Portland General Electric
121 SW Salmon Street · Portland, Ore. 97204

September 6, 2019

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street S.E., Suite 100
P.O. Box 1088
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RE: UE 358 New Load Direct Access Surrebuttal Testimony of Portland General Electric

Filing Center:

Submitted for electronic filing in UE 358 is Surrebuttal Testimony and Exhibits of Portland General Electric Company.

- UE 358 / PGE / 300
- Non-confidential exhibits 301 – 305

If you have any questions, please call me at (503) 464-7805. All formal correspondence, questions, or requests should be directed to the following email: pge.opuc.filings@pgn.com.

Sincerely,

Jay Tinker

Jay Tinker
Director, Rates and Regulatory Affairs

UE 358 / PGE / 300
Sims – Tinker

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 358

New Load Direct Access

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Brett Sims
Jay Tinker

September 6, 2019

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I. Introduction

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Brett Sims. I am the Senior Director of Strategy Integration & Commercial Initiatives for PGE.

My name is Jay Tinker. I am the Director of Regulatory Policy & Affairs for PGE.

Our qualifications were previously provided in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the Rebuttal Testimony of the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), and Calpine Solutions (Calpine) filed regarding PGE's New Load Direct Access (NLDA) investigation into Schedule 689. We collectively refer to these parties as Parties.

Q. Please summarize the Parties' positions in their rebuttal testimony?

A. Staff recommends that the Commission defer judgment on PGE's proposed Resource Intermittency Charge (RIC) and the Resource Adequacy Charge (RAD) for a general investigation that would address direct access (DA) issues more broadly, including whether the RIC/RAD should apply to both long term direct access (LTDA) and NLDA.[1] While Staff's opening testimony calls for delaying NLDA program implementation to allow necessary time for quality decisions on important DA policy questions, Staff's Rebuttal testimony suggests a shift -- that the NLDA program implementation does not need to be delayed. Staff also recommends that PGE's proposed standard offer options intended to be

[1] Staff/300, Gibbens/2.

compliant with the Oregon Renewable Portfolio Standard[2], be deferred to a separate investigation or PGE's next general rate case.

AWEC supports Staff's position that the RIC and RAD be investigated in a separate policy docket and recommends that Schedule 689 be approved absent the RIC and RAD charges.[3] Additionally, AWEC echoes the same arguments as in their opening testimony that the basis of the RIC charge is a FERC jurisdictional charge and already captured by PGE's imbalance charge under PGE's Open Access Transmission Tariff (OATT).[4]

Calpine agrees with both Staff and AWEC that a separate, more general investigation for the RIC and RAD is warranted to study resource adequacy (RA) as it relates to long-term planning and the associated procurement of capacity resources, and alternatives to the proposed charges.[5] Calpine also argues that Schedule 689 should not be held in abeyance pending a RIC and RAD investigation. Calpine responds to our reply testimony regarding RA and reiterates its claim that the RAD charge is unwarranted given how Calpine acquires energy.[6] However, Calpine provides an alternative proposal regarding the use of demand response, which we discuss later in our testimony. Calpine goes on to allege that the RIC charge is duplicative to PGE's imbalance OATT charge (PGE OATT Schedule 4R).[7]

Q. How is the remainder of your testimony organized?

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[2] ORS 469A.052.
[3] AWEC/200, Mullins/4.
[4] See PGE OATT, Schedule 4 Energy Imbalance Service, At Page 72. https://demo.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE8_14_04Tariff.pdf
[5] Calpine/300, Higgins/2.
[6] Calpine/200, Higgins/9.
[7] Calpine/200, Higgins/12.

A. In our introduction, we discuss the regional market conditions for RA and how it pertains to the charges we've proposed in this docket. The remainder of our testimony is organized as follows:

- The application and methodology of the RAD charge;
- The implementation and application of the NLDA queue and cap;
- Other remaining issues, such as the standard offer options, costs associated with RPS compliance, and the NLDA service agreement.

Lastly, we conclude our testimony in this docket.

II. The Commission Must Consider NLDA Impacts on Resource Adequacy

Q. Why should the Commission consider impacts on RA when making a determination on PGE's NLDA filing?

A. As the Commission is aware, the region continues to move toward a capacity shortfall driven by resource retirements. This shortfall is forecasted to present itself as soon as 2021. The immediate effects of a regional capacity shortfall may be masked by seasonal hydro conditions, but will continue to present as large amounts of capacity are removed from service and not replaced. As PGE has maintained in this proceeding, expanding the DA program through NLDA, without ensuring that capacity is available to serve these new loads, will deepen the RA challenge faced by PGE and the region. By definition, NLDA loads are unplanned for, and any loads associated with the program will be in addition to the loads assumed in RA assessments. It is essential for the Commission to ensure that the NLDA program decisions made for load service within the Commission's jurisdiction account for RA needs. To implement a NLDA program without RA solutions, even on a provisional basis, would unnecessarily jeopardize the reliability of the electric system and place the burden squarely on cost of service customers.

Q. Is the Commission able to decide whether NLDA customers must support RA within this docket?

A. Yes. The purpose of UE 358 is to investigate PGE's Advice No. 19-02 and the charges and options PGE proposed. More specifically, the intent of UE 358 is to investigate supply reliability, RA, and the ability for PGE to charge NLDA customers (via Schedule 689) the RIC and RAD charges to maintain these fundamental services. The record within this docket is sufficient to resolve the important question of whether NLDA customers are responsible to support RA in addition to the specific capacity charges in PGE's NLDA -- Schedule 689.

Q. Do the Parties agree that regional capacity and RA are of concern in the Northwest?

A. Yes. Staff and AWEC both agree that RA is an issue of regional concern that warrants an investigatory docket to equitably apportion and allocate the costs associated with RA.[8] Calpine's rebuttal testimony recognizes that the region's RA is increasingly strained by resource retirements.[9] CUB strongly agrees with PGE that the RIC and RAD are necessary in order to prevent unwarranted risk and cost shifting to COS customers as RA becomes increasingly concerning. CUB opposes an expansion of DA policy in which COS customers alone pay for the fixed costs of generation and unduly face the RA costs and risks originating from DA customers.[10]

Q. What procedural recommendations do Parties make in their rebuttal testimony?

A. Staff's primary recommendation is for the Commission to approve PGE's NLDA tariff without PGE's proposed capacity charges and the new standard offer service option, and to consider the RA concerns in a future DA policy docket. AWEC and Calpine support Staff's procedural recommendation. Calpine also indicates conditioned support for Staff's alternative recommendation offered in Staff's opening testimony.[11] Under the alternative approach, NLDA customers would pay for RIC and RAD service on a provisional basis, the costs of which can be offset through voluntary participation in demand response programs.[12] PGE responds to Calpine's alternative later in this testimony.

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[8] Staff/300, Gibben/2-3 and AWEC/200, Mullins/6.
[9] Calpine/200, Bass/4.
[10] CUB/100, Jenks/3.
[11] Calpine/300, Higgins/2.
[12] Id.

Q. What are the Parties' primary rationale for approving the NLDA tariff without the RIC and RAD?

A. Staff's primary rationale is that RA is not a concern in the near term.[13] As such, Staff argues the Commission should allow for an expansion of new loads even when there is no entity responsible to secure capacity, and to consider solutions for RA needs at a later time. Staff argues that even if PGE were to assess capacity charges on ESSs, that incremental improvements to PGE's system RA would not occur for over a year and a half, by which time Staff estimates a DA policy investigation may be complete.[14] AWEC argues that the incremental amount of 119 MWa unplanned for NLDA load would not create any reliability concerns in the Northwest.[15] Calpine recognizes that regional reliability may be compromised in the near term and that actions are necessary in order to maintain the current level of reliability we expect today. Yet, contrary to PGE's proposal, Calpine argues that capacity solutions should be delivered both through integrated utilities and from DA suppliers.[16]

Q. How do you respond?

A. Staff and AWEC's rationale is flawed and should be rejected. In fact, RA and reliability are pressing issues in our region with supply-demand balances already strained under peak and contingency conditions. We respond to Calpine's proposal for third-party supply of needed capacity later in this testimony.

Q. What does PGE rely on in its claim that RA is a pressing issue and should be addressed in the context of this docket?

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[13] Staff/300, Gibbens/4.
[14] Staff/300, Gibbens/ 4-5.
[15] AWEC/200, Mullins/4-5.
[16] Calpine/200 Bass/4.

A. The Northwest Power and Conservation Council's draft Resource Adequacy Assessment forecasts a regional loss of load probability (LOLP) of 7-8% in 2021 under reference case assumptions.[17] Adding new, large, unplanned-for NLDA loads will only increase the magnitude of the RA deficit and LOLP.

Q. Key to Staff's recommendation is that if an investigation were to be opened, it would be resolved in about a year. Do you share Staff's optimism that an investigatory docket will be resolved in about a year?

A. No. Staff's suggestion that a general DA policy investigation may be completed in approximately one year is optimistic.[18] In our experience with DA in other regulatory proceedings (e.g. UE 236 and UM 1587), the scope of the investigations tend to be broad, time consuming, contentious, with conclusions that could require changes of Commission rule or even recommended changes of state law The scope of the Commission's desired proceeding may continue for several years – a time in which the reliability of regional power supply appears threatened. The recommendation to delay suggests that the Staff view resource inadequacy as an acceptable risk. Staff's primary recommendation would delay decisions on planning and acquiring capacity resources while simultaneously facilitating large unplanned-for loads (perhaps even beyond the 119 MWa cap) to be served by entities with no plans or obligation to secure physical capacity resources.

Q. Does PGE support this procedural recommendation?

A. No. We strongly oppose this procedural recommendation. Were the Commission to adopt Staff's primary recommendation, the Commission would be contributing to a deepening of

[17] See PGE Exhibit 301.
[18] Staff/300, Gibbens/4.

the region's reliability risk challenges. NLDA customers, and the reliability risks they create, are squarely within the jurisdiction of the Commission. While the Commission may face limits in implementing broad, regional RA solutions, in this instance the Commission can and should take meaningful steps to improve RA conditions for load serving entities in its jurisdiction. The Commission must consider the immediate impacts of NLDA on RA and should not implement the NLDA program without a solution, interim or otherwise. Not doing so only serves to deepen the problem.

Q. Is PGE opposed to additional consideration of RA in a DA general investigatory docket?

A. PGE welcomes additional discussion of RA concerns for DA customers broadly. However, we firmly maintain that Schedule 689 should not go into effect until the Commission makes a determination (either final or provisional) regarding the need for RA planning and procurement requirements applicable to all load, and for NLDA customers to fairly support contribute to system reliability costs. Furthermore, NLDA customers should understand that they will not freely socialize reliability costs to COS customers prior to enrolling.

Q. Should the Commission choose to review PGE's proposed capacity charges in a general DA investigation, has PGE proposed an alternative approach that does not adversely impact customers while also not further impacting the region's RA?

A Yes. Should the Commission choose to review PGE's proposed RIC and RAD within a general policy docket, the Commission should allow NLDA customers to commence service as cost of service customers while maintaining position in the NLDA queue. To do this, the Commission could find good cause to allow a waiver of its conflicting rules. Following the conclusion of the policy docket and any associated rule-making, PGE proposes allowing those queued customers to choose between COS or NLDA tariffs. This approach strikes the right balance between the interests of large, sophisticated industrial users and the interests of COS customers who would be subject to undue cost and risk shifts from NLDA customers should the program be approved without the necessary structure to preserve RA. Alternatively, PGE would continue to waive any obligation for a Commission determination on its NLDA tariff filing, and the program can be held in abeyance until the policy investigation is complete.

Q. Does PGE support any other alternative approaches offered by Parties?

A. PGE continues to conditionally support Staff's alternative proposal offered in its opening testimony subject to important clarifications.[19] Calpine's rebuttal testimony also indicates conditional support for Staff's alternative proposal.[20] As originally suggested by Staff and clarified by PGE, during the pendency of a broader DA policy docket, all NLDA customers must make RIC and RAD payments to PGE to support reliability. Should NLDA customers choose to participate in PGE's demand response program, NLDA customers would be eligible to receive program participation payments which would fully or partially offset the capacity payments made to PGE. This interim solution would allow for customers to initiate service while directly contributing to the system's capacity needs. Calpine's rebuttal testimony indicates conditional support for this approach subject to the creation of a unique demand response tariff for NLDA customers with unique payment and performance requirements.[21] Following additional direction from the Commission, PGE would consider demand response program design recommendations in a subsequent NLDA compliance or

[19] Staff/100, Gibbens/10.
[20] Calpine/300, Higgins/4.
[21] Calpine/300 Higgins/7.

demand response tariff filing. However, it is also important to recognize that the efficacy of such approach, even on a provisional basis, would be dependent upon DR program design, participating customer demand and load-shape, as well as the value of alternative sources of capacity.

Q. What are the additional reasons Parties have given for the NLDA tariff being approved without the RIC and the RAD?

A. Staff seeks to prevent further delay to customers who want to participate in NLDA who have provided notice and are in the queue; allow more process to investigate the RIC and RAD and alternatives to the RIC and RAD; and to allow for the consideration of applying such charges to LTDA as well as NLDA customers. AWEC and Calpine provide similar arguments with the additional claim that there is no harm from a delayed decision on the RIC and RAD.

Q. If PGE's NLDA program is delayed, please address the concern that PGE would be harming customers who have queued their intent to enroll.

A. Were PGE's NLDA program to be delayed, potential customers would not be unduly harmed. As offered by PGE, all queued customers are free to advance their business plan and commence electric service while retaining the opportunity to either choose COS or participate in the NLDA program once important reliability, risk and equitable cost allocation questions area addressed. This approach ensures that eligible customers are not unduly harmed by investing in their facility due to a mistaken assumption about what NLDA prices, terms, and conditions are prior to the completion of a DA policy investigation.

Again, the intent of this docket is to make determinations on the aspects of PGE's 19-02 Advice filing that were not addressed in the NLDA rules. We strongly believe that it is in the best interest of all customers and the integrity of the electric system to provide determinations in this proceeding in order to ensure fairness for cost of service (COS) customers on a going forward basis as more DA loads come into PGE's balancing authority area (BAA).

III. Issues and Responses

A. The RAD

Q. Please briefly summarize PGE's proposed RAD and its purpose.

A. The RAD is a capacity-based charge to NLDA customers that reflects the cost of maintaining and providing RA. Given the nature of RA, the need for long-term planning and acquisition of physical capacity resources, and PGE's obligation to provide system reliability for all, it is a service that benefits all customers and should likewise be fairly paid for by all customers.

Q. Has PGE made any modifications to the RAD since its opening testimony?

A. No. However, through discovery and in our reply testimony, we provided alternatives for Parties to consider with regards to NLDA customers participating in demand response as a means of voluntary curtailment to provide RA and partially or fully offset the RAD related requirement.[22]

Additionally, while not a modification to our proposal, we discuss our proposed functionalization approach below.

Q. Please address the concerns that the RAD is discriminatory.

A. We see the question of discrimination raised by Parties to be a legal question and will address it fully in briefs. However, there is nothing in this docket that suggests a Commission decision regarding PGE's proposed NLDA program will directly impact LTDA rates. PGE fully expects that if it were to seek to apply the RAD, or some other similar charge, to LTDA customers, the Commission would need to weigh the facts and

[22] PGE/200, Sims – Tinker/16.

circumstances of such a request regardless of its decision in this docket. As we have explained throughout our testimony in this docket, NLDA and LTDA are fundamentally distinct with the former being unplanned for and subject to different program rules. In fact, we note that the Commission made a similar finding in authorizing the NLDA program.[23] While RA application is a broad concern that spans more than NLDA, the Parties have provided little support as to why the Commission would not have the authority to establish and implement the RAD charge for Schedule 689 in advance of a determination for LTDA.

1. Supplying Resource Adequacy

Q. Do all Parties agree that RA is important?

A. Yes. As we have previously stated, Parties generally accept that RA is a foundational requirement of a reliable electric system and a fundamental societal good. Calpine states that as "existing fossil fuel generation is retired, that the 'region's resource adequacy needs' will increase in order to support the current levels of reliability to which we all have become accustom and is required for a modern society.[24] AWEC agrees that "maintaining resource adequacy is important" and goes on to state that "if evidence shows that direct access customers are not maintaining the appropriate level of resource adequacy, this should be rectified."[25] Additionally, AWEC "agrees that cost of service customers should not subsidize direct access customers in any response, including with regard to resource adequacy."[26]

Q. What are the Parties' positions on the supply of RA and the need for the RAD?

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[23] See PGE's comments in AR 614 filed on June 19, 2018, at page 15. https://edocs.puc.state.or.us/efdocs/HAC/ar614hac73158.pdf
[24] Calpine/200, Bass/4.
[25] AWEC/200, Mullings/6-7.
[26] *Id.*

A. AWEC disagrees that PGE has adequately demonstrated that DA, specifically NLDA in this docket, customers do not provide the appropriate levels of RA and therefore the RAD is unnecessary.[27] Calpine agrees that the RAD is a RA cost and that reliability is a "policy imperative" and the Commission should determine what service the RAD is providing and "whether all, some or none of the RAD can be supplied by the ESSs."[28] Staff does not agree that RA is a need in the near term issue for PGE and expresses concern that the costs of RA are high even if there is a need..[29] Although CUB did not file a second round of testimony in this docket it is clear from reply testimony that CUB supports the need for the RAD as "the lack of capacity in the wholesale market is a fundamental problem that must be addressed" and the RAD "is a reasonable way to address the problem."[30]

Q. In his testimony, Mr. Bass asserts that Calpine provides RA service via "firm liquidated damage ("firm LD") contracts".[31] Do you agree?

A. No. Calpine's description and use of a firm LD contract only serves as a financial mechanism to provide monetary compensation if a supplier fails to deliver energy.[32] Calpine states as much in its testimony by describing a firm LD contract as an agreement where "Firm service may be curtailed within mutually agreed to recall times…If the seller interrupts, it will pay damages consistent with the terms of the contract…"[33] A firm LD contract only provides a financial incentive for suppliers and does not require the identification or availability of physical resources to ensure supply. Reliance on "Firm LD"

[27] *Id.*
[28] Calpine/200, Bass/12-13.
[29] Staff/300, Gibbens/4 and Gibbens/10.
[30] CUB/100, Jenks/17.
[31] Calpine/200, Bass/3.
[32] *Id.*
[33] *Id.*

energy purchases suggests that financial damages provide an acceptable substitute for system reliability and the avoidance of undesirable electric service curtailments – we strongly disagree with such premise.

Calpine goes on to suggest it is contributing to RA, arguing that if contracts for firm power from an unspecified source with liquidated damages is good enough for California's RA requirements it should be good enough for PGE.[34] The suggestion is misleading as Calpine does not disclose that the use of unspecified resources imported into California to meet RA requirements has been flagged by California ISO's Department of Market Monitoring (DMM) as an issue of concern that should be addressed. Like PGE the DMM argues that using unspecified market purchases originating out of system may have limited availability and value during emergency system conditions.[35] Additionally, Calpine seems to share these concerns as it stated, in the California proceeding, "Calpine does share Energy Division's concerns that import RA capacity may not be back by physical resources and transmission and hence may not be available when needed…"[36]

Regardless of these points, Calpine's argument that it is supporting RA appears to rely on the fact that there is no legal obligation for Calpine to support RA. Calpine correctly notes that "PGE has not identified any Commission rule or law that Calpine Solutions has violated…"[37] The ability for Calpine to freely socialize reliability costs onto COS customers is not present in other jurisdictions where it conducts business. Calpine freely admits that in other jurisdictions it is required to take actions that support RA and that it

[34] *Id.*
[35] Resource Adequacy Enhancements Issue Paper. California ISO. October 22, 2018. http://www.caiso.com/Documents/IssuePaper-ResourceAdequacyEnhancements.pdf
[36] Calpine Corporation Comments on Clarification to Resource Adequacy Import Rules, page 2. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M309/K943/309943892.PDF
[37] Calpine/200, Bass/4

does not take those same actions on behalf of its Oregon customers because it is not required.[38] Calpine has disclosed that it does not engage in long-term power supply agreements.[39] Instead Calpine indicates that to supply power to its customers it relies exclusively on shorter term market purchases without specified sources of supply. Calpine's activities clearly do not support RA and, therefore, shift costs onto COS customers as a result.

Q. If Calpine's suppliers do not deliver physical energy, then is Calpine required to ensure adequate supply is available to serve their customers?

A. No. Calpine describes the service it provides to its customers as "extremely simple; we buy wholesale and sell retail."[40] Calpine's described service manages credit and price risk. Notably, Calpine's described service does not include any assurance of adequacy or reliability.[41] PGE alone is left with the obligation to serve the load of all customers if Calpine is unable to secure or deliver necessary supply. As demonstrated in PGE/200 testimony, this occurs with relative frequency[42]. In Calpine's rebuttal testimony, Calpine admits that its sources of supply were unavailable to meet load eleven hours in 2018.[43] This is of great concern to PGE as we are not presently allowed to plan or procure capacity necessary to provide this physical supply, which becomes increasingly challenging as the regional supply, and the surplus energy market Calpine relies on, continues to become more constrained due to unit retirements.

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[38] *Id.*
[39] See PGE Exhibit 302.
[40] Calpine/200, Bass/5.
[41] Calpine/200, Bass/5-6.
[42] PGE/200, Sims – Tinker/32, Table 1.
[43] Calpine/200, Bass/8.

Q. AWEC also relies on the concept of firm LD contract being sufficient to supply RA.[44] How do you respond?

A. AWEC relies on FERC Order 890 which allowed certain types of contracts to be designated as network resources for purposes of procuring network transmission service to deliver to load within a balancing authority. FERC found that,

> the inclusion of a 'make whole' LD provision…does not disqualify that agreement from being designated as a network resource. However, other types of LD provisions may create incentives that are incompatible with the firmness of a power purchase agreement….Thus, as of the effective date of the Final Rule, power purchase agreements designated as network resources may only contain LD provisions that are of the 'make whole' type.[45]

As can be observed above, FERC did not comment on the contribution to RA from firm LD contracts. Rather, FERC provided clarification regarding what resources may qualify to be a designated network resource for use of network transmission. Even if FERC had directly linked designated network resources with RA, as of the date of filing this testimony, PGE and BPA are the only two entities with load in the PGE BAA that have designated network resources shown on PGE's OASIS.

AWEC goes on to maintain that DA customers are exposed to the RA risk of their supply choice arguing that, "one of the primary reasons customers choose DA is to have control over their electricity supply (including the associated risks and benefits), and RA is a component of this supply."[46] However, it is clear that RA is not a component of supply derived from unspecified sources in the short-term wholesale energy market. Additionally, the obligation of PGE to provide service to all loads within the balancing authority regardless of customer class does not support AWEC's suggestion that NLDA customers

[44] AWEC/200, Mullins/8.
[45] FERC Order No. 890, page 867, paragraph 1455.
[46] AWEC/200, Mullins/9.

will be exposed to the risks of their participation in the program. Rather should the Commission approve the NLDA program absent the RAD, NLDA customers will receive all reliability benefits while pushing the costs and risks onto COS customers.

Q. Is AWEC correct that PGE also uses firm LD contracts?

A. Yes. In response to AWEC DR 028, PGE stated that it "actively participates in the wholesale energy market to economically dispatch its generating units and reduce customers' net variable power costs."[47] However, the response also goes on to state that while "the potential output of PGE's generating units may be economically displaced by wholesale energy market purchases, however those units remain available to provide a physical source of power if required."[48] While PGE may optimize assets in the wholesale energy market on behalf of cost of service customers who pay for said assets, those assets still remain available to ensure RA even for customers who do not contribute to the costs. Allowing the NLDA program to move forward absent the RAD will result in a further increase of this cost and risk shifting.

Q. Does PGE agree with Staff's calculation of the daily reliability costs associated with the RAD that AWEC cites in its testimony?[49]

A. No. Staff's estimate relies upon a mistaken methodology. In response to PGE's Data Request 03[50], Staff's workpapers reveal that the estimate is based upon the forecasted RAD payments for an average LTDA customer over 10 years divided by seven (the number of days Staff estimates as the difference in the loss of load expectation ("LOLE") when considering COS and DA). That is incorrect. PGE's 2019 IRP filing shows that a fully

[47] AWEC/201, Mullins/6.
[48] *Id.*
[49] AWEC/200, Mullins/10.
[50] See PGE Exhibit 303.

subscribed LTDA and NLDA program would increase all customers LOLE to approximately 22 days per 10 years as opposed to PGE's targeted reliability level of 1 day per 10 years, indicating an increase of twenty-one days rather than seven.[51] PGE also finds Staff's usage of a reliable day per customer metric to be misleading. When correcting Staff's analysis to include all existing LTDA customers, their associated on-peak demand, the resultant cost of reliability per day is more than 10 times smaller. Regardless, a more appropriate reliability cost metric would consider the cost per MW or MWh or improved service, which would reflect a low cost in terms of loss of load events. Even still, the above numbers would reflect the payments necessary for DA customers to improve reliability for all customers served by PGE not LTDA customers alone. Simply put, Staff's estimate of reliability costs included in opening testimony is incorrect and should not be relied upon for decisions in this proceeding.

2. Pricing and Functionalization

Q. Did Parties share any concerns regarding methods to establish RAD pricing?

A. Yes. Staff, AWEC and Calpine all took issue with the limited amount of information on the methodology PGE would use to functionalize RA in the context of a cost of service study.

Q. How do you respond?

A. PGE appreciates Parties' understandable interest in desiring an established methodology to derive PGE's RAD costs and a finer estimate of PGE's expected costs. However, we maintain that the appropriate proceeding to review the segments of PGE's revenue requirement that are in service to RA is a general rate case. Nonetheless, we do see value in

[51] PGE's 2019 IRP, page 125.

further establishing the guiding principles of PGE's proposed functionalized RA costs. PGE's RA functionalization principles are as follows:

- RA is a service supplied through the provision of capacity and the costs of RA are attributable to all customers and classes (regardless of energy supplier);
- Costs associated with providing firm capacity from physical resources should be functionalized to RA service;
- Each resource's contribution is unique and dependent on the resource's characteristics;
- Each class' or schedule's need is unique and dependent on the characteristics of that class or schedule;
- Existing and incremental resources costs will be evaluated on the equivalent methodological basis and spread to all customers based on cost causation principles;
- A general rate case (GRC) is the most transparent and equitable way to functionalize costs associated with RA.

Q. Did PGE change its approach to calculating the RAD charge from its initial to its responsive testimony?

A. No. We continue to propose that the RAD price be calculated in the context of a GRC and RA be a service that is apportioned to all rate schedules and classes of customers. Apportioning costs by the cost of service study ensures that cost allocation and pricing is based on the amount of cost causation each schedule is placing upon PGE's system with regard to RA.

Q. Please review the process to determine the RAD charge.

A. In general, we see price setting for the RAD as following the same general process for any price:

- Establish the revenue requirement;
- Allocate (or functionalize) the revenue requirement by category (e.g. generation, distribution, transmission, and RA);
- Conduct a rate spread study to apportion the functionalized categories of costs to each rate schedule.

We expect that the price setting for the RAD will occur in the context of a GRC and therefore, will leverage the revenue requirement, generation marginal cost, and rate spread studies to determine and spread the costs attributable to RA and apportion those costs equitably based on cost causation principles.

Q. What will be the basis for functionalizing costs associated with RA?

A. Given the range of resources in PGE's generating fleet and the prospective incremental generating resource acquisitions, we expect to leverage PGE's net variable power cost (NVPC) and marginal generation cost studies along with the embedded costs of firm generation to calculate and allocate the portion of the generation revenue requirement that's associated with RA.

Q. How would PGE allocate costs to rate schedules?

A. Given that generation capacity and RA are a part of total generation, the generation marginal cost study provides the forum for providing a transparent method to spread system RA costs across rate schedules for pricing purposes. In the study, PGE will use an allocation factor (which assess RA need by schedule), similar to the existing coincident peak or total energy consumption factors, to determine each rate schedules RA proportional need. Thus, following the existing practices and principles that PGE currently uses for setting rates.

Q. Will RA be a category of cost that applies to all customer rate schedules (COS and DA)?

A. Yes. As we've stated in the previous rounds of testimony in this docket, RA is a service that's currently provided to all customers but paid for only by COS customers.[52] Historically, the costs of RA have been embedded in generation costs that show up in customer bills via their energy charges. This approach has over-simplified the service costs and allowed customers who do not receive supply from PGE to receive RA service while bypassing the associated costs. Through functionalizing RA, we plan to apply pricing for RA across all rate schedules ensuring that no class is able to receive the benefits of RA while other classes bear the costs.

Q. Why isn't PGE proposing its exact methodology and RAD price in this docket and instead developing the pricing methodology in a general rate case (GRC)?

A. The appropriate proceeding to determine the exact RAD pricing is in a GRC. Given that RA is a service provided to all customers (regardless of the energy provider) and is not currently separately functionalized, a GRC is the only forum which allows PGE to propose new rate design proposals via a COS and rate design studies. Also, a GRC provides all intervening parties an equal chance to provide comment and recommendations for alternative pricing design structures and methodology on PGE's proposal for RAD pricing which helps to ensure an equitable spread of costs across all rate schedules.

[52] PGE/200, Sims – Tinker/32.

Q. Is PGE proposing the Commission defer its decision on the RAD until the Company's next GRC?

A. No. PGE is not changing its proposal. Rather, we are explaining that the GRC is the most appropriate forum for PGE and parties to propose, review, and comment on specific pricing and rate design aspects. We continue to request that the Commission approve the RAD in this docket so that the specific rate design aspects can be handled in a subsequent GRC.

Q. PGE's proposal to determine the exact charge for the RAD in its next general rate case means it is not known to customers until then. Is this in conflict with PGE's argument that the terms and conditions be known to customers before they enroll in NLDA?

A. No. As part of our Schedule 689 advice filing (No. 19-02), we provided an indicative RAD price based on IRP analysis; however, we acknowledged that the actual RAD price may be different depending on circumstances such as incremental resource procurement or the specific rate design approach in a subsequent GRC. PGE's argument is that prospective NLDA customers should know that they are eligible for the RAD and it is a charge that will apply to their service. However, we are open to providing indicative pricing after this docket once we have the associated cost/pricing results for the RAD.

3. RAD Alternatives

Q. Have Parties discussed alternative mechanisms that might ensure RA and allow customers to avoid or mitigate the RAD?

A. Yes. In its reply and rebuttal testimony Staff discussed the concept of "self-supply" of RA in the form of a third-party solution, self-generation, and demand response or curtailment.[53] Calpine's rebuttal testimony considers the potential for ESSs to self-supply necessary

[53] Staff/100 Gibbens/18-19 and Staff/300 Gibbens/8-9.

capacity resources and the potential for NDLA customers to avoid RAD charges through participation in demand response programs (Calpine offers specific recommendation on adjusted demand response tariffs for DA customers).[54],[55]

In its testimony, AWEC states "there are any number of alternatives" and references the 704B framework in Nevada as well as long-term contracts with specified resources (e.g. third-party supply) but does not appear to propose any specific alternatives.[56]

Q. Please continue.

A. As we discussed in our testimony and responses to data requests[57], these concepts could all be developed to support RA.[58] In particular, demand response and self-generation resemble existing constructs that PGE has implemented, specifically Schedule 26 – Nonresidential Demand Response Pilot Program and Schedule 75 – Partial Requirements Service, and could be readily adapted to the framework suggested by Parties in this docket.

While PGE recognizes that NLDA customers or their ESS have the ability to enter into long-term contracts with physical resources and that such a construct could meet RA requirements, PGE has concerns with such a third-party supply of RA resources for numerous reasons.

Q. What primary concerns does PGE have with a third-party supplied option?

A. As we stated in our reply testimony, PGE is actively regulated under broad Commission authority and is the sole entity responsible and accountable for providing reliability to customers within its balancing authority, regardless of their energy supplier. Neither the

[54] Calpine/100 Higgins/9 and Calpine/300 Higgins/7.
[55] Calpine/200, Bass/2.
[56] AWEC/200 Mullins/9-10.
[57] See PGE Exhibit 304.
[58] PGE/200 Sims – Tinker/25-26.

obligation to serve nor level of Commission oversight apply to a third-party, and it does not appear that the Commission currently has the authority to extend such a framework to third-parties. PGE expects that voluntary standards imposed on a financially incented third party will fall short. It is our position that a third-party option with no oversight, accountability, or enforcement does not provide RA.

Q. Does PGE have concerns with the other options as well?

A. Yes, but to a lesser extent because the options raised by Parties all fit into a framework where the Commission has oversight. PGE acknowledges that these options require further development and analysis, but there is sufficient time to do so under the proposed implementation of NLDA and the RAD, specifically as part of a general investigation regarding DA or within a subsequent general rate case.

Q. Would any of the above alternatives replace the RAD? Why?

A. No. Instead, PGE recommends the Commission approve the RAD and allow for some, or possibly all, of the above alternatives to be further investigated and potentially implemented to serve to partially or fully offset the RAD. The ability to and degree of offset would depend on the details of the proposed alternative.

B. NLDA Queue and Program Cap

Q. Are there any customers in the queue that have already energized such that they would not be eligible under Commission rules?

A. We have questions of eligibility around a few customers in the queue. One of the customers, whose eligibility was in question, has energized their operations, which according to the rules, makes them ineligible for NLDA. No others have energized.

Q. AWEC alleges that PGE has changed its position regarding energization and eligibility. Is this correct? Please explain PGE's position.

A. No. Our perceived change in position is largely due to Parties' recommendation that the final determination for the RIC and RAD be made in a separate docket. As an interim solution where customers could still energize and begin operations prior to a final determination on the RIC and RAD and assuming a suspension of Schedule 689, we proposed that customers be allowed to go onto a COS schedule[59] in the interim to accommodate both customers and Parties. While our primary position is that the Commission can and should approve the RIC and RAD in this proceeding; however, if this is not possible, we have provided an alternative option preserving customer options, for Parties to consider.

Q. Even if the answer to the customers energizing were no, would PGE support a rule waiver for customers in the queue now, that regardless of when they energize, they should be eligible to participate in NLDA once all the terms are known?

A. To the extent the RIC and RAD issues are moved into UM 2024 or another general investigation, we would support allowing the customers to energize and be served temporarily as COS until such time as the RIC and RAD issues are determined whether in this docket or another.

1. Queue Implementation Issues

Q. What issues did Parties raise regarding the NLDA queue?

A. Staff responds to our proposal to suspend the NLDA tariff filing to coincide with the investigation for the RIC and RAD. Staff states that customers in the queue cannot energize

[59] PGE/200, Sims – Tinker/8.

and maintain their place queue position prior to the final determination of the NLDA tariff (i.e. once a customer energizes beyond construction needs, the customer would be deemed ineligible for NLDA).[60] As we stated earlier, Staff is opposed to our proposal to hold Schedule 689 in abeyance until there's a final decision made on the RIC and RAD charges. With a waiver of the NLDA rule for good cause, customers could energize and maintain eligibility. It is our position that this is fully within the Commissions authority and ability within this proceeding.

AWEC also responds to PGE's proposal from our reply testimony and states that a more fair and lawful approach would be for the NLDA tariff to be approved absent the RIC and RAD charges and for the queue participants to be able to take service under Schedule 689 absent the RIC and RAD until such time those charges are approved.[61] Calpine provided no further input regarding the implementation of the NLDA queue and defers to their opening testimony as Calpine's current position on the matter.[62]

Q. Do you agree with Staff's assertion that Schedule 689 cannot be held in abeyance until final decisions for the RIC and RAD are made?

A. No. In fact, the Commission and the utility may agree to suspend an investigation by way of ORS 757.215 (2) which states that, "This section does not prevent the commission and the utility from entering into a written stipulation at any time extending any period of suspension."[63]

Q. How do you respond to Staff and AWEC's positions regarding the NLDA queue?

[60] Staff/300, Gibbens/12.
[61] AWEC/200, Mullins/4.
[62] Calpine/200, Higgins/14.
[63] See ORS 757.215 (2).

A. Our position is that allowing eligible, queued customers to fully energize prior to the approval of the NLDA tariff (Schedule 689) would not delay construction and operation of queued customer facilities, and provide these customers an opportunity to evaluate the potential impacts associated with an approval of the RIC and RAD. PGE would support a limited initial waiver of the NLDA rule related to the load being new and incremental in order to provide customers the ability to commence service under COS, while retaining the choice to remain on COS or choose NLDA once the Commission makes a determination regarding the fundamental reliability and fairness issues raised.

Q. What was the original intent of the NLDA queue?

A. The original intent of the NLDA queue was to ensure that prospective NLDA customers would have the opportunity to provide their revocable notice of enrollment for service and have an opportunity to be included under PGE's NLDA cap amount of 119 MWa while Staff investigated the RIC and RAD through this docket. Additionally, the queue provided the Commission an ability to waive the rule-required one-year notice provision for the incremental load start date.[64]

Q. Is PGE open to extending the duration of the queue to coincide with a potential new investigation for the RIC and RAD?

A. Yes. We are open to extending the duration of the queue if a final determination for the RIC and RAD is not decided in this docket.

<u>*2. NLDA Cap Issues*</u>

Q. What issues did Parties raise with regards to the NLDA cap?

[64] See OAR 860-038-0740.

A. Staff disagrees with our position, that the NLDA cap is a hard cap, and suggests that, should the cap be reached, enrollment for NLDA service and the ability to exceed the cap be made on a case-by-case basis.[65] Staff suggests that it is PGE's obligation to ensure customers are notified of their ability to seek waivers of the cap so that customers are afforded sufficient time to file a waiver before being removed from the queue.[66]

AWEC questions the notion that PGE's 119 MWa cap would in fact create a reliability concern in the Northwest, and further cites that the 20% transition adjustment charge for the first five years ensures that NLDA customers are paying their share of system costs until a general investigation for the RIC and RAD is complete.[67] Calpine argues that if customers take service under PGE's "Daily Market Energy Option," their loads should not be counted towards the NLDA program cap, then further argues that, "The Commission should be careful not to allow this aspect of the DA program to be converted to another green tariff, which has its own rules and caps being examined under Docket No. UM 1953."[68]

Q. Do you agree with Calpine's recommendation to omit load from the NLDA cap if the customer is on PGE's "Daily Market Energy Option"?

A. No. Calpine's proposal is not founded on any rules or orders by the Commission on how loads are to be evaluated for the purposes of DA caps. Therefore, customers taking load under PGE's Daily Market Energy Option should be treated like any other load served by a third-party supplier (ESS).

Q. Do you agree with Staff's recommendation that PGE is obligated to inform customers of their right to seek a NLDA cap waiver?

[65] Staff/300, Gibbens/11.
[66] Id.
[67] AWEC/200, Mullins/5.
[68] Calpine/300, Higgins/13.

A. No. The intent of NLDA is to afford large sophisticated customers the ability to immediately choose their supply rather than subsequently enrolling in LTDA. Calpine even cites when referencing current and potential NLDA customers that, "These customers are sophisticated energy buyers that want control of the energy procurement and costs and have the wherewithal to assess the risks associated with their options."[69] From our experience in working with current and potential DA customers, we've observed that these customers are very adept at understanding energy pricing, supply optionality, and understand how to leverage the DA rules to their advantage. We see no reason why PGE ought to be the conduit to interpret and inform customers on their potential opportunities to seek a waiver for NLDA given their advance understanding of energy markets and regulatory/tariff matters.

Q. How do you respond to AWEC's assertion that the 119 MWa of NLDA would not pose any reliability issues for PGE?

A. We disagree with AWEC's qualitative assertion. As we stated in our last round of testimony, we estimate that 373 MW of incremental capacity is needed to support the reliability needs of existing LTDA customers[70] which supports the outcomes as outlined by the Northwest Power and Conservation Council's draft Resource Adequacy Assessment results included in PGE Exhibit 301.

Q. Does PGE agree with the statement by AWEC that suggests that the NLDA transition adjustment of 20% of fixed generation will be sufficient to compensate for RA until a separate investigation for the RIC and RAD is complete.

[69] Calpine/200, Bass/3.
[70] PGE/200, Sims – Tinker/20.

A. No. The issue at hand is how to appropriately acquire and charge for capacity to ensure RA for our customers. Whether or not the transition adjustment covers costs associated with RA is inconsequential as we think of the customer, as a whole, during and past the point of the transition adjustment. The basis of the 20% transition adjustment does not specify what cost categories are included; however, as stated in our cover letter for Advice Filing No. 19-02, "The charge would be applied during all years of service on Schedule 689. During the first 60 months, the Customer pays transition adjustments that include 20% of the fixed generation cost of energy supply, and a RAD charge less the amount of the transition adjustment."[71] As implied by our initial advice filing, the costs of RA may be covered by the transition adjustment; however, in the event that the transition adjustment is under-recovering costs associated with RA, COS customers would be subsidizing NLDA customers until the final determination of the RIC and RAD is made.

Q. Do any Parties agree with any of PGE's proposals regarding how load is measured against the NLDA cap?

A. Yes. Staff agrees with our position that customer loads and NLDA eligibility be tied to the distribution facility design.

C. The RIC

1. RIC Pricing and Characteristics

Q. Has PGE's recommendation and position on for the RIC charge changed?

A. No. The recycled claims of the Parties with regard to the RIC have been fully addressed in our earlier testimonies.

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[71] PGE Advice No. 19-02, at page 7.

Q. Is the RIC duplicative of the RAD?

A. No. We will not repeat the same arguments we have made in our previous testimony. However, we think it is worth noting that even if there were somehow overlap in the ability of capacity resources procured to provide RIC service, PGE's above-outlined approach for determining the RAD would avoid any double charging through the functionalization of RA related costs to determine the RAD.

Q. Does the Commission have the ability to approve the RIC?

A. Yes. Despite parties' claims, the RIC is clearly distinct from Energy Imbalance Service offered under Schedule 4R of PGE's OATT. Additionally, arguments by the parties that the RIC is related to OATT service because it uses the information conveyed on transmission schedules is unsupported.[72] These schedules contain the ESS's "projection of its hourly Electricity deliveries, measured in megawatt-hours (MWh) that are necessary to meet the aggregate hourly load of its Customers" and the ESS scheduling requirements are governed by Rule K of PGE's retail tariff, as approved by the Commission.[73]

D. Other Issues

1. NLDA Draft Contract

Q. What have Parties raised regarding the NLDA contract?

A. Staff agrees with Calpine that the NLDA customer contract ought to be reviewed and approved in this docket.[74]

Q. Does PGE agree with Staff's position?

[72] AWEC/200, Mullins/15.
[73] PGE Rule B, page B-3, section 17.
[74] Staff/300, Gibbens/13.

A. No. The proposal seems premature and would seek to advance NLDA prior to addressing foundational system reliability and customer cost-risk fairness concerns. The drafting of a NLDA customer contract requires tariff decisions to be made in this docket before the drafting and sharing of PGE's proposed NLDA contract. PGE has responded to DRs and provided Parties with the LTDA customer contract as a best faith effort. We would expect the contract approach and terms to be similar. However, there are also differences. Following the decisions from this docket, and while different from the LTDA program which did not require advance Commission approval of the contract, we have no objection to filing the draft contract for review. The LTDA customer contract, attached as an exhibit, will be used as a starting template for the proposed NLDA customer contract.[75]

2. RPS Cost Recovery

Q. Staff recommends deferring action on PGE's standard offer service proposal to a general rate case or separate investigation. Please comment.

A. PGE is required to make at least one standard offer under Oregon law.[76] The current option is a daily market option for long term DA and PGE has at least one customer participating. While a customer is on the daily market option, the pricing is a Mid-Columbia market index which does not consider RPS value or attributes. The customer is being served with a supply product that is not compliant with the RPS, and because there is no RPS cost adder charged to the standard offer service customer, the cost to comply with the RPS for that customer would be subsidized by COS customers. When PGE first designed the daily market option for the LTDA program, the RPS did not exist. PGE identified this issue when

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[75] See PGE Exhibit 305.
[76] OAR 860-038-0250 (1).

considering the NLDA program. Thus, PGE proposed the second standard offer service to provide a long term RPS compliant product to NLDA participating customers. To provide a NLDA standard offer service option and be RPS compliant, PGE proposed the new long-term market option.

Q. What would be the consequence of deferring action on the proposed standard offer service option?

A. The consequence is that PGE would be forced to choose between complying with the Oregon RPS requirements or shifting costs to shareholders and COS customers.

IV. Conclusion

Q. Please summarize PGE's recommendation for the Commission.

A. The scope of this investigation is to investigate the RIC and RAD charges, our long-term standard offer service and other policy items as raised in our advice filing for Schedule 689. The Commission can and should make a determination on the substantive issues raised in PGE's application – namely whether all customers, whether cost of service or NLDA, should have a responsibility to support resource adequacy, and to fairly share in both the benefits and costs of maintaining a reliable electric system. The Commission may make a lasting decision from this record or adopt a provisional solution while Parties participate in a broad and far-reaching DA policy docket. Irrespective of this decision, it is imperative that the Commission protect the reliability of the electric system by including mechanisms that ensure large new loads contribute toward the necessary costs of securing capacity required to meet the system's RA requirements. Any other outcome would unnecessarily threaten system reliability and unfairly burden cost of service customers with all reliability costs and risks.

List of Exhibits

PGE Exhibit	**Description**
301	Northwest Public Power Council's RAAC Steering 2024 Adequacy
302	UE 358 PGE DR 001 to Calpine Response
303	UE 358 PGE DR 003 to Staff Response
304	UE 358 PGE DR 006 to Calpine Response
305	Long Term Direct Access Template

2024 Resource Adequacy Assessment

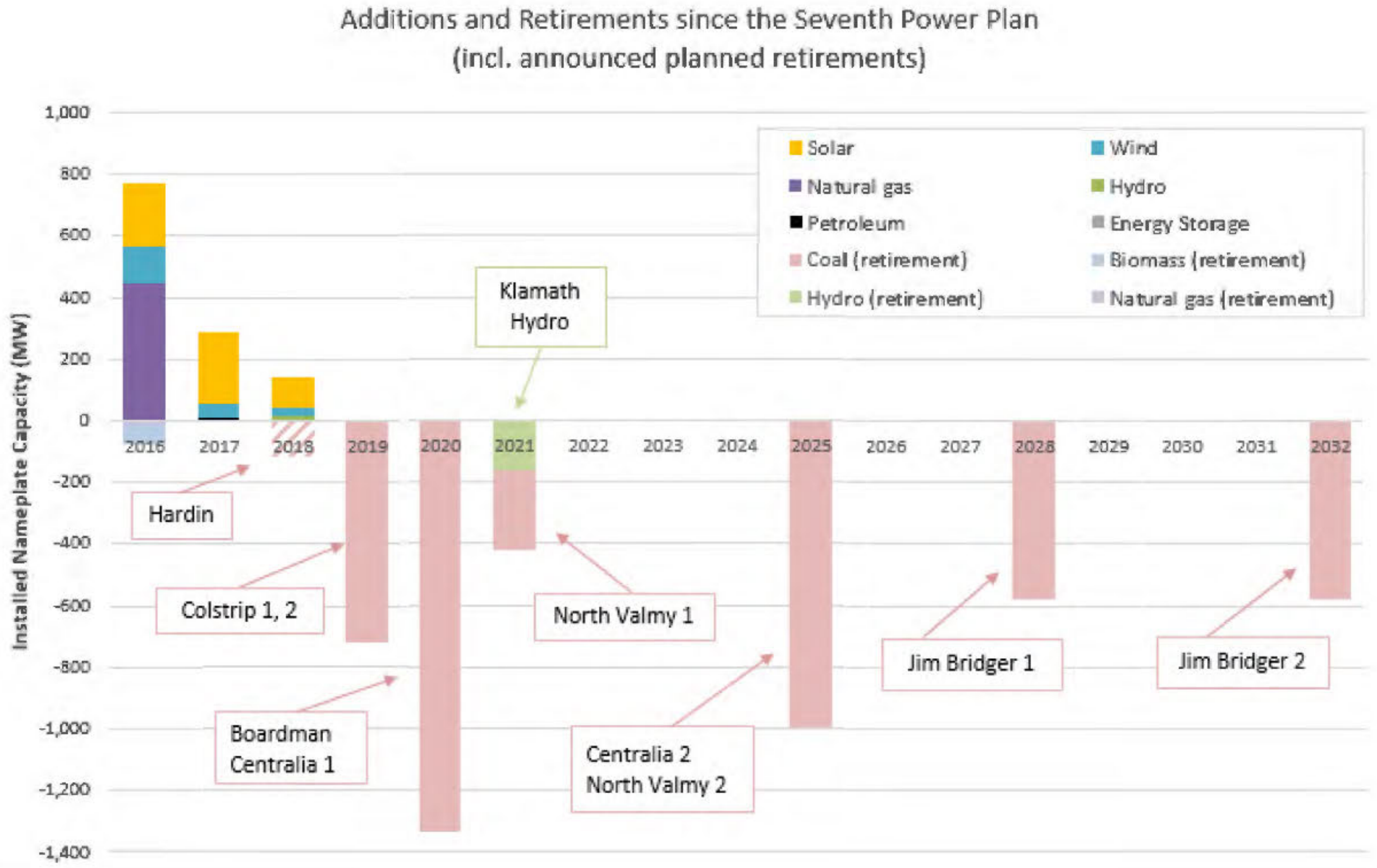
Resource Adequacy Advisory Committee
Steering Committee Meeting

NW Power and Conservation Council
August 30, 2019

Outline

- Projected Coal Retirements through 2032
- 2024 Reference and Early Coal Retirement Cases
- Classic GENESYS adequacy assessment
- Summary of enhancements in new GENESYS
- New GENESYS analyses
  - Single "bad" year dispatch comparison to classic GENESYS
  - Projections for RA assessment with new GENESYS
- Key issue – import availability

Projected Coal Retirements[1] (3,357 MW)



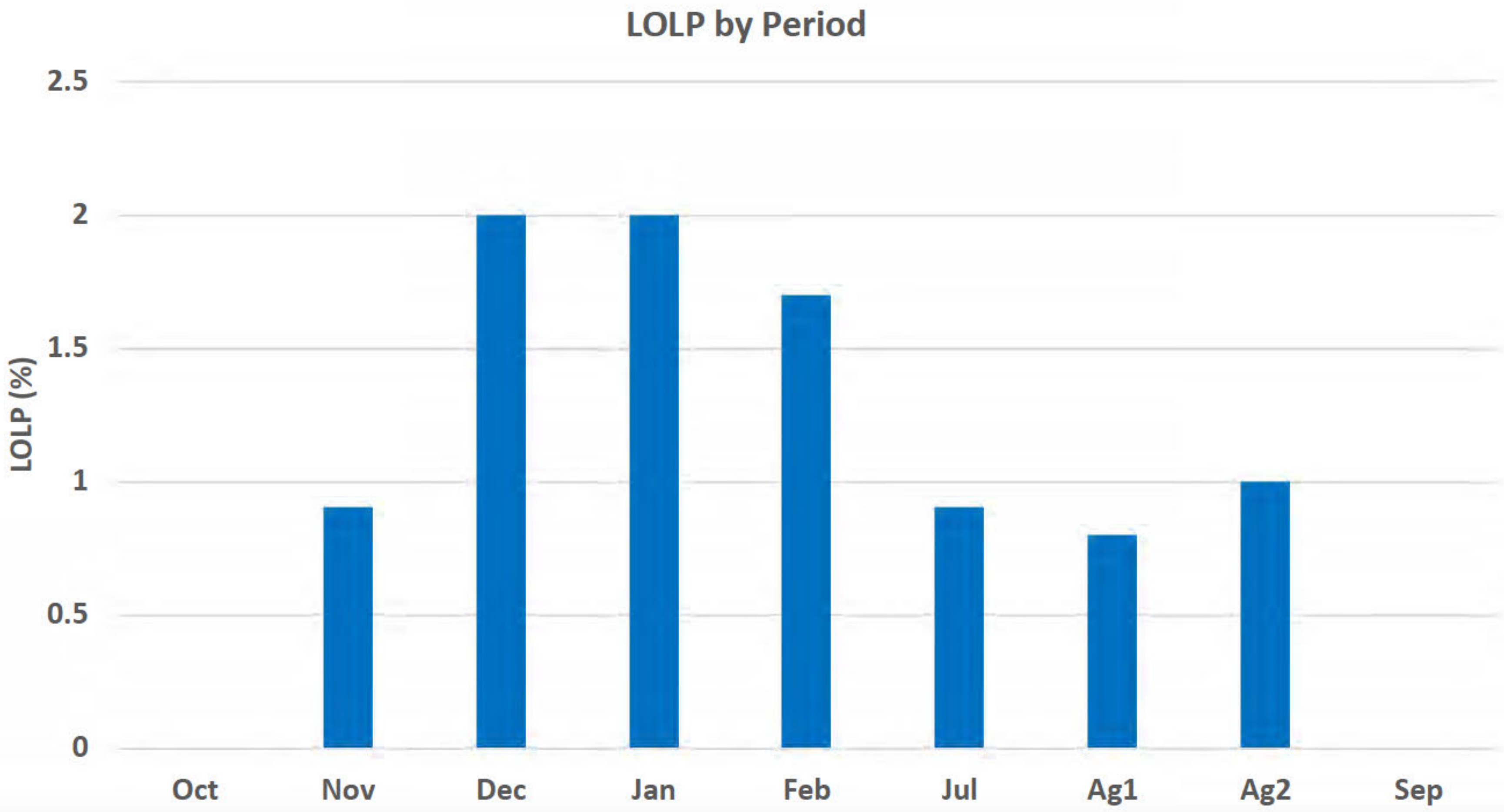
Major Coal Plants Serving PNW	Ref Retire Date (EOY)	Early Retire Date
Hardin (119 MW)	2018	2018
Colstrip 1 (154 MW)	2019	2019
Colstrip 2 (154 MW)	2019	2019
Boardman (522 MW)	2020	2020
Centralia 1 (670 MW)	2020	2020
N Valmy 1 (127 MW)	2021	2021
N Valmy 2 (134)	2025	2023
Centralia 2 (670 MW)	2025	2023
Bridger 1 (530 MW)	2028	2023
Bridger 2 (530 MW)	2032	2023
Colstrip 3 (518 MW)	TBD	TBD
Colstrip 4 (681 MW)	TBD	TBD
Bridger 3 (530 MW)	TBD	TBD
Bridger 4 (530 MW)	TBD	TBD

2021-24 Resource Adequacy Assessments

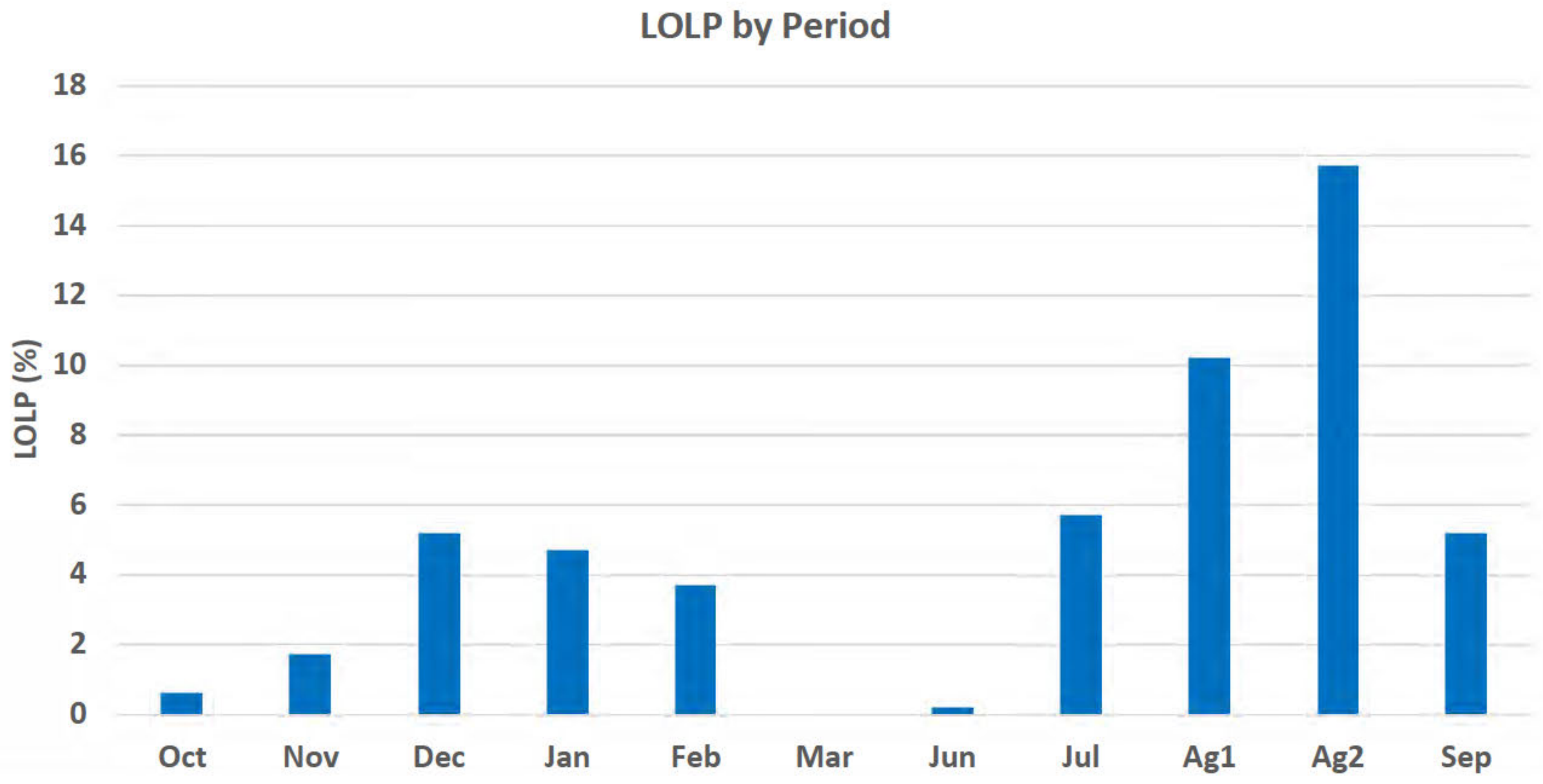
- 2021 LOLP = 7 to 8%
  1,619 MW Retired Capacity (Hardin, Colstrip 1 and 2, Boardman, Centralia 1)
- 2022 LOLP = 7 to 8%
  127 MW Retired Capacity (N Valmy 1)
- 2023 LOLP = 7 to 8%
  No coal retirements

- 2024 LOLP = 8.2% - with mostly winter shortfalls
  No coal retirements in reference case
- 2024 LOLP = 33% - with both winter and summer shortfalls
  1,853 MW Early retirement case (Centralia 2, Bridger 1 and 2, N Valmy 2)

Ref Case LOLP by Period



Early Coal Retirement LOLP by Period[1]



Future Uncertainties not Modeled Explicitly

- Out-of-region spot market supply
  - Region is connected to many other areas
  - Largest sharing between NW and SW
- Economic load growth
  - Non-temperature affected changes in long-term load
  - Economic growth or lack thereof
  - Possible immigration into region (climate change?)
  - Change in electrical use patterns (e.g. electric vehicles)

Sensitivity to Markets and Load Growth

LOLP (%)	1500	2000	2500	3000	3500	4500	5500
High Load (85th Percentile)	21.1	18.0	16.0	14.4	12.0		
Medium Load	12.5	10.2	8.2	6.9	5.2	3.8	2.9[1]
Low Load (15th Percentile)	7.0	5.2	4.0	3.1	2.0		

[1]Because classic GENESYS only has spot market available in winter, increasing imports to 5500 MW eliminates all winter shortfalls but the summer problems remain.

Sensitivity to Markets and Load Growth

Early Coal Retirement Case

LOLP (%)	2500	4500	6500	8500
High Load (85th Percentile)				
Medium Load	33.0	26.5[1]		
Low Load (15th Percentile)				

[1]The increased spot market availability did not reduce the overall LOLP much because most of the shortfalls occur in summer and the market is only available in winter.

New GENESYS Features

1. Explicit modeling of out-of-region resources and loads
2. Hourly simulation of individual hydro projects
3. Multiple NW node configuration (as opposed to 2-node)
4. Unit commitment
5. Dynamic allocation of balancing reserves
6. Forecast error effects (true-up stage)

Effects of New Features on LOLP

1. Out-of-region supply
   Will significantly lower LOLP
   Market supply increases from 2500 MW to over 8,000 MW
2. Hourly hydro simulation
   Impact unclear (may lower LOLP if classic GENESYS sustained-peaking capacity approximations are conservative)
3. Multiple NW nodes
   Likely to increase LOLP due to potential congestion issues
4. Unit commitment
   Likely to increase LOLP (unit commitment in classic GENESYS was limited)
5. Dynamic balancing reserves
   Likely to increase LOLP (classic GENESYS only modeled static hydro reserves)
6. Forecast error
   Likely to increase LOLP (if balancing reserves are properly assessed)

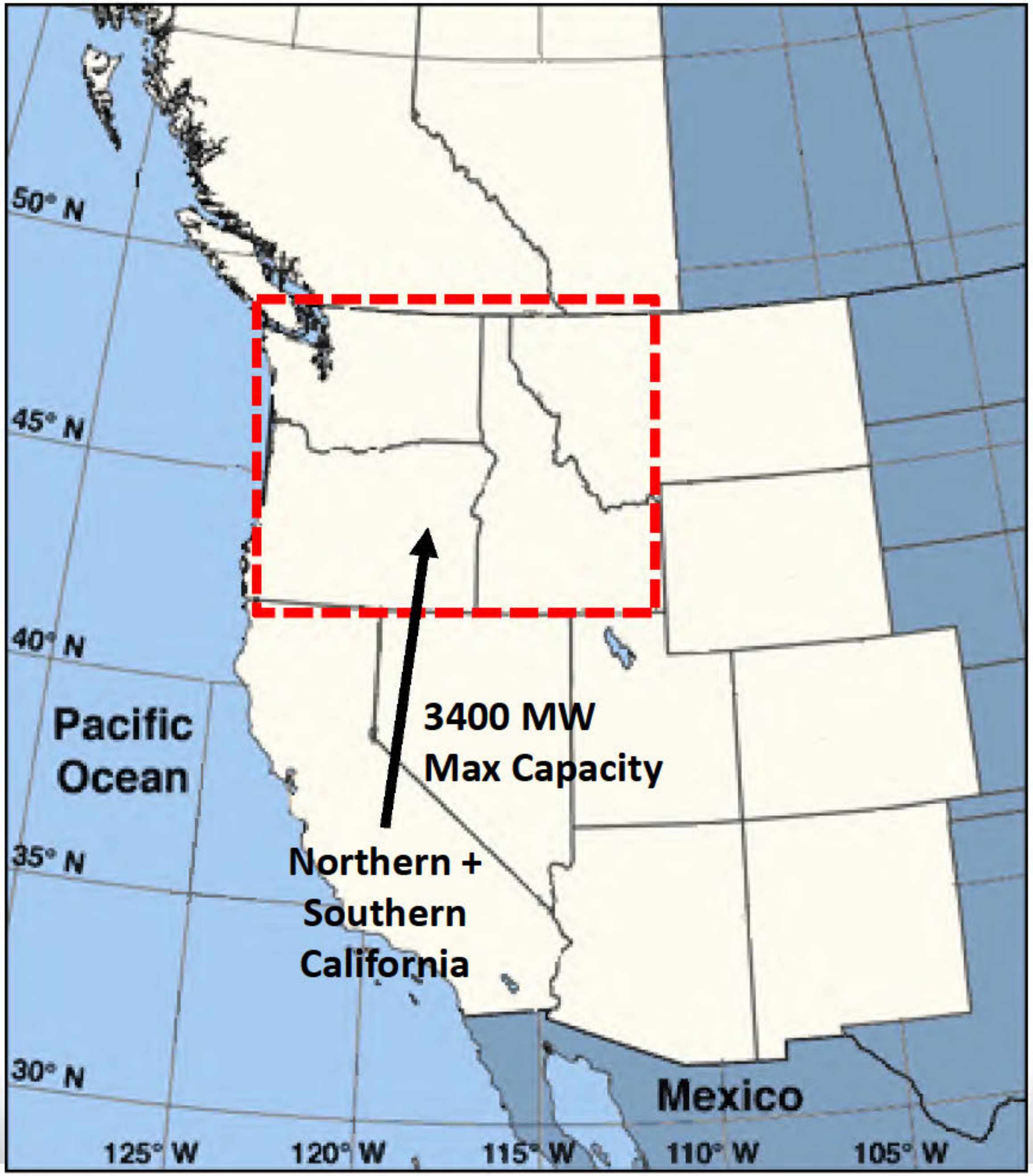
Incorporating Market Imports

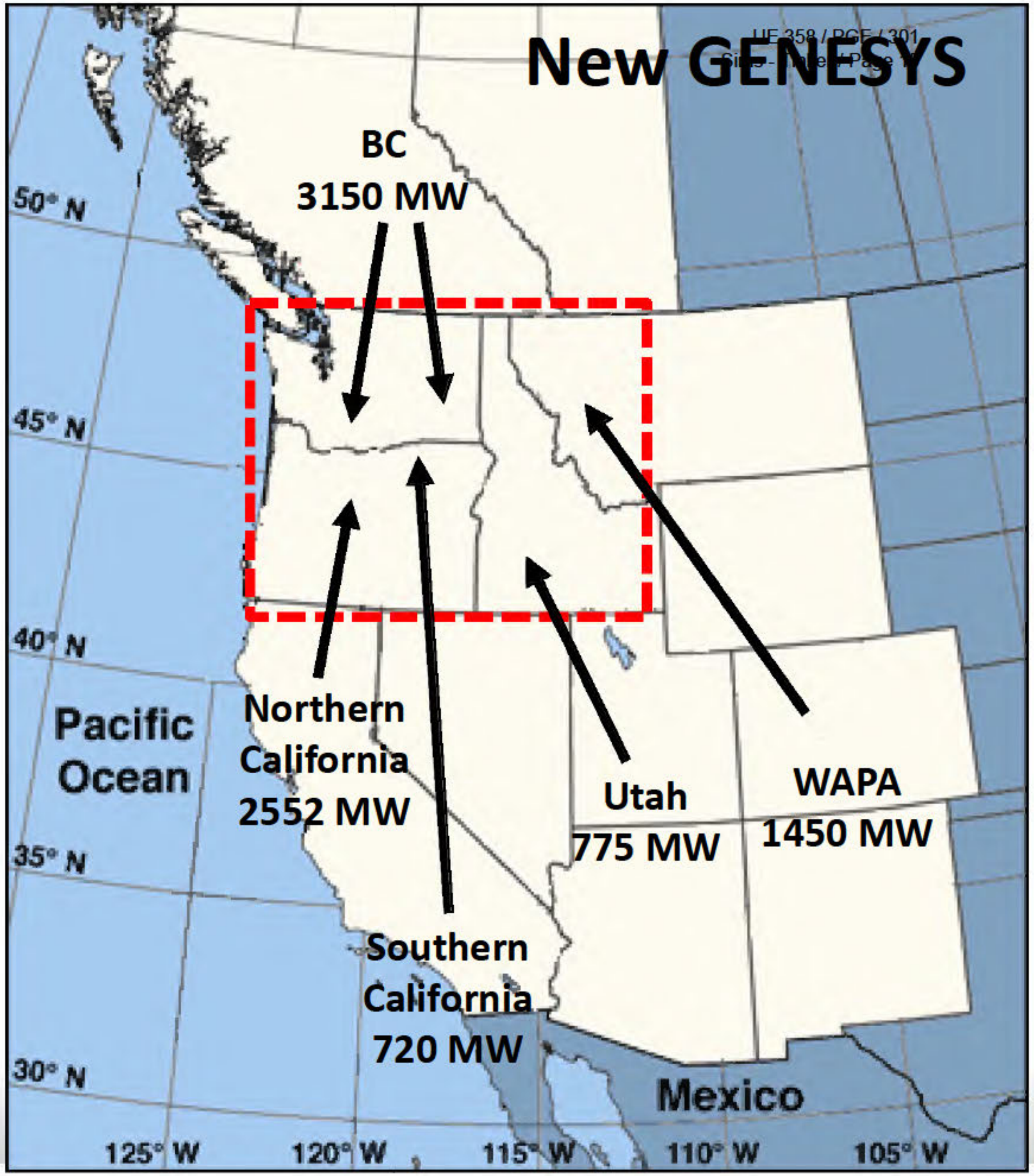
- Classic GENESYS
  - Max 2500 MW for Spot Market – during hour of need winter only
  - Max 3000 MW for Purchase Ahead – during off-peak hours ahead of future shortage
  - Max 3400 MW total import (spot + purchase ahead)
  - Only from California (as a surrogate for all imports)
  - Priced higher than any NW resource

- New GENESYS
  - Simulates dispatch of out-of-region resources & loads, dynamically assesses market size
  - From all WECC regions that have interconnections to the NW
  - Price reflective of resource type
  - Max 8600 MW total import (limited by transmission capacity)
  - Max import availability can be much higher than transmission limits
  - Availability greater in winter but some market supply in summer also

Transmission Capacity for Imports

From	To	Min Transfer Cap[1] (MW)
New GENESYS Assumptions (to potential market sources only[1])		
Northern California	Pac West	2552
LADWP	BPAOR	720
BC	PS North	2762
BC	Avista	388
WAPA	NW	1450
Pac Utah	Pac Idaho	775
Total		**8647**
Current GENESYS Assumption		
California	PNW	**3400**


50° N
45° N
40° N
35° N
30° N
Pacific Ocean
3400 MW
Max Capacity
Northern + Southern California
Mexico
125° W
120° W
115° W
110° W
105° W


New GENESYS
BC
3150 MW
50° N
45° N
40° N
35° N
30° N
Pacific Ocean
Northern California
2552 MW
Utah
775 MW
WAPA
1450 MW
Southern California
720 MW
Mexico
125° W
120° W
115° W
110° W
105° W

Classic vs. New GENESYS

Caveat: The beta version of the new model is functional and is providing reasonable early results. However, it is still in the second phase of vetting and is being refined for its hourly simulations. It is not yet at a level to confidently run full RA studies.

Test: Compare hourly simulated dispatch for the 2024 reference case using 1950 temperatures and 2001 hydro conditions (i.e. a "bad" year)

- Classic GENESY
  - 8 curtailments in Jan and Feb (highest single-hour curtailment 6400 MW)
  - Max imports 3400 MW
- New GENESYS
  - No curtailments
  - Max import up to 8650 MW

2024 Resource Adequacy Assessment

- Classic GENESYS
  - 8.2% LOLP – reference case
  - 33% LOLP – early coal retirement case

- New GENESYS[1]
  - 0% Inferred LOLP[1] – reference case
  - 0.5% Inferred LOLP[1] – early coal retirement case

[1]The New GENESYS has NOT yet been fully vetted for use to assess resource adequacy. However, we can infer what the LOLP might be by using the curtailment record from the classic GENESYS and applying a maximum of 8650 MW of imports year round.

Sensitivity to Markets and Load Growth

Early Coal Retirement Case

LOLP (%)	2500	4500	6500[1]	8500[1]
High Load (85th Percentile)				
Medium Load	33.0	26.5	0.9	0.3
Low Load (15th Percentile)				

Implied LOLP from New GENESYS is 0.5%

[1]For these scenarios, the specified import amounts were available for all months. They were designed only as a test to compare to the New GENESYS and are NOT intended to be a part of the adequacy assessment.

2024 Resource Adequacy Assessment

- Until the new GENESYS is fully vetted, the classic GENESYS model will be used for assessments
- However, the new model's simulation of out-of-region resources and loads indicates that import assumptions in the classic model may be understated
- This warrants further analysis of how much market supply, from all interconnected regions, the NW can reliably count on during conditions when resources may be scarce WECC-wide

Market Supply Assessments

- An Energy GPS report (attached) indicated that import availability may be much greater than 2500 MW but warned that "limitations on Aliso Canyon storage withdrawals will very likely limit available exports to the Pacific Northwest well below the 2,500 MW planning number."

- Records from this year's ACDC intertie loading data (attached) show that imports in some February hours were between 2500 and 3100 MW.

- Import availability from other interconnected regions has not been extensively investigated.

Proposed Action Items

1. More in-depth analysis of out-of-region market supplies from all interconnected regions is warranted
2. Analyses of transmission transfer capabilities and reliability is also warranted
3. Continue to vet the new GENESYS
4. Add the ability to limit imports in the new GENESYS
5. Base the 2024 Resource Adequacy Assessment on the classic GENESYS model results
6. Others?

Portland General Electric Data Request No. 01:

Does Calpine Energy Solutions, LLC conduct long-term resource planning for the contracted loads it serves? If yes, please provide copies of the last five years of resource plans. If no, please explain why Calpine Energy Solutions, LLC does not conduct long-term resource planning.

Calpine Energy Solutions, LLC's Response:

Calpine Energy Solutions, LLC ("Calpine Solutions") objects with respect to the request to supply "copies of the last five years of resource plans" to Portland General Electric Company ("PGE") on the grounds of commercial harm that could be caused by providing such information to PGE. PGE has significant market power in the region and Calpine Solutions is a direct competitor with PGE in the retail generation market. As an electricity service supplier, Calpine Solutions' market positions, as well as its strategies to serve its contracted and expected loads are highly commercially sensitive information, and disclosure of this information to PGE could cause significant commercial harm to Calpine Solutions.

Without waiving its objection, Calpine Solutions currently conducts regular long-term supply planning associated with compliance for the State of Oregon's Renewable Portfolio Standard ("RPS") and for risk management purposes. The overall approach is to identify supply and load imbalances associated with both known customer contracted load, as well as forecasted customer load and the timeframe and amount of future supply and load imbalances. The commercial and regulatory supply obligations are currently analyzed through the year 2027.

Attached as Exhibit DR 01 is an illustrative example of Calpine Energy Solutions, LLC's RPS Position Summary used for RPS compliance planning purposes, which demonstrates the type of data and information that Calpine Solutions includes in its long-term supply planning, without providing any actual data that could harm Calpine Solutions' commercial position if disclosed to PGE.

Date: August 1, 2019

TO:
KARLA WENZEL
MANAGER, PRICING AND TARIFFS
121 SW SALMON ST, 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com;

FROM: Scott Gibbens
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 358 - PGE Data Request filed July 18, 2019

Data Request No 03:

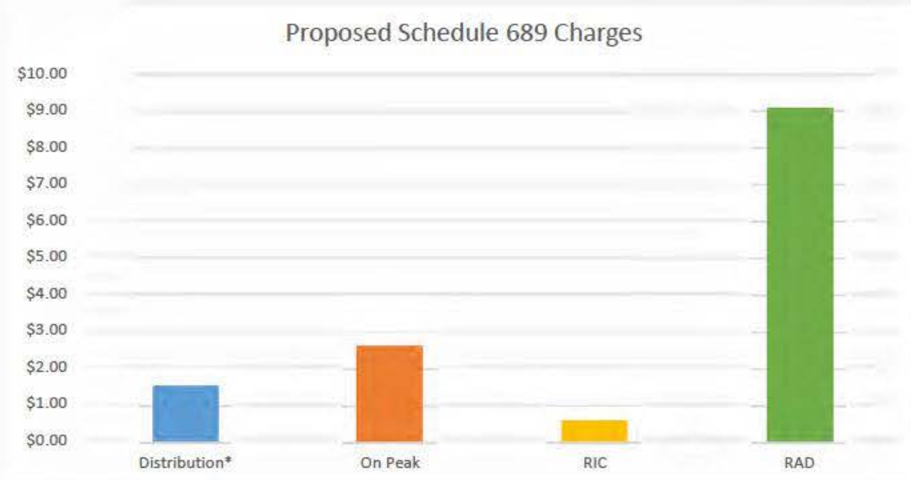
3. See Gibbens/14, line 11: Please provide the price impact analysis which shows the impacts to "direct access rates"

Staff Response No 03:

3. Please see attachment Staff Response to PGE DR No. 3A.

Schedule	489/689	
	Secondary	Primary
Distribution*	$1.53	$1.49
On Peak	$2.61	$2.53
RIC	$0.58	$0.58
RAD	$9.08	$9.08
Total	$13.80	$13.68
RAD%	66%	66%

*First 4000 kW



				Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
Customers - Three Phase				15	15	15	15	15	15	15	15	15	15	15	15	180	
Energy (MWh)																	
	On-Peak			42451.997	41455.874	41140.361	42069.71	42469.611	43450.973	46134.115	47949.039	48625.893	45479.264	42834.757	42810.908	526872.502	
	Off-Peak			30711.67	30352.79	29507.487	28803.18	30616.787	31234.449	32396.3	34412.277	33424.625	32009.412	30702.02	31127.206	375298.203	
Facility Capacity (kW)																	
	First 1,000 kW			14200	14200	14200	14200	14200	14200	14200	14200	14200	14200	14200	14200	170400	
	1,001-4,000 kW			47094	47094	47094	47094	47094	47094	47094	47094	47094	47094	47094	47094	565128	1651714
	Over 4,000 kW			74060	75293	76648	75670	75676	74856	77400	78353	77892	77946	76961	75431	916186	
Demand (kW)																	
	On-peak			111692	112611	115183	119714	121187	125313	132495	136040	135934	133363	122624	114808	1480964	
	Off-peak increment																
Reactive Demand (kVar)				18234	16936	18358	17487	17701	18810	21249	25817	22033	20750	18422	17612	233409	
Calendar Energy (MWh)				71237.851	71895.937	70054.265	75157.763	71263.576	79745.56	80805.937	84756.447	79658.198	76437.246	71285.523	71043.382	903341.685	
RAD Charge		9.08		$1,014,163	$1,022,508	$1,045,862	$1,087,003	$1,100,378	$1,137,842	$1,203,055	$1,235,243	$1,234,281	$1,210,936	$1,113,426	$1,042,457	$13,447,153	
Per Customer				$67,610.89	$68,167.19	$69,724.11	$72,466.87	$73,358.53	$75,856.14	$80,203.64	$82,349.55	$82,285.38	$80,729.07	$74,228.39	$69,497.11	$896,476.87	
PGE LOLE Goal:	1 day/10 yrs		1														
LTDA LOLE Incremental Delta:	8 day/10 yrs		8														
Total Cost/10 year		$8,964,768.75															
Reliability/ incremental day		$1,280,681.25															

Row	Schedule	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
7	**Schedule 485S 201-4,000 kW V2003**													
8	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Customers - Three Phase	2	2	2	2	2	2	2	2	2	2	2	2	24
10	Energy (MWh)													
11	On-Peak	556	666	602	577	561	546	647	680	700	638	582	534	7,290
12	Off-Peak	354	391	364	353	341	339	382	406	451	376	341	342	4,440
13	Facility Capacity (kW)													
14	First 200 kW	400	400	400	400	400	400	400	400	400	400	400	400	4,800
15	Over 200 kW	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	20,016
16	Demand (kW)													
17	On-Peak	1,759	1,925	1,828	1,812	1,918	1,886	1,955	2,072	2,034	1,956	1,732	1,684	22,561
18	Off-Peak Increment	34	0	0	0	0	0	0	0	0	0	0	0	34
19	Reactive Demand (kVar)	431	514	462	465	472	501	503	535	554	549	455	476	5,917
20	Calendar Energy (MWh)	853	963	964	921	974	869	1,109	1,103	1,040	1,066	979	882	11,722
22	**Schedule 485S 201-4,000 kW V2010**													
23	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Customers - Three Phase	8	8	8	8	8	8	8	8	8	8	8	8	96
25	Energy (MWh)													
26	On-Peak	1,525	1,569	1,576	1,514	1,490	1,577	1,570	1,544	1,653	1,521	1,540	1,649	18,727
27	Off-Peak	1,060	1,137	1,093	1,063	1,032	1,134	1,096	1,064	1,132	1,066	1,079	1,161	13,117
28	Facility Capacity (kW)													
29	First 200 kW	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	19,200
30	Over 200 kW	4,446	4,637	4,739	4,597	4,472	4,497	4,722	4,855	4,817	4,700	4,792	4,339	55,613
31	Demand (kW)													
32	On-Peak	4,752	4,911	4,990	4,871	4,747	4,801	4,977	5,079	5,055	4,939	4,957	4,662	58,741
33	Off-Peak Increment	9	1	1	9	36	2	3	6	0	25	77	17	186
34	Reactive Demand (kVar)	617	557	592	641	596	628	608	571	537	554	484	490	6,875
35	Calendar Energy (MWh)	2,422	2,465	2,664	2,552	2,721	2,660	2,873	2,649	2,517	2,719	2,780	2,827	31,848
37	**Schedule 485S 201-4,000 kW V2011**													
38	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0
39	Customers - Three Phase	8	8	8	8	8	8	8	8	8	8	8	8	96
40	Energy (MWh)													
41	On-Peak	2,071	2,085	1,980	1,939	1,897	1,907	2,096	2,084	2,138	1,906	1,853	1,806	23,763
42	Off-Peak	1,141	1,108	1,064	976	993	1,062	1,127	1,120	1,150	1,016	1,022	1,010	12,789
43	Facility Capacity (kW)													
44	First 200 kW	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	19,200
45	Over 200 kW	6,030	6,194	6 239	6,404	6,572	7,052	7,153	7,290	7,494	6,760	5,767	5,416	78,371
46	Demand (kW)													
47	On-Peak	5,958	6,052	6,117	6,254	6,385	6,753	6,835	6,949	7,109	6,531	5,753	5,477	76,173
48	Off-Peak Increment	3	36	7	0	0	10	7	0	0	0	0	0	63
49	Reactive Demand (kVar)	69	62	77	332	485	584	581	688	636	477	185	104	4,280
50	Calendar Energy (MWh)	3,009	2,909	3,039	2,887	3,118	2,914	3,473	3,253	2,972	3,070	3,051	2,833	36,530
52	**Schedule 485S 201-4,000 kW V2012**													
53	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0
54	Customers - Three Phase	99	99	99	99	99	99	99	99	99	99	99	99	1,188
55	Energy (MWh)													
56	On-Peak	10,452	9,807	9,873	9,490	9,492	9,999	10,303	10,752	11,090	9,669	9,583	10,168	120,679
57	Off-Peak	6,182	5,671	5,603	5,238	5,251	5,617	5,596	5,797	6,022	5,298	5,387	5,968	67,630
58	Facility Capacity (kW)													
59	First 200 kW	19,800	19,800	19,800	19,800	19,800	19,800	19,800	19,800	19,800	19,800	19,800	19,800	237,600
60	Over 200 kW	23,196	24,369	24,194	25,564	24,351	27,829	25,820	29,108	30,309	24,817	21,826	22,113	303,496
61	Demand (kW)													
62	On-Peak	33,091	34,067	33,750	35,274	34,356	36,803	35,579	37,966	39,191	34,812	32,373	32,747	420,009
63	Off-Peak Increment	430	375	540	232	205	452	119	279	4	111	233	85	3,065
64	Reactive Demand (kVar)	937	1,316	1,490	2,132	2,652	3,329	3,162	3,244	3,421	2,712	1,686	1,147	27,228
65	Calendar Energy (MWh)	15,583	14,097	15,451	14,585	15,909	15,325	17,136	16,805	15,464	15,727	15,892	16,236	188,210
67	**Schedule 485S 201-4,000 kW V2013**													
68	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0
69	Customers - Three Phase	32	32	32	32	32	32	32	32	32	32	32	32	384
70	Energy (MWh)													
71	On-Peak	5,023	5,063	4,942	4,806	5,009	5,030	5,272	5,596	5,779	5,105	4,724	4,697	61,046
72	Off-Peak	3,284	3,181	3,139	2,984	3,161	3,044	3,248	3,432	3,443	3,112	2,883	2,989	37,901
73	Facility Capacity (kW)													
74	First 200 kW	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	76,800
75	Over 200 kW	12,071	12,956	13,496	13,639	15,139	14,565	15,421	16,615	17,135	14,392	12,817	12,011	170,257
76	Demand (kW)													
77	On-Peak	14,341	14,969	15,614	15,704	16,796	16,389	17,053	18,027	18,444	16,317	15,043	14,339	193,036
78	Off-Peak Increment	16	75	5	27	98	61	65	14	3	0	52	127	543
79	Reactive Demand (kVar)	475	499	689	848	967	1,161	1,117	1,198	1,173	892	723	547	10,289
80	Calendar Energy (MWh)	7,782	7,508	8,067	7,715	8,816	7,924	9,184	9,168	8,334	8,635	8,074	7,734	98,941
82	**Schedule 485S 201-4,000 kW V2014**													
83	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0
84	Customers - Three Phase	3	3	3	3	3	3	3	3	3	3	3	3	36
85	Energy (MWh)													
86	On-Peak	409	502	553	580	418	568	528	682	706	717	735	591	6,989
87	Off-Peak	291	338	390	433	300	411	371	485	496	467	531	411	4,923
88	Facility Capacity (kW)													
89	First 200 kW	600	600	600	600	600	600	600	600	600	600	600	600	7,200
90	Over 200 kW	2,430	2,317	1,619	1,581	1,459	1,604	1,935	2,318	2,274	2,847	2,414	2,137	24,935
91	Demand (kW)													
92	On-Peak	2,488	2,411	1 878	1,823	1,728	1,857	2,132	2,442	2,394	2,866	2,497	2,255	26,771
93	Off-Peak Increment	15	8	0	0	0	0	20	17	0	2	20	10	92
94	Reactive Demand (kVar)	439	383	332	281	302	359	456	498	610	732	588	492	5,472
95	Calendar Energy (MWh)	656	764	942	1,003	775	960	969	1,185	1,086	1,244	1,344	1,008	11,936
97	**Schedule 485S 201-4,000 kW V2015**													
98	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0
99	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12
100	Energy (MWh)													
101	On-Peak	238	247	274	228	220	242	274	261	280	281	274	256	3,073
102	Off-Peak	130	142	158	122	123	133	163	142	154	170	155	144	1,736
103	Facility Capacity (kW)													
104	First 200 kW	200	200	200	200	200	200	200	200	200	200	200	200	2,400
105	Over 200 kW	732	757	780	745	723	721	741	762	752	743	741	713	8,910
106	Demand (kW)													
107	On-Peak	813	864	884	849	851	903	910	961	952	909	907	820	10,623
108	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0
109	Reactive Demand (kVar)	242	237	227	249	207	212	215	222	227	206	235	243	2,722

	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
110	Calendar Energy (MWh)	344	353	431	347	370	368	471	410	392	474	455	403	4,817		
111																
112	**Schedule 485S 201-4,000 kW V2016**															
113	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0		
114	Customers - Three Phase	7	7	7	7	7	7	7	7	7	7	7	7	84		
115	Energy (MWh)															
116	On-Peak	654	628	629	617	616	659	678	726	726	651	628	633	7,845		
117	Off-Peak	423	404	397	392	387	412	422	453	455	413	407	408	4,974		
118	Facility Capacity (kW)															
119	First 200 kW	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	16,800		
120	Over 200 kW	828	888	943	858	807	801	849	900	875	855	849	783	10,236		
121	Demand (kW)															
122	On-Peak	1,785	1,775	1 814	1,812	1,870	1,938	2,142	2,274	2,207	1,900	1,845	1,725	23,087		
123	Off-Peak Increment	0	6	5	5	0	40	20	0	0	0	0	0	76		
124	Reactive Demand (kVar)	10	33	36	45	52	61	65	58	57	74	51	45	587		
125	Calendar Energy (MWh)	1,009	940	1,024	1,000	1,082	1,051	1,186	1,198	1,067	1,119	1,099	1,047	12,821		
126																
127	**Schedule 485S 201-4,000 kW V2017**															
128	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0		
129	Customers - Three Phase	38	38	38	38	38	38	38	38	38	38	38	38	456		
130	Energy (MWh)															
131	On-Peak	5,480	5,400	5,327	5,145	5,120	5,238	5,458	5,608	5,857	5,505	5,269	5,364	64,771		
132	Off-Peak	3,292	3,226	3,173	3,057	3,110	3,078	3,217	3,332	3,470	3,308	3,236	3,371	38,869		
133	Facility Capacity (kW)															
134	First 200 kW	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	91,200		
135	Over 200 kW	12,574	12,916	13,522	13,425	13,003	13,577	14,248	14,974	15,417	13,919	12,474	12,232	162,281		
136	Demand (kW)															
137	On-Peak	15,072	15,373	15,807	15,707	15,462	15,862	16,300	16,856	17,186	16,210	15,138	15,003	189,976		
138	Off-Peak Increment	649	616	657	679	746	790	878	887	897	714	664	615	8,792		
139	Reactive Demand (kVar)	236	333	295	324	486	482	623	555	662	630	419	365	5,410		
140	Calendar Energy (MWh)	8,217	7,856	8,486	8,122	8,881	8,161	9,350	9,079	8,428	9,260	9,028	8,789	103,659		
141																
142	**Schedule 485S 201-4,000 kW V2018**															
143	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0		
144	Customers - Three Phase	27	27	27	27	27	27	27	27	27	27	27	27	324		
145	Energy (MWh)															
146	On-Peak	3,302	3,066	3,159	3,069	3,176	3,426	3,485	3,592	3,739	3,307	3,221	3,301	39,844		
147	Off-Peak	2,152	1,945	1,986	1,952	1,968	2,162	2,148	2,155	2,264	2,032	2,021	2,058	24,843		
148	Facility Capacity (kW)															
149	First 200 kW	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	5,400	64,800		
150	Over 200 kW	7,889	7,954	8,523	8,708	9,174	9,758	10,264	10,861	11,451	9,480	8,070	8,190	110,322		
151	Demand (kW)															
152	On-Peak	10,234	10,323	10,740	10,921	11,289	11,733	12,114	12,592	13,045	11,526	10,434	10,491	135,442		
153	Off-Peak Increment	59	21	44	7	0	8	20	4	8	0	0	36	207		
154	Reactive Demand (kVar)	902	909	906	1,139	1,159	1,284	1,320	1,365	1,371	1,223	980	869	13,427		
155	Calendar Energy (MWh)	5,110	4,564	5,137	4,972	5,551	5,484	6,071	5,836	5,425	5,611	5,565	5,392	64,716		
156																
157	**Schedule 489S GT 4,000 kW V2014**															
158	Customers - Single Phase	0	0	0	0	0	0	0	0	0	0	0	0	0		
159	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12		
160	Energy (MWh)															
161	On-Peak	243	171	150	150	143	350	1,173	2,334	1,974	1,214	695	266	8,863	13,399	
162	Off-Peak	97	89	95	86	85	192	704	1,309	971	558	263	87	4,536	1.954001	
163	Facility Capacity (kW)															
164	First 1,000 kW	1,000	1,000	1 000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000		
165	1,000 kW to 4,000 kW	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000	96,918	8076.5
166	Over 4,000 kW	3,987	4,202	4,398	4,095	3,911	3,889	4,061	4,247	4,156	4,085	4,062	3,825	48,918		
167	Demand (kW)															
168	On-Peak	1,545	1,348	508	592	921	3,388	7,005	8,139	8,262	7,484	4,210	2,536	45,938	3,828	2.109757
169	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	70	0	70		
170	Reactive Demand (kVar)	0	0	0	0	0	444	2,314	2,672	2,655	2,068	1,091	137	11,381		
171	Calendar Energy (MWh)	318	237	244	234	247	531	2,023	3,700	2,661	1,862	1,017	355	13,429		
172																
173	**Schedule 485P 201-4,000 kW V2010**															
174	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12		
175	Energy (MWh)															
176	On-Peak	1,092	1,126	1,124	1,102	1,099	1,198	1,215	1,234	1,222	1,275	1,093	1,195	13,975		
177	Off-Peak	697	758	699	692	686	786	751	781	769	846	684	790	8,938		
178	Facility Capacity (kW)															
179	First 200 kW	200	200	200	200	200	200	200	200	200	200	200	200	2,400		
180	Over 200 kW	3,516	3,516	3 516	3,516	3,516	3,516	3,516	3,516	3,516	3,516	3,516	3,516	42,192		
181	Demand (kW)															
182	On-Peak	3,271	3,409	3,582	3,327	3,380	3,364	3,679	3,700	3,732	3,590	3,374	3,277	41,685		
183	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0		
184	Reactive Demand (kVar)	899	826	844	843	902	952	995	1,121	1,009	958	846	787	10,982		
185	Calendar Energy (MWh)	1,700	1,932	1,770	1,987	1,649	2,244	2,072	2,085	1,932	2,145	1,628	1,758	22,900		
186																
187	**Schedule 485P 201-4,000 kW V2011**															
188	Customers - Three Phase	0	0	0	0	0	0	0	0	0	0	0	0	0		
189	Energy (MWh)															
190	On-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0		
191	Off-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0		
192	Facility Capacity (kW)															
193	First 200 kW	0	0	0	0	0	0	0	0	0	0	0	0	0		
194	Over 200 kW	0	0	0	0	0	0	0	0	0	0	0	0	0		
195	Demand (kW)															
196	On-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0		
197	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0		
198	Reactive Demand (kVar)	0	0	0	0	0	0	0	0	0	0	0	0	0		
199	Calendar Energy (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0		
200																
201	**Schedule 485P 201-4,000 kW V2012**															
202	Customers - Three Phase	6	6	6	6	6	6	6	6	6	6	6	6	72		
203	Energy (MWh)															
204	On-Peak	2,291	2,246	2 222	2,257	2,294	2,412	2,551	2,597	2,618	2,227	2,045	2,023	27,782		
205	Off-Peak	1,366	1,332	1 270	1,281	1,274	1,424	1,476	1,463	1,543	1,236	1,175	1,206	16,045		
206	Facility Capacity (kW)															
207	First 200 kW	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	14,400		
208	Over 200 kW	7,346	7,740	7,636	8,656	8,347	8,666	9,014	9,156	8,992	8,184	7,425	6,506	97,668		
209	Demand (kW)															
210	On-Peak	6,982	7,304	7,219	8,052	7,800	7,987	8,344	8,461	8,328	7,667	7,048	6,295	91,487		
211	Off-Peak Increment	0	0	0	0	0	73	0	0	0	0	0	0	73		
212	Reactive Demand (kVar)	54	58	86	203	246	219	305	280	259	192	134	50	2,086		
213	Calendar Energy (MWh)	3,476	3,669	3,391	3,919	3,297	4,338	4,244	4,200	4,037	3,502	2,949	2,859	43,881		
214																
215	**Schedule 485P 201-4,000 kW V2013**															
216	Customers - Three Phase	31	31	31	31	31	31	31	31	31	31	31	31	372		
217	Energy (MWh)															
218	On-Peak	7,583	7,360	7,310	7,306	7,604	7,902	8,365	8,814	8,446	7,530	6,994	7,138	92,349		
219	Off-Peak	4,497	4,206	4,240	4,130	4,357	4,584	4,833	5,041	4,804	4,475	4,120	4,239	53,525		
220	Facility Capacity (kW)															
221	First 200 kW	6,200	6,200	6 200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	74,400		

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ
222	Over 200 kW	23,057	23,594	23,764	26,524	27,461	28,924	30,325	31,581	28,949	25,422	21,337	20,305	311,243																			
223	Demand (kW)																																
224	On-Peak	23,873	24,327	24,472	26,736	27,502	28,586	29,162	30,863	28,716	25,835	22,497	21,373	313,942																			
225	Off-Peak Increment	31	15	9	0	0	110	679	4	0	0	0	281	1,129																			
226	Reactive Demand (kVar)	3,749	4,057	3,993	4,362	4,669	4,362	4,435	4,572	3,915	3,658	3,001	2,625	47,398																			
227	Calendar Energy (MWh)	11,482	11,861	11,214	12,668	11,051	14,123	13,911	14,331	12,855	12,140	10,178	10,076	145,888																			
228																																	
229	**Schedule 485P 201-4,000 kW V2014**																																
230	Customers - Three Phase	2	2	2	2	2	2	2	2	2	2	2	2	24																			
231	Energy (MWh)																																
232	On-Peak	384	424	436	431	485	451	513	505	499	496	462	440	5,526																			
233	Off-Peak	251	277	310	317	356	329	399	373	346	342	312	279	3,890																			
234	Facility Capacity (kW)																																
235	First 200 kW	400	400	400	400	400	400	400	400	400	400	400	400	4,800																			
236	Over 200 kW	1,031	1,227	1,232	1,305	1,343	1,201	1,318	1,391	1,423	1,376	1,302	1,235	15,384																			
237	Demand (kW)																																
238	On-Peak	1,169	1,329	1,333	1,393	1,424	1,308	1,404	1,463	1,490	1,451	1,390	1,336	16,490																			
239	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0																			
240	Reactive Demand (kVar)	223	225	252	218	276	230	226	211	260	226	220	216	2,783																			
241	Calendar Energy (MWh)	604	720	724	828	777	882	961	907	820	847	709	636	9,416																			
242																																	
243	**Schedule 485P 201-4,000 kW V2015**																																
244	Customers - Three Phase	2	2	2	2	2	2	2	2	2	2	2	2	24																			
245	Energy (MWh)																																
246	On-Peak	1,534	1,734	1,639	1,520	1,562	1,561	1,923	1,870	1,959	1,888	1,785	1,627	20,603																			
247	Off-Peak	1,026	1,046	1,017	961	933	946	1,149	1,150	1,173	1,163	1,068	1,042	12,671																			
248	Facility Capacity (kW)																																
249	First 200 kW	400	400	400	400	400	400	400	400	400	400	400	400	4,800																			
250	Over 200 kW	5,660	5,778	5 893	5,652	5,633	5,505	5,799	5,946	5,848	5,868	5,714	5,507	68,803																			
251	Demand (kW)																																
252	On-peak	5,460	5,601	5,688	5,498	5,791	5,670	6,091	6,409	6,145	6,036	5,871	5,501	69,761																			
253	Off-peak increment	0	0	0	0	0	0	0	0	13	0	0	10	23																			
254	Reactive Demand (kVar)	674	642	720	590	655	685	789	774	836	777	744	699	8,585																			
255	Calendar Energy (MWh)	2,434	2,851	2,578	2,748	2,305	2,835	3,238	3,125	3,038	3,085	2,613	2,364	33,213																			
256																																	
257	**Schedule 485P 201-4,000 kW V2016**																																
258	Customers - Three Phase	0	0	0	0	0	0	0	0	0	0	0	0	0																			
259	Energy (MWh)																																
260	On-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0																			
261	Off-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0																			
262	Facility Capacity (kW)																																
263	First 200 kW	0	0	0	0	0	0	0	0	0	0	0	0	0																			
264	Over 200 kW	0	0	0	0	0	0	0	0	0	0	0	0	0																			
265	Demand (kW)																																
266	On-peak	0	0	0	0	0	0	0	0	0	0	0	0	0																			
267	Off-peak increment	0	0	0	0	0	0	0	0	0	0	0	0	0																			
268	Reactive Demand (kVar)	0	0	0	0	0	0	0	0	0	0	0	0	0																			
269	Calendar Energy (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0																			
270																																	
271	**Schedule 485P 201-4,000 kW V2017**																																
272	Customers - Three Phase	8	8	8	8	8	8	8	8	8	8	8	8	96																			
273	Energy (MWh)																																
274	On-Peak	1,872	1,982	2,049	2,101	2,238	2,289	2,747	3,003	2,956	2,885	2,671	2,758	29,552																			
275	Off-Peak	1,283	1,332	1 397	1,468	1,522	1,526	1,890	2,067	1,997	2,017	1,903	1,914	20,318																			
276	Facility Capacity (kW)																																
277	First 200 kW	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	19,200																			
278	Over 200 kW	6,234	5,995	6,013	7,742	6,644	7,579	8,668	9,990	10,229	9,149	7,913	7,788	93,944																			
279	Demand (kW)																																
280	On-peak	6,401	6,198	6,201	7,633	6,736	7,499	8,390	9,468	9,665	8,743	7,772	7,671	92,377																			
281	Off-peak increment	0	7	19	0	0	0	0	0	0	40	0	0	66																			
282	Reactive Demand (kVar)	995	1,093	1,169	944	939	1,207	1,233	1,278	1,324	1,203	980	834	13,199																			
283	Calendar Energy (MWh)	2,999	3,399	3,346	3,954	3,474	4,315	4,888	5,245	4,806	4,958	4,189	4,138	49,711																			
284																																	
285	**Schedule 485P 201-4,000 kW V2018**																																
286	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12																			
287	Energy (MWh)																																
288	On-Peak	560	514	515	514	557	565	613	672	636	554	529	555	6,783																			
289	Off-Peak	381	334	339	329	372	357	380	442	385	352	335	375	4,380																			
290	Facility Capacity (kW)																																
291	First 200 kW	200	200	200	200	200	200	200	200	200	200	200	200	2,400																			
292	Over 200 kW	1,826	1,826	1 826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	21,912																			
293	Demand (kW)																																
294	On-peak	1,468	1,479	1,487	1,706	1,742	1,936	1,972	2,057	1,995	1,775	1,556	1,416	20,589																			
295	Off-peak increment	0	0	0	0	0	0	0	0	0	0	0	0	0																			
296	Reactive Demand (kVar)	0	0	0	0	0	0	0	0	0	0	0	0	0																			
297	Calendar Energy (MWh)	895	869	829	934	858	1,044	1,046	1,152	991	916	791	823	11,148																			
298																																	
299	**Schedule 489P GT 4,000 kW V2004**																																
300	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12																			
301	Energy (MWh)																																
302	On-Peak	3,588	3,533	3,519	3,699	3,872	3,846	3,969	3,966	4,122	3,815	3,621	3,756	45,306																			
303	Off-Peak	2,352	2,315	2,442	2,380	2,492	2,361	2,695	2,494	2,571	2,534	2,339	2,395	29,371																			
304	Facility Capacity (kW)																																
305	First 1,000 kW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000																			
306	1,001-4,000 kW	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000	139,596	11633																	
307	Over 4,000 kW	7,633	7,633	7,633	7,633	7,633	7,633	7,633	7,633	7,633	7,633	7,633	7,633	91,596																			
308	Demand (kW)																																
309	On-peak	11,148	9,938	9,646	10,595	11,746	11,313	11,220	11,828	11,952	10,608	10,266	10,591	130,851	10,904	0.937355																	
310	Off-peak increment	0	0	0	0	0	0	0	0	0	0	0	0	0																			
311	Reactive Demand (kVar)	3,503	2,980	2,973	3,250	3,364	3,216	3,203	3,251	3,383	3,119	3,384	3,225	38,851																			
312	Calendar Energy (MWh)	5,848	5,961	6,079	6,364	6,208	6,664	6,460	6,693	6,349	5,961	6,151	5,940	74,678																			
313																																	
314	**Schedule 489P GT 4,000 kW V2010**																																
315	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12																			
316	Energy (MWh)																																
317	On-Peak	3,246	3,395	3,274	3,299	3,127	3,558	3,518	3,505	3,532	3,635	3,369	3,485	40,944																			
318	Off-Peak	2,213	2,449	2,245	2,159	2,157	2,492	2,365	2,365	2,378	2,525	2,288	2,528	28,163																			
319	Facility Capacity (kW)																																
320	First 1,000 kW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000																			
321	1,001-4 000 kW	3,000	3,000	3 000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000																			
322	Over 4,000 kW	7,559	7,559	7 559	7,559	7,559	7,559	7,559	7,559	7,559	7,559	7,559	7,559	90,708																			
323	Demand (kW)																																
324	On-peak	9,841	10,745	10,376	11,124	10,595	10,952	10,863	11,223	11,304	11,366	11,753	10,461	130,603																			
325	Off-peak increment	0	0	0	0	0	0	0	0	0	0	0	0	0																			
326	Reactive Demand (kVar)	4,030	3,837	4,125	3,634	3,888	3,968	4,148	4,131	3,927	4,073	3,657	4,002	47,420																			
327	Calendar Energy (MWh)	5,189	5,993	5,359	6,047	4,882	6,843	6,201	6,072	5,734	6,229	5,181	5,325	69,054																			
328																																	
329	**Schedule 489P GT 4,000 kW V2011**																																
330	Customers - Three Phase	2	2	2	2	2	2	2	2	2	2	2	2	24																			
331	Energy (MWh)																																
332	On-Peak	8,355	8,262	7,889	7,960	8,118	8,488	8,532	8,822	9,356	8,838	8,236	7,994	100,849																			
333	Off-Peak	6,319	6,162	5,791	5,796	6,221	6,166	6,216	6,739	6,723	6,374	6,113	6,065	74,684																			

	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
334	Facility Capacity (kW)													
335	First 1,000 kW	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	14,400
336	1,001-4,000 kW	8,094	8,094	8,094	8,094	8,094	8,094	8,094	8,094	8,094	8,094	8,094	8,094	97,128
337	Over 4,000 kW	13,827	13,827	13 827	13,827	13,827	13,827	14,070	13,917	14,006	14,006	14,006	14,006	166,973
338	Demand (kW)													
339	On-peak	20,116	19,349	20,694	20,499	21,186	22,169	23,113	22,390	23,220	22,733	21,819	21,401	258,689
340	Off-peak increment	0	0	0	0	0	0	0	0	0	0	0	0	0
341	Reactive Demand (kVar)	2,577	2,615	2,624	2,724	2,741	2,928	2,993	7,320	2,929	3,010	2,706	2,892	38,059
342	Calendar Energy (MWh)	14,287	13,880	13,567	14,668	14,336	15,030	15,461	16,193	15,351	14,390	14,222	14,183	175,568
343														
344	**Schedule 489P GT 4,000 kW V2012**													
345	Customers - Three Phase	3	3	3	3	3	3	3	3	3	3	3	3	36
346	Energy (MWh)													
347	On-Peak	4,064	4,047	4,106	4,188	4,452	4,591	4,933	5,262	5,102	4,405	4,195	4,118	53,464
348	Off-Peak	2,674	2,524	2 529	2,642	2,755	2,836	3,097	3,308	3,094	2,724	2,623	2,617	33,423
349	Facility Capacity (kW)													
350	First 1,000 kW	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000
351	1,001-4,000 kW	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	108,000
352	Over 4,000 kW	4,000	4,313	4,616	3,979	3,928	3,591	4,367	4,756	4,497	4,550	4,143	3,596	50,336
353	Demand (kW)													
354	On-peak	11,087	11,806	12,691	14,017	14,514	15,419	15,727	16,459	16,152	15,256	12,966	11,595	167,689
355	Off-peak increment	0	0	0	0	0	0	0	0	0	0	0	0	0
356	Reactive Demand (kVar)	222	175	128	201	200	278	215	286	292	175	138	80	2,390
357	Calendar Energy (MWh)	6,405	6,738	6,442	7,566	6,658	8,400	8,465	8,864	7,952	7,210	6,244	5,965	86,911
358														
359	**Schedule 489P GT 4,000 kW V2013**													
360	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12
361	Energy (MWh)													
362	On-Peak	2,270	2,205	2,261	2,275	2,281	2,228	2,303	2,298	2,232	2,291	2,282	2,257	27,184
363	Off-Peak	1,672	1,737	1,682	1,674	1,667	1,722	1,646	1,651	1,714	1,658	1,661	1,686	20,171
364	Facility Capacity (kW)													
365	First 1,000 kW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
366	1,001-4,000 kW	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000
367	Over 4,000 kW	2,833	2,833	2,833	2,833	2,833	2,833	2,833	2,833	2,833	2,833	2,833	2,833	33,996
368	Demand (kW)													
369	On-peak	6,136	6,315	6,895	6,355	6,235	5,973	6,172	6,420	5,639	6,349	6,771	5,583	74,843
370	Off-peak increment	0	0	72	0	0	73	0	0	0	0	28	46	219
371	Reactive Demand (kVar)	359	484	386	461	582	812	938	978	868	891	290	0	7,049
372	Calendar Energy (MWh)	3,943	3,943	3,949	3,948	3,950	3,949	3,950	3,946	3,949	3,942	3,943	3,942	47,355
373														
374	**Schedule 489P GT 4,000 kW V2014**													
375	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12
376	Energy (MWh)													
377	On-Peak	3,005	2,978	2,812	2,852	2,899	3,033	3,286	3,233	3,282	3,236	2,994	2,831	36,440
378	Off-Peak	2,302	2,190	2,074	2,100	2,106	2,315	2,393	2,300	2,508	2,321	2,188	2,165	26,962
379	Facility Capacity (kW)													
380	First 1,000 kW	1,000	1,000	1 000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
381	1,001-4,000 kW	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000
382	Over 4,000 kW	5,079	5,079	5,079	5,079	5,079	5,079	5,079	5,079	5,079	5,079	5,079	5,079	60,948
383	Demand (kW)													
384	On-peak	7,402	6,948	7,551	7,734	8,325	8,606	8,527	8,682	8,566	8,731	8,150	7,819	97,041
385	Off-peak increment	0	0	0	0	0	0	0	0	0	0	0	0	0
386	Reactive Demand (kVar)	0	0	656	0	0	626	0	0	624	0	0	842	2,748
387	Calendar Energy (MWh)	5,167	4,886	4,952	5,006	5,348	5,679	5,533	5,790	5,556	5,182	4,996	5,307	63,402
388														
389	**Schedule 489P GT 4,000 kW V2016**													
390	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12
391	Energy (MWh)													
392	On-Peak	3,006	2,956	3,158	3,648	3,293	3,272	3,408	3,382	3,729	3,627	3,570	3,757	40,807
393	Off-Peak	2,152	2,324	2,244	1,875	2,352	2,495	2,481	2,628	2,403	2,626	2,805	2,740	29,127
394	Facility Capacity (kW)													
395	First 1,000 kW	1,000	1,000	1 000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
396	1,001-4 000 kW	3,000	3,000	3 000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000
397	Over 4,000 kW	3,467	3,745	4,187	5,018	5,328	5,328	5,622	5,622	5,775	5,775	5,775	5,775	61,417
398	Demand (kW)													
399	On-peak	7,428	8,006	8,368	9,668	8,988	8,788	9,575	9,329	9,881	9,347	9,055	9,655	108,088
400	Off-peak increment	0	0	0	0	1,752	0	0	0	0	0	0	0	1,752
401	Reactive Demand (kVar)	0	0	0	0	0	0	0	0	0	0	0	0	0
402	Calendar Energy (MWh)	5,280	5,402	5 524	5,645	5,767	5,889	6,010	6,132	6,254	6,375	6,497	6,649	71,424
403														
404	**Schedule 489P GT 4,000 kW V2017**													
405	Customers - Three Phase	2	2	2	2	2	2	2	2	2	2	2	2	24
406	Energy (MWh)													
407	On-Peak	6,799	6,617	6,575	6,693	6,600	6,377	6,883	6,656	6,881	6,691	6,477	6,528	79,775
408	Off-Peak	4,998	5,216	5,018	4,824	4,934	5,094	5,021	5,207	5,068	5,102	5,067	4,907	60,455
409	Facility Capacity (kW)													
410	First 1,000 kW	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000
411	1,001-4 000 kW	6,000	6,000	6 000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
412	Over 4,000 kW	11,842	11,842	11 842	11,842	11,842	11,842	11,842	11,842	11,842	11,842	11,842	11,842	142,104
413	Demand (kW)													
414	On-peak	18,563	18,944	18,651	18,891	18,415	17,545	18,619	18,854	18,438	19,796	17,530	16,477	220,723
415	Off-peak increment	0	0	0	0	37	0	0	0	0	153	0	0	190
416	Reactive Demand (kVar)	5,220	4,286	4,804	4,672	4,373	3,921	4,757	4,291	4,228	4,774	4,420	3,872	53,618
417	Calendar Energy (MWh)	11,675	11,897	11 527	11,752	11,366	11,752	12,043	11,949	11,871	11,820	11,357	11,194	140,203
418														
419	**Schedule 489P GT 4,000 kW V2018**													
420	Customers - Three Phase	2	2	2	2	2	2	2	2	2	2	2	2	24
421	Energy (MWh)													
422	On-Peak	7,876	7,290	7,397	7,307	7,685	7,708	8,129	8,492	8,415	7,727	7,396	7,819	93,241
423	Off-Peak	5,932	5,348	5,388	5,266	5,846	5,561	5,779	6,411	5,994	5,587	5,355	5,937	68,405
424	Facility Capacity (kW)													
425	First 1,000 kW	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000
426	1,001-4,000 kW	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
427	Over 4,000 kW	13,833	14,260	14,674	13,805	13,736	13,275	14,334	14,865	14,512	14,584	14,029	13,283	169,190
428	Demand (kW)													
429	On-peak	18,426	19,212	19,803	20,239	20,262	21,160	21,674	22,716	22,520	21,693	20,104	18,690	246,499
430	Off-peak increment	0	0	0	0	0	37	156	0	0	0	0	19	212
431	Reactive Demand (kVar)	2,323	2,559	2,662	2,545	2,553	2,617	2,681	2,888	3,127	2,640	2,736	2,562	31,893
432	Calendar Energy (MWh)	13,125	12,960	12,412	13,928	12,501	15,009	14,660	15,416	13,981	13,464	11,678	12,182	161,317
433														
434	**Schedule 489T V2007**													
435	Customers - Three Phase	0	0	0	0	0	0	0	0	0	0	0	0	0
436	Energy (MWh)													
437	On-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
438	Off-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
439	Facility Capacity (kW)													
440	First 1,000 kW	0	0	0	0	0	0	0	0	0	0	0	0	0
441	1,001-4 000 kW	0	0	0	0	0	0	0	0	0	0	0	0	0
442	Over 4,000 kW	0	0	0	0	0	0	0	0	0	0	0	0	0
443	Demand (kW)													
444	On-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
445	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0

	T–V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ
345		**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**	
347	Customers - Three Phase	15	15	15	15	15	15	15	15	15	15	15	15	180	
348	Energy (MWh)														
349	On-Peak	42,452	41,456	41,140	42,070	42,470	43,451	46,134	47 949	48,626	45,479	42,835	42,811	526,873	
350	Off-Peak	30,712	30,353	29,507	28,803	30,617	31,234	32,396	34,412	33,425	32,009	30,702	31,127	375,298	
351	Facility Capacity (kW)														
352	First 1,000 kW	14,200	14,200	14,200	14,200	14,200	14,200	14,200	14,200	14,200	14,200	14,200	14,200	170,400	
353	1,001-4,000 kW	47,094	47,094	47,094	47,094	47,094	47,094	47,094	47,094	47,094	47,094	47,094	47,094	565,128	1,651,714
354	Over 4,000 kW	74,060	75,293	76,648	75,670	75,676	74,856	77,400	78 353	77,892	77,946	76,961	75,431	916,186	
355	Demand (kW)														
356	On-peak	111,692	112,611	115,183	119,714	121,187	125,313	132,495	136,040	135,934	133,363	122,624	114,808	1,480,964	
357	Off-peak increment														
358	Reactive Demand (kVar)	18,234	16,936	18,358	17,487	17,701	18,810	21,249	25,817	22,033	20,750	18,422	17,612	233,409	
359	Calendar Energy (MWh)	71,238	71,896	70,054	75,158	71,264	79,746	80,806	84,756	79,658	76,437	71,286	71,043	903,342	
366		1014163	1022508	1045862	1087003	1100378	1137842.04	1203055	1235243	1234281	1210936	1113426	1042456.64	$13,447,153	
367		4405916	4324318	4254413	4267965	4401263	4497556.113	4729102	4959798	4941082	4666368	4428385	4452553.225	54328719.86	
369														0.247514632	
373							$1,792,953.75								
376													$896,476.87		
377													$8,964,768.75		

	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
446	Reactive Demand (kVar)	0	0	0	0	0	0	0	0	0	0	0	0	0
447	Calendar Energy (MWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
448														
449	**Schedule 489T V2012**													
450	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12
451	Energy (MWh)													
452	On-Peak	3,944	3,741	3 880	3,960	4,057	4,247	4,188	4,403	4,459	4,440	4,386	4,772	50,476
453	Off-Peak	3,000	2,762	2 865	2,885	2,951	3,274	3,071	3,159	3,460	3,185	3,217	3,660	37,486
454	Facility Capacity (kW)													
455	First 1,000 kW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
456	1,001-4,000 kW	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000
457	Over 4,000 kW	8,997	8,997	8,997	8,997	8,997	8,997	8,997	8,997	8,997	8,997	8,997	8,997	107,964
458	Demand (kW)													
459	On-Peak	12,804	8,745	10 570	10,724	11,079	11,616	10,305	11,676	11,723	11,530	11,570	13,191	135,533
460	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0
461	Reactive Demand (kVar)	437	1,635	1,851	2,293	2,290	2,039	2,116	2,452	2,450	2,321	2,094	2,213	24,191
462	Calendar Energy (MWh)	6,502	6,745	6,845	7,007	7,520	7,258	7,561	7,919	7,625	7,603	8,432	6,944	87,962
463														
464	**Schedule 489T V2013**													
465	Customers - Three Phase	1	1	1	1	1	1	1	1	1	1	1	1	12
466	Energy (MWh)													
467	On-Peak	4,326	3,872	4,138	4,465	3,970	3,932	4,134	4,213	4,058	4,156	3,726	4,098	49,087
468	Off-Peak	2,887	2,670	2 833	2,806	2,563	2,706	2,431	2,803	2,530	2,518	2,537	2,600	31,883
469	Facility Capacity (kW)													
470	First 1,000 kW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
471	1,001-4,000 kW	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	36,000
472	Over 4,000 kW	14,264	14,860	14,860	14,860	14,860	14,860	14,860	14,860	14,860	14,860	15,139	15,139	178,282
473	Demand (kW)													
474	On-Peak	17,031	19,301	14 858	16,578	15,549	16,021	15,280	17,356	18,422	18,157	18,977	15,994	203,524
475	Off-Peak Increment	0	0	0	0	0	0	0	0	0	0	0	0	0
476	Reactive Demand (kVar)	12,923	15,045	11,314	13,086	12,483	12,887	13,154	15,091	13,990	13,856	17,711	15,594	167,134
477	Calendar Energy (MWh)	6,542	6,970	7,271	6,533	6,637	6,566	7,016	6,588	6,674	6,263	6,698	7,213	80,970
478														
479	**Total Direct Access**													
480	Customers	293	293	293	293	293	293	293	293	293	293	293	293	3,516
481	Energy (MWh)	160,156	156,099	155,213	153,931	156,631	161,756	169,239	176,862	177,614	165,631	158,048	161,510	1,952,690
482	Facility Capacity (kW)	342,349	347,976	350,602	356,431	356,165	362,496	369,038	379,461	379,218	361,819	346,042	340,346	4,291,943
483	Demand (kW)	281,690	284,134	285,374	297,347	300,466	309,881	319,086	333,922	334,692	317,158	294,502	281,311	3,639,563
484	Reactive Demand (kVar)	42,546	45,360	43,693	46,482	47,539	49,992	53,152	60,530	55,324	51,990	49,958	45,408	591,974
485	Calendar Energy (MWh)	152,857	153,328	154,228	159,839	157,029	169,065	177,565	180,993	169,161	166,819	157,739	155,007	1,953,631
486														
487														

Portland General Electric Data Request No. 06:

Please identify all resource supply agreements in effect as of January 1, 2018 with a contract term of five years or greater. For each contract identify:

a. MW quantity of the contract

b. Term of the contract

c. The effective date and the termination date of the contract

d. The physical resource(s) supporting the contract

e. The resupply provisions associated with the contract (ex. Unit contingent, physical replacement, financial damages, non-firm)

f. Point of delivery

g. If applicable, long-term transmission rights used to deliver the resource to PGE's system including Assignment Reference (ARef) numbers

h. For the resources/contracts identified in this request, please provide the NERC electronic tag (e-tag) numbers and copies of the e-tags active during and including August 6th through and including August 10th, 2018.

Calpine Energy Solutions, LLC's Response:

Calpine Energy Solutions, LLC does not have any power supply agreements in effect as of January 1, 2018 with a term of five-years or greater.

[Customer name]

AND

PORTLAND GENERAL ELECTRIC COMPANY

COST-OF-SERVICE OPT-OUT AGREEMENT

UNDER SCHEDULE(S) [(choose only the schedule(s) applicable to Customer under this Agreement)** 485/489/490] (5-Year)**

SEPTEMBER ____, 2018

This Cost-Of-Service Opt-Out Agreement ("Agreement") is between ___________("Customer") and PORTLAND GENERAL ELECTRIC COMPANY ("PGE"). This Agreement is based on Customer's election to take service under the terms and conditions of Schedule(s) **[**(choose only the schedule(s) applicable to Customer under this agreement)** 485/489/490]**, as such Schedule(s) may be modified, amended, or succeeded from time to time. PGE and Customer are hereinafter sometimes referred to individually as "Party" and collectively as "Parties."

The Parties agree as follows:

1. Term and Termination of Agreement

Customer is electing to take service under the terms and conditions of Schedule(s) **[**(choose only the schedule(s) applicable to Customer under this agreement)** 485/489/490]**, as such Schedule(s) may be modified, amended, or succeeded from time to time following approval or equivalent action by the Oregon Public Utility Commission (hereinafter referred to as "Applicable Schedule(s)").

This Agreement shall remain in effect for a minimum term of five years from 12:01 a.m. January 1, 2019 to 11:59 p.m. December 31, 2023. Thereafter, it shall extend from year-to-year until notice is given to PGE, by Customer, and this Agreement is terminated three years later, on the anniversary date. Whether Customer wishes to terminate the Agreement at the end of the five year term or at a subsequent anniversary date, and regardless of which rate schedule Customer is being served under at the time, Customer must in all circumstances give PGE not less than 3 years advance written notice of its intent to terminate this Agreement. Upon receipt by PGE, such notice of intent to terminate this Agreement shall be binding on the Parties. At the time of termination of this Agreement, Customer will be considered a "new" Customer for purposes of determining available service options.

2. Service

PGE shall furnish to Customer, at each Service Point described in this Agreement, sixty-hertz alternating current of such phase and voltage as PGE may have available, subject to the General Rules and Regulations of PGE's current tariff, which tariff is typically available on PGE's website at: www.portlandgeneral.com/our-company/regulatory-documents/tariff.

3. Location(s) to be Served

Pursuant to this Agreement, PGE shall furnish service consistent with the Applicable Schedule, at the Customer location(s) listed on Exhibit A, which exhibit is attached hereto and incorporated by reference.

☐ If this box is initialed by Customer, Customer represents that: 1) it has one or more cost of service opt-out agreements in place with PGE; 2) the previously enrolled Service Point IDs ("SPIDs")continue to sum to at least 1 aMW; and 3) the location(s) to be served under this Agreement is an/are additional SPID(s) that does not/do not currently have a usage pattern demonstrating usage for a full 12 months of at least 8,760,000 kWh (1 MWa), however, each

Service Point listed in this Agreement meets the 250 kW Facility Capacity threshold requirement, and is thereby eligible, under the Applicable Schedule, to be opted-out of cost-of-service as an "additional location".

4. Description of Service Point(s)

The Service Point(s) for the service(s) provided under this Agreement is (are) specifically described as:

5. Pricing and Payment

Customer agrees to pay all applicable rates and charges specified in the Applicable Schedule(s), including but not limited to, those rates and charges related to Customer's election with regard to Energy Supply, in accordance with the terms and conditions of the Applicable Schedule(s) and Tariff Rules. Following receipt of bill, Customer shall make such payments to PGE when due.

6. Customer Address

All bills and notices issued under or pursuant to this Agreement shall be sent to Customer at the following address:

7. Successors and Assigns

Customer may assign this Agreement to a third party or a successor in interest as long as (a) in PGE's reasonable judgment, such third party's or successor's creditworthiness and ability to perform Customer's obligations outlined in this Agreement are at least as good as that of Customer; (b) Customer provides written documentation to PGE that substantiates the assignment; (c) the assignee or successor agrees to act in good faith to document his/her agreement to assume, be bound by and perform Customer's duties and obligations pursuant to the same terms and conditions as those contained in this Agreement (e.g. agrees to the execution of a Novation Agreement or a new agreement in their name containing the same terms and conditions); and (d) the assignee or successor agrees to timely complete his/her enrollment for Energy Supply.

8. Modification of Previous Agreements

Any other agreements pertaining to Customer's opting out of PGE's Cost of Service pricing for the location(s) and Service Point(s) designated in this Agreement are hereby superseded and replaced by this Agreement. For the avoidance of doubt, this Agreement is not intended to alter or supersede any agreement for Minimum Load Service, Alternate Service, or Dispatchable Standby Generation that may exist between the Parties.

9. Waivers and Other Conditions

For the duration of this Agreement, Customer waives any rights to receive Electricity (as defined in Rule B of PGE's tariff) from PGE under cost-of-service rates, and waives any claim against PGE under OAR 860-021-0010(5) based in any way on Customer's election of service under the Applicable Schedule(s). In connection with these waivers and the taking of service under the Applicable Schedule(s), by signing this Agreement Customer also acknowledges and agrees to abide by all of the Special Conditions listed in Schedule(s) **[**(choose only the schedule(s) applicable to Customer under this agreement)**** 485/489/490], as such may be modified, amended, or succeeded from time to time following approval or equivalent action by the Oregon Public Utility Commission.

10. Representations and Warranties

a) Representations and Warranties of PGE. PGE represents and warrants to Customer that:

   i. it has the full right, power and authority to enter into this Agreement, to grant Customer the rights set forth herein, and to perform its obligations hereunder;

   ii. the execution of this Agreement by the individual whose signature is set forth at the end of this Agreement, and the delivery of this Agreement by PGE, have been duly authorized by all necessary action on the part of PGE; and

   iii. this Agreement, once executed and delivered by PGE, constitutes the legal, valid and binding obligation of PGE, enforceable against PGE in accordance with its terms.

b) Representations and Warranties of Customer. Customer represents and warrants to PGE that:

   i. it has the full right, power and authority to enter into this Agreement and to perform its obligations hereunder;

   ii. the execution of this Agreement by the individual whose signature is set forth at the end of this Agreement, and the delivery of this Agreement by Customer, have been duly authorized by all necessary action on the part of Customer;

   iii. the execution, delivery and/or performance of this Agreement by Customer will not violate, conflict with, require consent under or result in any breach or default under (i) any applicable law or PGE tariff, including but not limited to Schedules 135 and 203, or (ii) with or without notice or lapse of time or both, any of the provisions of any contract or agreement to which it is a party or to which any of its material assets are bound ("Customer Contracts"); and

   iv. this Agreement, once executed and delivered by Customer (and assuming due authorization, execution and delivery by PGE), constitutes the legal, valid and binding obligation of Customer, enforceable against Customer in accordance with its terms.

c) No other Representations or Warranties. **EXCEPT FOR THE EXPRESS REPRESENTATIONS AND WARRANTIES CONTAINED IN THIS SECTION and SECTION 3 (IF THE BOX IN SECTION 3 IS INITIALED, SIGNIFYING IT IS APPLICABLE), (A) NEITHER PARTY TO THIS AGREEMENT, NOR ANY OTHER PERSON ON SUCH PARTY'S BEHALF, HAS MADE OR MAKES ANY EXPRESS OR IMPLIED REPRESENTATION OR WARRANTY, EITHER ORAL OR WRITTEN, WHETHER ARISING BY LAW, COURSE OF DEALING OR OTHERWISE, ALL OF WHICH ARE EXPRESSLY DISCLAIMED, AND (B) EACH PARTY ACKNOWLEDGES THAT IT HAS NOT RELIED UPON ANY REPRESENTATION OR WARRANTY MADE BY THE OTHER PARTY, OR ANY OTHER PERSON ON SUCH PARTY'S BEHALF, EXCEPT AS SPECIFICALLY PROVIDED IN THIS SECTION AND SECTION 3 (IF THE BOX IN SECTION 3 IS INITIALED, SIGNIFYING IT IS APPLICABLE)OF THIS AGREEMENT.**

11. Disclaimer of Consequential Damages

NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS AGREEMENT, AND EXCEPT TO THE EXTENT REQUIRED BY LAW, PGE SHALL NOT BE LIABLE TO CUSTOMER FOR ANY LOST OR PROSPECTIVE PROFITS OR ANY OTHER SPECIAL, PUNITIVE, EXEMPLARY, CONSEQUENTIAL, MORAL, INCIDENTAL OR INDIRECT LOSSES OR DAMAGES (IN TORT, CONTRACT OR BASED ON ANY OTHER LEGAL OR EQUITABLE THEORY) UNDER OR IN RESPECT OF THIS AGREEMENT, WHETHER OR NOT ARISING FROM PGE'S SOLE, JOINT OR CONCURRENT NEGLIGENCE AND WHETHER OR NOT PGE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

12. Jurisdiction and Venue

Subject first to the venue, jurisdiction, and appeals priority of the PUC, if applicable, any judicial action or proceeding seeking to enforce any provision of this Agreement, or based on any right arising out of this Agreement, shall be brought in the Multnomah County Circuit Court of the State of Oregon and each of the Parties irrevocably consents to the jurisdiction of such court (and of the appropriate appellate court) in any such action or proceeding and waives any objection to such venue.

13. Miscellaneous

Except as provided for in Section 3 above, location(s) to be served and Service Point(s) shall not be added or removed during the term of this Agreement. Notwithstanding the foregoing, Service Point(s) may be removed, provided all of the following criteria are satisfied:

a) The SPID is the subject of a purchase by an entity **other than** one controlled by, controlling, or under common control with Customer;
b) PGE grants its consent to the removal of the SPID during the term, as well as the assignment and delegation under Section 7 to the purchasing entity;
c) The Customer executes an assignment and delegation to the purchasing entity;
d) The purchasing entity timely completes his/her enrollment for Energy Supply; and
e) The purchasing entity contractually assumes all rights and all obligations contemplated under this Agreement with respect to the purchased SPID, by executing and delivering to PGE all documents and/or instruments as PGE deems necessary to document such agreement by the purchasing entity.

Except as outlined in the foregoing paragraph and for other modifications which result from changes approved by the Oregon Public Utility Commission in the applicable tariff provisions referenced and incorporated herein, no other modification of this Agreement shall be valid unless made in writing and signed by PGE and Customer.

No waiver of any provision of this Agreement shall be valid unless made in writing by the waiving Party, and no such waiver shall be deemed a waiver of compliance with any other provisions or conditions of this Agreement.

It is a condition of this Agreement that Customer continues to meet applicable statutory requirements and the requirements of PGE's Applicable Schedule(s) during the term of this Agreement. For the avoidance of doubt, Customer is expected to cease any current participation, and refrain from future participation, in any PGE program or pilot that would i) violate a statute, rule or Order of the OPUC, or ii) prohibit dual enrollment, as of the time and date Customer begins taking service under Schedule 485, 489, or 490. If, at any time during the term of this Agreement, Customer should fail to satisfy this condition, PGE shall have the right to terminate this Agreement and/or seek all such remedies that may be available to it under the law and/or in equity. To the extent the right to terminate is exercised by PGE, Customer will be considered a "new" Customer for purposes of determining available service options.

This Agreement and the services, rates, terms and conditions described in this Agreement, or incorporated by reference, are subject to all changes in applicable tariffs and all lawful orders of the Oregon Public Utility Commission.

[SIGNATURES ON FOLLOWING PAGE]

IN WITNESS WHEREOF, the undersigned Parties have executed this Agreement this ____ day of September, 2018.

____
(Company Name)

By: ______________________________________
(Signature)

____
(Printed Name and Title of Signatory Party)

____
(Date)

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________________________
(Signature)

____
(Printed Name and Title of Signatory Party)

____
(Date)

Approved as to rates ____________________