BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. NORTHWEST NATURAL GAS COMPANY Respondent.	DOCKET UG-______

NORTHWEST NATURAL GAS COMPANY

Direct Testimony of Robert J. Wyman

WEATHER NORMALIZED LOAD
COST OF SERVICE STUDY
RATE SPREAD & RATE DESIGN

Exh. RJW-1T

December 18, 2020

DIRECT TESTIMONY OF ROBERT J. WYMAN

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and position with Northwest Natural Gas Company ("NW Natural" or the "Company").

A. My name is Robert J. Wyman. My current position is Senior Rates and Regulatory Analyst for NW Natural. I am responsible for economic analysis, weather normalized residential and commercial class load, cost of service, and rate design. I have been a witness and supported witnesses and created technical work papers on multiple rate and advice filings with the Oregon and Washington utility commissions.

Q. Please summarize your educational background and business experience.

A. I hold a Bachelor of Science in Economics from the Robert D. Clark Honors College at the University of Oregon and a Master of Arts in Applied Economics from the University of Michigan. Prior to attending graduate school, I was employed by ECONorthwest, an economic consultancy, and worked in the firm's transportation and land use practice area. I was responsible for the technical analysis and consultation for dozens of projects, largely in the Pacific Northwest and Western states. When I joined NW Natural in 2016 as a Rates and Regulatory Analyst, I had a cumulative eight years of professional consulting experience with a focus on public finance and policy, urban economics, and financial feasibility (benefit-cost) analysis.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the methodology for NW Natural's weather normalized use-per-customer ("UPC") analysis for the Residential and Commercial rate classes, present the Embedded Cost of Service study ("EmCOSS"), and describe the rate spread and rate design proposal. At the end of this testimony, I describe how the rate spread proposal will allocate incremental revenue requirement to each NW Natural Washington Tariff rate schedule ("RS"), excluding special contract schedules. Finally, I explain how the Company proposes to mitigate rate impacts across all rate schedules.

Q. Would you please summarize your testimony?

A. My testimony is made up of three distinct sections: the Company's UPC weather normalizing methodology, the EmCOSS, and the proposed rate spread and the application of the Company's rate mitigation proposals. First, I will detail the UPC normalizing methodology (referred here as the "Normal UPCs") to create short-term weather normalized volumes for the Residential and Commercial rate classes. The normalized volumes are used to support the determination of the proposed revenue requirement presented in Exh. KTW-1T. Second, I will outline NW Natural's EmCOSS methodology and will show the embedded cost inputs by capital investment and operations expense categories, on a rate schedule basis. Third, I will show how the Company proposes to spread the incremental revenue requirement and apply rate impact migitation across rate schedules.

My testimony explains how the Normal UPCs were derived using an autoregressive model specification to interpret the relationship between temperature and natural gas usage to create weather normalized revenues for the Residential and Commercial rate classes for the test year of October 1, 2019 through September 30, 2020 ("Test Year"). I also explain how the Company derived Test Year revenues for the Industrial rate class.

This testimony also explains how the EmCOSS is used to assign incremental revenue requirement to rate schedules based on the "cost causality" principle (i.e., how much of the capital in-service investment costs and operations and maintenance ("O&M") and other expenses required to serve the Company's customers can be directly and indirectly attributable to each rate schedule). The EmCOSS submitted with this case indicates that the Large Commercial and Industrial rate schedules are paying more than their determined cost of service under present rates, which is consistent with past rate case results. The study also indicates that the two Residential rate schedules (RS 1 and RS 2 Residential) in addition to the RS 27 Dry-Out schedule are paying less than their determined cost of service, a result that is consistent with the results from the Company's last rate case, UG-181053. Also consistent is the finding that the two Small Commercial rate schedules are overpaying their cost to serve, albeit to a lesser extent than indicated in the prior rate case.

Finally, I describe the methodology by which NW Natural proposes to spread the incremental revenue requirement. The rate spread section indicates how the proposed spread of incremental revenue requirement will impact rate schedules and customers' average bills. As explained later in this testimony, the Company submits the EmCOSS based on its own load analysis in lieu of a "load study" described in WAC 480-85-030(5). We have chosen not to adjust the relative rate spread or propose rate design modifications for any rate class until a load study first can be completed and evaluated alongside other analyses. Therefore, the Company proposes to spread the incremental revenue requirement on an equal percent of margin basis to all rate schedules entirely through volumetric billing rates for both rate effective periods of the

Multi-Year Plan ("MRP"). As a result of this proposal, each rate schedule will retain its relative EmCOSS indicated revenue-to-cost and cost of service parity ratio at present rates.

Q. Are you introducing any exhibits with your testimony?

A. Yes. I am sponsoring Exhibits RJW-2, RJW-3, and RJW-4. Exh. RJW-2 is a summary of the Company's embedded cost analysis results and revenue requirement allocation by rate schedule, including the natural gas cost of service template in compliance with WAC 480-85-040(1). Exh. RJW-3 and Exh. RJW-4 indicate the total revenue increases by rate schedule, as well as the bill impact and rate increase by rate schedule.

II. WEATHER NORMALIZED LOAD

Q. What is Test Year weather normalized load?

A. The Test Year weather normalized load represents expected residential usage and commercial usage, by rate schedule, on the basis of 30-year average daily observed weather. The weather normalized volumes are a short-term load adjustment with respect to the effects of weather that is built using the following steps:

1. Weather data are collected to produce a 30-year historical benchmark for normal weather.
2. Actual weather data are paired with actual load data on a billing cycle and rate schedule basis. The paired data are used in a econometric time series analysis, as described below, to produce weather normalized UPCs for the Residential and Commercial rate classes for the Test Year period (i.e., the Normal UPCs).
3. For these rate classes, the Normal UPCs are multiplied by the Test Year customer counts to derive the Test Year weather normalized load.

The weather normalized load is used to calculate revenues at existing rates in the proposed revenue requirement presented in Exh. KTW-3. In addition to being a revenue requirement input, the Normal UPCs are also used to create rate schedule-specific load factors, an important input to the EmCOSS.

Q. Please describe how the Normal UPCs are derived.

A. The Normal UPCs represent estimated weather normalized usage on a per customer basis. The normalizing analysis relies on the relationship between temperature (measured in heating degree days, or "HDDs") and load by rate schedule and time of year (measured in daily increments).[1] The Normal UPCs were derived as described below:

- I collected daily high and low temperature data observed in Vancouver (NOAA Station 94298 -- Vancouver Pearson Airport) for the period June 1, 1990 through May 31, 2020 for two purposes: (1) to have recent actual weather data to statistically analyze against recent actual usage; and (2) to produce a 30-year historical benchmark for normal weather. Where gaps in the data are present, I used NOAA Station 356751 (Portland International Airport) to estimate, using a simple linear regression, normal degree days at Station 94298.
- I matched actual therm usage and actual HDDs for the period of January 2012 through February 2020. As part of this process, I used load data on a billing cycle basis, and matched actual weather observations with the days between cycle meter

[1] The degree day is a unit of measurement based on the difference between the average temperature for a day and a base set point. Degree days are additive in that the sum of the daily degree days over the course of the month is taken to represent that month's weather. The degree day is a common unit of measurement that allows for an analysis of increasing usage as a function of increasingly colder weather.

read dates. This process ensures actual usage recorded for each billing period is appropriately matched to the observed weather for the same period. I then created a weighting of the number of days, customers, and HDDs associated with each billing cycle for each schedule in the Residential and Commercial customer classes. I used a 59-degree Fahrenheit base set point for Residential schedules and a 58-degree Fahrenheit base set point for Commercial schedules as our temperature set points to convert temperature observations to HDDs.[2]

- After aggregating therm usage and weights on a monthly basis, I used these aggregates to regress therm use per premise per day against HDDs per day, using a type of econometric time series model specification. I created a model estimation for every firm sales schedule in the Residential and Commercial customer classes, as well as two class-wide estimations. Each model produced three categories of coefficients that explain usage per customer per day as a function of: (1) heating usage per HDD per day; (2) base usage per day by month; and (3) temporal effects on usage from prior periods.
- Normal daily HDD amounts were developed using daily HDD values derived from the benchmark 30-year weather data set.
- Finally, the estimated coefficients were used to build the weather normalized Normal UPCs on a daily basis using the 30-year HDD benchmark.

[2] The set point is taken to be the temperature at which customers begin to use energy for heating purposes. To obtain the best linear relationship for statistical purposes in relating usage to temperature, using the set point that provides the best fit as to when heating begins is important. The Company used the 59 degree Fahrenheit base for residential schedules and 58 degree Fahrenheit base for commercial schedules as our temperature set points for HDDs because we believe that these values produce the best linear relationship between therm load and HDDs. We use the set points to linearize the relationship so that we can use simplified time series model specification to derive weather normalized load by month and rate schedule.

Q. Why did you use load data through February 2020 for this analysis?

A. I opted to align the Normal UPCs produced from this firm sales residential and commercial rate class normalizing analysis with the period used to derive total normalized revenues for the revenue requirement as described in Exh. KTW-1T.

Q. Please describe the specification for the regression model.

A. I used an Autoregressive Integrated Moving Average ("ARIMA") time series model to estimate weather normalized load per customer per day as the weighted function of the number of days, customers, and HDDs associated with each billing cycle in the model period. An ARIMA model is a type of time series model specification for data observations that occur across equal intervals of time. ARIMA models are denoted as ARIMA(p,d,q) where p is the number of time lags in the autoregressive term; d indicates the number of times the independent variables are differenced; and q is the number of lags of moving averages. Together, these terms help fit the time series model by accounting for different temporal effects on usage that are associated with prior periods.

Q. Please describe the Company's ARIMA model specification selection process.

A. For every rate schedule modeled, I relied foremost on Durbin-Watson test statistics, r-squared values, and mean squared error results to assess model efficacy and choose appropriate ARIMA p and q terms.[3] I relied on the Augmented Dickey-Fuller test to determine the appropriateness of differencing load forecast data variables with the

[3] The Durbin-Watson test statistic, which is a test for autocorrelation, takes a value from 0 to 4. A value of 2 indicates no autocorrelation. A value less than 2 indicates positive autocorrelation, and a value greater than 2 indicates negative autocorrelation.

ARIMA *d* term to ensure model stationarity. Finally, I plotted model residuals to check for non-uniformity. To a lesser extent, I consulted the Akaike Information Criterion ("AIC") and the Bayesian Information Criterion ("BIC") metrics to evaluate models with different *p* and *q* terms against one another.[4]

Q. Please summarize the outcome of this model selection process.

A. For all of the rate schedules I modeled, I found that optimal test statistics were achieved with one lagged autoregressive *p* term, and either one or two moving average *q* term(s). The Dickey-Fuller test indicated model stationarity using these terms, and given degradation in the test statistics by its inclusion, I did not employ the differencing *d* term in any model specification.

Q. Please summarize the indicator variable selection process.

A. I also relied on Durbin-Watson test statistics, r-squared values, and mean squared errors, as well as AIC/BIC metrics to assess the choice of monthly indicator variables and optimize model estimation. For most rate schedules, I used an indicator variable for every month and dropped the constant term. Based on my analysis, I used fewer indicator variables and included the constant term for two lower-load schedules: RS 1 Residential and RS 27 Dry-Out.

Q. Does the ARIMA model perform better at weather normalizing load compared to a simple linear regression?

A. Yes, I find that the ARIMA model presented in this rate case outperforms a simple linear regression when compared against the model test statistics and metrics discussed

[4] When comparing models with the same variables but different *p* or *q* terms, in general the model with the lower AIC and BIC metric is perferable.

above.

Q. How are the results of the ARIMA model interpreted and evaluated?

A. The monthly indicator variables represent customer base load use. The customer heat load use coefficient is expressed as incremental usage per HDD. I used statistical software to evaluate the model estimation output against the 30-year daily normal HDD values in order to derive a normalized use per customer per day by month.[5] This analysis incorporated the effects of the ARIMA autoregressive and moving average terms on base and heat load use into the use per customer estimation. I repeated this process for every firm sales rate schedule in the Residential and Commercial customer classes.

Q. Were any post-estimation adjustments made to the Normal UPCs?

A. Yes. I weighted each individual schedule's UPC such that it contributes to the overall rate class UPC based on customer count. The purpose of this adjustment is to account for some statistical noise in the model estimates for the individual rate schedules, and ensure that each schedule's UPC builds up to its overall rate class UPC.

Q. Were any adjustments made to the Normal UPCs based on forecasted demand side management ("DSM") savings?

A. No. The Company previously included a forecasted DSM adjustment to its Normal UPCs such that it aligned with the rate effective date for its prior rate case. Staff indicated in that case any adjustments to the Normal UPCs, if they are made, should be based on events that align to the historical Test Year.

[5] I used the Stata statistical software package, and developed use per customer estimations based on model results using the "predict" command.

Q. Please summarize the ARIMA-estimated Normal UPCs.

A. The ARIMA model produced a Test Year Normal UPC of 672.7 therms for the Residential class and 3,278.3 therms for the Commercial class. Normal UPCs are further defined for each of the firm sales rate schedules within each class, to allow for the calculation of revenues using rates from each class.

Q. How are the Normal UPCs used to create Test Year volumes that generate revenues at existing rates for the proposed revenue requirement?

A. Residential and Commercial class Test Year monthly volumes were calculated by multiplying the weather normalized Normal UPCs for each rate schedule by the end-of-period customer counts.

Q. How are Test Year volumes built for the rate schedules not included in the Normal UPC analysis?

A. Test Year volumes for the Industrial class, as well as large commercial transportation and interruptible rate schedules, are the actual volumes consumed during the twelve months ended February 29, 2020, as described in Exh. KTW-1T.

Q. Where are the Test Year volumes used to build the revenues for the revenue requirement?

A. The derivation of Test Year revenues from the customer and volume forecasts is presented in a summary at Exh. KTW-4.

Q. Were there any changes in the UPC Forecast methodology from NW Natural's latest rate case, UG-181053?

A. Yes. I used consistent data collection, actual weather, load data alignment, and weighting methodologies, but began using the ARIMA statistical model specification used to produce the Normal UPC regression coefficients beginning with the 2020-21 Purchased Gas Adjustment ("PGA") and continuing with this rate case filing. For its last rate case, UG-181053, the Company employed a simple linear regression to fit the relationship between therm load and HDDs using the same 59- and 58- degree Fahrenheit set points. For this rate case, I have used an ARIMA time series model specification for the reasons described above. The choice of model specification, in this case ARIMA, is one of the final steps in the Normal UPC analysis methodology; each step prior is consistent with UG-181053. Further, I updated the weather and usage inputs to reflect more recent data points so that the actual data observations can be aligned as closely as possible to the Test Year period.

Q. What are the Company's other uses for the Normal UPCs?

A. The Company used the Normal UPC analysis to develop the design day load factor for the EmCOSS, as discussed below. The Normal UPCs are also used to estimate throughput volumes for the annual PGA. The methodology for calculating the Normal UPCs is consistent between the PGAs and rate case filings.

Q. Have you submitted work papers based on this section of your testimony?

A. Yes, I have submitted two work papers. The first is the normal weather model that derives the 30-year historical benchmark for normal weather. The second is the ARIMA analysis that derives the Normal UPCs.

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III. EMBEDDED COST OF SERVICE STUDY

A. Embedded Cost of Service Study Purpose, Principles, and Regulatory Considerations

Q. What purpose does a cost of service study serve?

A. The overall objective of a cost of service study, including an embedded cost study, is to apportion the incremental rate case revenue requirement to rate schedules based on each schedule's specific cost to serve (this is true of other types of cost of service studies, such as those based on long run marginal costs). Whereas a long run cost of service study evaluates the marginal (incremental) costs borne by each rate schedule with the addition of one new customer, the embedded cost of service study presented below is based on historical Test Year installed costs (e.g., gross plant and the accumulated depreciation on those capital assets) of assets in-service and expenses (e.g., for operations, maintenance, taxes) associated with the on-going provision of utility service.[6] By analyzing how the customers that make up each rate schedule contribute to these embedded capital costs and on-going expenses, the EmCOSS methodology works to apportion a utility's storage, transmission, and distribution costs, as well as total revenue requirement, based on cost causation.[7] As a general rule, cost causation is an influential factor in parties' discussions on how to allocate costs to specific rate schedules for rate spread; therefore, it serves the utility well to understand

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[6] In practice, a cost of service study can and usually does apportion costs using both an embedded and incremental approach, depending on the type of cost. For instance, an embedded cost study may apportion Test Year customer service costs across all rate schedules, but allocate these costs to specific schedules based on the incremental costs of an additional customer.

[7] For gas utilities that produce energy, an embedded cost of service model can similarly apportion commodity production costs based on cost causation.

the engineering and economic cost differences between customer classes and/or rate schedules.

Q. Please describe the economic principles that underlie a cost of service study.

A. Embedded cost studies and cost of service studies in general allocate costs based on cost causation to identify how the incremental revenue requirement should be allocated to rate schedules in order to move closer to *Pareto Optimality*.[8] The reasonable allocation of costs is determined by understanding the specific customer characteristics associated with each class and rate schedule in order to equitably allocate costs. Characteristics can include: Peak day demand and average usage characteristics, service type (firm vs. interruptible, sales vs. transportation), customer service needs, and average mains and service lines costs. A cost of service study works to identify not only how each characteristic of a rate class contributes to overall costs, but how these characteristics contribute to the utility's fixed and variable costs.

Economists have derived the principles of "subsidy-free prices" and "stand-alone costs" ("SAC") as a means for achieving *Pareto Optimality*. Subsidy-free pricing is achieved when the price of a good or service charged to a group of customers exceeds its marginal cost ("MC") but is less than the cost these customers otherwise would have incurred individually, the SAC. Prices set at a subsidy-free level provide customers economies of scale given that all customers are paying a portion of the fixed system

[8] *Pareto Optimality* is a state of allocation equilibrium where participants cannot be made collectively or individually better off given a change in cost or price, without also making other participants worse off. Cost of service studies generally measure the relationship between current utility rates and pareto optimal rates, on a rate class or rate schedule basis, as a "parity ratio" where a value of 1.00 indicates customers in that group are paying no more and no less than their full cost to serve. A change to the rate that results in deviation from 1.00 would signal either cost subsidization (greater than 1.00) or cost subsidy (less than 1.00).

costs where (Price > MC) while achieving equitable cost sharing of common costs. While the sharing of fixed and other common system costs is the most equitable outcome for customers, local distribution companies ("LDC") must be aware that price does not exceed the SAC to serve customers because customers would in theory be unwilling to take service (and/or move to the next best economic alternative) if prices exceed SAC. Therefore, the level of price is key to ensuring customer equity is achieved between rate classes/schedules with common utility costs fairly identified and allocated.

Q. Has the Washington Utilities and Transportation Commission ("Commission") stated its preference for cost of service study methodology?

A. Yes. The Commission, in General Order No. R-599 (docket No. UG-170003), issued on July 7, 2020, adopted Washington Administrative Code ("WAC") 480-85. These rules establish minimum filing requirements – including data inputs, methodologies, presentation of results – for any cost of service study filed with the Commission, and specifically direct utilities to calculate cost of service using an embedded cost method. The Commission states that its preference for the embedded cost methodology is based on long-standing precedent and stakeholder compromise.[9]

Q. Does the Company's EmCOSS meet the requirements of WAC 480-85?

A. Yes, with the exception of WAC 480-85-050(1). That particular section specifies that the usage data employed in any cost of service study must come from advanced metering technology that provides, at a minimum, daily natural gas usage readings. If

[9] *See*: Washington Utilities and Transportation Commission General Order R-599 at 11, and WAC 480-85-060.

these data are not available, the utility may conduct a "load study," defined as a study of daily usage data to produce rate class load profiles using a subset of sampled customers.[10]

Q. Does the Company have the daily meter reading capabilities deployed such that it can satisfy the requirements of WAC 480-85-050?

A. No. The Company does not have enough advanced metering infrastructure (AMI) described in WAC 480-85-050(1)(a) or other advanced metering technology as indicated in WAC 480-85-050(1)(c) to comply. While the Company is in the process of installing additional new meter sets that have daily advanced meter reading ("AMR") capabilities described in WAC 480-85-050(1)(b), it does not currently have consistent daily data representative of all its customer classes for a minimum of twelve months. Therefore, a random sampling of the subset of customers with advanced meters would not produce an unbiased weighting of premise characteristics, including: premise age, geographic location, and service size.

Q. Is the Company working to deploy advanced metering technology such that it can satisfy these requirements?

A. Yes, the Company has an on-going system-wide program called Periodic Meter Change for Cause ("PCC") that targets meter families for performance change-outs due largely to meter age and obsolescence. Older meter families are replaced through this program with AMR-capable sets. Given the PCC performance change-outs achieved to-date

[10] *See* WAC 480-85-030(5) (defining "load study" as "a statistical analysis of load data collected from sampled customers to estimate the load profiles of customer classes over a minimum twelve-month period.").

and anticipated installations in 2021, the Company expects to have daily read capabilities to begin collecting a representative sample of its customers by the end of 2021.

Q. Has the Company filed for an exemption of WAC 480-85-050(1)?

A. Yes, until the Company completes these PCC installations through 2021 and then collects a minimum twelve months of daily read data, it cannot currently complete a load study as defined in WAC 480-85-030(5) and required by WAC 480-85-050(1)(d). Therefore the Company has filed for a one-time exemption of WAC 480-85-050(1).[11]

Q. Does the EmCOSS methodology follow the same cost of service methodology presented in the Company's last rate case?

A. No. The EmCOSS follows the study methodology adopted under General Order No. R-599 and described at WAC 480-85-060. This is the Company's first rate filing since this cost of service methodology was adopted.

Q. Please describe the purpose of the EmCOSS methodology presented in this testimony.

A. The EmCOSS study methodology presented in this testimony is an engineering economics exercise that evaluates how much of the Company's capital investment costs, O&M and other expenses required to serve its customers can be directly and indirectly attributable to each rate schedule. The costs and expenses that form a basis for the EmCOSS follow the Company's Test Year for the twelve months ended September 30, 2020.

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[11] *See* UG-200952 "Petition for Limited Exemption from WAC 480-85-050(1)."

The EmCOSS follows three main steps: (1) functionalization; (2) classification; and (3) allocation. Functionalization places costs that make up the revenue requirement into categories based on broad utility functions and, following the approved methodologies prescribed in Table 3 of WAC 480-85-060(3), is based on Federal Energy Regulatory Commission ("FERC") Uniform System of Account categorization. The second step, classification, further splits the functional costs into three characteristics related to their marginal cost characteristic: (a) demand costs are closely related to plant in-service, are generally fixed, but are influenced by design day peak demand and average throughput; (b) energy costs are variable and are directly related to therms consumed; (c) customer costs can be fixed or variable and related to the number of customers taking service. Each functionalized and classified cost item is then assigned to each individual rate schedule through allocation factors that follow Table 4 of WAC 480-85-060(3). Some cost items are allocated based on direct assignment to specific rate schedules, however and I describe below how some costs are directly assigned and allocated through "special studies."

After allocating all revenue requirement cost elements, the EmCOSS calculates the relative ratio of revenue to incremental costs for each rate schedule at present rates. This ratio is used to understand cross-subsidies between rate schedules at current rates and can be used by the Company to inform its rate spread and rate design proposals.

Q. What costs does the EmCOSS directly assign through these special studies?

A. I directly assigned costs for the following items based on studies conducted using Company data such as job orders, mapping and other Geographic Information Systems ("GIS") data, accounting data, and billing and usage data:

- Distribution mains
- Service lines
- Meter sets and regulators
- Certain customer account services

Note that for some costs, such as distribution mains, I directly assign only a portion of the total costs; the remainder is assigned per WAC 480-85-060(1)(d) and Table 4 of WAC 480-85-060(3). I describe each of these studies in detail below.

Q. Please explain how the EmCOSS is presented with this rate case.

A. The full Excel-based EmCOSS model is submitted in its entirety as a workpaper accompanying this rate case. Each of the special studies is similarly submitted as workpapers; the output from each study is summarized in a tab in the EmCOSS, with an index identifying the external spreadsheet file(s). The natural gas cost of service template sponsored in Exh. RJW-2, which cross-references the revenue requirement results and summarizes the EmCOSS outputs, is also located within the EmCOSS model workpaper in compliance with WAC 480-85-040(1).

B. NW Natural's EmCOSS Inputs and Methodology

Q. Have you prepared a cost of service study for this proceeding?

A. Yes. Exh. RJW-2 presents the results of NW Natural's embedded cost of service study, the EmCOSS. The exhibit includes the natural gas of service template, and shows the indicated EmCOSS summary results and the EmCOSS-indicated spread of NW Natural's proposed revenue requirement by rate schedule.

The individual EmCOSS study inputs and methodology discussion sections are as follows:

1. Load Factor
2. Functionalized Plant Investment Costs:
    a. Distribution Mains and Assets
    b. Transmission Main
    c. Storage
    d. Service Lines
    e. Meters
    f. General and Intangible Plant
    g. Land and Structures
3. Operations and Maintenance Expense
    a. Customer Service and Billing
    b. Administrative & General
4. EmCOSS Study Insights and Outcomes

1. Load Factor

Q. What is the load factor?

A. The load factor is a ratio measure of each rate schedule's contribution to the design day peak load. For purposes of the EmCOSS study, I consider design day load on a Washington basis and attributable to Washington customers only. While load could potentially peak for other reasons on other systems, load peaking for NW Natural is a matter of space heating requirements, and so is related to weather.

Q. How is the load factor value interpreted?

A. The load factor is the ratio of normalized average usage to the estimated design day peak usage. A low load factor ratio indicates that a rate schedule has high peaking load relative to normalized average usage (i.e., it indicates the rate schedule has high weather sensitivity as load peaks during cold weather events). A high load factor indicates less weather sensitivity and more predicable base load usage throughout the year. Residential rate schedules, which use gas most significantly for heating purposes, are expected to have lower load factors relative to Industrial rate schedules that are more heavily comprised of processing load customers.

Q. How does the EmCOSS use the load factor?

A. The load factor is the basis for the design day (peak) and annual throughput (average) allocator that the EmCOSS uses to allocate distribution mains and assets, and transmission main investment to each rate schedule. The peak and average allocator is a weighted ratio of each rate schedule's contribution to the load factor-derived peak day deliveries and average throughput. Rate schedules with lower load factor ratios require more excess system capacity investment to meet design day load relative to higher load factor schedules, assuming equivalent annual load, and are therefore allocated more of these investment costs relative to higher load factor schedules.

Q. How is the load factor calculated for the EmCOSS?

A. The load factor for each rate schedule was estimated using Normal UPCs for the Residential and Commercial customer classes, and the Company's customer-specific Industrial class data for the remaining schedules.

The ARIMA-based Normal UPC analysis described earlier in this testimony produced a base and heat load coefficient for each rate schedule in the Residential and firm sales Commercial customer classes. I multiplied the historical 30-year HDD average by the heating coefficient, and by adding base load usage, I calculated the normalized load numerator for the load factor ratio. As part of its resource planning processes, the Company has estimated an 11-degree Fahrenheit design day temperature that I converted to HDDs, and using the Normal UPC-derived heating coefficient, I estimated the load factor denominator.[12]

Large Commercial interruptible and transportation service and Industrial schedules in rate classes RS 41 and RS 42 are not included in the Normal UPC analysis, as well as schedule RS 3 Industrial. Customers in these classes were not included in the Normal UPC analysis because the Company maintains separate customer-specific data for these customers. I queried four years of historical billing data by month and by day (where available) for all customers in these rate classes. I based the normalized load numerator for the load factor ratio on these volumes. Then, I calculated a maximum daily delivered volume ("MDDV") for each customer by year, and aggregated these volumes by rate schedule. Finally, I took the average aggregate MDDV value from four full years (2016-2019). This value is the basis for the load factor denominator.

Q. What were the results of the load factor analysis?

A. For the purposes of the EmCOSS, I estimate an overall load factor for Washington customers of 26.5 percent, with a firm load factor of 24.8 percent. The RS 2 Residential load factor is about 22.4 percent, meaning normal load for this schedule is about one-fifth of its design day load. The RS 3 Commercial load factor is about 23.6 percent,

[12] For NW Natural's 2018 IRP, the Company used a probabilistic planning standard to forecast peak load. This planning standard sets a daily resource capacity requirement such that the Company would be 99 percent certain it would be capable of meeting load going into any winter. Using this methodology, the Company has calculated an average system weighted temperature around this planning standard of roughly 11-degrees Fahrenheit.

while the RS 3 Industrial load factor is 51.8 percent. The larger RS 41 and RS 42 Commercial and Industrial rate classes have estimated load factors ranging from 31.1 percent to 61.6 percent.

2. Functionalized Plant Investment Costs

Q. Please outline the specific components of functionalized plant investment evaluated in your study.

A. The functionalized plant cost categories evaluated in this study include:

a) Distribution mains and assets, which is required for various purposes over time as the system grows, including: mains to serve new customers, and mains installed for safety and reliability purposes. The EmCOSS directly allocates a portion of these mains costs, based on an analysis of average installation cost per foot and length by rate schedule. The remainder of distribution mains costs are allocated based on the peak and average allocator. Distribution mains are designated as those less than 4 inches in diameter, and those 4 inches or greater.

b) Transmission main, constitutes the pipeline that transports gas from the interstate pipeline to delivery points on the Company's system.

c) Storage, which includes the incremental costs associated with underground storage.

d) Service lines, which includes costs associated with the piping and trenching from meter set to distribution main, and distribution main tie-in.

e) Meter set and regulator assemblies, which includes the cost of the meter and regulator, as well as the pipe fittings, bracket assemblies labor, and shop time required for assembly.

a. Distribution Mains and Assets

Q. Did you conduct a special study to directly assign distribution mains costs to individual rate schedules?

A. Yes, I directly assigned a portion of distribution mains costs using a special study. Costs not directly assigned are allocated based on the peak and average allocator.

Q. What were the inputs used to calculate the distribution main direct costs?

A. The main extension costs were evaluated using five calendar years (2015 – 2019) of historical accounting data of Washington main extension job orders. The accounting data include the total cost (excluding construction overhead) and footage installed per job, pipe size and material, and are delineated by service type (conversion vs new construction), and market segment. The market segments analyzed are as follow:

- Residential-single family new construction (“Residential New”)
- Residential-single family conversion (“Residential Conversion”)
- Commercial / Industrial (“Com/Ind”)

In addition to the five years of job orders data, I used a main extension forecast for 2020 that is produced by the Company’s Business Analytics team. This forecast uses three categories of extensions: Commercial mains, Residential mains, and system expansion main extensions. The latter category is overwhelmingly made up of new construction residential connections.

Neither the main extension jobs order data nor the forecast include a rate schedule breakout. We can delineate by market segment based on several factors, including: location of the main extension, pipe size, and the type of customers most likely to take service on the extension.

Q. How were the direct distribution mains costs calculated?

A. I used the main extension jobs order data to calculate the 5-year average cost per foot and average main length installed by market segment. Additionally, I used the same dataset to calculate the 5-year average cost per foot and median main length installed by pipe size (less than 4 inches, or greater than or equal to 4 inches) and material (polyethylene or wrapped steel). The accounting data used in the calculation of the average cost of main extension are in nominal dollars. Therefore, for purposes of the Test Year, the nominal main extension costs per foot for historical years were escalated to Test Year values using the Handy Whitman Index of Public Utility Construction Cost ("Handy Whitman Index") as published in the IHS Markit Power Planner.[13] The escalated values were used to create the average Test Year cost per foot input for the EmCOSS.

Q. How did you calculate the average distribution main extension *cost per foot* for each market segment and pipe size to a rate schedule?

A. I used a weighting methodology that employs three inputs: (1) the Company's main extension forecast; (2) the job orders data by market segment; and (3) the job orders data by pipe size. For every rate schedule, I used a 75-25 weight ("Segment Weight") to assign costs based on the forecast and the 5-year actual average cost per foot by market segment. For the commercial and industrial schedules, I further assigned costs by pipe size and type. I used pipe sizes and type for the large customer schedules as a

[13] Mains costs were inflated to Test Year values using the IHS Markit Power Planner Table A20: *Cost Trends of Gas Utility Construction: Pacific Region*. Mains; plastic value. Second Quarter, 2019.

method for further weighting main costs across schedules with wide variations in customer sizes, loads, and physical location off-main.

I directly assigned the Residential Conversion market segment to RS 1 and RS 2 Residential. For RS 27 Dry-Out, I assigned the Residential New market segment as well as the system mains expansion segment costs.

The Com/Ind market segment was assigned to both RS 3 Commercial and RS 3 Industrial customers. I used Company GIS data to query the pipe size of the main that customers in the RS 3 Commercial rate class have been connected to in the past 10 years, system-wide. Using this GIS data, I calculated the ratio of customers connected to mains of less than 4 inches and greater than or equal to 4 inches and used this ratio to assign costs once the Segment Weight had been applied.

For the RS 41 and RS 42 rate classes, I applied the same Com/Ind Segment Weight as used for the RS 3 rate class. Mains costs were further delineated by rate schedule using the 5-year GIS pipe size data. For these larger schedules, I categorized main connections by both pipe size and material due to the large variations in mains sizes and types connected to these customers.

Q. How did you calculate the average distribution main extension *length* for each market segment and pipe size to a rate schedule?

A. I used a similar methodology as described above to calculate the median main extension length (in feet) for each schedule. For RS 2 Residential and RS 27 Dry-Out, I used the Company's main extension and customer forecasts. For the Commercial and Industrial schedules, I used 5-year average installed feet of mains by pipe size and material type to estimate main extension lengths for three categories: Small Com/Ind, Large Commercial, and Large Com/Ind.

Q. How were the directly allocable distribution mains costs calculated and allocated?

A. First, I estimated the feet of Washington mains on the Company's system attributable to main extensions serving customers. I used the feet of mains greater than or equal to 4 inches reported in the Company's FERC Distribution Report as a basis for total mains footage.[14] Next, I used the 5-year GIS pipe size data to estimate what percentage of customers in the Commercial and Industrial rate classes are connected to distribution mains of equal or greater than 4 inches. Using the distribution main extension median installed feet described above, I calculated the feet directly attributable to these customer classes by pipe diameter category. I then allocated these attributable mains to rate schedules based on share of overall attributable costs, with a separate allocator for each of the two pipe diameter categories. I allocated the remaining unattributable feet using the design day peak and average allocator.

Q. How were the distribution assets costs allocated?

A. Distribution assets were allocated using the design day peak and average allocator.

b. Transmission Mains

Q. How were the transmission mains costs allocated?

A. Transmission mains costs were allocated using the design day peak and average allocator.

[14] The FERC Distribution Report is created by the NW Natural Engineering Department; it is used by the Plant Accounting team to validate that the feet of mains reported in the Company's asset management accounting databases is correct.

c. Storage

Q. How were underground storage costs allocated?

A. All underground storage plant costs were allocated to sales customers only, using a ratio based on Test Year average winter sales that exceed Test Year average summer sales.

Q. Were any underground storage costs classified as balancing?

A. No. The EmCOSS does not classify any storage costs as balancing to transport customers. NW Natural generally will utilize the interstate pipeline for daily and/or monthly system balancing, not underground storage assets. However, it is possible that our underground storage assets could be utilized for balancing all customer classes, including transportation. The Company feels any underground storage costs that could potentially be allocated to transport customers would be negligible.

d. Service Lines

Q. How are service line installation costs and average footage installed by rate schedule determined?

A. The calculation of average services cost per foot and the average footage installed was derived using 5 years of historical accounting data of Washington services job orders data (2015 – 2019) for customer service installations by market segment. These jobs order data are very similar to those of the mains order data; the orders include the total cost (excluding construction overhead) and footage installed per job, and pipe size and material. The important distinction is that the services orders are associated with customers on specific rate schedules.

Service costs for RS 2 Residential, RS 3 Commercial, and RS 27 Dry-Out were calculated using a five-year average of job costs per foot. Due to the small job sample size for the remaining Commercial and Industrial schedules, I used a GIS data query for services connection footage by Industrial rate schedule all-time in Washington. I estimated service cost by customer per rate schedule by multiplying the average footage by average cost per foot. I used the Handy Whitman Index to inflate nominal dollars to Test Year values.

e. Meters and Regulators

Q. Please outline how costs were calculated for meters and regulators.

A. A customer query was run out of NW Natural's customer information system ("CIS") that included each actively billed customer's meter set model number and delivery pressure. A summary of the CIS information provided the counts of meter set models by rate schedule. NW Natural's Engineering Department maintains an engineering Cost Estimating Guide that provides the assembly and capital cost for each assembled meter set (by meter model number) with regulator. I calculated weighted-average cost using the costs from the engineering cost guide and meter counts by rate schedule to derive the capital investment cost by customer by rate schedule.

Q. How were meters and regulators plant investment costs allocated to rate schedules?

A. I converted the average meter cost per customer per rate schedule to share of overall meters and regulators costs using customer count as a weight.

f. General and Intangible Plant

Q. How was general plant allocated to rate schedules?

A. I used a common allocator that was built using three factors: (1) net allocated plant balances for the storage, distribution, and transmission functions; (2) total O&M expense allocation; and (3) customer count. I created the common allocator using an equal weight of each of these three factors. These factors together represent a mix of each rate schedule's share of overall utility capital investments and operating expenses, accounting for the relationship between costs and customer count.

Q. How was intangible plant allocated to rate schedules?

A. I similarly used the common allocator to allocate intangible plant, as I considered these common costs. I examined the intangible plant assets at the materiality threshold of 0.5 percent and found no items directly allocable to specific rate classes or schedules.

Q. Were any of the Company's plant balances not covered in Table 3 of WAC 480-85-060(3)? How were these accounts allocated?

A. Yes, FERC Accounts 363.5 (CNG Refueling Facilities) and 363.6 (LNG Refueling Facilities) are not included in Table 3. I used the common allocator to allocate these plant balances to the rate schedules because the benefits associated with these facilities are not limited to any customer class.

g. Land and Structures

Q. How were land and structures allocated?

A. I allocated the general land and structures plant balances (FERC Accounts 389 and 390) based on functionalized storage, transmission, and distribution plant. For land and structures attributable to certain functions, I allocated the balance based on plant associated with that function only (e.g., storage related land and structures are allocated based on storage plant).

3. Operations and Maintenance (O&M) Expense

a. Customer Service and Billing

Q. What are the categories of customer service and billing O&M expenses that were evaluated in this study?

A. The EmCOSS includes a special study based on the following categories of O&M customer service related expenses for direct allocation:

- Gas Scheduling, which includes departments that schedule underground storage injections/withdrawals, as well as control the distribution system's daily operations.
- Gas Planning, which are operations that include short- and long-term gas acquisitions, planning, and analysis (e.g., of gas purchasing and hedging activities).
- Major Account Services, which is the team that interacts primarily with large commercial and industrial customers through the service election process, coordinates billing and addresses billing issues, as well as coordinates new large customer acquisitions.
- Account Services, including billing, payment processing, metering, collections, and construction field services.

Q. How were gas planning and gas scheduling costs evaluated and directly assigned to each rate schedule?

A. The gas scheduling and gas planning cost centers were evaluated using the O&M budget cost center for the Gas Scheduling and Planning Department. Cost categories include total salaries, administrative costs, and FTE counts for each cost center. These values are used to evaluate per customer costs for the EmCOSS, based on average hours spent on each customer at a calculated average labor rate.

The gas scheduling cost center was broken out into two functions: gas storage operations and gas control operations. Costs associated with gas storage operations were allocated to firm sales rate schedules only. Gas control operations costs were allocated to all schedules based on three factors: (1) service type (sales firm, sales interruptible, or transportation); (2) normalized annual throughput; and (3) the amount of time gas management staff estimate they spend working with customers of each service type.

The gas planning cost center was allocated to all service types based on the amount of time gas management staff estimate they spend working with customers of each service type. Costs are largely allocated to sales customers since little staff time is devoted to transportation customers who are responsible for procuring their own gas.

Once costs were assigned to each service type, they were directly allocated to each rate schedule based on weighted customer counts within that service type.

Q. How did you evaluate major account service costs?

A. Major Accounts Services costs were allocated only to the large RS 41 and RS 42 Commercial and Industrial rate classes, as well as RS 3 Industrial. Costs were further allocated to sales and transportation rate schedules based on reported staff time spent interfacing with each service type.

For all other accounts service costs, NW Natural has previously conducted a "Meter-to-Cash" study, which evaluates the incremental costs associated with providing these services to customers. The study evaluated the following cost center groups in the Company that directly serve customers:

- Account Services (meter reading scheduling, payment processing, collections)
- Contact Center (customer call center)
- Resource Management Center (field services scheduling/dispatch)
- Construction Field Services (field technicians and field scheduling)
- Office Services (bill printing)
- Treasury (costs that pertain only to payment processing)

Q. What is the purpose of the Meter-to-Cash study?

A. The Meter-to-Cash study was first developed by the Company in 2015. It was developed to estimate the incremental costs of customer additions associated with the account services functions listed above. The 2015 analysis was developed over several months, through meetings with managers and subject matter experts associated with each of the account services functions. These meetings helped to determine what individual cost centers and expense items should be associated with each activity, as well as what costs and activities are associated with three categories of rate schedules: Residential, Small Commercial, and Large Commercial / Industrial. Data were collected after these informational interviews were complete. Costs that are not directly tied to customer count were not included in the Meter-to-Cash study (e.g., software upgrade costs are not necessarily correlated to customer additions and are therefore not included).

Q. Has the Meter-to-Cash study been updated?

A. Yes. The Meter-to-Cash study was updated in 2018. This updated study is the basis for calculating the weighted customer service cost allocator for the EmCOSS. The 2018 nominal values were inflated to the Test Year using the Handy Whitman Index.

Q. How does the EmCOSS use the Meter-to-Cash study to allocate customer service related costs?

A. The Meter-to-Cash study produces an average account services cost by rate class based on the following four categories:

1. Meter Reading
2. Billing
3. Payment Processing
4. Collections (costs that pertain to payment processing)

I weighted these class-based average costs by rate schedule customer count to create an indirect allocator for customer service and billing O&M expenses.

Q. Did you directly allocate any additional customer service related O&M expenses?

A. Yes. I examined the Company's Washington allocated O&M expenses by type and cost center. Any costs identified as relating specifically to residential, or commercial and/or industrial classes were directly allocated to rate schedules as appropriate based on weighted customer count.

b. Administrative & General Expenses

Q. How were administrative and general expenses allocated?

A. The administrative and general expenses allocation follows Table 4 of WAC 480-85-060(3) where specified. For expenses not noted in the table, I used the common allocator, except for FERC Account 921. This account represents general payroll; I allocated most of these costs based on the customer-weighted customer services cost allocator described above. I identified a portion of FERC 921 expenses as directly attributable to specific rate classes and allocated these costs as such.

4. EmCOSS Study Insights and Outcomes

Q. Upon what basis is revenue at current rates compared against the revenue with the proposed incremental revenue requirement at the first rate effective date?

A. The EmCOSS compares the ratio of adjusted Test Year Revenues at Current Rates against the EmCOSS based Total Revenue Requirement at Unity, the difference being the proposed margin increase at the first rate effective date. This ratio is used to derive the Revenue-to-Cost Ratio at Present Rates, and then the Parity Ratio at Present Rates, which indicates each rate schedule's position relative to cost parity (i.e., the point that the schedule as a whole is neither over- or under-paying its EmCOSS determined cost of service).

Q. Does the EmCOSS compare revenue at current rates against the revenue with the proposed incremental revenue requirement at the second rate effective date?

A. No. In order to streamline the presentation of the EmCOSS with only one set of results, I use results at the first rate effective date only. I believe an evaluation at the second rate effective date would not move the position of any rate schedule relative to its indicated postion above or below rate parity.

Q. What do the results of the EmCOSS indicate?

A. The EmCOSS indicated Parity Ratio at Present Rates for each rate schedule is illustrated in Table 1 below. A Parity Ratio below the value of 1.00 indicates that customers on a given schedule are underpaying their EmCOSS determined cost of service. A value over 1.00 indicates that customers on a given rate schedule are paying more than their cost of service at margin rates. Per Table 1 below, the results of the EmCOSS indicate that RS 1 Residential, RS 2 Residential and RS 27 Dry-Out customers are not paying their cost of service at present rates while the remaining rate schedules are paying more. RS 3 Industrial are roughly paying right at their cost to serve.

Table 1
EmCOSS Parity Ratio at Present Rates, by Rate Schedule

RATE SCHEDULE	01 R	02 R	27	01 C	03 C	03 I	41 CSF	42 CSF
EmCOSS Determined Parity Ratio	**0.62**	**0.94**	**0.78**	**1.08**	**1.13**	**1.00**	**1.35**	**1.31**
RATE SCHEDULE	42 CSI	41 ISF	42 ISF	42 ISI	41 CTF 41 ITF	42 CTF	42 ITF	42 CTI 42 ITI
EmCOSS Determined Parity Ratio	**1.17**	**1.24**	**1.30**	**1.16**	**2.26**	**1.79**	**1.33**	**1.24**

Q. How do these results compare with the Company's last filed cost of service study?

A. The EmCOSS results are consistent with the Company's prior filing for the Large Commercial and Industrial rate schedules, as well as two Residential rate schedules (RS 1 and RS 2 Residential) in addition to the RS 27 Dry-Out schedule. Also consistent is the finding that the two Small Commercial rate schedules are overpaying their cost to serve, albeit to a lesser extent than indicated in the prior rate case. The prior cost of service study presented a rate class level evaluation, so the studies are not directly comparable across every rate schedule.

III. RATE SPREAD & RATE DESIGN

Q. What is the purpose of the rate spread section?

A. The purpose of this section is to show and summarize:

- NW Natural's incremental revenue requirement request;
- Discuss the results of the EmCOSS and how it relates to rate spread;
- Show the methodology for how the Company proposes to spread incremental revenue; and
- Show the revenue requirement spread by rate schedule and the corresponding average bill impact.

Q. Is NW Natural proposing any changes to its rate structure or to its current rate schedule offerings?

A. No. NW Natural is not proposing any additions or removals of rate schedules in Washington, nor is it changing any block rate structures or intra-schedule optionality that is currently offered.

Q. What is NW Natural's total incremental revenue requirement?

A. NW Natural has filed for an incremental Year One revenue requirement of $6.3 million in this case. It has also filed a Multi-Year rate adjustment in Year Two, with a revenue requirement of $3.2 million. See Exh. KTW-1T.

Q. Is any of the $6.3 million of Year One incremental revenue requirement or any of the $3.2 million Year Two adjustment attributable to special contract customers?

A. No. The special contract customers are not allocated any of the incremental revenue requirement given they are under fixed cost contracts.

IV. THE EmCOSS AND RATE SPREAD

Q. How does the EmCOSS relate to rate spread?

A. The EmCOSS provides the incremental capital investment and O&M costs, by functional category, and gives insights into cost causation across customer classes. In theory, spreading the incremental revenue requirement such that all schedules have a Revenue-to-Cost Ratio of 1.00 would align all customers to their indicated level of cost causation. In practice, rate spread (and rate design) tends to deviate from this strict application of cost study results, given such a change in the short-run would violate principles of rate shock and smoothing, neither of which are in the Company's or its customer's interests. It is also important to balance the interests of rate equity with rate volatility. The EmCOSS can, however, provide a baseline for incremental revenue requirement allocation by rate schedule.

Q. What are NW Natural's thoughts on using the EmCOSS results to spread revenue requirement?

A. NW Natural values the EmCOSS outputs as a baseline for understanding the basis of cost causality among the rate classes and schedules. Of course, as stated above, there are other important factors that should be considered, most importantly the idea that equitable distribution of the rate spread should be balanced against customer rate impacts. If the Company were to spread revenue requirement across rate schedules strictly in a way that results in each rate schedule paying its share of EmCOSS-indicated costs (i.e., if all schedules were suddenly brought to parity with their indicated cost causality), such a shift would result in rate shock for many customers and perhaps inadvertently signal rate volatility. Table 2 below shows the amount of the incremental revenue requirement that would need to be spread to each rate schedule in order to put each class in line with paying its embedded Year One costs per the results of the EmCOSS (e.g., the Year One Total Net Income Deficiency (Sufficiency)).

Table 2
EmCOSS Indicated Total Year One Incremental Revenue Requirement Deficiency (Sufficiency), by Rate Schedule

RATE SCHEDULE	01 R	02 R	27	01 C	03 C	03 I	41 CSF	42 CSF
EmCOSS Determined Target Revenue	**$210,855**	**$8,081,397**	**$142,215**	**$70**	**($697,138)**	**$19,270**	**($578,207)**	**($82,390)**
RATE SCHEDULE	42 CSI	41 ISF	42 ISF	42 ISI	41 CTF 41 ITF	42 CTF	42 ITF	42 CTI 42 ITI
EmCOSS Determined Target Revenue	**($33,638)**	**($97,484)**	**($194,404)**	**($11,972)**	**($99,036)**	**($143,670)**	**($153,739)**	**($106,319)**

As seen in Table 2 above, RS 2 Residential customers would bear the largest share of the incremental revenue requirement increase, followed by RS 1 Residential, if the Company were to adhere strictly to the indicated EmCOSS results. On a percent of total revenue basis, the indicated increase would be 74.3 percent and 15.2 percent for the RS 1 and RS 2 Residential rate schedules, respectively. The customers within the RS 41 and RS 42 rate classes would all realize rate reductions under such a scenario.

NW Natural believes that the factors of fairness and minimizing rate impact weigh in favor of not realigning rates completely to their indicated cost causality based on the results of the EmCOSS in this rate case, which would require large rate increases for some schedules while others receive decreases. Further, the Commission has stated that it is inclined to consider several factors when determining rate spread and rate design.[15]

Q. Has the Company conducted a cost of service analysis for any other schedule not included in the EmCOSS?

A. Yes. The Company has updated the cost of capital components of its cost of service analysis for tariff Schedule 10 – Charges for Special Metering Equipment, Rental Meters, and Metering Services ("Schedule 10").

Q. What is tariff Schedule 10?

A. Tariff Schedule 10 details the service charges for special metering equipment, rental meters and metering services. Meter rentals are charged on a monthly basis; metering services and charges can be either monthly or one-time charges.

Q. Please describe the Schedule 10 cost of service analysis.

A. The Company updated its Schedule 10 cost of capital to reflect an updated cost of debt and equity. The cost of service analysis calculates a monthly rental rate using net present value and a 21-year depreciable life.

Q. Please summarize the results of this analysis.

A. The results of the analysis reduce monthly charges in all meter size categories. This is a direct result of the cost of capital components being reduced from the previous Schedule 10 update.

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[15] *See* WAC 480-85-010 ("The cost of service study is one factor among many the commission considers when determining rate spread and rate design. The commission may also consider, as appropriate, such factors as fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.").

V. RATE SPREAD METHODOLOGY

Q. What method does NW Natural propose to use to spread the $6.3 million incremental Year One revenue requirement?

A. NW Natural proposes to spread the $6.3 million Year One incremental revenue requirement on an equal percent of margin basis for each customer rate schedule and block entirely through volumetric billing rates.

Q. What method does NW Natural propose to use to spread the $3.2 million incremental Year Two revenue requirement?

A. NW Natural proposes to spread the $3.2 million Year Two incremental revenue requirement on an equal percent of margin basis for each customer rate schedule and block entirely through volumetric billing rates.

Q. Please describe how this revenue spread proposal impacts each rate schedule relative to their EmCOSS indicated Parity Ratio at Present Rates.

A. Every rate schedule will either retain or approximately retain its current Parity Ratio at Present Rates for both rate effective periods.

Q. Why has NW Natural chosen this rate spread proposal?

A. NW Natural has chosen not to adjust the relative rate spread or propose rate design modifications for any rate class until a load study can be completed per WAC 480-85-050(1). While the Company's proposal does not move rate schedules closer to parity, it does balance the principles of fairness and rate stability while avoiding larger rate increases on one class, Residential, that would be required to move all schedules closer to parity based on EmCOSS indicated cost causation.

Q. Please explain how NW Natural proposes to spread the plant excess deferred income taxes ("EDIT") amortization credit amount already included in the Year One revenue requirement.

A. We must first remove the temporary plant EDIT amoritization credit of $462 thousand from the $6.3 million Year One incremental revenue requirement in order to calculate a billing adjustment for Schedule 305. This credit is then spread to all rate schedules on an equal percent of margin basis.

Q. Does NW Natural propose any rate impact mitigation in this rate case?

A. Yes. NW Natural proposes two temporary adjustments to offset the Year One revenue requirement increase: a suspension of its historical energy efficiency deferral, and an immediate credit of the Washington-allocable portion of the Block 24 property net gain on sale. The Company proposes one temporary adjustment to offset the Year Two revenue requirement increase: a credit of the Washington-allocable portion of the Astoria Resource Center property net gain on sale. See Exh. ZDK-1T.

Q. How does NW Natural propose to spread the Year One rate mitigation adjustments?

A. We propose to spread the historical energy efficiency deferral of approximately $1.4 million to residential and commercial sales rate schedules on an equal percent of margin basis.[16] We propose to spread the Block 24 property net gain on sale of $840 thousand to all rate schedules on an equal percent of margin basis.

[16] The historical engery efficiency deferral's final calculation will be complete in September 2021 when amortization amounts and interest rates are known. The Company proposes a final number to be completed with the compliance filing of this rate proceeding.

Q. How does NW Natural propose to spread the Year Two rate mitigation adjustment?

A. We propose to spread the Astoria Resource Center property net gain on sale of $43 thousand to all rate schedules on an equal percent of margin basis. In Year Two, the historical energy efficiency deferral amortization would resume and the Block 24 property rate credit will be removed.

VI. RESULTS AND BILL IMPACTS

Q. What is the rate impact to firm sales customers without the rate mitigation adjustments?

A. Table 3 below shows the incremental revenue requirement and average bill increase for firm sales customers before applying the rate mitigation adjustments.

Table 3
Incremental Revenue Requirement and Average Bill Increase
Firm Sales Customers Only (without rate mitigation adjustments)

	Year One		Year Two	
Rate Schedule	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*
01 R	$ 26,441	8.6%	$ 13,314	4.1%
02 R	$ 4,283,077	7.6%	$ 2,156,925	3.6%
27	$ 25,592	6.7%	$ 12,886	3.2%
01 C	$ 4,766	8.2%	$ 2,400	3.9%
03 C	$ 1,250,347	7.3%	$ 629,641	3.5%
03 I	$ 17,981	7.5%	$ 9,054	3.5%
41 C Firm Sales	$ 195,450	7.5%	$ 98,435	3.6%
41 I Firm Sales	$ 49,759	7.8%	$ 25,057	3.7%
42 C Firm Sales	$ 27,828	7.6%	$ 14,012	3.7%
42 I Firm Sales	$ 64,848	7.2%	$ 32,656	3.4%
Total All Schedules**	$ 6,255,478		$ 3,150,188	

* The average customer bill impact figure calculation excludes pipeline capacity charges for RS 41 and RS 42 rate classes, and thus the rate impacts for these schedules are overstated.
** The proposed margin revenue increase is based on volumetric billing rates rounded to the fifth decimal as necessitated by the Company's tariff. Therefore, there may be a small discrepancy with the indicated revenue requirement presented in Exh. KTW-1T.

Q. What is the rate impact to firm sales customers with the rate mitigation adjustments?

A. Table 4 below shows the incremental revenue requirement and average bill increase for firm sales customers, after applying the rate mitigation adjustments.

Table 4
Incremental Revenue Requirement and Average Bill Increase
Including Rate Mitigation Adjustments,
Firm Sales Customers Only

	Year One		Year Two	
Rate Schedule	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*	Revenue Req. Increase	Pct. Increase to Avg. Cust. Bill*
01 R	$ 16,043	5.2%	$ 23,523	7.3%
02 R	$ 2,598,752	4.6%	$ 3,811,026	6.4%
27	$ 15,525	4.1%	$ 22,773	5.8%
01 C	$ 2,892	5.0%	$ 4,240	6.9%
03 C	$ 758,463	4.4%	$ 1,112,591	6.2%
03 I	$ 15,465	6.4%	$ 11,443	4.5%
41 C Firm Sales	$ 118,572	4.5%	$ 173,912	6.4%
41 I Firm Sales	$ 42,798	6.7%	$ 31,663	4.6%
42 C Firm Sales	$ 16,883	4.6%	$ 24,758	6.5%
42 I Firm Sales	$ 55,796	6.2%	$ 41,266	4.3%
Total All Schedules**	$ 3,902,098		$ 5,459,263	

* The average customer bill impact figure calculation excludes pipeline capacity charges for RS 41 and RS 42 rate classes, and thus the rate impacts for these schedules are overstated.
** The proposed margin revenue increase is based on volumetric billing rates rounded to the fifth decimal as necessitated by the Company's tariff. Therefore, there may be a small discrepancy with the indicated revenue requirement presented in Exh. KTW-1T.

Q. Does your testimony present the revenue and rate changes applicable to all other rate schedules as well?

A. Yes. Exh. RJW-3 shows the revenue increases and average bill impacts by rate schedule, and Exh. RJW-4 contains the volumetric rate increases by rate schedule and block.

Q. Does this conclude your testimony?

A. Yes.

VII. LIST OF EXHIBITS