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

April 18, 2025

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

Subject: Tariff Advice Letter TA353-4, Formula Rate Mechanism

Dear Commissioners:

ENSTAR Natural Gas Company, LLC ("ENSTAR" or "Company")[1] transmits this filing in compliance with the Alaska Public Utilities Regulatory Act (AS 42.05) and Sections 3 AAC 48.200 - 3 AAC 48.430 of the Alaska Administrative Code:

Tariff Sheets

Tariff Sheet Number	Revision	Cancels Sheet Number	Revision	Schedule or Rule Number
7	First	7	Original	Index
306	First	306	Original	Section 2800
307	First	307	Original	Section 2800
308	First	308	Original	Section 2800
309	First	309	Original	Section 2800
310	First	310	Original	Section 2800
311	First	311	Original	Section 2800
312	First	312	Original	Section 2800
313	First	313	Original	Section 2800
314	First	314	Original	Section 2800
315	First	315	Original	Section 2800
316	First	316	Original	Section 2800
317	Original	317		Section 2800
318	Original	318		Section 2800
319	Original	319		Section 2800

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

ENSTAR requests approval from the Regulatory Commission of Alaska ("RCA" or "Commission") to implement a formula rate mechanism ("FRM") provision in its tariff. This provision will adjust the rates on an annual basis, similar to Cook Inlet Natural Gas Storage Alaska, LLC's ("CINGSA") currently effective FRM, for all ENSTAR gas sales and transport customers. ENSTAR currently provides service to approximately 155,000 customers.

The proposed FRM will allow ENSTAR to adjust its base rates annually by calculating rate adjustments using actual historical costs and revenues to reflect more accurately the cost of providing the service to its customers. The rate adjustments will be based on a pre-established formula, which accounts for specific cost and billing unit inputs. Similar approaches are already in effect for other Alaska utilities and have been utilized by this Commission for years to help mitigate the adverse financial impacts of operating in Alaska for the benefit of customers and utilities.

I. BACKGROUND

In Order U-18-043(15), the Commission directed CINGSA to propose a formula rate mechanism, recognizing that CINGSA and its customers could benefit from the stability of formula rates. Acknowledging the value formula rates bring to CINGSA and its customers, ENSTAR seeks Commission approval to bring similar stability to its customers and itself.

In preparing its proposal, ENSTAR reviewed CINGSA's FRM, the Commission's Simplified Rate Filing ("SRF") Procedures for Electric Cooperatives (3 AAC 48.700-790), Simplified Pipeline Tariffs regulations (3 AAC 48.450-490), and other instances of the use of formula rates in Alaska. In drafting the provision, ENSTAR used language and concepts from CINGSA's Commission approved FRM and the Commission's SRF regulations.

II. OVERVIEW OF PROPOSED REVISION

The proposed FRM provision provides for an annual revision ("FRMAR") to the Company's gas sales and transport Rate Schedules (Sections 2000, 2100, and 2200) that takes into account changes to ENSTAR's rate base (including the effects of depreciation), changes in expenses, and changes in billing units. Each FRMAR will be filed as a separate tariff advice letter (Section 2801a, Sheet 307). It is based upon data, with certain adjustments, from the preceding calendar year, referred to as the Test Year (Section 2801a, Sheet 307 and Section 2802a(12), Sheet 308).

The FRM provides that ENSTAR shall calculate an annual revenue requirement ("RR") that will adjust applicable rate schedules prospectively. In its annual filing the Company will request recovery of its total RR and provide all required schedules showing the computation of any adjustments (Section 2803a, Sheet 309). The annual RR shall be calculated according to the following formula:

$$RR = OM + DEP + OT + RI + IT$$

Where:

OM = all prudently incurred, reasonable and necessary operation and maintenance expenses and gas cost incurred during the Test Year adjusted for known and measurable changes and prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case (Section 2803b, Sheet 309).

DEP = depreciation and amortization expense is calculated on end of Test Year actual plant and asset balances at the depreciation and amortization rates utilized in calculating the tariff rates accepted and approved in Order U-22-081(15) or approved, accepted or utilized in calculating the tariff rates approved in a subsequent Concluded General Rate Case. The amortization related to regulatory assets shall be included in DEP upon approval or acceptance by the Commission (Section 2803c, Sheet 311).

OT = taxes other than income tax from the Test Year adjusted for known and measurable changes, and prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case (Section 2803d, Sheet 311).

RI = return on prudently incurred investment calculated as the Company's return (weighted average cost of capital) multiplied by the Test Year rate base (Section 2803e, Sheet 311).

- Rate of return shall be the weighted average cost of capital approved or accepted in the Company's last Concluded General Rate Case.

- Rate base shall be calculated using year-end values of the applicable accounts.

IT = income tax for the adjusted Test Year, adjusted for known and measurable changes occurring after the Test Year and before the Filing Date, and prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case (Section 2803f, Sheet 313).

Once the annual RR has been determined, it shall be adjusted by normalized gas cost, then allocated between the rate classes, and then between customer, capacity, and commodity costs using the same cost classification and allocation methodologies that were approved or accepted in the Company's last Concluded General Rate Case (Section 2803g, Sheet 314). Rates for the Company's Rate Schedules found in Sections 2000, 2100 and 2200 shall be calculated from the RR consistent with the rate derivation methodologies approved or accepted in the Company's last

Concluded General Rate Case. The billing units used will be actual billing units for the Test Year, modified for the normalizing adjustments (Section 2803h, Sheet 314).

The provision provides that the FRMAR filling shall include Schedules of Test Year Normalized Operating Revenues and Expenses, Rate Base, Weighted Cost of Capital, and Normalized Test Year Revenue Requirement in a similar format as the first four pages of the Company's 275(a) schedules, and its Cost Allocation by Customer Class, Allocation Factors, and Rate Design as provided in Docket U-22-081 and its most recent rate case filed in TA352-4. It shall also include a schedule and explanation of all normalizing, pro forma, annualizing and known and measurable change adjustments (Section 2804, Sheet 315).

A copy of the FRMAR filing will be provided to Commission Staff ("Staff") and the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section ("RAPA") at the time it is filed with the Commission, along with any Excel workbooks with working formulas used to create the schedules, exhibits or attachments in the filing (Section 2805, Sheet 316).

III. DISCUSSION OF PROPOSAL BY SECTION

The revisions to the index and specific tariff sections being added in this filing are discussed below:

Index ***(Sheet 7)***: A listing is being added for new Section 2800 – Formula Rate Mechanism.

Section 2801 – Formula Rate Mechanism ***(Sheet 307)*****:** A new proposed section for the FRM provides for an FRMAR to ENSTAR's Rate Schedules found in Section 2000 – Rate Schedules – General Service, Section 2100 – Rate Schedules – Large Transportation-Firm, and Section 2200 – Rate Schedules – Large Transportation-Interruptible. The annual revision shall be filed by tariff advice letter on or before April 15 of each year beginning after approval of this filing, unless ENSTAR files, or is in the midst of, a General Rate Case.

Section 2802 – Definitions ***(Sheets 307 through 309)*****:** A new proposed section providing meanings for specific defined terms used in Section 2800. The terms defined are 3 AAC, AOR, AS, FERC, Filing Date, Final Order, FRM, FRMAR, General Rate Case, Concluded General Rate Case, HDD, Test Year, TYEB, TY13-Month, Uniform System of Accounts, and USoA.

Section 2803 – FRMAR Calculation ***(Sheets 309 through 314)*****:** The new proposed section sets out, in detail, the calculation of the RR and the recalculation of the Rate Schedules. The RR is to be prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case. Known and measurable adjustments shall be limited to those changes that have occurred prior to the Filing Date, are more than likely to continue through the period in which the rates will be in effect and are consistent with the Commission's precedent regarding known and measurable adjustments.

Section 2804 – FRMAR Schedules ***(Sheet 315)*****:** This new proposed section identifies items to be provided with a FRMAR filing in addition to the tariff advice letter. The filing will include:

- Schedules of Test Year Normalized Operating Revenues and Expenses, Rate Base, Weighted Cost of Capital, and Normalized Test Year Revenue Requirement in similar format to the first four pages of the Company's 275(a) schedules and its Cost Allocation by Customer Class, Allocation Factors, and Rate Design as provided in Docket U-22-081;

- A schedule and explanation of all normalizing, annualizing, pro forma, and known and measurable change adjustments; and

- Tariff sheets showing the revisions to ENSTAR's rates.

Section 2805 – FRMAR Evaluation and Review Procedures ***(Sheet 316)*****:** The new proposed section provides that:

- A copy of the FRMAR filing will be provided to Staff and RAPA at the time it is filed with the Commission, along with any Excel workbooks with working formulas used to create the schedules, exhibits or attachments in the filing;

- ENSTAR will provide Staff with any requested clarifications or additional data as Staff reviews and evaluates the FRMAR filing; and

- ENSTAR shall work in good faith to promptly and fulsomely answer all questions raised by Staff. If ENSTAR and Staff agree that any calculations or schedules in the FRMAR filing should be revised, ENSTAR shall promptly file with the Commission the resulting adjusted rate calculations, revised tariff sheet, or revised FRMAR schedules.

Section 2806 – FRMAR Effective Date and Further Proceedings ***(Sheet 317)*****:** A new proposed section that discusses the effective date of FRMAR filings and further proceedings if a FRMAR filing is suspended. Since a FRMAR filing is filed as a tariff advice letter, it follows the timelines set out in AS 42.05.411, becoming effective at the end of the 45-day notice period, unless suspended. If the Commission suspends a FRMAR filing, the Company shall have the option to supplement its filing and request, and convert the filing to a General Rate Case Application. The section sets out the timelines for ENSTAR to provide notice that it intends to supplement the filing and the deadline to supplement.

IV. CONCLUSION

Implementing the proposed FRM will offer multiple benefits for ENSTAR's customers, the Commission, and the Company. First, the FRM will provide for more moderate rate changes, which will mitigate the level of rate increase that can occur when a utility experiences delays in cost recovery, such as ENSTAR's request currently pending before the Commission in TA352-4. Second, the FRM will allow the Commission to review ENSTAR's costs on a more frequent basis. Third, the FRM will better align costs with revenues and allow ENSTAR to timely share the benefits from cost efficiencies and other favorable circumstances with its customers.

The Commission should approve TA353-4 and allow ENSTAR's proposed FRM to take effect at the end of the statutory notice period.

Sincerely,

ENSTAR Natural Gas Company, LLC

Chelsea N. Guintu
Manager of Regulatory and Planning
Phone: 907-334-7620
Fax: 907-334-7657
Chelsea.Guintu@enstarnaturalgas.com

Attachments:
Attachment A – Index
Attachment B – Tariff Sheets
Supporting Testimony

ATTACHMENT A

TA353-4 Filing Index

Tariff Advice Letter 353-4

Attachment A – TA353-4 Filing Index

Attachment B – Tariff Sheets

Prefiled Direct Testimony of Chelsea N. Guintu, including 3 exhibits:
- Exhibit CNG-1: Resume of Chelsea N. Guintu
- Exhibit CNG-2: Tariff Sheets
- Exhibit CNG-3: Weather Normalization Adjustment

Prefiled Direct Testimony of Inna B. Johansen, including 1 exhibit:
- Exhibit IBJ-1: Resume of Inna B. Johansen

Prefiled Direct Testimony of Cyndee Fang, including 1 exhibit:
- Exhibit CF-1: Resume of Cyndee Fang

Attachment B

Contains the following tariff sheets:

Tariff Sheet 7, Revision 1

Tariff Sheet 306, Revision 1

Tariff Sheet 307, Revision 1

Tariff Sheet 308, Revision 1

Tariff Sheet 309, Revision 1

Tariff Sheet 310, Revision 1

Tariff Sheet 311, Revision 1

Tariff Sheet 312, Revision 1

Tariff Sheet 313, Revision 1

Tariff Sheet 314, Revision 1

Tariff Sheet 315, Revision 1

Tariff Sheet 316, Revision 1

Tariff Sheet 317, Original

Tariff Sheet 318, Original

Tariff Sheet 319, Original

ENSTAR Natural Gas Company, LLC

Effective:

Issued By: ENSTAR Natural Gas Company, LLC

ENSTAR Natural Gas Company, LLC

Section 2800 – Formula Rate Mechanism **D,N**

ENSTAR NATURAL GAS COMPANY, LLC

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

§2801 **Formula Rate Mechanism** **D,N**

§2801a **Application**

This Formula Rate Mechanism ("FRM") provides for an annual revision ("FRMAR") to the Company's Rate Schedules found in Section 2000 – Rate Schedules – General Service, Section 2100 – Rate Schedules – Large Transportation-Firm, and Section 2200 – Rate Schedules – Large Transportation-Interruptible. Rate calculations and adjustments required by this Section 2800 shall be determined on a revenue requirement basis.

§2801a(1) No provision contained within this Section 2800 will limit the Company's ability to file a General Rate Change Application or limit the RCA's authority over rates.

§2801a(2) Except as provided in Section 2801a(3), the Company will file a FRMAR by tariff advice letter on or before April 15 (or on the next Business Day after April 15 if April 15 is not a Business Day) of each year beginning after approval of TA353-4.

§2801a(3) The Company is exempt from filing a FRMAR for any Test Year for which:

§2801a(3)(a) The Company files a General Rate Change Application;

§2801a(3)(b) The Company is directed by the Commission to file the information required by 3 AAC 48.275(a) thus initiating a General Rate Case for a given Test Year; or

§2801a(3)(c) A General Rate Change Application or General Rate Case is pending before the Commission.

§2802 **Definitions**

§2802a In addition to the definitions set out in Section 200 of this Tariff, the terms listed below shall have the following meanings for the purpose of this Section 2800:

§2802a(1) The term "3 AAC" means the regulations of Commission as set out in Title 3 of the Alaska Administrative Code. The numbers following "3 AAC" are references to a specific regulation section.

§2802a(2) The term "AOR" means the Company's annual operations report filed with the Commission as required by AS 42.05.451(b). It includes the FERC Form No. 2.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2802a(3) The term "AS" means the Alaska Statutes. The numbers following "AS" are references to a specific statute section.

§2802a(4) The term "FERC" shall mean the Federal Energy Regulatory Commission.

§2802a(5) The term "Filing Date" means the date the Company files a FRMAR.

§2802a(6) The term "Final Order" means the last substantive order in a General Rate Case approving permanent rates, or accepting a settlement setting permanent rates, that becomes final and is not subject to further reconsideration by the RCA or appeal.

§2802a(7) The term "FRM" shall mean formula rate mechanism under this Section 2800.

§2802a(8) The term "FRMAR" means the FMR annual revision under this Section 2800.

§2802a(9) The term "General Rate Case" means a docketed proceeding before the RCA to review the entire revenue requirement (including cost of capital) and cost of service of the Company and involves the RCA review of the information required by 3 AAC 48.275(a). A General Rate Case may be initiated by a General Rate Change Application filed by the Company or by the action of RCA. A "Concluded General Rate Case" is one where a Final Order has been issued.

§2802a(10) The term "General Rate Change Application" means a request to change the rate schedules filed in accordance with AS 42.05.411 and 3 AAC 48.275(a).

§2802a(11) 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).

§2802a(12) The term "Test Year" means the twelve Months ending December 31 of the preceding calendar year.

§2802a(13) The Term "TYEB" means the Test Year End Balance, i.e., the balance at the end of the Test Year.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2802a(14) The terms "Uniform System of Accounts" and "USoA" mean the Uniform System of Accounts for Class A natural gas companies prescribed by Part 201 of the FERC regulations (18 C.F.R. Part 201) and required for use by 3 AAC 48.277(5). The number following "USoA" is a specific USoA account number.

§2803 **FRMAR Calculation**

§2803a The FRM shall calculate a revenue requirement ("RR") annually. The Company shall request recovery of its RR and shall include schedules showing the computation of any adjustments to the Test Year data. The annual RR shall be calculated according to the following formula:

$$RR = OM + DEP + OT + RI + IT$$

Where:

§2803b OM = all prudently incurred, reasonable and necessary operation and maintenance expenses and gas cost ("GC") incurred during the Test Year adjusted for known and measurable changes and prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case.

§2803b(1) Known and measurable adjustments shall be limited to Section 2803b(1)(a) through Section 2803b(1)(f) below and shall also be limited to those changes that have occurred prior to the Filing Date and that are more than likely to continue through the period in which the rates will be in effect and are consistent with the Commission's precedent regarding known and measurable adjustments.

§2803b(1)(a) The changes in the level of salary and wage rates that occurred during the Test Year, or are known and measurable, shall be annualized.

§2803b(1)(b) The changes in the cost of gas and gas revenues during the Test Year to reflect Test-Year end customers count.

§2803b(1)(c) The changes in the cost of gas during the Test Year to reflect the currently approved Determination of Gas Cost Adjustment found in Section 2301.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2803b(1)(d) The changes to the volumes, cost of gas and gas revenues to reflect weather normalization consistent with the methodology will be determine for each General Service Class (Section 2000) as follows:

§2803b(1)(d)(i) Use per Consuming Customer: The test year sales volume for each General Service Class will be divided by the test year number of average consuming customers;

§2803b(1)(d)(ii) Base Use per Customer*:* The Use per Consuming Customer for the months of June through August (non-heating months) will be totaled and divided by the number of days in those months (92) to determine Base Use per Day which will be multiplied by annual days (365);

§2803b(1)(d)(iii) Heating Load per Customer: The Base Use per Customer will be subtracted from the test year Use per Consuming Customer;

§2803b(1)(d)(iv) Heating Degree Days: The test year HDD for the months of June through August (non-heating months) will be totaled and divided by the number of days in those months (92) to determine the average daily base degree days which will be multiplied by annual days (365) (annual base degree days). The annual base degree days will be subtracted from the actual test year degree days, developing the Heating Degree Days;

§2803b(1)(d)(v) Heating Load per Degree Day: The Heating Load per Customer divided by Heating Degree Days;

§2803b(1)(d)(vi) Normalized Volumes: The delta between the actual test year degree days and the historical 10-year average of HDD will be multiplied by the Heating Load per Degree Day. The resulting adjustment will be added to the test year Use per Consuming Customer to determine the Normalized Use per Customer which will be multiplied by the test year average number of consuming customers; and

§2803b(1)(d)(vii) Weather Normalization Adjustment: The delta between Normalized Volume and test year sales volumes is multiplied by the current volumetric rate.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2803b(1)(e) The removal of ROU lease amortization replaced with Test Year lease payments.

§2803b(1)(f) The changes in uncollectible expense normalized for the changes in Test Year revenues to reflect adjustments described in Section 2803b(1)(a) through Section 2803b(1)(e) above.

§2803c DEP = depreciation and amortization expense is calculated on end of Test Year actual plant and asset balances at the depreciation and amortization rates utilized in calculating the tariff rates accepted and approved in Order U-22-081(15) or approved, accepted or utilized in calculating the tariff rates approved in a subsequent Concluded General Rate Case. The amortization related to regulatory assets discussed in Section 2803e(2)(i) below shall be included in DEP upon approval or acceptance by the Commission.

§2803d OT = taxes other than income tax from the Test Year prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case.

§2803e RI = return on prudently incurred investment calculated as the Company's rate of return (weighted average cost of capital) multiplied by the Test Year rate base.

§2803e(1) Rate of return shall be the weighted average cost of capital approved or accepted in the Company's last Concluded General Rate Case, except as provided in Section 2803e(1)(a).

§2803e(1)(a) If the Company refinances existing long-term debt or issues new or additional long-term debt during the Test Year, it will recalculate its weighted average cost of capital using its approved or accepted return on equity, its approved or accepted capital structure, and its new cost of debt. The new cost of debt calculation will include the costs of issuing the debt and any gain or loss on retiring the old long- term debt including any retirement or refinancing premium.

§2803e(2) Rate base is prepared in accordance with the following:

§2803e(2)(a) Known and measurable adjustments shall be limited to Section 2803e(2)(b), (f), (i) and (j) below and also be limited to those changes that have occurred prior to the Filing Date and are consistent with the ratemaking treatments approved or accepted in the Company's last Concluded General Rate Case.

§2803e(2)(b) Gas utility plant shall be the TYEB of USoA accounts 101-105.

D – "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2803e(2)(b)(i) ROU leases shall be removed from rate case and reclassified in accordance to ratemaking procedures approved or accepted in the Company's last Concluded General Rate Case.

§2803e(2)(c) Accumulated depreciation reserve shall be the TYEB of USoA accounts 108 & 111.

§2803e(2)(d) Plant completed not classified shall be the TYEB of USoA account 106.

§2803e(2)(e) Gas stored underground shall be the TYEB of USoA account 117.1.

§2803e(2)(f) The cash working capital allowance shall be calculated using the lead/lag time period (whether positive or negative) utilized in the Company's most recent lead lag study accepted or approved by Commission order.

§2803e(2)(g) Materials and supplies shall be the TYEB of USoA accounts 154 and 156.

§2803e(2)(h) Prepayments shall be the TYEB of USoA account 165.

§2803e(2)(i) Regulatory assets shall be the TYEB of the regulatory assets in USoA account 182.3 that were approved or accepted to be included in rate base by an order of the Commission.

§2803e(2)(j) Accumulated deferred income taxes ("ADIT") shall be those taxes, calculated for regulatory purposes, directly associated with an item in rate base (excluding Cash Working Capital) and shall include excess accumulated deferred income taxes ("Excess ADIT"). If any such ADIT amounts are debits, they shall be netted against the ADIT credits, and if the net amount is a debit, then it shall be an addition to rate base. The amount included in the rate base calculation for ADIT shall be the TYEB for the Test Year.

§2803e(2)(j)(i) Statutorily enacted changes in the state or federal income tax rate that occurred during the Test Year, or are known and measurable, shall be reflected in the calculation of the income tax allowance (per Section 2803f(2) below).

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2803e(2)(k) Net asset retirement obligation shall be those accounts for asset retirement obligations ("ARO") excluding any amounts and accounts included in the gas utility plant accounts (USoA accounts 101-105) or accumulated depreciation and amortization reserves (USoA accounts 108 and 111). If any such ARO amounts are debits, they shall be netted against the ARO credits, and if the net amount is a debit, then it shall be an addition to rate base. The amount included in the rate base calculation for net ARO shall be the TYEB.

§2803e(2)(l) Customer advances for construction shall be the TYEB of USoA account 252.

§2803f IT = income tax for the adjusted Test Year, adjusted for known and measurable changes occurring after the Test Year and before the Filing Date, and prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case.

§2803f(1) Income tax expense shall be calculated as follows:

§2803f(1)(a) Equity Return shall be calculated as rate base multiplied by the weighted cost of common equity from the Company's last Concluded General Rate Case,

§2803f(1)(b) After-tax net return shall be calculated as the equity return, plus or minus the net annual amortization of protected and unprotected Excess ADIT, as approved or accepted in Docket U-22-081;

§2803f(1)(c) Income tax expense before amortization of Excess ADIT shall be calculated as the after-tax net return multiplied by a composite gross-up state/federal income tax factor calculated as ((1/(1 – incremental state corporate income tax rate)) X (1/(1 - incremental federal corporate income tax rate))) – 1; and

§2803f(1)(d) Income tax expense shall be calculated as the income tax expense before amortization of Excess ADIT, plus or minus the net annual amortization of Excess ADIT.

§2803f(2) Statutorily enacted income tax rate changes that occurred during the Test Year, or are known and measurable, shall be annualized, per the income tax expense calculation described in Section 2803f(1)(c) above. The Company shall comprehensively account for, including establishing a regulatory liability or asset to account for, any such change in income tax expense in the calculation to ensure recovery of income tax expense under new and old income tax rates.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2803g **Cost Allocation**:

Once the annual RR has been determined as provided in Section 2803a through Section 2803f above, it shall be adjusted by normalized gas cost; then be allocated between the rate classes; and then between customer, capacity and commodity costs using the same cost classification and allocation methodologies that were approved or accepted in the Company's last Concluded General Rate Case.

§2803h **Derivation of Rates**:

Rates for the Company's Rate Schedules found in Sections 2000, 2100 and 2200 shall be calculated from the RR consistent with the rate derivation methodologies approved or accepted in the Company's last Concluded General Rate Case. The billing units used will be actual billing units for the Test Year modified for the normalizing adjustments set out in Section 2803b(1) above.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2804 **FRMAR Schedules**

In addition to the tariff advice letter, the FRMAR filing shall include the following:

§2804a Schedules of Test Year Normalized Operating Revenues and Expenses, Rate Base, Weighted Cost of Capital, and Normalized Test Year Revenue Requirement in similar format to the first four pages of the Company's 275(a) schedules and its Cost Allocation by Customer Class, Allocation Factors, and Rate Design as provided in Docket U-22-081.

§2804b A schedule and explanation of all normalizing, annualizing, pro forma, and known and measurable change adjustments.

§2804c Tariff sheets showing any proposed adjustments to the Company's rates.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2805 **FRMAR Evaluation and Review Procedures:**

§2805a A copy of the FRMAR filing will be provided to the Commission Staff and the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section ("RAPA") at the time it is filed with the Commission, along with any Excel workbooks with working formulas used to create the schedules, exhibits or attachments in the filing.

§2805b The Commission Staff shall review and evaluate the FRMAR filing, and may request clarification and additional data, and the Company shall provide the same.

§2805c The Company shall work in good faith to promptly and fulsomely answer all questions raised by the Commission Staff. If the Company and the Commission Staff agree that any calculations or schedules in the FRMAR filing should be revised, the Company shall file with the Commission the resulting adjusted rate calculations, revised tariff sheet, or revised FRMAR schedules.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

N

§2806 **FRMAR Effective Date and Further Proceedings**

§2806a A filed FRMAR becomes permanent at the end of the notice period described in AS 42.05.411 unless the Commission suspends the filing in accordance with AS 42.05.421.

§2806b If the Commission suspends the filing, the Commission may allow the filing to take effect on an interim basis, subject to refund.

§2806b(1) If the Commission suspends a FRMAR filing, the Company shall have the option to supplement its filing and request, and convert the filing to a General Rate Case Application.

§2806b(1)(a) The Company shall notify the Commission that it will supplement its filing and request, and convert the FRMAR filing to a General Rate Case Application, within 30 days of the Order suspending the FRMAR filing.

§2806b(1)(b) After giving the notification, the Company shall have an additional 45 days to supplement its filing and convert it to a General Rate Case Application.

§2806b(1)(c) The FRMAR filing may be updated to reflect those changes that have occurred prior to the date on which the Company supplements its filing under this Section 2806b, including updating adjustments made in the FRMAR filing. Any new or revised known and measurable adjustments shall be limited to those changes that have occurred prior to the date the Company supplements its filing.

§2806b(1)(d) The Company shall have the option to request a revision to any interim rates upon its filing converting the FRMAR to a General Rate Case Application.

ENSTAR Natural Gas Company, LLC

N

Reserved for Future Use

Effective:

Issued By: ENSTAR Natural Gas Company, LLC

ENSTAR Natural Gas Company, LLC

N

Reserved for Future Use

Effective:

Issued By: ENSTAR Natural Gas Company, LLC

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

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

In the Matter of the Consideration of the Formula Rate Mechanism Tariff Revision Designated as TA 353-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY
OF
INNA B. JOHANSEN

PREFILED DIRECT TESTIMONY
OF
INNA B. JOHANSEN

TABLE OF CONTENTS

I. POSITION AND QUALIFICATIONS

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

A. My name is Inna B. Johansen. My business address is 3000 Spenard Road, Anchorage, Alaska 99503. I am the Vice President of Regulatory and Gas Supply for ENSTAR Natural Gas Company, LLC ("ENSTAR") and Alaska Pipeline Company, LLC ("APC"). I will refer to ENSTAR and APC together as "ENSTAR" or "Company."[1]

Q. Briefly describe your professional experience and educational background.

A. I was employed by ENSTAR from 2006 to 2012, and I rejoined ENSTAR in 2014. Before my current position, I managed and worked in various departments within the Company, including Finance, Marketing, Operations, Gas Control and Regulatory. From 2013-2014, I held the position of Asset Manager at Southern Power Company ("SPC"), a subsidiary of Southern Company, working with multiple electric utilities and wholesale power buyers across multiple states managing the physical, financial, contractual, and operational activities associated with power purchase agreements. I have been leading the Gas Supply and Budget & Strategic Planning departments since 2015. In 2024, I became VP of Regulatory and Gas Supply. I hold a Bachelor of Arts in Finance from Kazakh State Academy of Business and a Master of Business Administration from Middle Tennessee State University Jennings A. Jones College of Business. My summary resume is attached as Exhibit IBJ-1.

Q. Briefly describe your current professional responsibilities.

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

A. I am responsible for all regulatory matters before the Regulatory Commission of Alaska ("RCA" or "Commission"), strategic planning, and gas supply for ENSTAR.

Q. Have you previously testified before the Regulatory Commission of Alaska?

A. Yes. I testified before the Regulatory Commission of Alaska ("Commission") in Dockets U-07-084, U-18-004, U-18-024 and U-22-081 on behalf of ENSTAR, and recently submitted prefiled testimony in ENSTAR's 2024 test year rate case filing, TA352-4.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to introduce ENSTAR's proposal to implement a Formula Rate Mechanism ("FRM") similar to other rate making mechanisms approved by the Commission and used by other Alaska utilities. I will discuss why maintaining a financially healthy utility is integral to providing safe and reliable energy service to its customers at reasonable rates. I will also address the necessity for using an adjustment to normalize for weather as an element of the FRM to eliminate rate volatility due to changes in weather.

Q. Who are ENSTAR's witnesses in support of its proposed formula rate mechanism?

A. ENSTAR's proposal is supported by my direct testimony and by the direct testimony of the following witnesses:

- Ms. Cyndee Fang with Atrium Economics, LLC ("Atrium") will support the FRM, explain the benefits of ENSTAR's proposed FRM for customers and the Company, compare the proposed FRM to the formula rate mechanism the

Commission required CINGSA to implement, and discuss similar mechanisms in other jurisdictions.

- Ms. Chelsea N. Guintu, Manager of Regulatory and Planning for ENSTAR, presents and sponsors the FRM calculation and tariff sheets.

III. PURPOSE OF PROPOSED PROVISION

Q. Briefly describe the FRM that ENSTAR is proposing in this filing.

A. ENSTAR is proposing a ratemaking mechanism that will allow the Company to adjust its base rates annually by calculating rate adjustments using actual historical costs and revenues to reflect more accurately the cost of providing the service to its customers. The rate adjustments will be based on a pre-established formula, which accounts for specific cost and billing unit inputs.

Q. Why is ENSTAR proposing the FRM?

A. Since its beginnings in 1961, ENSTAR has successfully performed its role as a natural gas public utility providing safe and reliable service to customers at reasonable rates. In Order U-16-066(19), the Commission affirmed ENSTAR's hard work and dedication to utility service, stating that "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."[2] ENSTAR is proud of the Commission's recognition and has continued operating in a cost-effective manner while maintaining the required level of service through repair and replacement of aging system assets, adopting new technologies to improve system efficiency, and expanding capacity to support growth, all while protecting critical infrastructure from physical and cybersecurity threats.

[2] Order U-16-066(19), *Order Resolving Revenue Requirement and Cost-of-Service Issues and Requiring Filings*, dated September 22, 2017 at 10.

As discussed below, to maintain its high quality of service, ENSTAR needs to update its aging infrastructure and respond to the rapidly changing Cook Inlet gas supply market. Addressing these issues will require significant capital investment, and the Company will need access to financing to fund this investment. A strong financial position is critical for ENSTAR to maintain its access to market-competitive financing. The inability to timely align revenues with capital investment and incurred costs will negatively impact ENSTAR's financial health and ultimately impact the Company's ability to secure the required capital on favorable terms.

Implementing the FRM offers multiple benefits for ENSTAR's customers, the Commission, and the Company. First, the FRM will provide for more moderate rate changes, which will mitigate the level of rate increase that can occur when a utility experiences delays in cost recovery. Second, the FRM will allow the Commission to review ENSTAR's costs on a more frequent basis. Third, the FRM will better align costs with revenues and, as a result, improve ENSTAR's financial health. Moreover, the FRM will also allow ENSTAR to timely share the benefits from cost efficiencies and other favorable circumstances with its customers. I will describe these benefits in more detail below.

A. Rate Change Stability

Q. How will the proposed FRM mitigate against potential large rate increases in the future?

A. By allowing ENSTAR to adjust rates annually, the FRM will mitigate the potential for large increases caused by not reflecting higher costs in rates until a general rate case. ENSTAR's current significant revenue deficiency and corresponding need to increase

its base rates to meet this deficiency is an example of such a situation. ENSTAR's revenue deficiency and proposed rate increase is described in its base rate case (TA352-4) filed on April 15, 2025. ENSTAR's proposed FRM will allow the Company to adjust rates annually to better align with changes in its cost of serving customers and will provide more predictable rates for customers.

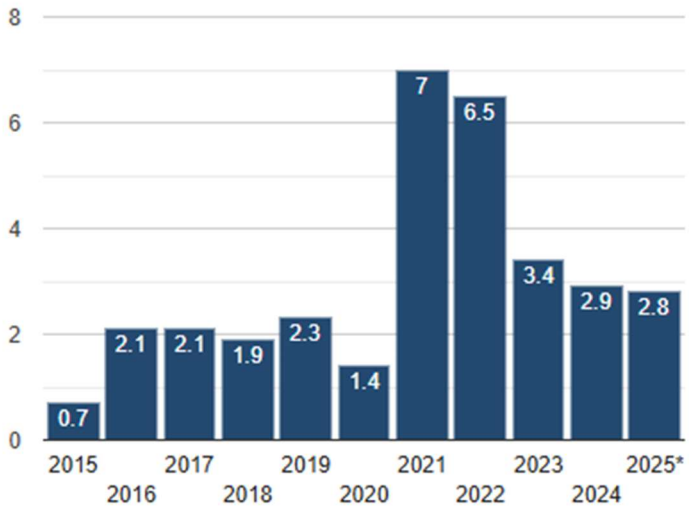
Q. Please provide an overview of some of the cost drivers behind ENSTAR's revenue deficiency and resulting proposed rate increase in its pending general rate case.

A. The Company's current revenue deficiency is the result of several significant cost drivers. First, the COVID-19 pandemic had substantial, unprecedented, and unpredictable effects on ENSTAR's operations, which were largely outside the control of ENSTAR. Although the Commission allowed Alaska utilities to record regulatory assets for uncollected residential utility bills and extraordinary expenses resulting from the pandemic, the repercussions from COVID-19 have continued to adversely impact ENSTAR's operations. Second, in recent years, the Company has faced record-high inflation that has caused the Company's costs to increase significantly. Between 2022 and 2024, the Anchorage Consumer Price Index saw an increase in inflation of over 11.5%. In addition, since ENSTAR purchases all its inventory and materials from the Lower 48 states, the overall U.S. inflation trends added additional cost pressure on our operations. Figure 1 below shows the annual U.S. inflation rates for calendar years from 2015 through 2025. As Figure 1 illustrates, the unprecedented inflation rates since COVID-19 are significantly higher than inflation between 2015 and 2020. The inflation data from prior periods is important because the actual impact of inflation is often

delayed months after inflation figures are published. While the rates appear to be decreasing, they still have not dropped to pre-pandemic levels.

Figure 1

United States Annual Inflation Rates (2015 to 2025)[3]



Moreover, significant delays in securing and receiving materials and supplies put additional pressure on costs. Changes in the labor market in ENSTAR's service territory were another factor that increased overall costs.

Q. What were some other drivers that contributed to ENSTAR's revenue deficiency in the current general rate case?

A. From the end of the test year in ENSTAR's last rate case (December 31, 2021) to the end of the test year in this case (December 31, 2024), the Company invested approximately $127 million in capital additions to maintain and improve its natural gas transmission and distribution system in Alaska. This is significantly higher than the

[3] Source: US Inflation Calculator using U.S. Labor Department data published on March 12, 2025. https://www.usinflationcalculator.com/inflation/current-inflation-rates/. The data for 2025 is the latest inflation data (12-month based) as of March 2025.

average of $22 million per year that ENSTAR has spent in the prior six years. Most of this investment was non-revenue producing, and included safety and reliability upgrades, regulator station replacements, control system replacements, and strategic distribution system reinforcements. During this time, the Company's base rates remained fixed at levels that reflected 2021 costs, thereby contributing to the revenue deficiency being addressed in the current general rate case.

Q. Are there other factors that contribute to ENSTAR's revenue deficiencies?

A. Yes. The cost of labor, including contracted union wage increases and increasing health care costs, safety-related costs with increased Pipeline and Hazardous Materials Safety Administration regulation regarding pipeline integrity, insurance, cybersecurity, and additional regulatory changes and compliance efforts, also impact ENSTAR's costs to provide service to its customers.

Q. What options does ENSTAR have to recover the increased costs caused by the factors described above?

A. As things stand now, to recover increased costs, ENSTAR must file a general rate case. While the Company could address its increasing costs by filing more frequent general rate cases, the time required to resolve a general rate case makes that option untenable.

Q. How long did it take to resolve ENSTAR's most recent rate case?

A. Docket U-22-081, ENSTAR's last general rate case, was filed in August 2022 based on 2021 test-year costs. The Commission final order in that docket was not issued until 2024, with final rates approved in May 2024.

Q. Has ENSTAR had the opportunity to capture the cost increases described above in its rates?

A. No. A utility filing a rate request before the RCA must base its request on a completed test year. From my experience, it generally takes three to nine months after the test year ends to prepare a rate request. During that time, conditions change, operations and construction (new investment) continue, inflation occurs, labor rates increase, and overall costs almost always increase. Pursuant to AS 42.05.175(c), the statutory timeline for the Commission to rule on a rate case is 450 days. If a final order is issued in a rate case proceeding at the end of this 450-day period, by the time the new rates are put into effect, the costs from the historical test year will be more than two years old. Without taking into account changes that have occurred since the test year, the utility's rates will almost certainly be based on costs that are below those actually incurred, especially in times of inflation which we have been experiencing.

Q. What is the impact of Alaska's 450-day statutory timeline on ENSTAR's ability to recover its costs?

A. ENSTAR's capital expenditures (net of contribution in aid of construction) in 2024 were $41.3 million, which were 2.3 times its annual depreciation expense of $18.0 million. The combination of ENSTAR's significantly greater capital spend relative to its internal cash generation through depreciation expense and the 450-day timeline subjects ENSTAR to an extraordinary delay in recovering its costs, such as capital, and exacerbates the risk that it will not be able to realize its authorized rate of return.

Q. Will ENSTAR's customers benefit from a revenue requirement calculated on an annual basis?

A. Yes. The Commission is aware that when a utility files for a base rate increase on a three to five year cadence, there is the potential for significant increases to customers'

bills. While the use of interim rates can partially mitigate this impact, a more frequent structured cost recovery mechanism, such as the proposed FRM, will result in gradual increases (or potential decreases) over the same period of time. Notably, rate adjustments under the FRM are reciprocal – that is, in a decreasing cost environment, customers would see rates reduced in a timely manner.

B. Timely Review of Costs by the Commission

Q. How often will the Commission review ENSTAR's costs and resulting rate adjustments under the FRM?

A. Under the proposed FRM, the Commission will review and assess various aspects of ENSTAR's cost of providing service every twelve months. The process will include annual updates under the pre-approved mechanism based on data-populated formulas using historical data. Ms. Guintu provides additional discussion on the FRM proposed annual evaluation and review procedures.

Q. Is the tariff review period adequate for the Commission to review ENSTAR's costs?

A. Yes. ENSTAR is proposing to limit the scope of changes to its overall revenue requirement using the FRM. The issues that typically require the most significant time and resources to address during ENSTAR's general rate cases—namely, return on equity, cost allocation, lead-lag, and rate design—will not be at issue in the annual FRM proceedings. Rather, these items will remain as approved by the Commission in ENSTAR's most recent general rate case.

The elements that will be adjusted on an annual basis will use a pre-established formula based on specific cost and revenue inputs, such as sales revenue, net plant in

service, operating expenses, taxes, and billing units. The proposed FRM will provide a more streamlined and predictable method for setting customer rates.

Q. Are there other benefits for the Commission from a more frequent review of ENSTAR's costs?

A. Yes, more frequent reviews by the Commission will provide improved visibility into ENSTAR's operations. The Commission will have a fuller understanding of, and opportunity to review, ENSTAR's recently incurred investments, expenses, and revenues between general rate cases. This is of particular relevance to the Commission because ENSTAR expects to incur significant capital investments to maintain its aging infrastructure and address gas supply constraints in the years to come.

Q. Will implementing a FRM eliminate entirely the need for general rate case filings from ENSTAR?

A. No. The proposed FRM process will not change ENSTAR's capital structure, authorized ROE, cost allocation, lead-lag, or rate design. Accordingly, ENSTAR will periodically need to file a general rate case to update these rate elements. Additionally, the Commission has the authority to direct ENSTAR to file a rate case at any time. However, with the FRM, ENSTAR and the Commission can reduce the number of costly and time-consuming general rate cases. This will lead to savings in time, effort, and resources, which ultimately benefit customers through lower utility rates.

C. Importance of a Financially Healthy Utility

Q. Why is it important for ENSTAR to maintain a strong financial position in providing essential service?

A. As a regulated utility, ENSTAR is responsible for providing safe and reliable service, under reasonable terms and conditions, to its customers, both current and future. This responsibility persists no matter the state of the financial or commodities markets and regardless of unexpected external events, such as major storms, economic cycles, and even such unprecedented events as the recent global pandemic.

ENSTAR's ability to remain financially robust is foundational to its obligation to provide affordable, safe, and reliable utility service to customers. To fund necessary investment in infrastructure to serve customers in Alaska at reasonable rates, access to capital on competitive terms is critical for ENSTAR and its customers. As with all investor-owned utilities, ENSTAR must meet debt and equity investor expectations and maintain strong credit metrics to continue to be able to obtain financing at competitive rates. That is true even though ENSTAR is a part of a larger organization, because the Company must compete with other investments for capital allocation by its shareholder. To that end, timely recovery of the costs for investments and operations as well as a reasonable overall cost of capital are extremely important for ENSTAR to maintain the ability to obtain financing at reasonable rates for customers.

Q. Why is inflation viewed as particularly harmful to the financial health of regulated utilities such as ENSTAR?

A. Most unregulated businesses have the ability to increase the prices they charge customers as their costs rise. As a regulated utility, ENSTAR is different. Under the levels of inflation seen over the last few years, the Company's costs have significantly diverged from those incorporated into rates, which has led to persistent and widening under-earnings and cash flow declines. For ENSTAR, recent inflation coincided with

the Company's need to increase capital spending to address aging infrastructure. The inflationary pressures that ENSTAR is experiencing are compounded by its delayed ability to recovery such costs in rates.

Q. Please identify the factors that affect ENSTAR's financial health.

A. The following factors are significant for ENSTAR's financial health:

- Inconsistent financial performance driven by lack of timely cost recovery;
- Persistent under-earning of ENSTAR's authorized returns;
- Increased exposure to gas supply risk and the inability to switch to an alternative fuel source; and
- Lack of progressive rate mechanisms such as a forward-looking test year, cost trackers or surcharges, along with the lack of a properly designed revenue decoupling mechanism; the effects of the lack of these mechanisms is exacerbated during periods of high inflationary rates.

As discussed by Ms. Fang, notwithstanding the adoption of interim rates, the use of a historical test year in Alaska, and the resulting delay in timely capital cost recovery, is a more restrictive rate making paradigm when compared to the mechanisms available in other jurisdictions.

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

A. No. A significant element of ENSTAR's financial health is the opportunity to earn its authorized ROE. As shown in Figure 2 below, ENSTAR has failed to earn its authorized ROE in each of the last three years following its 2021 test year. Factors such as inflation, increased labor costs, use of a historic test year, and a lack of timely cost

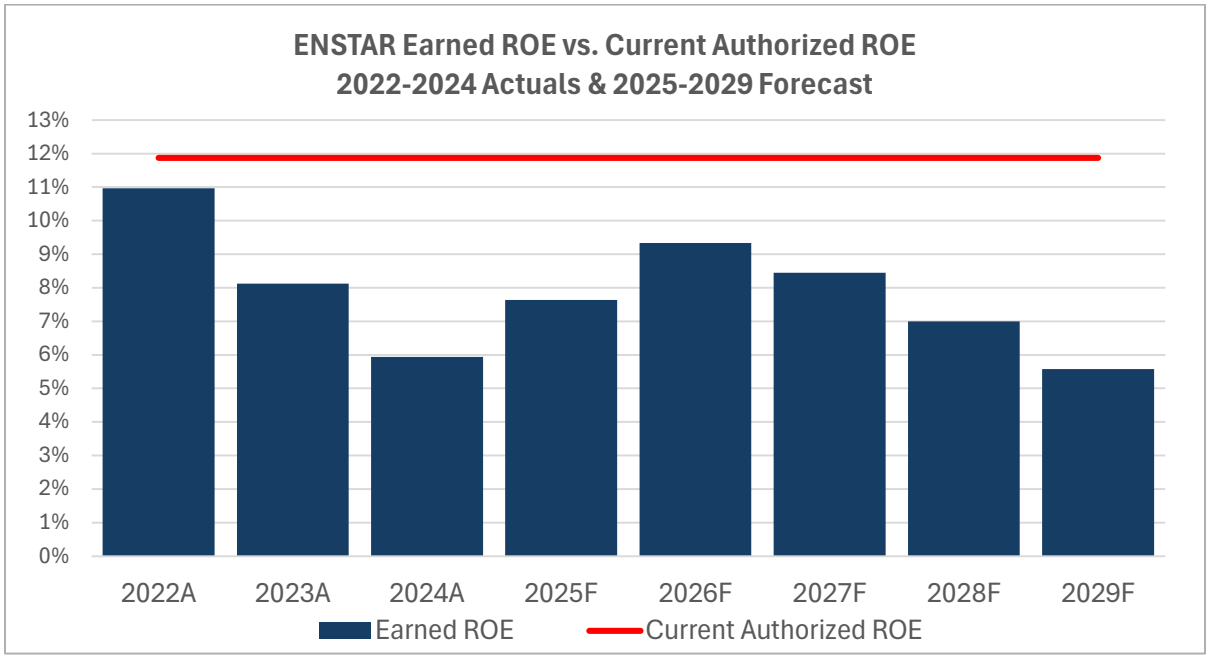
recovery mechanisms, result in customer rates that do not reflect actual current costs of providing service to customers.

ENSTAR projects that it will similarly be unable to earn its authorized ROE for forecasted years 2025 to 2029, due to the effects of its anticipated future capital spend. Figure 2 below provides ENSTAR's actual earned ROEs for 2022 to 2024 and forecasted ROEs for 2025 to 2029. To prepare the forecast for future years, ENSTAR assumed that the entire requested rate case filing has been approved by the Commission as filed in TA352-4, including the proposed ROE and overall cost of capital. In addition, ENSTAR used the following assumptions:

- Capital additions: the average annual projected capital investment of $65 million.
- Sales revenues: the historical ten-year average rates for customer growth and normalized use per customer were applied to calculate gas sales future revenue.
- Transport revenues: volumes are projected at the normalized level observed in 2024.
- O&M expenses excluding cost of gas: increased at 3% per year to account for annual inflation and other cost increases.
- Property Taxes and Depreciation: applied growth rates correlating to plant additions.

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

Figure 2



Q. Please explain how ENSTAR under-earns its revenue requirement.

A. The amount of financial net income on ENSTAR's income statements falls short of the return on invested assets authorized for ENSTAR in its rate of return, which is referred to as "under-earning." As illustrated in the above Figure 2, although ENSTAR recorded positive net income, the level was below what the Company was authorized to earn in rates from 2022 through 2024 (authorized return on equity is a red line in Figure 2).

Q. Despite ENSTAR's under-earning, does the Company continue to make investments to meet customers' needs?

A. Yes. To maintain its continued commitment to safe and reliable service, ENSTAR has invested approximately $127 million in capital to enhance its infrastructure and address critical capacity issues since its last general rate case. These investments included

safety and reliability upgrades; regulator station replacements; control system replacements; and strategic distribution system reinforcements among other critical investments for the benefit of our customers.

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

A. Yes. Pursuant to its currently approved capital plan, ENSTAR is projected to invest another $300-350 million over the next 5 years. This capital is designed to address several important issues. The capital plan includes projects that will enhance technology and ENSTAR's ability to protect and respond to external cybersecurity threats. The Company also plans to continue to focus on replacement of its aging infrastructure and creating a safer, more reliable natural gas distribution system for the Company and its customers.

Q. What are the financial implications of continuing to invest while under-earning?

A. ENSTAR's financial under-performance ultimately affects the availability and cost of needed capital as investor dollars can go elsewhere and/or demand a higher return. A persistent gap between the earned return and authorized return undermines ENSTAR's relative attractiveness as an investment. To justify continued capital deployment to ENSTAR, both debt and equity investors are likely to require higher interest rates and returns on equity, respectively, to compensate for the recurring earnings gap. In turn, this will drive up the Company's cost of capital and ultimately result in higher costs to serve customers.

Q. Can ENSTAR reduce operating expenses to increase earnings?

A. The single, largest controllable expense we have on an annual basis is labor (our employees). We could reduce our workforce, but we already focus on operating

efficiently and minimizing employee headcount to the extent possible, and any further reductions to our workforce would impact our ability to safely and reliably serve our customers. Aside from cutting workforce, other necessary O&M expenses or capital investment could be slashed, but those options are not conducive to operating a safe and reliable gas utility.

D. BENEFIT TO CUSTOMERS

Q. Please describe potential benefits that the FRM may offer ENSTAR's customers.

A. ENSTAR actively seeks to expand its distribution system into new service territories and add new large customers, which increase efficiency through economies of scale and the spread of fixed costs over more customers. Under the current regulatory process, these benefits would not incur to customers until the next general rate case. Under the FRM, these efficiencies and economies-of-scale will be reflected in the annual rate adjustment in a timely fashion, and reduce the overall cost of providing service for all ENSTAR customers.

Q. What other potential benefits would the FMR pass through to customers?

A. Besides efficiency and economies-of-scale, the FRM will pass on to ENSTAR customers any cost savings or tax reductions that occurred over the prior twelve months more promptly than in a general rate case.

Q. Does more frequent adjustment of rates benefit customers as well?

A. Yes. Instead of ENSTAR filing a rate case that demonstrates a revenue deficiency requiring a large increase in rates, the FRM will allow the Company to adjust its rates annually at more moderate levels. With the use of annual updates, any increases or

decreases are recognized more quickly and are reflected commensurately in the formula.

IV. WEATHER NORMALIZATION

Q. Why is ENSTAR proposing a weather normalization adjustment in the FRM?

A. Weather normalization neutralizes the effect of weather on utility revenues and certain operating costs. It adjusts test year customer gas usage which is used to develop the requested revenue requirement for the test year, allocate costs in the cost-of-service study, and calculate new rates. A "normal weather year" is a year that exhibits an average of the actual observed annual temperatures over the last ten years. ENSTAR measures the impact of weather in heating degree days ("HDD").[4] By adjusting for normalized weather, a test year that experiences more HDD than normal (cold year), will see a downward adjustment to the requested revenue requirement. Conversely, a test year that has fewer HDD than normal (warm year) will see an upward adjustment to the revenue requirement. As temperatures rise and fall, so does the Company's revenue. ENSTAR's rates for gas service includes a volumetric component, meaning, resulting revenues fluctuate depending on how much gas customers use during the test year. A normalization adjustment removes the abnormal weather deviations from expected, or "normal" levels, which is a primary driver of variations in gas volumes sold and outside ENSTAR's control. It allows ENSTAR to set future rates based on the

[4] Heating degree days ("HDD") are a measure of how cold the temperature was on a given day or during a period of days and is a standard unit of measure in the energy utility industry. A degree day compares the mean (the average of the high and low) outdoor temperatures for a day recorded for a location to 65° Fahrenheit (F) (although some entities may use a different base such as 55°F). For example, on a day where the average of the high and low temperature is 35°F, there would be 30 HDD. The more extreme the outside temperature, the higher the number of HDD. The U.S. Energy Information Administration notes that a high number of HDD generally results in higher levels of energy use for space heating, which has been ENSTAR's experience. ENSTAR tracks the HDD reported by the National Weather Service for the "official" Anchorage recording station (Anchorage International Airport), which uses the 65°F base measurement.

"normal" level of gas sales. For this reason, ENSTAR proposes to weather normalize its sales volumes in the FRM rate setting process to ensure that the Company's revenue requirement appropriately reflects revenues for weather during the rate-effective period.

Q. Can you provide an example of weather fluctuations that ENSTAR has experienced in its territory?

A. Yes. Table 1 below shows the actual HDD for the last eleven years, the annual change, the historical ten-year average HDD for the period of 2014 through 2023 ("Normal HDD"), and the difference between actual observed HDD and Normal HDD.

Table 1

HDD in ENSTAR's Service Territory Over the Last Eleven Years[5]

Year	Actual	Annual Change	Normal 10 -year Average	Actual vs. Normal	Actual vs. Normal %
2014	9,092	0%	9,363	(271)	-2.9%
2015	9,111	0%	9,363	(252)	-2.7%
2016	8,531	-6%	9,363	(832)	-8.9%
2017	9,884	16%	9,363	521	5.6%
2018	8,795	-11%	9,363	(568)	-6.1%
2019	8,177	-7%	9,363	(1,186)	-12.7%
2020	10,218	25%	9,363	855	9.1%
2021	10,530	3%	9,363	1,167	12.5%
2022	9,307	-12%	9,363	(56)	-0.6%
2023	9,988	7%	9,363	625	6.7%
2024	**9,870**	**-1%**	**9,363**	**507**	**5.4%**

As the data in the Table 1 shows, ENSTAR frequently experiences deviations from "normal" weather in its service territory.

[5] Source: National Weather Service, https://www.weather.gov/wrh/Climate?wfo=afc.

Q. Is there a strong correlation between HDD and ENSTAR's General Service customer usage?

A. Yes, as Figures 3 through 6 below demonstrate, there is a strong correlation between HDD and ENSTAR's General Service customer usage. The graphs show the average use per customer for each General Service class and the HDD from 2014 through 2024.

Figure 3

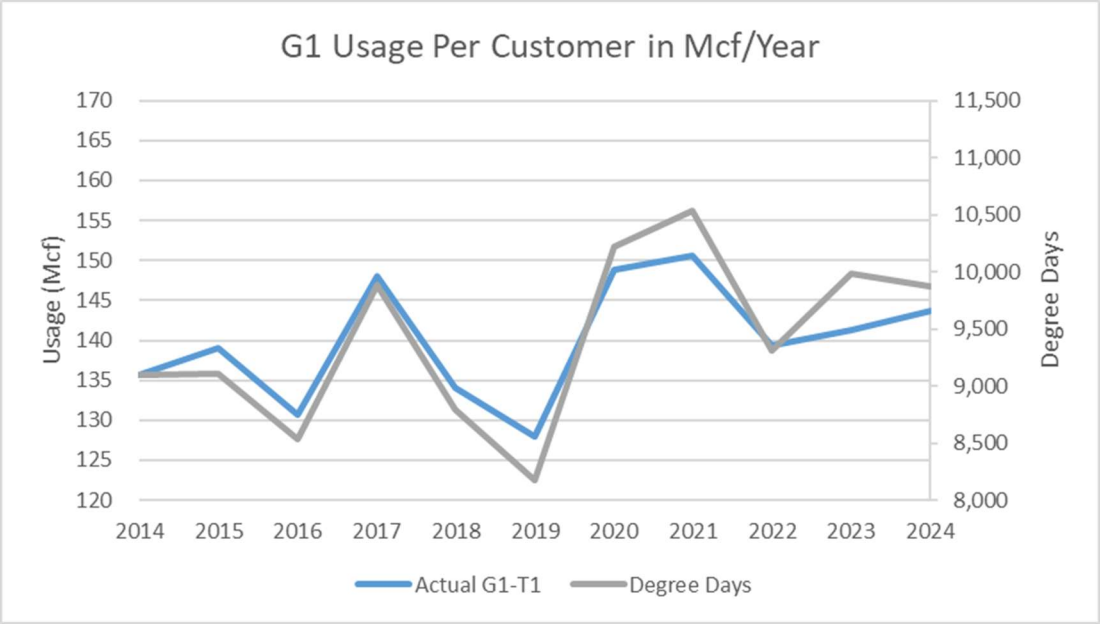


Figure 4

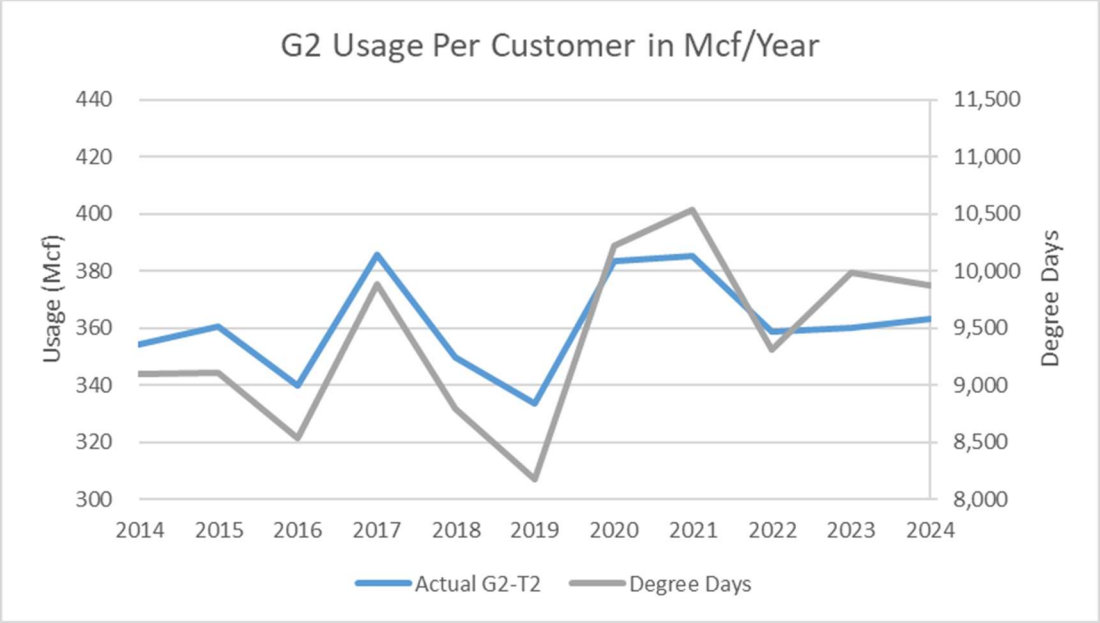


Figure 5

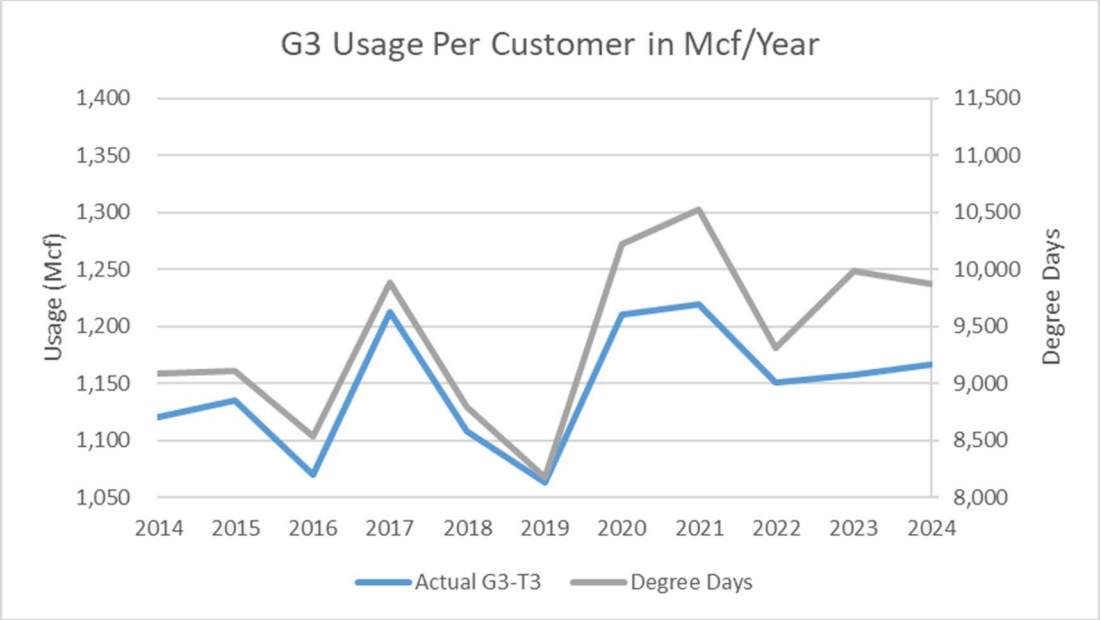
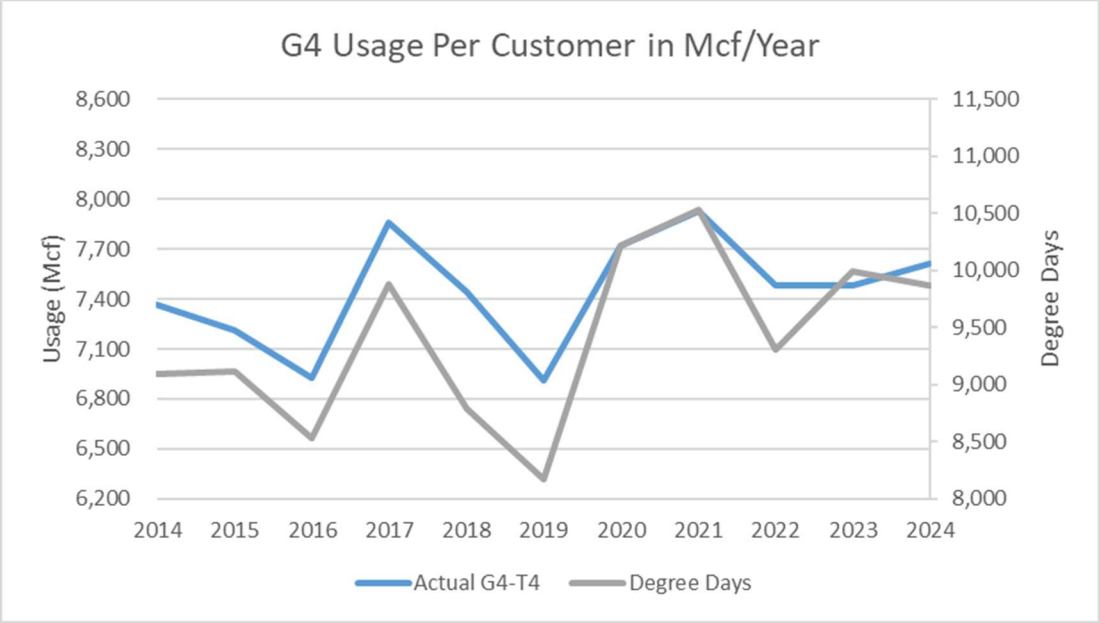


Figure 6



This strong correlation between ENSTAR's General Service customer usage and HDD is consistent throughout ENSTAR's history.

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

A. The detailed calculation of the weather normalization adjustment is provided by Ms. Guintu in her testimony. The methodology used is identical to the methodology ENSTAR used to normalize customer usage for weather in its last rate case (Docket U-22-081) and the recently filed general rate case in TA352-4. The proposed adjustment is also similar to the adjustment that was made in ENSTAR's approved revenue requirement in its 2000 test year rate case (Docket U-00-088) and the adjustment ENSTAR proposed in its 2009 test year rate case (Dockets U-09-069/U-09-070).[6]

[6] The U-00-088 revenue requirement was adjudicated by the Commission and set in Order U-00-088(12), dated August 8, 2002. The 2009 and 2021 test year rate cases were settled, and the Commission accepted the stipulations in Order U-09-069(10)/U-09-070(10) and Order U-22-081(11). The weather normalized volumes per customer proposed by ENSTAR were used to derive the tariff rates that were approved in that order.

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

A. No. The weather normalization adjustment will apply only to the G1 through G4 rate classes. ENSTAR is not proposing any volume adjustments to the large transportation customers and power plant volumes and revenues. The gas usage for these customers does not exhibit the same correlation between HDD and their consumption.

V. CONCLUSION

Q. Can you summarize ENSTAR's FRM proposal?

A. In this filing, ENSTAR is requesting approval to implement a FRM that will allow the Company to adjust its base rates annually by calculating rate adjustments using actual historical costs and revenues to reflect more accurately the cost of providing the service to its customers. The rate adjustments will be based on a pre-established formula, which accounts for specific cost and billing unit inputs. Similar approaches are already in effect for other Alaska utilities and have been utilized by this Commission for years to help mitigate the adverse financial impacts of operating in Alaska for the benefit of the customers and utilities. Adjusting rates annually will ensure that rates reflect current costs and will provide greater stability to the Company and its customers.

Q. Does this conclude your direct testimony?

A. Yes.

Inna B. Johansen

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, Alaska: 2014 – Present.

Vice President of Regulatory and Gas Supply: 2024 – Present

Director, Gas Supply Operations: 2019 – 2024

Senior Manager, Gas Supply and Financial Planning: 2016 – 2019

Gas Supply Manager: 2015 – 2016

Manager of Budgeting and Finance: 2014 – 2015

Southern Company, Birmingham, Alabama: 2012 – 2014

Southern Power Company/Asset Manager: 2013 – 2014

Alabama Power Company/ Budget Analyst: 2012 – 2013

ENSTAR Natural Gas Company/Alaska Pipeline Company, Anchorage, Alaska: 2006 – 2012

Business Development Manager: 2010 – 2012

Operations Analyst: 2008 – 2010

Financial Analyst: 2006 – 2008

Alaska Pacific Bank, Juneau, Alaska: 2004 – 2006

Accounting Specialist

EDUCATION

Kazakh State Academy of Management, Almaty, Kazakhstan – BA in Finance and Accounting, 1999

Middle Tennessee State University, Murfreesboro, Tennessee: MBA – Emphasis in Finance and Accounting, 2003

OTHER

Commonwealth North, Member

Resource Development Council, Member

Western Energy Institute, Energy Management Team, Member

American Gas Association, Gas Control Committee

Habitat of Humanity, Board Member, 2011 – 2012

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

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

In the Matter of the Consideration of the Formula Rate Mechanism Tariff Revision Designated as TA 353-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF CYNDEE FANG

PREFILED DIRECT TESTIMONY
OF
CYNDEE FANG

TABLE OF CONTENTS

EXHIBITS

I. POSITION AND QUALIFICATIONS

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

A. My name is Cyndee Fang, and I am employed by Atrium Economics, LLC ("Atrium") as a Director. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. Briefly describe your professional experience and educational background.

A. I have over 20 years of experience in the energy industry, focusing on regulatory, cost recovery, and rate design issues. I joined Atrium in December 2024. Before joining Atrium, I was Vice President of Regulatory at NorthWestern Energy. In this role, I was responsible for the development and execution of regulatory strategies in Montana, South Dakota, and Nebraska. I joined NorthWestern Energy in 2021 as the Director of Regulatory Affairs in Montana. Before NorthWestern Energy, I held various leadership roles at San Diego Gas & Electric, which included overseeing the Company's electric rate strategy, electric forecasting, electric load analysis and research, and origination teams. I began my career in the energy industry as a Public Utilities Rates Analyst at the Minnesota Department of Commerce, Energy Division.

I received my Bachelor of Science in Political Economics of Natural Resources from the University of California at Berkley. I completed all coursework required for a Ph.D. in Applied Economics at the University of Minnesota. My resume is attached as Exhibit CF-1.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting direct testimony on behalf of ENSTAR Natural Gas Company,

LLC ("ENSTAR" or the "Company").

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

A. I have not testified before the RCA. I have testified before the Montana Public Service Commission, the California Public Utilities Commission, and the Minnesota Public Utilities Commission, and submitted testimony before the Federal Energy Regulatory Commission and the Public Service Commission of the District of Columbia.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support ENSTAR's Formula Rate Mechanism ("FRM") proposal presented by Company witnesses Inna B. Johansen and Chelsea N. Guintu. ENSTAR's proposed FRM is modeled after the Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA") Commission-approved FRM. In Order U-18-043(15), the RCA ordered CINGSA to file proposed formula rates, recognizing that CINGSA and its customers could benefit from the stability of formula rates.[1] In this filing, ENSTAR seeks Commission approval to bring similar stability to itself and its customers. My testimony further discusses the benefits of ENSTAR's proposed FRM for the Company and its customers presented by Ms. Johansen and compares it to CINGSA's FRM and similar mechanisms in other jurisdictions.

III. BENEFITS OF ENSTAR'S PROPOSED FRM

[1] Order U-18-043(15), *Order Resolving Revenue Requirement and Cost-of-Service Issues and Requiring Filings*, August 16, 2019, at 90.

Q. What is a Formula Rate Mechanism?

A. A FRM is a ratemaking mechanism with which a utility may update its base rates to reflect changes in the cost to serve customers outside of a rate case based on a preestablished formula.

Q. Why is a Formula Rate Mechanism needed?

A. FRMs are used to better align customers' rates with the utility's ongoing costs and investments. For instance, as the utility places new plant into service, it would typically have to wait until a full general rate case until the plant and associated depreciation are placed into rates. With a FRM, there is a better alignment of the utilization of plant by customers to the recovery of costs for the utility. This reduces delayed recovery of current costs, which reduces the frequency of large rate increases needed to address this recovery gap and sends more accurate price signals to customers based on the utility's current operating environment.

Mechanically, a FRM will update rates on an annual basis using an updated test year revenue requirement that reflects costs incurred to serve customers in the prior year. In contrast with many rate riders (*e.g.* capital trackers, pension riders, etc.), a FRM is a more comprehensive mechanism in that it looks at a broader scope of the utility's cost to serve customers rather than just a single component.

Q. What are the benefits of a FRM?

A. A formula rate mechanism can provide the following benefits to both the utility and its customers:

- provide customers with greater rate stability through rates that more timely align with the cost of providing energy services;

- increase regulatory efficiency with more timely regulatory review and increased transparency to regulators and stakeholders; and
- more timely recovery of costs incurred to support a financially healthy utility.

Q. Please describe the benefits of aligning rates with the costs to serve customers.

A. Unlike most businesses that can adjust prices timely when changes in costs occur, the regulatory process necessary for the approval of price changes for utility services results in a delay between when costs are incurred and when prices can be changed to reflect those changes in costs. Under the Company's current regulatory framework without a FRM, delayed recovery of incurred costs occurs in between rate cases; that is, there is a delay between when a utility incurs incremental costs to serve customers and when it can recover those costs through customer rates. This type of delay can create financial strain for utilities, as they must cover capital related costs for critical infrastructure investments and operations expenses until changes in prices to recover those costs are approved. For customers, delayed recovery of incurred costs will result in outdated rates that do not reflect current costs, potentially leading to larger, more abrupt rate increases in future rate cases.

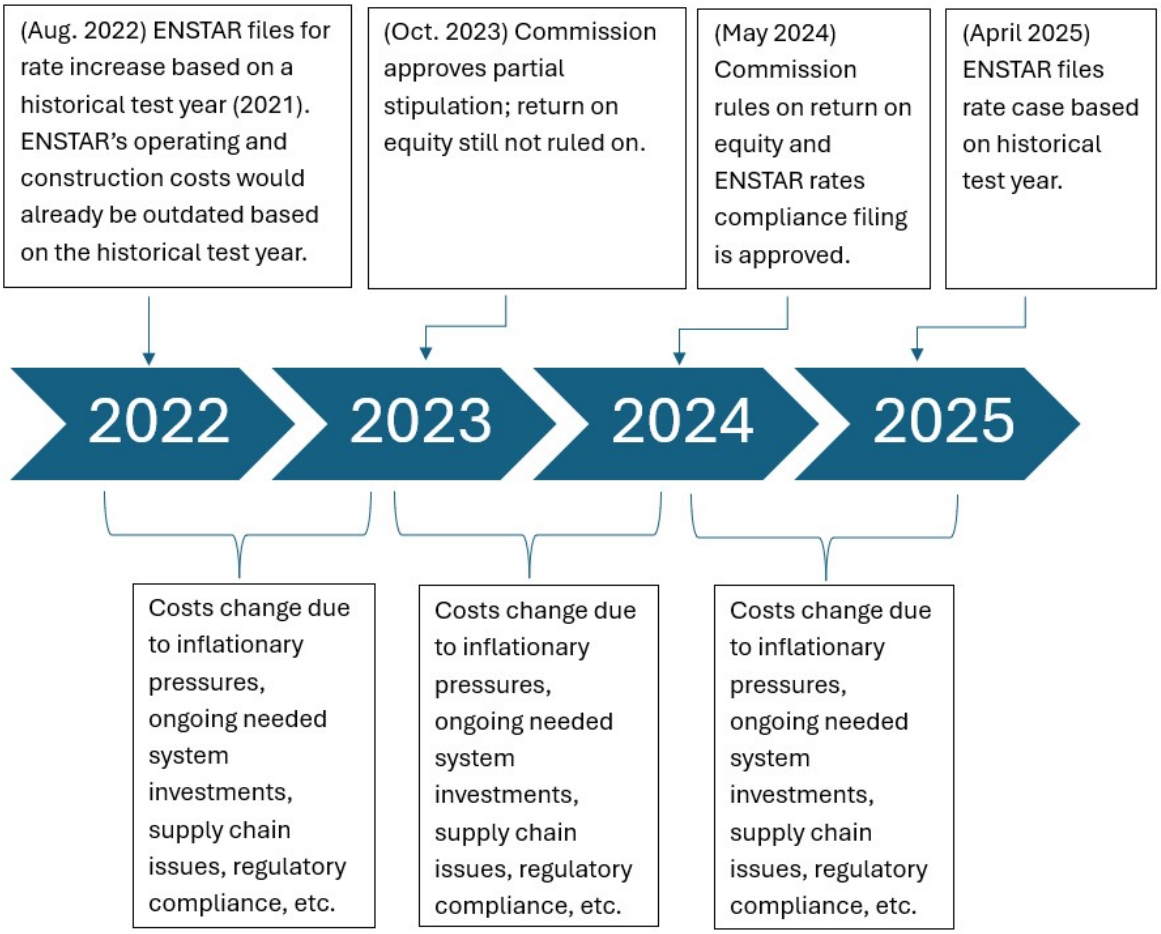
Q. Do you have an illustrative example to show how changing costs impact the traditional ratemaking process?

A. Yes. Figure 1 below provides a timeline of ENSTAR's last general rate case to the current one and commentary on how costs are reflected in rates. By the time the 2025 general rate case is filed, ENSTAR will only be recovering a level of costs incurred before the 2022 rate case was filed; specifically, the test year ending

December 31, 2021. This illustration shows a significant delay for the utility to recover its prudently incurred costs.

As shown in Figure 1, when ENSTAR filed its general rate application on August 1, 2022, for recovery of costs based on an historical 2021 test year, costs were already out-of-date by the time the filing took place. From there, it was not until May 8, 2024, that the RCA approved final rates that reflected 2021 test year costs. As discussed further by Ms. Johansen, during this time, ENSTAR's operation and construction costs continued to change due to inflationary pressures, and new capital investments were made to maintain safe and reliable service to customers. The RCA's order in that rate case did not take into consideration these changes in costs. This delay in timing could result in revenue deficiencies.

Figure 1: ENSTAR Rate Review Timeline



Q. Please explain the benefit of more timely cost recovery.

A. Timely cost recovery benefits both the utility and its customers by increasing financial stability and reducing the likelihood of disruptive rate increases. When utilities can recover costs with a shorter delay, they can reduce potential revenue shortfalls that could otherwise result in increased borrowing costs or delays in critical investments that may negatively impact service quality. Shorter recovery times can help utilities avoid these shortfalls and continue to invest in infrastructure, system safety, and reliability without unnecessary delays. For customers, a

structured cost recovery mechanism allows more predictable and gradual changes in utility bills for household budgeting purposes.

Q. Please explain the benefits of using a test year end balance instead of a 13-month average for rate base components.

A. The use of a year end balance for rate base components rather than a 13-month average (defined as the arithmetic sum of the beginning net balance of each month for the 12-month test period, plus the net balance at the end of the twelfth month of the test period, divided by 13) provides a more current reflection of utility costs and are more representative of the ongoing costs the utility will incur. Said another way, the balance of accounts such as plant in service are more representative of the utility's current position at year end, than by taking a beginning and ending balance of such accounts. It also better aligns the customer utilization of the rate base items with the costs the utility is incurring and subsequently the rates the customer pays. As discussed further below, most states that utilize FRM's allow for the use of a year end balance for plant in service accounts. This approach more accurately matches customer rates to utility costs and helps ensure revenue deficiencies do not grow exceptionally large due to infrastructure that is not fully reflected in rate base.

Q. Please explain the benefit of customers' bills reflecting more current costs that have been incurred.

A. Under traditional ratemaking, during times of increasing costs, customers often experience large rate spikes when a general rate case is approved, as years of unrecovered costs are suddenly incorporated into rates. In contrast, a FRM provides gradual, predictable adjustments, more in line with other goods and services, which

helps customers manage their energy bills. It also sends more accurate price signals to customers because there is a better economic relationship when current rates are based on more up to date cost of services. Proper economic price signals enable customers to make appropriate decisions on their energy use, type of energy use (electric or gas), and energy-related investments such as energy efficiency improvements to their homes or more energy efficient appliances.

Q. Please describe the regulatory efficiency benefits of a FRM.

A. Under the current general rate case structure, the regulatory review to determine just and reasonable rates, begins with the revenue requirement when a utility seeks to update base rates to reflect changes in cost of service. In a simplified form, the traditional revenue requirement formula is as follows:

Revenue Requirement = Expenses + (Rate Base x Cost of Capital)

Review of the revenue requirement then involves a review of updates to the following components since the last rate case:

- Expenses including operating and maintenance costs, depreciation and amortization on assets, income tax expense, ad valorem tax, and other expenses;
- Rate base, representing investor-supplied capital, is made up of plant in service – net of accumulated depreciation to date – and working capital, less deferred income tax and other miscellaneous adjustments; and
- Cost of capital to provide a fair return to investors.

The review of the proposed rates then includes:

- Updates to billing determinants (number of customers and throughput), and

- Cost of Service Studies to determine the allocation of costs between different customer classes and the rate design structure for customer rates.

This review involves understanding changes in the test year since the last general rate case. A rate case includes many complex costing and ratemaking issues.

When experiencing increasing costs to serve customers,[2] utilities must file general rate cases more often. The number of rate cases completed nationwide saw a notable increase following the onset of the COVID-19 pandemic. Annual completed rate case filings rose from just over 100 in 2014 – 2015 to 147 in 2019. After a brief dip in 2020, completed filings rebounded to approximately 150 per year in 2021, 2022, and 2023. However, in 2024 filings decreased to 99.[3] Between 2014 and 2018, annual U.S. net rate increase requests rose from $5.4 billion to $5.8 billion.[4]

A FRM will increase regulatory efficiency by providing the Company with a mechanism to update a limited scope of these issues – expense, rate base, and billing determinants – for more current historical actuals, reducing the utility's need to file general rate cases more often. The formulaic nature of these updates would limit the regulatory administrative burden of an additional annual compliance filing.

Q. Please describe the increased transparency benefits of a FRM.

A. Under the current general rate case structure, the utility presents updates to all of its cost of service components for Commission and stakeholder review of its overall

[2] Examples of potential causes of increasing utility costs to serve customers may include, but are not limited to, supply chain changes, inflation, rising interest rates, increases in uncollectible bills, or increasing compliance requirements, increased capital costs (e.g., depreciation, property taxes, and capital), as well as increased investments.

[3] S&P Global Market Intelligence. (n.d.). *Past rate cases by industry.* [Data set]. Capital IQ. Retrieved March 26, 2025, from CIQ Pro: Rate Case History.

[4] S&P Capital IQ. (2025). *U.S. Utility Rate Increase Requests (2014–2024)* [Data set]. Retrieved April 1, 2025, from https://www.capitaliq.spglobal.com/.

revenue requirement when seeking to update base rates. Under a FRM, the utility provides an annual filing updating the Commission and stakeholders of the changes in key components of cost of service – rate base, expense, and billing determinants – for review before implementation of updated base rates. The formulaic and targeted nature of these updates limits the burden for stakeholders when engaging in this annual process while maintaining the same degree of transparency for review.

Q. What are the concerns with implementing a FRM?

A. Some concerns have been expressed regarding a FRM:

- reducing the incentive for utilities to manage costs,
- less frequent regulatory review with fewer rate cases,
- burden of administering additional filings, and
- concerns about shifting financial risk from the utility to the customer.

Q. Do you agree with these concerns?

A. No. With a FRM, the utility will continue to be incentivized to manage costs. With the FRM, the utility will file updated costs annually for the Commission and stakeholders to review, providing greater visibility to changes in the utility's costs on a timelier basis.

There will be a more cost-effective, targeted, and timely regulatory review with a FRM providing benefits to both the utility and customers. Under the reduced size and complexity of the FRM structure, the annual filings will provide a more efficient review process for the Commission and stakeholders rather than engaging in a wide-ranging, administratively labor-intensive, and more costly general rate case. Any burden associated with administering these smaller, more frequent filings will be

limited. The formulaic nature of the FRM will limit the administrative burden of the additional annual filing.

Concerns about a shift of financial risk from the utility to customers are unfounded. ENSTAR's proposed FRM creates better symmetry of costs and revenues, which is beneficial to customers and the utility. The authorized return for ENSTAR is set through a general rate case and it does not change annually by the FRM. Smaller, more frequent rate changes will provide better bill stability to customers as they will not have to face large increases in a general rate case setting. When rates reflect more timely changes in the cost of service, customers' bills reflect both increases and decreases in costs between rate cases.

Q. How will customer rates change with changes in costs of service through ENSTAR's proposed FRM?

A. ENSTAR's updated revenue requirement will be allocated among customer classes in a cost-of-service study and rates designed using the methodology approved in ENSTAR's pending rate case TA352-4. In this way, rates under the FRM will both reflect ENSTAR's current cost to provide service to each customer class and maintain the cost-causer, cost-payer principle.

Q. Are there alternative mechanisms for achieving the same benefits?

A. Other adjustment mechanisms, such as cost recovery trackers, could allow for the adjustment of base rates outside of a rate case to better align rates with the cost of serving customers. Cost recovery trackers, such as infrastructure mechanisms or expense trackers, typically address a narrower scope of costs to serve customers and, therefore, have only limited ability to match customer rates with costs to serve.

Multiple filings would be needed to address similar cost levels compared to the more comprehensive FRM, resulting in less transparency (due to the need to track multiple filings separately) and reduced regulatory efficiency (due to the need to administer multiple filings). These alternatives are discussed further below.

A FRM offers a more comprehensive approach to cost recovery than traditional mechanisms like cost recovery trackers and standard surcharges, which often focus solely on specific capital investments. By incorporating changes in operational expenses and taxation, prior authorized cost of long-term debt, and alongside incremental capital investment costs, a FRM can create a more balanced and sustainable financial model for the utility. This holistic approach to cost recovery benefits customers by supporting consistent infrastructure improvements and maintenance, reducing the risk of service disruptions. It provides financial stability for utilities by preventing revenue shortfalls. Regulators may also benefit from a more predictable and transparent cost recovery structure, reducing the need for potentially more volatile rate adjustments.

Q. Have you reviewed ENSTAR's proposed FRM and do you agree with its mechanics?

A. Yes. I have reviewed the proposed FRM, the associated workpapers, and tariffs and found nothing that should preclude approval of such a mechanism for ENSTAR.

Additionally, I have reviewed the workpapers and found no issues with the operation of the annual update to the Company's revenue requirement.

Q. Is ENSTAR's proposed FRM similar to the FRM approved for CINGSA?

A. Yes. The FRM proposed by ENSTAR is largely identical to the mechanism approved for CINGSA.

Q. Please provide a brief history of the approval of CINGSA's FRM.

A. CINGSA was previously ordered to propose a FRM. The RCA found that CINGSA's rates were misaligned with its revenue requirement within a few years of completing a rate case.[5] Among the issues resolved in a non-unanimous stipulation were the mechanics for updating accounts annually, the cost of capital mechanics, and filing requirements.[6] The Commission accepted the stipulation, finding that the proposed FRM mechanism would likely produce just and reasonable rates, and provided a process to challenge that presumption.[7]

Q. Briefly describe the process by which CINGSA updates its FRM filing annually and how it compares to ENSTAR's proposed FRM.

A. CINGSA must file its Formula Rate Mechanism Annual Revision ("FRMAR") annually by tariff advice letter on or before June 15. The effective date for rates is August 1. A copy of CINGSA's FRMAR filing is provided to Commission Staff, Firm Storage Service ("FSS") Customers, and the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section ("RAPA"). Further, Commission Staff reviews and evaluates the FRMAR filing and may request clarification and

[5] Order U-18-043(15), at 90.
[6] Stipulation filed February 22, 2021, in Docket U-20-012.
[7] Order U-20-012(14), *Order Accepting Stipulation, Approving Tariff Sheets, and Closing Docket*, dated February 22, 2021, at 6:20-22.

additional data.[8] The annual filing requirements for CINGSA are the same procedures ENSTAR proposes for the FRM.

Q. How does ENSTAR's proposed FRM compare to CINGSA's FRM in ensuring transparency in the process and underlying cost details?

A. As noted previously, ENSTAR's proposal is very similar to CINGSA's, which includes annual filing requirements, review by Commission Staff, and processes for clarifying data or challenging costs.

Q. Are there differences between CINGSA's FRM and ENSTAR's proposed FRM?

A. Yes. There are limited differences between the mechanisms that are identified in the tables below. These differences are primarily due to the nature of CINGSA being a gas storage entity while ENSTAR is a gas transmission and distribution utility. This affects the use of certain accounts in the accounting process.

Q. Was CINGSA's FRM primarily based on a concern of depreciating rate base?

A. Yes. The Commission identified the ability to reflect CINGSA's depreciating rate base in a more timely manner in customer rates as one of the benefits supporting the approval of CINGSA's FRM.

Q. How are concerns about depreciating rate base addressed in ENSTAR's FRM proposal?

A. As discussed above, consistent with CINGSA's Commission approved FRM, ENSTAR's FRM proposal will result in rates that more timely reflect the return on and return of plant in service.

[8] Cook Inlet Natural Gas Storage Alaska, LLC Tariff Section 40.

Q. How does ENSTAR's proposed FRM compare with CINGSA's approved FRM?

A. Table 1, 2, and 3 below, describe and compare specific revenue requirements and rate design components of ENSTAR's proposed FRM and CINGSA's approved FRM.

Table 1: Rate Base Components Comparison of ENSTAR and CINGSA

Component	FERC USoA #	ENSTAR Treatment	CINGSA Treatment	Pro Forma Adjustment
Rate Base				
Gas Utility Plant	101 - 105	Stated at Test Year Ending Balance; adjustment to remove ROU leases	Stated at Test Year Ending Balance	
Accumulated Depreciation	108 & 111	Stated at Test Year Ending Balance	Stated at Test Year Ending Balance	
Completed Plant not Classified	106	Stated at Test Year Ending Balance	Stated at Test Year Ending Balance	
Construction Work in Progress	107	Balance set to $0 based on Pro Forma adjustment	Balance set to $0 based on Pro Forma adjustment	X
Gas Stored - Base Gas	117.1	Stated at Test Year Ending Balance	Stated at Test Year Ending Balance	
Cash Working Capital		Calculated using lead/lag time approved in latest lead/lag study	Calculated using lead/lag time approved in latest lead/lag study	X
Materials and Supplies	154 & 156	Stated at Test Year Ending Balance	Stated at Test Year Ending Balance	
Prepayments	165	Stated at Test Year Ending Balance	Stated at Test Year Ending Balance	
Regulatory Assets	182.3	Stated at Test Year Ending Balance and adjusted for regulatory assets approved by Commission	Stated at Test Year Ending Balance for regulatory assets approved in last general rate case	X
Accumulated Deferred Income Taxes		Calculated on items in rate base Statutory changes in federal or state income tax should be reflected	Calculated on items in rate base Statutory changes in federal or state income tax should be reflected	
Net Asset Retirement Obligations		Stated at Test Year Ending Balance ARO debits should be netted against ARO credits	Stated at Test Year Ending Balance ARO debits should be netted against ARO credits	
Customer Advances	252	Stated at Test Year Ending Balance	Stated at Test Year Ending Balance	

Table 2: Revenue, Expenses and Return Components Comparison of ENSTAR and CINGSA

Component	ENSTAR Treatment	CINGSA Treatment	Pro Forma Adjustment
Revenues			
Operating	Known and measurable adjustments to reflect current gas cost rate, reflect test-year end customer counts, to weather normalize revenues, and to remove any revenues not associated with the revenue requirement	Not Applicable	X
Expenses and Return			
Operating	Known and measurable adjustments to salary and wages, uncollectibles expense, inclusion of lease payment for Right of Use Assets (ROU assets and amortization is removed from rate base), cost of gas (as discussed in revenues), and removal of nonallowable expenses such as charitable donations No pro forma adjustments to allocated administrative and general costs	Known and measurable adjustments limited to level of salary and wages No pro forma adjustments to allocated administrative and general costs Shared services and overhead allocation factors are recalculated each year using methodology approved in last general rate case	X
Depreciation and Amortization	Uses depreciation or amortization rates approved in last general rate case	Uses depreciation or amortization rates approved in last general rate case	X
Taxes Other than Income Taxes	Consistent with rate making treatment approved in last general rate case	Consistent with rate making treatment approved in last general rate case	
Income Taxes	Prepared consistent with treatment approved in last general rate case Prescribed formula for calculating income tax expense	Prepared consistent with treatment approved in last general rate case Prescribed formula for calculating income tax expense	X
Rate of Return on Investment	Uses weighted average cost of capital approved in last general rate case Recalculate rate of return if debt is refinanced or new debt issued but use approved return on equity and capital structure	Uses weighted average cost of capital approved in last general rate case Recalculate rate of return if debt is refinanced or new debt issued but use approved return on equity and capital structure	

Table 3: Cost Allocation and Rate Design Components Comparison of ENSTAR and CINGSA

Component	ENSTAR Treatment	CINGSA Treatment
Cost Allocation and Rate Design		
Cost Allocation	Revenue Requirement is allocated between fixed and variable costs using cost classification ratios approved in last general rate case	Revenue Requirement is allocated between fixed and variable costs using cost classification ratios approved in last general rate case
Rate Design	Calculated using methodology approved in last general rate case Billing Units will be modified for normalization adjustments as discussed in revenues and expenses	Calculated using methodology approved in last general rate case Billing units are approved contract quantities or updated annual amounts

Q. Are there any other adjustments in ENSTAR's proposed FRM that are not in the CINGSA FRM?

A. Yes. The annual update of billing determinants will include an adjustment for normal weather which is discussed further by Ms. Johansen.

Q. Have you reviewed the methodology used by ENSTAR to weather normalize test-year usage?

A. Yes. ENSTAR's weather normalization methodology described by Ms. Johansen is generally consistent with and similar to other weather normalization methodologies used in the industry. Weather normalization aims to adjust the test-year usage to what it would have been if the temperature had been normal (ENSTAR defines "normal" as the ten-year historical average). Essentially, ENSTAR's weather normalization methodology calculates a usage per heating degree day ("HDD")[9] for heat-sensitive usage based on actual usage during the test year, and using this usage-per-HDD, and the difference between actual and normal HDD, adjusts usage to normal levels (i.e. "normalizes" usage).

ENSTAR's weather normalization methodology for the adjustment of test year sales volumes is a reasonable and standard method of normalizing weather-sensitive natural gas usage.

[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) and is discuss further by Ms. Johansen.

IV. ENSTAR'S FRM PROPOSAL ALIGNS WITH SIMILAR MECHANISMS IN OTHER JURISDICTIONS

Q. How does ENSTAR's proposed FRM compare with similar mechanisms in other jurisdictions?

A. ENSTAR's proposed FRM is similar to FRMs used in other jurisdictions throughout the United States. Specifically, FRMs allow for an updated test year on an annual basis that captures changing costs to the utility as well as changes in billing determinants (customer counts and volumes). Additionally, certain components are fixed as to the FRM, such as depreciation rates, return on equity, and income tax methodology.

Q. Are there any differences between ENSTAR's proposed FRM and other FRM?

A. There may be minor differences, such as which accounts can be updated with pro forma adjustments. One identifiable difference is in the methodology used for updating rates in the annual FRM filings. Some jurisdictions include an earnings test in the annual FRM filing to determine whether rates would be adjusted. These earnings tests typically revolve around a return on equity deadband utilizing the updated test year. If the resulting return on equity falls outside the deadband, that utility will usually adjust its revenues to get the return on equity back to its baseline amount. However, not all utilities utilize the deadband approach. Some utilities update their revenues to the approved return on equity without considering a deadband, which is similar to the approach ENSTAR is proposing, and for which CINGSA's FRM is based.

Q. In what other jurisdictions have Commissions approved FRM?

A. Based on a 2020 survey, *Alternative Ratemaking Plans in the U.S.*, conducted by Regulatory Research Associates ("RRA"),[10] a group within S&P Global Market Intelligence, approximately fourteen states utilize a FRM for electric and/or gas utilities.

- Alabama
- Arkansas
- Georgia
- Hawaii
- Illinois
- Louisiana
- Maine
- Massachusetts
- Minnesota
- Mississippi
- Pennsylvania
- Tennessee
- Texas
- Vermont

Atrium conducted a further review of alternative ratemaking mechanisms which is discussed further below.

[10] RRA Regulatory Focus: *Alternative ratemaking plans in the U.S.* 4/16/20.

Q. Are you aware of any other states that allow for FRMs for gas utilities?

A. Yes. In Arizona, the Arizona Corporation Commission ("ACC") recently voted on December 3, 2024, to adopt the ACC's policy statement regarding the use of formula rates broadly, that is, beyond just gas utilities, as proposed by the Chairman and another Commissioner.[11] The ACC's Order adopting the policy statement concluded that formula rates advance multiple ratemaking objectives, including improving transparency, oversight and stakeholder engagement, effecting a timelier cost recovery, reducing regulatory burden, and enhancing administrative efficiency.[12] The Commission further concluded that FRMs provide better protection for ratepayers and that maximum flexibility will benefit utilities and ratepayers alike. The ACC's decision will allow regulated utilities to propose formula rate plans in future cases for Commission approval. Specifically, Commissioner Myers made the following comment regarding FRMs (in Arizona the mechanism is called Formula Rate Plan),

> Chairman O'Connor and I brought forward this Formula Rate Plan proposal to advance multiple ratemaking objectives, including improving transparency, oversight and stakeholder engagement, a timelier cost recovery, reducing regulatory burden, and enhancing administrative efficiency.

The Chairman of the ACC also made the following comments:

> We must reduce regulatory lag, improve transparency, and deliver on our commitment to rate gradualism while maintaining affordable, reliable power and water.
>
> Formula rates which have been in use by the Federal Energy Regulatory Commission for over 60 years across the nation are a proven approach to accomplishing those objectives. I applaud Commission Myers for initiating the investigation into alternatives to our draconian methods that

[11] Docket No. AU-00000A-23-0012.
[12] Decision 79647 in Docket No. AU-00000A-23-0012.

> have resulted in lumpy rate increases that customers cannot budget for easily….[13]

The ACC order and comments made by Arizona Commissioners regarding formula rates echo the benefits identified in my testimony for FRMs. Namely, that FRMs promote transparency, administrative efficiency and timely cost recovery which provide a benefit to customers, the utility and other stakeholders.

Q. Did you do further research into the identified gas utilities with FRMs?

A. Yes. Atrium conducted an additional review of gas utilities operating under FRMs beyond those identified by RRA in 2020. This review included an evaluation of associated tariffs, workpapers from recent FRM filings, and applicable commission orders. Further, Atrium conducted a focused survey of gas utilities in the United States and found seven states that currently operate under FRM frameworks – Alabama, Georgia, Louisiana, Mississippi, Oklahoma, South Carolina, and Tennessee.

From each of these states, Atrium identified one or more utilities operating under a FRM and selected a representative utility for comparison to ENSTAR's proposed FRM and the existing CINGSA FRM. The utilities reviewed as part of this analysis include: Spire Alabama, Atlanta Gas Light (GA), Atmos Energy (LA), CenterPoint Energy (MS), Oklahoma Natural Gas Company, Dominion Energy (SC), and Piedmont Natural Gas (TN). While other FRM-operating utilities were identified in these states – such as Peach State Natural Gas (GA), Entergy Louisiana, Entergy New Orleans, Summit Utilities (OK), Arkansas Oklahoma Gas Corporation (OK), Piedmont Natural Gas (SC), Chattanooga Gas (TN), Atmos Tennessee, and Atmos Mississippi, and Spire (MS) – this analysis focused on the seven utilities listed above,

[13] ACC Adopts Formula Rate Plan Policy Statement, last accessed April 17, 2025.

one from each state that utilizes FRMs for gas utilities. The chosen utilities were based on a random selection of one utility per state, so that each state could be compared to ENSTAR's proposed FRM and CINGSA's approved FRM. Specifically, Atrium reviewed how each of these utilities' FRMs treat rate base items, expenses, billing determinants, and rate design.

Q. Please summarize those findings.

A. In reviewing the treatment of rate base and expense items across the surveyed utilities, including ENSTAR and CINGSA, the following observations were made:

- four of the seven jurisdictions approved FRMs utilizing test year ending balances for gas plant and accumulated depreciation. The other three jurisdictions utilize budget amounts, forward looking test years or average balances;
- a variety of methods including budget amounts, 13-month averages and year end balances are used for stored base gas, materials and supplies, and prepayments;
- while accumulated deferred income taxes are generally based on test-year balances, treatment of customer advances varies by utility;
- expense treatment saw more variability across the surveyed utilities;
- operation and maintenance expenses were typically based on actual test year balances, with specific pro forma adjustments that varied by state;
- examples of pro forma adjustments include known and measurable changes to labor rates and pensions, as well as removal of expenses not allowable for ratemaking purposes; and
- depreciation, amortization, and taxes other than income were generally taken as recorded in the test year. Income taxes were commonly calculated using statutory

tax rates, while the allowed return on equity would obviously vary by utility and state.

Finally, cost allocation and rate design methods showed variation across the surveyed utilities. Some, like Spire Alabama and Atmos Louisiana, engage in annual discussions or updates to cost studies, while others, such as Oklahoma Natural Gas and Dominion South Carolina, tie their allocations to principles established in their most recent rate cases. Piedmont Tennessee allows the commission to make a final determination on allocation proposals. Rate design practices also differ; but are largely based on a Commission approved methodology with an annual billing determinant update. These differences illustrate the flexibility allowed under a FRM.

Q. Do you have any other comments on states with an identified FRM in place?

A. Yes. Alabama is a prime example of successful implementation and continuance of FRMs. In Alabama, FRMs are called Rate Stabilization and Equalization Mechanisms ("RSE"). RSEs have been in use since 1982 with modifications made over time. *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives* by Ken Costello of the National Regulatory Research Institute ("NRRI") identifies three benefits of the RSEs: more thorough cost reviews, rate smoothing, and lessening of regulatory lag. NRRI's research paper further conducted a survey of Alabama Commission Staff in 2013 and found that Staff indicated that the RSE has worked well and staff is confident in its review of utilities' costs, earnings and other parameters in determining the reasonableness of any rate adjustments.[14]

[14] *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives* by Ken Costello at 67.

Q. Aside from FRM are other ratemaking mechanisms used to address the delayed recovery of incurred costs and changing costs?

A. Alternative ratemaking typically refers to regulatory processes and mechanisms allowing utility costs and rates to be updated or modified based on a manner outside of a typical general base rate proceeding. Various mechanisms are employed for natural gas utilities, ranging from full decoupling of revenues and costs to specific cost trackers that allow for updating costs such as capital investment, bad debts, or pensions. Other mechanisms include forward-looking multi-year rate plans or incentive-based rates based on predetermined incentive metrics. Additionally, many natural gas utilities have implemented capital cost trackers to address aging utility infrastructure, which helps make the system safer and more reliable. However, not all capital trackers are meant to address aging infrastructure, as some help stabilize utility earnings by allowing the utility to track costs for various capital projects outside of a general rate case.

Q. What alternative ratemaking mechanisms are most relevant to ENSTAR's proposed FRM?

A. The mechanisms most akin to ENSTAR's proposed FRM are often referred to as annual formula rate mechanisms, capital or infrastructure trackers, and expense trackers.

Q. Please briefly describe annual formula rate mechanisms, capital or infrastructure trackers, and expense trackers.

A. Annual formula rate mechanisms update a utility's test year for revenue requirement purposes to a period more recent than its last general rate case. This allows for costs,

revenues, and billing determinants to be updated yearly, which results in more meaningful rates based on the current operating environment. This type of mechanism is much more comprehensive than those that focus on a specific cost, such as a pension tracker. Annual formula rate mechanisms often include an earnings test based on a return on equity deadband to determine whether rates will be updated. This earnings test looks to see if the earned ROE based on the more recent test year falls outside a predetermined deadband, often 40 to 200 basis points.

Capital or infrastructure trackers, on the other hand, look only at specific utility plant replacements or specifically approved capital projects. As discussed above, this type of mechanism allows the utility to recover its capital-related investments on a more timely basis. Capital or infrastructure trackers could be used to address aging infrastructure, federal and state regulations, Commission or state policy goals, or generally to better match rates with the utility's current operating condition.

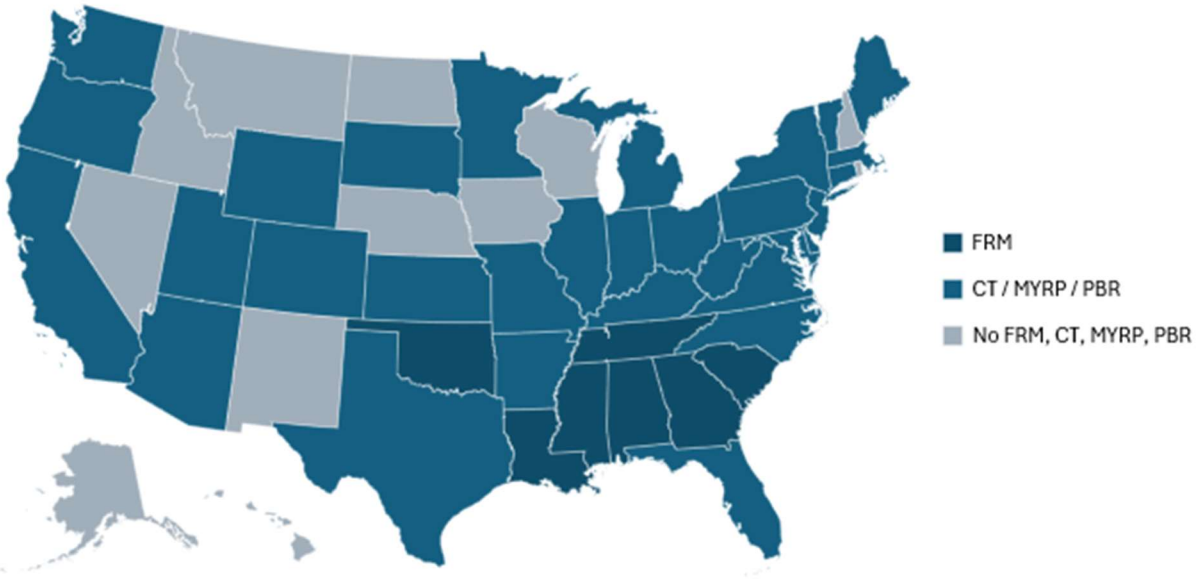
Expense trackers are like capital trackers, except instead of tracking capital-related costs, they track the operating expenses incurred by the utility for a specific period. The more recent expense levels are then used to update rates outside of a general rate case. There are various types of expense including trackers for fuel costs, pensions, uncollectibles, and depreciation expenses.

Q. Which states have alternative ratemaking mechanisms for natural gas utilities?

A. Atrium conducted a review of regulated natural gas local distribution companies in the United States to determine the prevalence of various alternative ratemaking mechanisms. Figure 2 below shows the specific alternative rate mechanisms by state (i.e., FRM, capital or infrastructure trackers ("CT"), multi-year rate plans ("MYRP"),

and performance-based rates ("PBR"), or some combination thereof). In summary, 38 of the lower-48 states have some form of alternative rate mechanisms for natural gas local distribution companies. Atrium's review identified seven states with formula rate plans, thirty-five with capital trackers, three with multi-year rate plans, and eight with some performance-based rates.

Figure 2: Survey of U.S. Natural Gas Utility Alternative Ratemaking Mechanisms



Q. In addition to CINGSA's FRM have other alternative regulatory mechanisms been approved by the RCA?

A. Alaska's regulatory landscape includes two additional mechanisms that share a FRMs core objectives: the Simplified Rate Filing (SRF)[15] and the Simplified Pipeline Tariff (SPT).[16] Both use streamlined, formula-based frameworks to update rates based on

[15] 3 AAC 48.700-790
[16] 3 AAC 48.450-490

historical test years with defined adjustments, providing utilities with a structured path to maintain cost recovery without initiating a full rate case.

In the case of SRFs, electric cooperatives have the ability to adjust rates as frequently as quarterly to maintain a target Times Interest Earned Ratio subject to certain bounds,[17] allowing the electric cooperatives to have timely recovery of changes in costs. While SRF and SPT are designed for specific utility types, they reflect the same underlying goals – enhancing stability, reducing administrative burden, and enabling more timely recovery of costs.

V. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

[17] Rate adjustments allowed on SRF regulations may not exceed a cumulative 20% increase in any three-year period, or a cumulative 8% in any 12-month period, excluding purchased power and fuel costs rate adjustments per Alaska Admin Code 3 AAC 48.770.

CYNDEE FANG

DIRECTOR

Experienced industry leader who strives to engage others to conceive, create, and execute practical solutions to the most challenging problems. Extensive experience and understanding of utility regulatory process including expertise in cost of service and rate design.

EDUCATION

University of Minnesota, Ph.D. (ABD), Applied Economics

University of California, Berkeley, B.S., Political Economics of Natural Resources

YEARS EXPERIENCE

20+

RELEVANT EXPERTISE

Cost of Service & Rate Design, Expert Witness, Regulatory Strategy

PROFESSIONAL HISTORY

ATRIUM ECONOMICS

DIRECTOR, 2024-CURRENT

NORTHWESTERN ENERGY

VICE PRESIDENT - REGULATORY; 2023 - 2024

- Oversaw the Company's regulatory activities in Montana, South Dakota, and Nebraska.
- Developed and executed a regulatory strategy to advance a more constructive regulatory framework to meet the Company's strategic needs.
- Established an in-house cost of service and rate design team.

DIRECTOR – REGULATORY AFFAIRS MONTANA; 2021 - 2023

- Developed and executed a strategy for Montana rate reviews to advance a more constructive regulatory framework.

SAN DIEGO GAS AND ELECTRIC

ENERGY SUPPLY - ORIGINATION & PORTFOLIO DESIGN MANAGER; 2020 – 2021

- Lead the portfolio design of Electric & Fuel Procurement (E&FP), as SDG&E right-sizes portfolio, with market analytics that inform and guide the long-term strategy including daily optimization activities and forward-looking planning efforts.
- Lead all competitive procurement of renewable energy and conventional resources beyond one year to fulfill SDG&E's energy and resource capacity needs.

FORECASTING, RESEARCH & ANALYTICS – MANAGER OF ENERGY RESEARCH & ANALYSIS; 2018 – 2020

- Lead and oversee load forecasting, research and analysis teams to ensure the advancement of data-driven decision making in support of the Company's strategic needs including the advancement of operational improvements to better address changing California energy policies. Key areas of focus include impacts of customer adoption of advanced technology (PV, EV) and analysis of COVID impacts.
- Development of collaborative internal stakeholder processes to ensure alignment on Company direction regarding electric sales forecast. Key areas of focus include identification of key drivers and CCA expansion.
- Establishment of collaborative relationships with external stakeholders to support the advancement of the Company's strategic objectives related to the sales forecast.

RATES AND PRICING – MANAGER OF CUSTOMER PRICING; 2017 – 2018

- Oversight of all aspects of the pricing policy to meet the strategic needs of SDG&E and ensure fair and equitable rates for SDG&E's 1.4 million electric customers.
- Development, advocacy and implementation of the Company's rate strategy, including the development of regulatory filings to advance this strategy.
- Development of collaborative internal stakeholder processes to ensure alignment on Company direction regarding electric rates.
- Establishment of collaborative relationships with external stakeholders to support the advancement of the Company's rate strategy needs to include representing the Company as a witness in regulatory proceedings and lead settlement negotiations.

RATE STRATEGY AND ANALYSIS MANAGER; 2015 – 2017
ELECTRIC RATES MANAGER; 2010 – 2015
PRINCIPAL/REGULATORY ECONOMIC ADVISOR; 2006 - 2010

MINNESOTA DEPARTMENT OF COMMERCE

PUBLIC UTILITIES RATES ANALYST; 2003 - 2006

- Development of the position of the Minnesota Department of Commerce on matters related to energy policy and presentation before the Minnesota Public Utilities Commission
- Implementation of Minnesota's Renewable Energy Objective, including the establishment of the Minnesota Renewable Energy Tracking System and compliance review of utility filings (integrated resource plans, certificate of need)

REGULATORY EXPERIENCE

The Pursuit of a More Constructive Regulatory Framework

Montana Cost Recovery

2022 Montana Rate Review – Docket No. 2022.07.078

- Witness: Priority Regulatory Mechanisms proposing new revenue adjustment mechanisms and redesign of existing mechanisms https://www.northwesternenergy.com/docs/default-source/default-document-library/billing-and-payment/2022-montana-rate-review/08-fang-direct-testimony-regulatory-policy.pdf
- Witness: Allocated Cost of Service and Rate Design presenting the Company's moderation proposals to allocated cost of service and rate design for customers https://www.northwesternenergy.com/docs/default-source/default-document-library/billing- and-payment/2022-montana-rate-review/31-fang-acos-rd-direct-testimony.pdf

Rate Design Policy to Advance Customer Needs

- Affordability Rulemaking – R.18-07-006: Order Instituting Rulemaking to Establish A Framework and Processes for Assessing the Affordability of Utility Service – SDG&E lead
- Residential Essential Use Study – A.19-11-019: Joint Utility Proposal for the Study to Identify Electric Essential Usage for Residential Customers – SDG&E lead
- Residential TOU Exclusions Pursuant to Section 745 – R.12-06-013: To ensure residential customers defaulting to TOU do not experience unreasonable hardship under TOU rates – Rate Design Policy witness
- SDG&E High Bill Mitigation Strategy – SDG&E lead

  Responsibilities include development of development of package of proposals, regular briefings to executive team, advocacy ahead of the filing of SDG&E's proposals, and identifications of witnesses and project teams, as well as serve as witness for PFM to eliminate the High Usage Charge (HUC) and PFM to change to timing of the California Climate Credit to provide customers with relief high bills during summer months.
- Residential TOU Exclusions Pursuant to Section 745 – R.12-06-013: To ensure residential customers defaulting to TOU do not experience unreasonable hardship under TOU rates – Rate Design Policy witness
- A.17-09-005: Application of San Diego Gas & Electric Company for Authority to Implement Rate Relief and Increase Spend in Support of the San Diego Unified Port District's Energy Management Plan – Cost Recovery and Rate Design witness
- A.17-02-008: Application of SDG&E for Authority to Implement Economic Development Rates – Cost Recovery and Rate Design witness

Rate Design to Advance Fair and Equitable Cost Recovery

Residential Rate Reform

- A.17-12-013: Application of San Diego Gas & Electric Company for Authority to Update Electric Rate Design Regarding Residential Default Time-Of-Use Rates and Fixed Charges
- R.12-06-013: SDG&E's Application in response to Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations Net Energy Metering Reform
- R.14-07-002: SDG&E Application in response to Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering

Rate Design Policy

- SDG&E General Rate Case Phase 2 Application for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design - Rate Design and Policy Witness
- A.15-04-012: SDG&E's 2016 General Rate Case Phase 2 Proceeding - includes proposal to update TOU periods o A.11-10-002: SDG&E's 2012 General Rate Case Phase 2
- A.14-01-027: SDG&E's 2015 Rate Design Window Filing – includes proposal to update TOU periods and residential baseline

Fair and Equitable Utility Cost Recovery

- SDG&E General Rate Case Application for Authority to Update its Electric and Gas Revenue Requirements and Base Rates - Cost Recovery and Rate Design witness; multiple years

  A.17-10-007: SDG&E 2019 General Rate Case – addressing affordability

  A.14-11-003: SDG&E 2016 General Rate Case

  A.10-12-005: SDG&E 2012 General Rate Case
- A.15-09-010: SDG&E's Wildfire Expense Memorandum Account (WEMA) Proceeding – Cost Recovery witness

Energy Supply Cost Recovery

- PCIA Reform - A.17-04-018: Joint Application of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company for Approval of the Portfolio Allocation Methodology for All Customers – *Cost Recovery and Rate Design witness for SDG&E*
- Establishment of Tree Mortality Non-Bypassable Charge (TM-NBC) - A.16-11-005: Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805 – *Cost Recovery and Rate Design witness for SDG&E*

- SONGS Decommissioning - A.14-12-007: Joint Application of SDG&E and SCE for 2014 SONGS Units 2 & 3 Decommissioning Cost Estimate and related Decommissioning – Cost Recovery witness o Establishment of Cost Allocation Mechanism (CAM) - A.11-05-023: SDG&E's Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power – *Cost Recovery and Rate Design witness*
- ERRA Trigger - A.17-05-012: Expedited Application of San Diego Gas & Electric Under the Energy Resource Recovery Account Trigger Mechanism – Witness proposing one-time bill credit
- ERRA Forecast - SDG&E's Energy Resource Recovery Account (ERRA) Forecast Application for the recovery of costs associated with electric procurement – *Cost Recovery and Rate Design witness, multiple years*

Rate Design to Advance Clean Energy Policy Goals

Development of Innovative Rate Design to Support Electric Vehicle Charging

- A.17-01-020: Application of SDG&E for Authority to Implement Priority Review and Standard Review Proposals to Accelerate Widespread Transportation Electrification – *Rate Design Policy and Cost Recovery witness*
- A.14-04-014: SDG&E's Electric Vehicle Grid Integration (VGI) Pilot Program – *Rate Design Policy and Cost Recovery witness*
- SDG&E was recognized as the 2020 Investor-Owned Utility of the Year by Smart Electric Power Alliance (SEPA) for its "Power Your Drive" program and the innovative VGI rate, an hourly dynamic grid integrated rate. https://sepapower.org/knowledge/2020-sepa-power-players- award-winners/

SELECTED PUBLICATIONS / PRESENTATIONS

Panelist at Critical Consumer Issue Forum (CCIF)

- Critical Consumer Issues Forum (CCIF) 14th Annual Kickoff Forum in Collaboration at 2023 NARUC Annual Meeting; Topic: "Exploring Rate Design & Other Regulatory Tools: Maximizing Grid Value & the Customer Experience."
- "Navigating the Challenges & Opportunities of Today's Regulatory Landscape" https://criticalconsumerissuesforum.com/wp-content/uploads/CCIF-2023-Navigating-Regulatory- Landscape-Report.pdf
- "The Customer-Centered Clean Energy Transition: Balancing Technology, People & the Planet"

Presenter/Instructor ad EEI Advanced Rate School at University of Wisconsin Public Utility Institute (WPUI); July 2021.

Advanced Workshop in Regulation and Competition – Annual Western Conference held by Center for Research in Regulated Industries, of Rutgers Business School, Rutgers University

- "Zen and the Art of Rate Design" – Webinar sponsored by Center for Research in Regulated Industries, of Rutgers Business School, Rutgers University, January 13, 2021 – Link to webinar Zen and the Art of Rate Design [nam02.safelinks.protection.outlook.com]
- Member of Western Conference Organizing Committee from 2015-2022.
- Author/Co-author and Presenter as well as chair/discussant – multiple years.
    - 2022 – "Residential Time of Use Rates…and how one utility got there"
    - 2019 – "A Modern Rate Architecture for California's Future"
    - 2017 – "Solar Adoption and Customer Consumption in the Residential Sector"
    - 2016 – "Solar Adoption and Customer Demand in the Residential Sector"
    - 2014 - "Revisiting Rate Structure Reform to Meet a Low Carbon Future"
    - 2013 - "Unbundling – A Needed Fix for Residential Rate Design"
    - 2012 - "Rate Structure Reform to Meet a Low Carbon Future"

"Residential Time of Use…and what it took to get there" Presentation at EPRI's Rates Working Group (September 2020)

Discussant for 2020 POWER Conference– Session: Retail Rate Design (April-May 2020, Energy Institute at Haas School of Business, University of California, Berkeley) - Link to 2020 POWER Conference https://haas.berkeley.edu/energy-institute/events/power-conference/past-power-conferences/2020- power-conference/

Panelist at CEC Workshop on Scope of Load Management Rulemaking (January 2020) - Link to workshop https://www.energy.ca.gov/event/workshop/2020-01/commissioner-workshop-scope- load-management-rulemaking-19-oir-01

Presentation at Advanced Rate Design Strategy Workshop hosted by Hawaiian Electric (July 2019) - Link to workshop https://www.hawaiianelectric.com/clean-energy-hawaii/grid-modernization- technologies/advanced-rate-design-strategy

Panelist at Forth Roadmap Conference 2019 – Session: Rate Design to Accelerate Transportation Electrification (June 2019) - Link to Roadmap 12 http://roadmapforth.org/program/

"A Modern Rate Architecture for California's Future" by Margot Everett (PG&E), Cynthia Fang (SDG&E), Andre Ramirez (SCE), and Jude Schneider (SCE); Public Utilities Fortnightly, Vol 156, No. 12; November 1, 2018.

"SDG&E's Design of Grid Integrated Rates" at Panelist at CEC Workshop: CA Vehicle-Grid Integration Roadmap (October 2018) - Link to workshop information https://www.energy.ca.gov/programs-and- topics/programs/california-vehicle-grid-integration-roadmap-update/past-workshops-and

Panelist at CPUC ZEV Rate Design Forum 2018: California Public Utilities Commission forum to review and evaluate electric rate designs that could support the state's zero-emission vehicle goals established by Governor Jerry Brown's executive order B-48-18: having 5 million light-duty zero-emissions vehicles on the road by 2030. (June 2018) - Link to CPUC ZEV Rate Design Forum 2018 https://www.cpuc.ca.gov/energy/electricrates/

Panelist at CPUC Rate Design Forum on Demand Charges and Advanced Rate Designs (December 2017) - Link to CPUC Electric Rate Forum 2017 https://www.cpuc.ca.gov/General.aspx?id=6442455548

Presentations at Utility of the Future Rate Group sponsored by Economics Incorporated

- "COVID 19 Impacts – Some Early Insights" (May 2020)
- "A Customer-Focused Alternative to Pricing" (November 2019)
- "SDG&E's Design of Real Time Pricing and Other Dynamic Rates" (April 2017)

STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

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

In the Matter of the Consideration of the Formula Rate Mechanism Tariff Revision Designated as TA 353-4 Filed by ENSTAR NATURAL GAS COMPANY, LLC	)))))	Docket No. U-25-____

PREFILED DIRECT TESTIMONY OF CHELSEA N. GUINTU

PREFILED DIRECT TESTIMONY
OF
CHELSEA N. GUINTU

TABLE OF CONTENTS

I. POSITION AND QUALIFICATIONS

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

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

Q. Briefly describe your professional experience and educational background.

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

Q. Briefly describe your current responsibilities.

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

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

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

Q. Have you previously testified before the RCA?

A. Yes, I provided testimony to the RCA on behalf of ENSTAR in Dockets U-19-101, U-22-081, and TA352-4, and on behalf of CINGSA in Dockets U-18-024 and U-21-058.

II. PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present and sponsor ENSTAR's Formula Rate Mechanism ("FRM") proposal. I will explain the mechanism and the reasons ENSTAR chose to include certain items and options in the FRM. I also sponsor the tariff sheets filed with TA353-4 that reflect the proposed provision, which are attached to my testimony as Exhibit CNG-2 for convenience.

III. ENSTAR'S PROCESS IN PREPARING A FRM

Q. What was ENSTAR's process in preparing a FRM?

A. ENSTAR reviewed CINGSA's FRM, the Simplified Rate Filing ("SRF") Procedures for Electric Cooperatives (3 AAC 48.700-790), and the Simplified Pipeline Tariffs ("SPT") regulations (3 AAC 48.450-490), which are other instances of the use of formula rates in Alaska. ENSTAR also engaged with Atrium Economics, LLC

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

("Atrium") for third-party expertise regarding similar mechanisms in other jurisdictions.

Q. Did ENSTAR review formula rate mechanisms in jurisdictions outside of Alaska?

A. Yes, ENSTAR's research on mechanisms similar to its proposed FRM extended to Lower-48 jurisdictions. ENSTAR witness Ms. Cynthia Fang of Atrium discusses the use of formula rates and other related rate revision mechanisms in other jurisdictions.

Q. Did ENSTAR take Commission policies into account when it prepared its FRM proposal?

A. Yes. First, ENSTAR is aware of the Commission preference for cost-based rates using a historical "test year with appropriate adjustments incorporating changes expected in the period in which the rates will be in effect."[3] In addition to this being the general policy of the Commission for general rate cases, the concept is reflected in the Commission's SRF procedures. As I explain below, ENSTAR's FRM is based on historic rate base and expenses with a limited number of known and measurable pro forma adjustments.

Second, in Order U-18-043(15) the Commission recognized that formula rates could provide the benefit of stability for a utility and its customers.[4] The National Regulatory Research Institute has identified stability of rates as one of the customer benefits of a formula rate mechanism.[5] In TA560-8, dated December 20, 2024,

[3] Order U-05-043(15)/U-05-044(15), *Order Establishing Revenue Requirement, Ordering Refunds, and Requiring Filings*, dated January 8, 2007 at 7.

[4] Order U-18-043(15), *Order Resolving the Revenue Requirement and Cost-of-Service Issues and Required Filings*, dated August 16, 2019 at 90.

[5] *Formula Rate Plans: Do They Promote the Public Interest?,* Briefing Paper 10-11, National Regulatory Research Institute, August 2010, at 11 states "[i]nstead of a utility filing a rate case proposing a double-digit increase in rates, for example, a [formula rate plan] could achieve the same increase more gradually over time."

Chugach Electric Association, Inc. ("Chugach") detailed the benefits that its customers receive from an SRF. These benefits included aligning revenues with operational costs, cost savings to customers by avoiding extensive regulatory procedures, and minimizing the complexity of administrative workload associated with general rate cases by allowing Chugach to allocate internal resources more effectively.

Q. How would ENSTAR's customers benefit from the stability of formula rates?

A. As discussed more thoroughly in the direct testimony of ENSTAR witnesses Ms. Fang and Ms. Inna B. Johansen, ENSTAR customers will benefit from the stability of formula rates as their bills will be adjusted annually to reflect current costs. Allowing ENSTAR to adjust its rates annually to take into consideration inflation, additional investment, and other prudent cost changes, lets customers plan for gradual rate changes as opposed to much larger changes between less frequent general rate cases.

Q. How did ENSTAR accommodate cost-based rates in its FRM proposal?

A. Similar to SRF filings under 3 AAC 48.710(b) and CINGSA's FRM Annual Revision, ENSTAR's FRM proposal begins with a historical test year, and provides for pro forma and normalizing adjustments in preparing its own annual revision (Formula Rate Mechanism Annual Revision or "FRMAR"). To accommodate the requirement for a streamlined review and approval process, the provision requires that the adjustments be prepared "consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case."[6]

Q. What do you mean by "streamlined review"?

[6] Section 2803e(2)(a) Sheet 311.

A. I use the term "streamlined" to mean a defined review and approval process that is intended to be less expensive and less time-consuming, as contrasted with a full general rate case proceeding. Formula rate revision mechanisms rely on certain methodologies and results (such as return on investment) determined in earlier general rate proceedings to simplify and accelerate the review and approval process. Some of them also utilize report data already on file with the regulatory body. CINGSA's annual FRM filing along with the Commission's Simplified Rate Filing Procedures for Electric Cooperatives (3 AAC 48.700-790) are examples of a streamlined formula rate revision methodology.

Q. What other features did ENSTAR incorporate in its proposal to accommodate the requirement for a streamlined review and approval process?

A. As discussed more thoroughly below, ENSTAR's proposed FRM provision provides for multiple items following the methodology of the results approved or accepted in ENSTAR's most recent general rate case. For example, depreciation and amortization expense is calculated using rates approved or accepted in its last concluded general rate case. Additionally, the return on equity and capital structure will stay the same as approved or accepted in ENSTAR's last concluded general rate case. ENSTAR will only update the cost of capital for any changes in the cost of long-term debt.[7]

Q. Will costs in the FRM be allocated among customers the same way as they are in rate cases?

A. Yes, capital and operating costs will be allocated between customer classes using the same cost classification and allocation methodologies that were approved or accepted

[7] This is similar to the CINGSA FRM provision that was stipulated to in Docket U-20-012. See the discussion of the specific provision below (Section 2803E) for more detail.

in ENSTAR's last concluded general rate case. ENSTAR will update the cost-of-service ("COS") study using the revenue requirement developed in each annual FRM filing.

Q. How is rate design treated in ENSTAR's FRM?

A. Similar to CINGSA's FRM, the structure and calculation of rates are consistent with the methodology approved or accepted in ENSTAR's last concluded general rate case. This is another treatment ENSTAR is proposing to streamline the review process.

Q. What other items were incorporated in ENSTAR's proposal to assist with a streamlined review and approval process?

A. Similar to CINGSA's FRM methodology, for the rate base account balances, ENSTAR proposes to use year-end balances of the relevant balance sheet accounts. There are two reasons for using year-end rather than 13-month average as in 3 AAC 48.275(a)(9). First, year-end balances are readily available (and thus verifiable) from the FERC Form 2 that ENSTAR is required to include as part of its annual operating report to the RCA. Second, year-end balances better reflect the total investment that is used to serve customers than a 13-month average.

In proposed Section 2805a (Sheet 316), ENSTAR also adds a requirement to provide a full copy of the FRMAR filing to the Commission Staff and the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section ("RAPA") at the time it is filed with the Commission, along with any Excel workbooks with working formulas used to create the schedules, exhibits or attachments in the filing. This proposed process closely follows the established process for CINGSA's FRM annual

filing. The FERC Form 2 along with Excel workbooks will allow the Commission Staff and RAPA to easily verify the submitted FRM filing.

Q. What features were designed into ENSTAR's FRM proposal to assist in avoiding more frequent rate case filings?

A. Similar to processes established in SRF and CINGSA's FRM, the proposed provision exempts ENSTAR from the requirement to file a FRMAR for any test year in which it has already filed a general rate case, or where ENSTAR has been directed by the Commission to file the information required by 3 AAC 48.275(a), thus initiating a general rate case. Further, ENSTAR is also exempt from the annual filing requirement if it has a general rate case pending before the Commission.

Q. Does ENSTAR's proposal limit the Commission's authority?

A. No, in fact Section 2801a(1) (Sheet 307) clearly states "[N]o provision contained within this Section 2800 will … limit the RCA's authority over rates."

IV. OVERVIEW OF FRM PROVISION

Q. Please describe the major sections of the FRM provision in ENSTAR's tariff sheets submitted with this filing.

A. Below I will describe the major sections of the tariff sheets.

A. Application

Q. Please describe the Application section.

A. The Application section of ENSTAR's Tariff (Section 2801a on Sheet 307) provides for a FRMAR to all ENSTAR's rate schedules. The annual revision shall be filed by tariff advice letter on or before April 15 of each year upon approval of this TA filing, unless ENSTAR files, or is in the midst of, a general rate case as was noted above.

B. FRMAR Calculation

Q. Please discuss the purpose of the FRMAR calculation.

A. The new proposed section sets out in detail the calculation of the Revenue Requirement ("RR") and the recalculation of ENSTAR's rate schedules. Section 2803 starts on Sheet 309.

Q. Please discuss the calculation of the RR.

A. The annual RR is calculated following the traditional calculation of an Alaska investor-owned utility revenue requirement, according to the following formula set out in Section 2803a (Sheet 309):

$$RR = OM + DEP + OT + RI + IT$$

As with general Alaska revenue requirement filings under 3 AAC 48.275(a), the FRMAR RR calculation starts with a historical Test Year's operating expense information adjusted for known and measurable changes and prepared consistent with the rate making treatments approved or accepted in ENSTAR's last concluded general rate case.

Q. What does "OM" stand for?

A. "OM" refers to all reasonable and necessary operation and maintenance expenses and gas cost incurred during the test year adjusted for known and measurable changes and prepared consistent with the rate making treatments approved or accepted in ENSTAR's last concluded general rate case.

Q. What kind of adjustments will be permitted under the provision?

A. A limited number of normalizing and balancing adjustments will be permitted, and those adjustments will be discussed in more detail below.

Q. What does "DEP" stand for?

A. "DEP" means depreciation and amortization expense. As discussed in more detail below, ENSTAR will calculate DEP based on end of test-year plant and asset balances using the depreciation and amortization rates approved by the Commission in ENSTAR's last concluded general rate case.

Q. What does "OT" stand for?

A. "OT" means taxes other than income tax during the test year, adjusted for known and measurable changes occurring after the test year and before the filing date, and prepared consistent with the rate making treatments approved or accepted in ENSTAR's last concluded general rate case.

Q. **What does "RI" stand for?**

A. "RI" means return on prudently incurred investment calculated as ENSTAR's rate of return (weighted average cost of capital) multiplied by the test year rate base using year-end balances of the related accounts. The tariff provision provides that the rate of return used in the FRMAR shall be the weighted average cost of capital approved or accepted in ENSTAR's last concluded general rate case, updated for any changes in the cost of debt as follows:

> If the Company refinances existing long-term debt or issues new or additional long-term debt during the Test Year, it will recalculate its weighted average cost of capital using its approved or accepted return on equity, its approved or accepted capital structure, and its new cost of debt. The new cost of debt calculation will include the costs of issuing the debt and any gain or loss on retiring the old long-term debt including any retirement or refinancing premium.[8]

Q. Are adjustments to rate base permitted?

[8] CNG-2, Section 2803e(1)(a) on Sheet 311.

A. Yes. Sections 2803e(2)(b)(i), 2803e(2)(f), and 2803e(2)(i) on Sheet 312 allows for the following adjustments to rate base: (1) removing the right of use ("ROU") leases; (2) calculating cash-working capital; and (3) including allowed regulatory assets. These adjustments will be discussed in more detail below.

Q. What does "IT" stand for?

A. "IT" means income tax for the adjusted test year, adjusted for known and measurable changes, and prepared consistent with the rate making treatments approved or accepted in ENSTAR's last concluded general rate case. The income tax adjustment is described in more detail below.

Q. What is the next step in the FRMAR?

A. Once the annual RR has been determined, Section 2803g on Sheet 314 provides it shall be adjusted by normalized gas cost; then be allocated between the rate classes; and then between customer, capacity and commodity costs using the same cost classification and allocation methodologies that were approved or accepted in the Company's last concluded general rate case.

Q. Does the provision set out how customer rates are determined once the COS study is applied?

A. Yes. Consistent with the discussion above, Section 2803h on Sheet 314 states that customer rate schedules shall be calculated consistent with the rate derivation methodologies approved or accepted in ENSTAR's last concluded general rate case. The billing units used will be actual billing units for the test year modified for the normalizing adjustments set out in Section 2803b(1) on Sheet 309.

C. FRMAR Schedules

Q. What is to be included with the FRMAR tariff advice filing?

A. Section 2804 on Sheet 315 states that in addition to the tariff advice letter, the FRMAR filling shall include the following:

- Schedules of Test Year Normalized Operating Revenues and Expenses, Rate Base, Weighted Cost of Capital, and Normalized Test Year Revenue Requirement in similar format to the first four pages of the Company's 275(a) schedules and its COS Study and Rate Design provided in ENSTAR's last concluded general rate case.
- A schedule and explanation of all normalizing, annualizing, pro forma, and known and measurable change adjustments.
- Tariff sheets showing any proposed adjustments to the Company's rates.

Q. Why did ENSTAR include the schedules discussed above?

A. These schedules are in a format that are familiar to the Commission, Commission staff, RAPA, and to ENSTAR's customers, and can easily be compared to the similar schedules in ENSTAR's last full general rate case 275(a) filings.

D. FRMAR Evaluation and Review Procedures

Q. Please discuss Section 2805 that starts on Sheet 316.

A. The proposed section provides that:

- A copy of the FRMAR filing will be provided to the Commission Staff and RAPA at the time it is filed with the Commission, along with any Excel workbooks with working formulas used to create the schedules, exhibits or attachments in the filing.
- ENSTAR will provide the Commission Staff with any requested clarifications or additional data as the Commission Staff reviews and evaluates the FRMAR filing.

- ENSTAR shall work in good faith to answer all questions raised by the Commission Staff promptly and fully. If ENSTAR and the Commission Staff agree that any calculations or schedules in the FRMAR filing should be revised, ENSTAR shall promptly file with the Commission the resulting adjusted rate calculations, revised tariff sheet, or revised FRMAR schedules.

E. FRMAR Effective Date and Further Proceedings

Q. Please discuss Section 2806 on Sheet 317.

A. This proposed section discusses the effective date of FRMAR filings and further proceedings if a FRMAR filing is suspended. The process closely follows procedures adopted in CINGSA's FRMAR. Since a FRMAR filing is filed as a tariff advice letter, it follows the timelines set out in AS 42.05.411, becoming effective at the end of the 45-day notice period, unless suspended. If the Commission were to suspend a FRMAR filing, ENSTAR shall have the option to supplement its filing and request and convert the filing into a General Rate Case Application. The section sets out the timelines for ENSTAR to provide notice of supplementing and the deadline to supplement.

Q. Why is it appropriate for ENSTAR to have the option to supplement its filing and request, and convert a FRMAR to a General Rate Case Application if the Commission suspends the filing?

A. In order to provide for a streamlined review and approval process, the proposed provision provides that most items follow the methodologies or specific findings and results approved or accepted in the most recent ENSTAR concluded general rate case. Under a FRMAR filing, ENSTAR will not be able to propose major methodology changes, or changes to items such as ROE, capital structure, and depreciation rates. It is ENSTAR's assumption that under AS 42.05.175 and AS 42.05.421, the suspension

of a FRMAR filing would place it under the same 450-day statutory timeline as a general rate case. With any suspension, ENSTAR would also likely be required to file supporting testimony. Given that and the extended timeline, fairness allows that ENSTAR be permitted to fully supplement its case and address items that it would not otherwise have been allowed to do in the FRMAR filing.

V. PRO FORMA ADJUSTMENTS TO FRMAR

Q. What pro forma adjustments is ENSTAR proposing in its FRMAR filing?

A. ENSTAR proposes the following FRMAR adjustments, which will be described in greater detail below:

- Removal of Disallowed Regulatory Assets;
- Removal of Miscellaneous Revenues and Expenses;
- Removal of Other Assets;
- Removal of Construction Work in Progress ("CWIP");
- Removal of ROU Lease;
- Gas Cost Adjustment;
- Weather Normalization Adjustment;
- Uncollectible Account Adjustment;
- Income Tax Adjustment;
- Payroll Adjustment;
- Cash Working Capital Adjustment;
- Year End Plant Adjustment; and
- Year-End Revenues Adjustment.

A. Removal of Disallowed Reg Assets

Q. Please describe the Removal of Disallowed Regulatory Assets adjustment proposed in ENSTAR's FRM.

A. This pro forma adjustment will reduce ENSTAR's rate base and operating expenses, as necessary, for disallowed regulatory assets and associated amortization expense.

B. Removal of Misc. Revenues and Expenses

Q. Please describe the Removal of Miscellaneous Revenues and Expenses adjustment.

A. This adjustment will remove certain operating expenses and miscellaneous revenues following Commission precedent. For example, ENSTAR will use this pro forma adjustment to remove expenses related to lobbying, charitable contributions, penalties, club dues, and incidental employee benefits. ENSTAR will also remove historical revenues not associated with the revenue requirement. One example is revenues associated with the Homer Surcharge. These revenues are recovered through a separate mechanism that includes items resolved by stipulation and accepted by the Commission in Order U-19-014(9), and they are not included in general system-wide rates. Additionally, atypical or non-recurring expenses will be removed under this adjustment.

C. Removal of Other Assets

Q. Please describe the Removal of Other Assets adjustment.

A. This adjustment will remove various regulatory assets that are to be excluded from rate base because they were not approved or accepted for inclusion in rate base by an order of the Commission. For example, the stipulation settling Docket U-14-111 (accepted

by the Commission) provided that ENSTAR shall not include the unamortized amounts of the Anchor Point Litigation in rate base, would be removed under this adjustment.

D. Removal of CWIP

Q. Please describe the Removal of CWIP adjustment.

A. In keeping with Commission precedent, ENSTAR will remove CWIP from the rate base calculation.

E. Removal of ROU Lease

Q. Please describe the Removal of ROU Lease Contracts adjustment.

A. This pro forma adjustment (listed at Section 2803b(1)(e) on Sheet 311 and Section 2803e(2)(b)(i) on Sheet 312) will be performed consistent with the methodology approved or accepted in ENSTAR's last concluded general rate case. In Docket U-22-081, ENSTAR removed ROU finance leases (and the associated accumulated amortization) and the ROU operating leases from rate base (and depreciation and amortization expense) and included the lease payments in administrative and general ("A&G") expenses.

Q. Did ENSTAR propose a similar treatment of operating leases in TA352-4?

A. Yes. ENSTAR filed a 2024 test-year general rate case in TA352-4. ENSTAR proposed the same methodology as utilized in Docket U-22-081.

F. Gas Cost Adjustment

Q. Please discuss the pro forma adjustment to normalize gas cost revenues.

A. 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 which typically takes effect annually on July 1. This adjustment is listed in Section 2803b(1)(c) on Sheet 309, gas cost revenues in the

test year will be removed and replaced with the most recent weighted average cost of purchased gas approved in its tariff. The new gas cost is then applied to the weather-normalized volumes, as discussed below, to calculate the adjusted cost of purchased gas.

G. Weather Normalization Adjustment

Q. Please describe the weather normalization adjustment.

A. This adjustment is listed in Section 2803b(1)(d) on Sheet 310. The weather normalization adjustment applies to ENSTAR's four General Service customer classes. The details of ENSTAR's proposed calculation are shown on Exhibit CNG-3. This methodology is the same as the weather normalization adjustment approved in its 2000 test year rate case (Docket U-00-088), proposed in its 2009 test year rate case (Dockets U-09-069/U-09-070), presented in its 2021 test year rate case (Docket U-22-081), and proposed in ENSTAR's most recent general rate case filed in TA352-4.[9]

Q. How is the weather normalization adjustment currently calculated?

A. ENSTAR's currently used weather normalization adjustment is performed in multiple steps. First, to determine the use per consuming customer, the test year sales volume for each General Service Class will be divided by the number of average consuming customers in the test year. Second, the use per consuming customer for the months of June through August (non-heating months) will be totaled and divided by the number of days in those months (92) to determine base use per day which will be multiplied by annual days (365) to determine the base use per customer. Third, the base use per

[9] The U-00-088 revenue requirement was adjudicated by the Commission and set in Order U-00-088(12), dated August 8, 2002. The 2009 and 2021 test year rate cases were settled, and the Commission accepted the stipulation in Orders U-09-069(10)/U-09-070(10) and U-22-081(11). The weather normalized volumes per customer proposed by ENSTAR were used to derive the tariff rates that were approved in that order.

customer will be subtracted from the test year use per consuming customer to determine the heating load per customer. Fourth, the test year heating degree days for the months of June through August (non-heating months) will be totaled and divided by the number of days in those months (92) to determine the average daily base degree days which will be multiplied by annual days (365) (annual base degree days). The annual base degree days will be subtracted from the actual test year degree days, developing the heating degree days. Fifth, the heating load per customer will be divided by heating degree days. Sixth, the delta between the actual test year degree days and the historical 10-year average of heating degree days will be multiplied by the heating load per degree day. The resulting adjustment will be added to the test year use per consuming customer to determine the normalized use per customer which will be multiplied by the test year average number of consuming customers. Finally, the delta between normalized volume and test year sales volumes is multiplied by the current volumetric rate.

Q. Will this pro forma be consistent with the methodology approved in ENSTAR's most recent general rate case?

A. Yes, similar to other adjustments discussed in my testimony, the methodology used for weather normalization in the FRMAR will be based on that established in the final order from the last concluded general rate case.

H. Uncollectible Account Adjustment

Q Please describe the uncollectible account adjustment.

A. As noted in Section 2803b(1)(f) on Sheet 311, ENSTAR will adjust its test year uncollectible (bad debts) expense to match normalized retail revenues (including the updated gas cost discussed above) and normalized volumes.

I. Income Tax Adjustment

Q. Please describe the details as to how income tax expense will be calculated.

A. This is discussed in Section 2803f on Sheet 313, unless ordered differently in ENSTAR's last concluded general rate case, ENSTAR will calculate income tax expense as follows:

- Equity Return shall be calculated as rate base multiplied by the weighted cost of common equity from the Company's last Concluded General Rate Case;
- After-tax net return shall be calculated as the equity return, plus or minus the net annual amortization of protected and unprotected excess Accumulated Deferred Income Tax ("ADIT"), as approved or accepted in Docket U-22-081;
- Income tax expense before amortization of excess ADIT shall be calculated as the after-tax net return multiplied by a composite gross-up state/federal income tax factor calculated as ((1/(1 – incremental state corporate income tax rate))/(1/(1-federal corporate income tax rate))) – 1; and
- Income tax expense shall be calculated as the income tax expense before amortization of excess ADIT, plus or minus the net annual amortization of excess ADIT.

Q. Is this consistent with the way the income tax allowance was calculated in Docket U-22-081?

A. Yes. It is also consistent with the income tax calculation proposed in ENSTAR's recent general rate case filing in TA352-4.

J. Payroll Adjustment

Q. Please describe the Payroll adjustment.

A. The purpose of the payroll adjustment set out in Section 2803b(1)(a) on Sheet 309 is to account for changes in the compensation of ENSTAR's employees compared to the test-year data, consistent with Commission precedent. This pro forma will be performed consistent with the methodology approved or accepted in its last concluded general rate case.

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. Additionally, this pro forma adjustment is consistent with adjustments included in CINGSA's FRM.

K. Cash Working Capital

Q. Please describe the Cash Working Capital adjustment.

A. As set out in Section 2803e(2)(f) on Sheet 312, the cash working capital allowance shall be calculated using the lead/lag days approved in the Company's most recent lead-lag study accepted or approved by Commission order.

Q. How was the cash working capital component of rate base determined in ENSTAR's last general rate case?

A. ENSTAR filed a lead-lag study in Docket U-22-081. Additionally, ENSTAR stipulated with the other parties to perform a lead-lag study in its next general rate case, which is included in the general rate case filed as TA352-4.

L. Year-End Plant Adjustment

Q. Please describe the Year-End Plant adjustment.

A. Section 2803e(2)(b) on Sheet 311 provides that the gas utility plant included in rate base at the test year end balance. The purpose of this adjustment is to synchronize depreciation and amortization expense with year-end plant balances, and consists of two items. First, depreciation expense is calculated on year-end plant balances using rates approved in the last concluded general rate case. Second, amortization expense on ENSTAR's software will be calculated by excluding software that became fully amortized by December 31 of the test-year. Finally, the monthly amortizations will be multiplied by 12 to calculate annualized software amortization expense. The amortization relating to regulatory assets discussed in Section 2803e(2)(i) on Sheet 312 shall be included upon approval or acceptance by the Commission.

M. Year-End Revenues Adjustment

Q. Please describe the Year-End Revenues adjustment.

A. Consistent with using year-end rate base, ENSTAR's current revenues from the General Service classes will be adjusted to match the number of customers in each class at test year-end, as listed in Section 2803b(1)(b) on Sheet 309. Specifically, revenues from monthly customer charges will be adjusted to reflect the number of customers during December of the test-year, with revenues from volumetric charges also being adjusted to reflect the number of test year-end customers.

Q. What other adjustment will be included on the Year-End Revenues adjustment?

A. The volumes of gas sold to the test year-end number of customers in each of the four General Service classes will be multiplied by ENSTAR's most recent weighted average cost of purchased gas approved in its tariff to calculate a representative level of GCA revenues for each sales class.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Chelsea N. Guintu

EMPLOYMENT

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

Manager of Regulatory and Planning: 2024 - Present

Supervisor of Rates and Regulatory Affairs: 2019 - 2024

Senior Financial Analyst: 2015 - 2019

Aldrich CPAs, Anchorage, AK: 2014 - 2015

Regulatory Consultant

The Brandon Skinner Group, Anchorage, AK: 2013 - 2014

Staff Accountant

Newhouse & Vogler CPAs, Anchorage, AK: 2013

Staff Accountant

Pacific Plumbing Supply Company, Anchorage, AK: 2009 - 2012

Office Administrator

EDUCATION

University of Illinois Springfield: Graduate Certificate in Public Utility Management and Regulation, 2020

University of Alaska Anchorage: Master of Business Administration with emphasis in Business Intelligence, 2016

University of Alaska Anchorage: Bachelor Business Administration with a major in Accounting, 2012

OTHER

Certified Public Accountant, Alaska

American Institute of Certified Public Accountants, member

ENSTAR Natural Gas Company, LLC

Effective:

Issued By: ENSTAR Natural Gas Company, LLC

ENSTAR Natural Gas Company, LLC

Section 2800 – Formula Rate Mechanism **D,N**

ENSTAR NATURAL GAS COMPANY, LLC

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

§2801 **Formula Rate Mechanism** **D,N**

§2801a **Application**

This Formula Rate Mechanism ("FRM") provides for an annual revision ("FRMAR") to the Company's Rate Schedules found in Section 2000 – Rate Schedules – General Service, Section 2100 – Rate Schedules – Large Transportation-Firm, and Section 2200 – Rate Schedules – Large Transportation-Interruptible. Rate calculations and adjustments required by this Section 2800 shall be determined on a revenue requirement basis.

§2801a(1) No provision contained within this Section 2800 will limit the Company's ability to file a General Rate Change Application or limit the RCA's authority over rates.

§2801a(2) Except as provided in Section 2801a(3), the Company will file a FRMAR by tariff advice letter on or before April 15 (or on the next Business Day after April 15 if April 15 is not a Business Day) of each year beginning after approval of TA353-4.

§2801a(3) The Company is exempt from filing a FRMAR for any Test Year for which:

§2801a(3)(a) The Company files a General Rate Change Application;

§2801a(3)(b) The Company is directed by the Commission to file the information required by 3 AAC 48.275(a) thus initiating a General Rate Case for a given Test Year; or

§2801a(3)(c) A General Rate Change Application or General Rate Case is pending before the Commission.

§2802 **Definitions**

§2802a In addition to the definitions set out in Section 200 of this Tariff, the terms listed below shall have the following meanings for the purpose of this Section 2800:

§2802a(1) The term "3 AAC" means the regulations of Commission as set out in Title 3 of the Alaska Administrative Code. The numbers following "3 AAC" are references to a specific regulation section.

§2802a(2) The term "AOR" means the Company's annual operations report filed with the Commission as required by AS 42.05.451(b). It includes the FERC Form No. 2.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2802a(3) The term "AS" means the Alaska Statutes. The numbers following "AS" are references to a specific statute section.

§2802a(4) The term "FERC" shall mean the Federal Energy Regulatory Commission.

§2802a(5) The term "Filing Date" means the date the Company files a FRMAR.

§2802a(6) The term "Final Order" means the last substantive order in a General Rate Case approving permanent rates, or accepting a settlement setting permanent rates, that becomes final and is not subject to further reconsideration by the RCA or appeal.

§2802a(7) The term "FRM" shall mean formula rate mechanism under this Section 2800.

§2802a(8) The term "FRMAR" means the FMR annual revision under this Section 2800.

§2802a(9) The term "General Rate Case" means a docketed proceeding before the RCA to review the entire revenue requirement (including cost of capital) and cost of service of the Company and involves the RCA review of the information required by 3 AAC 48.275(a). A General Rate Case may be initiated by a General Rate Change Application filed by the Company or by the action of RCA. A "Concluded General Rate Case" is one where a Final Order has been issued.

§2802a(10) The term "General Rate Change Application" means a request to change the rate schedules filed in accordance with AS 42.05.411 and 3 AAC 48.275(a).

§2802a(11) 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).

§2802a(12) The term "Test Year" means the twelve Months ending December 31 of the preceding calendar year.

§2802a(13) The Term "TYEB" means the Test Year End Balance, i.e., the balance at the end of the Test Year.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2802a(14) The terms "Uniform System of Accounts" and "USoA" mean the Uniform System of Accounts for Class A natural gas companies prescribed by Part 201 of the FERC regulations (18 C.F.R. Part 201) and required for use by 3 AAC 48.277(5). The number following "USoA" is a specific USoA account number.

§2803 **FRMAR Calculation**

§2803a The FRM shall calculate a revenue requirement ("RR") annually. The Company shall request recovery of its RR and shall include schedules showing the computation of any adjustments to the Test Year data. The annual RR shall be calculated according to the following formula:

$$RR = OM + DEP + OT + RI + IT$$

Where:

§2803b OM = all prudently incurred, reasonable and necessary operation and maintenance expenses and gas cost ("GC") incurred during the Test Year adjusted for known and measurable changes and prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case.

§2803b(1) Known and measurable adjustments shall be limited to Section 2803b(1)(a) through Section 2803b(1)(f) below and shall also be limited to those changes that have occurred prior to the Filing Date and that are more than likely to continue through the period in which the rates will be in effect and are consistent with the Commission's precedent regarding known and measurable adjustments.

§2803b(1)(a) The changes in the level of salary and wage rates that occurred during the Test Year, or are known and measurable, shall be annualized.

§2803b(1)(b) The changes in the cost of gas and gas revenues during the Test Year to reflect Test-Year end customers count.

§2803b(1)(c) The changes in the cost of gas during the Test Year to reflect the currently approved Determination of Gas Cost Adjustment found in Section 2301.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2803b(1)(d) The changes to the volumes, cost of gas and gas revenues to reflect weather normalization consistent with the methodology will be determine for each General Service Class (Section 2000) as follows:

§2803b(1)(d)(i) Use per Consuming Customer: The test year sales volume for each General Service Class will be divided by the test year number of average consuming customers;

§2803b(1)(d)(ii) Base Use per Customer*:* The Use per Consuming Customer for the months of June through August (non-heating months) will be totaled and divided by the number of days in those months (92) to determine Base Use per Day which will be multiplied by annual days (365);

§2803b(1)(d)(iii) Heating Load per Customer: The Base Use per Customer will be subtracted from the test year Use per Consuming Customer;

§2803b(1)(d)(iv) Heating Degree Days: The test year HDD for the months of June through August (non-heating months) will be totaled and divided by the number of days in those months (92) to determine the average daily base degree days which will be multiplied by annual days (365) (annual base degree days). The annual base degree days will be subtracted from the actual test year degree days, developing the Heating Degree Days;

§2803b(1)(d)(v) Heating Load per Degree Day: The Heating Load per Customer divided by Heating Degree Days;

§2803b(1)(d)(vi) Normalized Volumes: The delta between the actual test year degree days and the historical 10-year average of HDD will be multiplied by the Heating Load per Degree Day. The resulting adjustment will be added to the test year Use per Consuming Customer to determine the Normalized Use per Customer which will be multiplied by the test year average number of consuming customers; and

§2803b(1)(d)(vii) Weather Normalization Adjustment: The delta between Normalized Volume and test year sales volumes is multiplied by the current volumetric rate.

D – Removed "Reserved for Future Use."

D,N

§2803b(1)(e) The removal of ROU lease amortization replaced with Test Year lease payments.

§2803b(1)(f) The changes in uncollectible expense normalized for the changes in Test Year revenues to reflect adjustments described in Section 2803b(1)(a) through Section 2803b(1)(e) above.

§2803c DEP = depreciation and amortization expense is calculated on end of Test Year actual plant and asset balances at the depreciation and amortization rates utilized in calculating the tariff rates accepted and approved in Order U-22-081(15) or approved, accepted or utilized in calculating the tariff rates approved in a subsequent Concluded General Rate Case. The amortization related to regulatory assets discussed in Section 2803e(2)(i) below shall be included in DEP upon approval or acceptance by the Commission.

§2803d OT = taxes other than income tax from the Test Year prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case.

§2803e RI = return on prudently incurred investment calculated as the Company's rate of return (weighted average cost of capital) multiplied by the Test Year rate base.

§2803e(1) Rate of return shall be the weighted average cost of capital approved or accepted in the Company's last Concluded General Rate Case, except as provided in Section 2803e(1)(a).

§2803e(1)(a) If the Company refinances existing long-term debt or issues new or additional long-term debt during the Test Year, it will recalculate its weighted average cost of capital using its approved or accepted return on equity, its approved or accepted capital structure, and its new cost of debt. The new cost of debt calculation will include the costs of issuing the debt and any gain or loss on retiring the old long- term debt including any retirement or refinancing premium.

§2803e(2) Rate base is prepared in accordance with the following:

§2803e(2)(a) Known and measurable adjustments shall be limited to Section 2803e(2)(b), (f), (i) and (j) below and also be limited to those changes that have occurred prior to the Filing Date and are consistent with the ratemaking treatments approved or accepted in the Company's last Concluded General Rate Case.

§2803e(2)(b) Gas utility plant shall be the TYEB of USoA accounts 101-105.

D – "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2803e(2)(b)(i) ROU leases shall be removed from rate case and reclassified in accordance to ratemaking procedures approved or accepted in the Company's last Concluded General Rate Case.

§2803e(2)(c) Accumulated depreciation reserve shall be the TYEB of USoA accounts 108 & 111.

§2803e(2)(d) Plant completed not classified shall be the TYEB of USoA account 106.

§2803e(2)(e) Gas stored underground shall be the TYEB of USoA account 117.1.

§2803e(2)(f) The cash working capital allowance shall be calculated using the lead/lag time period (whether positive or negative) utilized in the Company's most recent lead lag study accepted or approved by Commission order.

§2803e(2)(g) Materials and supplies shall be the TYEB of USoA accounts 154 and 156.

§2803e(2)(h) Prepayments shall be the TYEB of USoA account 165.

§2803e(2)(i) Regulatory assets shall be the TYEB of the regulatory assets in USoA account 182.3 that were approved or accepted to be included in rate base by an order of the Commission.

§2803e(2)(j) Accumulated deferred income taxes ("ADIT") shall be those taxes, calculated for regulatory purposes, directly associated with an item in rate base (excluding Cash Working Capital) and shall include excess accumulated deferred income taxes ("Excess ADIT"). If any such ADIT amounts are debits, they shall be netted against the ADIT credits, and if the net amount is a debit, then it shall be an addition to rate base. The amount included in the rate base calculation for ADIT shall be the TYEB for the Test Year.

§2803e(2)(j)(i) Statutorily enacted changes in the state or federal income tax rate that occurred during the Test Year, or are known and measurable, shall be reflected in the calculation of the income tax allowance (per Section 2803f(2) below).

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2803e(2)(k) Net asset retirement obligation shall be those accounts for asset retirement obligations ("ARO") excluding any amounts and accounts included in the gas utility plant accounts (USoA accounts 101-105) or accumulated depreciation and amortization reserves (USoA accounts 108 and 111). If any such ARO amounts are debits, they shall be netted against the ARO credits, and if the net amount is a debit, then it shall be an addition to rate base. The amount included in the rate base calculation for net ARO shall be the TYEB.

§2803e(2)(l) Customer advances for construction shall be the TYEB of USoA account 252.

§2803f IT = income tax for the adjusted Test Year, adjusted for known and measurable changes occurring after the Test Year and before the Filing Date, and prepared consistent with the rate making treatments approved or accepted in the Company's last Concluded General Rate Case.

§2803f(1) Income tax expense shall be calculated as follows:

§2803f(1)(a) Equity Return shall be calculated as rate base multiplied by the weighted cost of common equity from the Company's last Concluded General Rate Case,

§2803f(1)(b) After-tax net return shall be calculated as the equity return, plus or minus the net annual amortization of protected and unprotected Excess ADIT, as approved or accepted in Docket U-22-081;

§2803f(1)(c) Income tax expense before amortization of Excess ADIT shall be calculated as the after-tax net return multiplied by a composite gross-up state/federal income tax factor calculated as ((1/(1 – incremental state corporate income tax rate)) X (1/(1 - incremental federal corporate income tax rate))) – 1; and

§2803f(1)(d) Income tax expense shall be calculated as the income tax expense before amortization of Excess ADIT, plus or minus the net annual amortization of Excess ADIT.

§2803f(2) Statutorily enacted income tax rate changes that occurred during the Test Year, or are known and measurable, shall be annualized, per the income tax expense calculation described in Section 2803f(1)(c) above. The Company shall comprehensively account for, including establishing a regulatory liability or asset to account for, any such change in income tax expense in the calculation to ensure recovery of income tax expense under new and old income tax rates.

D – Removed "Reserved for Future Use."

Effective:

ENSTAR Natural Gas Company, LLC

D,N

§2803g **Cost Allocation**:
Once the annual RR has been determined as provided in Section 2803a through Section 2803f above, it shall be adjusted by normalized gas cost; then be allocated between the rate classes; and then between customer, capacity and commodity costs using the same cost classification and allocation methodologies that were approved or accepted in the Company's last Concluded General Rate Case.

§2803h **Derivation of Rates**:
Rates for the Company's Rate Schedules found in Sections 2000, 2100 and 2200 shall be calculated from the RR consistent with the rate derivation methodologies approved or accepted in the Company's last Concluded General Rate Case. The billing units used will be actual billing units for the Test Year modified for the normalizing adjustments set out in Section 2803b(1) above.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2804 **FRMAR Schedules**

In addition to the tariff advice letter, the FRMAR filing shall include the following:

§2804a Schedules of Test Year Normalized Operating Revenues and Expenses, Rate Base, Weighted Cost of Capital, and Normalized Test Year Revenue Requirement in similar format to the first four pages of the Company's 275(a) schedules and its Cost Allocation by Customer Class, Allocation Factors, and Rate Design as provided in Docket U-22-081.

§2804b A schedule and explanation of all normalizing, annualizing, pro forma, and known and measurable change adjustments.

§2804c Tariff sheets showing any proposed adjustments to the Company's rates.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

D,N

§2805 **FRMAR Evaluation and Review Procedures:**

§2805a A copy of the FRMAR filing will be provided to the Commission Staff and the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section ("RAPA") at the time it is filed with the Commission, along with any Excel workbooks with working formulas used to create the schedules, exhibits or attachments in the filing.

§2805b The Commission Staff shall review and evaluate the FRMAR filing, and may request clarification and additional data, and the Company shall provide the same.

§2805c The Company shall work in good faith to promptly and fulsomely answer all questions raised by the Commission Staff. If the Company and the Commission Staff agree that any calculations or schedules in the FRMAR filing should be revised, the Company shall file with the Commission the resulting adjusted rate calculations, revised tariff sheet, or revised FRMAR schedules.

D – Removed "Reserved for Future Use."

ENSTAR Natural Gas Company, LLC

N

§2806 **FRMAR Effective Date and Further Proceedings**

§2806a A filed FRMAR becomes permanent at the end of the notice period described in AS 42.05.411 unless the Commission suspends the filing in accordance with AS 42.05.421.

§2806b If the Commission suspends the filing, the Commission may allow the filing to take effect on an interim basis, subject to refund.

§2806b(1) If the Commission suspends a FRMAR filing, the Company shall have the option to supplement its filing and request, and convert the filing to a General Rate Case Application.

§2806b(1)(a) The Company shall notify the Commission that it will supplement its filing and request, and convert the FRMAR filing to a General Rate Case Application, within 30 days of the Order suspending the FRMAR filing.

§2806b(1)(b) After giving the notification, the Company shall have an additional 45 days to supplement its filing and convert it to a General Rate Case Application.

§2806b(1)(c) The FRMAR filing may be updated to reflect those changes that have occurred prior to the date on which the Company supplements its filing under this Section 2806b, including updating adjustments made in the FRMAR filing. Any new or revised known and measurable adjustments shall be limited to those changes that have occurred prior to the date the Company supplements its filing.

§2806b(1)(d) The Company shall have the option to request a revision to any interim rates upon its filing converting the FRMAR to a General Rate Case Application.

ENSTAR Natural Gas Company, LLC

N

Reserved for Future Use

Effective:

Issued By: ENSTAR Natural Gas Company, LLC

ENSTAR Natural Gas Company, LLC

N

Reserved for Future Use

WEATHER NORMALIZATION ADJUSTMENTS

Purpose: To adjust for abnormal weather during 2024.

G1 Class:

Test Year Use per Consuming Customer (Mcf)			143.69	143.69
Base Use per Customer				
Jun Use per Customer		4.21		
Jul Use per Customer		3.55		
Aug Use per Customer		4.44		
Total		12.21		
No. of Days - Jun - Aug		92		
Base Use per Day		0.1327		
Annual Days		365		
Base Use per Customer			48.43	
Heating Load per Customer			95.26	
Heating Degree Days				
Actual Degree Days		9,870		
Base Degree Days:				
Jun	245			
Jul	203			
Aug	268			
Total	716			
No. of Days - Jun - Aug	92			
Average Daily	7.78			
Annual Days	365			
Annual Base Degree Days		2,841		
Heating Degree Days			7,029	
Heating Load per Degree Day			0.01355	
Excess Degree Days				
10-Year Normal		9,363		
Actual Degree Days		9,870		
Excess Degree Days			(507)	
Adjustment per Customer (Mcf)				(6.87)
Normalized Use per Customer (Mcf)				136.83
Test Year Customers				141,889
Normalized Volumes (Mcf)				19,414,078
Test Year Volumes (Mcf)				20,388,390
Excess Weather-related Volumes				(974,312)
G1 Volumetric Rate per Mcf				$ 1.4982
G1 Weather Normalization Adjustment				**$ (1,459,714)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G2 Class:

Test Year Use per Consuming Customer (Mcf)			363.32	363.32
Base Use per Customer				
Jun Use per Customer		10.54		
Jul Use per Customer		9.76		
Aug Use per Customer		11.35		
Total		31.65		
No. of Days - Jun - Aug		92		
Base Use per Day		0.3440		
Annual Days		365		
Base Use per Customer			125.57	
Heating Load per Customer			237.75	
Heating Degree Days				
Actual Degree Days		9,870		
Base Degree Days:				
Jun	245			
Jul	203			
Aug	268			
Total	716			
No. of Days - Jun - Aug	92			
Average Daily	7.78			
Annual Days	365			
Annual Base Degree Days		2,841		
Heating Degree Days			7,029	
Heating Load per Degree Day			0.03382	
Excess Degree Days				
10-Year Normal		9,363		
Actual Degree Days		9,870		
Excess Degree Days			(507)	
Adjustment per Customer (Mcf)				(17.14)
Normalized Use per Customer (Mcf)				346.18
Test Year Customers				5,947
Normalized Volumes (Mcf)				2,058,556
Test Year Volumes (Mcf)				2,160,467
Excess Weather-related Volumes				(101,910)
G2 Volumetric Rate per Mcf				$ 0.9602
G2 Weather Normalization Adjustment				**$ (97,854)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G3 Class:

Test Year Use per Consuming Customer (Mcf)			1,166.24	1,166.24
Base Use per Customer				
Jun Use per Customer		35.47		
Jul Use per Customer		37.39		
Aug Use per Customer		39.80		
Total		112.67		
No. of Days - Jun - Aug		92		
Base Use per Day		1.2246		
Annual Days		365		
Base Use per Customer			447.00	
Heating Load per Customer			719.24	
Heating Degree Days				
Actual Degree Days		9,870		
Base Degree Days:				
Jun	245			
Jul	203			
Aug	268			
Total	716			
No. of Days - Jun - Aug	92			
Average Daily	7.78			
Annual Days	365			
Annual Base Degree Days		2,841		
Heating Degree Days			7,029	
Heating Load per Degree Day			0.10232	
Excess Degree Days				
10-Year Normal		9,363		
Actual Degree Days		9,870		
Excess Degree Days			(507)	
Adjustment per Customer (Mcf)				(51.85)
Normalized Use per Customer (Mcf)				1,114.39
Test Year Customers				3,758
Normalized Volumes (Mcf)				4,187,988
Test Year Volumes (Mcf)				4,382,828
Excess Weather-related Volumes				(194,840)
G3 Volumetric Rate per Mcf				$ 0.9449
G3 Weather Normalization Adjustment				**$ (184,105)**

WEATHER NORMALIZATION ADJUSTMENTS (Continued)

G4 Class:

Test Year Use per Consuming Customer (Mcf)			7,609.31	7,609.31
Base Use per Customer				
Jun Use per Customer		275.36		
Jul Use per Customer		320.75		
Aug Use per Customer		311.83		
Total		907.93		
No. of Days - Jun - Aug		92		
Base Use per Day		9.8688		
Annual Days		365		
Base Use per Customer			3,602.12	
Heating Load per Customer			4,007.19	
Heating Degree Days				
Actual Degree Days		9,870		
Base Degree Days:				
Jun	245			
Jul	203			
Aug	268			
Total	716			
No. of Days - Jun - Aug	92			
Average Daily	7.78			
Annual Days	365			
Annual Base Degree Days		2,841		
Heating Degree Days			7,029	
Heating Load per Degree Day			0.57007	
Excess Degree Days				
10-Year Normal		9,363		
Actual Degree Days		9,870		
Excess Degree Days			(507)	
Adjustment per Customer (Mcf)				(288.85)
Normalized Use per Customer (Mcf)				7,320.46
Test Year Customers				1,015
Normalized Volumes (Mcf)				7,431,487
Test Year Volumes (Mcf)				7,724,721
Excess Weather-related Volumes				(293,234)
G4 Volumetric Rate per Mcf				$ 0.6581
G4 Weather Normalization Adjustment				**$ (192,977)**