Exhibit LDK-1T
Dockets UE-220066, UG-220067 and UG-210918
Witness: Lance D. Kaufman

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-220066, UG-220067 and UG-210918 (*Consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferred Accounting Treatment for Puget Sound Energy's Share of Costs Associated with the Tacoma LNG Facility.	

RESPONSE TESTIMONY OF LANCE KAUFMAN, PH.D.

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

July 28, 2022

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance D. Kaufman. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found at Exhibit LDK-2.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from Puget Sound Energy ("PSE").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide testimony on PSE's rate spread, rate design, load forecast, and customer driven plant.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I make the following recommendations:

- Allocate mains under 4-inches directly to schedules that benefit from small mains.
- Assign no share of Jackson Prairie to system balancing costs.
- Change the allocator for three customer related intangible assets from labor to customer.
- Require PSE to incorporate a study of labor and software used to support gas procurement in the Cost of Service Study of PSE's next general rate case.
- Treat gas procurement costs as labor costs for the purpose of suballocations.
- Allocate major customer account costs using customer count rather than customer therms.
- Limit large customer service allocations to the total system investment in large diameter services and adjust small diameter services proportionately.

- Spread rates to customers within 10 percent of parity using the average overall rate increase.
- Spread rates to customers more than 10 percent from parity using a 25% greater or lesser than overall average rate increase for schedules below and above parity respectively.
- Use any residual revenue requirement to make movement towards parity for customers within 10 percent of parity.
- Spread Schedules 141N and 141R revenue requirement proportionately to base rate revenue.
- Set the volumetric rate for the first five blocks of base rates and Schedules 141N and 141R proportionate to existing rates and limit rate increases for base rates and Schedules 141N and 141R to the first five blocks of Schedules 87 and 87T.
- Increase the fixed monthly charge of both Schedules 87 and 87T to $2,300.
- Set procurement charge in Schedule 87 to fully recover sales related expenses allocated to Schedules 87 and 87T.
- Reduce the demand charge for Schedules 87/87T to $1.20 per Therm.
- Use test year weather normalized load in every year of the rate plan for Schedules 87 and 87T.
- Limit Gas Customer Driven Plant Investment to investment based on forecasted new customers, average use per customer, and Rule 6 margin allowance.
- Exclude recovery of Tacoma LNG project costs from transportation rates.
- Exclude recovery of renewable natural gas costs from transportation rates.

II. NATURAL GAS COST OF SERVICE

Q. PLEASE SUMMARIZE THE NATURAL GAS COST OF SERVICE RECOMMENDATIONS THAT YOU MAKE IN THIS SECTION.

A. I recommend that the following changes be made to PSE's filed cost of service model:

- Allocate mains under 4-inches directly to schedules that benefit from small mains.
- Assign no share of Jackson Prairie to system balancing costs.
- Change the allocator for three customer related intangible assets from labor to customer.
- Require PSE to incorporate a study of labor and software used to support gas procurement in the Cost of Service Study of PSE's next general rate case.
- Treat gas procurement costs as labor costs for the purpose of suballocations.
- Allocate major customer account costs using customer count rather than customer therms.

I also make the following gas rate spread recommendations in this section:

- Spread rates to customers within 10 percent of parity using the average overall rate increase.
- Spread rates to customers more than 10 percent from parity using a 25% greater or lesser than overall average rate increase for schedules below and above parity respectively.
- Use any residual revenue requirement to make movement towards parity for customers within 10 percent of parity.
- Spread Schedule 141N and 141R revenue requirement proportionately to base rate revenue.[1]

[1] Because PSE proposed Schedules 141N and 141R, my testimony maintains the distinction between the two schedules for consistency's sake. However, I support the recommendation by Mr. Mullins to combine Schedules 141N and 141R into a single Schedule 141 as discussed in his response testimony.

a. Under 4-inch Distribution Pipe

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE TREATMENT OF 4-INCH DISTRIBUTION PIPE.

A. PSE's cost of service model allocates mains under 4 inches to large customer schedules, even though those customers receive no benefit from these mains. PSE has historically excluded Schedules 87 & 87T from the allocation of distribution mains under 4-inches.[2] PSE continues to believe that these customers receive no benefit from mains under 4-inches.[3] Nevertheless, PSE has modified its historical practice in this case and allocated these costs to all customers, including Schedules 87 & 87T. PSE explains this change as being based on its understanding of comments filed by Commission Staff in the recent Cost of Service ("COS") Rulemaking in Docket UG-170003.[4]

Mains under four inches clearly only benefit a subset of PSE customers. Accordingly, these costs should be directly assigned first to customers that receive benefit from the mains, then allocated among these customers using the methods proscribed in the COS rules.

Q. WHAT IS THE IMPORTANCE OF THIS ISSUE TO SCHEDULES 87/87T?

A. The allocation of under 4-inch mains to Schedules 87/87T increases these schedules' cost allocation by 50 percent. It is therefore extremely important that these costs be fairly and appropriately assigned.

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2 *See* Exh. JDT-1T at 20-21.

3 Exh. LDK-8 (PSE Response to NUCOR DR 3).

4 Exh. LDK-8 (PSE Response to NUCOR DR 6).

Q. PLEASE SUMMARIZE THE PURPOSE OF THE COMMISSION'S COST OF SERVICE RULES.

A. In Docket UG-170003, the Commission adopted Cost of Service rules applicable to natural gas investor-owned utilities.[5] The Commission's policy, memorialized in rule, is that the purpose of these rules is "to establish minimum filing requirements for any cost of service study filed with the commission,"[6] while noting that "[t]he cost of service study is one factor among many the commission considers when determining rate spread and rate design. The Commission may also consider, as appropriate, such factors as fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability."[7]

Q. DO THE COMMISSION'S COST OF SERVICE RULES REQUIRE THAT THE COSTS OF MAINS BE DIRECTLY ASSIGNED WHERE POSSIBLE?

A. Yes. Table 4 in WAC 480-85-060 sets forth Natural Gas Cost of Service Approved Classification and Allocation Methodologies, which include distribution mains. The allocation method for distribution mains is "Direct assignment of distributions mains to a single customer class where practical. All *other* costs assigned based on design day (peak) and annual throughput (average) based on system load factor."[8] In paragraph 77 of its order adopting WAC 480-85-060, the Commission made clear that "[o]ne principle of cost of service is assigning costs to a customer or customer class directly, where the costs can be directly attributed to that customer or customer class. It is not the Commission's intent to change this principle…"[9]

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5 Dockets UE-170002 and UG-170003, General Order R-599 (July 7, 2020).

6 WAC 480-85-010(1).

7 Dockets UE-170002 and UG-170003, General Order R-599 at ¶ 31 (July 7, 2020).

8 WAC 480-85-060(3), Table 4 (emphasis added).

9 Dockets UE-17002 and UG-170003, General Order R-599 at ¶ 77 (July 7, 2020).

Interpretation of customer class is required to understand this part of WAC 480-85-060. Customer class is not a defined term in WAC 480-85-030; however, it is a term of art in the field of regulation. This term is generically used to refer to a group of similarly situated customers. The term customer class can be used to refer to a broad group of customers, such as "commercial customers," or to a more specific group of customers, such as "Schedule 99." In some situations, a Schedule can include both commercial and industrial schedules, and thus span multiple customer classes. This illustrates that it is appropriate to apply a broad and flexible interpretation of the term customer class, as used in Table 4. AWEC recommends that, in this context, customer class be understood to refer to a group of customers to which a specific cost can be directly assigned. Under this interpretation, Residential, Commercial and Industrial, and Large Volume customers (Schedules 16, 23, 53, 31, 31T, 41, and 41T) form a customer class to which mains under 2 inches can be directly assigned, and these classes, in addition to Interruptible and Limited Interruptible (Schedules 16, 23, 53, 31, 31T, 41, 41T, 85, 85T, 86, and 86T), form a customer class to which mains from 2 to 3 inches can be directly assigned.

Q. IF DISTRIBUTION MAINS ARE TO BE DIRECTLY ASSIGNED WHERE PRACTICAL, WHY DOES PSE PROPOSE TO ALLOCATE MAINS UNDER 4 INCHES TO CUSTOMER CLASSES THAT RECEIVE NO BENEFIT FROM THE 4 INCH MAINS?

A. PSE explains that its interpretation of the requirements in WAC 480-85-060 related to natural gas distribution mains is informed by WUTC Staff's ("Staff") feedback on PSE's March 27, 2020 written comments in Docket UG-170003, wherein PSE sought clarification on whether the proposed rules would allow the use of main pipe diameter to allocate costs to some customer classes but not to others.[10] Specifically, PSE commented:

> Allocation methodology specifies "Design day (peak) and annual throughput (average) based on system load factor". PSE is unclear whether this rule would allow the use of main pipe diameter to allocate costs to some customer classes but not others. Additionally, would this rule allow direct assignment of costs to some customer classes but not others (e.g., special contracts)? PSE recommends further clarification for this allocation method.[11]

Staff responded that "[t]he rules are clear and do not allow for the use of main pipe diameter to allocate costs to some classes but not others. Special contracts are not required to be included in an embedded cost study and can be addressed on a utility by utility basis in a GRC."[12]

Q. IS PSE'S INTERPRETATION OF STAFF'S COMMENT, AND SUBSEQUENT ALLOCATION OF UNDER 4-INCH MAINS TO SCHEDULES 87 AND 87T REASONABLE?

A. No. PSE's comments referenced allocation of cost based on main size rather than direct assignment of costs based on main size, and thus, were not properly framed for addressing the direct assignment issues I raise in this testimony. Table 4 contemplates two "buckets" of costs for distribution mains – those that can be directly assigned and "all other costs." PSE's comment included multiple questions, making Staff's singular reply somewhat challenging to interpret. However, Staff's reply is most clearly directed towards PSE's question related to the "all other costs" bucket, which requires assignment based on design day (peak) and annual throughput (average) based on system load factor. In other words, Staff's comment was responsive to PSE's question related to "all other costs" – concluding that the rule is clear that main pipe diameter cannot be used to allocate the "all other costs" to some customer classes

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[10] Exh. LDK-8 (PSE Response to NUCOR DR 6).

[11] Dockets UE-170002 and UG-170003, General Order R-599 at Appendix A at 16 (July 7, 2020).

[12] *Id.*

and not others. Rather, that allocation would have to occur based on design day (peak) and annual throughput (average) based on system load factor. To read a prohibition on the use of main pipe diameter to apply to costs that can be directly assigned is in direct contravention to the requirement that distribution mains be assigned to a single customer class where practical, rendering PSE's interpretation illogical.

Q. IS PSE'S INTERPRETATION OF WAC 480-85-060 WITH RESPECT TO UNDER 4-INCH DISTRIBUTION MAINS CONSISTENT WITH SOUND POLICY?

A. No. There simply is no indication in the plain text of WAC 480-85-060, nor the Commission's order adopting this provision, that the Commission intended to depart from the principle of direct assignment where costs can be directly attributed. As stated by the Commission, "[a] core cost of service principle iterates that customers who can be directly assigned responsibility for a utility's costs to serve them should also be responsible for recovery of a utility's appropriate costs."[13]

Q. SHOULD THE COMMISSION ABANDON DIRECT ASSIGNMENT WHERE THE CUSTOMER CLASS RECEIVING DIRECTLY ASSIGNED COSTS INCLUDES MULTIPLE SCHEDULES?

A. No. I recognize that WAC 480-85-060's Table 4 states that "direct assignment of distribution mains to a *single* customer class where practical" could be interpreted to strictly mean one rate schedule. However, the term customer class commonly refers to the residential, commercial, and industrial classification. These classes clearly span multiple rate schedules and thus the rules contemplate direct assignment to multiple rate schedules. Furthermore, such an interpretation departs from the underlying policy framing the Commission's adoption of these rules – as stated above, "that customers who can be directly assigned responsibility for a

[13] Dockets UE-170002 and UG-170003, General Order R-599 at ¶ 49 (July 7, 2020).

utility's costs to serve them should also be responsible for recovery of the utility's appropriate costs" – and from the language in WAC 480-85-060(1)(d) which contemplates customer classes, plural. In this case, under 4-inch mains can be directly assigned to the customer classes that benefit from those investments, and those customers classes that do not benefit should thus be excluded from paying costs associated with those assets.

If the Commission disagrees with this interpretation, it should nevertheless decline to assign costs for under 4-inch mains to Schedules 87 and 87T pursuant to WAC 480-85-070, which allows the Commission to grant an exemption from the provisions of chapter WAC 480-85 "in the same manner and consistent with the standards and according to the procedures set forth in WAC 480-07-110." Such an exemption is appropriate as described above.

Alternatively, if the Commission interprets "single" customer class to apply to a single rate schedule, then the inverse scenario should also be true – that the direct assignment of costs to a single rate schedule where practical should also mean directly *not* assigning costs to a single rate schedule where practical. In this case, assigning under 4-inch mains to Schedules 87/87T and the Special Contract would effectively be excluding assignment from a "single" customer class.

Q. IF UNDER 4-INCH MAINS ARE DIRECTLY ASSIGNED TO A CUSTOMER CLASS, SHOULD THAT SAME CUSTOMER CLASS BE EXCLUDED FROM ALLOCATION OF MAINS 4-INCHES AND GREATER?

A. No. WAC 480-85-060(1)(d) provides "[i]f an allocation method in Table 2 or Table 4 in subsection (3) of this section requires direct assignment, any similar remaining costs in the account may not be allocated to the classes included in the direct assignment; except in circumstances where that class derives a direct benefit from the nondirect assigned costs. If a particular account contains several cost items, of which only certain items in the FERC account are directly assigned, the cost items that are not directly assigned will be allocated as appropriate."

The FERC accounts for mains include multiple cost items, which can be grouped by main diameter. Thus mains that are 4-inches and greater should be allocated as appropriate even if mains that are under 4-inches are directly assigned. Furthermore, under 4-inch mains are fed by larger mains, and thus customers who directly benefit from under 4-inch mains also directly benefit from 4-inch and greater mains.

Q. WHAT EVIDENCE IS THERE THAT SCHEDULES 87 AND 87T RECEIVE NO BENEFIT FROM MAINS UNDER 4 INCHES?

A. PSE has previously testified that "the mains serving these [Schedules 87 & 87T] customers were four inch or larger."[14] PSE has further testified that "a review of the meter sizes for the Non-Exclusive Interruptible (87 and 87T) showed that it is reasonable to assume that none of these customers are served from mains that are smaller than four inches."[15] PSE has also testified that the location of small mains are isolated in a manner such that they do not provide system benefits to large customers.[16]

Q. GIVEN THIS TESTIMONY FROM PSE, IS IT REASONABLE TO DIRECTLY ASSIGN MAINS UNDER 4-INCHES?

A. Yes, based on the testimony from PSE, mains under 4-inches provide direct benefits to a sub-group of PSE customers, or in this case a class of customers comprised of Schedules 16, 23, 53, 31, 31T, 41, 41T, 85, 85T, 86, and 86T, and should be directly assigned to these customers. This is consistent with the cost of service rules in WAC 480-85. It is, however, appropriate to

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14 Docket UG-190530, Exh. JDT-1T at 17-18.

15 *Id.*

16 *Id.* (The "[S]mallest main[s] are in isolated locations on PSE's gas distribution system and are unlikely to provide benefits to the large gas commercial and industrial loads served on Schedules 85, 85T, 86, 86T, 87, and 87T.").

allocate these costs across schedules within this customer class. The need to allocate costs within the subgroup that receives benefit from these smaller mains does not negate the ability, and WAC 480-85's requirement, to make an initial direct assignment of these costs to customers that benefit.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend small and mid-sized mains be directly allocated to schedules that receive benefit from them, prior to allocations among schedules, consistent with PSE's response to NUCOR DR 4.[17] This is consistent with past treatment and with current COS rules. The result of this treatment is summarized below.

Table 1

Total Expense Allocation	Residential (16,23,53)	Comm. & Indus. (31,31T)	Large Volume (41,41T)	Interruptible (85, 85T)	Limited Interruptible (86, 86T)	Non-Exclusive Interruptible (87, 87T)	Contracts
As Filed	$256,895,820	$91,436,528	$15,853,177	$7,899,360	$897,930	$7,876,188	$887,003
AWEC Mains	$258,998,936	$92,205,588	$16,149,989	$7,357,122	$849,345	$5,298,022	$887,003
Change	$2,103,116	$769,060	$296,812	-$542,238	-$48,584	-$2,578,166	$0

Q. IF THE COMMISSION ADOPTS YOUR INTERPRETATION OF DIRECT ASSIGNMENT OF MAINS, BUT MAKES A FACTUAL FINDING THAT ONE OR MORE SCHEDULE 87 OR 87T CUSTOMERS RECEIVE BENEFITS FROM MAINS UNDER 4-INCHES, DO YOU HAVE AN ALTERNATE RECOMMENDATION?

A. As I stated above, I am not aware of any such benefit, nor have I seen evidence from PSE that any such benefit exists for Schedules 87/87T customers. However, if the Commission finds credible evidence that any customer or group of customers on Schedules 87/87T is receiving a direct benefit from under 4-inch mains, I recommend the Commission consider alternatives that would preserve the direct assignment of under 4-inch mains rather than generally

[17] Exh. LDK-8 (PSE Response to NUCOR DR 4).

allocating all under 4-inch mains for such a limited exception. If the direct benefit of under 4-inch mains is limited to specifically identified pipe, this pipe could be directly assigned to Schedules 87/87T. If the Commission finds that a benefit of under 4-inch pipes is experienced by the smallest customers on Schedules 87/87T, but that the pipe providing this benefit cannot be specifically identified and directly assigned, I recommend that the threshold size for Schedules 87/87T be increased to exclude customers receiving benefits from under 4-inch pipe.

I also recommend that the Commission make separate determinations regarding Schedules 87/87T non-benefit for under 2-inch and under 4-inch pipe.

b. <u>Cost of Service: Jackson Prairie</u>

Q. PLEASE SUMMARIZE CONCERN WITH JACKSON PRARIE.

A. PSE attributes 21 percent of Jackson Prairie storage costs to system balancing.[18] PSE's share of Jackson Prairie has a working storage capacity of 8.25 billion cubic feet.[19] Ascribing 21 percent of storage costs would equate storage related balancing needs to 1.7 million dekatherms. This grossly misrepresents PSE's system balancing needs and the use and value of Jackson Prairie.

PSE's Jackson Prairie system balancing model is fundamentally flawed. The flaw in the Jackson Prairie balancing model becomes apparent when examining the following four scenarios:

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18 Exh. LDK-8 (PSE Response to AWEC DR 105). The attachment to this discovery response is summarized in Exhibit LDK-3.

19 https://www.pse.com/-/media/PDFs/001-Energy-Supply/005-Natural-Gas-Storage/4153_052_wb_JacksonPrairie_dcg.pdf?la=en&revision=192d5db2-8c8b-42e0-9345-fed19ba52ab8&hash=21B63A19173B941820E0B55C7A476BE6309DC1A4 and Exh. LDK-8 (PSE Response to AWEC DR 115).

1. Consider days where no injections or withdrawals are made at Jackson Prairie. When only days where no injections or withdrawals occur are considered, PSE’s model finds that substantial system balancing occurs and in these days ascribes 50 percent of Jackson Prairie costs to system balancing. Exhibit LDK-3 summarizes all days where no injections or withdrawals occur. In these days, substantial imbalances do occur between gas receipts and gas sales. However, PSE’s system accommodates these imbalances without the use of Jackson Prairie. This occurred in 78 days in 2020.
2. Consider days where Jackson Prairie is withdrawing gas and PSE’s model finds that PSE’s system is balancing excess gas. PSE ascribes on average 22 percent of Jackson Prairie to balancing when Jackson Prairie is in fact contributing to the imbalance rather than performing a balancing function. This occurred in 80 days in 2020.
3. Similarly, consider days where Jackson Prairie is injecting gas and PSE’s model finds that PSE’s system is balancing gas deficiencies. PSE ascribes 38 percent of Jackson Prairie to balancing when Jackson Prairie is in fact contributing to the imbalance rather than performing a balancing function. This occurred in 69 days in 2020.
4. Consider days where gas imbalances for sales and delivery customers offset, such as when sales customers are long and delivery customers are short, or vice versa. PSE’s model aggregates the absolute value of imbalances for these groups, such that even if the imbalances completely offset, PSE models the imbalances as compounding. This occurred in 271 days in 2020.

The first three scenarios above identify days where Jackson Prairie provides no balancing services or contributes to imbalances. This occurs in 227 days in 2020. On these days, PSE ascribes an average of 36 percent of Jackson Prairie to balancing services. The maximum imbalance, according to PSE, in these 227 days where Jackson Prairie provides no balancing services, is 55,919.[20] In the remaining days, where it is technically feasible for Jackson Prairie to provide balancing services, the maximum balance was 48,029.[21] This means that PSE's system accommodates larger alleged imbalances on days when Jackson Prairie provides no balancing services than on days where it is technically possible for Jackson Prairie to provide balancing services.[22] Jackson Prairie was developed to meet sales customers' procurement and capacity needs, not to serve a balancing function. Any balancing function that Jackson Prairie provides is incidental to its primary function. The imbalances that PSE is modeling are imbalances that either do not exist or that are accommodated through the interstate pipeline and gas pack on PSE's distribution system. I recommend that no Jackson Prairie costs be assigned to system balancing. The incremental impact of this recommendation is summarized below.[23]

[20] Exh. LDK-3. PSE's workpaper does not provide units for this value.

[21] Exh. LDK-3.

[22] While it is technically possible for Jackson Prairie to provide balancing services on these days, there is no evidence that Jackson Prairie actually does provide balancing services on these days.

[23] This comparison incorporates previous recommendations from this testimony into the base scenario. The "AWEC Balancing Costs" row reflects both AWEC's under 4-inch main treatment and AWEC's balancing cost treatment.

Table 2

Total Expense Allocatioı	Residential (16,23,53)	Comm. & Indus. (31,31T)	Large Volume (41,41T)	Interruptible (85, 85T)	Limited Interruptible (86, 86T)	Non-Exclusive Interruptible (87, 87T)	Contracts
AWEC Mains	$258,998,936	$92,205,588	$16,149,989	$7,357,122	$849,345	$5,298,022	$887,003
AWEC Balancing Costs	$259,193,998	$92,251,651	$16,121,469	$7,285,801	$848,495	$5,196,063	$848,528
Change	-$195,063	-$46,063	$28,520	$71,320	$851	$101,959	$38,475

c. <u>Customer Related Intangible Plant Allocation</u>

Q. WHAT IS YOUR CONCERN WITH PSE'S ALLOCAITON OF INTANGIBLE PLANT?

A. PSE allocates costs associated with its SAP and web content management software using labor. However, these software packages primarily prove customer functions and should be allocated using customer counts. I recommend changing the allocation of three specific assets associated with these software packages using the customer allocator rather than the labor allocator.

Q. WHAT INTANGIBLE PLANT DO YOU BELIEVE IS IMPROPPERLY ALLOCATED?

A. The three assets below are identified by PSE as relating to SAP software and web content management and analytics.

Table 3

Description	Book Cost
WEB, CONTENT MGMT & WEB ANALYTICS-S	$ 12,192,619.41
FTIP2 ECC - SW.CS.10YR	$ 5,957,009.14
FTIP ECC - SW.CN.10YR	$ 6,230,040.67

Web content is a customer cost. Costs associated with managing web content, including software costs, should therefore be allocated based on customers rather than labor. The FTIP assets are costs of implementing SAP.[24] SAP's primary function is to manage customer relations. Therefore, SAP software costs should be allocated based on customers rather than labor.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the three intangible assets identified in this subsection be treated as customer costs when generating intangible plant allocators. The impact of this recommendation is summarized below.[25]

Table 4

Total Expense Allocatio	Residential (16,23,53)	Comm. & Indus. (31,31T)	Large Volume (41,41T)	Interruptible (85, 85T)	Limited Interruptible (86, 86T)	Non-Exclusive Interruptible (87, 87T)	Contracts
AWEC Balancing Costs	$259,193,998	$92,251,651	$16,121,469	$7,285,801	$848,495	$5,196,063	$848,528
AWEC Intangible	$261,991,941	$90,313,193	$15,669,182	$7,072,516	$827,610	$5,044,312	$827,251
Change	$2,797,942	-$1,938,458	-$452,287	-$213,285	-$20,885	-$151,751	-$21,277

d. <u>Gas Procurement Labor and IT expense</u>

Q. WHAT ARE YOUR CONCERNS WITH PSE'S TREATMENT OF GAS PROCUREMENT LABOR AND IT EXPENSE?

A. PSE admits that gas procurement involves labor and requires the use of software.[26] However, PSE allocates no labor dollars or IT expenses to gas procurement. PSE justifies this because PSE has not studied the labor costs or IT costs involved in procuring gas.[27] PSE's failure to study labor and IT expense does not justify failing to allocate costs to procurement when it is known that these costs exist. This results in an under-allocation of costs to gas procurement.

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24 Exh. LDK-8 (PSE's response to AWEC DR 112).

25 Exh. LDK-4 provides the calculation of intangible plant allocators after these revisions. This Exhibit relies on data provided in PSE's response to NUCOR DR 10.

26 Exh. LDK-8 (PSE Response to AWEC DR 113).

27 *Id.*

Q. WHAT IS YOUR RECOMMENDATION REGARDING GAS PROCUREMENT LABOR AND IT EXPENSE?

A. I recommend that the Commission direct PSE to study what labor and IT expenses and assets are relied on when procuring and that this study be incorporated into the cost-of-service model in PSE's next general rate case. I also recommend that in this case, all dollars in FERC accounts 807.5 (Other purchased gas expenses) and 813 (Other gas supply expenses) be treated as labor dollars. The impact of this treatment is summarized below.

Table 5

Total Expense Allocation	Residential (16,23,53)	Comm. & Indus. (31,31T)	Large Volume (41,41T)	Interruptible (85, 85T)	Limited Interruptible (86, 86T)	Non-Exclusive Interruptible (87, 87T)	Contracts
AWEC Intangible	$261,991,941	$90,313,193	$15,669,182	$7,072,516	$827,610	$5,044,312	$827,251
AWEC Procurement Costs	$261,823,466	$90,399,468	$15,743,744	$7,058,264	$844,981	$5,063,465	$812,616
Change	-$168,474	$86,275	$74,562	-$14,252	$17,371	$19,153	-$14,635

e. <u>Major Customer Account Costs</u>

Q. PLEASE SUMMARIZE YOUR CONCERN WITH THE ALLOCATION OF MAJOR CUSTOMER ACCOUNT COSTS.

A. PSE charged $1 million to major customer accounts in the test year. These costs reflect the costs of the Business Services team which provides a variety of customer services to PSE's managed customers.[28] PSE allocates these costs based on the therms used in each schedule by PSE's 100 largest customers. These costs are more reasonably driven by meter count or site count rather than therms. I recommend that the major customer accounts be allocated based on customer count in each schedule for PSE's 100 largest customers.

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28 Exh. LDK-8 (PSE Response to AWEC DR 114) (According to PSE, the "Business Services team works to optimize the relationship with PSE's managed customers by advising on innovative energy solutions that promote resource conservation; reducing the complexity of customers' electric and natural gas systems; sustainability; green and environmental requirements; regional growth; social and environmental initiatives; complex billing; and construction needs.").

Q. WHAT TYPE OF COSTS ARE INCLUDED IN MAJOR CUSTOMER ACCOUNTS?

A. These costs include promotion of resource conservation, reducing complexity of gas systems, complex billing, and construction needs.

Q. WHY DO YOU RECOMMEND ALLOCATING THESE COSTS USING CUSTOMER COUNT RATHER THAN THERMS?

A. The services offered by the Business Services team are site specific, not load specific. Consider two customers, a large industrial customer with a single meter and site, and a large school district with many smaller meters that aggregate into a large load. The large school district will require substantially more management, even if the overall load of the school district is smaller than the industrial customer. Billing, conservation, distribution system, construction needs, and environmental requirements are all more complex for the large managed customer with many small loads relative to a managed customer with a single large load.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The table below compares PSE's proposed allocation of Major Customer costs with AWEC's proposed allocation of major customer costs.

Table 6

Schedule	Therms	Therm %	Customer Count	Count %
Residential (16,23,53)	0	0.00%	-	0.00%
Comm. & Indus. (31,31T)	28,158,754	9.86%	102	39.69%
Large Volume (41,41T)	29,587,147	10.36%	71	27.63%
Interruptible (85, 85T)	74,095,382	25.93%	55	21.40%
Limited Interruptible (86, 86T)	3,768,798	1.32%	15	5.84%
Non-Exclusive Interruptible (87, 87T)	118,602,573	41.51%	13	5.06%
Contracts	31,505,725	11.03%	1	0.39%

I recommend that this allocation of major customer costs be used when calculating PSE's account 903 allocator. The impact of this on cost allocations is summarized below.

Table 7

Total Expense Allocation	Residential (16,23,53)	Comm. & Indus. (31,31T)	Large Volume (41,41T)	Interruptible (85, 85T)	Limited Interruptible (86, 86T)	Non-Exclusive Interruptible (87, 87T)	Contracts
AWEC Procurement Costs	$261,823,466	$90,399,468	$15,743,744	$7,058,264	$844,981	$5,063,465	$812,616
AWEC Major Customer	$261,823,466	$90,959,905	$16,068,192	$6,973,124	$929,845	$4,378,694	$612,780
Change	$0	$560,436	$324,448	-$85,141	$84,864	-$684,772	-$199,836

f. Service Connections

Q. HOW DOES PSE TREAT SERVICE CONNECTIONS IN ITS COST OF SERVICE STUDY?

A. PSE allocates service connections to Schedules 85, 85T, 87, 87T, and Special Contracts. PSE makes this allocation using the following steps:

1. Identify acquisition costs for historic service connections.
2. Escalate acquisition cost to 2021 dollars using the Handy Whitman Index.
3. Calculate average cost by connection component, material, and diameter.
4. Identify material, diameter, and count of service connections for all Schedule 85, 85T, 87, 87T, and Special Contract customers.
5. Multiply average cost by count.
6. Calculate each Schedule's share of total service connection costs in 2021 dollars.

Q. WHAT TYPE OF COSTS ARE INCLUDED IN MAJOR CUSTOMER ACCOUNTS?

A. These costs include promotion of resource conservation, reducing complexity of gas systems, complex billing, and construction needs.

Q. WHAT CONSERNS DO YOU HAVE WITH PSE'S METHOD OF ALLOCATING SERVICE CONNECTIONS TO THESE SCHEDULES?

A. PSE's model contains an error that allocates three times more service connection costs to these schedules than it has actually incurred. This is due to a mismatch in the counts used to calculate average service cost from actual investments and the counts used to calculate service costs for each schedule. The table below illustrates the total investment, in 2021 dollars, by size and component for 4 inch and larger connections, and the calculated service connection costs for the corresponding components in Schedule 85, 85T, 87, 87T, and Special Contract customer service connections. The maximum amount of costs that should be allocated to these customers is 100 percent of costs. This is a maximum amount because it is possible that large customers on other schedules use the same size and type of services.

Table 8

Connection Type	Calculated Cost	Actual Investment ($2021)	Perent of Maximum
4" ST STUB	$4,311,105	$1,051,489	410%
6" PE STUB	$2,889,338	$972,373	297%
6" ST STUB	$743,812	$384,303	194%
8" ST STUB	$314,258	$183,317	171%
4" ST EXTN	$8,023,545	$2,283,122	351%
6" PE EXTN	$4,138,124	$1,193,690	347%
6" ST EXTN	$3,553,521	$1,835,986	194%
8" ST EXTN	$576,090	$360,056	160%
Total	$24,549,792	$8,264,336	297%

Q. WHAT IS YOUR RECOMMENDATION REGARDING ALLOCATION OF SERVICE CONNECTIONS?

A. I recommend that the calculated cost of service connections be reduced by 2/3. This reduces the calculated cost to the maximum amount for large service connections and applies a proportionate adjustment for smaller service connections. Exhibit LDK-5 provides the calculation of large customer service allocators.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The table below summarizes the impact of my adjustment on allocated expenses.

Table 9

Total Expense Allocation	Residential (16,23,53)	Comm. & Indus. (31,31T)	Large Volume (41,41T)	Interruptible (85, 85T)	Limited Interruptible (86, 86T)	Non-Exclusive Interruptible (87, 87T)	Contracts
AWEC Major Customer	$261,823,466	$90,959,905	$16,068,192	$6,973,124	$929,845	$4,378,694	$612,780
AWEC Services	$262,059,698	$91,160,738	$16,071,683	$6,623,154	$930,167	$4,350,896	$549,669
Change	$236,232	$200,833	$3,491	-$349,969	$322	-$27,797	-$63,111

Q. PSE RECOMMENDS SPECIFIC TREATMETN OF THE FREDRICKSON GATE STATION. WHAT IS YOUR RESPONSE?

A. The Fredrickson Gate Station is a part of the Tacoma LNG project. In the 2019 general rate case the Commission found that the Fredrickson Gate Station should be treated as common costs.[29] PSE disputes the Commission's finding and has proposed treating the costs of the Fredrickson Gate Station upgrade as unrelated to the Tacoma LNG plant.[30] However, PSE admits that the size of the gate station was increased to accommodate the LNG project,[31] and that the LNG Project's need for the Fredrickson Gate Station was in part due to the non-regulated uses of the LNG Project.[32] PSE represented in testimony that AWEC agrees with the treatment of the Fredrickson Gate Station.[33] This representation is not AWEC's current position, after reviewing the relevant data. AWEC recommends that the incremental costs of this gate station could be treated as common costs and could be excluded from transport rates. The costs associated with the incremental gate station are small and AWEC has not calculated the impact of this change at this time. There may be both a small revenue requirement impact

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29 Exh. JAP-1T at 52.

30 Exh. JAP-1T at 50-57.

31 Exh. LDK-8 (PSE Response to AWEC DR 102).

32 Exh. LDK-8 (PSE Response to AWEC DR 103).

33 Exh. JAP-1T at 56:14-16.

and cost of service impact to this recommendation that is not included in the rates that I propose in this testimony.

Q. WHAT IS THE OVERALL IMPACT OF YOUR COST-OF-SERVICE RECOMMENDATIONS?

A. Exhibit LDK-6 summarizes the AWEC Cost of Service Model results. The table below illustrates the parity ratio under current rates.

Table 10

	Parity Ratio Under Current Rates	
	PSE Filed COS Study	AWEC COS Study
Residential (16,23,53)	1.09	1.06
Comm. & Indus. (31,31T)	0.84	0.84
Large Volume (41,41T)	0.93	0.92
Interruptible (85, 85T)	0.77	0.94
Limited Interruptible (86, 86T)	1.28	1.27
Non-Exclusive Interruptible (87, 87T)	0.49	0.91
Contracts	1.59	2.67

Q. WHAT IS THE PARITY RATIO?

A. A parity ratio is "a customer class's revenue-to-cost ratio divided by the system's revenue-to-cost ratio,"[34] and provides a measure of the degree to which revenues from a group of customers covers that group's share of costs. A parity ratio above one indicates that revenues exceed the groups share of costs, while a parity ratio below one indicates that revenues are below the group's share of costs. A parity ratio of one indicates rate parity. This means revenues equal the share of costs.

[34] WAC 480-85-030(6).

Q. HOW ARE PARITY RATIOS USED WHEN DEVELOPING RATES?

A. Parity ratios are used to aid in the development of equitable and fair rate spreads. When parity ratios diverge sufficiently from one, it may be appropriate to increase rates in a manner that brings parity ratios closer to one over time. Two factors are considered to when establishing unequal rate increases across schedules.

The first factor considered is the magnitude of difference of the group's parity ratio from 1. For example, the residential parity ratio is within seven percent of unity. WUTC Staff, in past rate cases, has proposed that parity ratios within a 10 percent band of unity are reasonable differences, while differences in excess of 10 percent warrant corrective action.[35] In this case, Schedules 31, 85, and 86 fall outside the 10 percent band and warrant corrective action.

The second factor considered is rate shock and the need for gradualism. Rate shock can be avoided by gradually bringing unreasonable parity ratios back into the range of reasonableness.

Q. WHAT IS YOUR RECOMMENDATION FOR GAS RATE SPREAD, GIVEN THE RESULTS OF YOUR RECOMMENDED COST OF SERVICE STUDY?

A. I recommend that gas rates be spread based on specific percentages of the average rate increase. Customer groups within 10 percent of unity are in the range of reasonableness and should receive 100 percent of the average rate increase. Customer groups more than 10 percent distance from rate parity should receive 125 percent of the rate increase if they are below parity and 75 percent of the rate increase if they are above parity. Any residual revenue requirement should be used to bring customers within 10 percent of rate parity closer to rate parity. These

[35] Dockets UE-200900, UG-200901, and UE-200894, Exh. ELJ-1T at 16.

recommendations are summarized in the table below and compared against PSE's filed proposal.

Table 11

	Percent of Average Increase	
	PSE Filed	**AWEC**
Residential (16,23,53)	0.89	0.92
Comm. & Indus. (31,31T)	1.25	1.25
Large Volume (41,41T)	1.25	1.00
Interruptible (85, 85T)	1.50	1.00
Limited Interruptible (86, 86T)	0.00	0.75
Non-Exclusive Interruptible (87, 87T)	1.50	1.00
Contracts	0.73	0.86

The spread in the table above does not account for interdependencies between the Special Contract rate calculations and remaining revenue requirement. I understand that there is a feedback loop between these two values and that some additional updates may be required to comply with the terms of the Special Contract. This update would only affect the percent of average increase for Residential schedules and special contracts.

Q. HOW DOES PSE PROPOSE SPREADING SCHEDULE 141N AND 141R REVENUES?

A. PSE proposes to spread Schedule 141N and 141R revenues based on the cost of service study's allocation of rate base. I disagree that rate base is the appropriate allocator for these costs because the incremental revenue requirement included in these schedules includes operating expenses and changes in revenue. I recommend that 141N and 141R be spread based on equal percent of revenue. The table below compares the following three scenarios: (1) PSE's proposed spread under PSE's cost of service study, (2) PSE's proposed spread under AWEC's cost of service study, and (3) AWEC's proposed spread under AWEC's proposed spread for base rates.

Table 12

	Schedules 141N and 141R Spread		
	PSE Ratebase	**AWEC Ratebase**	**AWEC Revenue**
Residential (16,23,53)	64.2%	71.2%	71.7%
Comm. & Indus. (31,31T)	26.9%	21.8%	21.3%
Large Volume (41,41T)	4.3%	4.0%	4.0%
Interruptible (85, 85T)	2.2%	1.6%	1.6%
Limited Interruptible (86, 86T)	0.2%	0.3%	0.3%
Non-Exclusive Interruptible (87, 87T)	2.2%	1.1%	1.1%
Contracts	0.0%	0.0%	0.0%

III. RATE DESIGN

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS TO PSE'S NATURAL GAS RATE DESIGN.

A. I recommend the following adjustments to the rate design:

- Set the volumetric rate for the first five blocks of base rates and Schedules 141N and 141R proportionate to existing rates and limit rate increases for base rates and Schedules 141N and 141R to the first five blocks of Schedules 87 and 87T.
- Increase the fixed monthly charge of both Schedules 87 and 87T to $2,300.
- Set procurement charge in Schedule 87 to fully recover sales related expenses allocated to Schedules 87 and 87T.
- Reduce the demand charge for Schedules 87/87T to $1.20 per Therm.

a. Schedules 87/87T, 141N, and 141R Volumetric Rate Design

Q. WHAT IS PSE'S PROPOSED DESIGN FOR SCHEDLUES 87/87T, 141N, AND 141R VOLUMETRIC RATES?

A. PSE proposed increasing the first block of Schedule 87/87T by 19.5 percent and the second through sixth block by the overall average increase of 17.9 percent. PSE proposed a fixed charge per therm for every block for Schedules 141N and 141R.

Q. WHAT CONCERNS DO YOU HAVE FOR PSE'S PROPOSED VOLUMETRIC RATES?

A. PSE's base rates utilize a declining block structure which allows recovery of fixed costs through the initial blocks. PSE's proposal to use a single rate for all volumetric blocks under Schedules 141N and 141R bypass the function and purpose of Schedules 87 and 87T's declining block structure. Absent a multi-year rate plan, PSE would have a sequence of independent rate cases and the revenues collected under Schedules 141N and 141R would be base revenues thus exposed to the existing declining block structure. It is therefore appropriate for Schedules 141N and 141R to mirror rate design treatment in base rates.

I am also concerned that the rate increases in this case are inappropriate for application to the final sixth block in Schedules 87/87T. PSE's revenue requirement increases in this case are primarily due to the increased costs of PSE's distribution system.[36] These cost increases are driven by PSE's distribution system expansion. However, this system expansion is not attributable to Schedules 87/87T. Schedules 87 and 87T customer counts and gas usage have not increased in the last 10 years. Therefore, these costs are fixed with respect to 87/87T volumes. Ten of PSE's 13 customers taking service pursuant to Schedules 87 and 87T have marginal gas use in the sixth block. This means that the first five blocks of Schedules 87/87T

[36] Nearly all of the non-procurement revenue increase in this schedule is related to distribution demand.

can effectively recover these fixed costs with minimal risk that load variations lead PSE to under-recover or over-recover revenue.

Q. DO YOU HAVE OTHER CONCERNS THAT LEAD YOU TO RECOMMEND MINIMIZING CHAGNES TO THE SIXTH BLOCK?

A. Yes. PSE's long-term gas decarbonization plan relies on substantial reductions in PSE's gas throughput. If these reductions are achieved, PSE will have to substantially increase rates for low volume blocks as the volume of use in larger blocks decrease. PSE should begin sending customers price signals now to smooth the transition to a low throughput system and ensure that PSE can accommodate decarbonization of its gas system without excessive rate shock. With an early transition to higher low-volume rates, PSE will be able to achieve a longer time-period over which low-volume rates are ramped up. A critical path to successful decarbonization of PSE's gas system is early and accurate price signaling.

Q. WHAT IS YOUR RECOMMENDED RATE DESIGN FOR VOLUMETRIC COMPONENTS OF SCHEDULES 87/87T, 141N, AND 141R?

A. I recommend that the declining block structure for the first through fifth blocks be preserved and applied to all volumetric rate increases, and that no volumetric rate increase be applied to the sixth block of Schedules 87/87T. Exhibit LDK-7 summarizes these proposed rates.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THE VOLUMETRIC COMPONENTS OF SCHEDULES 87/87T, 141N, AND 141R?

A. Yes, Schedules 141N and 141R as filed by PSE include revenues related to gas sales, specifically LNG storage and RNG. In section VI, I recommend that these revenues be removed from Schedules 141N and 141R. If the Commission declines to remove these revenues, I recommend that Schedules 141N and 141R rates be differentiated for Schedule 87 and 87T customers such that Schedule 87T rates do not include revenue requirement associated with LNG storage and RNG.

b. Fixed Monthly Charge

Q. WHAT DOES PSE PROPOSE FOR SCHEDULES 87/87T FIXED MONTHLY CHARGE?

A. PSE proposes a fixed monthly charge of $715.15 and $1,027.98 for Schedules 87 and 87T respectively.

Q. WHAT EXPENSES DOES THE FIXED MONTHLY CHARGE RECOVER?

A. The fixed charge recovers customer related costs. Under the AWEC Cost of Service Study, Schedules 87/87T are allocated $650,000 in customer related costs. PSE's proposed monthly charge is insufficient to recover customer costs. PSE's test year includes 181 bills for Schedules 87/87T. A fixed monthly charge of $3,600 is necessary to recover customer costs. In the interest of a gradual transition to cost based rates, I recommend making 50 percent movement toward $3,600. This can be accomplished by setting both Schedule 87 and 87T monthly charge to $2,300.

Q. IS YOUR RECOMMENDATION REGARDING FIXED MONTLHY CHARGES CONSISTENT WITH PSE'S TRANSITION TO DECARBONIZED GAS?

A. Yes. As PSE decarbonizes its gas system, I expect total throughput to decline in Schedules 87/87T.[37] When this occurs, it is important for PSE to continue to recover its operating costs. Because customer costs do not decline with use, it is appropriate to fully recover customer costs through the customer charge. Setting a monthly charge to the level necessary to recover customer costs will ensure that PSE has appropriate incentives to reduce gas throughput.

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37 *See* Exh. JJJ-6.

c. Procurement Charge

Q. WHAT IS PSE'S RECOMMENDATION FOR THE PROCUREMENT CHARGE?

A. PSE recommends that the procurement charge for Schedules 87/87T increase by the overall average rate increase. This is problematic because it disregards the cost-of-service model's functionalization of costs into commodity and storage costs. Transport customers should not pay commodity or storage costs. This can only be accomplished if the procurement rate exactly recovered procurement costs.

Q. WHAT IS YOUR RECCOMENDATION FOR THE PROCUREMENT CHARGE?

A. I recommend that the procurement charge be set to exactly equal the procurement cost identified in the AWEC cost-of-service model.

d. Demand Charge

Q. WHAT ARE SCHEDULES 87/87T'S DEMAND CHARGE?

A. Schedules 87/87T loads can be either firm or interruptible. The demand charge is an optional charge that is applied to the firm contract demand. Thus, this charge only recovers the costs associated with firm demand. PSE concurs that the demand charge relates to the cost of firm demand.[38]

Q. WHAT IS THE COST OF FIRM DEMAND FOR SCHEDULES 87/87T?

A. The cost of firm demand for Schedules 87 and 87T is $0.95. This is calculated as the incremental cost allocated to Schedules 87/87T when an incremental unit of firm demand is added to Schedules 87 and 87T allocation factors without changing those schedules' total demand, as shown in the table below.[39]

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38 Exh. LDK-8 (PSE Response to AWEC DR 111) and Exh. JDT-1T at 31:15-21.

39 These calculations are made under AWEC's COS model.

Table 13

	Demand in Therms	Sch 87/87T Revenue Requirement Total	Per Therm
Low Demand	296,082	$6,940,918	
High Demand	308,082	$6,952,279	
Change	12,000	$11,362	0.95

Q. WHAT IS PSE'S PROPOSED DEMAND CHARGE?

A. PSE proposes to move the demand charge incrementally closer to cost in testimony, but this proposal is not implemented in PSE's workpapers.[40] In its workpapers, PSE increases the demand charge by the overall average increase for Schedules 87/87T.[41] This moves demand incrementally further from cost.

Q. WHAT IS YOUR RECOMMENDED DEMAND CHARGE?

A. I recommend making 50 percent movement towards a cost-based demand charge. The current demand charge is $1.45, while a cost-based demand charge is $0.95. My recommendation reduces the demand charge to $1.20.

Q. WHAT RATES DO YOU PROPOSE UNDER THE AWEC RATE SPREAD, RATE DESIGN, REVENUE REQUIREMENT, AND LOAD FORECAST?

A. My recommended rates are included in Exhibit LDK-7.

IV. LOAD FORECAST

Q. WHAT ISSUES DO YOU HAVE WITH PSE'S LOAD FORECAST FOR EXISTING SCHEDULE 87 CUSTOMERS?

A. PSE's filing relies of an unreasonable forecast for Schedule 87, as it forecasts a large step down in load for 2022. Schedule 87's actual weather normalized use in 2022 did have this

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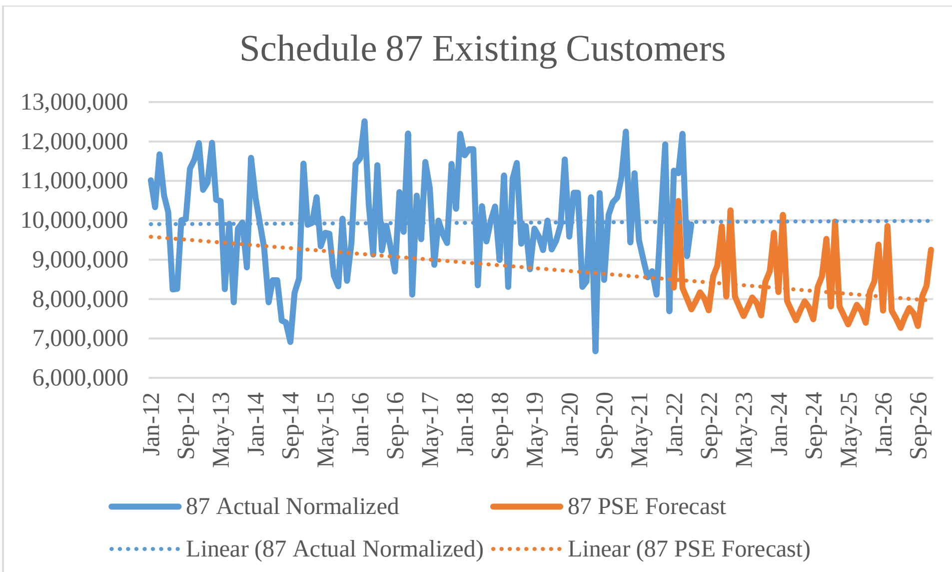
40 Exh. JDT-1T at 31:20-21.

41 Exh. JDT-5.

large step down. This demonstrates that PSE's 2022 forecast was grossly inaccurate. PSE's forecast also has a substantial negative trend over the forecast horizon. Schedule 87's weather normalized load shows no trend.

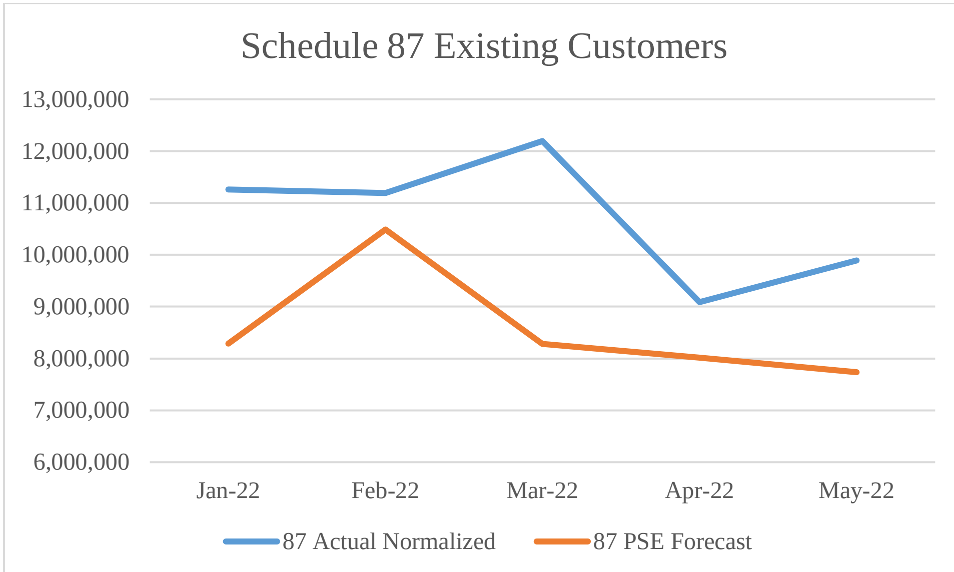
The figure below illustrates Schedule 87's historic weather normalized use, the filed forecast, and linear trend lines for each. Note that historic use has no trend, while forecasted use has a significant negative trend. This forecast clearly deviates from historic load patterns.

Figure 1



The figure below provides a closer look at the overlapping period of actuals and forecast. Note that in every month the forecast falls substantially below actuals. This illustrates that PSE's forecast of a large step down in 2022 did not materialize.

Figure 2



Actual weather normalized use was 25 percent higher than PSE's forecast from January 2022 through May 2022. This is an unreasonable amount of deviation given that these schedules are not weather sensitive, historic use has been normalized, and the forecast is only projecting a few months from the forecast date. The absence of trend in historic use suggests that this error will grow over time.

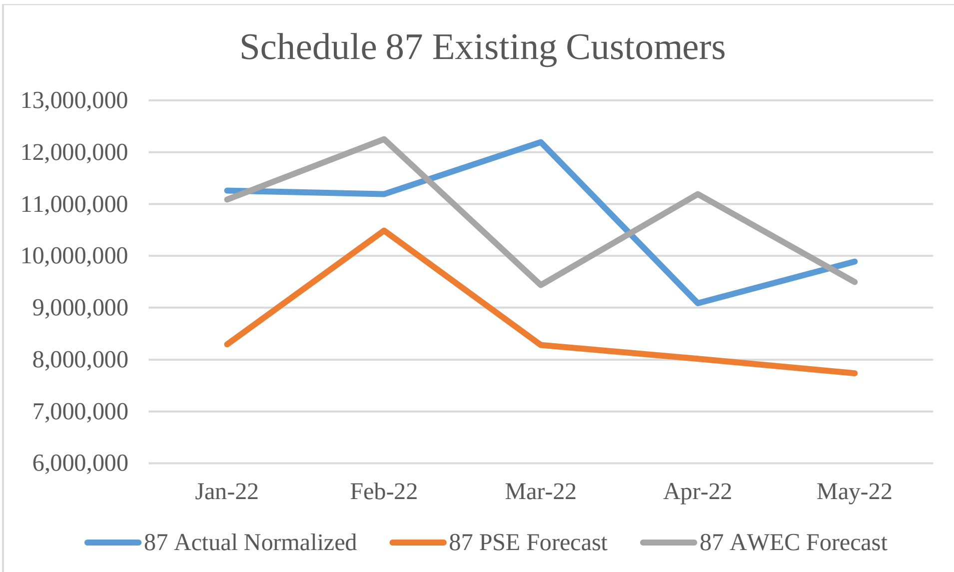
Q. WHAT IS YOUR RECOMMENDATION FOR FORECASTING SCHEDULES 87 AND 87T LOAD?

A. I recommend that test year weather normalized historic use be used in every year of the rate plan for Schedules 87 and 87T. This recommendation is based on the fact that there is no trend in use over the last 10 years, and on the fact that there is no evidence in the record to provide a reasonable basis to deviate from base year customer use for this schedule.

Q. HOW DOES YOUR PROPOSED FORECAST COMPARE TO ACTUALS FOR 2022?

A. Under my proposed forecast, the difference between forecast and actual use from January 2022 to May 2022 reduces from PSE's 25 percent under forecast to a 0.3 percent under forecast. This is a much more reasonable level of error. This is illustrated in the figure below.

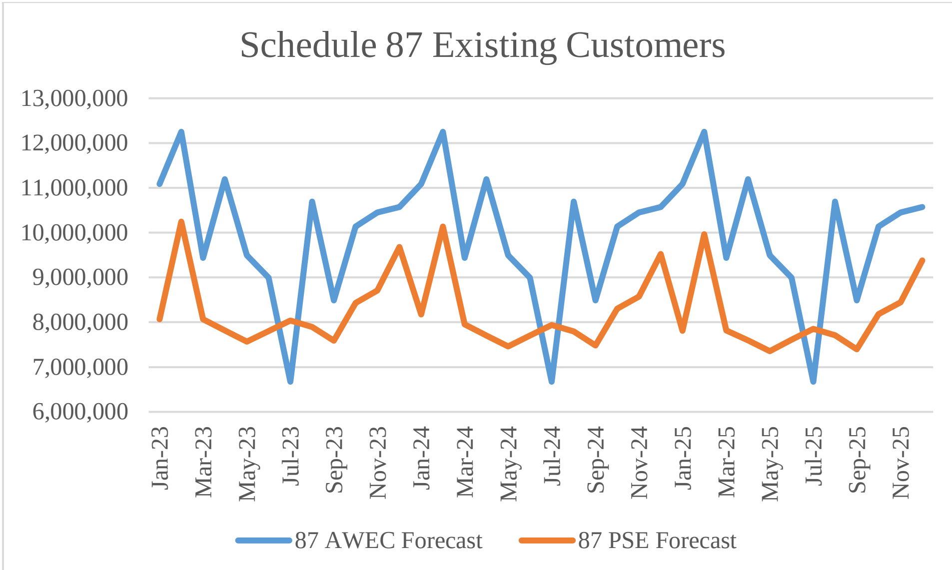
Figure 3



Q. HOW DOES YOUR PROPOSED FORECAST COMPARE TO PSE'S FORECAST OVER THE RATE PLAN?

A. The figure below compares PSE's forecast to a forecast based on actual historic use.

Figure 4



The table below summarizes the difference in forecasted delivered therms by year Schedules 87 and 87T.

Table 14

Year	AWEC Forecast	PSE Forecast	Difference
2023	119,461,282	99,901,847	19,559,435
2024	119,461,282	98,746,511	20,714,771
2025	119,461,282	97,118,998	22,342,284

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED LOAD FORECAST?

A. My recommendation has two impacts. First, it increases revenues under current rates. This affects the Schedule 141N revenue requirement in all years. Second, it reduces the rate change necessary to recover Schedule 87 allocated revenues. The table below summarizes the difference in base revenues under current rates using PSE's forecast and AWEC's recommended forecast. This change in revenue is equally applicable to PSE's Schedule 141N and AWEC's modified treatment of rate plan revenues as described in the Response Testimony of Bradley G. Mullins.

Table 15

Year	AWEC Revenue	Filed Revenue	Difference
2023	$533,512,109	$532,694,007	$818,102
2024	$537,657,282	$536,782,510	$874,771
2025	$538,589,856	$537,636,726	$953,131

Q. HOW DOES PSE IMPLEMENT THE LOAD FORECAST IN RATES?

A. PSE spreads the load change equally across all six energy blocks. This is not consistent with PSE's forecast. PSE's forecast does not include a reduction in number of customers, only a reduction in use per customer. PSE has admitted in discovery that if this occurs, then load changes would be concentrated in the final two or three energy blocks.[42] PSE spreads the load reduction across all six energy blocks. Because the first three energy blocks have higher rates, erroneously spreading the load reduction to these blocks will under forecast revenues even if the PSE forecast were accurate.

Q. HOW DO YOU RECOMMEND THAT PSE IMPLEMENT BLOCKING OF THE SCHEDULE 87 FORECAST?

A. Under my proposed forecast method there is no need to modify PSE's blocking methodology because the issue self-corrects when forecast load equals test year load. If PSE's filed forecast is adopted, Schedule 87 blocking should be corrected. I recommend that load reductions be apportioned to blocks proportionately to the marginal load in each block of the test year. This correction requires access to customer level historic data, which are not available to me, but are available to PSE.

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[42] Exh. LDK-8 (PSE Response to AWEC DR 108).

V. GAS CUSTOMER DRIVEN PLANT INVESTMENT

Q. WHAT CONCERNS DO YOU HAVE RELATED TO CUSTOMER DRIVEN PLANT INVESTMENT?

A. PSE has requested $703 million related to gas customer driven plant investment.[43] These plant additions are investments that PSE has made or plans to make on behalf of new gas customers receiving service from January 1, 2019 through December 31, 2025. However, PSE's forecast of customer driven plant investments was created as part of its 5-year business planning cycle and is out of date.[44] The forecast was made based on the line extension rules that were in effect in 2021.[45] PSE's Rule 6 was revised effective January 1, 2022 with more than 50 percent reductions to the line extension allowance of every schedule.[46] This greatly increases the required customer contribution for customer driven plant investment.

PSE's forecast for customer driven investment is also out of sync with PSE's load forecast used to set rates. PSE's customer driven plant investment forecast was based on an expectation of adding 56,961 customers from July 1, 2021 through December 31, 2025.[47] However, the forecast used to calculate rates only includes 43,000 new customers over the same period.

PSE's customer driven plant investment far exceeds a reasonable level of investment given PSE's revised extension allowance and load forecast.

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43 Exh. CAK-4r, Table 3.

44 Exh. LDK-8 (PSE response to AWEC DR 32).

45 *Id.*

46 PSE Natural Gas Tariff Rule 6, 2nd Revision of Sheet No. 16-B.

47 Exh. CAK-4 at 4:8 (original exhibit). PSE's revised testimony removed these numbers; however, the revision does not indicate that the removed numbers were incorrect.

Q. HOW DID PSE FORECAST CUSTOMER-DRIVEN PLANT INVESTMENT?

A. According to PSE, forecasted funding for customer requests is "based on applying the corporate load forecast to the current years cost of serving customer requests (based on 2020 actuals) and is then adjusted for anticipated changes such as tariff revisions and inflated by the traditional escalators such as inflation, labor, materials, and contracts. Forecasts include the margin allowance under both electric and gas tariffs that are applied as a credit against the cost of the project."[48] However, PSE appears not to have incorporated anticipated changes to Rule 8 into either the customer growth forecast or the margin allowance. This is apparent because forecasted annual expenditures do not reduce despite the customer allowance reducing by more than half and the forecasted number of customers declining by 25 percent.[49] PSE also confirmed that the forecast was based on previous rather than current line extension rules.[50]

PSE's filing also includes pro forma additions for the last six months of 2021. These pro forma additions appear to overestimate the actual customer driven additions made in 2021.

Q. HOW DO YOU RECOMMEND FORECASTING CUSTOMER DRIVEN PLANT INVESTMENT?

A. Customer driven plant investment should be consistent with customer growth implied in PSE's load forecast. The investment should also be limited to PSE's approved margin allowance. Costs in excess of the margin allowance should not be allowed into rates.

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[48] Exh. CAK-4 at 4-5.

[49] Exh. CAK-4, Table 3.

[50] Exh. LDK-8 (PSE response to AWEC DR 32).

Q. HOW MANY NEW CUSTOMERS DOES PSE FORECAST DURING THE RATE PLAN?

A. PSE's forecast of new customers was provided in PSE's workpaper "NEW-PSE-WP-JDT-3-GAS-NORMALIZED-REVENUE-22GRC-01-2022(C).xlsx". The annual customer additions by schedule are summarized below.[51]

Table 16

	PSE Forecasted Customer Additions			
Sch.	**2022**	**2023**	**2024**	**2025**
23	9608	9578	9430	9293
31-C	259	316	291	219
31-I	-18	-18	-17	-18
31T-C	0	0	0	0
31T-I	0	0	0	0
41-C	-2	0	-2	-2
41-I	0	0	0	0
41T-C	0	0	0	0
41T-I	0	0	0	0
53	0	0	0	0
85-C	0	0	0	0
85-I	0	0	0	0
85T-C	0	0	0	0
85T-I	0	0	0	0
86-C	-6	-6	-6	-6
86-I	0	0	0	0
86T-C	0	0	0	0
86T-I	0	0	0	0
87-C	0	0	0	0
87-I	0	0	0	0
87T-C	0	0	0	0
87T-I	0	0	0	0

PSE only includes new customers in Schedules 23 and 31-C.

[51] Summarized from the non-confidential tab "F2021 Forecast."

Q. WHAT IS THE EXPECTED LEVEL OF PLANT ADDITIONS FOR NEW CUSTOMERS ON SCHEDULE 23?

A. PSE Rule 6 allows a maximum margin allowance of $1,996.52 for each new Schedule 23 service. The table below calculates the maximum plant additions, net of CAIC, under this rule and PSE's filed forecast.

Table 17

	PSE Forecasted New Customer Therms			
	2022	**2023**	**2024**	**2025**
New 23 Customers	9,608	9,578	9,430	9,293
Allowance per Customer	$1,997	$1,997	$1,997	$1,997
Residential Investment	$19,182,564	$19,122,669	$18,827,184	$18,553,660

Q. WHAT IS THE EXPECTED LEVEL OF PLANT ADDITIONS FOR NEW CUSTOMERS ON SCHEDULE 31-C?

A. PSE Rule 6 allows a maximum margin allowance of $2.02 per annual therm. The table below calculates the maximum plant additions, net of CAIC, under this rule and PSE's filed forecast.

Table 18

	PSE Forecasted New Customer Therms			
	2022	**2023**	**2024**	**2025**
Therms per Customer per Month	338	342	345	344
Annual Therms Per Customer	4,060	4,108	4,136	4,122
New Sch 31 Customers	259	316	291	219
New Customer Therms	$1,051,528	$1,298,177	$1,203,546	$902,738
Allowance per Therm	$2.02	$2.02	$2.02	$2.02
Commercial Investment	$2,124,086	$2,622,317	$2,431,163	$1,823,531

Q. HOW DOES AWEC'S FORECASTED CUSTOMER DRIVEN-PLANT ADDITIONS COMPARE TO PSE'S FILED FORECAST?

A. AWEC's forecasted plant additions are substantially lower than PSE's forecast. The table below compares PSE's filed forecast with AWEC's forecast and recommended plant adjustment.

Table 19

	Forecasted Customer Driven Investment			
	2022	**2023**	**2024**	**2025**
Residential	$19,182,564	$19,122,669	$18,827,184	$18,553,660
Commercial	$2,124,086	$2,622,317	$2,431,163	$1,823,531
AWEC Forecast	$21,306,650	$21,744,986	$21,258,347	$20,377,192
PSE Filed	$103,000,000	$79,900,000	$71,300,000	$62,300,000
AWEC Adjustment	**($81,693,350)**	**($58,155,014)**	**($50,041,653)**	**($41,922,808)**

I recommend reducing forecasted customer-driven investment by a total of $232 million from 2022 to 2025.

Q. WHY DOES YOUR RECOMMENDED METHOD FOR FORECASTING CUSTOMER DRIVEN INVESTMENT NOT ACCOUNT FOR ANY COSTS BEYOND THOSE COVERED BY THE RULE 6 MARGIN ALLOWANCE?

A. All costs associated with meeting gas customer driven requests should be borne by shareholders or new customers. PSE's plan to decarbonize its gas system relies heavily on a substantial reduction in total through-put while simultaneously adding extremely low load factor customers. As PSE's throughput declines and delivered gas is decarbonized, gas and distribution costs per therm will rise dramatically. AWEC views these customer additions as highly uneconomic and anticipates that new customers are unlikely to provide long-term incremental revenues to cover the cost of system investments made to serve them. In order to appropriately incentivize new customers to make economic decisions regarding investment in gas service and gas equipment, PSE should send accurate price signals to new customers and shareholders. Existing customers should not subsidize continued and uneconomic growth of PSE's gas system in the face of gas decarbonization and declining throughput.

VI. SCHEDULES 141N AND 141R COSTS

Q. WHAT IS YOUR CONCERN WITH SCHEDULES 141N AND 141R COSTS?

A. PSE proposes allocating Schedules 141N and 141R's revenue requirement to schedules using PSE's cost of service model's rate base allocation. In this testimony I propose allocating these schedules proportional to base revenue. However, a large share of the revenue in these schedules is due to sales related costs: liquified natural gas and renewable natural gas. These costs should only be recovered from sales customers.

a. <u>Tacoma LNG costs in Schedules 141N and 141R</u>

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH TACOMA LNG COSTS.

A. Under PSE's filed case, a substantial share of the Tacoma LNG project will be paid for by transport customers. This conflicts with the function of the Tacoma LNG project and the stipulated agreement regarding cost allocations for the project. The Tacoma LNG project was developed to provide service to sales customers. The Commission has approved a stipulation between PSE and AWEC's predecessor, the Northwest Industrial Gas Users, to assign Tacoma LNG project costs to sales customers.[52] In that stipulation, parties agreed that "PSE will support the interclass allocation of the Tacoma LNG Facility costs to only sales customers on the basis of their contribution to PSE's total retail design day system peak demand (Dth/day)."[53] Most of the Tacoma LNG project costs appear in rates through Schedules 141N and 141R.[54] These schedules are allocated to all customers including transport customers.

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[52] Docket UG-151663, Full Settlement Stipulation (Sep. 30, 2016).

[53] *Id.*, ¶ 32.

[54] Exh. LDK-8 (PSE's supplemental response to NUCOR DR 11).

Q. HOW DOES PSE'S TESTIMONY REPRESENT THE TREATMENT OF THE TACOMA LNG PROJECT?

A. PSE indicates that Tacoma LNG project costs are assigned to sales customers through the cost of service model.[55] This is correct, but only for costs included in the base year. The base year only includes $19 million in LNG related plant, $4 million associated with LNG transportation equipment and ARO, and $15 million for LNG related mains.[56]

Q. HOW ARE TACOMA LNG COSTS ACTUALLY ALLOCATED?

A. PSE proposes to recover the majority of the LNG costs through Schedules 141N and 141R. In Rate year 1 (2023), the LNG project accounts for 71 percent of Schedule 141N revenue and 32 percent of Schedule 141R revenue. The table below summarizes the revenue requirement of the Tacoma LNG project included in Schedules 141N and 141R under PSE's filed case.[57]

Table 20

	2023	2024	2025
Schedule 141N	$13,891,350	$13,809,112	$13,726,260
Schedule 141R	$26,374,432	$26,041,279	$25,701,040
Total	$40,265,782	$39,850,391	$39,427,300

PSE's filing proposes spreading these revenues to customers based on allocated rate base. This would result in transport customers being assigned substantial costs associated with the LNG project because of the disproportionately large amount of LNG revenue requirement in Schedules 141N and 141R relative to base rates.

[55] Exh. JDT-1T at 16.

[56] NEW-PSE-WP-JDT-4-GCOS-MODEL-PSE-22GRC-01-2022 Sheet "Input Accounts" rows 66 and 72.

[57] Exh. LDK-8 (PSE's supplemental response to NUCOR DR 11).

Q. WHAT IS YOUR PROPOSED TREATMENT OF TACOMA LNG PROJECT COSTS

A. I recommend that Tacoma LNG costs embedded in Schedules 141N and 141R be recovered from sales customers. My primary recommendation is that these costs be removed from general rates and recovered through a separate rider schedule, which would be deferred and trued up annually coincident with PSE's Purchased Gas Adjustment ("PGA"). Alternatively, this could be accomplished through different rates in 141N and 141R for Tacoma LNG costs.

b. <u>Renewable Natural Gas costs in Schedules 141N and 141R</u>

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH RENEWABLE NATURAL GAS COSTS.

A. PSE includes renewable natural gas ("RNG") costs in the revenue requirement underlying Schedules 141N and 141R. As discussed by Mr. Mullins, these costs are incurred to meet emissions requirements for service provided to sales customers. Under the principle of cost causation, these costs should not be assigned to transport customers. However, Schedule 141N and 141R costs are allocated to all customers, including transport customers, using a general allocator.

Q. WHAT IS YOUR RECOMMENDATION REGARDING RNG COSTS?

A. I recommend that RNG costs be allocated to and recovered from sales customers. My primary recommendation is to adopt Mr. Mullins' recommendation to remove these costs from general rates and establish a renewable natural gas tracking mechanism as set forth in his response testimony. Alternatively, this could be accomplished through different rates in 141N and 141R for Tacoma LNG costs. The table below summarizes the RNG costs included in Schedules 141N and 141R in PSE's filed case.

Table 21

	2023	2024	2025
Schedule 141N	$17,793	$18,839	$31,399
Schedule 141R	$1,792,274	$5,287,210	$8,624,481
Total	$1,810,067	$5,306,049	$8,655,880

Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?

A. Yes.