BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 490

In the Matter of	)
	)
NW NATURAL,	)
	)
NW NATURAL REQUEST FOR A	)
GENERAL RATE REVISION	)
	)

OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

APRIL 18, 2024

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In the Matter of NW NATURAL, NW NATURAL REQUEST FOR A GENERAL RATE REVISION	)))))))	OPENING TESTIMONY OF THE OREGON CITIZENS' UTILITY BOARD

Q. Please state your name, occupation, and business address.

A. My name is Bob Jenks. I am the Executive Director of the Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/101.

Q. What is the purpose of your testimony? {Abstract Introduction}

A. I will primarily address two issues:

- This is a very large increase for residential customers. I will discuss the implications of this increase and propose a mechanism for addressing the potential rate shock associated with this case.
- I will discuss NWN's proposed changes to the renewable natural gas (RNG) automatic adjustment clause (AAC).

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I. RATE SHOCK

A. Ratepayers need rate shock protection.

Q. What is important to know about this proposed increase and its impact on residential customers of NW Natural?

A. This is a large increase. NW Natural (NWN or the Company) is proposing a 16.62% increase in revenue in this case.[1] Residential customers represent more than 90% of NWN accounts.[2] Residential customers living in single family homes will see an increase of 18.1% and residential customers living in multifamily homes will see an increase of 15.6%.[3]

But this increase relates only to the non-commodity costs of NWN – the costs of delivering gas and managing a gas distribution system. The commodity costs will be addressed later in the Purchased Gas Adjustment mechanism (PGA). Gas prices can be volatile, and the PGA commodity increase can be significant. In 2021, NWN's rates went up 13.2% for residential customers due to the PGA update.[4] In 2022, NWN's customers faced a general rate increase of 8.46%,[5] but when combined with the PGA, residential customers faced a 25% increase.[6] This led to CUB negotiating an agreement with NWN to delay part of the filing until after the winter heating season, resulting in a 15% increase in January and an additional increase in March.[7]

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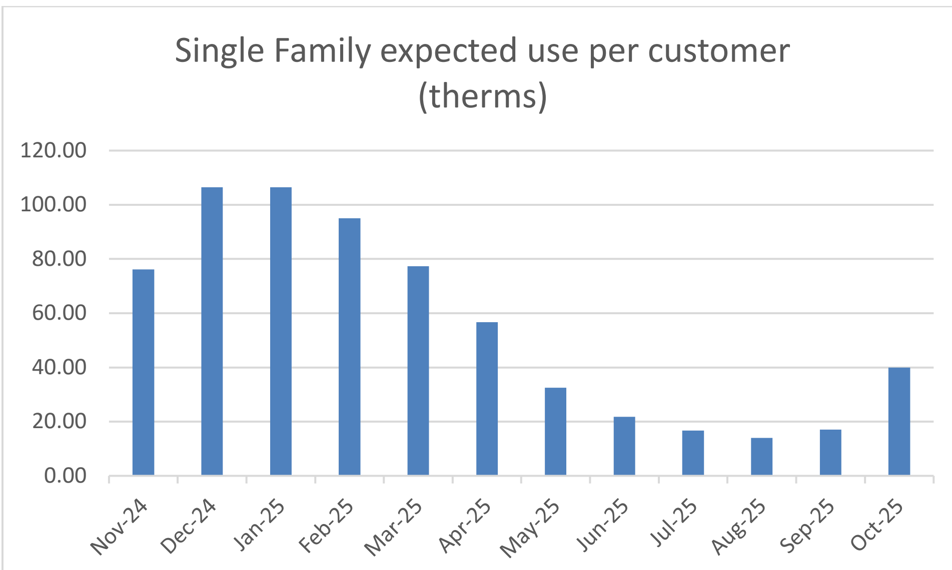
[1] UG 490 - NW Natural's Exhibit A to Executive Summary, p. 1
[2] UG 490 – NW Natural's Executive Summary, p. 2
[3] UG 490 – NW Natural's Exhibit A to Executive Summary, p. 2
[4] UG 432 – Staff Report RA 2 & RA 6, Special Public Meeting October 20, 2021, p. 11
[5] OPUC Order No 22-388 p. 1
[6] UG 459 – Staff Report RA 5, Special Public Meeting, October 25, 2022, p 5
[7] *Id.*

So, while this proposed increase is 18% for most residential customers, it could easily grow by 10%, 12%, or even 15% when the commodity costs are added later this year. Customers could face an increase that is greater than the 2022 increase which led to an adjustment to mitigate the size of the winter increase.

Q. Why are you focusing on the size of the winter increase?

A. The primary use of natural gas for residential customers is space heating. Average winter usage is five times as high as summer usage.

Table 1: Monthly Natural Gas Usage[8]



Rate increases for general rate cases and PGAs go into effect on November 1. This works well for the utility because it allows it to charge a higher rate during the months with the greatest usage. A rate increase in April or May would bring in much less revenue in its first few months. But for customers the results can be difficult. A cold, arctic weather system in the winter can significantly increase the

[8] CUB Exhibit 102.

amount of gas it takes to heat a home, while hot weather in the summer has little impact on gas bills.

Q. What should be done to help alleviate this problem?

A. In the winter of 2022/2023, the Oregon Public Utility Commission (PUC or Commission) implemented a rate shock mitigation proposal that CUB negotiated with NWN which reduced winter heating bills for NWN's customers[9]. This shows that it is possible to address this problem. However, relying on negotiated agreements during the PGA assumes that parties can quickly put together an agreement during the shortened timetable of the PGA process and limits the tools that are available to address rate shock. CUB believes that a better way to address this problem is to establish a mechanism to address rate shock that the Commission can implement when conditions warrant it.

Q. What is rate shock?

A. In the context of utilities, rate shock occurs when there is a sudden, large rate increase which is significant enough that customers find it difficult to adjust their budgets to absorb the increase. Customers are feeling financial pressures from the rising cost of essentials: housing, energy, food, medicine, medical bills, childcare and transportation.

Rate shock is particularly a concern for big increases that come in the winter when bills are at their highest. Customers pay bills, so a 15% or 20% increase in a large winter bill is much more difficult to absorb than a 15% to 20% increase on a summer

[9] Exhibit 103

bill. Rate shock is a big problem for customers that live paycheck-to-paycheck. Adjusting to rate shock means adjusting how much a person pays for food, medicine, other utilities, and other expenses in order to make up for the increase in their electric bill. For customers who live paycheck-to-paycheck, absorbing a $40 to $60 increase in one bill can be very difficult, and absorbing a bill that is more than $100 above normal due to a combination of rate increases and cold weather can be nearly impossible.

Q. Does the Commission have the power to address rate shock?

A. Yes. The Commission has several tools that it has identified that it can deploy to reduce the rate shock to customers. In 2003, Commissioner Beyer testified to the Oregon legislature that the PUC had tools to address rate shock and the PUC would utilize those tools. According to Commissioner Beyer's testimony, the Commission has three tools that can be used to address rate shock:

- Deferring or phasing in the rate increase—with or without carrying charges;
- Setting the rate at a level that is not lower than the lowest reasonable rate; and
- Requiring the utility to propose and implement other rate mitigation measures.[10]

Q. Has the Commission deployed these tools?

A. Not exactly. Most of the big issues in significant rate cases reach the Commission through stipulation, and the Commission has adopted stipulations which include proposals to deal with rate shock. But because stipulations do not set precedents, there are not clear standards for when to apply these tools, or how to do so.

Q. Is relying on stipulations an adequate way to address rate shock?

[10] UE 426 – CUB/103.

A. Absolutely not. In the case of a natural gas utility, most of the work on the general rate case occurs before the utility files its PGA. For example, CUB's final round of testimony is July 2, 2024, approximately 1 month before PGAs are filed. The overall rate increase, the combination of the general rate case and the PGA is not known when we file our evidence in this case. The final settlement conference is scheduled for July 24, 2024, is also before the PGA is filed and the hearing in this case begins on the day that the PGA should be filed. This makes it nearly impossible to handle rate shock through settlement of a general rate case.

The entity that is best able to address rate shock is the utility. It has visibility into all of the cost drivers, controls investment decisions, and the timing of general rate cases and most single-issue rate cases. But a utility has an incentive to make investments, which will bring in additional return on equity (ROE).

It is important to think about incentivizing the utility to take more responsibility for overall rate levels. NWN is asking for an extremely large rate increase, and the commodity is not included yet. While some expenses such as ensuring regional centers are built to withstand earthquakes may seem reasonable, the timing of these investments is controlled by the Company. Did it consider prioritizing and spreading these projects out over several years to ensure that the rates produced are affordable? Currently, there is no incentive for a utility to manage the timing of its investment in order to prevent rate shock.

Q. How should the Commission address this problem?

A. CUB believes the answer lies in designing a policy around rate shock that can be implemented even in cases where the rate shock is not evident early in the year. Such a policy would require defining a standard for rate shock and identifying the response, so it can be easily implemented. And most importantly, such a policy should create better incentives for the utility to manage and prioritize its spending in order to avoid rate shock.

B. CUB's Rate Shock Standard Proposal

Q. Does CUB have a recommendation as to a standard definition of rate shock?

A. Yes. While CUB recognizes that what is unaffordable to one person is different from what is unaffordable to another person, we do believe that it is possible to set a standard for when the Commission will implement a response to rate shock.

To this end, CUB recommends that the Commission look to the Oregon legislature's mechanism to limit rent increases.[11] This rent increase limit can be viewed as a Legislative policy decision about what is a reasonable level of increase for the cost of housing. Because utilities are a part of the cost of housing, CUB believes that this is a good starting point for discussing the standard that the Commission should use for determining when rate shock should be addressed. The legislature's limit was established as the lower of two limits:

- 10%, or
- 7% + Consumer Price Index.[12]

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[11] Kyra Buckley, *New rental cap kicks in, limiting hikes to 10% next year for some Oregonians*, Or. Pub. Broad. (Sept. 26, 2023, 5:02 PM), https://www.opb.org/article/2023/09/26/oregon-rent-increase-caps/.
[12] *Id.*

Under this standard, if the Consumer Price Index (CPI) was 2%, the limit on an annual rent increase would be 9%. If the CPI was 5%, the limit on rent increases would be 10%. While the legislature has established these as hard annual caps on rent increases, CUB is proposing that the PUC establish a similar mechanism that triggers implementing the three tools, noted above, that it has described as ways to mitigate rate shock. While the rent cap applies to individual tenants, CUB is proposing a mechanism on a residential class basis, whereby rate increases that hit a certain established Rate Shock Threshold would trigger a rate shock finding and require application of tools to mitigate that shock.

The Commission could also establish a higher or lower trigger amount if it felt that would be appropriate. CUB recognizes that the volatility of natural gas commodity prices could lead to the PGA, by itself tripping the trigger. The Commission could consider establishing a trigger at 15% if it is concerned about absorbing the commodity costs. But CUB believes that setting a common standard for rate shock which then triggers rate shock mitigation is necessary.

Q. The first tool the Commission has described is deferring or phasing in the rate increase—with or without carrying charges. How would CUB propose that the Commission implement this tool?

A. The first tool, phasing in the rate increase with or without carrying charges, would allow the Commission to approve a rate increase, but limit how much of that rate increase could be allowed to go into effect immediately and provide a schedule for phasing in the remainder of the increase.

For electric utilities, CUB is proposing that the standard be applied on an annual basis and amounts above this cap could go into rates the following year. But gas utilities are different – so much of a gas utilities revenue from residential customers comes from winter space heating. This means that the Commission can provide a great deal of relief to customers by delaying the amounts above the cap until after the winter heating season.

CUB recognizes that there may be circumstances where the financial health of the utility requires that higher rates be phased in more quickly, but that should be discouraged. The Commission is currently allowed to implement a rate increase on an emergency basis without an investigation, subject to refund after the investigation happens and this is rarely used. CUB believes that allowing utility rates to increase above the Rate Shock Threshold should also be limited. Further, the utility is expected to manage its costs between rate cases.[13]

As to the carrying charges, CUB recommends that the Commission reject using the Company's cost of capital for carrying charges. The cost of capital includes a return on equity, which means that shareholders would be rewarded for proposing rate increases above the Threshold and that customers would, in effect, be fully financing their temporary rate reduction. The Commission has other options for carrying charges. It can phase in or delay the increase without a carrying charge. This would

[13] *See Gearhart v. Pub. Util. Comm'n of Oregon*, 255 Or. App. 58, 63, 299 P.3d 533, 538 (2013), aff'd, 356 Or. 216, 339 P.3d 904 (2014).

provide a powerful incentive for utilities to control their costs. The Commission could also use the modified blended treasury rate, recognizing that once the Commission approves, but delays the rate hike, the utility is no longer at risk as to getting the money from customers, only the timing is at issue.

Q. What about the second tool, setting the rate at a level that is not lower than the lowest reasonable rate?

A. CUB believes that this is an extremely important tool. This is based on recognizing that there is normally a range of reasonableness when rates are established centering around the utility's ROE.[14] When establishing ROE, most expert witnesses first determine a reasonable range of ROEs and then make a recommendation as to where within this reasonable range to set the ROE. This ROE range can be viewed as the range of reasonableness for rates, generally. As long as the Commission is setting rates that seek to allow the utility to receive earnings that are within this range, the rates are reasonable. Because of this range, the Commission can reduce rate shock by setting rates at the lowest level that is reasonable but still in the reasonable range.

This is an important tool to manage rate shock. Most businesses compete in competitive markets, where customers have other options. If that business sets a price that is too high for its product, then customers will go elsewhere, and profits will fall. Subjecting utilities to similar market discipline, where if prices rise too quickly it will

[14] Or. Pub. Util. Comm'n, Docket Nos. UE 180, UE 181, UE 184 *In re Portland General Electric Company*, Order No. 07-015, 26 (Jan. 12, 2007) (citing *Duquesne Light Co. v. Barasch*, 488 US 299, 312 (1989)).

affect profits, creates a powerful incentive for a utility to prioritize its spending and investments and think about the price impact it is placing on customers.

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Q. What about the third tool, ordering the utility to take actions that mitigate rate shock. Does CUB have a recommendation as to how the Commission should implement this tool?

A. Yes. CUB believes that when a utility goes beyond the Rate Shock Threshold for a rate increase the Commission should require the Company to take certain actions:

- The rate effective date associated with costs that do not need to be recovered during the winter months should be delayed and not placed on winter bills. This would help avoid creating circumstances where the increase combined with cold weather make bills unaffordable for customers with space heating.
- The Company should be required to submit a plan to the Commission outlining what it is doing to mitigate the rate shock. This plan should include increasing efforts to educate customers about its Bill Discount Program (BDP), equal pay, energy efficiency and other options that might help the customer deal with the impact.
- A shut-off moratorium should be implemented for a 6-month period, allowing customers some time to manage the increase.
- For 12 months after the increase, the Company should be required to report to the Commission the number of customers, by zip code, who have 30-day arrearages, the number that have 60-day arrearages, the number that have received shut off notices, the number that have been shut off and any other information the Commission believes will be helpful in understanding the impact of the increase.
- The Commission could order the Company to suspend or reduce the amortization of certain deferred accounts or other single issue ratemaking mechanisms, to reduce the impact of the rate increase.

Q. These rate increase triggers are set for residential customers, do you have a proposal for other customer classes?

A. Rate shock is not something that is limited to residential customers. Other classes of customers also have trouble absorbing large increases. There would be a fairness question if the Commission used these rate increase caps to limit increases to residential customers but allowed the full increases to other classes of customers. CUB proposes that the residential rate increase triggers be used to limit the recovery to other classes of customers consistent with the rate spread of those elements. For example, if the Commission delayed 50% of the increase for residential customers until the following year, all customer classes would see 50% of their increase delayed to the following year.

B. Applying this Rate Shock Standard to NW Natural

Q. Can you provide more detail about how this could be applied to NWN in this case?

A. Yes. There are several parts to this standard which CUB believes should be applied:

- The Commission should apply the trigger to this case, along with the PGA and other rate changes that will be added to rates in November;
- The Commission should delay recovery of amounts above the trigger;
- The Commission should reduce the ROE to the lowest that is allowable; and
- The Commission should adopt appropriate rate shock reporting requirements.

1. *Applying the Trigger to NW Natural*

When to apply the trigger.

The rate effective date for this case is November 1, 2024, just as the winter months approach. This is the same time that the PGA goes into effect and the PGA is usually the vehicle to adjust any single issue ratemaking mechanisms. This means that we are primarily concerned with rate changes that occur on November 1 each year.

Gas costs go first

In applying the trigger, we will need to consider the impact of this rate case, the PGA, and any additional costs that are added to the rate effective date. Because the PGA is a forecast of the actual commodity costs that will be incurred over a 12-month period with a true up mechanism, delaying it will impact the following year's PGA true-up. The PGA is an ongoing mechanism with a new forecast and a true-up from the previous year being implemented on November 1 of each year. This can be contrasted to the NWN's general rate case, which projects one year of expenses as a "test year" which is used to set a rate level that is "just and reasonable" and will be ongoing. There is no expectation that rates will reset in 12 months, and utilities are not required to have the test year match the first 12 months of rates. The rate established by the general rate case will not be subject to a true up but is ongoing until the utility files a new general rate case.

Assuming that adding the PGA costs do not, by themselves, breach the triggering amount, these gas costs should be implemented as approved by the Commission. Establishing this will then establish how much room is left under the trigger for base rates in the general rate case, and single issue ratemaking that rides on the PGA's coattails.

If gas costs exceed the trigger, then the cap will be applied to PGA costs and PGA costs above the cap will then flow into the PGA true up the following year, subject to sharing, unless the Commission directs otherwise. If the gas costs do not exceed the trigger, then the difference between the gas cost increase and the trigger amount would be the amount that the general rate case would be allowed to increase rates.

As an example, if inflation is 3%, then the trigger is 10%.[15] If the PGA case represents a 2% rate increase, then there is room for an additional 8% before tripping the trigger. This 8% would then apply to the general rate case and single issue rates.

2. *Delaying the amount above the trigger.*

Once the trigger amount has been established and the revenue requirement associated with various ratemaking mechanisms is identified, the amount above the trigger should be set aside. For electric utilities, CUB recommends that it be recovered in a future year. However, in the case of a gas utility where so much of the usage is for winter space heating, delaying the increase until bills drop in the Spring may be adequate. The Commission will need to decide whether there should be a carrying charge. CUB recommends no carrying charge or one set at the modified blended treasury rate.

Reducing the ROE

CUB is not hiring an ROE witness nor making a recommendation as to the range of reasonable return or where the precise ROE should be set. NWN is proposing an increase in its ROE to 10.1 % from the current 9.4%.[16] The request to increase its ROE should be flatly rejected. Increasing the ROE under these circumstances, where the utility is seeking a large rate increase is not reasonable.

[15] *See* CUB/100, Jenks/7–8 above.
[16] UG 490 – NW Natural's Executive Summary at 3.

CUB recommends that the Commission set NWN's ROE at the lowest level possible that still allows the Company a reasonable return. Based on recent cases for other utilities, CUB would expect this to be below 9.4–9.5 percent, which are the current ROEs of regulated Oregon utilities.

Q. What other actions should the Commission order NW Natural to take?

A. The Commission should consider requiring the Company to take several additional steps:

- Rather than moving the amount of the increase above the rate shock threshold to April 1, the Commission should consider moving the rate effective date of the general rate case to April 1, 2025. There is some logic in aligning rates with forecasted gas costs at the beginning of the winter heating season. This allows gas costs to reflect the buying decisions NWN has made over the course of the year as it prepares to meet winter demand. This logic doesn't apply to the base rates that are established in the general rate case and that will be in effect for a period exceeding one year.
- By December 1, 2024, the Company should be required to submit a plan to the Commission outlining what it is doing to mitigate the rate shock. This plan should include increasing outreach efforts to educate customers about its bill discount program, equal pay, energy efficiency and other options that might help the customer deal with the impact.
- A shut off moratorium should be implemented for a 6-month period after the trigger date (November 1 to May 1), allowing customers some time to manage the increase.

  For 12 months after the rate effective date, the Company should be required to report to the Commission, by zip code, the number of customers who have 30-day arrearages, the number that have 60-day arrearages, the number that have received shut off notices, the number that have been shut off, the number that are on payment plans, and the number that are on equal payment plans.

Q. Could your mechanism lead to more frequent rate cases as utilities raise rates more frequently, but by lower amounts, in order to stay below the trigger?

A. Yes. One way to avoid the rate shock caused by sudden big increases is to have a series of smaller increases, therefore, a utility could respond to CUB's proposal by increasing the number of general rate cases it files.

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Q. Won't more rate cases make the regulatory process more difficult and less efficient?

A. It doesn't have to. In the 1990s, Oregon allowed utilities to implement Alternative Forms of Regulation (AFORs) that allowed for automatic annual rate changes. My memory of these mechanisms is that they were limited to 5 years and allowed the utility to raise rates by the rate of inflation minus a productivity factor. If the rate of inflation was 2%, and the productivity factor was 0.5%, the utility could raise rates by 1.5%. These plans were largely dropped because utilities wanted to seek higher rate increases than the AFORs allowed.

Cascade Natural Gas filed a series of four rate cases between March 2015 and March 2020 as it was making a series of investments in aging pipelines.[17] But Cascade made these cases simple. Generally, it did not relitigate things from the last rate case or ask for a bunch of new policy changes or new ratemaking mechanisms. It did not push to increase its ROE. It filed what might be considered stripped down rate cases that focused on new investment, which parties were able review.

Rate cases do not have to be large and onerous. Stakeholders react to what a utility is requesting. A utility can keep it simple. It can be argued that the problem is not that there are too many rate cases, but that utilities see rate cases as opportunities to

[17] UG 287, UG 305, UG 347 and UG 390

reallocate risk between shareholders and customers, design new single-issue ratemaking mechanisms and address public policy issues. The problem may be that rate cases are much more complicated and contentious than a rate case needs to be.

Q. What about the Company's discussion of multi-year rate cases, is that something that CUB could support?

A. The Company did not make an actual proposal for multi-year rate cases, and because the devil is in the details, there is no basis for CUB to support or oppose their efforts. But for the sake of regulatory efficiency, CUB potentially could support some elements of a multi-year rate setting process. But we suspect our view would be much more limited than NWN's view of multi-year ratemaking.

For example, CUB might be able to support a 2-year rate case, where the first year looked at the Company's overall revenue requirement and the second year added a limited set of discreet items, such as new non-routine capital investments but excluded most of the routine items that are updated in a normal general rate case (ROE, compensation…).

CUB supported the AFORs in the 1990s. Those had few limits on what could be updated, but such updates were designed to ensure that rates increase by an amount that was less than the rate of inflation.

CUB’s general belief is that the regulatory process is inefficient. Stakeholders spend a lot of time on issues that are always being relitigated. In this case, for example, the issue of the AAC for RNG is being relitigated, as is the line extension allowance. Relitigating these issues crowds out the ability of the regulatory process to investigate new issues. On the electric side, we have spent a great deal of many proceedings relitigating issues related to the Power Cost Adjustment Mechanisms (PCAMs), based on concerns about their historic performance. But we have spent almost no time investigating whether our power cost forecasting mechanism/methodologies are well-geared to the future when resources are increasingly dispatched by third-party independent system operators, not utilities.

It is problematic that the primary way regulation changes and adapts is through utilities making broad proposals in rate cases that are usually one-sided mechanisms designed to shift risk to customers and profits to shareholders. The initial proposal is often a wish list that is unacceptable to other stakeholders and quickly creates divisions that cannot be easily overcome. Relying on utilities to take the lead on developing proposals for a more efficient regulatory process is akin to asking the fox to design a more efficient hen house.

To the degree the Commission, not the utility, wants to examine ways to create more efficient ratemaking, or any other policy issues, it seems like a Commission-led investigation that begins with a set of principles that the Commission believes are necessary is a better place to begin.

II. DEFERRALS AND AUTOMATIC ADJUSTMENT CLAUSES (AACs)

Q. What is the purpose of this section of your testimony?

A. My testimony responds to NWN's proposal detailed in NW Natural/1500, NW Natural/2000, and NW Natural/1717 to revise its Schedule 198 RNG AAC to 1) allow for a deferral between the in-service and rate effective dates of RNG AAC-eligible investments; and 2) alter the Commission-approved earnings test to remove the current deadband of 50 basis points below and 50 basis points above authorized Return on Equity (ROE), and set the earnings test at NW Natural's authorized ROE.[18] As an alternative to requesting a deferral between the in-service and rate effective dates, NWN has indicated its concern could be addressed by adding flexibility to the RNG AAC to allow rates to go into effect shortly after an RNG project enters service.[19] Currently, the RNG AAC must be filed by February 28th of each year.[20] The contours of the RNG AAC were fully litigated and carefully designed by the Commission in PUC Order No. 22-388 from the previous NWN rate case.[21]

Q. Why does NWN believe these changes are warranted?

A. According to the Company, these changes are warranted because it has shifted its approach to procuring RNG, and it is seeking a simpler framework for its RNG investments to lead to faster regulatory approval.[22] The Company states that Oregon's Climate Protection Program (CPP) places a large compliance obligation

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[18] UG 490, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, NW Natural's Executive Summary and Direct Testimony and Exhibits, NW Natural/2000/Kravitz-Therrien/11, lines 2-7.
[19] *Id*. at 12.
[20] *Id*.
[21] *See In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision*, Docket No. UG 435,OPUC Order No. 22-388, 79–86 (Oct. 24, 2022).
[22] UG 490 – NW Natural/1500, Kravitz-Chittum/12–3.

to reduce or offset the total therms of natural gas used on its system, which will require aggressive decarbonization action.[23] According to NWN, while it will seek to maximize Community Climate Investment (CCI) credits as a CPP compliance mechanism, it will also need to invest in a substantial amount of RNG to comply with the CPP.[24] Additionally, the Company states that weather variability and load growth significantly impacts the ability of CCI credits to cover its total CPP compliance requirement.[25] Interestingly, while the Company states that it "will pursue least cost/least risk CPP compliance actions[,]" on the next page of its testimony it states that it "has aligned its RNG acquisition goals with the RNG targets of the State of Oregon established in SB 98."[26] Even though the CPP has briefly been invalidated on narrow procedural grounds, since NWN must comply with the mandates of the CPP once it is re-established, the Company argues that it should be allowed to defer the costs of RNG projects incurred between the in-service and rate effective date in the RNG AAC.[27] According to the Company, it is only fair for it to receive this treatment because Oregon-regulated electric utilities subject to the Renewable Portfolio Standard (RPS) enjoy similar treatment in their Renewable Adjustment Clauses (RACs).[28] Finally, NWN argues that the changes it seeks to the RNG AAC earnings test are warranted because the current framework creates a perverse incentive for the utility to decrease RNG production because a project's revenue requirement increases as RNG production increases.[29]

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[23] *Id*. at 6.
[24] *Id*. at 7, 11.
[25] *Id*. at 8, 10-11.
[26] *Id*. at 11–12.
[27] *Id.* at 15.
[28] *Id*. at 15-16.
[29] *Id*. at 19.

Q. Please summarize your recommendations.

A. CUB respectfully recommends that the Commission decline to adopt the Company's proposed changes to its RNG AAC. The Company has failed to present adequate evidence to justify the changes it seeks. First, it is perplexing that the Company argues it will be pursuing the least cost/least risk means to comply with the CPP, while also saying it is aligning its RNG procurement strategy with the goals of SB 98 (2020).[30] The Commission previously weighed in on the Company's RNG procurement strategy and the interplay between SB 98 and the CPP in various forums, and the Company does not currently have an RNG procurement strategy that has been acknowledged by the Commission as reasonable.[31] Second, the impacts of weather variations and load growth on NWN's system do not justify the changes to the mechanism. Third, the comparison to the contours of the RAC used for RPS-eligible investments for electric utilities is not apt because the CPP was adopted by administrative rule and contains no similar cost recovery language. Further, the Commission has previously held that the current RNG AAC already aligns with the cost recovery provisions found in SB 98.[32] Finally, the Company's proposal to alter the earnings test on the RNG AAC should be rejected.

Q. You mention that it is perplexing that the Company states that it will both be seeking the least cost/least risk means of complying with the CPP *and*

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[30] *Id*. at 10-11; *see* ORS 757.396.

[31] *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, 2022 Integrated Resource Plan*, Docket No. UE 435, Order No. 23-281, 11 (Aug. 2, 2023) ("Without an analysis that demonstrates that the level of RNG procurement proposed is the least-cost, least-risk way to meet the company's compliance needs, we cannot acknowledge [RNG procurement]").

[32] *See* UG 435 - OPUC Order No. 22-388, 79-86 (Oct. 24, 2022).

that that it is aligning its RNG procurement strategy with SB 98. Why is this perplexing?

A. It is perplexing for a variety of reasons. The CPP is a binding, comprehensive greenhouse gas reduction program that was adopted by the Oregon Department of Environmental Quality (DEQ) through administrative rule. SB 98 is a voluntary program established through legislation sponsored by NWN that sets permissive standards for potential RNG procurement. The Commission and stakeholders have been abundantly clear with the Company that while compliance with the CPP will likely require NWN to pursue some RNG investments, the Company should not presuppose that it *must* procure RNG up to the permissive goals established in SB 98.

Q. Please explain.

A. Certainly. The Company's current RNG AAC was fully litigated in NWN's last general rate case: UG 435. There, the Commission was crystal clear about the interplay of the CPP and SB 98 as it pertains to the RNG AAC:

> SB 98 is a legislatively approved but voluntary RNG procurement target, while the CPP is a comprehensive, mandatory greenhouse gas emissions cap and reduction regime adopted by administrative rule. Under the requirements of the CPP, any emissions reduction measure the utility takes, which *may* include RNG procurement, will necessarily be in service of CPP requirements. At the same time, the magnitude of the CPP's emissions reduction requirements and potential customer rate impacts require us to apply a high level of scrutiny to whether the utility is pursuing the least cost, least risk portfolio of emission reduction measures. It is possible that a prudent strategy may include RNG, but this will depend on the costs and risks relative to alternatives. *We are concerned about the potential incentive created by the availability of an AAC to skew the company's analysis of costs and risks of alternative CPP compliance measures towards RNG projects. Specifically, we are concerned about the potential for RNG to be automatically eligible for more favorable cost recovery up to the SB 98 spending limits without a demonstration that*

> *RNG at that level is least cost, least risk relative to other CPP compliance portfolio configurations.*[33]

The Commission was clear that an AAC should not alter how the Company views RNG procurement and that the Company should not maximize RNG procurement up to the levels of SB 98 without a definitive showing that these levels are necessary to comply with the CPP. Further, as proposed in this rate case, the RNG AAC will allow significantly more favorable cost recovery for RNG investments than other carbon reduction investments, which is likely to lead the Company to skew its analysis in favor of RNG investments. The Company is proposing exactly what the Commission cautioned NWN and stakeholders about.

Q. You mention that there should be a definitive showing that RNG procurement up to SB 98 levels is the least cost/least risk means of complying with the CPP in order for those levels to be procured. Has the Company shown that this level of procurement is necessary?

A. No. Not only has the Company failed to demonstrate that procuring RNG up to the permissive levels in SB 98 is the least cost/least risk of complying with the CPP, its long-term RNG procurement strategy was rejected by the Commission. In its last Integrated Resource Plan (IRP), the Commission stated that NWN presented RNG "as an assumed resource up to—and, in CUB's view, beyond—the voluntary targets in SB 98."[34] While the Company made some changes to its RNG modeling throughout the IRP process, the Commission ultimately declined to acknowledge NWN's entire RNG procurement strategy.[35] Importantly, the Commission noted that the Company

[33] OPUC Order No. 22-388 at 81.
[34] OPUC Order no. 23-281 at 11.
[35] *Id.*

had failed to demonstrate "that the level of RNG procurement proposed is the least-cost, least-risk way to meet the company's [CPP] compliance needs."[36] Therefore, while the Company does not currently have a Commission-approved RNG procurement strategy, NWN believes that changes to its RNG procurement strategy warrant the changes it seeks to the RNG AAC in this proceeding.

Q. Should the Commission adopt NWN's proposed RNG AAC changes given that it does not have a long-term RNG procurement strategy that has been approved?

A. Definitely not. The Company makes high level assertions about its need to shift its RNG procurement strategy to comply with the CPP and SB 98, but that procurement strategy is not at issue in this rate case. The Company's long-term RNG procurement strategy is appropriately examined in the IRP setting, and it should be required to bring forward a fulsome analysis in its next IRP once the new CPP rules have been enacted. The changes to the RNG AAC that NWN seeks in this proceeding would unarguably give more favorable ratemaking treatment to RNG investments, which would skew the Company's analysis towards preferring capital RNG investments—which is exactly what the Commission expressed concern about in the quote above. Further, these changes are one-sided and represent a substantial departure from the reasoned and balanced RNG AAC that the Commission adopted last year in UG 435.

Q. NWN argues that the lack of a deferral between the in-service and rate effective dates of RNG investments means it is being denied full cost recovery. Speaking of UG 435, was this issue addressed there?

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[36] *Id*.

A. Yes, extensively. The impact of SB 98's cost recovery language was a central issue in UG 435. NWN repeatedly argued that the provision that allows for recovery of all prudently incurred costs meant that it needed a deferral between the in-service and rate effective dates of these resources.[37] In the UG 435 Order, the Commission was clear that it:

> disagree[d] that SB 98 must be interpreted as a legislative requirement to remove all regulatory lag and shareholder risk from RNG cost recovery. That interpretation, taken to its logical extent, would reach deep into the Commission's ratemaking function and prevent us from achieving balanced outcomes and establishing just and reasonable rates, radically and fundamentally changing the Commission's ratemaking task. An intention to make this fundamental change is absent from the legislative history. We see no evidence from the legislative history that, as a fundamental premise of its environmental policy, the legislature expected through SB 98 to eliminate the Commission's duty to consider the risk balance between utilities and their customers.[38]

Further, the Commission was clear that SB 98 does not even require an AAC to be developed in the first place.[39]

Q. If this was fully litigated in the last general rate case, why is the Company arguing here that it be allowed to defer the costs between the in-service and rate effective dates of RNG projects?

A. The Company argues it is entitled to this treatment because it must comply with the CPP, which places binding greenhouse gas emissions requirements on it. However, unlike SB 98 or the RPS, the CPP contains no provisions around cost recovery. The Company cannot argue that the RNG AAC denies it full cost recovery, in part, because the Commission was clear in the last rate case that even SB 98 "did not

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[37] *See, e.g.*, UG 435 – NW Natural/1500, Kravitz/6, lines 4-5.
[38] OPUC Order No. 22-388 at 80.
[39] *Id*.

specifically mandate the use of anything other than the Commission's normal ratemaking methodologies, *which we use to enable timely and full recovery of prudently incurred costs*."[40] Since the Commission has held that normal ratemaking methodologies—i.e., the general rate case format—enables timely and *full* recovery of prudently incurred costs, NWN cannot argue that the RNG AAC does not allow it to fully recover its prudently incurred costs. The RNG AAC enables the Company to add RNG capital costs into rates without a general rate case which results in more favorable ratemaking treatment to the Company than normal ratemaking methodologies. NWN's reliance on the CPP to allow it a deferral between the in-service and rate effective dates falls short for a number of reasons.

Q. What about the Company's argument that it should receive this deferral because the electric utilities have a similar format for their RACs?

A. The electric utilities' renewable investments are governed by provisions of 2007's SB 838 and 2016's SB 1547. It has cost recovery language that is different than SB 98, the law that NWN is relying on. While NWN continues to assert that SB 98 requires dollar-for-dollar recovery of RNG-related costs,[41] the Commission found that this is not true:

> Parties to this case offer us widely divergent interpretations of the cost recovery provisions of SB 98. We largely agree with Staff that the legislature's primary intention in its SB 98 cost recovery language was to ensure that the Commission would allow recovery of the relatively high costs for RNG resources, even though such resources would not otherwise be expected to meet our prudence standard due to their high cost relative to traditional alternatives. As Staff notes, the legislature did not specifically mandate use of anything other than the Commission's normal ratemaking methodologies, which we use to enable timely and full

[40] *Id*.

[41] NW Natural/1500, Kravitz–Chittum/14-20; *see also* UG 435 – NW Natural Closing Brief at 78-79 (Aug. 22, 2022).

> recovery of prudently incurred costs, resulting in just and reasonable rates. The statutory language of SB 98 states that qualified investments and the associated operating costs may be recovered through an AAC. It does not otherwise express a clear intention to deviate from the legislature's traditional deference to the Commission's application of its long-established ratemaking mechanisms, nor to have the legislature tightly control cost recovery mechanisms with an intention to prioritize the companies' interests over customers' interests.
>
> We disagree with NW Natural that SB 98 must be interpreted as a legislative requirement to remove all regulatory lag and shareholder risk from RNG cost recovery. That interpretation, taken to its logical extent, would reach deep into the Commission's ratemaking function and prevent us from achieving balanced outcomes and establishing just and reasonable rates, radically and fundamentally changing the Commission's ratemaking task. An intention to make this fundamental change is absent from the legislative history. We see no evidence from the legislative history that, as a fundamental premise of its environmental policy, the legislature expected through SB 98 to eliminate the Commission's duty to consider the risk balance between utilities and their customers. We also see no evidence that either the Commission, individual legislators, or other stakeholders viewed the legislative proposal in such a way.[42]

CUB reiterates our arguments from UG 435 that NW Natural cannot claim that any statute or regulation requires an AAC for RNG-related procurement.[43] NWN's proposal for a deferral to track RNG costs between the in-service date would result in an inequitable distribution of cost and risk, with the Company's customers holding the short end of the stick. The Company's proposal is not grounded in any legal obligation and should be rejected. While SB 98 has similar cost recovery language to the RPS, the Commission already held that SB 98 does *not* require an AAC and that a cost recovery determination should be made through a request for a general rate revision.[44]

[42] OPUC Order No. 22-388 at 80.
[43] *See* UG 435 - CUB's Opening Brief, 17-27 (Aug. 10, 2023).
[44] OPUC Order No. 22-388 at 80.

Q. What about the Company's arguments around the impacts of weather variation and load growth?

A. NWN's arguments around the impacts of weather variation and load growth are simply attempts to shift risk to customers. There are risks associated with weather and its effects on load. There are risks associated with load growth. I remember similar arguments made in the context of decoupling and PGA sharing. But these are the basic normal business risks that for-profit companies in all kinds of lines of business manage and the Company is using RNG as an excuse to try to shift them to customers. NWN's arguments around the impacts of weather variation and load growth related to RNG are insufficient to justify changes to the mechanism in the Company's recently decided general rate case.

Q. What about the proposal to allow flexibility in the RNG AAC to allow a change to the filing date each year?

A. We already argued about this – there is no compelling reason to change what has already been agreed to. The Company is already getting favorable cost recovery through an AAC compared to a general rate case—which the Commission has held it could use. This would place an unnecessary burden on the Commission and Commission stakeholders.

Q. What about NW Natural's proposal to change the earnings test?

A. While we appreciate that NWN has not proposed to remove the earnings test, it should stay in its current form. This issue was litigated before the Commission in the last rate case, and the Commission created the 50 basis points deadband above and below ROE as a reasonable compromise:

> We find, however, that it is important still to protect customers from unforeseen and potentially costly events that could occur with respect to the company's ability to acquire, produce, or deliver RNG after a forecast is made. The lower deadband of 50 basis points on the earnings test applied to these costs will serve this purpose, while still not precluding the company from updating its forecast of costs on a prospective basis on November 1 of each year under the AAC, a process which gives the Commission a more practical opportunity to review of the prudence and reasonableness of those costs. The upper deadband of 50 basis points above authorized ROE is allowed as a way to ensure that there is symmetry on the earnings test and an opportunity for the company to benefit, as part of our implementation of SB 98 in a balanced manner that ensures, overall, a reasonable opportunity to recover the company's prudent costs. We do this despite some concern that the deadband above authorized ROE could create an incentive for the company to over-forecast the costs of RNG. We will rely on our authority and obligation to review utility actions for prudence and reasonableness to ensure appropriate forecasts and look forward to any learnings on this topic as the AAC is implemented.[45]

An earnings test is necessary to incentivize NW Natural to operate efficiently. Without it, the Company would have no incentive to keep costs in check. If there is no deadband on the earnings test, NWN loses an important incentive to control costs. Higher-than-forecasted RNG production increases the project's overall revenue requirement, even though per-unit costs decline.

What NWN is asking for would make the cost recovery mechanism unbalanced. The Commission acknowledged the need for balance in its decision in NWN's last rate case:

> The upper deadband of 50 basis points above authorized ROE is allowed as a way to ensure that there is symmetry on the earnings test and an opportunity for the company to benefit, as part of our implementation of SB 98 in a balanced manner that ensures, overall, a reasonable opportunity to recover the company's prudent costs.[46]

[45] *Id.* at 82–84.
[46] *Id.* at 84.

The Commission adopted this approach despite its concern that a deadband above the ROE could incentivize the Company to over-forecast RNG costs.[47]

The Commission has stated that while a specific targeted ROE is usually established to set rates in a general rate case, returns for a utility are considered reasonable if they are within a range.[48] The Commission found that the 100 basis point deadband was a sufficient buffer barely six months ago.[49] NWN has not shown that this should change. CUB maintains that an earnings test preserves this incentive to control costs, aligns with Commission precedent, is durable, and can accommodate changes in NW Natural's ROE over time.

Q. Does an earnings test discourage NWN from producing RNG?

A. No. The Company can't argue that the earnings test would stop it from producing RNG *because it has a compliance mandate*. More importantly, when NWN invests shareholder capital in a new RNG project, it is setting itself up to receive its ROE on that project for the life of that project. The suggestion that earning 50 basis points less than its authorized ROE (but still a reasonable amount) for a short term at the front end of the project will undercut this investment is nonsensical. It is also not supported by any economic analysis showing a material change in shareholder profits from the project. Furthermore, the current deadband is modest—the Company will only be affected up to 50 basis points *and* will receive a full true up if the costs go outside that deadband.

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[47] *Id.*
[48] *In re Portland General Electric Company*, OPUC Docket Nos. UE 180, UE 181, UE 184, Order No. 07-015 at 26 (Jan. 12, 2007).
[49] Order No. 22-338 at 83–84.

Q. Do you have any other comments on NWN's AAC proposal?

A. At the same time the Company is relitigating issues that were decided in its last rate case, it is saying that general rate cases are too complicated, and regulation needs to be simplified with multiyear rate cases.[50] One way to simplify the rate setting process is to respect the Commission's decisions and not relitigate major issues.

Q. Does this conclude your testimony?

A. Yes.

[50] NW Natural/100, Palfreyman-Kravitz/32–36.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Oregon Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

NW Natural												
UG 490 CUB DR 9												
Test Year Projected All Inclusive per therm Rates, Residential												
A. All Residential Customers (Weighted by Customer Class)												
Customer Fixed Charge	$ 9.89											
Proposed UG 490 Total Base Rate	$ 0.90649											
All Residential Customer Count	643,247											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
Weighted Avg UPC	75.91	106.04	106.05	94.69	77.02	56.51	32.44	21.65	16.63	13.95	16.95	39.80
All Inclusive per therm Rate:	$ 1.03676	$ 0.99975	$ 0.99974	$ 1.01092	$ 1.03489	$1.08149	$1.21131	1.363268	1.50117	1.61511	1.48990	1.15493
B. Existing Single-Family Residential Customers												
Customer Fixed Charge	$ 10.00											
Proposed UG 490 Total Base Rate	$ 0.90649											
End of Test Year Customer Count	566,945											
% of all Residential Customers	88.14%											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
UPC	76.21	106.45	106.45	95.06	77.31	56.72	32.56	21.74	16.70	14.02	17.02	39.96
All Inclusive per therm Rate:	$ 1.03771	$ 1.00043	$ 1.00043	$ 1.01168	$ 1.03583	$1.08279	$1.21357	$1.36652	$1.50519	$1.61996	$1.49407	$1.15675
C. New Premise Single-Family Residential Customers												
Customer Fixed Charge	$ 26.25											
Proposed UG 490 Total Base Rate	$ 0.90649											
End of Test Year Customer Count	3,081											
% of all Residential Customers	0.48%											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
UPC	51.16	73.09	75.00	63.93	53.54	39.89	22.82	13.93	9.46	8.16	11.05	27.36
All Inclusive per therm Rate:	$ 1.41964	$ 1.26563	$ 1.25647	$ 1.31712	$ 1.39682	$1.56460	$2.05661	$2.79084	$3.68135	$4.12299	$3.28285	$1.86582
Multi-Family Residential Customers												
New Premise MF												
Customer Fixed Charge	$ 24.25											
End of Test Year Count	1,525											
% of all Residential Customers	0.24%											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
	51.16	73.09	75.00	63.93	53.54	39.89	22.82	13.93	9.46	8.16	11.05	27.36
Existing MF												
Customer Fixed Charge	$ 8.00											
End of Test Year Count	71,695											
% of all Residential Customers	11.15%											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
	76.21	106.45	106.45	95.06	77.31	56.72	32.56	21.74	16.70	14.02	17.02	39.96
Total MF Customer Count	73,221											

MEASURE: HB 3575
EXHIBIT: R
H Business, Labor, and Consumer Affairs
DATE: 4-14-03 PAGES: 7
SUBMITTED BY: LEE BEYER

BEFORE THE HOUSE COMMITTEE
On
BUSINESS, LABOR & CONSUMER AFFAIRS

<u>HB 3575</u>

Testimony of Lee Beyer, Commissioner
Oregon Public Utility Commission

April 14, 2003

I am here today to discuss the effects of the HB 3575 on the Public Utility Commission and the parties we regulate.

This bill amends numerous laws that govern utility ratemaking and other proceedings before the Commission. Some of these changes merely codify existing regulatory standards used by the Commission. Others create new processes and restrictions.

Let me start by saying that the Commission is not wildly enthusiastic about this bill. We do not particularly see a need for it and realize that it will embark us on a considerable rule making adventure over the next 12 to 18 months. We also are concerned about the way it treats the four industries we regulate differently and believe that this may lead to confusion about fairness in Oregon's regulatory process.

However, we feel strongly that everyone involved in the regulatory process must feel that it is fair and provides equal access to all parties. If the parties and the Legislature feel that this is a journey that should be taken, we are ready to do so.

Before getting into the details of the bill, I would also like to commend the sponsoring parties for working with the Commission to address our concerns. Their proposed amendments have resolved many of our initial concerns.

Now to the details; in view of the numerous and varied changes proposed by this bill, I would like to walk through the bill's substantive changes section by section.

<u>Section 1</u> makes two specific changes to the Commission's general powers to incorporate language from the Natural Gas Act. The United States Supreme Court construed this Act in its *Hope* decision, which established constitutional ratemaking standards used today. Section 1 inserts language to clarify that the Commission has discretion to set the lowest reasonable rates for a utility, and that reasonable rates must provide revenue only for prudent expenses and investment.

The Commission is already required to follow the Supreme Court's decision in *Hope.* Accordingly, Section 1 makes no change in the law or in Commission practice.

Section 3 modifies the Commission's process used in contested cases. It incorporates many ideas raised during the HB 3615 Task Force review relating to *ex parte* communications. It also restricts the involvement of the Governor's Staff, Executive employees, Legislators, and employees of the Legislature in Commission decision-making.

Current law restricts private communications between a party to a case and a decision-maker. The law defines decision-maker to include an administrative law judge (ALJ) and a Commissioner but exempts communications with Commission staff.

HB 3575 expands these restrictions by limiting decision makers from communicating with (1) staff witnesses, (2) Assistant Attorney Generals that represent staff, and (3) staff members that participate in settlement discussions. The proposal to expand ex parte restrictions to include communications with individuals in the first two categories should not significantly change Commission practice. Our internal operating guidelines currently prohibit agency decision makers from privately communicating with any staff member who appeared as a witness in a particular proceeding, or any Assistant Attorneys General that represented Staff in that proceeding.

The proposal to restrict communications with any staff member that participates in settlement discussions, however, is more problematic. Settlement discussions are an important part of our proceedings. The Commission prefers that parties resolve disputes informally rather than proceed with contested litigation. Because these events play an important role, parties prefer that experienced staff members participate in these discussions to help negotiate a settlement that will likely be approved by the Commission.

Due to limited agency resources, however, agency decision makers also must rely on these experienced staff members to provide technical advice. Thus, a conflict exists between the parties' need for key staff at settlement conferences and the Commissioner's need to obtain competent technical advice.

These expanded ex parte restrictions do not apply to all senior staff. HB 3575, however, requires the Commission to adopt rules addressing communications between agency decision makers and staff members not identified above. The Commission's internal operating guidelines noted previously currently address these communications. Consistent with the Commission's obligations to conduct fair and impartial proceedings, these guidelines restrict the conduct of any senior staff that provides technical advice. In providing this assistance, senior staff members are expected to provide independent, expert recommendations and refrain from advocacy.

Finally, it is important to note that the proposed ex parte restrictions are more stringent than those currently imposed on other agencies by the Administrative Procedures Act (APA). While the APA restricts ex parte communications on "a fact in issue," HB 3575 restricts "any communication concerning the issues, merits or facts of the case." The need for this more rigid standard is unclear.

Section 4 requires at least one Commissioner to attend hearings at which substantive testimony is presented related to a request by an electric or natural gas public utility to change rates. A Commissioner need not attend such a hearing if agreed to by all parties to the proceeding.

In response to recommendations by the HB 3516 Task Force, the Commissioners are attending most evidentiary hearings. Moreover, parties may now request an opportunity to appear before the Commission for oral argument. Of these two proceedings, the Commission has found that the oral arguments are of more benefit to the decision-making process than attending evidentiary hearings.

Because the Commissioners are attending more hearings, the proposed requirement that one Commissioner attend major energy cases should not significantly impact current Commission practice.

We have reservations, however, about making Commissioner participation mandatory even if attendance does not benefit the decision-making process. Moreover, we question the basis to require Commissioner attendance at hearings involving rates for energy utilities but not telecommunications utilities.

Section 5 states that the Commission shall enter findings of fact and conclusions of law "*based upon a preponderance of the evidence in the record of the case*." The Commission is already required to use this standard. Thus, like Section 1, this section makes no change in the law or in Commission practice.

Section 6 requires the Commission to audit accounts of each electric and natural gas utility on a schedule set by Commission rule. The Commission recently renewed its audit program after it had been disbanded for several years. The current policy is to conduct audits in advance of general rate filings and investigate special issues as they merit. Consequently, the proposal to require the Commission to perform these audits should not significantly change current Commission policy. Again, however, we question the requirement for energy utilities while excluding telecommunications utilities.

Section 7 clarifies that, in setting rates for energy utilities, the Commission may take action to mitigate rate increases that would adversely affect customers or the state's economy. These actions include:

1. deferring or phasing-in the rate increase—with or without carrying charges,
2. setting the rate at a level that is not lower than the lowest reasonable rate, and
3. requiring the utility to propose and implement other rate mitigation measures.

The Commission currently has the authority to take any of these actions to mitigate the impact of a rate increase. Consequently, like Sections 1 and 5, this new language makes no change to the law or Commission practice.

Section 8 amends the suspension process used by the Commission to investigate energy utility rate filings. This section requires the Commission to rule on a rate request within nine months of when the rate is to go into effect. No longer would Commission inaction allow a tariff to go into effect by operation of law.

This section substantially modifies the traditional suspension concept used to review and approve utility rate filings. Rather than allowing a filing to go into effect by operation of law, the Commission would be under a legal obligation to rule one way or the other within the nine months suspension period. If it failed to act within that time period, the Commission would be subject to a writ of mandamus.

Section 9 amends laws that govern tariff filings by requiring energy utilities to provide additional justification and notice of rate changes scheduled to take effect upon less than 30 days notice. Utilities must establish the need for the filing and provide copies of work papers and supporting documents on a notice list maintained by the Commission. This section also requires that a majority of the Commission approve any change to rate schedules, and that the Commission establish by rule various procedures to implement the amendments.

The change requiring a majority of Commissioners to approve rate changes is a substantive change to existing regulations. If there is no suspension of a tariff, it will no longer go into effect by operation of law.

The remaining amendments in this section are primarily procedural and should not significantly impact Commission practice. The purpose for these procedural changes, however, is unclear, as the Commission is not aware of any abuse of filings requesting rate changes on less than 30 days notice. Moreover, we again question the adoption of new standards and procedures for energy utilities while excluding telecommunications utilities.

Section 10 amends the deferred accounting provisions by limiting any deferral requested by an electric utility to five (5) percent of the utility's gross revenues. The Commission may exceed this cap if it determines, after a hearing, that a greater deferral is necessary to protect the financial integrity of the electric utility and the public interest.

Limiting the amount of a deferral to five (5) percent of the revenues of an electric utility may have unintended consequences. The power cost deferrals filed by Portland General Electric and PacifiCorp in 2000-01 greatly exceeded this cap. Had the Commission limited those deferrals to the five (5) percent cap, these utilities would have been forced to try to recover these expenses in a general rate filing. Under ratemaking standards, however, those higher power costs probably would have been considered transitory and not appropriate to include in base rates going forward. While HB 3575 allows the Commission to exceed the cap under certain circumstances, the restriction may prevent electric utilities from recovering prudently incurred expenses.

Again, we question the adoption of such a restriction for electric utilities, while excluding natural gas and telecommunications utilities.

Section 11 requires the Commission to conduct a proceeding to investigate and review the use of deferred accounting and report to the 2005 Legislative Assembly. This provision is consistent with the Commission current concerns with deferred accounting and desire to review current statutes, rules and procedures. We question, however, the need to include a request for such an investigation—including topics for consideration—in statute.

No effect on ORS 757.262 mechanisms; change is housekeeping prompted by other changes in deferred accounting in Section 10.

Section 12

Section 12 moves the current deferred accounting provisions for certain purchases from Bonneville Power Administration (BPA) out of ORS 757.259 into ORS 757.663, which authorizes these purchases.

No effect on ORS 757.663 purchases; change is housekeeping prompted by other changes in deferred accounting in Section 10.

Section 13

This section states that amendments in HB 3575 apply only to proceedings before the Commission that were commenced on or after the effective date of the Act.

This section merely indicates when these proposed changes would take effect, if HB 3575 is enacted.

I. Introduction

Q. Please state your name, occupation, and business address.

A. My name is John Garrett. I am a Utility Analyst employed by the Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/Garrett/201.

Q. What is the purpose of your testimony?

A. My testimony addresses:

1. NW Natural's (the Company or NWN) changed method for calculating the Company's revenue requirement for **Uncollectible Expense (Section II)**, including the Company's adjustment for Division 21 Customer Notice, which reduces the notice provided to customers;
2. The invention of **The "New Premise" Customer Class (Section III)** and its discriminatory and inequity implications;
3. The Company's new **Line Extension Allowance (LEA) for Residential Customers (Section IV)** and its risk of generating costly stranded assets**;** and
4. **Broader Economic Conditions and the Company's Rate Request (Section V)**.

Additionally, I am currently evaluating materials provided by the Company around several issues I intend to discuss in future testimony. To arrive at just and reasonable rates, it is very important to consider if, particularly during a period of prolonged economic downturn, the Company is appropriately prioritizing investments in accordance with their importance and immediate need. Several areas CUB is examining for overspend are office construction, earthquake contingency planning, and revamping Information Technology & Services (IT&S) Additionally, I will continue to review the Company's testimony and discovery responses related to the change in how the company handles depreciation and spending on software.

All told, CUB is concerned that the Company is investing in new projects too fast,[1] despite four years of unfavorable economic conditions,[2][3] and intends to keep investing aggressively,[4] while anticipating a weak economy[5] and experiencing less customer growth,[6] all of which would continue to drive up rates, when their captive ratepayers are already struggling to afford their current rate.[7]

To that end, CUB will also be closely monitoring the Company's testimony and analysis, which will be considered in CUB's analysis and rebuttal testimony. My recommendations may change accordingly based on further review and as informed by discovery and testimonies offered by other parties.

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[1] *See* CUB/Garrett/206 – Rate Base Initial Findings.

[2] *See* Consumer Price Index – West Region. March 2024. https://www.bls.gov/regions/west/news-release/consumerpriceindex_west.htmand and The Federal Reserve Economic Data, Unemployment Rate in Oregon, Apr. 2, 2024, https://fred.stlouisfed.org/series/ORUR.

[3] *See* NW Natural/400Coyne-Nelson/Page 9:13-18.

[4] *See* NW Natural/400/Coyne-Nelson/Page 38 ("As discussed in Section VII of our Direct Testimony, NW Natural expects to invest approximately $1.4 billion in infrastructure in the 2023-2027 period, or approximately 62 percent of the Company's net utility plant.").

[5] *See* NW Natural/400Coyne-Nelson/Page 9:13-18 ("Economic and capital market conditions have been unsettled due to increasing inflationary pressure and the prospects for weaker economic growth or recession as the Federal Reserve tightens monetary policy. After experiencing steady economic growth from 2017-2019, the consequences of COVID-19 forced the U.S. economy into a sharp recession in 2020. Gross Domestic Product ("GDP") has tracked unevenly since then…") and NW Natural/1300/Wilson-Sparley/ Page 12: 9-16.

[6] *See* CUB/Garrett (New Service Lines Installed: Note the decline in new customer hookups, beginning in 2017 and continuing to the present at faster rates) and NW Natural/1700/Walker 12: 13-14.

[7] *See* NW Natural/1300/Wilson-Sparley/Page 6/ Line 1.

II. Uncollectible Expense

Q. What is uncollectible expense?

A. Uncollectible expense "is the amount owed to NW Natural from customers that cannot be collected and the Company writes off."[8] Put simply, uncollectible expense is unpaid bills.

Q. What does the change in NW Natural's uncollectible expense say about ratepayer hardship over the past five years?

Figure 1 was provided by the Company in its opening testimony.[9] It is an illustration of ratepayers struggling to afford NW Natural's essential services over the past four years. It is a very serious and sobering image. Since NW Natural's last rate increase (UG 435) about two years ago, the average unpaid "accounts aged more than 150 days" seems to have stabilized at around 790% above 2019 levels.[10]

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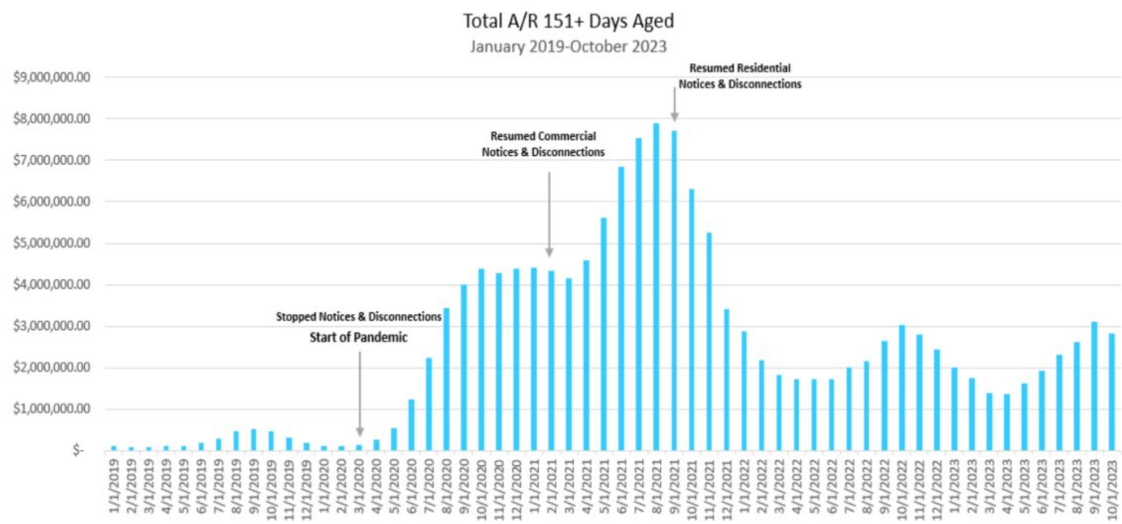
[8] NW Natural/1300/Wilson-Sparley/ Page 3:9-10.
[9] *See* NW Natural/1300/Wilson-Sparley/ Page 6.
[10] *See* CUB/Garrett/202/Uncollectible Expense.

Figure 1



It is no stretch to imagine that within the uncollectible expense are the unpaid bills of Oregonians that are now houseless; in 2023, Governor Tina Kotek described houselessness in Oregon as a "manmade" and "humanitarian disaster."[11] CUB is concerned about how this graph might look in a few years if NW Natural's rates, alongside other essential cost-of-living expenses, continue rising so fast.

Q. What is the standard method for calculating the Company's revenue requirement for uncollectible expenses?

A. The standard method for calculating the revenue requirement for uncollectible expense is simple, elegant, and fair. The revenue requirement is set to the 3-year past average uncollectible expense rate. Sometimes the 3-year past average will prove to be higher than the actual expense in the test year, benefiting the Company, and

[11] *See* Oregon Public Broadcasting. January 2023. "Oregon Gov. Tina Kotek takes first actions on 'humanitarian disaster' of homelessness." https://www.opb.org/article/2023/01/10/oregon-housing-crisis-homeless-population-governor-tina-kotek-executive-orders/.

sometimes it will be lower, benefiting ratepayers. It is founded on verifiable billing and revenue data. Some of its most important benefits are upholding ratemaking integrity and maintaining regulatory efficiency.

Q. What was the revenue requirement using the standard method?

A. CUB estimates the standard method would indicate a revenue requirement of $2.67 million (0.242% of annual revenue).[12] It is important to note that the uncollectible expense has probably been affected by a flurry of macroeconomic factors, along with regulatory and NW Natural policy changes, from over the past three years, but in 2023, uncollectible expense was $2.62 million (0.284% of 2023 annual revenue), so the 3-year past average was very close to the most current measure.

Q. Did the Company use the Standard method?

A. No**.** The Company proposed a different method, whereby it conceptualizes as many factors that could affect the uncollectible expense as it chooses. The Company then assigns values to those factors based on complex and sometimes confusing logic. The Company's method for calculating the Company's revenue requirement for uncollectible expense is much more complex than the standard method, was very difficult and time-consuming to vet, and is much less grounded in the foundational Bonbright ratemaking principles.[13]

Q. What Revenue Requirement did the Company propose?

A. The Company's method results in a revenue requirement of $4.49 million, which is $1.82 million more than the standard method indicates.[14]

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[12] *See* CUB/Garrett/202 - Uncollectible Expense.
[13] *See* Principles of Public Utility Rates by James C. Bonbright. 1961. https://www.raponline.org/wp-content/uploads/2023/09/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf.
[14] *See* CUB/Garrett/202 - Uncollectible Expense.

Q. What changes did the Company make to the standard method for determining uncollectable expense?.

A. The Company made a number of changes. Let me highlight two: an adjustment due to changes in disconnection rules and an adjustment based on economic forecasting. The revised Division 21 rules require NW Natural to provide more notice time to customers before disconnecting service. Specifically, the required notice period increased from 15 days to 20 days.[15] In order to comply with this requirement, NW Natural explained that it needed to forgo its three-day call-ahead notice of disconnection that the Company previously provided to customers.[16] As the Company explained:

> Historically the Company provided a call-ahead to the customer three days and one day prior to disconnection. Now, the Company still provides the one-day call-ahead but has eliminated the three-day call-ahead. NW Natural historically received payment from about 20 percent of the customers it reached out to with the three-day call ahead. [NW Natural] took the September 2023 account balance aged 60+ days of $6.8 million and multiplied it by the 20 percent to reach $1.4 million of accounts receivable that we would expect to collect from the three-day call ahead. Of that $1.4 million, [the Company] typically see[s] 6 percent of accounts receivables turn into delinquent accounts that are deemed uncollectible and written off. The $1.4 million multiplied by 6 percent equates to $81,000 of incremental uncollectible expense. To convert that to a percentage, [NW Natural] took the $81,000 divided by the $1.1 billion of 2023 budgeted total revenues. Therefore, with the reduction in payments resulting from the removal of the three-day call-ahead, NW Natural expects it will see an increase in uncollectible expense of 0.007 percent.[17]

Because 20% of customers historically responded to the 3-day notice and paid their outstanding balance, NWN wants to assume that without that 3-day notice, these customers will not pay their bill and it will become an uncollectable expense --they

[15] *See* OAR 860-0210405.
[16] *See* NW Natural/1300/Wilson-Sparley/Page 9.
[17] NW Natural/1300/Wilson-Sparley/Page 15–16.

will not respond to the day ahead notice and they will not pay their bill to get reconnected. These are customers who by virtue of responding to the 3-day notice are demonstrating that they can pay their arrearage to maintain service.

Another factor the Company considers in its method for calculating the Company's revenue requirement for uncollectible expenses is "Weaker Economic Conditions," which NW Natural appraised at $1.1 million.[18] This factor seems to forecast that soon more customers will not be able to afford their bills, and in anticipation of this, the Company proposes a forward-looking increase to customers' bills.

Q. Would simply setting the revenue requirement for the uncollectible expense to a value based on the standard method result in just and reasonable rates?

A. Using the standard method would certainly be better than what the Company is proposing. However, because the standard method includes the period of time when Oregon was recovering from the pandemic, we are not sure that it is representative of the future. CUB plans to review Staff's uncollectable proposal and will make a recommendation in Rebuttal/Cross Answering testimony.

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[18] *See* NW Natural/1300/Wilson-Sparley/ Page 10-12.

III. The "New Premise" Customer Class

Q. What are "new premise" residential customers and why does the Company propose separating them into their own rate class?

A. The Company proposes bifurcating the residential class according to a new attribute: existing versus "new premise" customers. "New premise" customers are new customers connected to the gas system for the first time as of November 1, 2024.[19] The Company draws this distinction because it projects "new premise" customers will have lower average usage than existing customers: on average new premise customers are expected to use 449 therms/year, whereas existing customers average 660 therms/year.[20] Due to the Company's decoupling mechanism, this discrepancy results in an "intra-class equity concern" that the Company proposes to address by charging "new premise" customers a $26.25 customer charge and existing customers a $10 customer charge.[21]

Q. Does the Company's proposal create new, unaddressed equity concerns?

A. Yes. Due to the "new premise" customer's higher customer charge, a typical "new premise" customer will pay about 51% more than an existing customer for using the same amount of gas.[22] Over the course of a year, the total surcharge for a typical new premise customer will be equivalent to adding three winter-month bills to their rates, relative to existing customers.[23]

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[19] *See* NW Natural/100/Palfreyman-Kravitz/ Page 28-29.
[20] *Id.*
[21] *Id.*
[22] *See* CUB/Garrett/203/New Premise Customer Rates.
[23] *See* CUB/Garrett/203/New Premise Customer Rates.

Table 1:
Existing Customer and New Premise Customer Charges Compared[24]

	Existing Customer	New Premise Customer	Difference
Proposed UG 490 Total Base Rate ($/therm)	0.90649	0.90649	
Annual UPC (set equal for analysis)	449	449	
Annual Variable Charges	$407.01	$407.01	$0
Customer Charge	$10	$26.25	$16.25
Mo/Yr	12	12	
Annual Fixed Charge	$120	$315	$195
Annual Rate ($)	$527.01	$722.01	$195.00
Annual Rate/ Therm ($/therm)	1.173750579	1.773929133	51.1%

The expected typical usage of a "new premise" customer is not distinct from a large portion of existing customers. Table 2 shows that over the last three years, nearly a third of the Company's existing residential customers used 449 therms or less, meaning the typical "new premise" customer's usage profile is not lower than nearly a third of existing customers.

Table 2: Oregon Residential Customers Using 449 Therms or Less[25]

Oregon Residential (02R) Accounts with Full Year Billing				
	Total Accounts	**Accounts with 449 Therms/ Yr or Fewer**	**%age That Used 449 Therms or Less**	**Average Annual Usage (Therms)**
2021	603,141	193,417	32.07%	614.5
2022	611,191	157,881	25.83%	677.5
2023	617,097	179,075	29.02%	640.1
Average	610476	176791	28.97%	644.0

CUB is concerned that charging "new premise" customers 51% more than ~180,000 existing customers with the same usage is discriminatory. Furthermore, examining the profile of NW Natural's anticipated "new premise" customers raises

[24] *See* CUB/Garrett/203/New Premise Customer Rates.
[25] *Id.*

additional equity and discrimination concerns. Table 3 shows that 11% of the Company's existing customer base is made up of multifamily customers. Comparatively, 33% of "new premise" customers will be multifamily customers. This is concerning, since multifamily customers tend to be renters and/or lower-income. Targeting them with a higher rate runs counter to the attempts by this Commission to address energy burden.

Table 3: New Premise Customers Breakdown[26]

"New Premise" Customers			Existing Customers		
	Customers	Percentage		Customers	Percentage
New MF	1525	33%	Existing MF	73,221	11%
New SF	3081	67%	Existing SF	566945	88%
Total "New Premise"	4606		All Res Cust Count	643,247	

While the Company proposes a customer charge that is $2 lower for multifamily customers across existing and "new premise" customers,[27] which CUB supports, this does little to offset the $18.25 increase to the customer charge for "new premise" multifamily customers from UG 435 to UG 490.

IV. The Line Extension Allowance (LEA) for Residential Customers

Q. Please provide an overview of your LEA testimony.

A. First, I assess the Company's novel LEA design, which maximally incents "lower-use" customers to connect to NW Natural's system.[28] This design starkly contrasts the standard of providing higher allowances for customers that use more of a utility's product and subsequently generate higher revenues. The Company's LEA design

[26] *See* CUB/Garrett/203/New Premise Customer Rates.
[27] *See* NW Natural/1717/Walker/ Page 4.
[28] *See* NW Natural/1900/Therrien/ Page 25-26.

implies that the product the Company delivers is becoming less cost-competitive, and that the ideal NW Natural customer hooks up to the system but uses little to no therms of gas.

Next, I unpack the interplay between the Company's LEA design and its proposed "new premise" residential customer class. The Company proposes charging "new premise" customers a $26.25 customer charge (as opposed to a $10 customer charge for existing customers), which results in a ~51% higher rate-per-therm for new customers with the same usage as existing customers.[29] Over the 25-year LEA repayment period in the Company's modeling, the customer charge alone will cost the "new premise" new customer $7,875, meaning the new customer could save $7,875 by discontinuing gas service.

Next, I examine the reasonableness of the assumptions in NW Natural's LEA economic justification modeling. My findings suggest that, due to the Company's modeling assumptions, it either over-projects new customer benefits, or residential rates will be unaffordable within 25 years. I also discuss several factors the Company omitted in its LEA modeling: customer choice, customer attrition, and the cost of stranded assets. In its LEA modeling, the Company failed to assess whether its "new premise" customers would notice their unprecedented customer charge, seek out cheaper alternatives to NW Natural's service, and ultimately terminate gas service within the 25 years required to pay off the LEA. I examine the likelihood that new

[29] *See* CUB/Garrett/203/New Premise Customer Rates.

customers could terminate NW Natural service on economic grounds, which would result in stranded asset costs for existing customers that are not included in NW Natural's modeling.

Finally, I model the stranded asset costs for LEAs, and net costs to existing customers of various "new premise" customer attrition scenarios. At a 1% "new premise" customer attrition rate, the net cost of stranded assets for existing customers would be about $43 million.[30] If half of "new premise" customers that received an LEA in 2025 terminated NW Natural service in 15 years, which is about the time their gas furnace would be replaced, the net cost of stranded assets for existing customers would be $36 - $44 million.[31]

My findings illustrate the extraordinary economic harm to existing customers if LEAs become stranded assets, and the necessity to consider the impacts of customer attrition for an LEA design that depends on drastically increasing rates for new customers. My analysis indicates that incenting growth of the gas system at this time poses unacceptable risks to existing customers, and that NW Natural's LEA should, alongside Avista's LEA,[32] be phased down to $0.00.

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[30] *See* CUB/Garrett/204/LEA Modeling.
[31] *See* CUB/Garrett/204/LEA Modeling.
[32] *See* UG 461 – Order No. 23-384.

Q. What is NW Natural's proposed residential LEA policy and what distinguishes it from typical LEA polices?

A. The Company's LEA policy is Schedule X.[33] The Company describes it as follows:

> Based on the results of the LEA model, we are proposing four levels of LEA determined by the expected usage at the residence. For low use customers (between 0-250 therms annually), the LEA will be set at $3,600. For typical new customers (between 251-450 therms), the LEA will be set at $3,100. For higher use customers (between 451-650 therms), the LEA will be set at $2,600. For the highest use customers (651 therms and higher), the LEA will be set at $1,800 (based on 1,000 therms).[34]

The Company states, "[t]he proposed LEA model is responsive to a lower-use future by sending price signals to consumers associated with their expected usage."[35] The expected usage of an LEA recipient, and their LEA cap, is determined by which gas appliances are installed at the residence.[36] Different appliances have different usage expectations determined by NW Natural, so the sum of the expected usages for each appliance of a home determines how much LEA money a customer can receive.[37] CUB Exhibit 204 – LEA Modeling shows the expected therms per appliance in new and converted (from electric) homes of various gas appliances.

It is very important to understand exactly what the policy incents, because although it bears a resemblance to incentivizing efficiency or lower *usage* appliances, its focus and expected ramifications are quite different. Rather than maximally incenting higher-efficiency appliances, which provide the same or better service for less fuel use, the LEA design maximally incents connecting homes that have fewer

[33] NW Natural/1717/Walker/Page 2.
[34] NW Natural/100/Palfreyman-Kravitz/Page 32:3–9.
[35] *Id.*
[36] *See* NW Natural/1900/Therrien/Page 25-26.
[37] *See* CUB/Garrett/205 - LEA Tiers.

gas appliances. This very well may incent customers who do not use much gas and/or don't particularly rely upon gas to connect to NW Natural's system.

Examining the Company's expected usage by appliance chart alongside the LEA tiers reveals the extent of the issue. The only clearly more efficient appliance that could be incented is a "Backup to Heat Pump" instead of a gas furnace. This alone could have been incented, thereby avoiding the maximal incentivization of customers that are not more efficient and just have two or so luxury appliances, like a spa, a pool, a barbeque, a decorative fireplace, or decorative logs; many of which, alongside other low use appliances such as ranges and dryers, do not seem likely to reliably tie a customer to NW Natural's expensive service for long enough to recuperate the cost of the LEA (25 years according to NW Natural's modeling)[38] or avoid generating stranded LEAs over the next 60 years.

Aside from potentially incenting a hybrid heating system instead of a gas furnace, which is a very specific case, the policy seems senseless. Why does it make sense to spend more money, on a longer pipe say, that will be used less? A Company with a product that it wants to deliver (or is even indifferent about the volume it sells/delivers, as a decoupled utility like NW Natural is meant to be) would not do this.

All told, the focus of the LEA design is on lower use appliances and not high efficiency appliances. This implies that the product the Company delivers is

[38] *See* Natural/1902/Therrien/DCF Summary Example

becoming less cost competitive – the company wants new customers, but only if they don't have much use for the primary product it sells. This draws into question the sensibility of incenting growth of the residential gas sector at all, a concern CUB consistently posed in response to all three Oregon gas company IRPs since Oregon implemented decarbonization policies.

Q. The Company assumed a Washington-style Climate Commitment Act (CCA)-based carbon-offset cost, instead of the Oregon Climate Protection Program's Community Climate Investment (CCI) cost, in its supplemental LEA economic justification filing[39]— was this a reasonable response to the invalidation of the CPP?

A. No. It is CUB's understanding that the CPP was invalidated on procedural grounds, not economic grounds or because the CPP's CCI offset was deemed inappropriately high. To use the CCA's offset allowance instead, which is a different offset set according to different parameters, for a different program with a different structure, in another state, while assuming other elements of Oregon's CPP replacement will be the same, makes less sense than simply assuming the new CPP structure will have a similar CCI allowance. It is CUB's understanding that the Company's opinion that the CCI is too high[40] is a matter for the Oregon DEQ to consider, not the OPUC to accept or deny in a rate case, and to CUB's knowledge the Oregon DEQ has not indicated that it intends to implement a CPP-like program with a lower CCI cost. Thus, CUB's examination of the Company's LEA economic justification focuses on

[39] *See* UG 490 – NW Natural/2000, Kravitz-Therrien/17 (proposing to use Washington's Climate Commitment Act (CCA) compliance allowances as a proxy for CCI).
[40] *See* NW Natural/2000/Kravitz-Therrien/ Page 16-17.

the CPP/CCI-derived modeling (NW Natural/1900), rather than the supplementary CPP/CCA-derived modeling (NW Natural/2000), although the largest concerns CUB outlines are valid regardless of which offset assumption is used.

Q. What are CUB's high-level concerns with the modeling assumptions for the Company's CPP-based LEA economic justification?

A. The Company's LEA modeling is very complex; nevertheless, CUB examined it closely and has several concerns. At a high-level, CUB notes that the model projects substantial new customer benefits that grow rapidly over time while the CPP cost remains static. The model contains three new customer benefits: their usage-based revenues, a CPP benefit and a new benefit introduced to LEA modeling by NW Natural, the "Contribution to New Non-Growth Capex" benefit. The second two benefits increase rapidly over the course of the 25-year analysis, and by year 25 they are worth $1,521 per new customer per year. This is more than twice the customer's usage-based revenue ($722/yr).

Initially, CUB was skeptical that the new benefits were modeled too high, but upon further inspection, developed a possibly greater concern. As modeled, the benefits do not appear to be pure economies of scale that would arise independent of rate increases; they appear to model anticipated rate increases for residential customers. The three benefits appear to be higher expected revenues from new customers, resultant of their 1. Higher "new premise" rates, 2. Higher rates associated with decarbonizing existing customers (CPP benefit), and 3. Higher rates associated with NW Natural anticipating extraordinary investments in things that do not increase throughput or revenue (“New Non-Growth Capex”).

CUB is concerned that if the benefits are modeled too high, or new customer rates are expected to skyrocket, the LEA is unjustified. If the benefits are over-projected in the model, the modeling is not robust and does not justify the proposed LEAs. If residential rates for the gas system are going to skyrocket according to this model, this should drive customers away from the gas system and onto the electric system, creating stranded LEAs and negative impacts to existing customers, resulting in significant costs that are not included in the model.

Aside from this concern, CUB is concerned that as modeled, the CPP cost does not rise over time, and underestimates future decarbonization policy compliance costs. The CPP cost is predominantly dependent on a future RNG price of $22/dth that does not increase for 23 years.[41]

Q. How does the Company’s proposed “New Premise” residential customer class relate to its proposed LEA?

A. The LEA economic modeling is highly dependent on collecting a much higher customer charge from “new premise” customers, which effectively raises their rates by 51% relative to existing customers.[42] Without this substantial rate increase for new customers, the Company’s LEA economic modeling implodes. Thus, CUB argues

[41] *See* NW Natural/1905/Therrien – Supporting DCF assumptions.
[42] *See* CUB/Garrett/203/New Premise Customer Rates.

that the LEA's implications for existing and new customers must consider the consequences of charging new customers "new premise" residential rates.

Ultimately, the Company's LEA economic justification rests upon the following assumption: even though "new premise" customers will use distinctly less gas, and quite possibly be less reliant upon NW Natural's service, 100% of them will be willing to pay ~50% more per therm than existing customers[43] and none will terminate service before the 60-year useful life of the LEA is up.

CUB argues this assumption is unreasonable, and that a meaningful quantity of customers will notice the customer charge, calculate that it alone will cost them $315/yr ($26.25/ month x 12 months/yr), or $7,875 in 25 years, and terminate NW Natural service within 25 years. This would have serious implications for the Company's modeling as is, which examines a 25-year time horizon, and even larger implications if the full useful life (60 years) and costs of stranded assets for existing customers is considered.

Q. Please provide a high-level economic comparison of relevant gas versus electric options available to potential NW Natural customers seeking residential energy service.

A. CUB/Garrett Exhibit 208 – Table 4: Residential Gas v. Electric Heating Systems compares gas and electric options for heating based on simple information available to the average consumer. General heating system costs and attributes were acquired

[43] *See* CUB/Garrett/203/New Premise Customer Rates.

from two Forbes "Home" articles[44][45] and an energy.gov webpage.[46] Information on dual fuel (gasoline or propane) backup generators were found on Home Depot's website.[47]

It is important to note that over a 15–20 year period, or about the anticipated lifespan of the gas and electric heating appliances,[48] the $26.25 NW Natural "new premise" customer charge costs a total of $4,725 to $6,300, which is a serious drawback to connecting to the gas system regardless of receiving an LEA and not paying to be hooked up. Overall, it shows that paying so much for a whole extra utility service, even without any usage, makes the gas options substantially less cost competitive, and that gas space heating is no longer the cost-effective choice for customers. This is consistent with the Company's declining number of new service connections since 2017, which have especially declined in recent years.[49]

Gas and electric stoves are available at a wide range of prices which largely overlap,[50] suggesting cost-conscious consumers could choose either path regarding

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[44] *See* Lawrence Bonk, "How Much Does Heat Pump Installation Cost?", Forbes Home (Feb. 29, 2024), https://www.forbes.com/home-improvement/hvac/heat-pump-installation-cost/.

[45] *See* Cellucci, N. and Pelchen, L. How Much Does A Gas Furnace Cost In 2024? Forbes Home (Feb. 22, 2024) https://www.forbes.com/home-improvement/hvac/how-much-does-a-gas-furnace-cost/

[46] *See* Heat Pump Systems, Dep't of Energy, https://www.energy.gov/energysaver/heat-pump-systems (last visited April 17, 2024).

[47] *See* Portable Generators, The Home Depot, https://www.homedepot.com/b/Outdoors-Outdoor-Power-Equipment-Generators-Portable-Generators/Dual-Fuel/N-5yc1vZbx9nZ1z1cr39 (last visited April 17, 2024).

[48] *See* Lawrence Bonk, "How Much Does Heat Pump Installation Cost?", Forbes Home (Feb. 29, 2024), https://www.forbes.com/home-improvement/hvac/heat-pump-installation-cost/.

[49] *See* CUB/Garrett/203/New Premise Customer Rates.

[50] *See* Portable Generators, The Home Depot, https://www.homedepot.com/b/Outdoors-Outdoor-Power-Equipment-Generators-Portable-Generators/Dual-Fuel/N-5yc1vZbx9nZ1z1cr39 (last visited April 17, 2024).

the initial purchase. While a preference for gas-specific appliances, such as gas stoves and fireplaces could influence customers, this preference must be weighed against the added costs of having gas service in addition to electric service. It is important to note that if NW Natural did not have an LEA, customers could still choose to pay the premium for NW Natural service if the alternatives did not suit them. In this case, the customer would bear responsibility for this choice rather than dispersing a much larger responsibility across existing customers over a period of 60 years. Paying for the LEA outright would cost the new customer about $3,100; paying for it through NW Natural's LEA disperses ~$16,000 over all existing customers over 60 years.[51]

The Company markets its product as a good backup system in the event of a power outage.[52] The necessity for residential backup systems when the power occasionally goes out is a modern, and for many people, luxurious concept, particularly in the relatively mild climate of NW Natural's service territory. Nevertheless, CUB Exhibit 208 shows that backup generators, which do not require NW Natural's service, provide a cheaper and generally superior option in the event of an outage. Portable dual fuel gasoline/ propane generators come in many sizes and capacities to meet customer preferences. They are available at Home Depot with delivery for <$1,000 to $3,500+.[53] Backup generators can power electric appliances flexibly and would serve the people most vulnerable to catastrophic consequences of

[51] *See* CUB/Garrett/204 - LEA Modeling.
[52] *See* NW Natural/1900/Therrien/Page 26.
[53] *See* Portable Generators, The Home Depot, https://www.homedepot.com/b/Outdoors-Outdoor-Power-Equipment-Generators-Portable-Generators/Dual-Fuel/N-5yc1vZbx9nZ1z1cr39 (last visited April 17, 2024).

an electric outage, such as people who rely on electrically-powered medical devices, better.

Again, whether or not the Company has an LEA does not prevent Oregonians from choosing NW Natural options, such as whole-home backup generators supplied by natural gas, if they have deep pockets and a strong preference. CUB is not here to stand in their way, but is instead looking out for NW Natural's existing customers, who do not deserve the risk of LEAs becoming stranded assets.[54]

Q. Although this comparison is important for utility planners and rate-makers to consider, does it reflect the choice "new premise" customers will likely have and the risk of NW Natural's LEA policy resulting in stranded LEAs?

A. No. Often the decision to install gas appliances and request a NW Natural LEA is made by a home developer that will not be responsible for paying NW Natural's "New Premise" residential rates. Particularly with the "New Premise" customer class appearing suddenly and unexpectedly, "new premise" customers are likely to already have gas appliances installed in their new home before realizing the expense of NW Natural's "New Premise" residential service. Thus, it is important to consider if a "new premise" customer would terminate NW Natural's service on economic grounds, even after moving into a home with gas appliances and a NW Natural hookup already installed.

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[54] *See* CUB/Garrett/204 - LEA Modeling.

Q. Could "new premise" customers, who buy homes with gas appliances and a gas hookup already installed by a home developer and NW Natural, still terminate NW Natural service on economic grounds, resulting in stranded gas system assets?

A. It depends, but in many cases yes. Unfortunately, renters would struggle to free themselves of NW Natural's "New Premise" residential rates, even if they felt confused, aggravated, and burdened by them, because they cannot realistically replace an essential appliance in a rental unit. Thus, they would probably need to pay whatever rates their "New Premise" customer class designation requires to have essential services like heating and cooking.

New multi-family and single-family homeowners, however, depending on the gas appliances that are already installed in their new home, could still save large sums of money by terminating NW Natural's service after seeing the Company's "New Premise" residential rates.

For example, a $3,600 Tier 1 (0 – 250 therms) LEA recipient, who must have at least two gas appliances and very low annual usage, could simply do without their gas fireplace, decorative logs, or gas barbeque, and replace a gas stove with a state-of-the-art, stainless steel electric induction stove using 3-5 years of savings from not paying NW Natural's customer charge. This could save the new customer thousands of dollars.

For customers desiring a backup system for some cooking or heating when the electricity occasionally goes out, many backup generators costing between 3 to 8 years of NW Natural's customer charge ($945 - $2520) and could do the trick, and also power some AC in the summer, refrigerators, lights, essential medical devices, and other electric appliances.

For "typical new customers (between 251-450 therms)" that receive a Tier 2 LEA of up to $3,100, and perhaps have a gas furnace, they too could justify replacing a gas furnace using savings achieved by cutting NW Natural's "new premise" customer charge from their bills and achieving much higher efficiencies with a heat pump. CUB anticipates that after 15 years, about when the furnace would age out, is an especially likely time for a person to do this. They would also get air conditioning out of the exchange for Oregon's increasingly hot summers.

Simply put, there is a lot of economic wiggle room for homeowners to save money if they realize that NW Natural's "New Premise" customer charge is very costly, and begin exploring alternative means to get comparable or better services.

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Furthermore, growing concerns over the negative health impacts of indoor gas appliances[55][56] may drive customers to replace gas appliances with electric alternatives before the end of the appliances' useful lives anyway, a benefit of terminating NW Natural service that would stack upon potentially positive economic trade-offs.

And of course, climate concerns could lead a significant segment of customers to move away from the gas system to cleaner electricity.

It should be noted, that although "new premise" customers could save money by terminating NW Natural service even after buying a home with gas appliances, this outcome is indeed costly and far from ideal for Oregonians. If the "new premise" homeowners simply chose electric appliances *before* paying for the gas appliances and their installation, they would not have stranded gas appliance assets themselves, totaling thousands of dollars, and existing NW Natural customers would not be on the hook for paying up to $16,000[57] for a stranded residential gas hookups.

Q. Why is it necessary to consider customer attrition for NW Natural's LEA policy when in the past, utility LEA policies typically did not consider this?

A. For water or electric utilities operating in monopoly territories, customer attrition and stranded LEAs are not realistic possibilities. Plumbing and electricity are modern necessities and virtually every home requires them. Conversely, being connected to

[55] *See* Public Health Law Center, March 2024, "Cooking With Smoke: How The Gas Industry Used Tobacco Tactics To Cover Up Harms From Gas Stoves",http://publichealthlawcenter.org/cookingwithsmoke.

[56] *See* Heat Pump Systems, Dep't of Energy, https://www.energy.gov/energysaver/heat-pump-systems (last visited April 17, 2024).

[57] *See* CUB/Garrett/204 – LEA Modeling.

the gas system is optional; the essential services of the gas system can generally be replaced by electric alternatives and other solutions, although not easily depending on the gas appliances the customer has already invested in. While some customers, particularly renters, are especially constrained to stay with NW Natural's gas service, homeowners could, and from a modeling perspective should, terminate gas service if it is not economically sensible, resulting in stranded assets that will impact existing customers.

Given the long useful lives of LEAs, 60 years, and enduring expenses of stranded LEAs, which unlike larger assets are not reviewed for their enduring used and usefulness, it is important to consider the full costs LEAs becoming stranded.

Q. What is the cost to existing customers if a new customer's LEA becomes a stranded asset?

A. The cost to existing customers associated with an LEA becoming stranded depends on the initial cost of the LEA and how soon the gas hookup becomes stranded. See CUB/Garrett Exhibit 204 – LEA Modeling, which shows the stranded asset cost for a $3,100 (NW Natural Tier 2) LEA, which all remaining NW Natural customers are liable to pay over the course of the LEAs useful life, if an LEA becomes stranded at various times after it was installed.[58]

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[58] *See* CUB/Garrett/204 – LEA Modeling.

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Q. What will be the net cost of stranded assets for existing customers under various new customer attrition scenarios?

A. At a steady rate of 1% customer attrition, assuming new customers received Tier 2 $3,100 LEAs, after 10 years the nominal net cost of stranded LEAs would be $43 million.[59]

If after 15 years (about the time customers will change out their gas furnace), half of the ratepayers that received an LEA in 2025 terminate NW Natural service, the net cost of stranded LEAs for existing customers will be $24 to $29 million.[60] Table 5 provides more information regarding possible year15 customer attrition scenarios.

Table 5: Stranded Asset Costs Associated with Customer Attrition After 15 Years

LEA	Total Cost	Total Remaining Cost After 15 Years Per LEA	Net Value of Stranded LEAs (25% Attrition)	Net Value of Stranded LEAs (50% Attrition)	Net Value of Stranded LEAs (75% Attrition)
$3,100 (Tier 2)	$16,168.46	$10,461.65	$14,532,108.03	$29,064,216.06	$43,596,324.08
$2,242 (Past 3-yr Avg Res LEA)	$13,006.70	$8,563.00	$11,894,720.58	$23,789,441.17	$35,684,161.75

[59] *See* CUB/Garrett/204 - LEA Modeling.
[60] *See* CUB/Garrett/204 - LEA Modeling.

The total and enduring costs of the LEAs through time are truly impressive. The useful life of a service line is at least 60 years. This means that a "new premise" customer will go through 3 or 4 life cycles of their heating equipment before the line to their home is paid off. And if they leave the system before the 2080s, someone else has to pick up their stranded cost.

Q. If the Company's LEA policy entails such risks, why might it be motivated to have it anyway?

A. The Company has a financial incentive for growth and LEAs, because the LEAs are rate based and the Company's profit is a product of its total rate base and its rate of return. Furthermore, growth in its residential customer base and overall load can lead to new main distribution line investments, and other gas infrastructure, which further increases the Company's overall rate base and profit (along with risk for stranded asset costs for ratepayers). It is important to note that CUB's stranded asset modeling is limited to service lines, and that more infrastructure could become stranded.

As it stands, the risk of the LEAs becoming stranded falls on existing customers, who are liable to pay for the total costs of the LEA regardless of whether new customers continue to use NW Natural service and contribute revenues. Thus, the Company has an opportunity for profit without bearing the risks of the investments.

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V. Broader Economic Conditions and the Company's Rate Request.

Q. Provide a high-level overview of NW Natural's rate request.

A. On December 29, 2023, NW Natural requested a $154.9 million increase to its revenue requirement, a 16.6% overall increase to ratepayers an 18.1% rate increase residential ratepayers.[61]

The rate request comes two years after the Company's previous rate request, UG 435, which resulted in an OPUC approved increase to the revenue requirement of $62.7 million and an increase to residential rates of 8.46%.[62]

Noteworthy among the drivers of the current rate request is a net increase in the Company's rate base (ie Company assets) of ~$380 million.[63] This indicates that the Company invested heavily in new projects over the last several years.

Q. Provide an overview of the broader economic conditions leading up to the Company's rate request.

A. In 2020, global supply chains and economies were dramatically affected by the COVID-19 pandemic. In Oregon, unemployment spiked to levels not witnessed in many decades.[64] Since 2021, inflation in the Western US has consistently been very high, reaching nearly 8 - 9% for months on end in 2022.[65] Inflation "measures how

[61] *See* NW Natural/Executive Summary/ Page 1.
[62] *See* UG 435 Commission Order 22-388.
[63] *See* CUB/Garrett/206 – Change to Rate Base.
[64] *See* The Federal Reserve Economic Data, Unemployment Rate in Oregon, Apr. 2, 2024, https://fred.stlouisfed.org/series/ORUR.
[65] *See* Consumer Price Index – Urban, Western Region, March 2024. https://www.bls.gov/regions/west/news-release/consumerpriceindex_west.htm.

much more expensive a set of goods and services has become over a certain period, usually a year."[66] Thus, broader measures of inflation are an indication of how costs have risen for other companies and across markets.

In its initial filing, CUB notes that the Company references inflation dozens of times, largely in reference to cost-drivers. The Company states:

"Economic and capital market conditions have been unsettled due to increasing inflationary pressure and the prospects for weaker economic growth or recession as the Federal Reserve tightens monetary policy. After experiencing steady economic growth from 2017-2019, the consequences of COVID-19 forced the U.S. economy into a sharp recession in 2020. Gross Domestic Product ("GDP") has tracked unevenly since then."[67]

Economic metrics like inflation do not just affect the cost of doing business though. In the uncollectible expense section of its testimony, NW Natural discusses how weak economic conditions negatively impact ratepayers' ability to afford their service,[68] which CUB notes is an essential service that ratepayers rely upon for heating and cooking. The section also includes a graph showing how unpaid bills have been much higher over the past four years.[69] Based on source data for the

[66] *See* International Monetary Fund. Back to the Basics Compilation. Inflation: Prices on the Rise. (April 2024).
[67] *See* NW Natural/400Coyne-Nelson/ Page 9:13-18.
[68] *See* NW Natural/1300/Wilson-Sparley.
[69] *See* NW Natural/1300/Wilson-Sparley/ Page 6.

graph, CUB estimates that over the past two years, unpaid bills have stabilized since the COVID spike in 2021 at around 790% above 2019 (pre-pandemic) values.

CUB is concerned that behind the numbers are the unpaid bills of customers that are now houseless, an issue which Governor Tina Kotek declared a State of Emergency upon entering office in 2023.[70] In her inaugural address, she described it as a "manmade" and "humanitarian disaster."[71]

Q. Why are broader economic conditions relevant to NW Natural's rate request?

A. NW Natural's rate request indicates its margin revenue (ie cost to provide service without considering changes in fuel costs) rose ~30%,[72] or an average of 15% per year. This is notably higher than the inflation rate in the same period, and while there are legitimate reasons that a utility's rates could exceed the rate of inflation, CUB is concerned that they cannot fully account for this difference.

Q. What are the common responses of well-managed business to high inflation?

A. In September 2021, the Harvard Business Review published a topical article titled "6 Strategies to Help Your Company Weather Inflation." The authors state, "Cutting expenses is a vital part of how companies should deal with inflation. A study of 5,700 global companies showed those that cut costs to improve

[70] *See* Orgon Public Broadcasting. "Oregon Gov. Tina Kotek takes first actions on 'humanitarian disaster' of homelessness." Jan 2023. https://www.opb.org/article/2023/01/10/oregon-housing-crisis-homeless-population-governor-tina-kotek-executive-orders/.

[71] *Id.*

[72] *See* UG 490 NW Natural/1803 Rev Req Rate Effect (Total margin revenue increase is 29.3%, res class is 30.5%).

productivity during inflationary periods showed higher shareholder returns."[73] This suggests that keeping production costs down when inflation is high is an important aspect of running a profitable business in competitive markets, where cost-conscious consumers provide downward pressure on prices through their purchasing habits (ie choosing the lowest priced options).

The authors also state that cost-cutting should "clearly distinguish between strategic and nonstrategic cost-cutting" and "[protect] signature customer and employee experiences."[74] Further, "Managers must identify where investments should be pulled back and cost savings realized; where you can more selectively trim costs to improve the return on operating expenses…"[75]

Around the same time, in a CEO's guide for dealing with high prices, published by McKinsey & Company in 2022, the authors suggest companies should "double down on efforts to keep in-house costs under control."[76]

Simply put, business managers for companies in competitive markets, where competition for consumer patronage replaces the oversight of regulators, discuss cutting costs, prioritizing investments, and even "accepting smaller margins"[77] as normal company responses during high-inflation periods, like the one beginning in early 2021. Thus, passing through higher costs is not the only response to things

[73] *See* Heinrich et al., "6 Strategies to Help Your Company Weather Inflation." Harvard Business Review. https://hbr.org/2021/09/6-strategies-to-help-your-company-weather-inflation.
[74] *Id.*
[75] *Id.*
[76] *See* McKinsey and Company, "How business operations can respond to price increases: A CEO guide, March 2022, https://www.mckinsey.com/capabilities/operations/our-insights/how-business-operations-can-respond-to-price-increases-a-ceo-guide.
[77] *See* Koenigsberg, Oded, "3 Strategic Options to Deal with Inflation." Harvard Business Review. Jan 2022. https://hbr.org/2022/01/3-strategic-options-to-deal-with-inflation.

like inflation, and company managers should know to reduce costs where reprioritizing allows, and perhaps anticipate reduced profit margins.

Q. At a high level, what might explain the dissonance between the Company's rates and the inflation rate?

A. One possibility that CUB is exploring, is whether the Company appropriately responded to economic conditions and reprioritized investments to prevent unreasonable increases in rates for its captive customers.

CUB argues that to arrive at just and reasonable rates, it is very important to consider if during a period of prolonged economic downturn, the Company is appropriately reprioritizing investments in accordance with their importance and immediate need. Several areas CUB is examining for overspend are office construction, earthquake contingency planning, and IT&S revamping. Projects within these categories resulted in additions to rate base of at least $84 million, and potentially significantly more.[78]

All told, CUB is concerned that the Company is investing in new projects too fast,[79] despite four years of unfavorable economic conditions,[80][81] and intends to keep investing aggressively,[82] while anticipating a weak economy[83] and

[78] *See* CUB/Garrett/206 – Change to Rate Base.
[79] *See* CUB/Garrett/206 – Change to Rate Base.
[80] *See* Consumer Price Index – West Region. March 2024. https://www.bls.gov/regions/west/news-release/consumerpriceindex_west.htmand and The Federal Reserve Economic Data, Unemployment Rate in Oregon, Apr. 2, 2024, https://fred.stlouisfed.org/series/ORUR.
[81] *See* NW Natural/400Coyne-Nelson/Page 9:13-18.
[82] See NW Natural/400/Coyne-Nelson/Page 38 ("As discussed in Section VII of our Direct Testimony, NW Natural expects to invest approximately $1.4 billion in infrastructure in the 2023-2027 period, or approximately 62 percent of the Company's net utility plant.").
[83] *See* NW Natural/1300/Wilson-Sparley (See "Weak Economic Conditions").

experiencing less customer growth,[84][85] all of which drive up rates,[86] when their captive ratepayers are already struggling to afford their current rate.[87]

Q. Does that conclude your testimony?

A. Yes.

[84] *See* CUB/Garrett/207 - New Service Lines Installed (Note the decline in new customer hookups, beginning in 2017 and continuing to the present at faster rates).
[85] *See* NW Natural/1700/Walker 12: 13-14.
[86] *See* NW Natural/Executive Summary: 2.
[87] *See* NW Natural/1300/Wilson-Sparley 6: 1.

WITNESS QUALIFICATION STATEMENT

NAME: John Garrett

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ADDRESS:

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EDUCATION:

Master of Public Policy
Oregon State University,
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Colgate University,
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EXPERIENCE: Provided testimony on behalf of the Oregon Citizens' Utility Board for dockets UG 461 and UM 1908. Provided comments on behalf of the Oregon Citizens' Utility Board for LC 81, LC 83, UM 2033 and UM 2056. Worked as a Graduate Researcher for Oregon State University examining the socio-economic impacts of renewable energy development in Oregon. Worked as a Research Assistant for the Archbold Biological Station Agro-ecology Research Ranch examining the socio-economic impacts of conservation polices on Floridian agriculturalists.

MEMBERSHIP: National Association of State Utility Consumer Advocates

Uncollectible Expense Revenue Requirement		
Standard Method of Calculation:		
3-yr Past Avg (2021 -2023)	0.242%	Source: UG 490 CUB DR 14
NWN Total Rev	$1,100,000,000.00	Source: NW Natural/ 1300/Wilson-Sparley/Page 16
Revenue Requiremnt	$2,665,997.94	
NWN Method (single factor analysis):		
Factor:	"Weaker Economic Conditions"	
Factor Weight	0.100%	Source: NW Natural/ 1300/Wilson-Sparley
NWN Total Rev	$1,100,000,000.00	Source: NW Natural/ 1300/Wilson-Sparley/Page 16
Revenue Requiremnt For Factor	$1,100,000.00	
Total Revenue Requirement of NWN Method	$4,900,000.00	Source: UG 490 CUB DR 13

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 CUB DR 9

For residential customers in each month of the Test Year, what are the projected use-per- therm rates (inclusive of the customer charge) for:

a. all residential customers?

b. existing residential customers?

c. new premise residential customers?

Response:

(a., b., c.) See supporting workbook UG 490 CUB DR 9 Attachment 1.

Projected use per therm rates were calculated by dividing each month's projected usage per customer (UPC) into the monthly fixed charge, and then adding the UG 490 projected base rate.

Note: The response to "a. all residential customers" uses a weighted average of the UPC and customer fixed charge of all Residential categories: existing single family, existing multi-family, new premise single family, and new premise multi-family.

Oregon Residential (02R) Accounts with Full Year Billing				
	Total Accounts	Accounts with 449 Therms/ Yr or Fewer	%age That Used 449 Therms or Less	Average Annual Usage (Therms)
2021	603,141	193,417	32.07%	614.5
2022	611,191	157,881	25.83%	677.5
2023	617,097	179,075	29.02%	640.1
Average	610476	176791	28.97%	644.0

Source: UG 490 CUB DR 10

Soucre: UG 490 CUB DR 9

New Premise Customers			Existing Customers		
	Customers	Percentage		Customers	Percentage
New MF	1525	33%	Existing MF	73,221	11%
New SF	3081	67%	Existing SF	566945	88%
Total New Premise	4606		All Res Cust Count	643,247	

Data Source: UG 490 CUB DR 9 Attachment 1

	Existing Cust	New Premise Cust	Difference		
Proposed UG 490 Total Base Rate ($/therm)	0.90649	0.90649			
Annual UPC (set equal for analysis)	449	449			
Annual Variable Charge	$407.01	$407.01	$0		
Customer Charge	$10	$26.25	$16.25		
Mo/Yr	12	12			
Annual Fixed Charge	$120	$315	$195		
				Avg Winter Bill	Multiple of Difference
Annual Rate ($)	$527.01	$722.01	$195.00	$67.42	2.9
Annual Rate/ Therm ($/therm)	1.173750579	1.773929133	51.1%		

Data Source: UG 490 CUB DR 9 Attachment 1														
Inputs: Existing customer rates with 449 th annual usage profile														
Proposed UG 490 Total Base Rate ($/therm	0.90649													
Customer Charge (existing cust)	$10.00													
	24-Nov	24-Dec	25-Jan	25-Feb	25-Mar	25-Apr	25-May	25-Jun	25-Jul	25-Aug	25-Sep	25-Oct		
UPC	51.16	73.09	75	63.93	53.54	39.89	22.82	13.93	9.46	8.16	11.05	27.36	**Annual Thems**	449.39
Monthly Rate	$56.38	$76.26	$77.99	$67.95	$58.53	$46.16	$30.69	$22.63	$18.58	$17.40	$20.02	$34.80	**Annual Rate:**	527.3675
Winter Months Avg	$67.42													

NW Natural

UG 490 CUB DR 9

Test Year Projected All Inclusive per therm Rates, Residential

A. All Residential Customers (Weighted by Customer Class)												
Customer Fixed Charge	$ 9.89											
Proposed UG 490 Total Base Rate	$ 0.90649											
All Residential Customer Count	643,247											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
Weighted Avg UPC	75.91	106.04	106.05	94.69	77.02	56.51	32.44	21.65	16.63	13.95	16.95	39.80
All Inclusive per therm Rate:	$ 1.03676	$ 0.99975	$ 0.99974	$ 1.01092	$ 1.03489	$1.08149	$1.21131	1.363268	1.50117	1.61511	1.48990	1.15493

B. Existing Single-Family Residential Customers												
Customer Fixed Charge	$ 10.00											
Proposed UG 490 Total Base Rate	$ 0.90649											
End of Test Year Customer Count	566,945											
% of all Residential Customers	88.14%											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
UPC	76.21	106.45	106.45	95.06	77.31	56.72	32.56	21.74	16.70	14.02	17.02	39.96
All Inclusive per therm Rate:	$ 1.03771	$ 1.00043	$ 1.00043	$ 1.01168	$ 1.03583	$1.08279	$1.21357	$1.36652	$1.50519	$1.61996	$1.49407	$1.15675

C. New Premise Single-Family Residential Customers												
Customer Fixed Charge	$ 26.25											
Proposed UG 490 Total Base Rate	$ 0.90649											
End of Test Year Customer Count	3,081											
% of all Residential Customers	0.48%											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
UPC	51.16	73.09	75.00	63.93	53.54	39.89	22.82	13.93	9.46	8.16	11.05	27.36
All Inclusive per therm Rate:	$ 1.41964	$ 1.26563	$ 1.25647	$ 1.31712	$ 1.39682	$1.56460	$2.05661	$2.79084	$3.68135	$4.12299	$3.28285	$1.86582

Multi-Family Residential Customers												
New Premise MF												
Customer Fixed Charge	$ 24.25											
End of Test Year Count	1,525											
% of all Residential Customers	0.24%											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
	51.16	73.09	75.00	63.93	53.54	39.89	22.82	13.93	9.46	8.16	11.05	27.36
Existing MF												
Customer Fixed Charge	$ 8.00											
End of Test Year Count	71,695											
% of all Residential Customers	11.15%											
	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25
	76.21	106.45	106.45	95.06	77.31	56.72	32.56	21.74	16.70	14.02	17.02	39.96
Total MF Customer Count	73,221											

Northwest Natural Gas Co
Determination of Cost of Service

Input Capital Costs and Rates

Cost of Capital	% of Captial	Cost	Weighted Cost	
Debt	50%	4.27%	2.136%	Source: UG 490 - OPUC DR 378 Attachment 1/ Input Output - Exh 1905
Common Equity	50%	10.10%	5.050%	Source: UG 490 - OPUC DR 378 Attachment A/ Input Output - Exh 1905
	100%		7.186%	
State Tax Rate			7.60%	
Federal Tax Rate			21%	
Revenue Sensitive Rate			2.74%	Source: UG 490 - OPUC DR 378 Attachment 1/ Input Output - Exh 1905
Deprecation Rate			1.67%	
Property Tax Rate			1.50%	Source: UG 490 - OPUC DR 378 Attachment 1/ Input Output - Exh 1905
Incremental O&M			79.19	
Investment: LEA			3100	

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Depreciation	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
O&M	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
Property Taxes	46	44	43	41	40	39	38	37	35	34	33	32	31	30	29	28	26	25	24	23
Taxes on Equity Return																				
State	16	16	15	15	14	14	13	13	13	12	12	11	11	11	10	10	9	9	9	8
Federal	41	40	39	38	36	35	34	33	32	31	30	29	28	27	26	25	24	23	22	21
Total Taxes	57	56	54	52	51	49	47	46	45	43	42	40	39	38	36	35	33	32	31	29
Return on Rate Base																				
Debt	65	64	62	60	58	56	54	53	51	49	48	46	45	43	41	40	38	37	35	33
Equity	155	151	146	141	137	132	128	124	121	117	113	109	106	102	98	94	90	87	83	79
Total Return	220	214	207	201	194	188	183	177	172	166	161	156	150	145	139	134	129	123	118	112
Subtotal Cost of Service	454	445	435	425	416	407	399	391	383	375	367	359	351	343	335	327	319	311	304	296
Revenue Sensitive Items	13	13	12	12	12	11	11	11	11	11	10	10	10	10	9	9	9	9	9	8
Total Cost of Service to Finance LEA	$ 467	$ 457	$ 447	$ 437	$ 428	$ 419	$ 410	$ 402	$ 394	$ 385	$ 377	$ 369	$ 361	$ 353	$ 345	$ 337	$ 328	$ 320	$ 312	$ 304

Total Cost of Asset Over 25 Years	$ 9,094
Total Cost of Asset Over Asset Life	$ 16,168

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Remaining Cost of Asset by Year		$ 15,701	$ 15,244	$ 14,797	$ 14,360	$ 13,932	$ 13,513	$ 13,103	$ 12,701	$ 12,307	$ 11,922	$ 11,545	$ 11,176	$ 10,815	$ 10,462	$ 10,117	$ 9,780	$ 9,452	$ 9,132	$ 8,820
Rate Base -Net of Deprecation and Def Tax	3065	2982	2886	2794	2707	2623	2542	2465	2390	2315	2240	2164	2089	2014	1939	1864	1789	1714	1638	1563
Income Taxes																				
Gross up - Equity	212	206	200	193	187	181	176	171	165	160	155	150	145	139	134	129	124	119	113	108
Less: State Tax	16	16	15	15	14	14	13	13	13	12	12	11	11	11	10	10	9	9	9	8
Federal Taxable Income	196	191	184	179	173	168	163	158	153	148	143	138	134	129	124	119	114	110	105	100
Less: Federal Tax	41	40	39	38	36	35	34	33	32	31	30	29	28	27	26	25	24	23	22	21
Return	155	151	146	141	137	132	128	124	121	117	113	109	106	102	98	94	90	87	83	79
Deffered Taxes																				
Book Deprecation	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Tax Deprecation	116	224	207	191	177	164	152	140	138	138	138	138	138	138	138	138	138	138	138	138
Book-Tax Difference	64	172	155	140	125	112	100	88	87	87	87	87	87	87	87	87	87	87	87	87
Tax Effect	17	46	42	38	34	30	27	24	23	23	23	23	23	23	23	23	23	23	23	23
MACRS Depreciation - 20	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%
Property Tax Base	3048	2935	2844	2756	2673	2593	2515	2441	2366	2291	2216	2141	2066	1991	1916	1841	1765	1690	1615	1540
Tax Calculation Check	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	27.00400%																			
	72.9960%																			

	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
Depreciation	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
O&M	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
Property Taxes	22	22	21	21	20	20	19	19	18	17	17	16	16	15	15	14	13	13	12	12
Taxes on Equity Return																				
State	8	8	7	7	7	7	7	6	6	6	6	6	5	5	5	5	5	4	4	4
Federal	20	19	19	18	18	17	17	16	16	15	15	14	14	13	13	12	12	11	11	10
Total Taxes	28	27	26	26	25	24	24	23	22	21	21	20	19	19	18	17	16	16	15	14
Return on Rate Base																				
Debt	32	31	30	29	29	28	27	26	25	25	24	23	22	21	20	20	19	18	17	16
Equity	76	73	71	69	68	66	64	62	60	58	56	54	52	50	48	46	44	42	40	38
Total Return	108	104	102	99	96	93	91	88	85	82	80	77	74	71	69	66	63	60	57	54
Subtotal Cost of Service	289	284	280	276	272	268	264	260	256	252	248	244	240	236	232	228	224	219	215	211
Revenue Sensitive Items	8	8	8	8	8	8	7	7	7	7	7	7	7	7	7	6	6	6	6	6
Total Cost of Service to Finance LEA	$ 297	$ 292	$ 288	$ 284	$ 280	$ 276	$ 272	$ 268	$ 264	$ 259	$ 255	$ 251	$ 247	$ 243	$ 239	$ 234	$ 230	$ 226	$ 221	$ 217
Remaining Cost of Asset by Year	$ 8,516	$ 8,219	$ 7,926	$ 7,638	$ 7,354	$ 7,074	$ 6,798	$ 6,527	$ 6,259	$ 5,996	$ 5,736	$ 5,481	$ 5,230	$ 4,983	$ 4,740	$ 4,501	$ 4,267	$ 4,037	$ 3,811	$ 3,590
Rate Base -Net of Deprecation and Def Tax	1498	1450	1413	1375	1337	1299	1261	1224	1186	1148	1110	1072	1033	995	956	916	877	837	797	757
Income Taxes																				
Gross up - Equity	104	100	98	95	92	90	87	85	82	79	77	74	71	69	66	63	61	58	55	52
Less: State Tax	8	8	7	7	7	7	7	6	6	6	6	6	5	5	5	5	5	4	4	4
Federal Taxable Income	96	93	90	88	85	83	81	78	76	73	71	69	66	64	61	59	56	54	51	48
Less: Federal Tax	20	19	19	18	18	17	17	16	16	15	15	14	14	13	13	12	12	11	11	10
Return	76	73	71	69	68	66	64	62	60	58	56	54	52	50	48	46	44	42	40	38
Deffered Taxes																				
Book Deprecation	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Tax Deprecation	69	0	0	0	0	0	0	0	0	0	1	2	3	4	5	6	7	8	9	10
Book-Tax Difference	17	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(51)	(50)	(49)	(48)	(47)	(46)	(45)	(44)	(43)	(42)
Tax Effect	5	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(13)	(13)	(13)	(13)	(12)	(12)	(12)	(12)	(11)
MACRS Depreciation - 20	2.23%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Property Tax Base	1493	1464	1427	1389	1351	1313	1275	1238	1200	1162	1124	1085	1047	1008	968	929	889	849	809	768
Tax Calculation Check	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	Year 41	Year 42	Year 43	Year 44	Year 45	Year 46	Year 47	Year 48	Year 49	Year 50	Year 51	Year 52	Year 53	Year 54	Year 55	Year 56	Year 57	Year 58	Year 59	Year 60
Depreciation	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
O&M	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
Property Taxes	11	10	10	9	8	8	7	6	6	5	5	4	3	3	2	1	1	(0)	(1)	(2)
Taxes on Equity Return																				
State	4	4	3	3	3	3	2	2	2	2	2	1	1	1	1	0	0	(0)	(0)	(1)
Federal	10	9	9	8	7	7	6	6	5	5	4	3	3	2	2	1	0	(0)	(1)	(1)
Total Taxes	13	13	12	11	10	10	9	8	7	6	6	5	4	3	2	1	1	(0)	(1)	(2)
Return on Rate Base																				
Debt	15	14	14	13	12	11	10	9	8	7	6	5	4	3	3	2	1	(0)	(1)	(2)
Equity	36	34	32	30	28	26	24	21	19	17	15	13	10	8	6	4	1	(1)	(3)	(5)
Total Return	51	49	46	43	40	37	34	30	27	24	21	18	15	12	9	5	2	(1)	(4)	(8)
Subtotal Cost of Service	207	202	198	194	189	185	180	176	171	167	162	158	153	148	144	139	134	129	125	120
Revenue Sensitive Items	6	6	6	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	3
Total Cost of Service to Finance LEA	$ 213	$ 208	$ 204	$ 199	$ 195	$ 190	$ 185	$ 181	$ 176	$ 171	$ 167	$ 162	$ 157	$ 152	$ 148	$ 143	$ 138	$ 133	$ 128	$ 123
Remaining Cost of Asset by Year	$ 3,373	$ 3,161	$ 2,952	$ 2,749	$ 2,550	$ 2,355	$ 2,165	$ 1,980	$ 1,799	$ 1,623	$ 1,451	$ 1,284	$ 1,122	$ 965	$ 813	$ 665	$ 522	$ 384	$ 251	$ 123
Rate Base -Net of Deprecation and Def Tax	716	675	634	593	551	509	467	424	381	338	295	251	207	163	119	74	29	-16	-61	-107
Income Taxes																				
Gross up - Equity	50	47	44	41	38	35	32	29	26	23	20	17	14	11	8	5	2	(1)	(4)	(7)
Less: State Tax	4	4	3	3	3	3	2	2	2	2	2	1	1	1	1	0	0	(0)	(0)	(1)
Federal Taxable Income	46	43	41	38	35	33	30	27	24	22	19	16	13	10	8	5	2	(1)	(4)	(7)
Less: Federal Tax	10	9	9	8	7	7	6	6	5	5	4	3	3	2	2	1	0	(0)	(1)	(1)
Return	36	34	32	30	28	26	24	21	19	17	15	13	10	8	6	4	1	(1)	(3)	(5)
Deffered Taxes																				
Book Deprecation	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Tax Deprecation	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Book-Tax Difference	(41)	(40)	(39)	(38)	(37)	(36)	(35)	(34)	(33)	(32)	(31)	(30)	(29)	(28)	(27)	(26)	(25)	(24)	(23)	(22)
Tax Effect	(11)	(11)	(11)	(10)	(10)	(10)	(9)	(9)	(9)	(9)	(8)	(8)	(8)	(8)	(7)	(7)	(7)	(6)	(6)	(6)
MACRS Depreciation - 20	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Property Tax Base	727	686	644	603	561	519	476	433	390	347	303	259	215	171	126	81	36	-9	-55	-101
Tax Calculation Check	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

LEA Cost: 3100

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Total Cost of Service	$ 467	$ 457	$ 447	$ 437	$ 428	$ 419	$ 410	$ 402	$ 394	$ 385	$ 377	$ 369	$ 361	$ 353	$ 345	$ 337	$ 328	$ 320	$ 312	$ 304
Remaining Cost of Asset by Year	$ -	$ 15,701	$ 15,244	$ 14,797	$ 14,360	$ 13,932	$ 13,513	$ 13,103	$ 12,701	$ 12,307	$ 11,922	$11,545	$ 11,176	$ 10,815	$ 10,462	$10,117	$ 9,780	$ 9,452	$ 9,132	$ 8,820

Total Cost of Asset Over 25 Years	$ 9,094
Total Cost of Asset Over Asset Life	$ 16,168

	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
Total Cost of Service	$ 297	$ 292	$ 288	$ 284	$ 280	$ 276	$ 272	$ 268	$ 264	$ 259	$ 255	$ 251	$ 247	$ 243	$ 239	$ 234	$ 230	$ 226	$ 221	$ 217
Remaining Cost of Asset by Year	$ 8,516	$ 8,219	$ 7,926	$ 7,638	$ 7,354	$ 7,074	$ 6,798	$ 6,527	$ 6,259	$ 5,996	$ 5,736	$ 5,481	$ 5,230	$ 4,983	$ 4,740	$ 4,501	$ 4,267	$ 4,037	$ 3,811	$ 3,590

	Year 41	Year 42	Year 43	Year 44	Year 45	Year 46	Year 47	Year 48	Year 49	Year 50	Year 51	Year 52	Year 53	Year 54	Year 55	Year 56	Year 57	Year 58	Year 59	Year 60
Total Cost of Service	$ 213	$ 208	$ 204	$ 199	$ 195	$ 190	$ 185	$ 181	$ 176	$ 171	$ 167	$ 162	$ 157	$ 152	$ 148	$ 143	$ 138	$ 133	$ 128	$ 123
Remaining Cost of Asset by Year	$ 3,373	$ 3,161	$ 2,952	$ 2,749	$ 2,550	$ 2,355	$ 2,165	$ 1,980	$ 1,799	$ 1,623	$ 1,451	$ 1,284	$ 1,122	$ 965	$ 813	$ 665	$ 522	$ 384	$ 251	$ 123

New Residential Hookups per Year	5556
Annual Attrition	**1%**

# Customers	**Year cust leaves**										
Year After LEA Policy Implementation		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	1	56	56	56	56	56	56	56	56	56	56
	2		55	55	55	55	55	55	55	55	55
	3			54	54	54	54	54	54	54	54
	4				54	54	54	54	54	54	54
	5					53	53	53	53	53	53
	6						53	53	53	53	53
	7							52	52	52	52
	8								52	52	52
	9									51	51
	10										51
LEAs Stranded Annually		56	111	165	219	272	325	377	429	481	531
Total LEAs Stranded											2966

	Year cust leaves										
Year After LEA Policy Implementation		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	1	$ 872,424.64	$ 872,424.64	$ 872,424.64	$ 872,424.64	$ 872,424.64	$ 872,424.64	$ 872,424.64	$ 872,424.64	$ 872,424.64	$ 872,424.64
	2		$ 838,535.32	$ 838,535.32	$ 838,535.32	$ 838,535.32	$ 838,535.32	$ 838,535.32	$ 838,535.32	$ 838,535.32	$ 838,535.32
	3			$ 805,799.74	$ 805,799.74	$ 805,799.74	$ 805,799.74	$ 805,799.74	$ 805,799.74	$ 805,799.74	$ 805,799.74
	4				$ 774,167.37	$ 774,167.37	$ 774,167.37	$ 774,167.37	$ 774,167.37	$ 774,167.37	$ 774,167.37
	5					$ 743,590.96	$ 743,590.96	$ 743,590.96	$ 743,590.96	$ 743,590.96	$ 743,590.96
	6						$ 714,026.38	$ 714,026.38	$ 714,026.38	$ 714,026.38	$ 714,026.38
	7							$ 685,432.26	$ 685,432.26	$ 685,432.26	$ 685,432.26
	8								$ 657,769.88	$ 657,769.88	$ 657,769.88
	9									$ 631,011.25	$ 631,011.25
	10										$ 605,135.86
Annual Stranded Asset Sum		$ 872,424.64	$ 1,710,959.96	$ 2,516,759.69	$ 3,290,927.06	$ 4,034,518.02	$ 4,748,544.40	$ 5,433,976.66	$ 6,091,746.54	$ 6,722,757.79	$ 7,327,893.65
Total Cost of Stranded Assets											$ 42,750,508.42

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 CUB DR 11

In Schedule X on NW Natural/1717/Walker/Page 2 the Company states: “The Calculation of the estimated therm usage assumes usage in a permanent structure occupied 12 months per year and may be adjusted where service is requested where occupancy is known or expected to be less than 12 months per year. The estimated therm usage is determined from the type and number of appliances to be installed.” For residential customers, assuming the residence is occupied 12 months of the year, please provide a table showing the expected usage in therms for each gas appliance (such as a water heater, furnace, back-up furnace, fireplace, grill, range, etc.) that the Company will use in their Construction Allowance calculation.

a. Please provide a narrative explanation of how the Company expects to monitor which appliances are ultimately installed and used in a new residence, for the duration of the period required to collect adequate revenues from the new residence to recover the Construction Allowance.

b. Please add a column to this table that indicates whether each of the appliances can be supplied by natural gas from an on-site tank, propane from an on-site tank, or both.

c. Has NW Natural considered these non-pipeline alternatives for purveying the energy needs of customers of various usage-needs with equivalent services without constructing growth-related gas distribution system infrastructure?

d. If the answer to part “b.” is yes, please provide all workbooks and documentation of the analysis or analyses.

Response:

Therm loads used for analysis in determining allowances

Residential Equipment	New Construction therms	Conversion therms	Interchangeable fuel (propane/natural gas)
Furnace	415	449	Not easily - varies by mfgr
Water Heater	123	123	Not easily - varies by mfgr
Heating Fireplaces	121	220	Not easily - varies by mfgr
Decorative Fireplace	24	22	Not easily - varies by mfgr
Decorative Logs	0	0	Not easily - varies by mfgr
Range	21	21	Not easily - varies by mfgr
Dryer	2	2	Not easily - varies by mfgr
Barbeque	12	12	Not easily - varies by mfgr
Spa	218	218	Not easily - varies by mfgr
Pool	229	229	Not easily - varies by mfgr
Generator (small)	12	12	Not easily - varies by mfgr
Generator (whole home)	26	26	Not easily - varies by mfgr
Backup to Heat Pump	70	70	Not easily - varies by mfgr

a. Please provide a narrative explanation of how the Company expects to monitor which appliances are ultimately installed and used in a new residence, for the duration of the period required to collect adequate revenues from the new residence to recover the Construction Allowance.

   NW Natural performs a review of all Residential Conversion Customers to ensure agreed upon equipment has been installed. Equipment is verified through on-site visit by field technician at time of meter set or turn on or by a paid equipment invoice provided from a known equipment installation contractor.

In new Residential New Construction scenarios, NW Natural requests that the builder/developer specify the equipment installed in homes (in the Service Agreement).

b. Please add a column to this table that indicates whether each of the appliances can be supplied by natural gas from an on-site tank, propane from an on-site tank, or both.

NW Natural does not determine the availability of propane tanks at customer homes. Since end-use equipment is not interchangeable between fuels without modification (usually involving new parts and work by a technician), the likelihood of a customer switching from natural gas to propane (and back again) is determined to be very low. Some appliances cannot be converted (depending on manufacturer) and both warranty and insurance coverage can be invalidated by converting equipment.

This link explains the risks and challenges associated with converting equipment between natural gas and propane. "Propane 101" LINK www.propane101.com/lpgasapplianceconversions.htm#:~:text=Understanding%20Gas%20Appliance%20Conversions&text=In%20other%20words%2C%20connecting%20a,because%20of%20gas%20service%20pressure.

c. Has NW Natural considered these non-pipeline alternatives for purveying the energy needs of customers of various usage-needs with equivalent services without constructing growth-related gas distribution system infrastructure?

No. NW Natural has not evaluated the feasibility of on-site tank and/or propane from an on-site tank fuel scenarios.

d. If the answer to part "b." is yes, please provide all workbooks and documentation of the analysis or analyses.

N/A

Project	Category	Test Year Gross Plant	Test Year Accumulated Depreciation	Rate Base
200067-1 Tech Refresh - Large Servers/Storage (Hardware) [1]	Equipment end of Life	$ 1,991,774	$ (630,728)	$ 1,361,046
201693-2 NCS Tech Refresh Network [1]	Equipment end of Life	$ 4,119,836	$ (653,543)	$ 3,466,293
201695 Tech Refresh - Field Telemetry OR	Equipment end of Life	$ 3,091,526	$ (185,312)	$ 2,906,214
202033 2020 & 2021 & 2022 Meter Purchases [1]	Equipment end of Life	$ 4,654,683	$ (269,196)	$ 4,385,487
202146 Tech Refresh - Cellular [1]	Equipment end of Life	$ 4,774,286	$ (504,204)	$ 8,777,028
202218 Enhanced EFV Remediation	PHMSA Compliance	$ 4,780,692	$ (123,448)	$ 4,657,244
202232 Newport Switchgear Replacement	Equipment end of Life	$ 1,859,192	$ (121,661)	$ 1,737,531
202245-2 IT&S Service Management Tool Enhancement [1]	**IT&S Project**	**$ 3,109,602**	**$ (493,287)**	**$ 2,616,315**
202264 Planview Implementation [1]	**IT&S Project**	**$ 3,373,698**	**$ (1,087,825)**	**$ 2,285,873**
202324 Columbia City Regional Station Rebuild	Equipment end of Life	$ 1,639,376	$ (52,685)	$ 1,586,691
202345-3 IT&S Enterprise Foundations - Cloud Foundations	**IT&S Project**	**$ 2,790,559**	**$ (942,745)**	**$ 1,847,814**
202350 C2 Boil Off compressor rebuild	Equipment end of Life	$ 1,229,078	$ (70,805)	$ 1,158,273
202360-2 Meter Modernization - Meter/ERT Installations OR (Cust. Acq.)	Equipment end of Life	$ 15,977,162	$ (789,816)	$ 15,187,346
202360-3 Meter Modernization - Meter/ERT Purchases - (Meter Shop)	Equipment end of Life	$ 33,703,650	$ (875,307)	$ 32,828,343
202360-5 Meter Modernization Project Migration to Temetra (Cloud SW)	Equipment end of Life	$ 3,921,355	$ (487,580)	$ 3,433,775
202363 OPS 4 Wire Migration OREGON	Equipment end of Life	$ 3,477,909	$ (231,977)	$ 3,245,932
202399 Application Lifecycle Mgmt - Digital Portal [1]	**IT&S Project**	**$ 3,242,341**	**$ (514,343)**	**$ 2,727,998**
202401 North Coast Trans Feeder Uprate	Addresses Capacity Constraint	$ 3,957,396	$ (68,268)	$ 3,889,128
202412 Security Enhancements Program (OR)	**Resource Center**	**$ 7,283,735**	**$ (128,307)**	**$ 7,155,428**
202444 Corvallis Grainger Reg Sta Rebuild	PHMSA Compliance	$ 1,985,737	$ (47,656)	$ 1,938,081
202480 P31 - McMinnville	PHMSA Compliance	$ 1,488,967	$ (44,804)	$ 1,444,163
202484 SE 76th & SE Morrison DR Replacement	Equipment end of Life	$ 1,086,882	$ (15,850)	$ 1,071,032
202486 Outer Powell Grading	Public Works	$ 3,836,103	$ (49,491)	$ 3,786,612
202502 Sherwood DC HVAC Electrical Enhancements	**Resource Center**	**$ 1,835,339**	**$ (58,057)**	**$ 1,777,282**
202518 Mist Al's Dehy	Equipment end of Life	$ 1,020,118	$ (12,874)	$ 1,007,244
202528 Mist Fire System Upgrade [1]	**Resource Center**	**$ 1,392,993**	**$ (43,505)**	**$ 1,349,488**
202539 PLNG Boil off compressor	Equipment end of Life	$ 4,235,039	$ (202,937)	$ 4,032,102
202552 2022 New Pressure Telemetry	PHMSA Compliance	$ 1,081,799	$ (34,112)	$ 1,047,687
202559 PLNG Valve Replacement	Equipment end of Life	$ 3,833,897	$ (198,660)	$ 3,635,237
202574 NLNG T-1 Tank improvements	OSHA Compliance	$ 3,148,709	$ (75,893)	$ 3,072,816
202579 Central Resource Center Ph. 2	**Resource Center**	**$ 9,168,967**	**$ (274,052)**	**$ 8,894,915**
202580 Miller Station TI	**Resource Center**	**$ 3,233,074**	**$ (96,669)**	**$ 3,136,405**
202609 E04 6"-8" N Eugene ILI Conversion	PHMSA Compliance	$ 2,035,255	$ (55,043)	$ 1,980,212
202647 HWY 99 (I-5 to McDonald) Grading	Public Works	$ 1,180,823	$ (41,431)	$ 1,139,392
202648 Molalla Grading Toliver Rd 4in HP	Public Works	$ 1,604,102	$ (56,282)	$ 1,547,820
202651 P30 Willis Creek HDD Install	PHMSA Compliance	$ 3,540,263	$ (47,224)	$ 3,493,039
202658 Gimmal Records Management Upgrade	IT&S Project	$ 1,176,427	$ (172,660)	$ 1,003,767
202661 Mist Well Rework 2023	PHMSA Compliance	$ 4,638,667	$ (131,720)	$ 4,506,947
202663 2022 GC500 Gas Generator Overhaul	Equipment end of Life	$ 1,278,443	$ (40,337)	$ 1,238,106
202665-2 DRA Data Reporting & Analytics	**IT&S Project**	**$ 14,399,779**	**$ (2,044,048)**	**$ 12,355,731**
202667-1 TSA Security Directive 2C (HW)	**IT&S Project**	**$ 2,762,646**	**$ (690,662)**	**$ 2,071,984**
202667-2 TSA Security Directive 2C (On Prem)	**IT&S Project**	**$ 3,430,446**	**$ (462,767)**	**$ 2,967,679**
202689 Canby Grading South Ivy St	Public Works	$ 1,312,939	$ (39,507)	$ 1,273,432
202690 Electrical System Upgrade Phase 2	Equipment end of Life	$ 2,037,599	$ (25,714)	$ 2,011,885

202690 Electrical System Upgrade Phase 2 | Equipment end of Life | $ 2,037,599 | $ (25,714) | $ 2,011,885

Project	Category	Gross Plant	Accumulated Depreciation	Rate Base
202719 Mist Instrument and Control Upgrade (Mixed Utility Non-Utility)	Equipment end of Life	$ 1,975,683	$ (31,167)	$ 1,944,516
202721 Clevest Optimization	IT&S Project	$ 6,586,408	$ (654,030)	$ 5,932,378
202722 SAP Treasury	IT&S Project	$ 2,582,099	$ (378,966)	$ 2,203,133
202723 Identity Gov & Admin Auto	IT&S Project	$ 2,843,835	$ (603,782)	$ 2,240,053
202725 Composition SW 2.0	IT&S Project	$ 3,886,110	$ (408,672)	$ 3,477,438
202741 Network Microwave Tech Refresh	Equipment end of Life	$ 1,817,379	$ (111,837)	$ 1,705,542
202744-1 Network Tech Refresh Data Center (HW)	Equipment end of Life	$ 1,425,767	$ (274,068)	$ 1,151,699
202746-1 Network Tech Refresh IT	Equipment end of Life	$ 2,397,010	$ (586,165)	$ 1,810,845
202756-2 Tech Refresh Cellular (Radio)	Equipment end of Life	$ 1,092,762	$ (67,067)	$ 1,025,695
202758 Tech Refresh PC + Tech Vending Machine	Equipment end of Life	$ 1,687,779	$ (307,038)	$ 1,380,741
202761 Boeckman Rd and Canyon Creek Bridge	Public Works	$ 1,404,244	$ (30,562)	$ 1,373,682
202769 Website Portals - Sitecore Enhancement	IT&S Project	$ 2,361,816	$ (390,408)	$ 1,971,408
202778 New Pressure Telemetry - Ph 5	PHMSA Compliance	$ 1,853,397	$ (54,587)	$ 1,798,810
202780 ESRI Replatform to Utility Network	IT&S Project	$ 1,237,894	$ (13,933)	$ 1,223,961
202782 GC500 Cold Standby	Equipment end of Life	$ 3,589,135	$ (43,825)	$ 3,545,310
202787 Mist Gas Conditioning at Well Heads	Equipment end of Life	$ 4,074,305	$ (64,273)	$ 4,010,032
202788 GC600 Cold Standby	Equipment end of Life	$ 1,097,631	$ (31,169)	$ 1,066,462
202802 2023 GC500 Gas Generator Overhaul	Equipment end of Life	$ 2,156,076	$ (44,217)	$ 2,111,859
202804 FWM: IQGEO Upgrade	IT&S Project	$ 1,503,293	$ (220,633)	$ 1,282,660
202821 PLNG Pretreatment Improvements	Equipment end of Life	$ 2,257,177	$ (50,342)	$ 2,206,835
202840 Genesys Replatform	IT&S Project	$ 2,034,779	$ (306,581)	$ 1,728,198
202846 UI Planner RePlatform	IT&S Project	$ 1,584,567	$ (166,667)	$ 1,417,900
202848 Wilsonville Day Rd	Public Works	$ 2,269,605	$ (60,157)	$ 2,209,448
202850 Distribution Valve Zoning Study [1]	PHMSA Compliance	$ 1,393,383	$ (28,158)	$ 1,365,225
202862 Legacy Mapping Replacement (IQGEO)	IT&S Project	$ 4,822,800	$ (421,673)	$ 4,401,127
202870 PowerPlan Optimization	IT&S Project	$ 1,484,051	$ (296,810)	$ 1,187,241
202889 Happy Valley 172nd & Armstrong Cir Grading	Public Works	$ 1,033,713	$ (15,611)	$ 1,018,102
202890 Clackamas Co Stafford Rd Grading - South (North 2025)	Public Works	$ 1,105,679	$ (15,030)	$ 1,090,649
202891 SE Gate Rebuild	Equipment end of Life	$ 2,303,808	$ (32,600)	$ 2,271,208
202899 Brooks to Salem Measurement	Addresses Capacity Constraint	$ 1,060,802	$ (15,262)	$ 1,045,540
990133 Albany Trans ILI 10 in.	PHMSA Compliance	$ 2,151,918	$ (25,428)	$ 2,126,490
990192 Resource Center Decant Systems/Seismic/Truck Scale	Resource Center	$ 4,759,165	$ (88,699)	$ 4,670,466
990793 Mist Well Rework 2022-2032	PHMSA Compliance	$ 2,769,822	$ (17,725)	$ 2,752,097
990853 S36 Mid Willamette Valley Trans	PHMSA Compliance	$ 2,154,613	$ (24,551)	$ 2,130,062
990854 S24 Granger	PHMSA Compliance	$ 2,158,774	$ (25,242)	$ 2,133,532
990899 Seismic/RMV Projects	PHMSA Compliance	$ 1,984,873	$ (27,716)	$ 1,957,157
990967 ITSM 3.0	IT&S Project	$ 1,338,951	$ (145,155)	$ 1,193,796
990969 Performance-Based Metrics for Rates	IT&S Project	$ 1,668,374	$ (165,769)	$ 1,502,605
Other	Various	$ 282,462,778	$ (159,252,842)	$ 118,702,990
		$ 554,095,118	$ (178,691,409)	$ 375,403,709 <-----Change from UG 435 to UG 490

[1] Rate base amounts are slightly overstated due to Plant Model limitations on assets that went into service prior to the actual data cutoff for this case (September 30, 2023).

Data Source: UG 490 CUB DR 19

Sum of "IT&S Project" and "Resource Center", less possible contributors within "Various," in Rate Base "Change from UG 435 to UG 490:"
$83,619,276.00

CUB is still examinging what kinds of projects fell within "PHASMA Compliance," which appears to include earthquake resiliency projects CUB is examining.

NW Natural

Rates & Regulatory Affairs
UG 490
Request for a General Rate Revision
Data Request Response

Request No.: UG 490 Coalition DR 57

Please state the number of new service lines installed in the last ten years. Please provide this information in the form of total number of service lines per year and their length.

Response:

Please see the table below for the number of service lines installed in Oregon in the last ten years, as well as their total footage and average footage per service.

Year	Oregon Service Count	Oregon Total Footage	Oregon Ave Footage/Service
2014	7,742	532,026	69
2015	7,615	506,631	67
2016	8,223	552,458	67
2017	8,833	606,513	69
2018	8,302	574,944	69
2019	8,075	528,228	65
2020	7,402	462,644	63
2021	7,306	468,538	64
2022	6,568	406,321	62
2023	4,685	292,723	62

Table 4: Residential Gas v. Electric Heating Systems

	NWN Gas Service w/ Gas Furnace	NWN Gas Service w/ Hybrid Heating	Cold- Climate Air Source Heat Pump	Air Source Heat Pump	Electric Service w/ Air Source Heat Pump and Backup Generator
NWN New Premise Customer Charge (15 Years-Worth)	$4,725	$4,725	N/a	N/a	N/a
Gas Furnace	$5,500	N/a	N/a	N/a	N/a
Heat Pump (without IRA rebate)*	N/a	N/a	$11,000	$7,000	$7,000
Hybrid Gas Furnace/ Electric Heat Pump*	N/a	$8,350	N/a	N/a	N/a
Generator Cost **	N/a	N/a	N/a	N/a	~$2,500
Total Cost Less Usage Charge	$10,225	$13,075	$11,000	$7,000	$9,500
Air conditioning?	No	Yes	Yes	Yes	Yes

Table 4: Continued

Flexibility during electric outage?	Could power gas appliances.	Could power gas appliances.	Nothing would be powered.	Nothing would be powered.	Could flexibly power electric appliances and outage contingency devices, providing for heating, AC, refrigerators, lights, phones, and medical devices.
Efficiency?	Significantly less efficient than heat pumps, except possibly in frigid temperatures.	Good for "frigid" climates with temperatures that frequently drop below freezing, offering heat pump efficiency in cold conditions and a gas furnace during prolonged frigid temperatures.	Cold climate air source heat pumps are more expensive, but uphold higher performance at colder temperatures.	Air source heat pumps are highly efficient (3x more efficient than furnaces), but lose their efficiency edge over the higher-efficiency furnaces at frigid temperatures. "It's also important to note that the pump won't be useless during extreme weather events: The efficiency will	
Variable Rate: Gas versus Electric	This is the most complex comparison and cannot realistically be made to be consumer-friendly. It would be very challenging for anyone to do, particularly on a 15-year forward-looking basis. That said, assuming the customer is a Portland-area resident with access to NW Natural and PGE bills[2], NW Natural's proposed usage rate in UG 490 is about half PGE's proposed usage rate in UE 435 [3]; however, an electric heat pump "can deliver up to three times more heat energy to a home than the electrical energy it consumes,"[4] meaning the heat pump could easily offset the difference in gas and electric usage rates through higher efficiency. This is particularly true in a climate that does not consistently drop below freezing, meaning heat pumps operate closer to optimal efficiency. It would not be unreasonable for a customer to conservatively assume that at present, this factor is titled in favor of electric heating or roughly a wash, and their per-therm variable rate could be exchanged for a comparable per-kWh variable rate. If a customer was to research the forward outlooks of the gas versus electric systems in a decarbonizing Oregon, responses to gas company IRPs…				