSC reporting requirement.

2. Purchase price to be recorded by the Utility Affiliate shall be the lesser of cost or current fair market value.

C. **Billing**

Billing for property sales shall be rendered in the month of transfer. The bill shall supply sufficient detail so that the Utility Affiliate may audit the basis for the calculation of the property valuation. Bills should be sent to the Utility Affiliate. Terms shall be generally consistent with those contained in Section VII of this Manual except that there will be no charge for late payment.

SECION VII

INTERCOMPANY BILLINGS AND PAYMENTS (EXPENSES INCURRED BY UTILITY ON BEHALF OF NON-UTILITY AFFILIATES)

A. **General**

The Utility Affiliate Accounting Department will bill Non-Utility Affiliates. Invoices will be issued for the following: Corporate Support Services, services requested directly by a Non-Utility Affiliate, sale of property (tangible and intangible), sale of materials and supplies, and other reimbursable expenses, including applicable loadings.

B. **Payments**

Payments are due and payable from Non-Utility Affiliates within thirty (30) days from the date of the invoice. Invoices not paid in full within thirty (30) days will accrue interest on the unpaid portion at 1 1/2% per month.

SECTION VIII

EMPLOYEE TRANSFERS

A. General

Non-Utility Affiliates are responsible for staffing their respective organizations. From time to time, the Non-Utility Affiliates may contract with Utility Affiliates for the services of certain support personnel in those instances where it is not practical for the Affiliates to have its own staff. To avoid diversion of management talent that would adversely affect the Utility Affiliate, each such Utility Affiliate will monitor the time spent by its employees who perform work for a Non-Utility Affiliate.

B. Thirty-Percent Limit

Individual Utility Affiliate management employees are not to spend more than thirty percent (30%) of their total annual hours (2080) in providing services to a Non-Utility Affiliate. Each Utility Affiliate is responsible for reviewing labor charges to Non-Utility Affiliates. For special one-time projects, employees may be exempt from this rule.

C. Transfer of Employees

Utility Affiliate employees may accept employment with a Non-Utility Affiliate; however, they must resign from the Utility Affiliate.

D. Annual List of Employee Transfers

Each Utility Affiliate must provide the State Commission, if required, with an Annual Report identifying those management employees who transferred to a Non-Utility Affiliate.

SECTION IX

INTERCOMPANY INVESTMENTS AND ADVANCES

A. **Advances and Investments**

From time to time, each Affiliate may have "excess" cash available for short-term investment. When this is the case, such cash may be advanced to **SEMCO ENERGY, INC.** for use in connection with the general business of **SEMCO ENERGY, INC..** Such advances, considered temporary cash investments by the Affiliates, will be governed by the terms and conditions set forth in B. below.

From time to time, each Affiliate may have the necessity to borrow funds on a short-term basis for use in its business. Such borrowings shall be made from **SEMCO ENERGY, INC.** and shall be governed by the terms and conditions set forth in C. below.

B. **Advances**

1. Any Affiliate may, from time to time, offer to advance funds to **SEMCO ENERGY, INC.** for use in connection with the general business of **SEMCO ENERGY, INC.**. Each Affiliate represents that it is sufficiently credit-worthy to perform all of its obligations; that it has authority to make advances and to borrow hereunder; that such advances will not violate the terms or conditions of any credit agreement or any mortgage, indenture or other form of security agreement of such Affiliate or the provision of any statute, rule or ordinance applicable to such Affiliate; and that such advances shall be made exclusively for investment purposes. It is understood and agreed that the Affiliate making the advance shall have the right at any time to demand payment from **SEMCO ENERGY, INC.** of all or any part of the principal amount of the advance then outstanding. **SEMCO ENERGY, INC.** shall have the right, at any time, upon advice to the advancing Affiliate, to prepay, without premium, all or any part of the principal amount then outstanding.

2. Interest on the outstanding principal balance of advances made hereunder shall accrue from the date of making until the repayment thereof, on a 365-day simple interest basis, at the Repurchase Agreement under the beginning of the month rate as quoted by Michigan Bank - Port Huron. Such rate will be used in calculating interest on all advances until a new rate is obtained the next month. Advances outstanding hereunder shall bear interest on the average daily principal amount from time to time outstanding and interest shall be payable monthly within ten (10) days after the end of the month by **SEMCO ENERGY, INC.** to the advancing Affiliate.

C. Procedures for Borrowing and Repayments

1. At least 24 hours prior to making any borrowings hereunder, an Affiliate proposing to borrow shall notify the Chief Financial Officer ("CFO") of **SEMCO ENERGY, INC.**, by telephone or in person, of its intention to make such borrowing. Promptly, thereafter, the CFO or his designee shall determine whether the notifying Affiliate meets the credit standards established for intercompany advances hereunder. If such Affiliate fails to meet such standards, the CFO shall so notify the Chief Executive Officer of **SEMCO ENERGY, INC.** who shall advise the CFO whether such borrowing is approved or disapproved. Th CFO shall, in all cases, advise such party whether the proposed transaction is approved or disapproved no later than 10:00 a.m., Port Huron, Michigan time on the day the borrowing is proposed to be made. No borrowing shall be made hereunder without express authorization by the CFO.

2. When a borrowing Affiliate wishes to reduce the principal amount of its loan from **SEMCO ENERGY, INC.**, the Affiliate initiating any such transaction shall give notice by telephone or in person to the CFO no later than 11:30 a.m. Port Huron, Michigan time, on the date such reduction is to be effective. Forthwith, the borrowing Affiliate shall transfer to an account in a bank designated by **SEMCO ENERGY, INC.** the amount of principal by which the loan is to be reduced.

3. When **SEMCO ENERGY INC.** agrees to make, or increase the principal amount of, a loan hereunder to a borrowing Affiliate, **SEMCO ENERGY, INC.** shall give notice by telephone or in person to the borrowing Affiliate no later than 11:30 a.m. Port Huron, Michigan time, on the day on which such loan is to become effective. Forthwith, **SEMCO ENERGY, INC.** shall transfer to an account in a bank designated by the borrowing Company the amount of such loan or increase.

4. Interest on the outstanding principal balance of loans made hereunder shall accrue from the date of making until repayment thereof, on a 365-day simple interest basis at the rate paid by **SEMCO ENERGY, INC.** for its average line of credit as such rate exists from time to time, for loans to Utility Affiliates and at such rate plus 1/2% for loans to all other Affiliates, provided, however, that the interest rate shall be no higher than the borrowing Affiliate would pay to borrow from lenders who are not Affiliates. Loans outstanding hereunder shall bear interest on the average daily principal amount from time to time. Outstanding and interest shall be payable monthly within ten (10) days of the time the borrowing Affiliate receives an invoice from **SEMCO ENERGY, INC.**

When changes in interest rates occur it shall be the responsibility of the CFO or his designee to notify the borrowing Affiliate for the purposes of computing interest, borrowings shall be deemed to be outstanding on the date such are made but not on the date such are repaid.

D. **Long-Term Borrowings**

Long-term borrowings will be covered under separate agreements with the individual parties.

E. **Authorized Persons**

Each Affiliate shall have the responsibility of designating its Officers or other employees authorized to execute transactions hereunder, and represents that such Officers or other employees shall be duly authorized to do so

F. **Administration of the Procedures for the Investment and Advances Policy**

The procedures of the Intercompany Investment and Advances Policy shall be administered by the **SEMCO ENERGY, INC.** CFO or his designee who shall be advised by each Affiliate of its respective transactions consummated pursuant to this Policy on the date thereof and who shall keep a set of master books as a record thereof. To facilitate the efficient investment of available cash or borrowing of funds, each affiliate may designate SEMCO ENERGY, Inc. as its cash management agent.

G. **New Parties and Affiliates**

Any corporation, at least 50% of the voting stock of which is owned by an Affiliate, may participate in the Intercompany Investment and Advances Policy.

SECTION X

INTERCOMPANY TAX ALLOCATION

A. GENERAL

SEMCO ENERGY, INC., its subsidiaries and its natural gas distribution divisions shall file a consolidated federal income tax return. It is appropriate to allocate the consolidated group in a manner which reflects the contributions to and reductions in such tax liability attributable to the operation of each member. In order to accomplish this, Federal income tax liability will be allocated based upon the terms below.

B. APPORTIONING THE CONSOLIDATED FEDERAL INCOME TAX

C. LIABILITY

SEMCO ENERGY, INC. and its subsidiary corporations are members of an affiliated group of corporations within the meaning of Section 1504 of the Internal Revenue Code of 1954, as amended (the "Code"), which has elected to file consolidated Federal income tax returns pursuant to Code Section 1501. In order to establish a method of allocating its consolidated Federal income tax liability among its members in a manner which reflects the contributions to and reductions in such tax liability attributable to the operations of each member, the following procedures shall be applied:

1. **Definitions:** The following terms shall have the following meanings:

   a. "Affiliated Group" shall mean **SEMCO ENERGY, INC.** and those of its subsidiary corporations which from time to time constitute an affiliated group within the meaning of Code Section 1504. In addition, the natural gas divisions will be treated as subsidiary corporations within the content of the apportionment agreement.

   b. "Member" shall mean a corporation which is included in the Affiliated Group.

   c. "Separate Return Tax Liability" shall mean the tax liability of each member computed as if it had filed a separate Federal income tax return for the taxable period, taking into account the adjustments prescribed in subparagraphs (a) through (i) of Treas. Reg. Sect. 1.1552-1(a)(2)(ii) except that, if such computation with respect to a Member does not result in a positive amount of tax liability, such Member shall be deemed to have no Separate Return Tax Liability.

   d. "Consolidated Tax Reduction" (hereinafter referred to as "CTR") shall mean the sum of the CTRs of all Members. The CTR of each Member shall equal the excess, if any, of its Separate Return Tax Liability over that proportion of the Affiliated Group's consolidated Federal income tax liability which such Member's Separate Return Tax Liability bears to the sum of the Separate Return Tax Liabilities of all Members.

e. "Loss" shall mean

   1. For years for which the Affiliated Group incurs Federal income tax liability, the excess of a Member's deductions over income other than net Section 1201 gain, or;

   2. For years for which the Affiliated Group does not incur any Federal income tax liability, the excess of Member's deductions over income, computed in the manner used to compute its Separate Return Tax Liability.

f. Net Capital Gain or Loss" shall mean the net capital gain or loss of a Member computed in the manner used to compute its Separate Return Tax Liability.

g. "Unused Credit" shall mean the excess of the sum of the credits allowed by Section 38 and 40 of the Code earned by a Member computed without regard to the applicable limitations over the sum of such credits allowable in computing such Member's Separate Return Tax Liability.

2. **Payments with Respect to Consolidated Federal Income Tax Liability and CTR by or to Members:**
   Each Member having Separate Return Tax Liability for any taxable year (or portion thereof) to which this Agreement applies shall pay the amount of such Liability (adjusted to reflect any prior payments on account of Such Liability) to **SEMCO ENERGY, INC.** on the date on which **SEMCO ENERGY, INC.** files its quarterly consolidated Federal income tax payments for the taxable year involved or within a reasonable time thereafter, as determined by **SEMCO ENERGY, INC.** At the same time as such payments are made, or within five days thereafter, the amount of any CTR allocated to any Member pursuant to paragraph 3 or 4 shall be paid to such Member by **SEMCO ENERGY, INC.** except the CTR allocated to a Member which would otherwise pay an amount equal to it. Separate Return Tax Liability may, at **SEMCO ENERGY, INC.'** discretion, be applied to offset such Liability with only the difference between such Liability and CTR allocated to such Member being payable by or to such Member to or by **SEMCO ENERGY, INC.**

3. **Allocation of CTR**: Any CTR shall be allocated to those Members which had the Losses, Net Capital Losses or Unused Credits to which the CTR is attributable, as follows:

a. Losses:

(i) Each Member which incurs a Loss shall have allocated to it an amount of CTR equal to the product of its Loss times the applicable statutory tax rate.

(ii) If, in any year for which the Affiliated Group incurs Federal income tax liability, a Member which incurs a Loss also incurs a net Section 1201 gain, the amount of CTR allocated to such Member pursuant to paragraph 3(a)(1) shall be reduced by an amount equal to the product of such net Section 1201 gain times the applicable statutory tax rate.

b. Unused Credit:
Each Member which earned an Unused Credit shall have allocated to it an amount of CTR equal to its Unused Credit.

c. Net Capital Losses:
Each Member which incurs a Net Capital Loss shall have allocated to it an amount of CTR equal to the product of:

(i) that portion of the sum of the Net Capital Losses of all such Members, to the extent used on the Affiliated Group's consolidated Federal income tax return to offset the sum of the net capital gains of all other Members which each such Member's Net Capital Loss bears to the sum of the Net Capital Losses of all Members.

multiplied by

(ii) the applicable statutory tax rate.

4. **Special Rules for the Allocation of CTR Computed for Taxable Years in which the Amount of CTR is Less Than the Sum of the Amounts Computed Pursuant to Paragraph 3:**
Notwithstanding the provisions of paragraph 3 (a) and (b), for any taxable year (or portion thereof) to which this Agreement applies, if the amount of CTR computed pursuant to paragraph 1(d) is less than the sum of the amounts computed pursuant to paragraph 3, each Member which had a Loss or Unused Credit for such year shall be allocated that proportion of the amount of CTR remaining after deducting the amounts allocated pursuant to paragraph 3(c) which the sum of such Member's Unused Credit plus the amount allocated pursuant to paragraph 3(a) with respect to such Member for such year bears to the total of such sums with respect to all Member.

5. **<u>Allocation of Overpayments and Deficiencies</u>:**

a. If, upon audit by the Internal Revenue Service of the Affiliated Group's consolidated Federal income tax return for any taxable year (or portion thereof) to which this Agreement applies, or upon a determination by **SEMCO ENERGY, INC.**, any adjustments are made in the amount of the Affiliated Group's consolidated Federal income tax liability which result in a overpayment of or deficiency in the amount of the consolidated Federal income tax liability paid by the Affiliated Group for such year, the amount of such overpayment or deficiency shall be allocated to those members which had the items of income, deduction or credit to which such overpayment or deficiency is attributable.

b. Notwithstanding paragraph 5(a), the amount of any decrease in consolidated Federal income tax liability which results from the carryback or carryover of a consolidated net operating loss, consolidated Section 38 or 40 credit or any combination of the foregoing shall be allocated to those Members which had the Losses or Unused Credits which generated such carryback or carryover in that amount which bears the same relationship to the total amount of such decrease in consolidated Federal income tax liability as the sum of the amount calculated pursuant to paragraph 3(a) and the Unused Credit with respect to each such Member for the year in which the carryback or carryover arose bears to the total of such sums with respect to all Members.

c. Notwithstanding paragraph 5(a), the amount of any decrease consolidated Federal income tax liability which results from the carryback or carryover of a consolidated net capital loss shall be allocated to those Members which had the Net Capital Losses which generated such carryback or carryover in that amount which bears the same relationship to the total amount of such decrease in consolidated tax liability as the amount of each such Member's Net Capital Loss for the year in which the carryback or carryover arose bears to the sum of such Net Capital Losses of all Members.

d. **SEMCO ENERGY, INC.** shall refund the amount of any overpayment allocated to each member and each Member shall pay to **SEMCO ENERGY, INC.** the amount of any deficiency allocated to such Member at the time reasonably designated by **SEMCO ENERGY, INC**. Any payments required by this paragraph shall include the pro rata amount of any interest and penalties applicable to such overpayment or deficiency.

6. **Effect of Disaffiliation of a Member**:
This Policy shall apply to any Member which subsequently ceases to be a Member to the extent that such former Member's operations are included in the Affiliated Group's consolidated Federal income tax return for any taxable year (or portion thereof) to which this Policy applies.

7. **Effective Date:**
This Tax Allocation Policy shall apply to each taxable year of the Affiliated Group beginning on or after that date for which a consolidated Federal income tax return is filed.

Affiliated Transactions Review

For the period 1/1/2019 – 12/31/2021

Distribution:
Colleen Starring, President SEMCO Energy Gas Company Division
John Sims, President ENSTAR Natural Gas Company Division
Mark Moses, Vice President of Finance, Chief Financial Officer, and Treasurer
Tracy Vincent, Controller
Jennifer Dennis, Director of Regulatory Affairs of SEMCO Energy Gas Company Division

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March 28, 2022

Tracy Vincent
Controller
SEMCO Energy, Inc.
1411 Third Street, Suite A
Port Huron, MI 48060

Dear Ms. Vincent:

We have provided Internal Audit ("IA") Services related to the Affiliated Transactions Review for SEMCO Energy, Inc. ("SEMCO" or the "Company"). Our services were performed from February 21, 2022, to March 30, 2022, in accordance with the applicable terms of our engagement letter ("EL") dated February 18, 2022, and the *Statement on Standards for Consulting Services* as issued by the American Institute of Certified Public Accountants ("AICPA").

The accompanying pages of our report include the following sections:

- Background, Objective and Scope
- Results
- Appendix A - C

This report is intended solely for the information and use of management and the Board of Directors and is not intended to be and should not be used by anyone other than these specified parties. The Company's external auditors and regulators (specifically, the Michigan Public Service Commission ("MPSC") and the Regulatory Commission of Alaska ("RCA")) may be provided with a copy of this report in connection with fulfilling their respective responsibilities.

Yours truly,
Deloitte & Touche LLP

By: ______________________

CJ Brennan
Partner

Table of Contents

SECTION I: BACKGROUND, OBJECTIVE AND SCOPE

An affiliated transaction review of SEMCO Energy, Inc. ("SEMCO" or the "Company") is conducted every three years in accordance with the Michigan Public Service Commission ("MPSC" or "Commission"') Case No. U-20822. The MPSC authorizes the rates charged to all the Company's Michigan gas utility customers. The prior affiliated transaction inspection was conducted in February of 2019 and covered the period January 1, 2016, through December 31, 2018.

IA consulting services were performed that reviewed the MPSC Guidelines for Transactions between Affiliates ("Guidelines") and the specific policies and procedures that SEMCO Management implemented to support compliance with the Guidelines. A work plan was prepared that included tests specific to each Guideline. The procedures performed included interviews, observations, and inspection of documentation; refer to ***Appendix C*** for a summary of these procedures.

This report contains the findings, conclusions, and recommendations resulting from the review of SEMCO's compliance with the Guidelines, as it relates to transactions between SEMCO Energy Gas ("SEMCO Gas"), a division of SEMCO Energy, Inc. and SEMCO's regulated and non-regulated affiliates. A timeline showing all companies that were affiliated with SEMCO during the period January 1, 2019 through December 31, 2021 (the "review period") is included as ***Appendix A***.

The objective of this review was to ascertain SEMCO's compliance with the Guidelines, as amended and adopted by the Commission. Refer to ***Appendix B*** for a complete listing of the guidelines issued by the Commission.

SECTION II: RESULTS

Status of Prior Findings:
No exceptions were noted during the prior review, conducted in 2019, that required remediation action(s) by SEMCO Management.

Procedures and Findings:
For current reporting results and a description of the procedures performed, refer to ***Appendix C***. No exceptions were noted during the review.

Note: *Guidelines 1 through 10: Refer to* ***Appendix B*** *for a full listing of the Guidelines.*

APPENDIX A: SEMCO ENERGY GAS AFFILIATED COMPANIES

1/1/2019 – 12/31/2021

Affiliate	Products/Services provided to/from regulated utility	Assignment/ Allocation Methodology	Date Acquired /Formed	Company Number
SEMCO Holding Corporation	None	N/A	2012	0
SEMCO Energy, Inc.	Holding company that provides shared services such as Corporate Communications, Legal, Accounting, Finance	Direct charge or indirect allocation using the MMF	1977	1
SEMCO Energy Ventures, Inc	None	N/A	1986	2
Alaska Pipeline Company	None	N/A	1977	10
Hotflame Gas, Inc.	None - Maybe transfer of asset	N/A	1998	05
SEMCO-CINGSA Storage Company	Natural Gas Storage facility in Alaska provides service to ENSTAR.	Direct charge	2010	06
Alaska Storage Holding Company, LLC	None	N/A	2010	07
Cook Inlet Natural Gas Storage Alaska, LLC	None	N/A	2010	08
SEMCO Pipeline Company	Utility provides operation and maintenance services on the Greenwood Pipeline	Direct charge based on contract	1989	03
SEMCO Gas Storage	Utility leases gas storage	Direct charge based on contract	1989	04
NORSTAR Pipeline Company, Inc	None	N/A	2001	11

APPENDIX B: MPSC GUIDELINES FOR TRANSACTIONS BETWEEN AFFILIATES

Guideline	Guidance
1.	The utility shall ensure that the Commission has access to books and records of the holding company and each of its affiliates and their joint ventures. Any objections to providing access as requested under this guideline must be raised before the Commission, and the burden of showing that the request is unreasonable or unrelated to the proceeding is on the party seeking to deny or withhold access.
2.	Each utility, holding company and its subsidiaries and the joint ventures of the holding company and or its subsidiaries shall employ accounting and other procedures and controls related to cost allocations and transfer pricing to ensure and facilitate full review by the Commission and to protect against cross-subsidization of non-utility activities by the utility’s customers.
3.	The holding company and each of its subsidiaries and the joint ventures of the holding company and or its subsidiaries shall keep their books in a manner consistent with generally accepted accounting principles (i.e., GAAP) and, where applicable, consistent with the Uniform System of Accounts.
4.	The utility shall furnish the Commission with: • Consolidated 10K reports and shareholders’ reports of the consolidated utility and/or its parent company on an annual basis. • Annual reports concerning the utility's intercompany transactions. The report shall provide a specific explanation of the nature of each transaction and a specific description of the basis for the cost allocations and transfer pricing established in each transaction. • Annual balance sheets and income statements of the non-regulated subsidiaries of the utility and/or the non-consolidated subsidiaries of the parent company. • Reports of internal audits conducted regarding transactions between the utility and its non-utility affiliates, which shall be submitted with the annual report for the year 2000 and with subsequent annual reports due at the end of each third year following 2000. The audit report shall address transactions occurring since the last audit report and shall determine whether appropriate cost allocation procedures and transfer pricing methods were followed and whether the utility and its affiliates are maintaining records that are adequate to facilitate an effective audit of the transactions. The Commission staff may require more frequent reports or conduct additional audits where appropriate. • Copies of Federal income tax returns, whether on a consolidated or non- consolidated basis, need not be submitted to the Commission, but they shall be available to the Commission for inspection and review at the utility's Michigan business office.
5.	The utility shall avoid a diversion of management talent that would adversely affect the utility. An annual report identifying personnel transferred from the utility to non-utility subsidiaries is required. The report shall provide the name of each employee the employee's former function or department within the utility, and the function or department of the subsidiary to which the employee was transferred.
6.	The utility shall notify the Commission in writing within thirty days prior to any transfer to non-utility affiliates of any utility assets or property exceeding a market value of $100,000. At the time that notice is provided, the utility shall make available to the Commission information that demonstrates how the transfer price was determined. Asset transfers from regulated to non-regulated shall be at the higher of cost or fair market value and non-regulated to regulated shall be at the lower of cost or fair market value. All services and supplies provided by non-regulated enterprises shall be at market price or 10% over the fully allocated cost, whichever is less.
7.	Market, technological or other similar data transferred, directly or indirectly, from the utility to a non-utility affiliate shall be transferred at a higher of cost or fair market value.

Guideline	Guidance
8.	In its Annual Report, each utility shall provide information on any arrangement that allows an affiliate to obtain credit in a manner that permits a creditor, upon default, to have recourse to or in any way encumber the utility's assets.
9.	A utility may file an application for a waiver from any provision of these guidelines. The application shall demonstrate the basis for the waiver. The Commission, in deciding the application, may consider the costs and benefits of compliance. For good cause shown, the Commission may grant the waiver if compliance is determined to be impractical or unreasonable under the circumstances.
10.	For purposes of applying these guidelines, "affiliate - and "subsidiary" shall have the same meanings as the definitions provided for "associated companies, " and "subsidiary company, " respectively, in the Uniform System of Accounts for gas and electric utilities, which are adopted by Commission rule. Other words in the Uniform System of Accounts that are used in the definitions of "associated companies," and "subsidiary company." (e.g., "control') shall also retain their defined meanings (See R 460-9001, R 460.90211).

APPENDIX C: PROCEDURES AND FINDINGS

Guideline One

The utility shall ensure that the Commission has access to books and records of the holding company and each of its affiliates and their joint ventures. Any objections to providing access as requested under this guideline must be raised before the Commission, and the burden of showing that the request is unreasonable or unrelated to the proceeding is on the party seeking to deny or withhold access.

Work Performed

SEMCO Management was interviewed to identify any requests received during the three-year review period (2019 – 2021). The format of the requests, which members of Management were contacted, and how SEMCO responded to the Commission was discussed:

- Many MPSC requests were directed to the Director of Regulatory Affairs or to the Controller. Management indicated that all requests for information, including the required filings, were completed by the due dates required by the Commission.
- Communication directed to the Controller is generally financial in nature.
- MPSC was interviewed to corroborate Management's assertions during the three-year review period. It was concluded that no Commission requests for information were denied or remain outstanding during the period under review (2019 – 2021).

Findings

No exceptions were noted.

Guideline Two

Each utility, holding company and its subsidiaries, and the joint ventures of the holding company and or its subsidiaries shall employ accounting and other procedures and controls related to cost allocations and transfer pricing to ensure and facilitate full review by the Commission and to protect against cross-subsidization of non-utility activities by the utility's customers.

Work Performed

A reconciliation was completed between the Affiliated Transactions Policy Manual and the MPSC Guidelines. There were not any discrepancies noted.

Management allocates indirect expenses such as taxes, benefits, and salaries of parent company employees using the Modified Massachusetts Formula (MMF). SEMCO's formula averages the percentage of property held, wages paid, and gross margin of each company under the parent and uses the resulting percentage to allocate indirect costs to those subsidiaries. The indirect allocation calculations for 2019, 2020, and 2021 were obtained and the following procedures were performed:

- Compared the summary sheet detail to certain supporting documents (e.g., consolidating balance sheet, income statement, and payroll records) for the three components of the formula for all the affiliate companies.
- For a sub-selection of balances in the summary sheet detail, compared the supporting documents used in tying out the MMF to the system of record JD Edwards ("JDE").
- Footed and cross-footed the detail of each year's allocation formula summary sheet.
- Recalculated the allocation factors used to allocate donations, government affairs, and human resources expenses for each of the three years. ENSTAR, the Alaska-based Local Distribution Company ("LDC"), maintains its own human resources functions and was therefore not allocated for any such shared services from the parent.

- Obtained and inspected the 2019 – 2021 MMF calculation to verify it was reviewed by the Controller.

A listing of SEMCO Affiliate companies was obtained and inspected to identify the general ledger accounts in which affiliate transactions were recorded by SEMCO. Subsequently, the sub-ledger intercompany account activity was obtained and tied the detail to the information reported by SEMCO to the MPSC in the MPSC Annual Reports. A sample of transactions was then obtained and categorized by classifying transactions[2] into one of the following categories, including a description of the nature of testing performed:

Payroll transactions including complete transfers, time allocations, and overhead allocations;

- Obtained supporting documentation for each selected transaction, such as the Payroll Proof Journal / Edit Report, to validate the allocation was appropriate and correctly calculated.

Asset transactions including transfers, reclassifications or expirations;

- Obtained and inspected work orders, including relevant explanations, or supporting documentation, for the transaction to validate that it was an appropriate allocation.

Indirect allocations between affiliates (in accordance with MMF allocation formula), or;

- Selected multiple months from each year under review and recalculated the percentage used to allocate overhead to the SEMCO policy. The detail of the allocation was recalculated to the final journal entry. Finally, this detail was agreed to the overhead allocation calculation.
- Recalculated allocations of indirect expenses using the MMF and tested multiple allocations from each of the three years under review.

Direct expenses which are affected through intercompany accounts reflecting affiliate transactions;

- For the selected samples, obtained and inspected direct labor charges from each of the three years under review, including the Payroll Proof Journal/Edit Report, and reconciled the selected items to the general ledger entry without exception.
- Tested direct expense transactions including payroll disbursements, payroll deductions, and other intercompany charges (e.g. settlement). We obtained supporting documentation to consider the appropriateness of the charges.

Services provided by utility affiliates to non-utility

- Work orders and other documentation examined including the Transaction listing supported the cost basis and management approval.

Using the intercompany transaction listing, 25 transactions were judgmentally selected for the period under review.

- Selected 8 transactions from the Intercompany Account Detail report for the year ended December 31, 2019. These selections are categorized as follows:

Year	Transaction Type	No of Selections
2019	Asset Transaction	**1**
	Dir Exp Utility to Non-Utility	**2**
	Direct Expense	**3**
	Indirect Allocations	**1**
	Payroll Transaction	**1**
Total		**8**

[2] D&T classified transactions and used the classifications as a mechanism to help ensure coverage of the various types of intercompany transactions.

- Selected 9 transactions from the Intercompany Account Detail report for the year ended December 31, 2020. These selections are categorized as follows:

Year	Transaction Type	No of Selections
2020	Asset Transaction	**0**
	Dir Exp Utility to Non-Utility	**0**
	Direct Expense	**0**
	Indirect Allocations	**0**
	Payroll Transaction	**9**
2020 Total		**9**

- Selected 8 transactions from the Intercompany Account Detail report for the year ended December 31, 2021. These selections are categorized as follows:

Year	Transaction Type	No of Selections
2021	Asset Transaction	**0**
	Dir Exp Utility to Non-Utility	**1**
	Direct Expense	**2**
	Indirect Allocations	**2**
	Payroll Transaction	**3**
2021 Total		**8**

Findings

No exceptions were noted.

Guideline Three

The holding company and each of its subsidiaries and the joint ventures of the holding company and or its subsidiaries shall keep their books in a manner consistent with *generally accepted accounting principles (i.e. GAAP) and, where applicable, consistent with the Uniform System of Accounts.*

Work Performed

The accounting principles and accounting structure were discussed with SEMCO Management for the years 2019, 2020, and 2021. The MPSC Uniform System of Accounts was inspected and SEMCO's Annual Reports for 2019, 2020, and 2021[3] were reviewed to validate:

- Management disclosed no significant issues or deviations from GAAP. Management indicated the Company would follow GAAP unless the MPSC provides specific accounting instructions through an accounting order to treat an item differently.
- There were not any deviations identified from GAAP in the Annual Reports.
- There were not any instances of non-compliance with the MPSC Uniform System of Accounts identified during the procedures.

Findings

No exceptions were noted.

[3] The 2021 Annual Report received from management was the final report, but at the time of testing it had not been submitted to the MPSC. Fieldwork occurred in March and the report is due to the Commission at the end of April.

Guideline Four

The utility shall furnish the Commission with:

- *Consolidated 10K reports and shareholders' reports of the consolidated utility and/or its parent company on an annual basis.*
- *Annual reports concerning the utility's intercompany transactions. The report shall provide a specific explanation of the nature of each transaction and a specific description of the basis for the cost allocations and transfer pricing established in each transaction.*
- *Annual balance sheets and income statements of the non-regulated subsidiaries of the utility and/or the non-consolidated subsidiaries of the parent company.*
- *Reports of internal audits conducted regarding transactions between the utility and its non-utility affiliates, which shall be submitted with the annual report for the year 2000 and with subsequent annual reports due at the end of each third year following 2000. The audit report shall address transactions occurring since the last audit report and shall determine whether appropriate cost allocation procedures and transfer pricing methods were followed and whether the utility and its affiliates are maintaining records that are adequate to facilitate an effective audit of the transactions. The Commission staff may require more frequent reports or conduct additional audits where appropriate;*
- *Copies of Federal income tax returns, whether on a consolidated or non-consolidated basis, need not be submitted to the Commission, but they shall be available to the Commission for inspection and review at the utility's Michigan business office.*

Work Performed

Management was interviewed to determine whether the required filings had been prepared and submitted timely, including the MPSC Annual Report and Transactions between Affiliates Reports for 2019 and 2020, which were provided to the MPSC. The reports for 2021 were not yet due to the Commission as of the time of our fieldwork. We noted the following:

- Management indicated the filings specified in Guideline Four were prepared and submitted to the MPSC, as required during the periods under review (2019 – 2020).
- We contacted the MPSC to corroborate management's assertions that all filings specific to Guideline Four were prepared and submitted to the MPSC as required during 2019 and 2020. Additionally, based on the procedures performed and interviews with SEMCO Management, it was concluded that all filings were submitted to the MPSC as required during 2019 and 2020.
- The 2021 draft report was inspected, and it appeared the Company is on track to submit the reports on time.
- Transactions between affiliates referenced in the MPSC filings were reconciled during our testing to the Intercompany Account Detail from the general ledger.

Findings

No exceptions were noted.

Guideline Five

The utility shall avoid a diversion of management talent that would adversely affect the utility. An annual report identifying personnel transferred from the utility to non-utility subsidiaries is required. The report shall provide the name of each employee the employee's former function or department within the utility, and the function or department of the subsidiary to which the employee was transferred.

Work Performed

The Transactions between Affiliates Report submitted to the MPSC were obtained and inspected to determine the nature and extent of employee transfers that took place during 2019, 2020, and 2021.

- In 2019, there were two transfers. Both transfers were from (Co.2) to (Co.1). One transfer consisted of a non-management role, thus Guideline 5 did not apply. Through inquiry, the other transfer did not adversely impact the utility, as the individual was always apart of (Co.1).

- In 2020, there were two transfers. One transfer from (Co.4) to (Co.1). One transfer from (Co. 2) to (Co. 25). None of the transfers were relevant to Guideline Five, as both transfers were either to a Utility or non-management roles. Guideline Five applies to transfers to Non-Utility and management role transfers.

- In 2021, there was one transfer: from (Co.2) to (Co.1). The transfer was relevant to Guideline Five, as the individual transferred from (Co.2) to (Co.1) Non-Utility. Through inquiry, it was validated that transfer from MPSC to Parent Non-Utility did not adversely impact the utility, as the individual is still in charge of overseeing accounts payable.

At the time of fieldwork, the 2021 Transactions Between Affiliates Report was not finalized. However, the Affiliated Transaction Reports - Employee Transfers was obtained, which included employees who transferred from 2019 – to 2021. Through inspection, it was validated that two employees transferred from a utility to a non-utility subsidiary during the period under review, as noted above.

Findings

No exceptions were noted.

Guideline Six

The utility shall notify, the Commission in writing within thirty days prior to any transfer to non-utility affiliates of any utility assets or property exceeding a market value of $100,000. At the time the notice is provided, the utility shall make available to the Commission information that demonstrates how the transfer price was determined. Asset transfers from regulated to non-regulated shall beat the higher of cost or fair market value and non-regulated to regulated shall be at the lower of cost or fair market value. All services and supplies provided by non-regulated enterprises shall beat market price or 10% over fully allocated cost, whichever is less.

Work Performed

The "Consolidated Property Rollforward" schedules were obtained and inspected to identify asset transfers between affiliates during the periods under review (2019 – 2021). Additionally, SEMCO Management was interviewed to identify whether transfers from the utility to a non-utility occurred, and if there were any, did they exceed a market value of $100,000.

- Management indicated there were no transfers exceeding $100,000 during the three years under review.
- The Consolidated Property Rollforward schedules were inspected and no transfers exceeding $100,000, were identified which supports Management's assertion. During the interviews with Management, it was noted most of the activity between companies appeared to be associated with moving Construction Work in Progress (CWIP) to fixed assets.
- The Intercompany Transactions Detail for document types "AT" (asset transfer) were reviewed and it was validated that there were not any asset transfers to non-utility affiliates over $100,000.

Findings

No exceptions were noted.

Guideline Seven

Market, technological or other similar data transferred, directly or indirectly, from the utility to a non-utility affiliate shall be transferred at the higher of cost or fair market value.

Work Performed

Through interviews with SEMCO Management, it was noted that no market, technical, or similar data transfers from the utility to a non-utility took place during the periods under review (2019 – 2021). Additionally, the intercompany account activity from the general ledger was reviewed to identify market, technical or similar data transfers from the utility to a non-utility that took place during the review period. No data transfers were identified through the procedures.

Findings

No exceptions were noted.

Guideline Eight

In its Annual Report, each utility shall provide information on any arrangement that allows an affiliate to obtain credit in a manner that permits a creditor, upon default, to have recourse to or in any way encumber the utility's assets.

Work Performed

Management described that the borrowing agreements prohibit sub-companies from entering into the credit agreements described in Guideline Eight.

Further, the Annual Reports were inspected for the years of 2019, 2020, and 2021, and there were not any agreements relevant to Guideline Eight identified. The individual borrowing agreements, as well as a diagram depicting the financing and borrowing agreements in place for SEMCO, were obtained and inspected, further supporting Management's assertions that:

- No assets of SEMCO's utility business were pledged as security to any non-utility affiliate creditors.
- The non-utility affiliates are precluded, per SEMCO's internal policy (SEMCO's Treasury Policies and Procedures), from entering into their own credit agreements, including any which would possibly encumber SEMCO's assets.
- No such arrangements were identified in our review.

Findings

No exceptions were noted.

Guideline Nine

A utility may file an application for a waiver from any provision of these guidelines. The application shall demonstrate the basis for the waiver. The Commission, in deciding the application, may consider the costs and benefits of compliance. For good cause shown, the Commission may grant the waiver if compliance is determined to be impractical or unreasonable under the circumstances.

Work Performed

Management indicated, through interviews, that there were no formal waiver applications filed with the Commission during the periods under review (2019 - 2021). Additionally, the MPSC contact was interviewed and was unaware of any formal applications.

Findings

No exceptions were noted.

Guideline Ten

For purposes of applying these guidelines, "affiliate - and "subsidiary" shall have the same meanings as the definitions provided for "associated companies," and "subsidiary company," respectively, in the Uniform System of Accounts for gas and electric utilities, which are adopted by Commission rule. Other words in the Uniform System of Accounts that are used in the definitions of "associated companies," and "subsidiary company" (e.g., "control') shall also retain their defined meanings (See R 460-9001, R 460.9021)

Work Performed

SEMCO's Affiliate Transactions Policy Manual was obtained, and the terms "affiliate" and "subsidiary" were reviewed and compared to the definition within the Uniform System of Accounts. No material differences were noted between the use of the terms "affiliate" and "subsidiary" as identified in Guideline Ten.

Findings

No exceptions were noted.

Summary of Costs to ENSTAR to Perform All Corporate and Shared Services Activities

ENSTAR's Cost for AltaGas Corporate and SEMCO Energy Shared Services Expenses			
Shared Services Function	**SALARIES & BENEFITS**	**THIRD PARTY & OTHER EXPENSE**	**TOTAL**
Board of directors	$ -	$ 55,002	$ 55,002
Executive Management	267,676	10,863	278,539
Accounting / Tax	620,265	250,427	870,692
Corporate Compliance & Communications & Records Maintenance	965,122	119,445	1,084,567
Finance / Treasury	268,777	248,831	517,609
Information Technology / Procurement	428,854	994,751	1,423,605
Human Resources	52,815	97,859	150,674
Safety & Risk	30,384	5,520	35,904
Facilities	-	113,953	113,953
TOTAL	**$ 2,633,894**	**$ 1,896,652**	**$ 4,530,546**

Estimated ENSTAR Cost if AltaGas Corporate and SEMCO Energy Shared Services Activities Were Performed Directly by ENSTAR				
Shared Services Function	**FTE REQUIRED**	**SALARIES & BENEFITS**	**THIRD PARTY & OTHER EXPENSE**	**TOTAL**
Board of directors		$ -	$ 1,477,627	$ 1,477,627
Executive Management	2	3,460,058	140,419	3,600,477
Accounting / Tax	5	816,322	450,000	1,266,322
Corporate Compliance & Communications & Records Maintenance	2	439,118	332,281	771,399
Finance / Treasury	4	1,063,383	1,500,066	2,563,449
Information Technology / Procurement (1)	5	869,042	1,103,469	1,972,511
Human Resources	3	455,602	29,538	485,140
Safety & Risk	1	198,062	629,627	827,689
Facilities (2)		-	113,953	113,953
TOTAL (1), (2), (3)	**22**	**$ 7,301,587**	**$ 5,776,979**	**$ 13,078,566**

(1) In addition to the O&M items identified in the ENSTAR standalone costs, ENSTAR would be required to implement some systems/hardware (ERP, Cybersecurity, etc.) currently provided by SEMCO Energy, which would result in additional O&M expenses and/or capital expenditures necessary to provide the company with the support currently provided via shared solutions.

(2) This analysis does not include any requisite incremental capital or expense costs (O&M, depreciation and property taxes) specifically related to the additional 22 FTEs.

(3) Since ENSTAR is a division of SEMCO Energy, Inc. and not a legal entity, this analysis is hypothetical and represents a conservative estimate of the costs ENSTAR would bear to perform the activities currently provided by AltaGas Ltd. and SEMCO Energy Inc. on its behalf.