EXH. JBK-3
DOCKETS UE-220066/UG-220067
2022 PSE GENERAL RATE CASE
WITNESS: JOSH B. KEELING

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-220066** **Docket UG-220067**

SECOND EXHIBIT (NONCONFIDENTIAL) TO
THE PREFILED RESPONSE TESTIMONY OF

JOSH B. KEELING

ON BEHALF OF NW ENERGY COALITION, FRONT AND CENTERED, AND SIERRA CLUB

JULY 14, 2022

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Flexible Load Plan

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Jason Salmi Klotz

July 9, 2021

BEFORE THE PUBLIC UTILITY COMMISSION

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Table of Contents

I. Introduction and Overview

Q. Please state your name and position with Portland General Electric Company (PGE).

A. My name is Jason Salmi Klotz. I am a Principal Product Development Specialist in PGE's Product Portfolio Management group. I have lead responsibility for PGE's Flexible Load Plan (FLP) submitted to the Public Utility Commission of Oregon (Commission or OPUC) in Docket UM 2141 (UM 2141). My qualifications appear at the end of this testimony.

Q. Please summarize your testimony.

A. In this testimony, I discuss PGE's FLP. More specifically, I explain PGE's proposal for submitting a portfolio-level, multi-year plan, and cost recovery options to address that plan, later this year.

Q. Has the Commission issued any decisions regarding PGE's FLP?

A. Yes. In UM 2141, PGE submitted the FLP, which was recently accepted by Commission Order No. 21-158. In that order, the Staff of the Commission summarized PGE's filing as:

> PGE filed its Flexible Load Plan (FLP or Plan) in compliance with the Commission's acknowledgement of PGE's 2019 IRP. While the FLP is a comprehensive informational filing, it proposes only one action for Commission consideration: to move to portfolio level multiyear planning, budgeting, reporting, and cost recovery for PGE's flexible load activities. If the Commission adopts Staff's recommendation to accept the FLP, PGE will subsequently submit a portfolio-level plan for Commission approval later this year.

Q. What is the definition of flexible load?

A. Flexible load is a dynamic resource typically located at or near a customer site, which can modify load in response to a rate design or a dispatch instruction originating or issued by PGE. One such example is electric vehicle supply equipment, enabled with "smart" technology and located at a multifamily establishment. Flexible load resources are developed in partnership with our customers.

Q. Why is flexible load important?

A. In order to pursue the state's greenhouse gas emissions reduction goals and our system's decarbonization goals, PGE must pursue all possible resource options. Flexible load is a resource which can help balance intermittent renewables and provide resiliency, as well as other system and customer benefits. Customers who participate in flexible load offerings can help lower their overall energy costs while providing valuable system benefits. This same value proposition supports our long-standing energy efficiency (EE) investments.

Q. What is the purpose of the FLP?

A. The purpose of PGE's FLP is to: 1) implement portfolio-level planning that will optimize, leverage, and consolidate PGE's numerous flexible load activities across different customer sectors; and 2) provide the Commission and stakeholders insight into PGE's flexible load planning and development activities inclusive of demand response (DR) activities. This will allow PGE to move from designing and managing measures independent of each other, to coordinating their development to optimize benefits and costs across a portfolio of flexible load resources. In short, PGE proposes to shift to portfolio-level, multi-year planning, budgeting, and reporting for its flexible load resources. PGE's FLP, as submitted and accepted in UM 2141, is provided as PGE Exhibit 601.

Q. How would the FLP interact with or be informed by PGE's Integrated Resource Plan (IRP)?

A. PGE's flexible load acquisition goals are set in the IRP, as determined by a flexible load resource's ability to be the lowest cost, least risk resource. The current flexible load goal was approved in PGE's 2019 IRP (Docket LC 73). In support of these goals, PGE will submit a Flexible Load Multi-Year Plan (Multi-Year Plan) per the Commission's decision in UM 2141.

PGE envisions the Multi-Year Plan to have two phases: Phase I will demonstrate how PGE will acquire flexible load in 2022 and 2023 in pursuit of the 2019 IRP goal of 211 seasonal megawatts (MW), include a budget necessary to support this, and a proposal for cost recovery. This Phase 1, Multi-Year Plan is currently scheduled to be submitted in Q4, 2021. To align PGE's newly developing Distribution System Plan (DSP) with the IRP, PGE envisions Phase II of the Multi-Year Plan to be submitted in late 2022. Phase II of the Multi-Year Plan will establish flexible load targets and budgets to meet goals set in PGE's 2022 IRP's Preferred Portfolio as well as PGE's 2022 DSP. PGE's DSP will create locational forecasting and an action plan for flexible loads. This will inform the Phase II Multi-Year Plan with more granular resource detail than was available during Phase I of the Multi-Year Plan.

Q. What are your current projections for FLP costs?

A. Three components make up our total cost projections for years 2021 and 2022: demonstrations, pilots, and programs. Each of these is offered under an approved Commission tariff and summarized below.

- Demonstrations are currently conducted in the Testbed Pilot (Testbed). Phase I of the Testbed is set to expire at the end of 2021, with annual costs estimated to be approximately $3.2 million. PGE is planning to propose Phase II of the Testbed in August 2021; if approved it is estimated to cost approximately $2.0 million in 2022.
- Pilot work, which presently includes Residential Smart Electric Vehicle Charging and Residential Energy Storage, is estimated to cost approximately $2.9 million in 2021 and $4.9 million in 2022.

- Maturing DR pilots on a pathway to program status (i.e., Flex Peak Time Rebate, Residential Thermostats, Energy Partner and Multifamily Water Heaters) are estimated to cost approximately $13.6 million in 2021 and $14.0 million in 2022.

FLP costs are expected to increase as PGE adds additional products to our portfolio such as single-family water heaters and new construction bundles.

Q. How is the rest of your testimony organized?

A. In the next section, I discuss PGE's current regulatory treatment of flexible load resources and explain why most of those costs are not included in the current general rate case (GRC). I then provide details for alternative cost recovery methods and explain why those alternatives are appropriate given the evolving nature of the flexible load resources. Next, I discuss the potential for including flexible load costs in a future GRC. Finally, I provide concluding remarks to summarize PGE's FLP proposal.

II. Current Regulatory Treatment

Q. Please describe how the Commission currently regulates PGE's flexible load resources.

A. Beginning in 2011, following deployment of PGE's advanced metering infrastructure system, PGE initiated its DR pilots with Energy Partner, which provided an automated DR option for large non-residential customers. Those costs were deferred for separate ratemaking treatment under Docket UM 1514 and approved for cost recovery via PGE Schedule 135. Since then, Energy Partner has evolved into two DR pilots[1] and PGE has implemented the following additional DR pilots, all of which have cost recovery through PGE Schedule 135:

- Energy Partner – Docket UM 1514 – PGE Schedules 25 and 26.
- Direct Load Control Thermostats – Docket UM 1708 – PGE Schedule 5.
- Peak Time Rebate – Docket UM 1708 – PGE Schedule 7.
- Multifamily Residential DR Water Heater – Docket UM 1827 – PGE Schedule 4.
- DR Testbeds – Docket UM 1976 – PGE Schedules 13, 14, and 25.

Q. Are there other flexible load activities which are not represented by the above list?

A. Yes, PGE is conducting a residential energy storage pilot through Schedule 14, Docket UM 2078. Additionally, our residential electric vehicle charging pilot has a DR component. These costs are deferred through Docket UM 2003. In addition, Electric Avenue has demonstrated some flexible load capabilities and DR savings through utilization of a peak pricing surcharge. These costs are deferred through Docket UM 1938. PGE has separately developed and made available a Time-of-Day rate. Within the Testbed, PGE is also conducting collaborative work with the Energy Trust of Oregon on two EE and flexible load

[1] The non-residential direct load control pilot (PGE Schedule 25) and the non-residential DR pilot (PGE Schedule 26).

demonstrations: single-family, DR-enabled water heaters and DR-enabled ductless heat pumps. The Testbed is also conducting work with FleetCarma to test various time of use structures and incentives for electric vehicle charging.

Q. Are these activities included in your total flexible load cost estimate?

A. Yes.

Q. Have you included any of these pilots' costs in this GRC?

A. As discussed in PGE Exhibit 500, PGE shifted the pilots' labor-related costs to base rates because labor is more flexible and can be applied to a variety of DR programs, whereas the non-labor components are dedicated to individual programs and only for specific activities. Non-labor pilot costs, therefore, will continue to be deferred and amortized through supplemental schedules until Commission action on the Multi-Year Plan.

Q. Why are the non-labor costs being deferred and not shifted to base rates?

A. Base rates represent regular, stable, and ongoing costs of doing business. Although base costs are subject to certain variability, they can be forecasted with reasonable accuracy and their variability typically falls within a normal range of business risk. PGE's DR pilots, however, are still in a state of transition. They face considerable uncertainty with respect to costs and customer participation levels, and in some cases completion of testing and deployment of enabling technologies. The pilots are also subject to future evaluations to finalize learnings and to establish the means to achieve overall goals. Even as the pilots transition to programs, they are not immediately mature and stable. Instead, there is a period of significant ramping and growth as the programs experience increases in scale and scope. In short, until the programs become fully mature and stable, they do not represent regular, on-going costs suited for forecasting in base rates but are more appropriate for alternative cost recovery treatment.

Q. If most of the costs are not included in this GRC, why is PGE discussing the FLP in testimony here?

A. In comments provided in UM 2141, the OPUC Staff and other parties did not indicate a preference for PGE shifting its flexible load costs from deferred accounting treatment to base rates at this time, but did express a strong interest in having PGE discuss in the GRC how we plan to move forward with the FLP and Multi-Year Plan. Ultimately, all parties including PGE agree that it is time to move away from deferred accounting.

Q. Why is there a need to move away from deferred accounting?

A. Deferred accounting has been useful and appropriate during the pilots' initial phases when operating parameters and enabling technologies were being tested and evaluated over a series of years. This allowed PGE to accumulate sufficient data and customer survey results to provide meaningful learnings to guide the pilots to cost-effective, scalable operations. As PGE has expanded the number and magnitude of DR pilots, however, the treatment of the pilots as separate deferrals has made it increasingly difficult to identify aggregate rate impacts. Consequently, there is consensus that a more comprehensive approach is needed.

III. Proposal for FLP

Q. Does PGE have a proposal for the FLP and multi-year plan that would replace deferred accounting?

A. Yes. PGE believes there are two similar methods that provide a reasonable alternative to deferred accounting. Both involve cost recovery by means of a supplemental schedule, with or without a balancing account, as described in more detail below. Ultimately, the two methods align with a multi-year plan that would be for a set amount of cost recovery over a specific period of time. As described below, they also allow for a transition from the first alternative to the second alternative if PGE were to continue the FLP through a series of multi-year plans.

A. Supplemental Schedule with Balancing Account

Q. Please describe the first of the two alternative methods.

A. The first alternative would involve cost recovery through use of a supplemental schedule supported by a balancing account mechanism. This alternative recognizes the significant amount of ramping and growth flexible load resources will experience as they expand their scale and scope in transitioning from pilots to programs. This is particularly evident by PGE's 2019 IRP goal of expanding flexible load resources from the current 68 MW to 211 MW by 2025. This alternative would also recognize that some determination remains on the overall efficacy of having certain operations and maintenance activities for flexible load resources being performed by third-party contractors versus internal PGE personnel and systems. To address the significant change that is inherent in this phase of PGE's flexible load development, PGE proposes to establish a mechanism that consists of the following aspects:

- A supplemental schedule to collect a levelized, forecasted plan amount over two years. The supplemental schedule can remain fixed over the period or allow the flexibility of updates, if appropriate, to account for changes in programs, scale or scope, and/or goals.
- A balancing account to track the flow of costs and tariff collections. This would allow the matching of revenues and costs over time so that intertemporal cost fluctuations would not impact PGE's operating results in a given year.

B. Supplemental Schedule without a Balancing Account

Q. Please describe the second of the two alternative methods.

A. The second alternative would also involve cost recovery through use of a supplemental schedule but not one supported by a balancing account mechanism. This alternative recognizes the continued transition from evolving programs to mature programs and the remaining growth the flexible load resources will experience as their final scale and scope are being identified and achieved. To address the level of change inherent in the latter phase of flexible load development, PGE proposes the establishment of a mechanism that consists of the following aspects:

- A supplemental schedule to collect a levelized, forecasted plan amount over two years. The supplemental schedule can remain fixed over the period or allow the flexibility of updates, if appropriate, to account for changes in programs, scale or scope, and/or goals.
- No balancing account to track the flow of costs and tariff collections. This means all FLP costs and revenues will flow to PGE's income statement and that PGE

would bear the forecast risk of annual costs against revenue (i.e., intertemporal cost fluctuations would impact PGE's operating results).

C. Additional Considerations

Q. Please explain how either of the two methods described above would address situations where PGE either underspends or overspends the established plan amount in conjunction with either under- or over-achievement of plan goals.

A. I envision that the Multi-Year Plan will entail a maximum amount of cost recovery for the supplemental schedule to collect over the specified period. Because the proposed supplemental schedules would not involve an automatic true-up to actual costs, as occurs with the current deferrals, PGE also proposes the following treatment:

- If PGE incurs more cost than the forecasted maximum amount of cost recovery, and if PGE does not achieve flexible load capacity greater than the established goal, then PGE will absorb the excess costs.
- If PGE incurs more cost than the forecasted maximum amount of cost recovery, and if PGE achieves flexible load capacity greater than the established goal, then: 1) customers will absorb the excess costs in proportion to the amount of excess capacity compared to forecasted capacity; and 2) PGE will absorb any additional costs above the customers' share.
- If PGE incurs less cost than the forecasted maximum amount of cost recovery, and if PGE does not achieve the flexible load capacity goal, then PGE will refund the underspend costs to customers.
- If PGE incurs less cost than the forecasted maximum amount of cost recovery, and if PGE does achieve or exceeded the flexible load capacity goal, then PGE and

customers will share the underspent costs on a 90/10 basis, with customers being refunded 90% of the underspent costs and PGE retaining 10%.

- Finally, during the preparation of test year forecasts for general rate cases, PGE will fully separate multi-year plan costs from base costs so as not to double collect them.

IV. Regulatory Alignment Mechanisms

Q. Do you foresee a possible move of FLP costs to base rates?

A. Yes. After flexible load programs become mature and stable, PGE agrees that they could be suited for incorporation into base rates. There are two considerations associated with this eventual outcome, however, that would need to be addressed. The first is whether OPUC Staff and parties prefer to have flexible load costs embedded in base rates or continue to be separated by means of a supplemental schedule. This consideration relates to the nature of base rates that entails:

- All cost and recovery determinations are tied to rate case filings.
- There is no potential for annual updates of FLP costs to account for changes in programs, scale or scope, and/or goals between rate cases.
- FLP costs would be determined as part of all other costs in base rates.
- Actual FLP costs would be subject to similar managerial pressures as other base costs.
- PGE will bear the forecast risk of annual costs against revenue.

In summary, the decision to move FLP costs to base rates will be based on: 1) the degree of transparency desired between base rates and a supplemental schedule; and 2) the extent to which flexible load will consist of elements that are more suited to separate rate treatment versus base rates. In other words, assuming the persistence of rapidly emerging technologies and changing customer preferences, a portion of flexible load will continue to involve demonstration projects and pilots with considerable degrees of uncertainty and changing costs.

Q. What is the second consideration that you wish to address regarding an FLP transition to base rates?

A. The second consideration relates to the matching of risks and benefits associated with the FLP. Although mature, stable flexible load programs appear suited to base rate recovery, they would still be subject to considerable forecast risk as technologies evolve and customer preferences change in between rate cases. In addition, PGE believes there should be the recognition that flexible load replaces supply-side resources for which PGE earns a return on those owned as rate base. In summary, I propose that flexible load resources, as eventually included in base rates, provide PGE with earnings potential.

Q. How would this earnings potential be achieved?

A. There are two ways this could be accomplished. The first is more complex but has precedent in prior rate making. With this method, PGE's flexible load costs would be applied to an asset account rather than expense, and that account's balance would be included in rate base for which it would earn PGE's authorized weighted average cost of capital similar to all other rate base. This asset would then be amortized over a period of years, with the amortization cost representing the "return of" component of rate making.

Q. What is the precedent for this method.

A. In the 1990s, utilities in Oregon were incented to invest in EE and were allowed to incorporate those costs in rate base for "return on" as part of the Commission-approved "SAVE" program. That program ended with the establishment of the Energy Trust of Oregon and the Public Purpose Charge.

Q. What is the less complex method to achieve earnings potential for the FLP?

A. This method is simply a cost-plus-fee approach where a return percentage is applied to the FLP cost forecast and the total cost-plus-fee amount is incorporated into rates. In reality, this approach could be equally applied to the supplemental schedule method, as discussed in

Section III, if the Commission were to agree that: 1) the supplemental schedule method remains preferrable to base rate recovery; and 2) the fee adder represents a reasonable benefit and incentive for PGE.

Q. Are there other earnings mechanisms PGE is exploring to align customer investment in flexible load, state policy and utility investment?

A. Yes, there are several that PGE has been following that will inform a future proposal to the Commission.

Q. Please provide an informative example.

A. Consolidated Edison (ConEd) in New York worked with their Commission, stakeholders and the community to develop a performance incentive mechanism that aligned with the communities' interest in local investment, grid planning's desire to address a local load pocket, and the ability of the utility to attract investment. The project known as the Brooklyn Queens Demand Management Program,[2] a non-wires alternative, deferred an investment of $1 billion into a seven-year project at roughly half the costs. The program included direct install, multi-family efficiency, flexible load auction mechanism, partnership with the New York City Housing Authority, distributed generation, and voltage optimization. The New York Public Service Commission (NYPSC) adopted an incentive mechanism which included an authorized rate of return on program costs and the potential for ConEd to receive up to 100 basis points in performance incentives above their authorized rate of return. In addition, 45 basis points of return were tied to achieving the proposed demand reductions, 25 basis points were tied to increasing diversity of DER in the marketplace, and 30 basis points were

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[2] https://www.coned.com/en/business-partners/business-opportunities/brooklyn-queens-demand-management-demand-response-program; https://breakingenergy.com/2014/12/22/ny-psc-approves-con-edison-bqdm-program/

tied to achieving a lower $/MW value than traditional investment solutions. The project came in part to be known as the REV Test Bed,[3] where ConEd also issued a Request for Information for local contractor work and conducted local customer outreach. In 2017, ConEd stated the net present value of the project to be $94.9 million including $65.5 million of benefits from delaying load transfers, $549 million of benefits from delaying substation/transmission investments, and $133 million in benefits from avoided capacity, energy, distribution, environmental, and line losses. The NYPSC has extended the project from its initial 3-year scope to having no termination date. The total benefits of the project were $747.8 million against $652.9 million in costs.

Q. Are there Northwest examples that are informing PGE's perspective and possible proposal?

A. Yes, in 2019 the Washington Legislature passed Senate Bill 51116, the Clean Energy Transformation Act, which authorized a rate of return on utility power purchase agreements and distributed energy resource investments including DR. Additionally, in their 2018 GRC, Northwestern Energy proposed a rate of return on all demand side management (DSM) investment. The proposal, which ultimately was not approved, had the support of the Northwest Energy Coalition and the Sierra Club. In 2004, Nevada become the first state to permit utilities to earn a bonus rate of return on DR and EE investment, which become regulatory assets that are eligible to earn a return of up to 5% more than traditional supply-side investments on the equity portion of the authorized return. We know of seven other states (i.e., North Carolina, Hawaii, Michigan, Texas, Vermont, Rhode Island, and Massachusetts) where the utility received an earning mechanism for DSM investments.

[3] REV is the acronym used for Reforming the Energy Vision effort in New York state.

Q. What are the anticipated next steps for PGE on the issue of regulatory alignment?

A. As stated in chapter 5 of the FLP, PGE is making investments to acquire and develop flexible load. PGE's investment supports our work to provide customers with energy solutions, which can help lower bills, support communities, and decarbonize the grid. PGE showed in its Exploring Pathways to Deep Decarbonization[4] study that we will need hundreds of MW of flexible load and distributed energy resource development to meet Oregon's greenhouse gas reduction goals. Aligning investment and earnings opportunities can help the PGE system, its customers, and the state reach those goals by attracting investment. To meet these aggressive targets, it is our intention to propose an adjustment mechanism either via the Multi-Year Plan process or the Distribution System Plan process, where appropriate stakeholder engagement can occur.

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[4] See PGE Exhibit 602, Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory.

V. Conclusion

Q. Please summarize your proposal regarding the FLP.

A. Except for certain labor costs discussed in PGE Exhibit 500, we have not included flexible load costs in the current GRC. Instead, we intend to issue a portfolio-level, multi-year plan and budget in October 2021 in UM 2141, and propose that the Commission approve the transition of FLP cost recovery from current schedules to a multi-year plan, as discussed in Section III, above. We will also propose in a future GRC, flexible load costs be considered for continued use of a supplemental schedule and/or base rates and that return-on potential be applied to those costs.

VI. Qualifications

Q. Mr. Salmi Klotz, please describe your qualifications.

A. I have 17 years of experience in the industry having worked for the Vermont Public Service Commission, the Federal Energy Regulatory Commission, the California Public Utility Commission, Bonneville Power Administration, the Northwest Energy Efficiency Alliance, the OPUC and PGE. My career has mostly focused on the role of DSM, smart grid technologies and their ability to affect retail and wholesale market functions. I hold a Bachelor of Arts in English and Philosophy from the University of Montana Missoula, a Master of Environmental Policy and Law, and a Juris Doctorate from Vermont Law School. I am a member of the Oregon State Bar. For the last six years I have also been teaching Energy Policy and Law at the University of Oregon School of Law.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

December 24, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: UM 2141 Portland General Electric Company Flexible Load Plan

Dear Filing Center:

Attached for filing is Portland General Electric Company's (PGE) Flexible Load Plan, docketed as UM 2141. PGE identified a missing footnote, number 85, and this errata filing contains that footnote.

Thank you,

/s/ Karla Wenzel

Karla Wenzel
Manager, Regulatory Policy & Strategy

Enclosure

PGE's Flexible Load Plan

December 2020

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Table of Contents

List of Tables

List of Figures

Flexible Load Plan Road Map

The Flexible Load Plan has four parts. Chapter 1 is a review of current activity. Within Chapter 2 the reader will find a proposal focused on operations, funding, goal setting and practices. PGE's proposal in Chapter 2, requests acceptance of a practice entailing multiyear planning and budgeting, yearly updates and quarterly reporting. Costs would be recovered through Schedule 135[1] similar in nature to energy efficiency planning, budgeting and cost recovery through Schedule 109[2].

The following provides a roadmap through the Flexible Load Plan:

- Chapter 1 is a review of current activity with a brief description of the pilot or program activity. A more comprehensive review of each pilot or program activity can be found in the Appendix, including but not limited to discussion regarding the pilot or program goals, market potential, lesson learned, management of costs and cost effectiveness, evaluation, and moving the activity from pilot to program

- Chapter 2 is a review of current planning practices, goal setting, and regulatory treatment. The section goes on to propose a treatment of flexible load similar to energy efficiency, where PGE will adopt many of the planning, development, budgeting best practices in place in Oregon and the region. PGE proposes to have flexible load treated on a portfolio basis over a course of years with a multiyear budget updated annually and aligned with a multiyear flexible load plan. Additionally, PGE proposes a funding mechanism similar to how energy efficiency is funded. This will give the Commission and stakeholders the necessary level of transparency and oversight.

- Chapter 4 is a review of how PGE assesses cost effectiveness. Here PGE responds to Commission Staff's requests, found in Docket LC 73, for valuation changes to PGE cost effectiveness methodology.

- Chapter 5 attempts to open a discussion on regulatory alignment of the resource, such that customer, stakeholder, and shareholder interests are aligned around the procurement of flexible load as we decarbonize our system at the greatest benefit and at least cost to our customers.

- Within the Appendix the reader will find detail on each of our programs including cost benefit tables and scoring. Additionally, we have included a table of expenditures and forecasted budgets. These tables also include a transparent look at our progress to

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[1] Schedule 135 is PGE's cost recovery tariff for demand response pilot costs that are not already recovered in rates. https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_135.pdf
[2] Schedule 109 is PGE's tariff to collect costs from customers for SB 838 energy efficiency activity. https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_109.pdf

acquire capacity to meet our 2016 IRP savings goals. Lastly, the Appendix includes a user adjustable cost benefit spreadsheet provided in response to Commission Staff's comments in LC 73 whereby Staff requested PGE consider several adjustments to cost effectiveness.

Flexible Load Plan Executive Summary

Purpose of the Flexible Load Plan

The purpose of the Flexible Load Plan is multi-part:

1. The Flexible Load Plan attempts to demonstrate the evaluation of demand side resource development at Portland General Electric (PGE) within the context of other jurisdictional activities, policy changes within Oregon, at the regional and federal level and PGE's future resource needs informed by our decarbonization strategy.

2. To show maturity of program and resource development and propose a change in practice which will give Commission transparency, comprehensive review and regular reporting of PGE's flexible load resource build activity. This sole proposal for Commission acknowledgment is informed by similar best practice in the region where entities are attempting to build demand side management resources.[3]

3. Demonstrate to the Commission and Stakeholders how PGE will conduct flexible resource development through a measure development structure: PGE uses small, discretely targeted activity through demonstration projects to inform pilot activity; promising measures will be taken to scale, which will evolve to programs that are dispatchable by our power operations team. Show how PGE currently leverages the Smart Grid Testbed as a key part of this evolution and commitment to transparency.

4. Transparently communicate our current cost effectiveness methodology and practice and to further show how this practice will evolve with identification of energy values that flexible load is anticipated to provide to PGE's system.

5. Lend insight into how our Integrated Resource Plan and for the forthcoming Distribution System Plan practices model and identify the value of flexible load.

6. Communicate to the Commission, stakeholders and customers our commitment to the development of customer-sited resource development through customer-centric development practices

[3] As there is no written standard for the Commission's review of this Flexible Load Plan, PGE prefers the Commission to acknowledge the Plan but understands that acceptance of the Plan is also an option.

7. Communicate to the Commission, stakeholders and policy makers that PGE is open and ready to discuss regulatory alignment to best situate the company to accelerate investment in flexible load and similar distributed energy resources.

8. Comprehensive and transparently share with all interested parties PGE program activity, costs and savings.

Summary of the Request for Commission Acknowledgement

Though the Flexible Load Plan is extensive, as it is an attempt to transparently and comprehensively review PGE's flexible load activity, it includes only one proposal for Commission acknowledgement. That proposal is a request to move from the current disjointed approach involving multiple deferrals, timelines, and reporting to a comprehensive, multi-part measure development, portfolio level planning, and budget practice similar to best practices employed throughout the region. The detail of this proposal is in Chapter 2.

Relationship to IRP, DSP, Transportation Electrification Plan, and Smart Grid Report

The Flexible Load Plan is focused on flexible load. It is not meant to replace any part of the IRP, the forthcoming DSP, the Transportation Electrification Plan, or the Smart Grid Report. The Flexible Load Plan attempts to show the relationship of flexible load and our flexible load resource build activity in the context of present and planned activity. For example, while the Flexible Load Plan addresses transportation electrification activity, it only addresses the portion that will have a flexible load component, such as grid-enabled home electric vehicle chargers. This measure was identified in our Demand Response Potential Study, found in PGE's 2019 Integrated Resource Plan. Though the Flexible Load Plan discusses these measures, it is not meant to replace the requirements or the planned activity set out in the IRP or PGE Transportation Electrification Plan. Furthermore, the Flexible Load Plan discusses distribution system and resource planning (DSP and DRP, respectively) only to show how PGE envisions flexible load as an important element of DSP modeling, planning processes, and practices. Discussion of DSP within the Flexible Load Plan is not an attempt to influence or preempt an aspect of the Commission UM 2005 Distribution System Planning proceeding. PGE recognizes DSP as a separate planning process.

Summary of Program Evolution from Demonstration, Pilot to Program

At the heart of the Flexible Load Plan is a review of our evolved measure development practices. This process has a three-part structure: demonstrations, pilots, and programs. The process is governed by a Product Lifecycle Management (PLM) stage-gated development process. The structure leverages the Testbed to accelerate development in two significant aspects. First, it utilizes the current investment and high levels of customer engagement to operate small demonstration projects that will inform pilot development on matters of technology viability, energy service values, and planning values. Second, this measure development framework leverages the Testbed's accelerated grid state, where grid system operations and investments have been made in synergy with DER development, customer engagement, and education. These unique characteristics of the Testbed allow PGE to identify and learn from a more advanced state of the grid, thus informing broader grid development activities throughout the organization, including measure development itself.

The following Figure is a synopsis of our measure development process. Further detail can be found in Chapter 2 of this document.

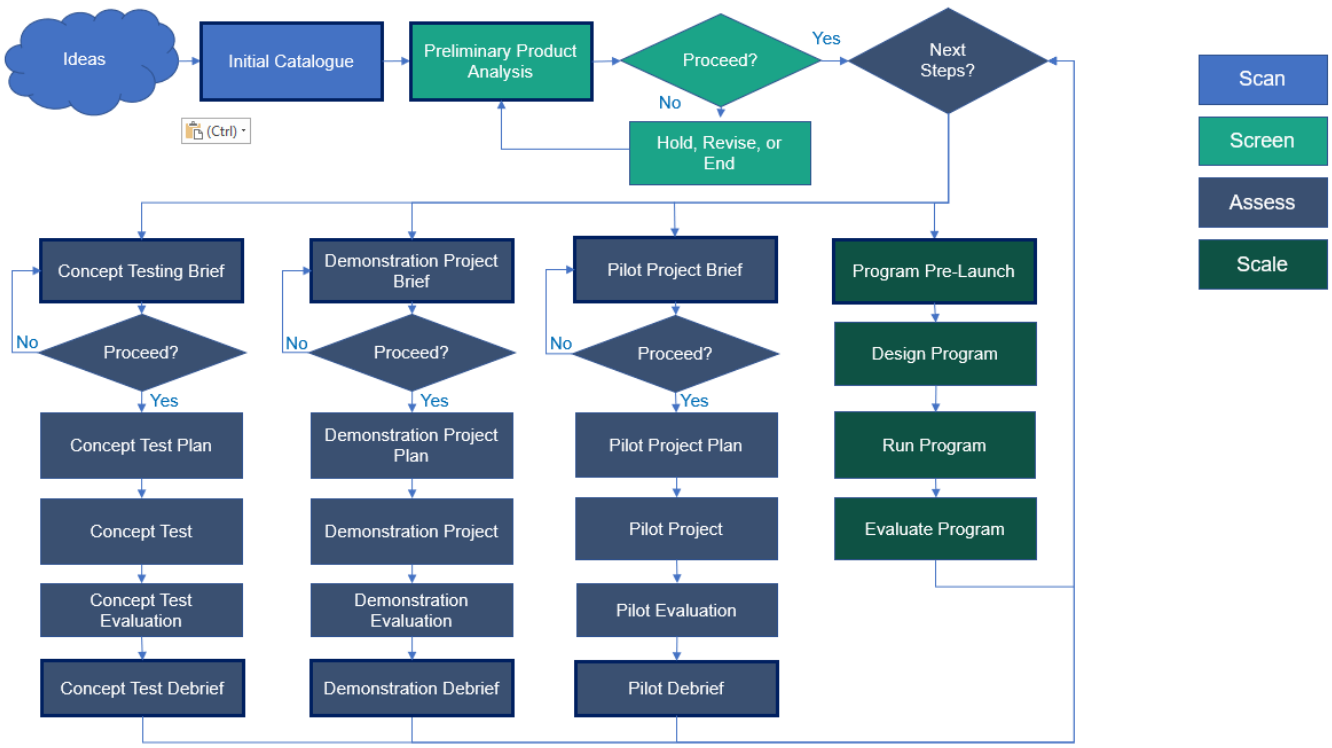

Figure 1 – PGE's Measure Development Process

Purposed Next Steps – Multiyear Operations Plan and Budget

Through this Flexible Load Plan, PGE requests that the Commission acknowledge our proposal to move from the current measure by measure, pilot to program practice accompanied by requests for deferred accounting and later ratemaking, to a more holistic portfolio development process with multiyear plans, budgets, cost recovery, and regular reporting. The Flexible Load Plan contemplates, if acknowledged, a follow-up filing in which PGE would communicate its multiyear flexible load development plans, the associated multiyear budget, and cost recovery.

Chapter 1 Introduction

Chapter Summary

Chapter 1 does not request any action from the Commission. Rather, it communicates the need for a Flexible Load Plan, lays out a history of demand response, and the rationale for why PGE has begun using the term, flexible load. Table 1 in this chapter ties flexible load to grid services, as defined and outlined by the Commission in Docket UM 1751. (Chapter 4 of the Flexible Load Plan reviews these UM 1751 storage use cases and applies them directly to flexible load.) Chapter 1 also raises the concept of a virtual power plant, comprised of multiple flexible load measures, which in aggregate, supply grid services visible to and dispatchable by PGE Power Operations. Chapter 1 then gives a high-level review of planning practices, and finally reviews measure activity, costs, cost effectiveness, and savings. Pilot and program detail can be found in the Appendix of the Flexible Load Plan. Chapter 1 is meant to prepare the reader with necessary information to make the most of the subsequent chapters.

1.1 Purpose of the Flexible Load Plan

The purpose of the Flexible Load Plan is to present a transparent and comprehensive report of current activity that PGE is undertaking to meet our demand response targets set forth in PGE's Integrated Resource Plan (IRP). Additionally, the Flexible Load Plan is meant to communicate and demonstrate PGE's evolving vision of the DR resource such that a greater number of grid services and hours of operation can be obtained. This folds the concept of demand response into a broader category recognized nationally as load flexibility or flexible load. The more expansive concept of flexible load allows for the aggregation of multiple types of behind-the-meter technologies into "Virtual Power Plants." These Virtual Power Plants will lend services to the distribution grid below the substation and the bulk system, when possible, above the substation. The Flexible Load Plan also documents PGE's current practices, openly communicates challenges and constraints, and articulates PGE's understanding of the current limitations of flexible load. The Flexible Load Plan offers a proposal for a new structure for the Public Utility Commission of Oregon (OPUC or Commission) to consider regarding flexible load planning, budgeting, cost recovery, and development.

The Flexible Load Plan also transparently communicates present cost effectiveness practices and PGE's envisioned activity to address the full valuation of flexible load. Flexible load is a new resource to PGE, our customers, and our regulators; PGE is still exploring its capabilities and their associated value. PGE continues to measure cost effectiveness according to the PUC's methodology in Docket UM 1708[4]. PGE is open to applying alternative cost effectiveness frameworks, including the methodology proposed by Staff in Docket LC 73 and forthcoming

[4] Commission Order 15-203, UM 1708, PGE Compliance Filing April 28, 2016, "A proposed Cost Effectiveness Approach for Demand Response."

methodology from The National Efficiency Screening Project (NESP).[5] While there are merits and drawbacks to each of these approaches, PGE hopes that by comparing these methodologies, we can engage stakeholders in an open dialogue regarding cost effectiveness practices.

PGE views the connection to the customer as the most important and valuable connection the company will make. To this end, PGE is seeking to meet customers' needs through the development of new energy solutions. As PGE wants to help customers manage their total energy costs, flexible load programs can help customers lower their bills and better understand how their actions can affect system costs and drive decarbonization. PGE plans and actively manages customer price impacts, recognizing that increased costs affect our relationship with customers.

1.2 History of Demand Response

1.2.1 Early Program History:

Since the 1970s, DR programs have successfully managed load balance during times of grid stress and high-power prices. Detroit Edison was the first utility to implement a load control program in 1968[6]. Similarly, Florida Power and Light deployed a measure with electric water heaters in the 1980s and has since expanded the program to cover central heating and cooling, as well as pool pumps.[7] This program remains one of the longest-running DR programs in the country.

The first DR program in the Northwest was launched after the passage of the 1980 Northwest Power Act (Power Act)[8], with its emphasis on demand-side measures. Established in 1985, the City of Milton-Freewater's program utilized timers to control water heater load[9]. In 2014, the program was updated and expanded to include heating and air conditioning load as part of the NW Smart Grid Demonstration Project[10]. Additionally, large industrial customers[11] taking direct service from the Bonneville Power Administration (BPA) were required to make 25% of their load interruptible as a condition of service. During the 2001 Western Energy Crisis (Energy Crisis), this

[5] The National Efficiency Screening Project mission is to improve cost-effectiveness screening practices for distributed energy resources. NESP is set to release a new cost effectiveness national standard practice manual later this summer. https://nationalefficiencyscreening.org/wp-content/uploads/2019/06/NSPM-for-DERs.pdf.

[6] EPRI, The Demand-Side Management Information Directory, EPRI EM-4326, 1985.

[7] Residential On Call ™ Program. *Available at*: https://www.fpl.com/save/programs/on-call.html

[8] Pacific Northwest Electric Power Planning and Conservation Action 16 USC Chapter 12H (1994 & Supp. I 1995) Act of Dec. 5, 19080, 94 Stat. 2697.

[9] Milton-Freewater's original demand response program used a radio energy management system to send a radio signal to the units to cycle off connected loads, reducing energy when the peak demand set-point was reached.

[10] Of note, when the utility began to replace the old units with the newer models, many customers did not know the units existed. This indicates that certain DR programs can operate without significant disruption while creating efficiencies for utilities and customers. Bonneville Power Administration "*Milton-Freewater: A frontier for new technology.*" September 5, 2014*. Available at*: https://www.bpa.gov/news/newsroom/Pages/Milton-Freewater-A-frontier-for-new-technology.aspx

[11] These customers included aluminum smelter and pulp and paper. The aluminum smelters would rotate which plants would provide the required demand reductions every two weeks.

became the Demand Buy-Back program, and proved successful in lowering demand during times of extreme stress and high prices. Pacific Gas and Electric (PG&E) ran a similar program from 2000-2014 for large customers[12].

In the 1990s, California utilities created a program called the Base Interruptible Program[13]. In exchange for a reduced rate, the utility had the right to call on participants (large business customers) to lower their demand by a specific, contracted amount during emergencies. The program was rarely, if ever, called upon prior to the Energy Crisis, during which it provided over 1,200 MW of DR in the PG&E service territory and was instrumental to managing demand. More recently, the program has been adapted to integrate with the California Independent System Operator (CAISO) and is called upon when the CAISO is in emergency conditions[14].

1.2.2 Post Energy Crisis Advancements

The success of DR in responding to the Energy Crisis led to a renewed national focus on advancing DR as a resource. In the Energy Policy Act of 2005[15] (EPACT '05) Congress required a series of actions by the Federal Energy Regulatory Commission (FERC) with regards to DR and encouraged states to look into the benefits of DR and Advanced Metering Infrastructure (AMI). EPACT '05 offered states federal assistance for "technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs[16]". Specifically, EPACT '05 required the FERC to provide technical assistance to the states, and to publish an annual report on progress of the DR and advanced metering development[17]. The *Demand Response and Advanced Metering Assessment* continues to be issued annually and catalogues national DR and advanced metering activity, consumer access to DR programs, regulatory activities, ongoing barriers to DR participation, and DR potential[18].

In 2008, the FERC also issued the first in a series of rulemakings on DR, Order No. 719: *Wholesale Competition in Regions with Organized Electric Markets*, which required that organized markets (ISO/RTO) offer opportunities for DR resources to participate on a comparable basis with generation and eliminated certain barriers to DR participation. In 2011, the FERC issued Order No. 745: *Demand Response Compensation in Organized Wholesale Energy Markets*[19]*,* which

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[12] This program originated as E-16 Tariff in Advice No. 00-03, Effective 07/01/00, and was modified.
[13] Pacific Gas and Electric. "*Base Interruptible Program*." *Available At:* https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/base-inerruptible/base-inerruptible.page
[14] Pacific Gas and Electric. "*Base Interruptible Program*." *Available At:* https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/base-inerruptible/base-inerruptible.page
[15] 42 USC 15801
[16] 16 USC 2642(a)(5)
[17] 16 USC 2642 (e) (1-3).
[18] 2007 -2019 Reports Available at https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp
[19] Order No. 745 also challenged traditional notions of State vs. Federal jurisdiction and was soon addressed by the U.S. Supreme Court in *Federal Energy Regulatory Commission v. Electric Power*

required ISO/RTO markets to compensate DR resources at the full locational marginal price (LMP).

In 2007, the OPUC responded to EPACT ’05 when the Commission required that utility IRPs include assessments of “all known resources,” including DR, to meet system planning and load requirements[20].

In 2016, the Oregon legislature passed Senate Bill 1547[21] (SB 1547) which established Energy Efficiency (EE) and DR at the top of the loading order[22] for Oregon utilities. In reference to DR, Section 19 of SB 1547 states, “[d]emand response resources result in more efficient use of existing resources and reduce the need for procuring new power generating resources, which, in turn, reduces energy bills, protects the public health and safety and improves environmental benefits”. SB 1547 also enables the OPUC to direct utilities to “plan for and pursue the acquisition of cost-effective demand response resources”[23].

1.2.3 Definition of Demand Response

PGE uses the Northwest Power and Conservation Council’s (NWPCC) definition of DR as

> *a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by*

Supply Association et al (EPSA). Justice Kagan issued the majority decision in the case noting that DR, though a resource developed on the retail part of the electric system has direct effects on the wholesale energy system, is a viable and important resource to control energy costs and the FERC does have the authority to require its jurisdictional entities to create pathways for market entrance of DR.

[20] UM 1331, Order Number 07-449, at p. 2 (November 2007) “all known resources for meeting the utility’s load should be considered, including supply-side options which focus on the generation, purchase and transmission of power . . . and demand-side options which focus on conservation and demand response.”

[21] Senate Bill 1547 78th Oregon Legislative Assembly (2016).

[22] Loading Order sets a priority list for electricity sources. The concept of a “Loading Order” was first introduced in The Northwest Power Act (Public Law 96-501) with creation of an obligation by BPA to acquire all cost-effective conservation (EE) prior to purchasing any new resource. The Northwest Power Act was nationally influential as it was the first instance that created a planning obligation to treat a demand-side resource on par with a generation resource. Since the Northwest Power Act’s passage, the treatment of EE on an equivalent basis with generation has become standard practice in utility planning.

The Northwest Power Act also directly influenced the development of the Loading Order rulemakings in California. In 2003 the California Energy Commission (CEC) issued a Staff Report entitled, *2003 Integrated Energy Policy Report,* followed three years later by a similar report entitled *Implementing California’s Loading Order for Electricity Resources*.[22] Through these two documents, the CEC first established the need to create a system loading order for resource and fuel diversity and then affirmed that utilities have the obligation to first seek acquisitions of EE and DR before any other generating resources. The loading order adopted by the Oregon Legislature in SB 1547 mirrors the language adopted by the CEC.

[23] Senate Bill 1547 78th Oregon Legislative Assembly (2016), Section 19, Codified as ORS Chapter 757.054

an agreement, potentially financial, or tariff between two or more participating parties.

PGE interprets this definition broadly to include a series of grid services offered by the customers to the utility or grid. DR is a category of services ranging from intra-hour services to behavior-based reductions or shifts in energy demand. To create a better categorization of customer-sited energy resources, PGE is looking to shift our language from DR to flexible load. PGE's shift is not new or novel; the industry as a whole has been evolving toward flexible load for several years. Additionally, PGE's working definition of flexible load is consistent with the NWPCC's working definition of DR as several different types of customer-sited technologies can offer the services embedded within the NWPCC's definition. Further, the use of the term Flexible Load is in harmony with Lawrence Berkley National Lab's definition of Demand Flexibility - "the capability of distributed energy resources DERs to adjust a building's load profile across different timescales"[24]. Here the authors, Tom Eckman and Lisa Schwartz, state that there are many economic values of demand flexibility for utility systems. The value of a single "unit" (e.g., kW, kWh) of grid service provided by demand flexibility is a function of the:

- Timing of the impact (temporal load profile)
- Location in the interconnected grid
- Grid services provided
- Expected service life (persistence) of the impact
- Avoided cost of the least-expensive resource alternative that provides comparable grid service[25].

1.2.3.1 Making the Case for Flexible Load

Flexible load is a cornerstone of PGE's commitment to decarbonization while maintaining reliability and affordability. Because flexible load can provide a range of essential grid services, it can help PGE meet the challenges of supporting a future where variable renewable resources provide the bulk of the energy supply. Additionally, if designed with the customer in mind, flexible load programs can address issues of equity and environmental justice.

In April of 2018 PGE issued *Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory*, our "Decarb Study[26]", which explored technology pathways to

[24] Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings, April 202, SEEAction, Tom Eckman & Lisa Schwartz. Available at https://emp.lbl.gov/publications/determining-utility-system-value.
[25] Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings, April 202, SEEAction, Tom Eckman & Lisa Schwartz. Available at https://emp.lbl.gov/publications/determining-utility-system-value.
[26] Gabe Kwok and Ben Haley "*Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory*" Portland General Electric, April 24, 2018. *Available a*t:

achieving an 80% reduction in greenhouse gases (GHGs) across the economy in our service area. The study focused on three bookend scenarios:

- a “High Electrification” pathway relying on electrifying space and water heating in buildings and deploying bulk energy storage to balance high levels of renewable generation;
- a “Low Electrification” pathway including a variety of renewable fuels, electrolysis, and power-gas facilities; and
- a “High Distributed Energy Resource” (DER) pathway, which is highly electrified and distributed, with increased rooftop solar PV and distributed energy storage in buildings and industry. Each of these pathways included high levels of battery electric vehicles (EVs).

Electrification of passenger transportation is a critical component of decarbonization. Within each of the three pathways, passenger vehicles are at least 90% electric by 2050[27]. Charging off peak and as when renewable generation is high or during the middle of the night, and actively managing EV load can mitigate peak load impacts while ensuring that passengers complete all of their intended trips.

Additionally, the Decarb Study found that by 2050, 90% of the generation mix must be carbon free in order to meet the established emissions reduction target. The total quantity of electricity produced must also be increased due to electrification of end-use demand such as heating, cooling, water heating and transportation. However, balancing electricity supply and demand becomes more challenging when variable renewable energy resources are the principal source of electricity supply, as these variable renewable resources have a fuel source, such as wind or solar irradiance, that cannot be stored or controlled.

The supply of energy must be balanced with the demand for energy in real time, down to the second. Today, PGE relies largely on a mix of thermal and hydro resources to provide the grid services that are needed to meet moment-to-moment changes in generation and load. This balance becomes more challenging as more variable renewable resources are added to the system. For example, the Decarb Study shows that renewable generation exceeds load in approximately half of all hours in 2050. To help balance the system, the scenarios in the Decarb Study included expansive customer participation in flexible load programs. Across all scenarios, by 2050, 75% of light duty vehicles and water heaters as well as 50% of space heating and conditioning and clothes washing and drying were assumed to be enrolled in a flexible load program. One key finding of the Decarb Study was that customer adoption of technologies that

https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/exploring-pathways-to-deep-decarbonization-pge-service-territory.pdf?la=en.

[27] Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory, at p.6, Portland General Electric, April 24, 2018. Available at https://www.google.com/search?q=Exploring+Pathways+to+Deep+Decarbonization+for+the+Portland+General+Electric+Service+Territory&sourceid=ie7&rls=com.microsoft:en-US:IE-SearchBox&ie=&oe=&safe=strict&gws_rd=ssl#

were critical to decarbonization, including electric vehicles and heat pumps, also created new and important opportunities for grid balancing via load flexibility. In fact, flexible load programs in the High Electrification scenario grew to about 2,000 MW by 2050, helping to reduce the need for new dispatchable generation resources. While the role of flexible load becomes especially critical in the context of deep decarbonization, these programs can also bring value to customers today. Chapter 4 describes each of the grid services that flexible load can provide and offers insight into the value of providing these services.

PGE also believes that deployment of flexible load solutions can help address environmental justice and equity challenges. Flexible load programs, by their nature, are accessible to all PGE customers regardless of socioeconomic demographics. Yet, without intentional efforts to build equity into our development and deployment of flexible load solutions, systemic energy inequities will persist, including a high energy burden for low-income customers.

To better understand how PGE can design these programs to ensure equitable practices, we have deployed personnel in the PGE Testbed who are tasked with studying and addressing equity issues. Their work is providing invaluable insights that informs future program design, and leads to the direct, meaningful, and measurable benefits that increase access to flexible load solutions and lower the energy burden of our low-income customers.

1.1.1.1 Long Term Evolution of Program Strategy

PGE's vision for flexible load is a high-value portfolio of grid services that support the decarbonized, decentralized grid through co-optimization of generation and load. Flexible load can move beyond providing peak capacity alone; with automation of control systems, flexible load has the potential to offer high value grid services. Incorporating thoughtful program design and customer centric operations can minimize the impact on customers providing these services.

DR Service Product	
Shed	Capacity
	Energy
	Economic DR
	Emergency DR
	Distribution Deferral
Shift	Time of Use
	Some Behavior Programs
Shimmy	Load Following
	Contingency Reserve
	Frequency Response
Shape	Energy Efficiency
	Some Behavior Programs

Figure 2 – PGE's Vision of Demand Response Services

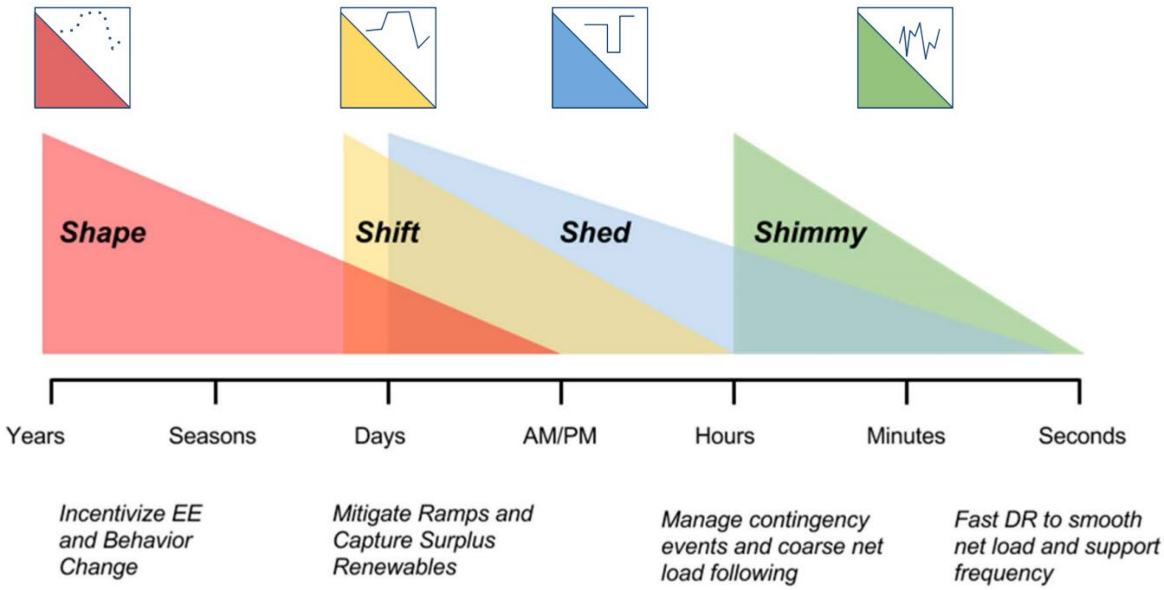

Figure 3 – Evolution of Demand Response and Flexible Load Services

Figure 3 reflects the different planning and operational time horizons of DR and flexible loads, as well as the types of grid services that flexible loads can provide. More detail on the function and requirements of each service are available in section 4.4.1, Flexible Loads as a Grid Service.

Resources that “shape” load operate over years or seasons to reshape the overall load but are not necessarily responsive to system events. These programs help address power costs by reducing the amount of MW to be procured or built to meet peak electric demand. This category includes EE and behavioral programs.

PGE’s program portfolio presently falls into the “shift” and “shed" categories. Generally, such programs are called day-ahead and reduce energy demand for a set number of hours during system peaks. These reductions are accomplished through either a shift in usage, as in our Flex pilot, or through a load shed or shift, as in the Energy Partner program[28].

As technology improves and costs come down, PGE’s flexible load offerings are evolving capabilities to provide grid services in real time as part of a dynamic portfolio capable of optimizing benefits across capacity, energy, and flexibility products. Programs in this category are responsive within minutes or seconds. Additionally, some “shimmy” services, such as frequency response, may be called upon rarely, while other products, such as regulation and load following, are called upon continuously for balancing service.

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[28] Within the PGE Smart Grid Testbed, PGE is also using the Peak Time Rebate program to test renewable integration and carbon reduction messaging. These additional use cases offer PGE an opportunity to study the impact of using this program more frequently. The results of these tests inform the way that PGE incorporates flexible load resources into IRP planning and future operations.

PGE's multifamily water heater pilot represents the most advanced form of flexible load. This pilot uses intra-hour dispatch which should prove able to respond to both distribution and wholesale grid needs by providing a flexible product to balance load and generation.

While PGE is excited about the opportunities for flexible load to provide a variety of grid services, building a portfolio that is capable of providing response in all timeframes—Shape, Shift, Shed, and Shimmy—will best enable PGE to co-optimize the flexible load resource to maximize the value across all resources for PGE's customers. This bundling across response times and technologies will enable the creation of Virtual Power Plants.

This vision of flexible load is in harmony with recent Commission decisions to define various use cases for demand side assets. For example, in UM 1751, *HB 2193 Implementing an Energy Storage Program*, the Commission issued Order 17-118 whereby the Commission delineated a series of energy services which a distribution-sited or demand side-sited resource – in this case energy storage – could provide to the grid.

Table 1 – Energy Storage Use Cases[29]

Category	***Service***	***Value***
Bulk Energy	Capacity or Resource Adequacy	The energy storage system is dispatched during peak demand events to supply energy and shave peak energy demand. The energy storage system reduces the need for new peaking power plants.
	Energy Arbitrage	Trading in the wholesale energy markets by buying energy during low-price periods and selling it during high-price periods.
Ancillary Services	Regulation	An energy storage operator responds to an area control error in order to provide a corrective response to all or a segment portion of a control area.
	Load Following	Regulation of the power output of an energy storage system within a prescribed area in response to changes in system frequency, tie line loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.
	Spin/Non-Spin Reserve	Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spin reserve is off-line generation capable of being brought onto the grid and synchronized to it within 30 minutes.
	Voltage Support	Voltage support consists of providing reactive power onto the grid in order to maintain a desired voltage level.
	Black Start Service	Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout.
Transmission Services	Transmission Congestion Relief	Use of energy storage to store energy when the transmission system is uncongested and provide relief during hours of high congestion.
	Transmission Upgrade Deferral	Use of energy storage to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth, regulate voltage, or avoid the purchase of additional transmission rights from third-party transmission providers.
Distribution Services	Distribution Upgrade Deferral	Use of energy storage to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the distribution system to accommodate load growth or regulate voltage.
	Volt-VAR Control	In electric power transmission and distribution, volt-ampere reactive (VAR) is a unit used to measure reactive power of an AC electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity (1).
	Outage Mitigation	Outage mitigation refers to the use of energy storage to reduce or eliminate the costs associated with power outages to utilities.
	Distribution Congestion Relief	Use of energy storage to store energy when the distribution system is uncongested and provide relief during hours of high congestion.
Customer Energy Management Services	Power Reliability	Power reliability refers to the use of energy storage to reduce or eliminate power outages to utility customers.
	Time-of-Use Charge Reduction	Use of energy storage to reduce customer charges for electric energy specific to the time (season, day of week, time-of-day) when the energy is purchased.
	Demand Charge Reduction	Use of energy storage to reduce the maximum power draw by electric load in order to avoid peak demand charges.

Flexible load, DR, and energy storage can all be viewed from an integrated perspective. These services, outlined in *Table 1*, can be supplied by a host of different technologies with various degrees of accuracy, timing, and duration. For example, a thermostat can be operated to reduce peak load for a four-hour period but may also provide more frequent reductions over shorter durations. A battery may be capable of supplying all of the above services for 4+ hours depending on its chemistry, but a water heater may also be capable of supplying many of the same services at a fraction of the cost.

1.2.3.2 Developing the Virtual Power Plant

PGE is building DR and flexible load with an end-state in mind whereby flexible loads act in concert, aggregated at the substation level; this concept has been dubbed a “Virtual Power Plant”. Virtual Power Plants are unique to the assets behind the substation; in other words, a Virtual Power Plant’s operational profile is limited by the specific flexible load technologies that are aggregated at each substation[30]. A Virtual Power Plant operates to service energy needs below the substation on the distribution system and energy needs above the substation on the bulk energy system.

Advanced visualization and operation controls are needed to manage and operate a Virtual Power Plant, as not all Virtual Power Plants can supply the same services in the same way. Additionally, each Virtual Power Plant may have local distribution infrastructure constraints. Each Virtual Power Plant must service distribution system operation requirements first and may therefore provide different grid services. Additionally, a Virtual Power Plant may be able to provide different grid services at different times. For example, a Virtual Power Plant that is primarily providing distribution system deferral could also provide regulation reserves when the system is not constrained.

In order to the manage Virtual Power Plant PGE is building an Advanced Distribution Automation System (ADMS) as part of the integrated grid. The ADMS system includes an advanced communication network to allow near real-time visualization of the health and operation of the distribution network and to provide monitoring of the availability of local Virtual Power Plant services.

As PGE builds more advanced DR and flexible load programs, it is essential that this work is done in concert with the investments in ADMS to provide the communication capabilities and networks necessary to use the resource for grid services and be able to visualize the resource either individually or as part of a Virtual Power Plant. These communications are necessary for flexible loads to provide the grid services that require dispatch and communications in real time.

[29] Modified from Akhil et at.2015., Oregon Public Utility Commission UM 1751, Order 17-118, March 2017, page 17.
[30] For example, one substation’s Virtual Power Plant may see a predominance of solar and battery storage; another substation’s Virtual Power Plant may be primarily demand response.

1.2.4 *Device Data, Resource Development, and the Customer Experience*

PGE is developing flexible load demonstrations, pilots and programs to empower our customers to control their overall energy costs, reduce system costs, decarbonize and provide benefit to the community while maintaining reliability. Our work in the Testbed is researching and testing different ways to engage with our customers and to communicate the value of participating in flexible load programs. PGE's current DR activities are providing bill savings and participation opportunities for all customers. These programs are first and foremost efforts to better meet our customer needs. PGE is working to build a portfolio of flexible load programs which benefits all customers and allows customers to engage with and participate in a decarbonized energy platform.

PGE customers expect to have an excellent experience with flexible load programs; these positive customer experiences create ongoing success for these programs. Additionally, customers deserve to know and understand how participation in these programs drives meaningful change, whether through reductions in cost, meeting decarbonization goals, or supporting their community.

For PGE to have effective relationships with customers, PGE will need to reshape how customer information and data is shared. PGE must also leverage technologies made by other manufacturers whether a solar inverter, a water heater or a thermostat. These technologies will help shape the customer experience, the resource, and grid operations. OEM terms and conditions place limits on data access. Thus, access to data is increasingly more important to PGE and to the expansion of flexible load program capabilities.

As explored further in Chapter 3, PGE would like to open a discussion with the Commission to address data sharing.

1.3 Planning Practices

PGE has a long history of planning for DR programs within the IRP process. In the early 2000s, PGE explored the potential for DR pilots, including direct load control (DLC) of space heating and water heating, to contribute to meeting our capacity needs. Over time, PGE's approach to evaluating demand response and flexible load in the IRP has gained sophistication, largely by leveraging outside expertise through a series of demand response potential studies. PGE first conducted a third party DR potential study as a joint exercise with PacifiCorp in 2004 as a result of OPUC Order No. 03-408[31]. PGE subsequently contracted with Quantec, LLC to update the

[31] Available at: https://app.nwcouncil.org/media/4502/dr_assessment.pdf.

study to inform the 2007 IRP[32] and with Brattle to conduct potential studies to inform the 2009, 2013, and 2016 IRPs.[33,34,35]

Demand response potential studies typically involve three steps:

1. **Quantifying the technical potential**, or the amount of the resource that is technically possible, without consideration of cost or other market barriers. It considers all measures or resource opportunities, the savings associated with each, and the number of opportunities to implement or install each resource over a 20-year planning period.

2. **Determining the achievable potential,** which accounts for market barriers, as well as technology and market maturity. Historically, EE planners in the Northwest have assumed that market barriers limit achievable potential to no more than 85% of technical potential. This maximum achievability assumption is based on the 1980s Hood River Conservation Project funded by the Bonneville Power Administration[36]. In the context of DR and other flexible load resources, this maximum achievability assumption would vary depending on the type of resource being considered, as the market barriers to acquiring flexible load resources may be more significant than those of EE[37]. Achievable potential[38] also employs curves called ramp rates to quantify the amount of potential acquired in a given year out of the total technical potential available. Ramp rates reflect program maturity, technology maturity, market readiness, and program budgets.

3. **Applying an economic screen,** which determines the amount of potential that is cost effective for PGE to pursue. The economic screen involves an estimation of costs and benefits of each program and a cost effectiveness determination based on an agreed upon cost effectiveness framework. Cost effectiveness is discussion in more detail in Chapter 4.

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[32] See Section 4.3 in PGE's 2007 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc43haa105740.pdf.

[33] See Section 4.2 in PGE's 2009 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc48haa151359.pdf.

[34] See Section 4.2 in PGE's 2013 IRP, available at: https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/pge-2013-irp-report.pdf?la=en.

[35] See Section 6.3 in PGE's 2016 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc66haa144338.pdf.

[36] The Hood River Conservation Project was intended to test the upper limits of a utility retrofit program. HRCP sought to install an extensive package of retrofit measures in all the electrically heated homes in Hood River, Oregon. The results from the Hood River Conservation Project form the basis for the energy efficiency planning in the Northwest and nationally today.

[37] To date, there has been no similar study on DR or flexible load saturation potential.

[38] Note that some potential assessments also consider program potential, but the same considerations that define program potential can be considered as part of the determination of achievable potential.

These steps are summarized in Figure 4

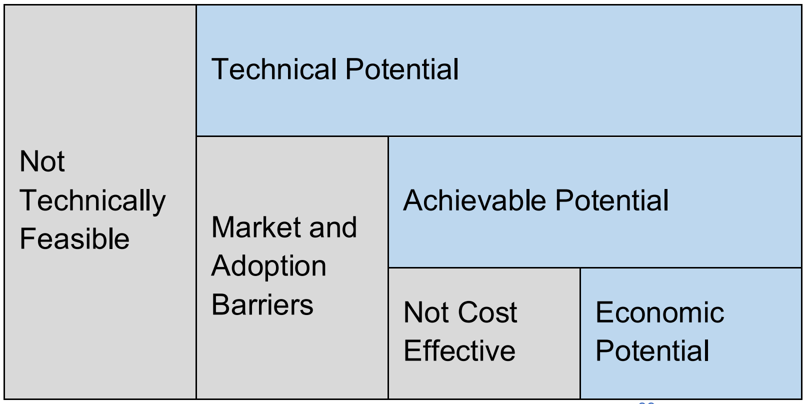

Figure 4 – Types of Flexible Load Potential[39]

PGE's approaches to incorporating the results of demand response potential evaluations into IRP analyses and the IRP action plans have evolved over time. PGE incorporated a DR forecast into the 2009 IRP based on the potential from the Brattle Study, with adjustments built on PGE's experience and the specific activities that the Company planned to undertake. PGE incorporated DR forecasts into the 2013 IRP based on the findings in the Demand Response Potential Study conducted by Brattle Group.[40] The work was further informed PGE's assessment of participation in the Company's curtailment tariff. In the 2016 IRP, PGE again improved on DR forecasting; PGE developed a DR portfolio based on the DR potential study but adjusted the DR portfolio for potential interactions between programs. This adjusted DR portfolio went into the preferred portfolio and was ultimately reflected in the IRP Action Plan.

In the 2019 IRP, PGE leveraged the information from the DR Potential Evaluation from the 2016 IRP to inform a broader study of DERs. The 2019 IRP Navigant Distributed Energy Resources Study applied customer propensity to adopt models across a wide range of DERs, including DR. The study developed an internally consistent set of low, reference, and high DER adoption scenarios that accounted for interactive effects between DERs, including DR programs.[41] The study resulted in three DER adoption scenarios (low, reference, and high), which flowed into PGE's IRP needs assessment and portfolio analysis and Action Plan. The study developed an internally consistent set of low, reference, and high DER adoption scenarios that accounted for

[39] Adapted from U.S. Environmental Protection Agency. *Guide to Resource Planning with Energy Efficiency*. Figure 2-1, November 2007

[40] PGE 2013 IRP Report, Section 4.2 Demand Response Potential Study, available at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwjlpf-wiIXqAhUiHzQIHYIpDAIQFjAAegQIAhAC&url=https%3A%2F%2Fwww.portlandgeneral.com%2F-%2Fmedia%2Fpublic%2Four-company%2Fenergy-strategy%2Fdocuments%2Fpge-2013-irp-report.pdf%3Fla%3Den&usg=AOvVaw1WtS_gz367mTEVdY7OXDjD

[41] See Section 5.1.1 in PGE's 2019 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc73haa162516.pdf.

interactive effects between DERs, including DR programs[42]. The study resulted in three DER adoption scenarios (low, reference, and high), which flowed into PGE's IRP needs assessment and portfolio analysis and IRP Action Plan.

The studies to support long term planning over the last five IRPs have helped PGE to develop a more nuanced understanding of DR and to incorporate more rigorous treatment of DR over time. The studies have also helped inform the design of new DR programs by leveraging those consultants' outside expertise and insights. While this work has been integral to PGE's continued progress on planning for and implementing DR programs, it has also created some challenges that are worth considering as PGE contemplates alternative planning approaches:

- DR forecasts produced by these studies are exogenous to IRP modeling. This means that PGE cannot readily test potential interactions between new resource additions and alternative DR portfolios, potentially resulting in sub-optimized DR targets. This is a similar challenge to the EE forecasts from the Energy Trust.
- The studies incorporate limited information from PGE's actual deployment of DR programs, and therefore may be influenced more by national trends than local circumstances.
- The studies have limited transparency and ability to update input assumptions and incorporate learnings due to outside experts' use of proprietary models.

In the past, the insights provided by the outside studies have outweighed these drawbacks. However, as the role of DR grows in PGE's portfolio, the relative impact of some of the shortcomings of these exercises also grows. PGE discusses new potential approaches to planning for flexible load within the IRP and DRP process in Chapter 2.

1.4 Program Information

1.4.1 Chapter Synopsis and Road Map

This Section is a high-level review of PGE's current Flexible Load portfolio, including brief descriptions of each activity. A ribbon at the top of each description shows total costs of the life of the activity, size of the resource in megawatts, and the date of the next expected evaluation.

PGE includes these program descriptions to ground the reader in PGE's current program activities. In the remainder of this document, PGE refers back to these programs to provide examples that illustrate how PGE is enacting the programmatic and product changes described in Chapters 2-4. PGE also includes a more detailed write-up of each activity in Appendix 1 of this filing. This Chapter does not contain a proposal for Commission action; rather this Chapter and Appendix 1 serve as a demonstration of PGE's continued commitment to open and transparent

[42] See Section 5.1.1 in PGE's 2019 IRP, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc73haa162516.pdf.

reporting, and a reference for the remainder of this document. Readers who are familiar with PGE's programs may wish to jump to Chapter 2.

The collection of PGE's flexible load program work is an impressive advancement in PGE's programs and capabilities since the initial ramp-up to meet the 2016 IRP DR goals. Each of these activities targets a unique space within the flexible load resource ecosystem. Multifamily water heater is proving the use case for a fast-acting, flexible load resource. Water heaters are ubiquitous in electric homes and are capable of providing year-round grid services multiple times a day while minimizing customer impact. The Flex pilot is proving DR and the benefits of customer participation without requiring capital investment by the customer. The Flex pilot will demonstrate a variety of participant values to our customers. These customer value propositions are being explored in the PGE Smart Grid Testbed (Testbed).

1.4.2 Non-Residential Demand Response Energy Partner Program

Total Costs	Megawatts Procured	Next Evaluation
$9.8M (Jun 2017 to EOY 2020)	21.8 MW	Q2-2021

1.4.2.1 Program Description

PGE established Energy Partner as a non-residential DR program designed to reduce peak demand requirements during specific time windows in the winter and summer seasons. The primary source of this reduced demand (load) is from large customers, with an option for small and medium customers to participate as well. The Energy Partner Program provides firm capacity and may evolve to provide intra-hour grid services to support reliability and renewables integration. The 2018 target was 14MW of DR, increasing to 20MW for 2019, and ultimately reaching 27MW by January 1, 2021.

PGE launched its non-residential DR pilot in December 2017 and directly administered the pilot with support from:

- CLEAResult for program implementation; and
- Enbala for technology integration via their Virtual Power Plant software platform.

In 2017, PGE found that the selected third-party administrator was falling short of load goals and began taking a more active management role in the prior "turnkey" DR program. PGE's active management proved beneficial for multiple reasons. First, it provided PGE the flexibility to develop a variety of product offerings and to adjust the offerings as necessary in the future. A second reason for PGE to work directly with customers is portfolio resiliency. With the loss of the third-party demand response provider in 2017, PGE had to execute new contracts and deploy new technology to current participants which presented customer retention risk. Directly administering the program should avoid such operational risks. PGE's administration of the program also allows for better bundling and/or cross-marketing of the program with other offerings such as EE, renewables, storage, and dispatchable standby generation.

As Energy Partner matures, it may evolve from solely a capacity resource to other use cases such as load following and renewable firming. Including business DR provides an opportunity to accelerate learnings, as well as test and optimize new use cases.

1.4.3 Multifamily Water Heater Pilot

Total Costs	Megawatts Procured	Next Evaluation
\$4.1M (cumulative through EOY 2019)	3.4MW	Summer 2020-21 (due in March 2022)

1.4.3.1 Program description

The Multifamily Water Heater pilot aims to enable and operate electric water heaters for demand flexibility. This program provides capacity as well as intra-hour energy and lays the foundation for PGE's DR programs to offer intra-hour grid services to support reliability and renewables integration. The approach is relatively novel as it capitalizes on the density of electric water heaters found in multifamily dwellings. This density is necessary for several reasons:

1. Broadly-distributed assets are more expensive per unit installation, whereas concentrations of units allow PGE to enable water heaters for a fraction of the cost;
2. Many multifamily units install the water heater within the living space using electric resistance water heaters. Installation of heat pump water heaters is not a common practice. This niche allows PGE to test advanced use cases from electric resistance water heaters without affecting the Energy Trust's and the Northwest Energy Efficiency Alliance's (NEEA) efforts to promote adoption of more efficient heat pump water heaters;
3. Installing a concentration of these units in multifamily buildings provides PGE an opportunity to accelerate working with water heaters as a flexible load resource compared to current deployments of DR enabled heat pump water heaters.

Water heaters provide a cost-effective approach to supplying grid services. PGE developed the Multifamily Water Heater Program to learn about the connectivity and controllability of a flexible load resource from a highly dynamic, ubiquitous appliance. PGE's learnings from this pilot will also help inform our approach to single family water heaters.

1.4.4 Smart Thermostat Pilot

Total Costs	Megawatts Procured	Next Evaluation
$5.5M (Cumulative through EOY 2019)	13.7MW	Summer 2020 (due July 2021)

1.4.4.1 Pilot Description

The Direct Load Control Smart Thermostat Pilot aims to enroll and operate connected residential thermostats to control electric heating and cooling load. This program provides firm capacity; PGE is working with the Energy Trust to explore how thermostats and other efficacy measures can be paired to provide longer duration energy optimization. To participate in the program, PGE customers must have a qualifying heating, ventilation, or air conditioning (HVAC) system (ducted heat pump, electric forced-air furnace, or central air conditioner). The pillars of the pilot rest on two delivery channels:

1. **Bring Your Own Thermostat.** Customers may enroll online in PGE's DR program by purchasing a new qualifying thermostat, or using an existing qualifying thermostat attached to a qualifying HVAC system. Customers receive a $25 enrollment incentive and $25 for each DR season that they participate in (defined as 50% of the DR hours called within a season). Customers are permitted to opt-out of any or all events.

2. **Residential Thermostat Direct Installation.** Customers with a qualifying HVAC-system can participate by having a qualified thermostat, installed, provisioned, and enrolled into PGE's DR platform by a PGE contractor. This channel provides a no cost thermostat for customers with ducted heat pumps or electric forced air furnaces due to the high DR capacity value. Customers with central air conditioners are charged an incremental cost of $50. Customers from this channel are excluded from receiving PGE enrollment or seasonal participation incentives.

1.4.5 Flex 2.0 - Peak Time Rebate and Time of Use

Total Costs	Megawatts Procured	Next Evaluation
$3.9M (Cumulative EOY 2019)	6.9MW	Estimated August 2022

1.4.5.1 Program Description

This pilot provides energy optimization by alerting residential customers to shift use out of high demand periods and deliver peak reduction.

In 2016, PGE launched a two-year Residential Pricing Pilot (Flex 1.0) in which a combination of 12 opt-in and opt-out Time of Use (TOU), Peak Time Rebate (PTR), and Behavioral DR (BDR) scenarios were tested. Approximately 14,000 customers were enrolled in control or treatment groups and provided valuable insights into customer response to, and expectations of, programs of this nature. In June 2018, Cadmus completed an independent evaluation of the Flex 1.0 pilot and confirmed that PGE can cost-effectively obtain demand savings through pricing and behavior-based DR programs and offered specific recommendations on those scenarios that delivered both the highest value and levels of customer satisfaction.

Based on those findings, PGE worked with OPUC staff and stakeholders to develop the Flex 2.0 “Residential Pricing Pilot”. The first step for implementing Flex 2.0 was launch of a PTR program in April 2019. The vast majority of PGE’s residential customer base is eligible to participate in this voluntary program, and 77,000 residential customers enrolled in the pilot on an opt-in basis by the end of 2019, exceeding our Year 1 enrollment goal by 40 percent.

The PTR pilot provides educational energy saving tips and rewards customers for shifting their energy usage during 3-4 hour “event” periods. Customers are notified a day ahead of the event via text and/or e-mail (based on their preference). After the event, they are notified of the result of their specific effort and, if applicable, their earned incentive. There is no “penalty” should a customer use more than expected energy during an event, making PTR a no-risk, “win-only” program for our customers.

PGE is working with OPUC Staff on the design of a new TOU rate and plans to submit a revised Schedule 7 tariff to include the new pricing structure in Q2/Q3 2020. The TOU pricing plan could be combined with PTR to enhance year-round savings and provide daily load shift value to PGE.

1.4.6 Residential Battery Energy Storage Pilot

Total Costs	Megawatts Procured	Next Evaluation
$66K	160kW	Est. June 2021

1.4.6.1 Program description

Behind the meter batteries are considered flexible load as they will adjust customer load and are expected to provide a host of valuable grid services. In the Single-Family Battery Pilot[43], a fleet of batteries will act in aggregate to provide grid services; individually they will provide customer services. The Battery Pilot will provide capacity, grid services, and home energy back-up for the customer. While PGE has established the value of some grid services through modeling, this pilot will confirm this value through operational demonstration and establish values for other services that are difficult to model. The pilot intends to aggregate 525 residential batteries totaling 2-4MW

[43] These batteries are cited on the customer side of the meter and are thus included in the definition of “flexible load” while other utility-scale pilots do not meet this definition.

in size and 6-8MWh in duration. Each battery will provide between 3-6kW of power output and 12-16kWh of energy storage.

In April 2020, PGE submitted a proposal[44] to the Commission to leverage battery energy storage systems installed on residential customer homes. These battery systems will be located behind the utility electric meter and serve as a dispatchable resource providing a range of grid services.

[44] PGE filed Advice No. 20-08, Schedule 14 Residential Battery Energy Storage Pilot, on April 21, 2020, with a requested effective date of August 1, 2020.

Chapter 2 Planning, Goal Setting, Regulatory Treatment

Chapter Summary

Chapter 2 of the Flexible Load Plan requests action from the Commission regarding PGE's proposal to move to multiyear planning and budgeting. The proposal includes regular quarterly engagement and updates with Commission Staff, as well as regular report submittals to the Commission regarding progress, spending, and savings. This is a change in practice from current single measure development and cost recovery to portfolio-level planning and cost recovery. PGE's proposal is informed by best practices undertaken in the Northwest around energy efficiency planning, funding, and acquisition. The proposal is meant to give the Commission, Staff, and stakeholders an extraordinary amount of transparency and collaboration regarding PGE's work to develop flexible load.

Chapter 2 also discusses PGE's evolved planning and measure development practices. Within this Chapter, PGE shares how we conduct measure development and strategic market engagement. PGE calls this process Product Lifecycle Management (PLM). It is a stage-gated process that judges a product's market readiness. The PLM process is informed by practices from the private market and is similar to the process used by the Northwest Energy Efficiency Alliance (NEEA). PGE requests understanding from the Commission and stakeholders as to why we have created an evolutionary type of measure development which starts at demonstration, before moving to pilot, and finally program.

PGE efforts to develop flexible load are leading the region, but we do not have the benefit of regional co-development, as granted to energy efficiency. Therefore, PGE will need to identify planning values and validate technologies through small demonstration work, much of which will leverage the PGE Testbed. Such activities and investments in energy efficiency are generally shared by the region. PGE has designed this measure development structure to accelerate measure development while controlling costs. Whereas in the past, PGE's single measure planning, funding and pilot-to-program scaling work has been, to an extent, siloed, the structure shared in this chapter should addresses cost, cost effectiveness, and program scaling issues that PGE is currently managing within our present program offerings.

Lastly, Chapter 2 gives the reader insight into our customer outreach and diversity, equity, and inclusion (DEI) practices and how they will inform measure development. Chapter 2 also attempts to connect our DRP, Smart Grid and IRP work to the activity outlined in the Flexible Load Plan. The inclusion of this discussion is not meant to displace or replace the need or requirements of the other individual reports, nor is it meant to influence the activity in UM 2005. We provide this discussion only in attempt to make connections for the reader and our stakeholders.

2.1 Chapter Synopsis and Road Map

This chapter is the focal point of the Flexible Load Plan, as it sets forth PGE's proposal to move to portfolio level planning and budgeting. It also proposes a shift in regulatory practice to align with Demand Side Management (DSM) best practices seen throughout the Northwest and the nation.

PGE proposes to move to a multiyear planning and budgeting framework to align with the targets established through our resource planning process. PGE also proposes to provide annual updates to the proposed multiyear plan which details program implementation and operation. Further PGE would provide bi-annual budget updates for the first two years after which PGE would shift to annual budget updates. This proposed framework allows PGE to plan over a period of years with a known budget that can be used across a portfolio of activity. Cost effectiveness will be measured and reported at both the measure and portfolio basis. This proposal is similar to the practices of other regional utilities operating DSM and the planning framework employed by the Energy Trust and NEEA.

Additionally, this chapter communicates PGE's movement to a new product lifecycle framework, an internal process known as Product Lifecycle Management. This process is intended to ensure cross functional input and program development, among other things. Additionally, PGE communicates a shift in our strategic program development within the new construction market (to leverage delivery savings) and the retrofit market (by offering a bundled approach to all DSM and flexible load offerings, including close coordination with EE delivery). Lastly, this chapter reviews our IRP treatment of Flexible Load and discusses how Flexible Load will be incorporated into distribution system planning. This chapter also communicates PGE's commitment to reporting to the Commission, Commission Staff and stakeholders.

2.1.1 Introduction

As noted in the introduction, the Pacific Northwest has been investing in energy efficiency since 1980. Forty years of investment has allowed the region's utilities to establish best practices for development, procurement, modeling and reporting; these practices are emulated across the country. PGE's review of Northwest DSM practices informs the proposal below. This review indicates that PGE should adopt multiyear planning, coupled with multiyear budgeting and portfolio acquisition as a best practice to achieve both sustained programmatic success and cost effectiveness. These practices should be coupled with yearly updates and regular reporting to the Commission and stakeholders to provide transparency and accountability.

2.2 Practice Change Framework

PGE's Flexible Load Plan is a demonstration of PGE's commitment to a new type of resource development and new procurement practices with the goal of building advanced flexible load programs through a customer centric partnership. The Flexible Load Plan also demonstrates PGE's embrace of new approaches to strategic planning, project/product/program design, organizational structure, stakeholder engagement, and cross-utility collaboration.

PGE, with guidance from the OPUC, is pursuing innovative, customer-focused programs using flexible load technologies embedded in the distribution grid. These technologies present novel challenges to all parties. Decarbonization of Oregon's economy is a goal embraced by PGE, our customers, the OPUC, and the State of Oregon. Achieving this goal requires PGE to innovate and deliver measurable customer value and benefits. An effective demonstration-to-pilot-to-program lifecycle is critical to accomplishing our collective decarbonization and flexible load resource development goals.

PGE instituted a framework which utilizes five essential pathways to flexible load resource development[45]. Table 2, is a representation of these five essential pathways:

Table 2 – Five Essential Pathways to Innovation and DSM Resource Development

Strategic Planning	**Implement a long-term strategy for program development, cost control, transparency and collaboration**
Designing to Scale	**Design demonstrations and pilots to maximize learning and prepare for full scale deployment**
Organization	**Create leadership support and accountability, dedicated resources and cross functional collaboration within the utility for effective program development**
Stakeholder Engagement	**Collaborate effectives across industry stakeholders to design and execute meaningful projects**
Cross-Industry Collaboration	**Share best practices and lessons among utilities to accelerate effective demonstration, pilot to program evolution**

[45] Note: this section focuses on program development; program operations and evaluation are covered separately in detailed program write-ups in the appendix to this document.

2.2.1 Strategic Planning

Over the last four years, PGE has emerged as a national leader in developing the flexible load resource. PGE's leadership in this space is primarily due to the top-down alignment of flexible load with the Company's corporate strategy to decarbonize, electrify, and perform. Flexible load resources are significant to PGE's future and our ability to deliver a clean energy future to our customers and community. Therefore, it is essential to have a long-term strategic plan for product and program development that ties the Company's three strategic imperatives to flexible load products and programs.

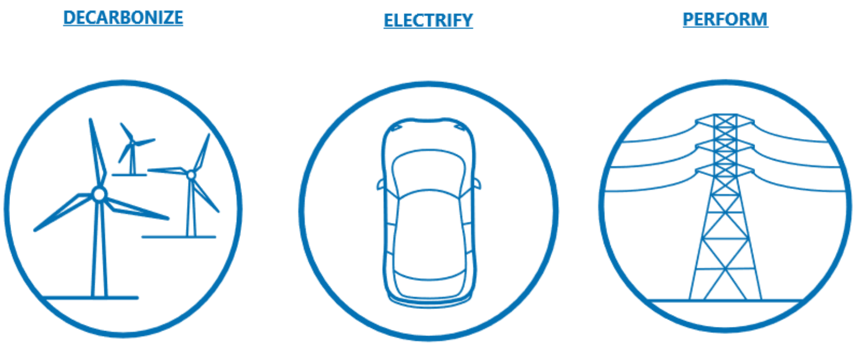

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Figure 5 – PGE's Long-Term Imperatives for a Clean Energy Future

2.2.1.1 Decarbonize

PGE, in partnership with our customers and community, has chosen climate action. Increasingly, our customers want their energy choices to be cleaner than ever. To that end, in 2018, more than 90 percent of PGE's energy supply is generated right here in the Pacific Northwest. PGE is committed to reducing our greenhouse gas emissions by more than 80%. PGE recently announced a renewable energy facility, Wheatridge, that is the first-of-its-kind in North America, combining wind and solar energy with battery storage at scale. Additionally, PGE has emerged as a leader in developing flexible load resources, as exemplified by our pioneering work on the Smart Grid Testbed. The Testbed is implementing simple customer solutions, devices, and behavioral changes to reduce the carbon in PGE's system and reduce investments in large generation resources.

2.2.1.2 Electrify

Approximately 35% of Oregon's end use demand for energy is currently served by electricity; the rest is served by served by direct combustion of natural gas and petroleum.[46] To help our customers meet their goals of driving decarbonization of the entire economy, PGE will lead the way through beneficial electrification pilots and programs that impact end uses like transportation – powering society with energy that we make cleaner every day. In doing so, PGE will capture

[46] Oregon Department of Energy. 2018 Biennial Energy Report. *Available At:* https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-Biennial-Energy-Report.PDF

the benefits of new technology, leading to an increasingly flexible and reliable grid and the connectivity and controllability needed for a Virtual Power Plant.

2.2.1.3 Perform

PGE is at its best when we deliver what customers want, namely affordable, reliable, cleaner energy choices. This is particularly critical as society undergoes a clean energy transformation. PGE seeks to serve and provide equitable access to all customers, not just the most profitable. PGE knows that the heart of business is keeping the power on safely, reliably, and affordably. To keep the grid running smoothly, PGE must continue to increase efficiency. PGE also seeks to deliver exceptional customer experiences, which includes empowering and enabling our customers to control their total energy costs by providing them new platforms to extract benefits from our service. Flexible load programs allow PGE to perform to our customers' expectation and standards.

2.2.2 Designing to Scale

PGE is implementing a new framework for program development. The first stage of this process focuses on smaller scale demonstrations of technology, product, and approach. Successful demonstrations continue on to a pilot stage, with controls to appropriately manage the progression to scale and to achieving cost effectiveness. The objective is to produce a long term, cost effective program with stability of approach, customer experience, and predictable costs and performance.

2.2.3 Organization

In the past two years PGE hired new leaders, new talent, and reorganized our customer programs, services, and support groups to overcome organizational silos and competing priorities. These groups are accountable to senior leaders through yearly accountability goals and scorecards which assess performance of the individual, team, and management. For example, the performance of the Smart Grid Testbed affects the assessment of the Team's most senior leader - the Vice President of Grid Architecture, Integration, and System Operations, Larry Bekkedahl. Additionally, PGE has created a Product Life Cycle Management process to engage business units across the utility in the design, execution, evaluation, and scaling of our flexible load projects.

2.2.4 Stakeholder Engagement

Stakeholder engagement and support is essential for meeting the aggressive, innovative goals that PGE and the OPUC have adopted for flexible load deployment. To ensure meaningful and beneficial stakeholder engagement in the development of flexible load resources, PGE designed its Product Lifecyle Management process to assess the necessary level of engagement for each of phase of the lifecycle. Varying levels of stakeholder engagement will exist for the ideation, design, implementation, and evaluation of resources. PGE's stakeholder engagement activities are described in more detail in Section 3.6, below.

2.2.5 Cross Industry Collaboration

As noted above, industry collaboration is key to the Company successfully delivering flexible load resources that will ultimately culminate in a Virtual Power Plant. PGE has been working to establish coordination with the Energy Trust through the Smart Grid Testbed advisory groups and regular monthly coordination meetings with the project team. Additionally, PGE has recently opened a conversation with PacifiCorp about co-development of demonstration and pilot projects that may offer enhanced customer experience and cost saving opportunities. PGE has also engaged with the Northwest Energy Coalition (NWEC) and NEEA about sharing lessons learned from our work and furthering regional collaboration. Lastly, PGE has been sharing our work with the region through various regional forums such as the NWPCC's Demand Response Advisory Council and GridFWD and nationally through the Electric Power Research Institute (EPRI) and the Peak Load Management Alliance (PLMA).

2.3 From Demonstration, to Pilot, to Program Lifecycle

Designing to Scale	Design demonstrations and pilots to maximize learning and prepare for full scale deployment

Much of PGE's flexible load resource was developed as DR or pilot activity. The arc of this development was circumstantial. In the lead up to PGE's 2016 IRP, the company had less than 15MW of DR procured through a single large commercial and industrial program. In the 2016 IRP, PGE identified 77MW/69MW of Winter/Summer DR potential capacity available on its system. As part of Order 17-386, the Commission adopted the identified DR potential as PGE's goal for 2021. When reviewing PGE's proposed 2016 IRP DR goals, Staff noted its concern that PGE was "stuck in a pilot cycle."[47]

In the same docket, the Commission issued a white paper on the concept of a DR Testbed as a tool for accelerating the demonstration to program lifecycle as part of an acknowledgement that the acquisition of 77MW/69MW by end of year 2020 was a necessary but challenging task.[48]. In turn, PGE pursued the rapid development of a DR resource with the understanding that these efforts were novel and thus required the regulatory latitude that comes from conducting pilot activity. While the initial build of PGE DR activity would not be cost effective, PGE has an

[47] LC 66, Staff's Final Comments, Page 22, May 12, 2017

[48] LC 66, Staff's Final Comments, Appendix A Demand Response Testbed Overview. "The fundamental purpose of the DR Testbed is to test a number of hypotheses and critical assumptions about the potential of DR in the Northwest that are difficult or impossible to obtain during the initial rollout of PGE's proposed DR programs. Without such a concerted effort, and in light of the Brattle study results (imperfect as they are) and the recent information from the NWPCC about the value of DR to the region, the prudence of PGE selecting lower acquisition targets without answering fundamental questions about actual DR resource potential in its service territory would be in question.
Time is also of the essence in order to address the potential gap identified in 2021. PGE cannot wait to begin deployment of its proposed DR programs, so Staff is interested in near term actions that are consistent with the larger long-term strategy and goals."

obligation to demonstrate a pathway to cost effectiveness. Details on PGE's pathway to cost effectiveness are in Chapter 3.

In pursuit of the 2016 IRP DR goals, PGE launched a series of development acceleration activities, including business practice changes, team augmentation, technical assistance, IT development, customer bill coordination, evaluation activity, market studies, and customer insight studies.[49] Past challenges with PGE's DR programs have been incorporated as learning opportunities that inform PGE's current demonstration-pilot-program approach for building innovative grid services products. Moreover, these learnings will influence our efforts to meet our 2021 DR capacity goals.

Compared to many other utilities across the country who do conduct demand response program PGE lacks a strong, well-established, large commercial and industrial customer base. Many of the large industrial and commercial customers in PGE's service territory have chosen to take service from Electricity Service Suppliers. Thus PGE, unlike other utilities nationally, needs to procure most of its DR from residential and small commercial customers. Sourcing DR from residential and small commercial customers requires certain program adaptations. Before program launch, PGE must invest in educating a broader customer base. Program offerings must be simple, acceptable, stable, and convenient.

To date, PGE has built its DR pilots independent of one another. The Company has relied on prior demonstrations and pilot activities, as well as national meta-study information, to build cost estimates for DR resources. This approach has led to individual product forecasting and multiple deferral filings, instead of portfolio level forecasting and cost recovery planning. More explicitly, because of this approach, each pilot or offering has its own budget, IT solution, personnel, evaluation process, tariff, and cost-effectiveness analysis. Thus, PGE's attempts to build DR resources have met a series of consequential and interrelated financial challenges, discussed later in this chapter, Chapter 3 and Appendix 1. PGE's 2016-2021 demand response resource development cycle has informed us that financial planning at the portfolio level is necessary to increase strategic alignment and cost savings.

Over the span of four short years (2016-2020), PGE has learned key lessons regarding the pace at which to scale a flexible load resource. These lessons are reflected in the demonstration-pilot-program process detailed in this chapter. They also inform program improvements that are enabling PGE to meet our 2016 IRP DR goals, as well as future flexible load goals.

PGE has begun moving to a portfolio level view for pilots and products. A portfolio view allows us to capture the financial value associated with a group of pilots or products, similar to practices employed by EE providers. This approach appropriately aligns portfolio goals with our overall business strategy and provides opportunities for PGE to be nimble by integrating ongoing improvements and shifting investments to the strategies that prove effective.

[49] PGE conducted a series of customer surveys to identify customer awareness, understanding and wiliness to participate in utility guided programs.

PGE has developed a resource build with an evolutionary concept and framework, moving through the demonstration-pilot-program process. PGE first accelerated efforts to meet our 2016 IRP DR goals by developing resources as pilots[50]. In this filing, PGE proposes a three-step evolutionary process:

1. **Demonstration stage** – Demonstrations are initial, small-scale efforts designed to prove the viability of a technology, hypothesis, or idea; or to answer discrete technical and/or customer-related questions. Demonstrations may involve either the exploration of novel technologies or ideas or the application of existing technologies. Demonstrations enable PGE to manage the risks of new ideas and identify any key problems or issues before committing substantial resources resource and time Within the Smart Grid Testbed, PGE is conducting numerous demonstrations to explore the capabilities of new products and practices, and identifying if, when, and how these products and practices can be integrated into PGE operations.

2. **Pilot stage** – Pilots are limited-scale efforts designed to validate the business case and manage the implementation risks associated with successful demonstrations or other projects that have attained a certain level of readiness as defined by PGE's Product Lifecycle Management process. Pilots test the implementation, customer engagement, and marketing approach, test customer satisfaction and acceptance, provide final validation of the business case, and demonstrate cost effectiveness or identify a pathway to cost effectiveness. Pilots help PGE, the Commission, and stakeholders assess whether an offering is ready to become a program, where it becomes a permanent part of PGE operations. Many of PGE's current activities, such as Peak Time Rebates and Smart Thermostats, are in pilot phase.

   Pilots are a way to test a new idea believed to provide potential benefits to ratepayers in a manner that minimizes risk. If the pilot is successful, it can be rolled out for wider adoption and incorporated into base rates. If the pilot is unsuccessful, it can be discontinued or redesigned. Pilots, as covered in this document, include projects such as research studies, product demonstrations, "field tests". A pilot is not a required step before adopting a service or practice.

   This process does not cover research activities paid for through existing R&D budgets. R&D budgets, O&M budgets, and other such sources that are determined as part of base rates can be utilized to fund research projects, initial market research, tests, or "demonstrations."

   Pilots are intended to test an idea that has the potential, if supported by learnings from the pilot, to be widely rolled out to customers. Pilots demonstrating stability

[50] PGE launched a series of pilots, including a multifamily water heater pilot, a smart thermostat pilot in coordination with Energy Trust, a unique redesigned commercial and industrial customer offer through Energy Partner, a peak time rebate customer offering and a first-of-its-kind Testbed.

and certainty of concept or practice can move to the program stage. During the pilot stage, the core concept is tested and a strategy for implementation is developed. If appropriate, a transition plan for rollout should be developed.

3. **Program stage –** Programs are the last evolutionary step wherein an activity is cost effective, performance is stable and reliable, and the budgets are forecastable within an acceptable tolerance. Programs should deliver a product or service at scale. Since a program is a sustained and discrete offering, the program should have well-defined scope. Similar to pilots, but to a lesser degree, programs can also have such restrictions or parameters as the number of subscribers, the total spend, and requirements to avoid shifting costs. The key feature that distinguishes a program from other activities is its ongoing nature. Staff has reiterated that this guidance addresses new and emerging programs, and does not apply to well-established, existing practices.

Figure 6 shows PGE's program evolution process. The size of the activity grows as the maturity of the product, program, or service moves through the evolution. PGE is moving each of our initial 2016 IRP DR resource build activities through this process in pursuit of each becoming a mature program offering. Later in this chapter, PGE details the recommended pilot-to-program criteria. Each program write-up within A.2 applies the pilot-to-program criteria so the Commission and stakeholders can assess the activities which PGE recommends as necessary to move our 2016 IRP DR resource activity into a stable, long-term, and cost effective program.

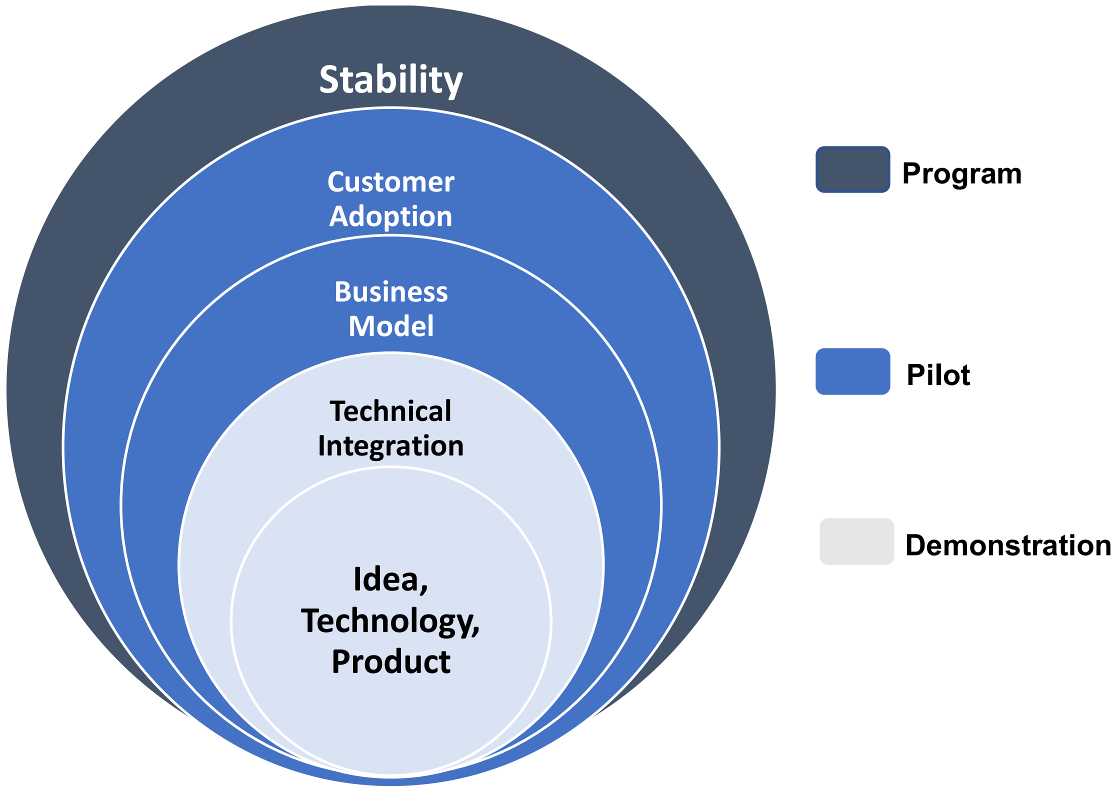


Figure 6 – Program Evolution

Learnings from demonstrations and pilots must inform the decision whether to deploy a product or service at scale. PGE's Product Lifecyle Management (PLM) process is the funnel through which potential ideas and products must travel on the way to program status. PLM provides the key questions to answer, the deliverables, the decision-making criteria, timelines for evaluation, and other protocols necessary to manage the rollout of a full-scale offering. By creating a funnel that enables PGE to test more ideas, products, and technology, promising projects are able to mature and reach full-scale deployment, while poor concepts are discarded early with less wasted effort and resources. This deliberate process for product advancement allows PGE to create compelling and cost-effective solutions for customers that align with our goals of serving load, reducing carbon, and maintaining reliability.

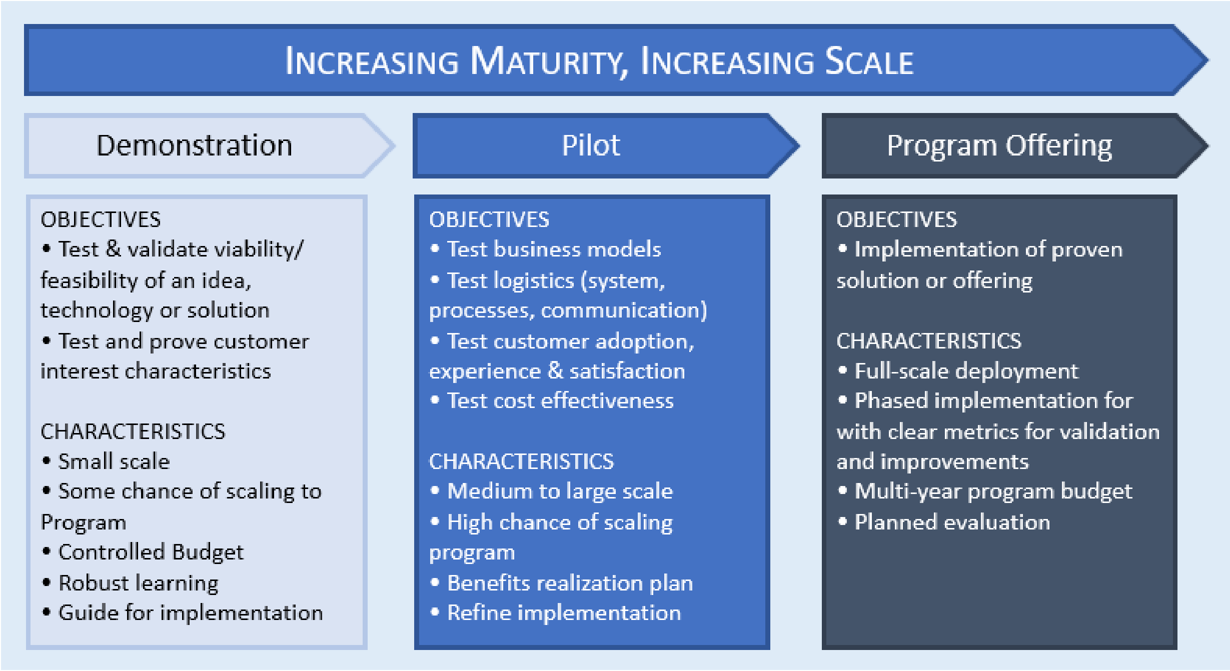


Figure 7 – Evolution Path in the Demonstration-to-Pilot-to-Program Lifecycle

Figure 6 shows that as products move through the pipeline, the probability that they will scale into full market deployment increases. Products with little chance for scaling should fall out of the pipeline quickly. Products that do not advance in the pipeline are not failures; rather they are opportunities to capture and incorporate lessons learned to inform future efforts.

2.4 Proposed Approach to Pilot to Program

For a flexible load resource to reach maturity, it must be aligned with, and integrated into, PGE's real time operations. While current Commission Orders require that PGE dispatch DR pilots from the Program Management department in order to meet learning and utilization objectives[51], PGE is working to assure that each DR resource developed as part of the 2016 IRP DR build can be aligned with our grid operations and has a path to dispatch integration. PGE's Program Management is working closely with Power Operations and the Balancing Authority to identify how best to integrate flexible load activities into real time operations so the resource can be utilized as any other resource in PGE's supply stack.

Unlike traditional generation resources, flexible load resources are customer-based, with operating parameters that are still being defined. These new, customer-based resources require PGE's system planners and grid operators to think differently about how aggregated distribution resources should be valued, developed, and dispatched to meet electricity demand on an hourly, sub-hourly, or resource adequacy basis. Likewise, if Power Operations makes a decision to dispatch DR, it needs certainty that the resource will perform at the expected level. PGE must be able to centrally dispatch DR on a resource and system level. Consequently, PGE now views the integration of the DR resource into real time operations as a necessary factor in determining whether a DR pilot has matured to a program.

The pilot-to-program offering criteria outlined below were gained through numerous learnings in the context of an accelerated resource build with a high degree of risk. Consequently, many of the Company's DR customer offerings have remained in pilot phase. PGE sees five key interrelated considerations for the transition from pilot to program offering:

1. Customer Experience
2. Program Parameter and Infrastructure Stability
3. Grid Performance
4. Financial Performance
5. Dispatch Integration

2.4.1 *Customer Experience*

Each DR and flexible load program must achieve a stable and sustainable customer participation level based on the learnings of the pilot coupled with effective recruitment and retainment practices. Pilot learnings identify the keys to customer satisfaction and ensure that participating customers have a solid understanding of their commitment and their reward for providing service when requested.

[51] Commission Orders in dockets UM 1514 and UM 1708 required PGE to dispatch DR pilots multiple times per year to ensure PGE not only builds the capacity, but also learns about and utilizes the resource. However, this requirement to dispatch the resource outside of economic dispatch parameters meant that each pilot must be dispatched, not from the Power Operations department, but from the Customer Programs department.

PGE must measure and understand participant satisfaction and look for ways to sustain, if not improve, performance.

2.4.2 *Program Parameters and Infrastructure Stability*

Each DR and flexible load program must have: 1) stable parameters as specified in an approved operating tariff; 2) stable and mature technology to provide the necessary infrastructure; and 3) stable operating processes that are well understood by participating customers.

2.4.3 *Grid Performance*

Grid performance and monitoring is essential to unlock the value from co-optimizing flexible load across capacity and grid services, as well as capturing locational value. As flexible load is capable of providing more grid services and PGE's implementation of ADMS enables locational dispatch, PGE will be able to dispatch Virtual Power Plant resources at the substation level. This granularity is necessary for capturing locational value and for ensuring flexible load resources are operating within the physical limits of the substation and distribution equipment behind which they are located.

To meet grid performance requirements, PGE must understand both aggregate event performance as well as hourly and sub-hourly dispatch performance for both planning and operational purposes. For DR and flexible load programs providing sub-hour grid services, PGE will need to be able to monitor the performance of the aggregate resource in real time in order to document compliance with reliability standards.

2.4.4 *Financial Performance*

That each DR and flexible load program (or a combined portfolio of multiple products) is cost effective. Additionally, each program must have an approved mechanism for cost recovery. A more detailed discussion of cost effectiveness is addressed in Chapter 3.

2.4.5 *Dispatch Integration*

PGE must establish DR and flexible load program dispatch protocols from integration and use by real-time operations. Programs must integrate not only with PGE optimization and dispatch systems, but also with the Western EIM. While DR can be accommodated in the EIM through exogenous communications[52], to fully capture the full value of DR in the EIM, PGE's goal is to ultimately include DR and flexible load programs within the EIM optimization. operators. This means that each flexible load resource will need a 'master file' whereby the generation

[52] Phone calls or email, for example.

optimization tool[53] knows the resource by its operational capability and constraints. In addition, each DR and flexible load program must perform within a 15-20% variable tolerance in order to be considered reliable enough for dispatch integration. This means that when PGE calls for capacity from such a program, we can predict, within a 15-20% error band, the amount of grid services that will be provided by the resource. It also means that the nominated load for each pilot or program must perform well enough so that Power Operations considers the resource viable for utilization.

PGE is actively working to include the Energy Partner program - the most mature program in the PGE DR/flexible load portfolio - into PGE's generation optimization tool with a master file. Energy Partner will be the first of our DR programs mature enough to attempt this integration. The goal of the Energy Partner program is to provide 27MW of peak capacity by end of year 2020. Program Management is currently working with Power Operations to incorporate Energy Partner into existing dispatch practices, such that Energy Partner is seen agnostically, as a resource within the resource stack, and dispatched based on its operating profile. The process for this integration has started. Figure 8 maps our current Energy Partner dispatch practices and protocols.

[53] PGE uses ABB Ability Portfolio Optimization tool to provide a generation schedule for energy and ancillary services, fuel nominations, and support the development of Base Schedules for the Energy Imbalance Market. This tool has the capability to optimize a combined portfolio of supply resources (traditional generation) and demand response/ distributed generation assets modelled as Virtual Power Plants.

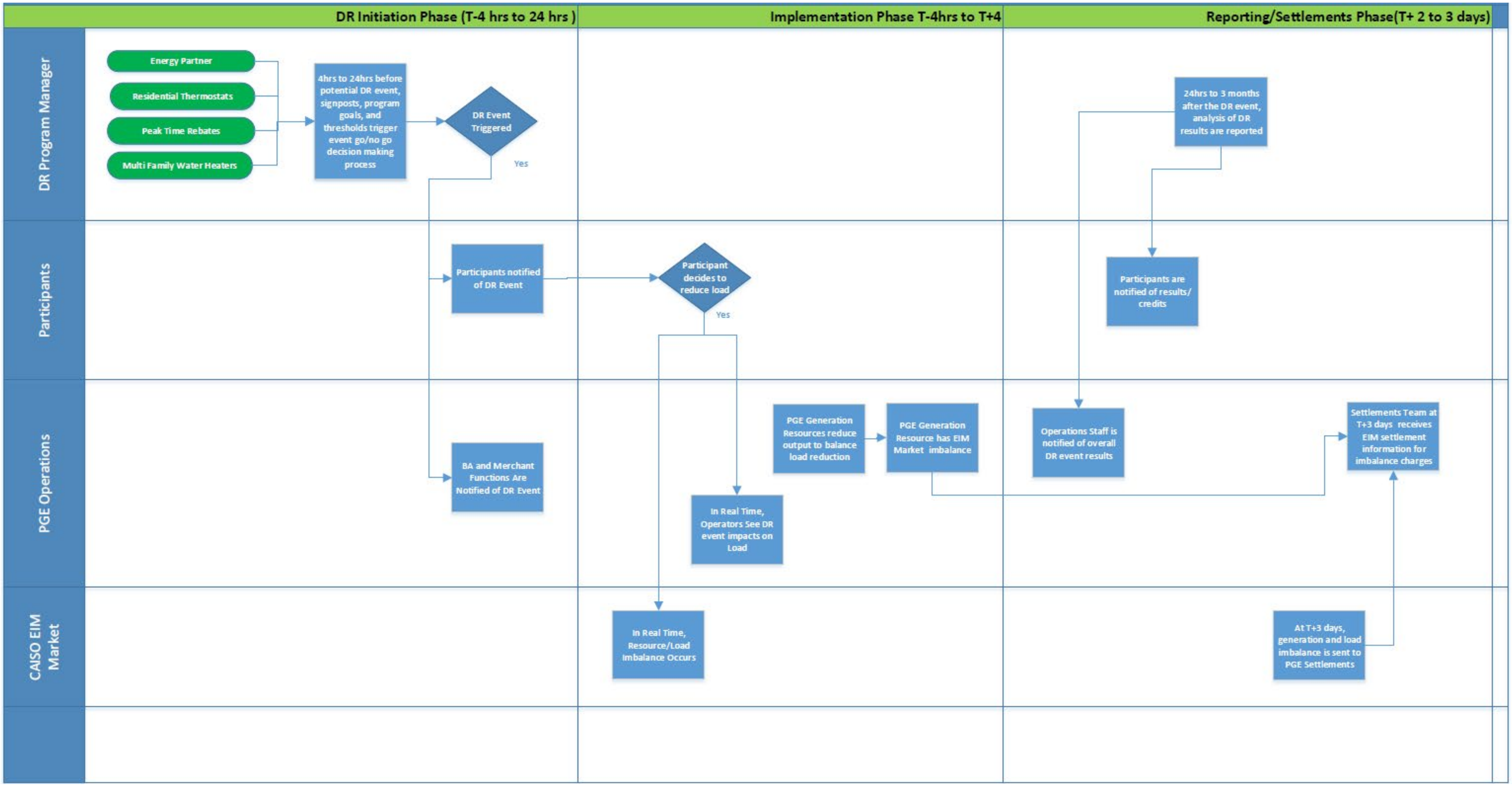


Figure 8 – Current State Process for Demand Response Program Operational Integration

The most immediate takeaways from Figure 8 are:

- The full integration of Energy Partner into real time operations will require process changes in Power Operations, the Balancing Authority, the Customer Programs Team, and Energy Partner itself. This will include communications to the participants about the change and how it may, or may not, affect them and their expectations.

PGE has been working cross functionally with the Customer Programs, Power Operations, and Balancing Authority teams to develop an approach to flexible load dispatch. Using the processes outlined in Figure 8, as the current state, Figure 9 was developed to show necessary process changes.

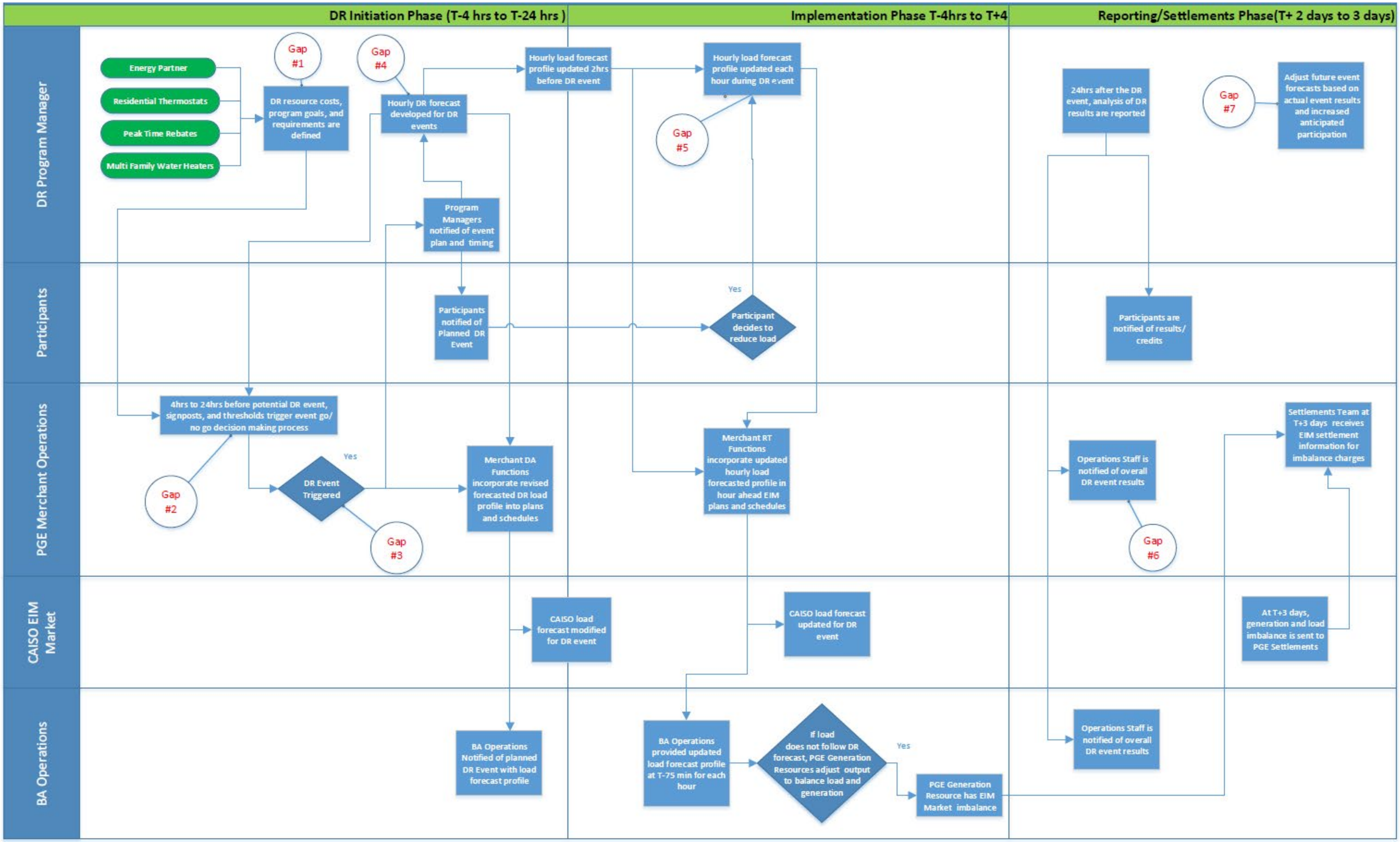


Figure 9 – Future State Process for Demand Response Program Operational Integration

Figure 9 is meant to guide PGE's work to place flexible load into real time operations activities to be operated as any other resource and dispatched to meet economic and grid reliability needs. The figure identifies seven areas for improvement and recommendations for action:

Gap 1. DR program operations parameters need better definition, clarity and visibility.

Recommendation: DR Program Managers define overall program costs, incremental dispatch cost, must run requirements, other program goals, and sign-posts important to the economic dispatch trigger process.

Gap 2. The DR event trigger process should be better defined for economic dispatch and the "go/no go" decision-making process should lie with Power Operations.

Recommendation: DR Program Managers and Operations Leads partner to define the economic dispatch signposts and thresholds that will be used to trigger DR event "go/no go" decision-making process.

Gap 3. The final decision to trigger a DR event for economic dispatch should be made by Power Operations using the appropriate parameters, thresholds, and sign-posts.

Recommendation: Power Operations partners with DR Program Managers to stand up decision-making process for economic dispatch of DR event.

Gap 4. DR load reduction hourly forecasts for each event are not part of the current process.

Recommendation: DR Program Managers develop a process for providing hourly DR forecasts for the entire event duration of planned and future DR events.

Gap 5. DR event load reduction real time monitoring is not part of current process.

Recommendation: DR Program Managers develop a process for gathering real time information on actual load reduction and provide updated forecast for remaining duration of the event.

Gap 6. A "Post DR Event Results Summary" is needed to provide program managers and operations staff updated information for settlements analysis and next event planning.

Recommendation: DR Program Managers develop a process for providing a complete "DR Event Results Summary" a maximum of 48 hours after the conclusion of the event.

Gap 7. Past event results and changing customer participation should be used to modify DR Program parameters and forecasts to enhance the future DR event trigger process.

Recommendation: DR Program Managers to develop a process for updating key DR parameters for future program enhancement.

PGE will also adopt the following structure and review consideration for pilots and programs as outlined by Commission Staff in October 2020.

2.4.6 Pilot and Program Investigation and Proposal Components and Criteria

2.4.6.1 Pilot Review Considerations

When reviewing pilot proposals, PGE will address with following queries:

1. Is this research valid and valuable for the ratepayer?
    a. How does this new research fit into existing services and other ongoing research?
    b. Is this new research, or has it been conducted already?
    c. Does this pilot have the potential to result in wider adoption?
2. Will this research result in the desired information?
    a. Will this research provide the information needed to answer the research question?
    b. Is the pilot structured such that it will further the intended policy objective?
    c. At the end of this research, the pilot will: i) end, ii) be redesigned as a new pilot, or iii) transition into wider adoption (through a program, upgrade or other). Will this research lead to this decision point?
3. Will this research be conducted in a way that limits the risk to the ratepayer? Including:
    a. A scope with a clearly stated research question.
    b. A statistically sufficient population of units to perform the research.
    c. A duration that is limited, but sufficient to conduct the research and evaluation.
    d. A budget of appropriate size.

Overall, the purpose of these questions is to reduce risk to ratepayers while allowing the utility to test a concept in a pilot framework.

2.4.6.2 Pilot Proposal Components

PGE will submit the following items with each pilot proposal:

1. The purpose of the research (including, if applicable, which legislative or Commission order it supports, and how it supports the implementation of the directives contained therein).
2. The research question.
3. The overall pilot design strategy: What is the theory behind this strategy? The major design components should address the research question.
4. The potential benefits to the ratepayer if the pilot succeeds.
    a. Portfolio consideration: A description of how this pilot complements or adds to related utility activities and addresses a market gap/opportunity not currently addressed by current operations or ongoing research, and how overlap with existing work is minimized.
    b. In support of EO 20-04: Will there be any positive or negative impact in reducing GHG emissions as a direct result of this pilot, or if applied to wider adoption?

   c. In support of EO 20-04: Will there be any positive or negative impact on any "vulnerable populations or impacted communities" as a direct result of this pilot, or if applied to wider adoption?
5. Context: Prior research and relevant market research supporting this strategy. What are the major barriers that stand between this concept and wider adoption? What is the technical/conceptual viability of what is being tested, i.e. how market-ready is it? Has this been implemented elsewhere?
6. A research plan that includes:
   a. The learning objectives that will inform the research question(s) and how these objectives will be achieved.
   b. Participation target: Who, or what, will this pilot target?
   c. Potential scale: what is the ultimate potential?
   d. Number of participants or test subjects: include statistical rationale for this number.
   e. Evaluation strategy: A description of how the evaluation will be conducted. How will we know if it worked? The evaluation plan should answer whether or not the idea should be rolled out for broader adoption. Include what is necessary to measure results at the needed level of statistical certainty.
7. Schedule: A timeline that shows when each component of the plan will be implemented. The duration of the pilot must be limited, yet sufficient to answer the question. The schedule should include time for conducting the evaluation, final reporting, and any necessary activities to wind down the research.
8. Budget: What will this cost? The budget should be sufficient to answer the question and limited in scope and costs to reduce risk to the ratepayer. Budget should include O&M expenses and revenues, broken down by FERC account, capital costs, number of FTE employees, and number of contractors.
9. Decision points: Built-in milestones or dates where the pilot is evaluated against project objectives to determine if the pilot requires a change in scope or should end early.
10. Reporting requirements: The proposed cadence of utility reporting on progress and results. This may include GHG emissions reductions if applicable.

2.4.7 Transition

To aid in Commission Staff's oversight role, PGE will provide the Commission the appropriate information when proposing a pilot-to-program transition. This will include well-structured evaluation to aid Staff in their validation of pilot performance, including an assessment of readiness to transition from pilot to program, or whether to end the pilot or reformulate it into a new pilot.

2.4.7.1 Transition Review Considerations

When a pilot comes to an end, PGE will provide Commission Staff the necessary information to address the following consideration:

1. Was the pilot run successfully? Were the research objectives accomplished and did the pilot answer the research question? If the pilot was successful, Staff can review results prior to transition from pilot-to-program; if the pilot was not successful, the concept may be worth revisiting in a new pilot, or it may be best to cease research on the topic.

2. Did the results of the pilot indicate that the idea is worth adopting? The evaluation results will play a key role in Staff's assessment. If there are positive results with quantifiable ratepayer benefits, this indicates that the concept is worth pursuing for the goal of broader adoption.
3. Did new, pressing questions or obstacles arise as a result of this research? If a significant barrier is identified, there may be a benefit in running another pilot or some other form of research to prepare for rollout. If no new, serious challenges arise, it is time to plan for transition into wider implementation, whether that be as a program, or other form of implementation.

If it is determined that the pilot should transition into wider adoption, Staff may work with the utility on a transition plan to apply learnings from the pilot in a timely and effective manner.

PGE agree with Staff that applying a framework to review pilot results will help roll out beneficial ideas more quickly, so that the risks taken on by ratepayers will turn into benefits sooner and be shared with ratepayers.

Chapter 3 Programs

3.1 Program Review Considerations

Programs are expected to provide benefits to ratepayers for an extended duration with relatively stable costs and benefits, with the understanding that there may be a predictable band of fluctuation in productivity. As a sustained offering, program proposals will provide information to assess the following considerations:

1. Predictable outcomes.
2. Discrete offerings.
3. A repeatable process to deliver the program offering.
4. Just and reasonable rates.
5. Measurable benefits.
6. Ongoing implementation.
7. Periodic evaluations.

Staff understands that there will be more fluctuations and learning in the early stages of a program, which makes the above considerations important in creating a stable, lasting offering.

3.2 Program Proposal Components

Key components to a program proposal include:

1. The purpose of the program (including, if applicable, which legislative or Commission order it supports, and how it supports the implementation of the directives contained therein).
2. Program goals.
3. Expected benefit to the ratepayer.
    a. Portfolio consideration: a description of how this program complements or adds to related utility activities and addresses a market gap/opportunity not currently

addressed by current operations or ongoing research, and how overlap with existing work is minimized.

   b. In support of EO 20-04: Will there be any positive or negative environmental or carbon impact?
   c. In support of EO 20-04: Will there be any positive or negative impact on any “vulnerable populations or impacted communities”?

4. The overall design strategy: What is the theory behind this strategy? How is this going to work? The major design components should lead to the program’s goals.
5. Prior research and market research that supports this strategy (including learnings from past pilots if applicable).
6. Participation target: Who, or what, will this program target?
7. Potential scale, and other relevant market research.
8. Schedule: A timeline that shows when each component of the plan will be implemented.
9. Budget: What will this cost? Budget should include expenses and revenues, costs by FERC account, FTE of employees and of contractors, and any anticipated capital costs.
10. Reporting requirements: The proposed cadence of utility reporting on progress and results. This may include GHG emissions reductions if applicable.
11. Evaluation plan: This plan includes what will be measured, how it will be measured, and how the results will be verified. This evaluation is typically conducted by a third-party unless the utility has a persuasive reason to conduct it in-house.

3.2.1 Follow-Up

PGE will work with Commission Staff when questions arise on the process and guidance presented herein. PGE will continue to meet with Staff and other interested parties to discuss process and its potential impact on current work.

3.3 Moving to a Portfolio Level Development and Deployment

Designing to Scale	Design demonstrations and pilots to maximize learning and prepare for full scale deployment

Current practices require that PGE file a proposal for each product offering, channel, and program expansion. Although this process was adequate in the past with few pilots, it is proving to be inefficient, resulting in long deployment timelines and a Piece-meal approach to budgeting.

In adopting the Product Life Cycle Management process, PGE shifted its focus from individual program launches to portfolio optimization. Our portfolio roadmap outlines market approaches and strategies to capture increased DR capacity through least cost channels.

PGE has identified two focus areas and four strategies for portfolio optimization. Figure 10 shows the high-level focus area and strategy. Greater detail is provided in subsequent sections.

Focus	Building Flexibility & Transportation Electrification	Ensure buildings (homes and businesses) & electric vehicle charging infrastructure is flexible, efficient, and automated
Focus	Virtual Power Plant	Integrate and manage resources to improve system-wide flexibility and optimization.
Strategy	Customer Engagement	Engage customer to actively decarbonize our region to understand their priorities
Strategy	Products & Services	Meet customer needs in homes, businesses, and campus/communities
Strategy	Engagement to Build & Leverage Partnership	Engage and lead partners to create an flexible ecosystem
Strategy	Policy & Regulatory Evolution	Engage with policy makers and regulators to assure understanding of investment strategy and deployment approach

Figure 10 – Areas of Focus and Strategic Approaches

Flexible, efficient, and automated solutions enable portfolio optimization across multiple grid services. Portfolio automation and optimization allows for the stacking of solutions and cost sharing that enable programs to be cost effective. Cost effective programs are attractive to customers and enable PGE and its customers to choose holistic solutions to decarbonize the electric grid at least cost. PGE is addressing these areas of focus with four strategies:

1. A focus on **customer engagement**, which is centered around identifying customer-centric solutions that empower customers to decarbonize and electrify, while controlling costs. As noted above, PGE's Testbed includes numerous research efforts that target customer engagement, identify customer preferences, and address energy system inequities.

2. PGE is **providing products and services** that meet the needs of homes, businesses, and communities. PGE is using customer and performance feedback identified through the demonstration-to-pilot-to-program lifecycle to adapt product offerings to meet customer and operational needs.

3. PGE is actively **building and leveraging key partnerships**, such as municipal partnerships to provide decarbonized, flexible solutions to actively shape local ecosystems. This is accomplished via important rules and regulations such as zoning and building permitting.

4. PGE recognizes that it cannot be as effective and efficient in supporting its customers in their drive for connected, flexible, and decarbonized load without **policy and regulatory evolution** that specifically allows for PGE to actively engage in building flexible load behind the meter.

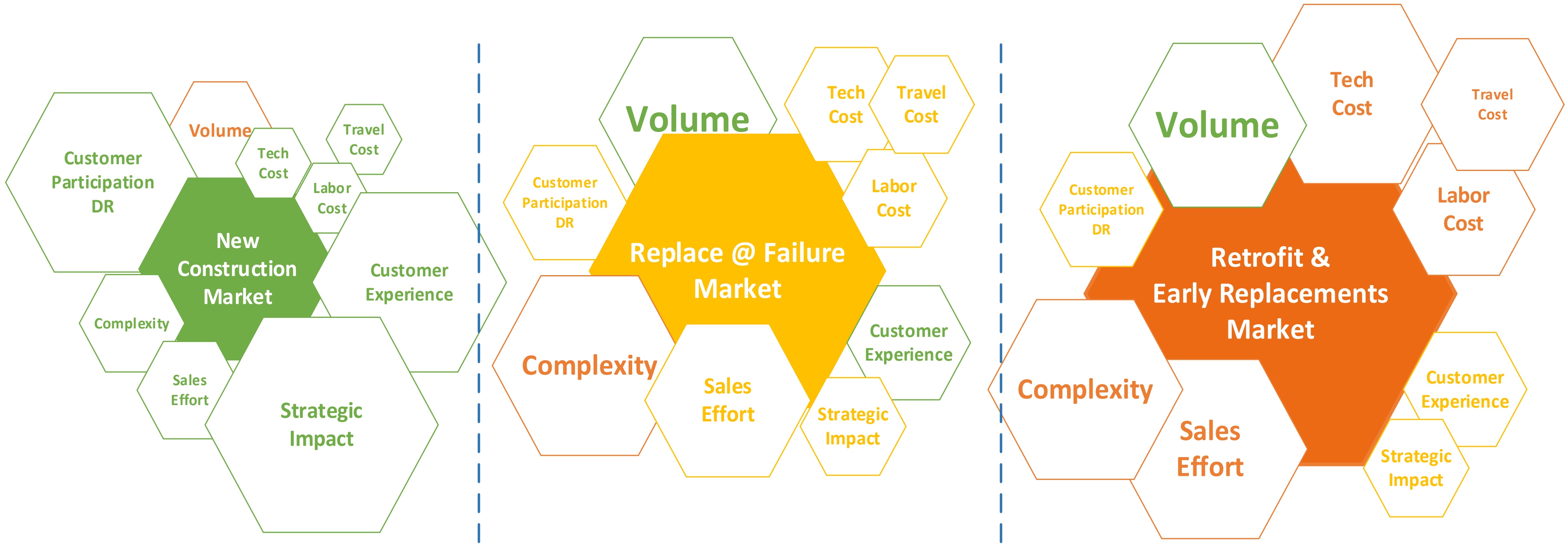
3.3.1 Market Organization – Effective Deployments of Products and Services

The first focus area is building a Virtual Power Plant, as described above (Chapter 1), and interwoven, below.

The second area of focus is building flexible load within the built environment and within transportation electrification infrastructure. This work looks to ensure that buildings (homes and businesses) and electric vehicle charging infrastructure are enabled to provide flexible services to the grid. The goal is to create a built environment and electric vehicle infrastructure capable of being incorporated into real time operations by PGE through resource integration and distribution system planning activities. PGE discusses our approach to distribution system planning in later in this chapter.

If the proposal to move to multiyear strategic planning and budgeting is approved PGE will more easily move to portfolio level planning. PGE first demonstrated portfolio level planning with our 2019 Transportation Electrification Plan.[54] This will allow us to not only plan for related expenditures across a series of activities it will also enable us to work across market opportunities. Presently PGE's demand response activity is more focused on the retrofit and early replacement market. However, if PGE were to bundle our activities, we could leverage strategic endeavors to assure new home builders install a pre-provisioned smart thermostat. The installation of this thermostat would come at a lower price creating opportunity for PGE to reach more customers across the replacement and retrofit market while maintaining and overall cost-effective approach to a smart thermostat program. By applying a portfolio lens to our market approach, PGE is able to stack offers and solutions and to spread overall program overhead costs.

[54] Portland General Electric, 2019 Transportation Electrification Plan, OPUC Docket UM 2033, Available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=haa102039.pdf&DocketID=22127&numSequence=1



- **Lowest cost – wholesale prices**
- **Limited market Size**
- **Opt-Out Design resulting in high participation**
- **Volume Sales**
- **Cost savings due to DR-ready products & scaled installations**
- Sets expectations for all homes: new & existing
- **Flip Entire Projects**
- Products Delivered Seamlessly to Future Occupants

- **Medium costs – retail prices**
- **Large market**
- **Opt-In design resulting in ~20-30% participation**
- **One-off Sales**
- **Cost Savings Due to DR-ready products**
- **Contractor already on site**
- Reliant on trade allies
- **More complex to delivery bundled products + experience**
- Naturally occurring sales

- **High costs – retail prices**
- **Expensive DR + communications equipment**
- **Expensive labor costs**
- **Expensive travel costs**
- **Adoption hurdle due to remaining value of existing equipment – limited customer shared cost structures**
- **Large market**
- **One-off Sales**
- Consumer marketing required

Legend
Good
OK
Bad

Figure 11 – Working Across Market to Bundle Customer Offerings

Figure 11 depicts three different opportunities for product and equipment solutions to be deployed to customers. The surrounding hexagons represent characteristics of that opportunity. The size of the hexagons refers to their relative importance and market size. Green hexagons denote generally good and unproblematic characteristics presented by that opportunity, whereas yellow hexagons depict more challenging situations that can be overcome. Orange hexagons are complicated, costly situations and environments. The following provide additional detail on each opportunity:

- *New construction focus.* There is considerable benefit to working in the new construction market. The builder, developer, and owner/tenant must purchase equipment to operate the building and pay for installation, creating an opportunity for PGE to influence this decision. There is a relatively small difference in cost between inefficient, inflexible equipment and efficient, "smart" equipment. The approach reduces costs for program implementation as it mitigates high long-term costs of retrofitting so-called "dumb" equipment. This is also the time when close to 100% of the potential load can be captured, because EE and DR incentives can be offered to lower customers' initial capital investment in exchange for ongoing participation in the Virtual Power Plant. Additionally, capturing the new construction market has a strategic impact, as the existing building market takes cues from new construction regarding the standard practices for remodeled, modernized building. The downside to this market is that it is relatively small. Electric Vehicle Service Equipment (EVSE) is a natural fit here.

- *Replace upon failure.* The replace upon failure market takes advantage of existing equipment naturally failing over time. This provides an opportunity for program incentives to pay the incremental costs for "smart" equipment. This program approach pays very little, if any, for installing the product. The challenge in capturing this market is that there is a very short window of influence between the time of equipment failure and the customer's replacement decision. It is necessary to cultivate a deep trade ally network that already engages with the customer. Additionally, it is difficult to deploy product bundles (multiple products) in an integrated fashion because trade allies usually specialize to a product line or a product line within a particular appliance in one product type. Finally, the structure of this market poses challenges for providing a consistent, high quality customer experience. However, the addressable market is multiple times the size of the new construction market and offers promise for driving volume.

- *Retrofit and early replacement.* The retrofit and early replacement market is dominant in driving the volume of flexible load resources today. The upside is the volume of products that can either be retrofitted or replaced early; the downside is that very few customers will cover the cost to retire functioning equipment early or to upgrade/retrofit existing equipment. The cost of retrofitting unconnected equipment is usually cost prohibitive from both a program and a customer perspective. However, the size of this market makes strategic investments a key part of accelerating the development of flexible load into the Virtual Power Plant.

3.3.2 Product Bundling

PGE is moving from a product-by-product approach towards bundling products for delivery in each target market. To enable the full value of bundling, PGE will be exploring new ways of capturing the full value of a flexible home. This is a critical step in making it cost effective to invest in equipment upgrades that allow all customers to participate. The result is a much higher density in program participation right from the start. For example, in the near future water heaters will be pre-built with demand response enablement. Similarly, EVSE will demand response capable. These two home loads can be bundled and offered at the value of the service provided. An additional approach to bundling is where a thermostat can be offered at the same time as the new water heater is installed. This approach helps PGE and by relation the Energy Trust lower deployment costs.

A core bundle is to target the single-family new construction market. Such an approach revolves around taking existing (or soon to be launched products) and adapting the entire product bundle for implementation by builders and developers. This approach allows for close to 100% of new homes to be grid-enabled, connected, and participating in grid services by the time the new homeowner moves in.

Stand-alone programs targeting existing technology in customer homes can only capture approximately 25% of the connected load. Bundling allows individual products to share delivery infrastructure and drives down the relative cost-per-acquired flexible load device for the Virtual Power Plant. This creates a virtuous cycle where more devices get connected, economies of scale are realized, and technology matures, which in turn drives down equipment costs.

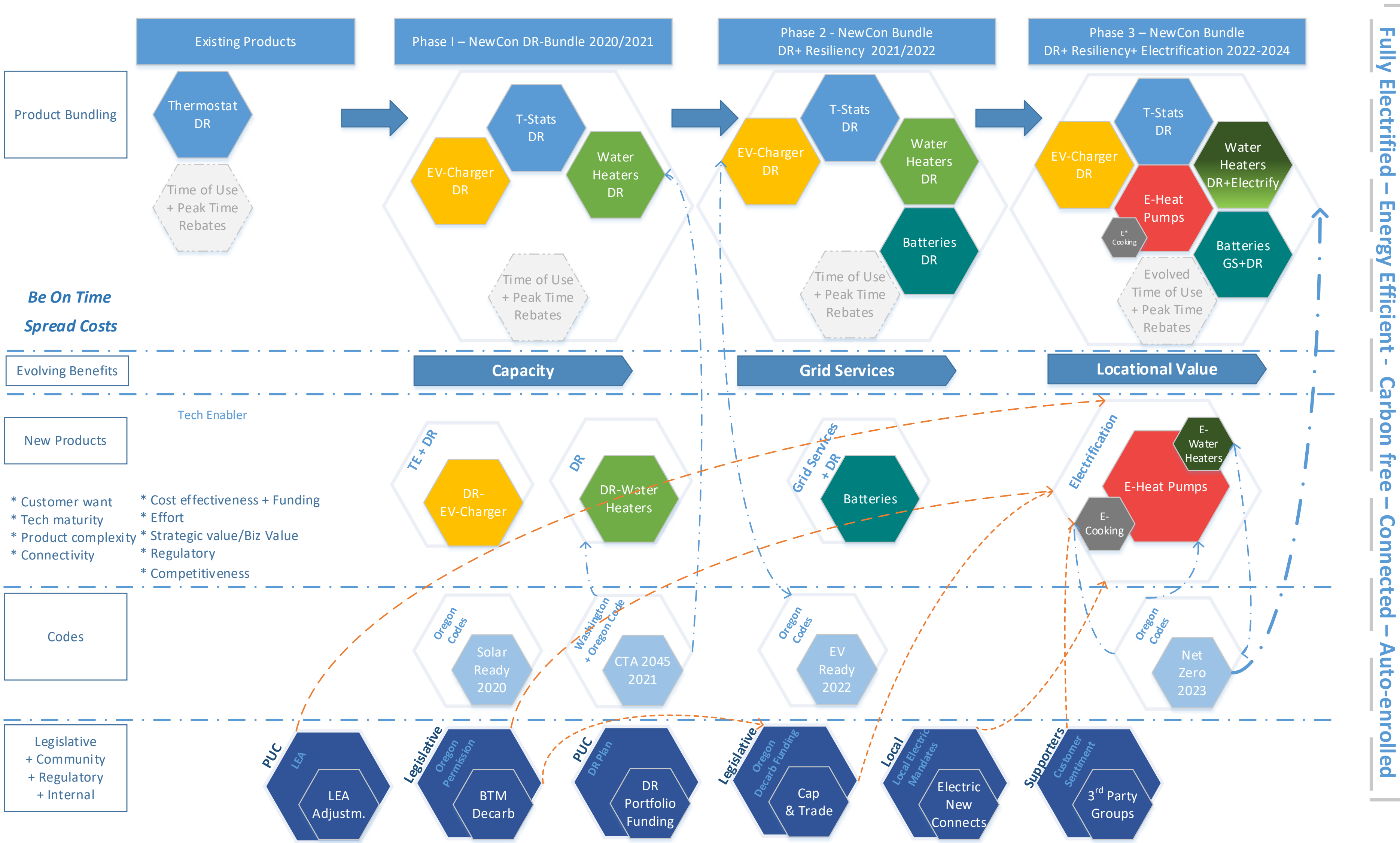


Figure 12 – Evolution of New Construction Bundles

3.3.2.1 Cross-Marketing

It is important to recognize that PGE's approach will require us to take advantage of naturally occurring every-day sales and installations by retailers, manufacturers, homeowners, or contractors. Similarly, each product still requires its cycle of testing, learning how to manage the load, and the successful delivery of DR events and seasons. This provides critical mass to answer questions in the demonstration and pilot stages of specific programs. However, the medium-term vision is to drive down the costs of each product solution by cross-marketing and cross-delivering the products via bundles, which yields greater program participation.

3.3.2.2 Code Evolution

Leveraging the universal application of codes and standards to enable grid connectivity of flexible load could lead to rapid growth in Virtual Power Plants while significantly reducing costs. Today, codes and standards primarily target EE or renewable energy development; expanding codes and standards to enable grid connectivity would significantly simplify the program development process. Building and appliance codes make or break the cost-effectiveness of product solutions. Codes can set up a home or appliance to be decarbonized and grid-ready, thereby avoiding substantial retrofit costs, which could in turn negatively influence the success of products for decades to come. Setting standards that extend beyond the customary EE and renewable-focused codes towards minimum standards and requirements for grid-connectivity allows for much-reduced costs in building the Virtual Power Plant at a quicker pace.

On the bottom third of Figure 12 one can see the adjustments to codes and standards that could accelerate or support PGE's development of the flexible load resource.

3.3.2.3 Bundle Evolution

Figure 13 shows how new product development fits into bundles and how those bundles reach the retrofit, existing building and upgrade market in phases.

The retrofit market will continue to be addressed by designing stand-alone products that target specific end-uses. As these products mature, they will be bundled together into integrated product offerings. The delivery of bundles to this market will initially be more difficult and challenging, but will yield savings over time, enlarging the cost-effective reach of each individual product in the bundle.

With bundling, customers can be recruited to participate in multi-product solutions, reducing overall program administration and customer acquisition costs. Installing products as a coordinated bundle reduces labor costs and other associated expenses[55]. Additional cost savings can be achieved from using common or merged software systems for tracking, managing, and dispatching installed assets.

[55] For example, travel to the location of installation, registration of the product, and establishing communications with the device.

These approaches will require demonstration to pilot to program development. As our pilots mature into programs their challenges such as performance, communications and customer acceptance will be known and likely stable enough to be offered across the new construction, replacement and retrofit market. However, to assure that pilot approaches to single family water heaters are ready to be deployed within a bundle, PGE will undertake demonstrations, such as our single-family water heater demonstration in the Testbed. Similar demonstration efforts will be needed to address other novel challenges and research requirements as we prepare new technology to be included.

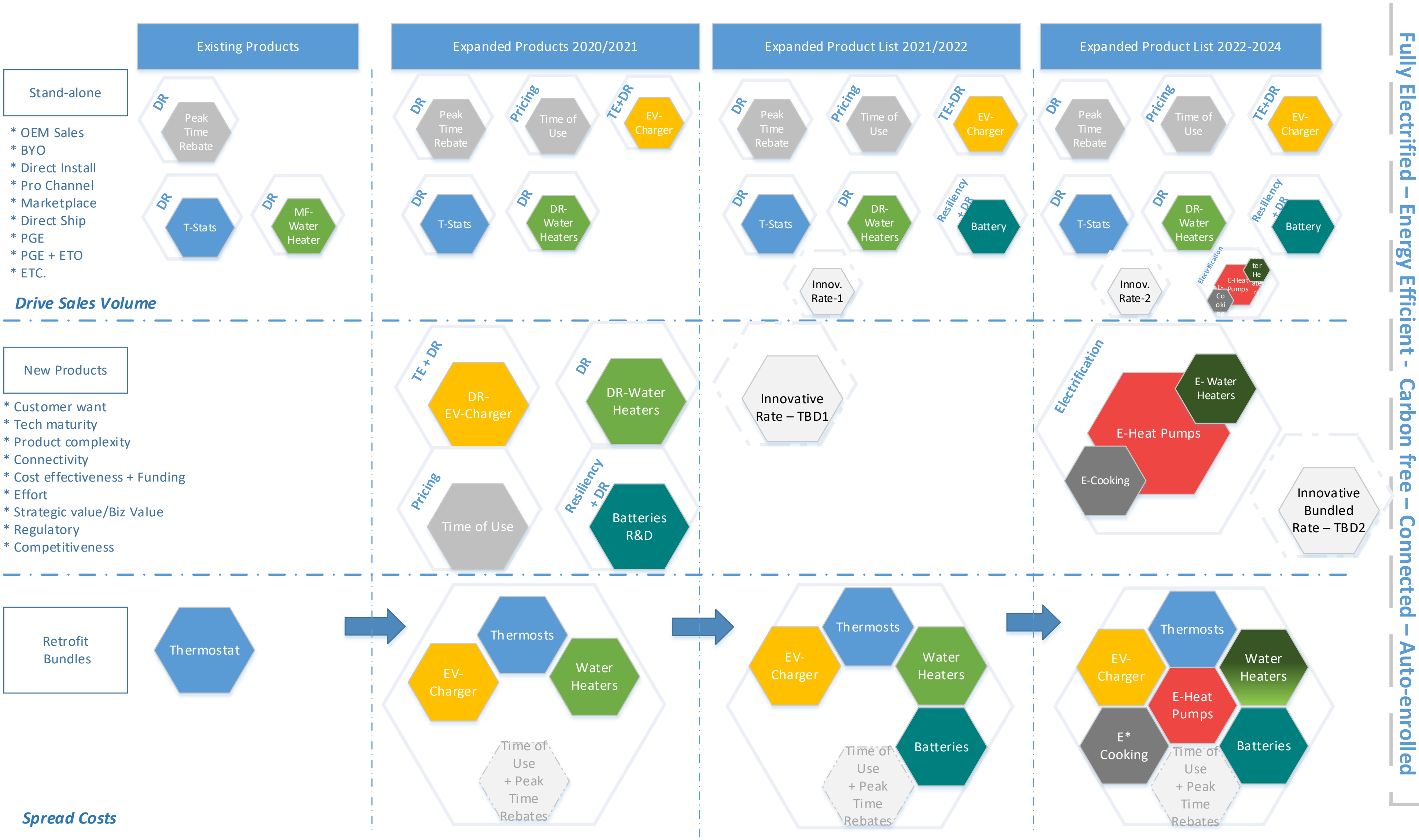


Figure 13 – BUILDINGS – Single Family – Existing Construction - Retrofit + Replace + Upgrade at System Failure – 5-year Roadmap

3.3.2.4 Products for Multifamily Home New Construction and Retrofit

The multifamily home market offers a unique opportunity to capture multiple flexible load devices at a single location; however, reaching this market requires addressing unique challenges and barriers. Figure 14 shows the products PGE intends to include in the bundle for the multifamily home new construction and retrofit market. Figure 14 also provides a timeline of the product build, how the products are bundled, and when the products and bundles will reach the market.

As noted above, PGE's first offering tailored to this market is the multifamily water heater program. In 2020, PGE plans to add the business EV charging program as a program offering for the multifamily and business markets. PGE is also considering line voltage thermostats, which could offer high volumes of winter DR from electric baseboard heaters. However, this product will likely require a demonstration stage to explore ways to address expected barriers, including high installation costs.[56] For this product to become cost effective, flexible load and EE benefits should be bundled; this approach requires a partnership with the Energy Trust in order to incorporate EE incentives. PGE expects the bundle to expand by developing products that allow for the connection of ductless mini-splits into the Virtual Power Plant in later years.

[56] Controls for this product must be installed by a licensed electrician.

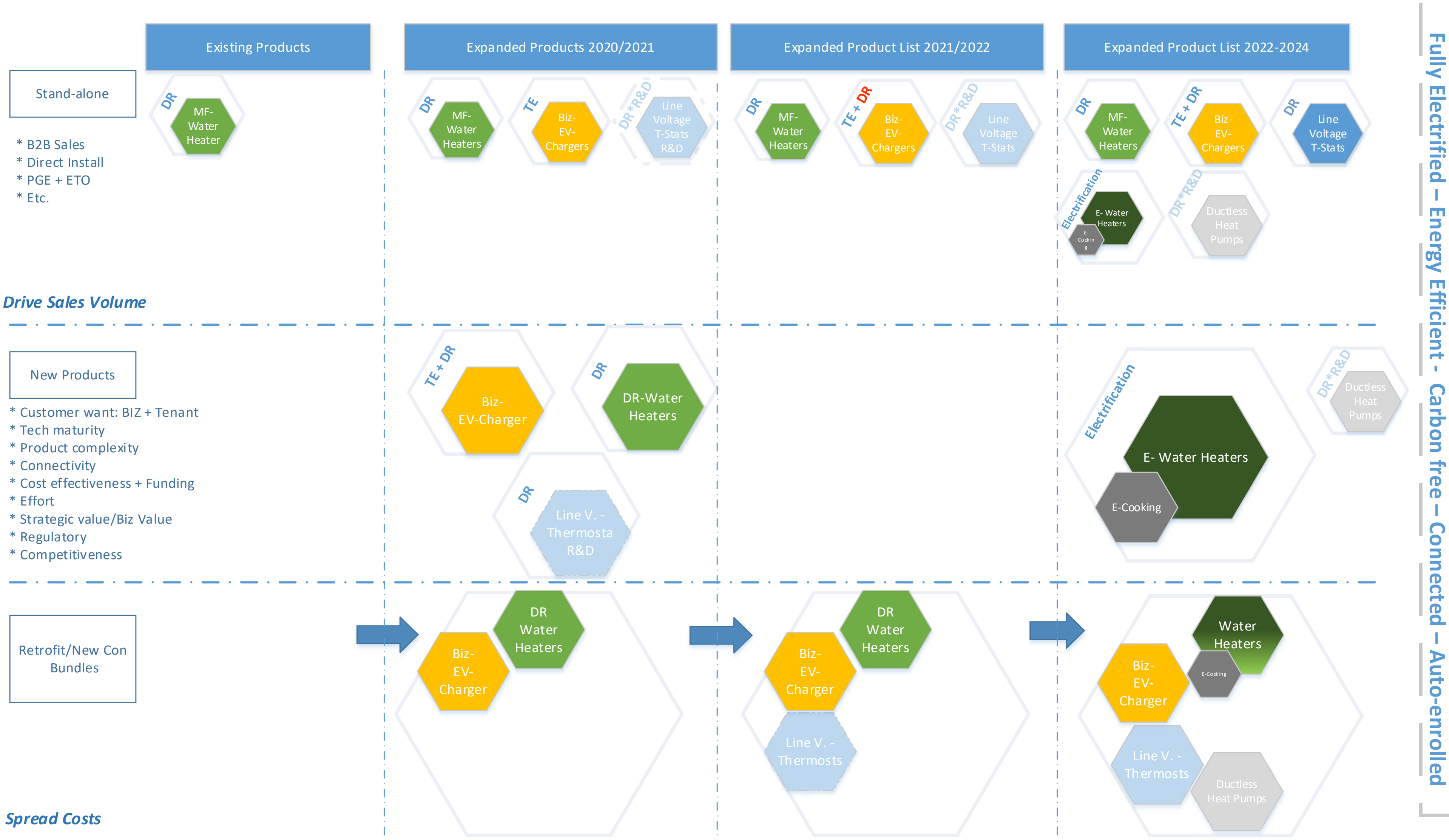


Figure 14 – BUILDINGS – Multifamily – New Con/Retrofit + Replace + Upgrade at System Failure – 5-year Roadmap

3.3.2.5 Products for Commercial Retrofit, Replace, and Upgrades

The Commercial Retrofit, Replace, and Upgrade market is another area in which PGE plans to expand flexible load program offerings and bundles. The commercial retrofit market includes grid-connected transportation, batteries, automated energy management, water heater, and HVAC controls. Figure 15 illustrates PGE's product roadmap for this market space and its channels.

One important mechanism in this market is the ability for PGE to offer grid-service participation incentives to encourage the customer to install efficient automated equipment that integrates with the Virtual Power Plant. The customer benefits though efficiency gains and better performing equipment, while PGE secures the right to operate the equipment to provide grid services.

Today, PGE's sole product in this space is the Energy Partner program. In 2020, PGE plans to add the business EV charging program to this sector as well. Additionally, new opportunities are arising for PGE to offer our customers resiliency offerings via flexible load strategies and technologies. With the help of PGE's Market Insights team, PGE's Portfolio Planning, Product Management and Development teams, is exploring other innovative program designs shaped by customer preference and values.

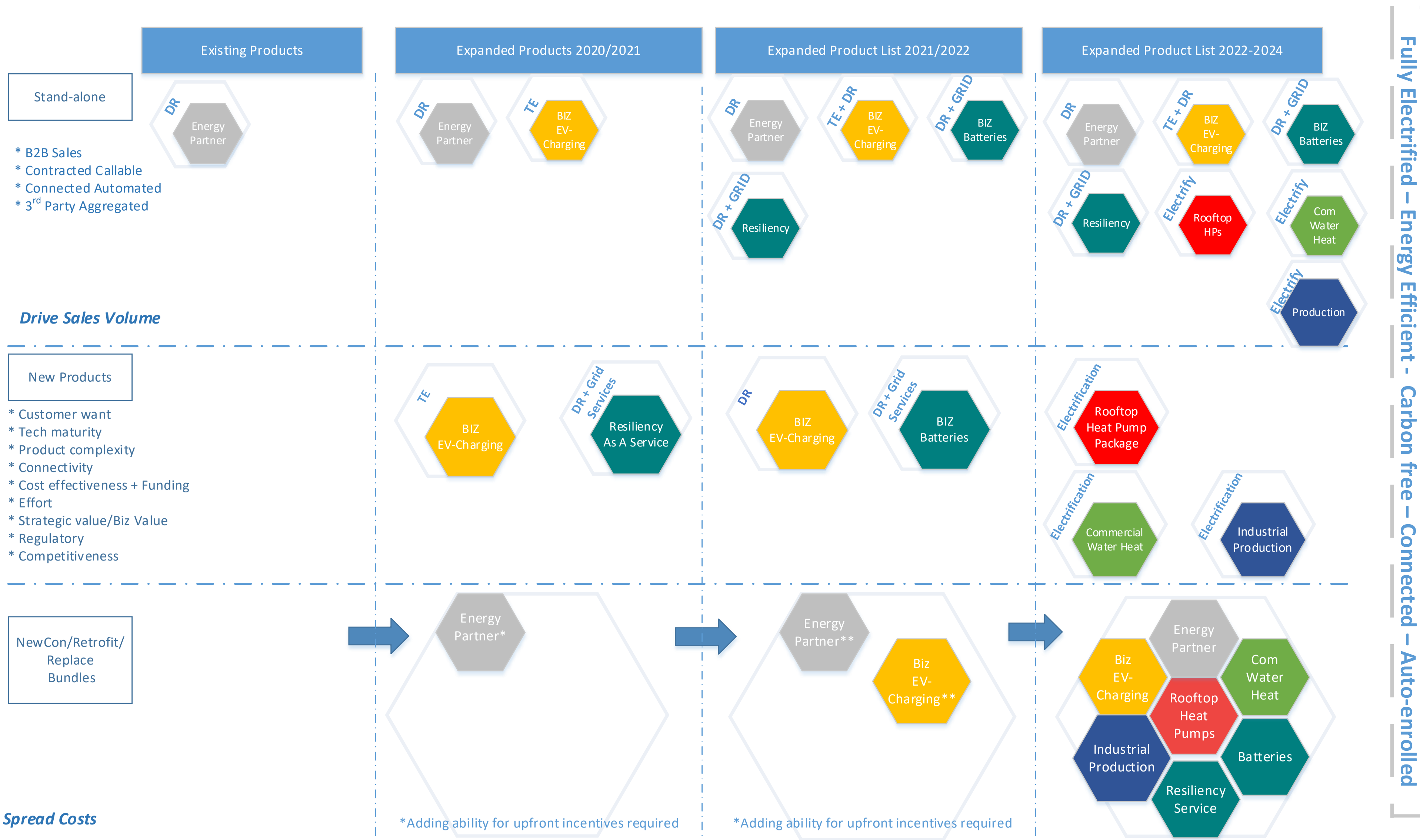


Figure 15 – BUILDINGS – Commercial – Retrofit + Replace + Upgrade at System Failure – 5-year Roadmap

3.3.2.6 District Energy Solutions

PGE is partnering with municipalities and governments to offer tailored services to large-scale planned communities. PGE refers to this sector as district energy. Reaching this sector requires unique program development and acquisition strategies that results in a more holistic implementation for larger projects and communities. This approach extracts product bundles from residential and C&I markets and applies them to large projects. Delivering district energy projects requires close coordination with external partners. PGE recognizes that, by offering builders and planners tailored solutions, our programs help meet the needs of the market to create large, well-coordinated flexible loads and help decarbonize the built environment. Figure 16 represents how the above items can be combined into a suite of products for a comprehensive district solution.

One recurring factor in current district energy projects is the desire to future-proof by providing enhanced resiliency specifically as it applies to critical infrastructure. PGE anticipates that many of these projects will include comprehensive energy supply and grid services agreements between PGE and the customer.

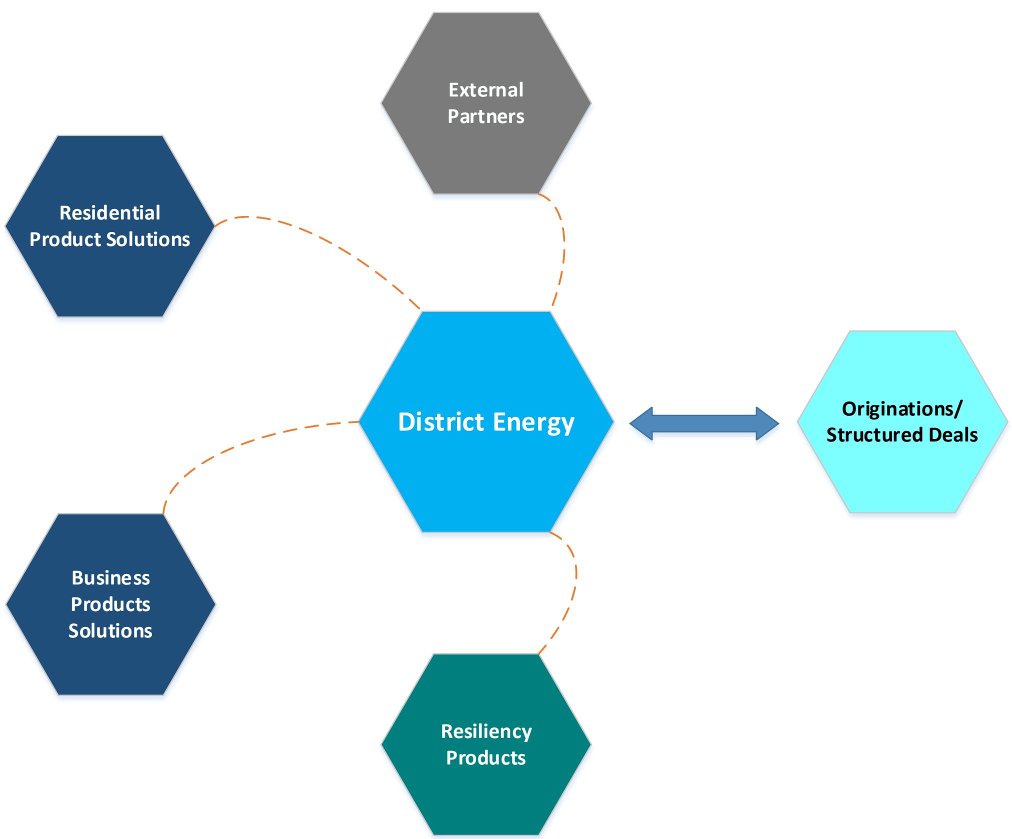


Figure 16 – Comprehensive Customized District Solutions – Perform, Decarbonize, Engage

District energy offers an opportunity to showcase how coordinated and intentional investments in large developments uses flexible load to enable the Virtual Power Plant. By employing applied systems thinking, PGE plans to engage with customers before and during the design of these projects to establish the optimal mix of resources and maximize value. Choosing the correct design, the proper equipment, and creating inter-connectivity between design elements allows for cost effective Virtual Power Plants that would be cost prohibitive in a retrofit scenario.

Stacking incentives from EE, DR, and auxiliary services with renewable resources allows costs to be driven down while driving momentum towards customer-centric, decarbonized, integrated solutions. A rare opportunity exists to create solutions where residential, commercial, and industrial solutions provide cross-sector benefits, creating a more robust and holistic grid interplay with the Virtual Power Plant.

3.4 Practices Proposal

This section contains PGE's proposal to the Commission to move to multiyear portfolio planning and budgeting. PGE asks the Commission to acknowledge the reasonableness of this practice change. This practice change would involve a subsequent filing to the Commission wherein PGE would delineate activity it would undertake to meet multiyear savings goals building to the 2025 savings goal adopted in the PGE 2019 IRP. This subsequent filing would include a budget proposal to reach the savings goals. The proposed practice outlined below also include regular reporting to the Commission and regular quarterly meeting with Commission Staff. The subsequent filing, tentatively referred to as a multiyear plan, would seek Commission approval. The multiyear plan would transparently communicate the activity to be undertaken, the milestones to be reached, and the dollars needed to meet savings goals. PGE's program staff has been open, transparent, and collaborative with Commission Staff, and will continue to work with Staff on the development of a multiyear plan.

Multiyear and Strategic Planning	Implement a long-term strategy for program development, cost control, transparency, and collaboration
Designing to Scale	Design demonstrations and pilots to maximize learnings and prepare for full scale deployment

Moving from demonstration to program requires that PGE implement a cohesive strategy for program development that maximizes technical, operational, and customer lessons learned. PGE proposes to efficiently and effectively acquire flexible load resources using a scalable and repeatable process.

As described in detail below, this will include PGE's 1) potential assessment and identification of multiyear flexible load acquisition goals through the IRP; 2) development of short- and long-term strategies to achieve identified goals; 3) budgeting; and 4) allocation of the necessary funding through a recovery mechanism similar to Schedule 109[57], or alternatively Schedule 135[58] [59]. PGE will implement its programs using demonstration projects, pilots, and programs. Finally, third-party evaluators will conduct program evaluations and PGE will share the results of those evaluations with the Commission and stakeholders. The high-level elements of this process are outlined in Figure 17.

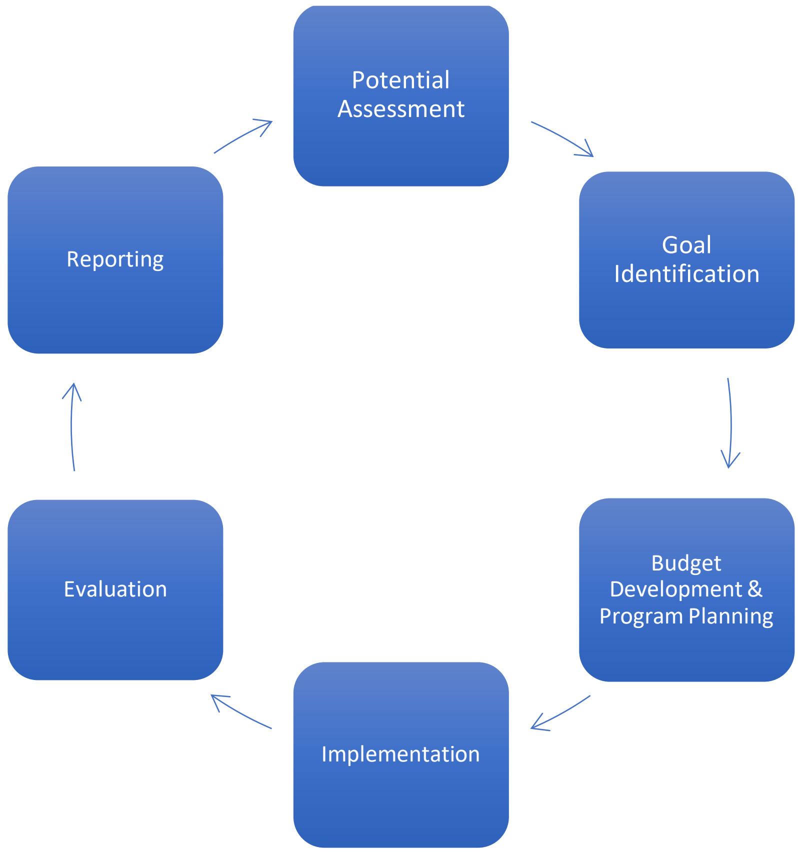


Figure 17 – Elements of PGE's Process to Acquire Flexible Load Resources

3.4.1 Goal Identification

PGE has a long history of planning for demand response and flexible load within the IRP. With each IRP, PGE refines and improves our planning practices and sets new overall goals for flexible load resources. However, the IRP does not set prescriptive, programmatic targets or detailed implementation plans. By grounding of PGE's flexible load goals in the IRP process, planning and

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[57] Portland General Electric Schedule 109 Energy Efficiency Funding Adjustment, available at; https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_109.pdf.

[58] Portland General Electric Schedule 135 Demand Response Cost Recovery Mechanism, available at; https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_135.pdf.

[59] This approach is not unlike that employed in California for the acquisition of demand response. In December 2017, the CPUC approved a 5-year budget for 2018-2022 of $1.16 billion for utility-operated DR programs that will provide approximately 1,600 MWs of DR capacity by 2022. The costs of the programs are from ratepayers through retail electricity rates. CPUC Decision D.17-12-003.

program development aligns the overall goal remains aligned with the Company's identified resource needs. PGE has identified areas for improved alignment between IRP planning and the on-the-ground experience gained through program deployment. In the near term, our priorities are:

- Improved Characterization of Flexible Load Program Attributes: The three key resource attributes within IRP planning include: cost; performance constraints; and, for flexible load, customer participation. As PGE gains experience operating programs in our service territory, we can inform these three key attributes with information gained from PGE's deployment of flexible load programs with our customers.

- Improved Quantification of Flexible Load Program Benefits: In recent years, PGE gained expertise at incorporating system value for VERs and energy storage in terms of capacity, energy, and flexibility into IRP modeling. PGE can leverage and adapt this expertise to better incorporate the unique characteristics of flexible load programs.

- Moving Toward Endogenous Treatment Within Portfolio Analysis: In the long term, PGE seeks to incorporate flexible load endogenously in the IRP, rather than exogenously via third party studies. PGE expects this to be challenging because the attributes of flexible load resources are so different from those considered in traditional planning exercises. PGE expects that more holistic treatment of flexible load within the IRP will require incremental improvements over the course of multiple planning cycles, similar to the process for incorporating VERs and energy storage.

As PGE works to develop more innovative approaches to flexible load within the IRP process, there are some aspects of the current practice that will be important to retain. The current practice utilizes the IRP process to establish high level goals for flexible load deployment but does not rely upon the IRP to set prescriptive program-specific targets or to conduct cost effectiveness analysis for specific programs as they are designed and deployed. The most appropriate role for the IRP will continue to be high level goal setting, while program-specific decision-making is built on the insight and expertise of program staff, based on the current opportunities within PGE's service territory.

- Continue using the IRP to set overall system goals for flexible load deployment,
- Continue setting prescriptive targets and details at the program level,
- Continue analyzing cost-effectiveness outside of the IRP.

PGE discusses the role of Distribution System Planning in Section 3.9 and 3.10.

3.4.2 Program and Budget Planning

Taking the goals identified through the IRP process, PGE program staff will develop a multiyear plan to achieve the goals. This plan will cover both the goals identified for the near term as well as the longer-term achievable potential. The plan will cover the types and volume of activities along with the demonstrations and pilots necessary to meet longer term objectives. As part of the multiyear plan, PGE program staff will identify a two-year budget. This process along with reporting requirements and cadence is described in further detail below.

3.4.2.1 Program Planning

To develop the portfolio of programs necessary to achieve PGE's flexible load acquisition goals, PGE program staff will identify the market strategy and program(s) suited for each area of identified potential. These will be defined by the nature of the market opportunity. For example, programs are often grouped around sectors (e.g., residential, commercial, industrial, agriculture), new versus existing construction, technologies with widget-based savings versus those requiring a more customized analysis, or the channel through which potential program participants are reached, such as retail or contractor networks. As described above, bundling these offerings when marketing programs to customers is a best practice and a necessary step on the pathway to cost effectiveness.

Each program will be comprised of one or more flexible load products or services. These will be based on the nature of the product or service and the level of confidence in the amount of flexible load. The opportunities can be classified among the following types:

1. **Demonstration Projects** will be used when products or services have a fair degree of uncertainty for one or more aspects of performance. These measures require specific testing or experimentation. Generally, the uncertainties are technical in nature and testing will be done on a limited basis to explore new approaches to deployment, aggregation, or customer participation. PGE will identify the plans and resources necessary for these measures. Unlike energy efficiency, where the region has collectively invested in demonstration work through the RTF and NEEA, PGE does not have such supporting infrastructure for flexible load. As a result, PGE must be allowed to conduct small scale demonstration projects as seen in the Testbed.

   Presently, as outlined above, the Testbed is PGE's primary conduit for demonstration work. This work is funded through a separate deferral. The proposed multiyear plan and budget will reflect how the Testbed is used and will account for Testbed funding. Any demonstration work that PGE identifies as necessary to conduct outside the Testbed will also be part of the multiyear plan and submitted to the Commission for funding approval. The onus will be on PGE to both demonstrate incremental funding is needed and that the project will benefit our flexible load portfolio long term. As noted in the Commission's LC 66 Testbed white paper, demonstration work will save money and accelerate development of flexible load resources[60]. PGE proposes funding for these activities be small and discrete but not be factored into portfolio cost effectiveness. Demonstration projects are not meant to be cost effective. The following figure shows the demonstration process

[60] LC 66 , Staff Final Comments, Appendix A, May 12, 2017 available at https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=lc66hac132649.pdf&DocketID=20423&numSequence=111.

leading to pilot development. For all Testbed demonstration the DRRC would continue to approve proposal for demonstration work. Where Testbed funds are being used the DRRC would have final approval or denial of the proposed work. The process shown below includes an internal approval by Product Lifecycle Management for continuity of planning and budgeting. The multiyear planning process proposed along with the quarterly DRAG meeting would further inform stakeholders and Commission Staff of demonstration development and progress.

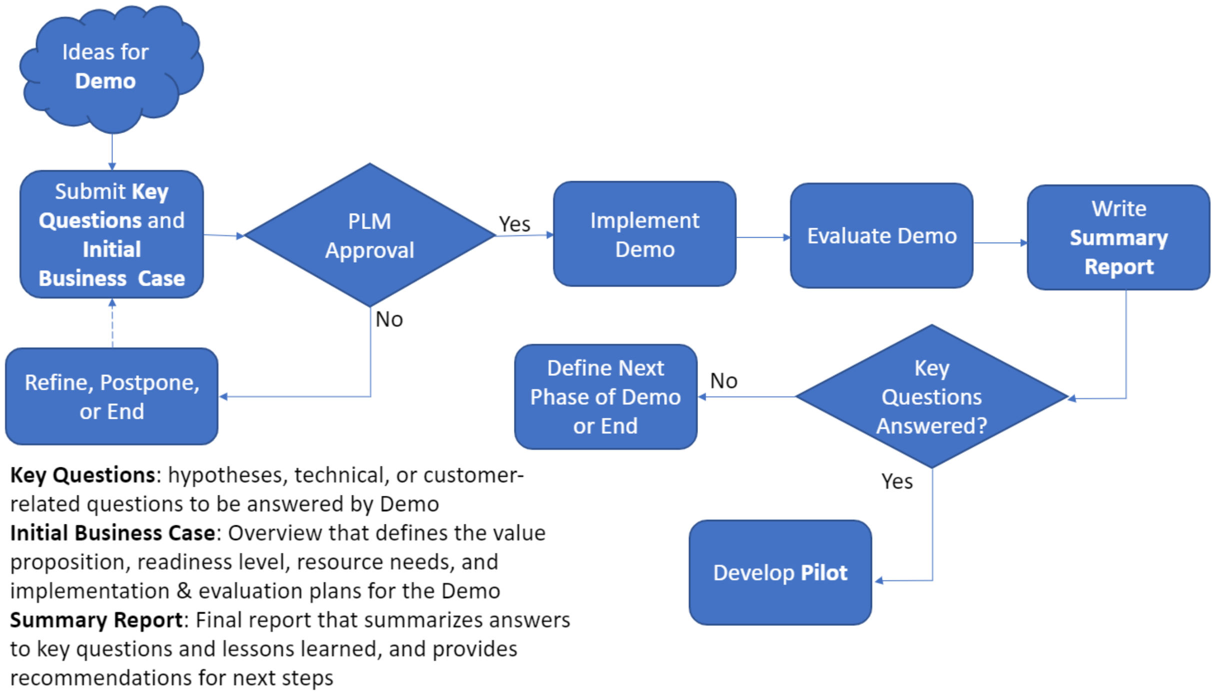

Figure 18 – Demonstration Process

2. **Pilots** are used for products and services showing a promising path to cost-effective deployment. These resources will be incorporated into PGE customer program operations but are at a scale too small to be incorporated into PGE's real time operations. Pilots are typically used to answer a specific number of limited questions about market strategies or program participation. Pilots are accompanied by a plan detailing the questions to be addressed and the evaluation strategy used to answer them. Creating a plan for each pilot helps PGE prioritize and coordinate resources across pilots and will ensure that the plan aligns with the necessary resource objectives Pilots begin with the creation of a Business Case. The creation of a Business Case assures justification for the resource spend. The business case also clearly defines the objectives, resources, and team roles necessary for a successful deployment. The managers of each group whose work will support the pilot will approve or deny the pilot proposal through the Project Lifecycle Management. Major considerations for approval will include availability of resources, demonstration of a clear pathway to cost effectiveness.

Project Lifecycle Management approval requires detailed plans for research and evaluation. These plans include the goals and indicators of pilot success, identification of the research questions, and the resources needed to implement the pilot. At the completion of the pilot, a memo is prepared to document the findings. Based on the results of the pilot, next steps will be determined. A diagram of this process is shown below:

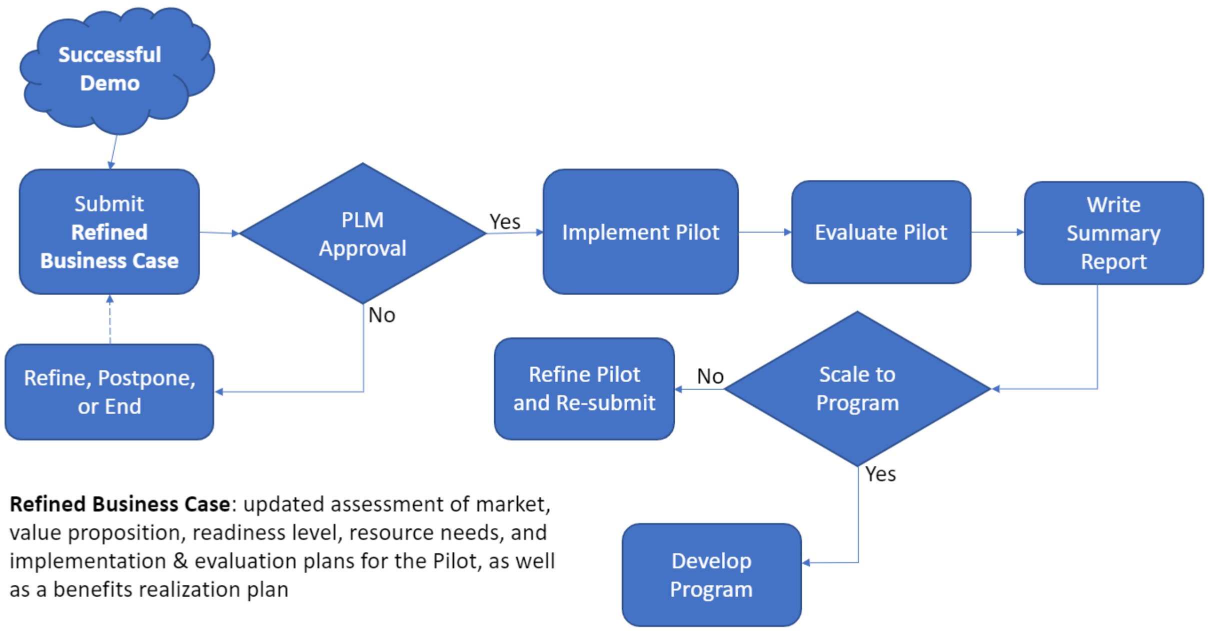

Figure 19 – Pilot Process

3. **Programs** exhibit a high degree of regularity in both impact and implementation costs. On average, these products and services are cost effective across a wide variety of metrics and methodologies defined through the IRP and/or DRO processes. Through a series of documented deliverables required to advance an offering through the PLM phase gates, PGE is able to design, build, and launch demos, pilots, and programs that result in proposal filings at the Commission. The diagram below details the iterative and collaborative process PGE will follow and the roles for PGE staff:

4. In addition to the demonstration to program process for offering development, PGE must carve out space for other high value flexible load offerings, such as large custom projects and offerings capable of providing significant EE and DR value. Custom projects are those in which the impact and cost are unique to each implementation of a measure and an analysis is performed to estimate the quantity of flexible load, implementation cost, and cost effectiveness of a measure beforehand. These are common for programs targeting larger commercial and industrial facilities. For these opportunities, the size of the flexible

load justifies the additional work and complexity involved. Custom projects are typically implemented with calculators built to determine the cost effectiveness and incentive for each instance based on the estimated savings and implementation costs.

Solutions capable of providing overlapping EE and flexible load benefits may also require additional time and resources, as they generally provide high flexible load value. Potential overlap with EE includes heat pump water heaters, which provide both EE and flexible load; smart thermostats; and even bundled measures where a combination of EE and DR measures may provide benefits beyond the sum of their individual components. An example of this last category could include the bundling of weatherization in combination with a smart thermostat, in which additional weatherization would allow for longer and/or larger thermostat setbacks for DR. In these instances of combined EE and DR opportunities, PGE will work with Energy Trust in an approach that considers both the EE and flexible load benefits. PGE will work with Energy Trust to co-develop the tools and processes necessary for such an approach, including the development of offerings, roles for market deployment, and funding/cost allocations.

Finally, as part of the multiyear planning process, PGE will consider the various market delivery pathways to reaching program participants. Included in these possible strategies are the use of a Program Management Contractor (PMC), Program Delivery Contractors (PDC), and direct-to-customer approaches. It is important to note that in both of these models, the contractor remains directly under the oversight of the utility and therefore under the Commission's jurisdiction. Additionally, PMCs and PDCs typically are paid directly for their services rather than through the splitting of the customer's incentive. These are key differences between this program model and the third-party DR provider model described above.

PGE will share its program and market strategies with stakeholders during the development of its multiyear plan along with the accompanying budget, discussed below.

3.4.3 Budget Development

PGE proposes to budget on an annual basis in rolling two-year periods, on the same cycle as the Energy Trust. Running parallel budget and program planning cycles can create synergies, increase deployment, and enhance savings. PGE program staff will use the goals set for the two-year period and the strategies identified to determine the budget necessary for each of the two years. The budget will consider fixed costs such as contracting, as well as variable costs such as incentives, which are measured on a per widget or per unit of flexible load.

The process of budgeting will consist of two development rounds. A first round will consist of the initial estimates developed by program staff, to be reviewed with stakeholders as part of the development of the multiyear plan. Program budgets are also reviewed to ensure consistency with a reasonable expectation of funding, recognizing that year-over-year cost increases may need to be limited.

PGE aims to have a transparent and open process, which allows stakeholders to engage in PGE's program planning and evaluation. To achieve this, PGE will create a multiyear plan and budget highlights program progress, successes, and areas of improvement, and cost effectiveness. This plan will be made publicly available and PGE will solicit feedback from Commission Staff and interested stakeholders. The plan intends to consolidate existing reports, creating efficiencies and streamlining reporting mechanisms. The plan will reflect all of PGE's behind-the-meter activity including DR, energy storage, electric vehicle load control, rate schedule development, microgrid activity (including that connected with distributed resource planning), self-generation, activity coordinated with Energy Trust, and other marketing, outreach, and educational activities.

After this review, budgets will be revised by program managers and become the final operating budget. This budget will determine the funding needed through the recovery mechanism, while accounting for any carryover of unspent funds from the previous year and any funding reserves deemed necessary.

This approach will set a known budget for a two-year period of resource procurement and will allow portfolio activity to be flexible within the time period. This will give PGE the flexibility to balance minor variances from expected activity levels across the portfolio to take advantage of opportunities as they emerge[61]. The stability of funding encourages the utility to work with its resources most efficiently.

By following a process similar to Energy Trust, PGE will be able to identify and align areas for collaboration with the Energy Trust, including developing market strategies, joint measure development, and deployment of resources. This practice will require PGE to plan internal resource allocation and also identify when, where, and at what cost contracting services should be used, requiring PGE to compete its internal costs against third party PMCs and PDCs.

3.4.4 Program Management

This approach will require PGE to manage its flexible load programs on an ongoing basis, including tracking of program-related and overhead spending; program acquisitions of capacity, energy, and ancillary resources; and program incentive budgets and spending. Consistent with Energy Trust's approach to program management, all activity will be tracked in a manner related to the method used in sales forecasting in other industries, where activity is tracked and categorized in terms of its likelihood of follow through, from initial leads to offers, commitments, and completed installations. Insights from the Testbed's load disaggregation work will inform tracking and marketing approaches to improve effectiveness.

For compatibility with Energy Trust's data on completed EE projects, PGE will track its flexible load activity using a data model, consisting of the projects, site(s) where projects are completed, participants involved in the project, and any measures or other activity associated with the project, including energy and/or capacity, measure costs, and incentives provided. A basic diagram of this model is shown below:

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[61] For example, if PGE saw growth above forecast in multifamily new construction

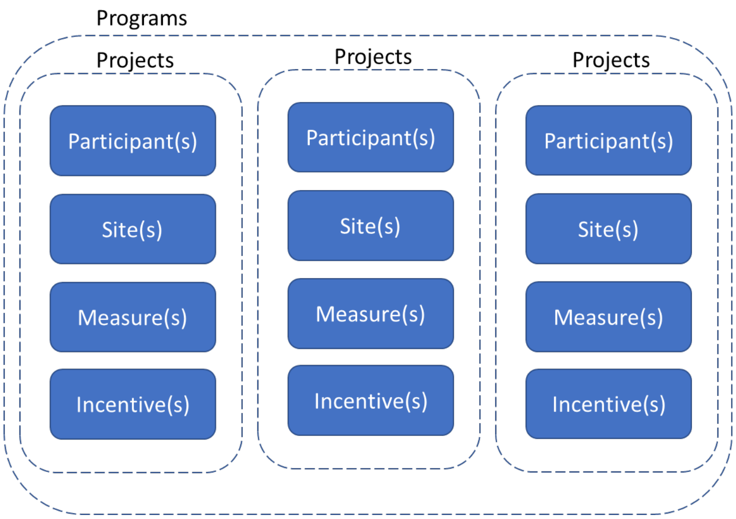

Figure 20 – Repeatable Data Model to be used across Flexible Load Activities

Over the program implementation cycle, there are three measurement points for savings. These are: **Planning savings** that measure expected savings prior to the launch of a pilot or program; **Average realized savings** which are measured during the operation of a pilot or program and **Evaluated Savings** which are measured after the fact by independent third parties. PGE would like to work with the Commission to identify the appropriate methodologies and inputs for each of these measurement points.

3.4.5 Program Evaluation

PGE will conduct regular evaluations of its flexible load activities. Consistent with current and best practices, each program will undergo process and impact evaluations. Energy Trust typically follows a process of evaluating several program years in one evaluation for cost efficiency:

- **Process evaluations** are conducted to review the effectiveness of program processes. During a process evaluation, the evaluators will typically interview program participants to gauge their level of satisfaction with the various components of a program. Evaluators will also interview those program staff involved in the day-to-day and overall management of a program for perspective on the performance of the program as well.

- **Impact evaluations** are conducted to determine the extent to which a program's claimed achievements have been realized. This is referred to as the realization rate and is often applied to savings after the fact.

Both types of evaluations will be conducted by third party evaluators. The evaluators will be selected through a competitive bidding process from a pool of qualified contractors. Evaluation results will be shared and reviewed with the Demand Response Advisory Group (DRAG) to ensure accountability and neutrality in the results, after which evaluations will be posted publicly.

These evaluations will be a critical component to inform future program planning. Process evaluations help to inform program design by highlighting potential areas of concern or evaluating improvements that have been implemented. Impact evaluations can inform future estimates of program achievements by informing things such as the technical realization rate and participation in DR events.

3.4.6 Reporting

To keep the Commission and other stakeholders informed of PGE's activities, PGE will report on its activity through various reporting channels:

- PGE will provide bi-annual updates on expenditures and incentives to Commission Staff through a simple spreadsheet tracker during the first two years. After two years, updates would occur annually. PGE proposes more frequent updates initially in recognition of the novelty of the proposed process change.
- Similarly, PGE would provide quarterly updates during DRAG meetings on program information, including number of sites or customer served and capacity acquisitions. This would shift to yearly reporting after the first two years. The quarterly DRAG meetings offer a venue for more in-depth discussions. These meetings allow for frequent Commission staff and stakeholder input.
- In-depth annual reports will detail the achievements of PGE's flexible load programs from the prior year. This will include overall capacity and flexible load acquisitions in relation to the program goals, along with financial details such as incentives and expenditures relative to budgets. A proposed list of reporting practices, contents, and cadence for the first two years is provided in the table below. Thereafter PGE would switch to yearly reporting:

Table 3 – Report Contents and Cadence First Two years

Metric	Portfolio Level	Cadence	Program Level	Cadence	Notes
Flexible energy and capacity acquired	✓	Y	✓	Y	Totals relative to annual goals
Incentives Provided	✓	Y	✓	B	
Expenditures	✓	Y	✓	B	Relative to budgets
Levelized Costs	✓	Y	✓	Y	
Total Resource Cost Test	✓	Y	✓	Y	Benefit-cost ratio
Utility Cost Test	✓	Y	✓	Y	Benefit-cost ratio
Administrative Costs	✓	Y	✗	Y	As percent of annual expenditures
Customer Satisfaction		Y	✓	Y	From evaluations
Sites/Customers served	✓	Y	✓	B	Some C&I customers have multiple sites
Schedule 135 Recovery	✓	Y	✓	Y	
Goal Setting	✓	Y	✓	Y	
Capacity Acquisition Reporting	✓	Y	✓	B	

Y = Yearly   B = Bi-annually

As noted above, PGE will report on the cost-effectiveness of its overall flexible load portfolio, as well as the cost-effectiveness of individual programs and products. Overall portfolio cost effectiveness will allow PGE to meet the identified goals while still effectively allocating resources to a mix of emerging and well-established activity. This gives the utility the flexibility to fund demonstrations and pilots for emerging measures that may not be cost-effective in the near term, while supporting resource acquisition through programs at scale and maintaining cost-effectiveness at the portfolio level. To meet PGE's ambitious flexible load goals, it must acquire cost-effective flexible load in the near term while also supporting the development of additional resources.

This regular reporting will give the Commission and stakeholders visibility into PGE's work and the costs relative to its accomplishments. It will also obligate PGE to transparently identify any issues move swiftly towards their resolution.

3.5 Product Management Lifecycle

Organization	Create leadership support and accountability, dedicated resources and cross functional collaboration within the utility for effective program development

Since 2014, PGE has utilized a Product Lifecycle Management (PLM) process to systematically prioritize the development of the portfolio of products. PLM provides oversight of products from concept through to development, operationalization, and reassessment. Figure 21 illustrates how PLM answers key questions regarding the product portfolio, including is the idea or product viable/feasible? is there a market and business case? is the product ready to launch? Post-launch, PLM reviews product performance, as well as whether it needs to be updated, discontinued, and / or replaced. The following section summarizes PGE's current PLM processes. It is important to note that these processes are continually refined based on lessons learned during execution of the process.

Figure 21 – Product Lifecycle

PLM oversight of the product portfolio is delivered via a system of controls. First among these is a governance framework to ensure clear management of the process. The process owner coordinates product development and ensures that relevant stakeholders have been engaged and that an informed recommendation is brought forward for consideration. The approver has ultimate authority and accountability for product lifecycle decisions. The process owner engages subject matter experts on relevant matters; they inform recommendations that the process owner brings forward for consideration.

A regular cadence of formalized meetings provides several controls. Weekly management meetings assess new development opportunities, identify and remediate issues, and schedule product development. Biweekly Advisory Committee meetings communicate the status of efforts in a consistent and timely manner, provide a forum for formal decisions regarding the product lifecycle, and deliver a quarterly review at the portfolio level.

An ongoing market assessment identifies customer needs and PLM intake controls ensure that product ideas address those needs. Prioritization criteria ensure that product ideas are in line with PGE's strategic imperatives to decarbonize, electrify, and perform. Market "fit" is determined by market research to ensure that development efforts are in line with customer needs.

PGE's development and reporting controls include a suite of standardized planning documents. Chief among these is the Product Plan, whose stage gate criteria ensure the requisite steps have been completed at the pertinent stage of the product lifecycle. The Product Plan is an umbrella document that encompasses a swath of subsidiary controls. It starts with the Product Proposal and Development Schedule, and proceeds through the Business Case, Financial Analyses and Budget Tracking. The Product Plan lays out Stakeholder Roles and Responsibilities and includes a Logic Model to ensure that products deliver on and are assessed against strategic goals. It compiles distinct product planning documents including development, marketing, communications, evaluation, data management, and risk management plans. The Product Plan also includes an ongoing performance review to provide oversight into the operation of developed products. Related PLM documents include the product brief, which provides a quick overview of products for stakeholders. Lastly, the stage gate recommendations and decision log documents respectively memorialize the process owner's recommendations and the approver's decisions after each stage gate, including any contingencies thereto.

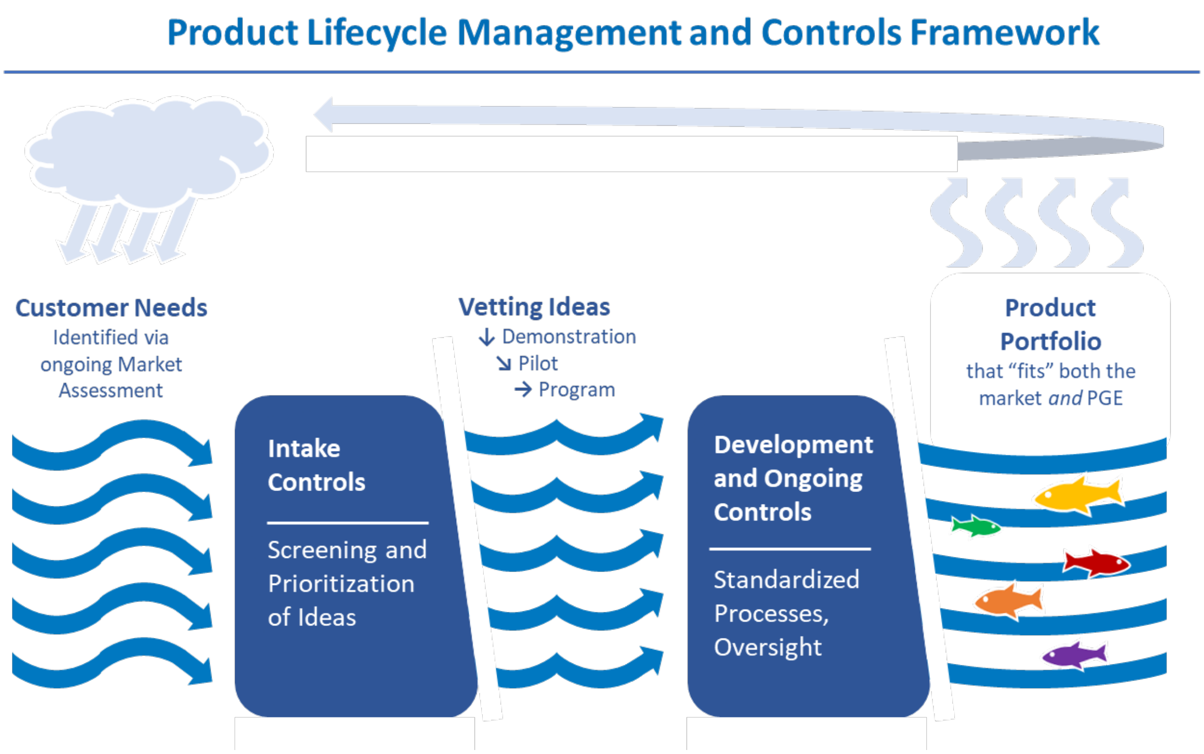

Figure 22 – Product Lifecycle Management and Control Framework

Figure 22 and the above descriptions illustrate how the PLM control framework provides robust oversight of PGE's product portfolio. It delivers better visibility into the product lifecycle; identifies controls that are right-sized to the size and complexity of the effort; establishes clear expectations, ensures timely communication, strengthens alignment with internal stakeholders, and forces standardization so that stakeholders know what to expect and when.

3.6 Stakeholder Engagement

Stakeholder Engagement	Collaborate effectively across industry stakeholders to design and execute meaningful projects

Stakeholder engagement and support is essential for meeting the aggressive, innovative goals that PGE and the OPUC have adopted for flexible load deployment. PGE knows that technology providers, regulators, customers, and advocates must collaborate on new concepts, establish common ground, and avoid unproductive disputes in the pursuit of cutting-edge projects. This is why PGE has established the DRRC for the Testbed. The Committee is seated by participating cities, the Citizens' Utility Board, NWPCC staff, NEEA, the Energy Trust, the Pacific Northwest National Laboratory (PNNL), the Oregon Department of Energy (ODOE), the Alliance of Western Energy Consumers (AWEC), Commission Staff, and other partner organizations. PGE collaborates with these stakeholders to design and implement our Testbed and flexible load demonstration projects.

Additionally, PGE is coordinating with Commission through DRAG meetings, where PGE meets with Staff and, when invited, the Energy Trust, to report and seek guidance on project development.

Furthermore, in order to improve communications and engagement with our customers, PGE hired three Community Relationship Managers within the Smart Grid Testbed. Our Community Relationship Managers have begun implementing a Testbed community engagement strategic plan to inform practices throughout our flexible load activity. The community engagement strategic plan identifies the goals and objectives of outreach efforts of the Community Relationship Managers working in the Smart Grid Testbed and is outlined below:

Table 4 – Smart Grid Testbed's Community Engagement Strategic Plan

Goal	Objectives	Outcomes	Deliverable/Metric
Identify and build durable relationships with key stakeholders	• Identify and create inventory of stakeholders and establish points of contact for key/priority relationships	• Engagement with key stakeholders and mechanisms for ongoing communication	• List of prioritized stakeholders with assigned relationship owners
Identify disparities in service or program participation	• Collect and synthesize customer data from all relevant sources • Analyze data and identify areas where disparities in services and/or programs exist	• Shared themes and insights from test bed data sources • Share identified barriers to participation specific to environmental/social/climate justice communities • Share recommendations for programmatic changes based on the data	• Community Snapshot • Quarterly Community Insights Meeting • End of project evaluation report
Leverage community engagement best practice	• Identify and leverage best practices in community engagement • Research community engagement practices at other utilities • Apply equity lens to all community engagement planning and activities	• Stakeholders and community members included in planning and implementing community engagement strategies • Approach adopted for clear and transparent communication about the participant's role and level of influence	• Collective community engagement work plan • Individual testbed-specific work plans
Establish Outreach PACE model and facilitate implementation of community and key stakeholders' feedback	• Provide insights gained from SGTB community engagement to appropriate PGE departments	• CRM-led cross-functional Quarterly Community Insights meeting and Community Outreach PACE	• Community Outreach PACE • List of prioritized stakeholders with assigned relationship owners
Demonstrate a commitment to continuous improvement	• Review community engagement strategic plan regularly • Review best practices and current engagement strategies and techniques	• Documented lessons learned and application of methodology to aid in evaluating continuous improvement and applicability to broader service territory longer term • Incorporate best practices and new engagement strategies and techniques	• Repository of lessons learned, best practices, strategies and techniques for community engagement

The primary goal of the SGTB is to identify new strategies that will help address the 2021 electric generation resource needs identified in PGE's 2016 Integrated Resource Plan (IRP), and confirmed in the 2019 IRP. These strategies are centered around driving demand Response (DR) and flexible Loads, which are identified as a carbon free, cost-effective, customer-based resource which helps address anticipated 2021 resource needs. Foundational to the success of the project is ensuring that we are focused on understanding the ability of customers and communities within the SGTB to participate in PGE DR programs, and within that context, identifying their desire, motivations and tensions (barriers to entry). The creation of the Community Relations Manager (CRM) positions provides a channel for engaging underrepresented and underserved customers, increasing knowledge about the SGTB and load flexibility, and building/nurturing relationships with stakeholders to reinforce PGE's commitment to this work' community engagement efforts will be focused within the three testbed communities: North Portland, Hillsboro, and Milwaukie. Testbed efforts will also provide a means for PGE to demonstrate the value of, and need for, broader community engagement across our service territory to achieve DR uptake and other clean and equitable energy future outcomes.

3.6.1 Empowering community voices

The energy industry is evolving rapidly, and those who are affected by disparities must have a say in the change. PGE is a trusted advisor and critical touchpoint for helping all people understand how the energy system works, how to advocate in regulatory spaces and which programs might benefit them.

3.6.2 Eliminating barriers in public process

Community groups play a critical role in shaping public processes and must continue to be invited to discussions about equitable policymaking. For example, in 2017, the Oregon State Legislature passed Senate Bill (SB) 978, which required a public process to explore how new technologies and policies might impact the electricity regulatory system. SB 978 eased the path for groups like the Coalition of Communities of Color, OPAL Environmental Justice and Verde to bring their voices to the Oregon Public Utility Commission, where they advocated for the protection for low-income ratepayers, the development of community-based renewable energy projects, workforce diversity in the energy sector and other key issues

One barrier to inclusive participation in energy public processes is a lack of funding to support historically excluded stakeholders. Where appropriate, community advocates should be compensated for their unique consultation. PGE, Pacific Power and other partners submitted an agreement to make funds available to community organizations to cover expenses associated with their participation in SB 978.

3.6.3 Better data sharing

We believe inclusive engagement is possible only when information about who benefits from programs and services is shared openly. In collaboration with state and federal agencies, OPUC, Community Action Program (CAP) agencies, and community-based organizations, PGE will work to provide better demographic data on our pilots and programs by identifying the benefits and burdens associated with our energy system. This will help stakeholders understand where to focus further efforts.

3.6.4 Enhancing customer interactions

As we engage with customers throughout our service area, it's critical to keep in mind that communication needs vary. For example, not everyone will speak English or have access to online resources.

PGE has the responsibility to serve customers whose needs, whether related to income, language, health, age, or other situations, differ from the majority of our customers. We regularly review our practices to ensure we are accommodating these customers. For example, we have staffed our contact center with Spanish-speaking representatives. Thanks to our diverse workforce, we can also call upon employees who speak Russian, Farsi and other languages when additional help is needed. As our service area becomes more multicultural and digital, we're leaning into spaces that are new and challenging. We must continue to set the bar higher for creating smooth, accessible customer experiences. Without Smart Grid Testbed we have issued collateral in Spanish, English and Russian.

3.7 Cross-Industry Collaboration

Cross-Industry Collaboration	Share best practices and lessons among utilities to accelerate effective demonstration to pilot to program evolution

PGE has been working to establish coordination with the Energy Trust through the Testbed via the DRRC, DRAG and regular monthly coordination meetings within the Testbed. PGE has been working with the Energy Trust to coordinate our approach to residential and commercial thermostats, single family heat pump water heater, ductless heat pumps, roof top solar plus storage and strategic energy management. PGE view Energy Trust of Oregon as is most important partner in flexible load development. Our proposal to move to multiyear planning and budgeting should accelerate and better our coordination and collaboration.

Additionally, PGE has recently opened a conversation with PacifiCorp about co-development of demonstration and pilot projects. PGE is hopeful that PacifiCorp and PGE can identify beneficial opportunities which may save both utilities' customers money. Lastly, PGE has been sharing our work with the region through various regional forums such as the NWPCC DRAC, and also nationally through EPRI and the Peak Load Management Alliance.

Salmi Klotz / 2

Industry Collaboration is important to the development of Flexible Load. Analogous efforts to support energy efficiency development have been established in the Northwest. These activities and collective investment in entities like NEEA and the RTF provide significant benefits to the region's utilities, are the envy of other regions, and make our approach to energy efficiency one of the, if not the most well established in the country. PGE views such cross-industry collaboration as a necessity for flexible load development and will pursue similar establishment.

3.8 Utility Role in Flexible Load Development

3.8.1 PGE is Optimally Positioned to Develop and Optimize Flexible Load Resources

Flexible loads need to be dispatched automatically and at grid scale, to ensure maximum benefits are achieved. This can only be accomplished when integrated with and managed by the grid operator. PGE has the planning, development, and operations experience needed to optimize flexible load across a portfolio of value streams.

Planning for least cost resource development and acquisition is key to meeting our customer's needs. PGE's IRP provides strategic direction for resource acquisition. Flexible Load is inextricably linked both to the IRP process and to PGE's commitment to customers to decarbonize at least cost.

Additionally, in order for flexible load to reliably provide grid services, it must integrate with the monitoring and dispatch tools used by PGE's real time operations[62]. PGE is required to maintain the balance between generation and load on a second to second basis, and to meet NERC and WECC reliability standards where performance is measured in seconds and minutes. For flexible load to be fully optimized in real time operations, it must be fully visible and dispatchable by PGE's operations staff.

3.8.2 Optimizing Flexible Load as an Integrated Resource

PGE views Flexible Load as a system resource, a tool with which to help decarbonize our system and integrate variable renewable resources at least cost while maintaining reliability. We commissioned our Decarb Study[63] to understand if a decarbonized energy future is attainable while serving the growing electric and energy needs of our customers. The findings of the study show a decarbonized future is attainable even with today's technology, but to enable the kind of future suggested by the study, major changes are required in the way our society produces, delivers, and uses all forms of energy. This includes driving down greenhouse gas emissions in our own resource portfolio while creating a modernized, smart grid to help efficiently integrate clean, renewable resources and enable electrification. Flexible loads are key components of this

[62] For example, PGE's balancing authority uses OSI's monarch platform to provide Supervisory Control and Data Acquisition (SCADA), Energy Management System (EMS), and Enterprise PI for real-time monitoring and tagging. PGE also uses a suite of operations tools from OATI, including the OASIS platform, webEIM, webTrans.

[63] Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory, April 24, 2018, available at https://investors.portlandgeneral.com/static-files/6e630aff-fcff-44e2-9ddb-82232f24bcd4.

modernized grid and the study found – in the High Electrification Pathway – that more than 900MW of flexible load could be needed by 2050. To achieve this success, PGE must build, monitor and utilize flexible load in real-time. Enabling the full capabilities of flexible load requires PGE to make investments today not only to build the flexible load resource but also to capture the greatest benefit through reliable, secure real-time control that is fully integrated with PGE's operations.

In order for flexible load to support decarbonization in the way envisioned by PGE's Decarb Study, flexible load must be aggregated into Virtual Power Plants as described in Chapter 1. These Virtual Power Plants must then be optimized in real time across the range of services that they are capable of providing. For example, if the Virtual Power Plant is providing distribution deferral, the limitations of the distribution equipment must be respected in order for the flexible load to also provide flexibility reserves or other grid services. In order to optimize flexible load across multiple value streams, PGE must be able to integrate it into PGE real time dispatch and monitoring systems. This integration is what enables flexible load to operate on par with generation resources.

PGE is committed to the investments necessary to support the utilization and optimization of flexible load. These investments include: an ADMS, distribution automation; and Distributed Energy Resource Management Systems (DERMS). These are the tools and the integrated operating platforms that will enable PGE's customers to realize the greatest overall value from flexible load. PGE's Smart Grid Report outlines this vision[64].

The Testbed offers PGE an opportunity to test strategies to implement this new integrated grid platform[65]. Within our Testbed, PGE is investing in several demonstration efforts. Section 3.11 of this Plan outlines a series of related flexible load demonstration projects meant to judiciously approach the implementation of our integrated grid vision. An example is PGE's investment in a demonstration of a standalone DERMS solution which offers a multifaceted opportunity to advance PGE's ability to build the Virtual Power Plant by enabling location-specific monitoring and control. This will be the region's first test of a Virtual Power Plant. PGE is using the Testbed to demonstrate the capability for flexible load to provide a host of grid services.

The integrated grid is a highly complex system that requires controls and monitoring at distinct points as well as modeling and planning to optimize value and grid services. Figure 23 shows how PGE will structure and utilize our investments to capture the greatest value from our flexible load investments, with the goal of enabling their full integration into grid operations.

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[64] Oregon Public Utility Commission, UM 1657, July 2019. PGE's 2019 Smart Grid Report.

[65] PGE filed information about the integrated grid platform in our 2019 Smart Grid Report in OPUC Docket UM 1657. Discussion of Integrated Grid can be found through the report but particularly within Section 5.

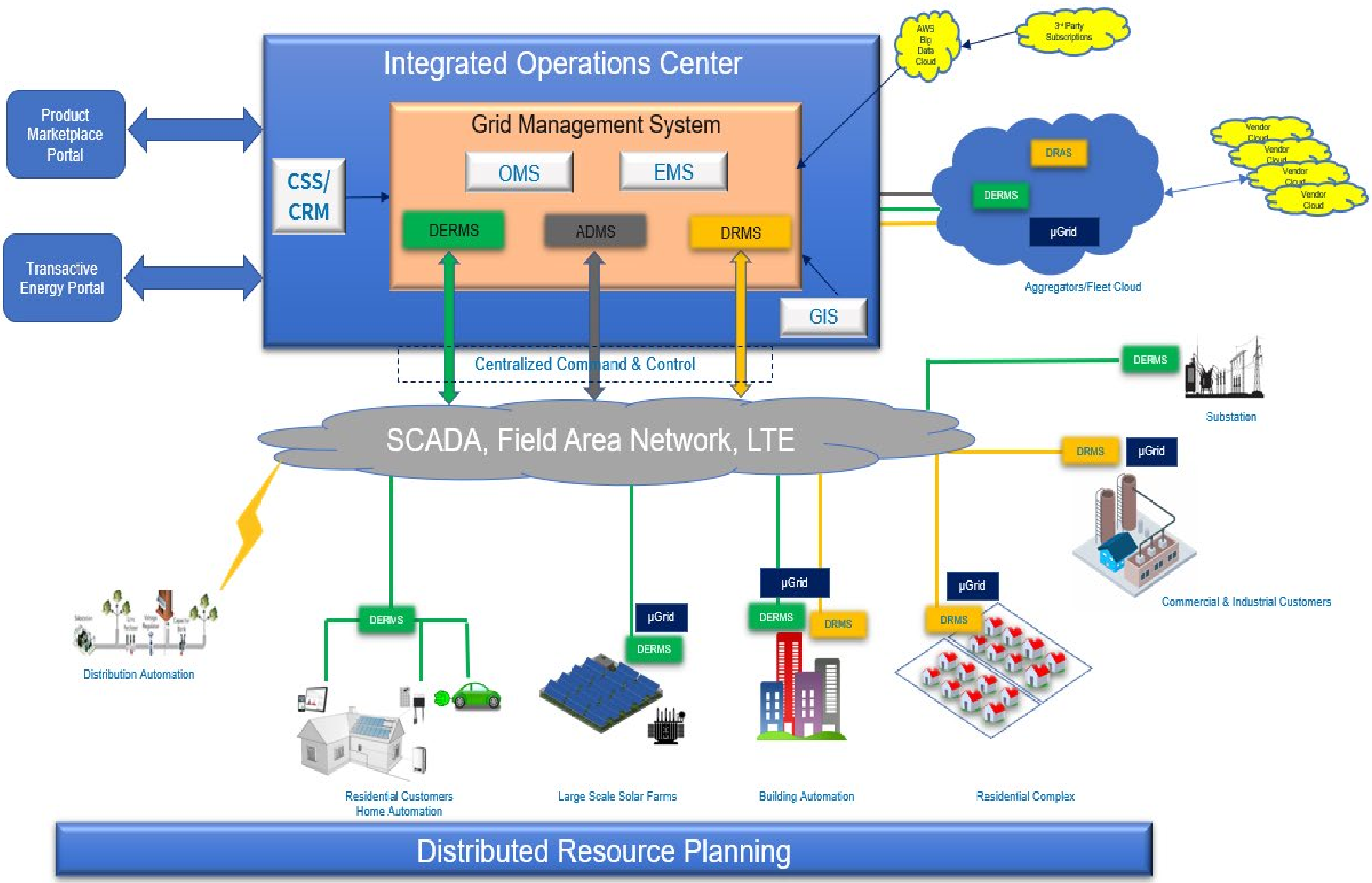

Figure 23 – PGE ADMS Vision

In this integrated approach, all aspects of the flexible load resource are visible, whether through residential grid enabled appliances, an electric vehicle, or through grid interactive buildings and microgrids. Our approach is part of a broader planning effort through our Distribution Resource and Distribution System Planning activity. Clarity of the market potential and reliance on technology to integrate and operate in real-time are necessary to plan, build and operate the resource. This Flexible Load Plan documents PGE's vision and commitment to building a flexible load resource that is fully optimized in PGE's operations. This integration is necessary to capture the full value of flexible load in pursuit of decarbonization at least cost.

3.8.3 PGE as Provider and Operator of Flexible Load

Customer engagement and participation will be critical to achieving long-term decarbonization at the lowest cost to customers, and flexible operation of electrified end uses is a key strategy. The development and optimization of flexible load is a partnership between PGE, the Commission, and our customers. Inserting another entity between PGE as the grid operator and our customer as the provider of flexible load, threatens the optimization, value, and the rate of the resource build. Having overall responsibility for incorporating flexible load into the portfolio allows PGE to strategically partner with third parties in ways that leverage their capabilities without introducing inefficiencies. PGE's envisions partnerships with third parties playing a key role in an efficient, effective flexible load ecosystem. Maintaining an integrated system allows PGE to harness the real-time operational capabilities of these resources.

PGE has learned from past experience, and validated with research into other states, that using third party demand response providers creates poor customer experiences and limited grid value and use. California experimented for several decades with third party demand response providers yet has still not fully integrated flexible load resources into grid operations and the wholesale market[66]. Latency of communication, intra-day coordination and customer protection issues hamper the third party demand response provider approach. Latency of performance arises

[66] In 2003 a working group including CPUC and CEC participants developed a vision for demand response: "All California electric consumers should have the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals, by not later than 2007."
The document also laid out objectives, goals, principles and a timeframe for achieving that vision. In CPUC Decision D.03-06-032, the Commission endorsed several aspects of the vision statement, including a goal of achieving demand response capacity of 5% of annual system peak demand by July 1, 2007. The adopted goals were specified to be above and beyond any "demand response achieved through the emergency programs. See also California Public Utility Commission Decision D.06-1-049 ((November 30, 2006) where the Commission began modifying their approach to demand response and directing utilities to release RFPs for aggregator acquired demand response. See also CPUC Decision D.13-12-029 Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols where the Commission began attempts to integrate demand response into wholesale markets. Finally see CPUC Decision 17-10-017, section 2.3 which shows the Commission still addressing items like mismatched supply plans, wholesale market participation, incorporating and valuing demand response megawatts.

because the utility must contact the third party demand response provider to trigger and manage an event. This limits the types of grid services available and thus the overall grid operations and planning value of flexible load. This added inefficiency would challenge the viability of multi-nodal programs such as hot water heaters and would all but eliminate the potential to optimize for a different service each hour[67].

Third party demand response providers are also not regulated by the OPUC. Additionally, third party demand response providers do not have the same obligations as a utility to serve customers and to ensure reliability. In PJM, NYISO, and ISO-NE, third party demand response providers have manipulated the market through the artificial inflation of customer baselines and other mechanisms. The FERC has taken action against the following third party providers:

- In 2013, Enerwise Global Technologies, Inc directed one of its participating customers to increase its load prior to an event to inflate potential payments. Not only did this implicate the customer in a wrongful act but it was an attempt to extract above market payments without providing a beneficial service to the grid[68].
- In 2013, Competitive Energy Services, LLC engaged in a scheme to fraudulently inflate a customer's energy load baselines and then offer load reductions against that inflated baseline[69].
- In 2012, EnerNOC submitted overstated baseline data for five DR assets, violating ISO-NE's tariff by submitting inaccurate data for settlement without first exercising due diligence[70].
- From 2007-2008, North America Power Partners 1) registered 101 customers before obtaining their authorization or verification of their willingness and ability to participate in the PJM capacity auction; 2) knowingly submitted inaccurate values, overstating the capacity value of their portfolio by 39.5 MW and 3) failed to respond over 9 times to a PJM frequency response event when their resource had been bid in and cleared the auction; no customer was notified of the event or their participation obligation[71].

PGE is concerned that without this direct regulatory oversight, third party providers could have increased opportunities to manipulate participating customer data for financial gain. These demand response providers engaged in these activities despite the oversight of the Market Operator, the independent market monitor, and FERC enforcement action. Additionally, participation in an organized market ensures that all parties are subject to the market operator's

[67] For example, water heaters could provide winter peaking capacity for the morning ramp, then regulation /energy imbalance over mid-day, and again provide peaking capacity over the evening peak.
[68] *Enerwise Global Technologies, Inc*. 143 FERC ¶ 61,218. Issued June 7, 2013
[69] *FERC v. Lincoln Paper & Tissue, Inc*., No. 1:13-cv-13056 (D. Mass.) & *FERC v. Silkman,* No. 1:13-cv-13054 (D. Mass.)
[70] *EnerNOC Inc. and Celerity Energy Partners San Diego LLC*, 141 FERC ¶ 61,211 (2012) (order approving stipulation and consent agreement).
[71] *North America Power Partners*, 133 FERC ¶ 61,089 (2010) (order approving stipulation and consent agreement).

tariff and are thus under the FERC's direct jurisdiction. These providers could extract payments from all customers without providing the contracted grid service, with limited to no regulatory oversight.

In contrast to third party suppliers, a utility is fully under the oversight of the Commission. This is particularly important for PGE because of the predominance of residential customers in our customer mix; therefore, a majority of the available flexible load resides with residential customers. This means two things. First, the relationship between the provider of flexible load programs and services needs to be under direct regulatory oversight to protect against misbehavior and to prevent a third party demand response provider from taking undue advantage of customers who may not understand the value of their participation[72].

In 2017, when PGE ended a contact with a third party demand response provider for non-performance, the entity exited the market, leaving PGE and regulators with questions and concerns[73]. To make the third-party demand response provider model work, the third-party demand response provider negotiates with customers, taking a percentage of performance payments. Customers should have transparency to the value of the service they provide and should be paid commensurately. PGE provides that transparency through filed rates and tariffs. These tariffs transparently lay out how and how much the customer is compensated. The Commission oversees these activities and can request modification at any time.

In an effort to address performance of third party demand response providers, the CPUC's Energy Division began experimenting with an auction mechanism to procure demand response in 2014[74]. Again the results show California is continuing to struggle with third party provided demand response[75].

Recent evaluation of this third-party procurement approach found significant challenges and misgivings. Despite spending a collective $63M over 5 years, the evaluation found third party programs were 1) far less active in the day-ahead market then other demand response resources supplied by the utilities, 2) the prices for these third party megawatts were far less competitive then other resources, 3) these third party demand response megawatts were not effective in offsetting the dispatch of gas plant during peak hours; 4) underperformance was particularly acute among residential demand response providers; 5) pricing for the capacity megawatts provided was not competitive until sometime in 2017; 6) the Commission Staff concluded that prices

[72] CPUC D.08-06-015, Decision Modifying Decision 07-05-029. Where the Commission out of concern over performance gaming and customer compensation made several changes to demand response programs operated by aggregators in the state.

[73] OPUC Order No. 17-429, October 24, 2017, see also first modifications to the EnerNoc contracted requested and approved in OPUC Order No. 16-037, January 2016.

[74] In D.14-12-024, the California Public Utilities Commission (Commission, or CPUC) authorized investor-owned utilities (IOUs) to conduct pilot Demand Response Auction Mechanism (DRAM) auctions in 2015 and 2016 for procuring demand response (DR) capacity aggregated by third-party providers, also referred to as demand response providers (DRPs),1 to be delivered in 2016 and 2017.

[75] California Public Utilities Commission, ED's DRAM Evaluation Updates & Recommendations: Public Workshop, January 16, 2019.

provided were not competitive in the energy markets; and finally 7) Commission Staff could not determine whether the third party approach successfully provided the contracted capacity[76].

It should also be noted that this approach could not produce day-of dispatch. These third-party demand response providers could only supply the contracted megawatts on a day-ahead basis. As PGE pursues decarbonization goals, it will be important to maximize the performance capability of various flexible load programs on all operations horizons—from resource adequacy planning to intra-hour “shimmy” programs. As described in Chapter 1, the true value of flexible load lies in a portfolio of programs operating as a Virtual Power Plant. If, like California’s experiment with third-party DR auctions, the megawatts provided are only available day-ahead, this would significantly lessen the portfolio value of the flexible load.

PGE is expanding our flexible load portfolio to help provide grid services to meet PGE’s planning and reliability obligations. PGE does not support the use of customer dollars to invest in third party demand response provider business models that are unregulated by the PUC. Flexible load offers carbon-free capacity—a resource that is built on a long-term planning basis to provide certainty that PGE will be able to meet peak load events. Third party demand response providers do not have a mandatory obligation to serve load. Giving these parties, whose responsibility to the system is held fast only by a passing monetary interest, the responsibility to build a resource needed to meet reliability and planning obligations would jeopardize grid operations, customer experience, customer prices, reliability and safety.

3.8.4 PGE Can Maximize Value Through Regional Collaboration

Regional collaboration was one of the keys to unlocking the potential for energy efficiency; PGE is working to develop a similar regional approach to demand response and flexible load. To advance and accelerate the development of flexible load PGE understands that investment must be made to shape building codes; appliance standards and communication protocols; interconnection requirements; and integration standards.

The Northwest has made such investments in energy efficiency, and these collective investments have supported the advancement and establishment of energy efficiency. The regional coordination between the region’s utilities, the NWPCC, Bonneville Power Administration (BPA), the Energy Trust and NEEA have had national effect. Investment in this work would likely not have materialized had the region relied on external entities or created a patchwork system of utility directed programmatic investment and external entity program offerings. Similar to our collective regional investment in EE, PGE envisions regional investment and coordination to advance the development of flexible load. PGE staff, staff from the Northwest Energy Coalition (NWEC) and NEEA have initiated discussions about regional coordination for DR and flexible

[76] California Public Utility Commission, Energy Division’s Evaluation of Demand Response Auction Mechanism, Final Report, January 4, 2019.

load. To this end NWEC will be sponsoring a webinar in June on CTA-2045 regional coordination. The Washington Legislature passed House Bill 1444 in 2019 codifying CTA-2045[77].

PGE is working and coordinating with Energy Trust regarding coordinated deployment of flexible load technologies to customers. Energy Trust and PGE are currently coordinating deployment of smart thermostats and solar plus storage; in 2020, we will begin a demonstration project studying the combined EE and DR value of ductless heat pumps.

While coordinated deployment of energy efficiency and DR is a best practice, it is important to note that energy efficiency and flexible loads are not similar in terms of ongoing operations. Energy efficiency programs generally involve engagement with the customer once, while flexible load requires continued engagement and participation because the resource is used as part of grid operations. The energy efficiency investment permanently lessens customer energy demand; flexible load is more complicated as demand is moved throughout the event, hour, day or season to match the needs of the grid

Our coordination work with Energy Trust has only just begun but shows extraordinary promise. This type of partnership will save customers money, better establish the working relationship between the Energy Trust and PGE, create stronger customer experiences, and save customers money. Lastly, this coordination will allow for better resource build than if third party demand response provider were allowed to disrupt what is a promising Oregon-centric approach.

3.8.5 Flexible Load Resource Build Costs Should be Non-by-passable

As mentioned above, flexible load is a long-term real resource in which PGE is investing for the long-term benefit of our system and customers and is recognized, along with energy efficiency, as a preferred resource in Oregon SB 1547 and a strategy identified in the Governor's Executive Order No. 17-20. However, this cost is currently recovered only from cost of service customers, yet the investment provides benefits to all system users. PGE proposes to recover the cost of our flexible load offerings from all system users, and is raising this in Docket No. UM 2024, which is ongoing.

Additionally, while Direct Access customers are currently unable to participate in PGE's flexible load programs, cost-effective flexible load could be available from these customers. Many of these Direct Access customers have expressed interest in participating in Energy Partner. These customers may also wish to participate in the TE and business charging pilots that are currently under development. PGE would like to explore options for Direct Access customers to participate in Flexible Load programs.

3.9 Distributed Resource Planning

Robust distributed energy resource planning is required to achieve our goals around equitable, affordable, and sustainable decarbonization of the energy economy. For this reason, PGE has

[77] Washington 2019 Legislative Session, House Bill 1444. Available at: http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Bills/1444-S.pdf.

established a Distributed Resource Planning (DRP) team focused on the development and application of new planning, operational practices, and tools to help us contend with a changing system. PGE will gain significant experience in planning for flexible loads and DERs within a comprehensive system planning context. In particular, the DRP function which will make progress towards addressing questions related to DER forecasting and potential, grid services, and resource characterization, which will be of mutual value to both DRP and IRP planning activities.

The future DRP will build new capabilities in PGE's core business of planning the electric system. These new capabilities will be fundamental in enabling the Company to leverage the grid as a platform for integrating localized energy resources, while putting PGE in a position to lead the conversation on integrating new technologies in a responsible, measured, and optimal way. This initiative has been designed to proceed flexibly, with minimal investment required to meet immediate needs, and the optionality to accelerate activities if required. PGE is using a phased approach to future DRP work as shown in Figure 24.

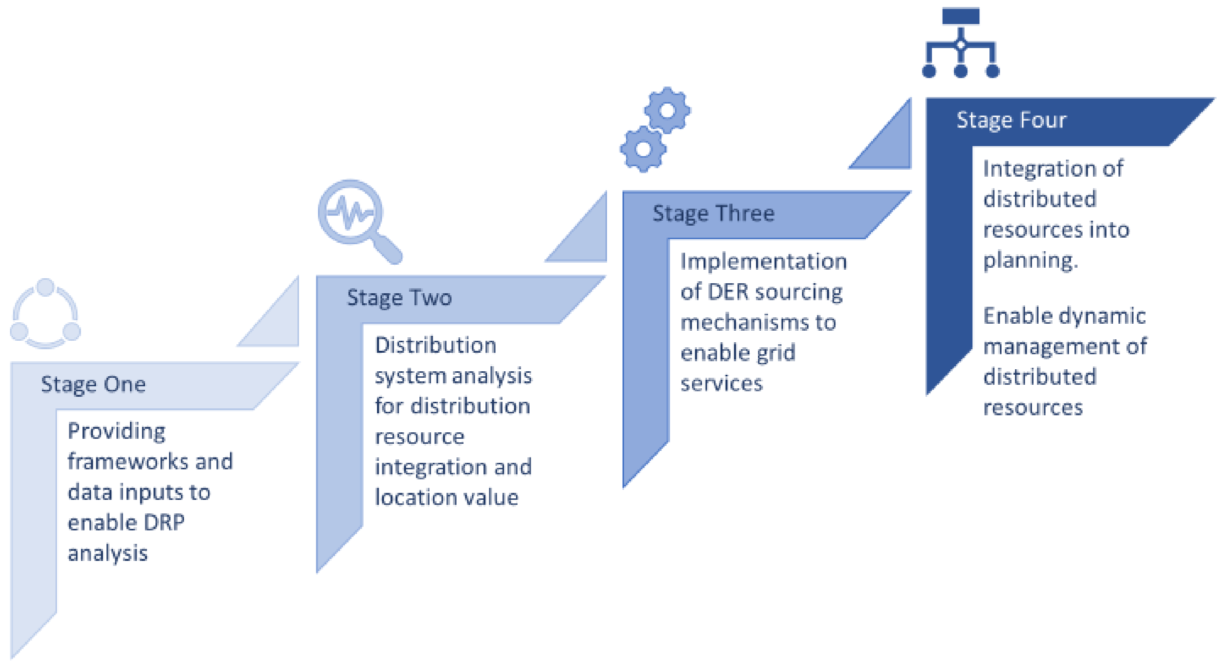

Figure 24 – Four Stages on DRP Implementation

3.9.1 Coordination Between IRP and DSP

PGE continues to advance our understanding of how planning practices can best support the evolution of flexible load. As we evolve our understanding, Distributed Resource Planning will become an important part of PGE's resource planning activity and reporting to the Commission and stakeholders. The four focus areas and the roadmap outlined above are the guiding vision for the detailed work to be conducted.

Currently, PGE conducts comprehensive distribution system planning (DSP) to support a robust and reliable distribution network, but it is not fully integrated with the new market realities engendered by flexible loads and DERs. Through the development of the first formal DSP filing[78], foundational steps to the DSP have already been made in the normal course of business. While UM 2005 is still underway, PGE has already begun working on many of the elements of distribution system planning in a variety of venues. Staff notes in their 2019 white paper[79] that there are a multitude of dockets that touch on elements of DSP across many areas of the business, including Resource Value of Solar[80], the IRP[81], Transportation[82], and Storage dockets[83], as well as the various DR pilots underway[84]. Under the future DSP process, PGE intends to develop tools and capabilities to model DERs including flexible loads. This will include foundational elements like resource characterization, costs, benefits, and operational constraints, which are important to distribution system planners and operators. Integrating information on flexible loads as a resource is a critical step to provide more visibility of customer-sited resource potential and impacts on transmission and distribution ("T&D") planning and operations.

The specific distribution system benefits that PGE intends to quantify and plan for will be discussed elsewhere, but at a high level, the DRP intends to establish planning methods to understand and value distribution services that require a finer granularity than provision of bulk system services (e.g., energy, capacity). In order to accomplish this, PGE must develop more accurate and well-defined resource characterization for flexible loads.

Local context and resource needs can and do vary throughout the distribution system. To progress towards truly integrated DER planning for distribution system benefit, DRP capabilities must include development of a planning paradigm that seeks to optimize portfolio selection and placement of specific flexible load resources to match specific system needs for different geographic and temporal metrics.

To answer these complex questions for the entire system will undoubtedly take successive iterations of planning rounds, and PGE is committed to developing the analytical framework needed to drive flexible load planning closer to this holistic vision. Because bulk system value can be expected to continue to provide the largest share of system benefits, the quantification of distribution services and locational value will be carried out (at minimum) with the assumption of constrained optimization to balance flexible loads between bulk system and location-specific dispatch. PGE has already begun modeling this for resources like battery storage and will broaden its capabilities to encompass more flexible loads in the course of DSP.

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[78] See UM 2005 "Investigation into Distribution System Planning", accessible here: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=21850

[79] See Docket UM 2005, Staff Report, March 13, 2019.
[80] Oregon Public Utility Commission Docket UM 1716
[81] Oregon Public Utility Commission Docket LC 73 (PGE's 2019 Integrated Resource Plan)
[82] Oregon Public Utility Commission Dockets UM 1811, UM 1826, UM 2033
[83] Oregon Public Utility Commission Docket UM 1751 and UM 1856
[84] Oregon Public Utility Commission Dockets UM 1708 and UM 1514

Distribution-sited battery storage is an example of the interdependency between DRP and IRP. In the 2019 IRP, PGE demonstrated potentialities where net cost was negative for distribution-sited battery storage in scenarios where a range of plausible locational values was taken into account (see IRP section 6.4). In the 2019 IRP, this treatment was indicative and drew on past IRP work on energy storage. Going forward, these, and related questions of locational value of DERs, will be addressed by modeling conducted in support of the DRP. Results and assumptions provided by this modeling will be included as inputs to subsequent rounds of the IRP. PGE plans to strategically leverage existing tools and capabilities - and develop new ones where necessary - to ensure that the DSP provides a consistent, transparent, and robust characterization of flexible load and DER resource potential.

3.10 Access to Customer Device Data

3.10.1 Background

PGE’s ultimate goal is to support the cost effective and equitable integration of diverse distributed energy resources into our grid. PGE supports the region’s goal of decarbonization through smart electricity use, such as transportation and building electrification. PGE continues to support the changing needs of our customers and their use of electricity. Recognizing our role in supporting our customers’ priorities and their changing usage, PGE has adopted the strategic imperatives of decarbonization and electrification. This Plan articulates the role of flexible load in achieving these dual goals.

In order for PGE to meet our customer demands, we must integrate, operate, and optimize flexible loads within the distribution grid. This requires PGE to monitor and operate grid-connected devices participating in our programs so that these resources are able to accurately respond to planned and unplanned grid events.

As the planner and operator of the grid, PGE needs to evaluate the results of our programs. This data is needed to ensure that participating flexible loads are optimized across the various grid services, and that PGE is able to capture the data necessary to demonstrate compliance with mandatory reliability standards. Additionally, PGE uses this data to inform effective program design through improved customer offerings and engagement, and also to enhance program performance. The ability to acquire insights from this data is important to our ability to identify, acquire, and optimize ever-increasing levels of DER megawatts.

Generally, device manufacturers provide the software platform - typically via cloud services - that interacts with their devices and provides data to utilities (or DERMs providers, who in turn have utilities as customers) for program operation. Often, these device manufacturers deliver these services through anonymized result data that is generated long after the event has occurred.

PGE seeks a framework that allows utility access to standard device data for program participants who enroll grid-connected devices into PGE programs. Such solutions would be at the customer’s direction and agreement; the data would be utilized solely for the purpose of effectively planning and operating the electric grid. [85]

PGE has experienced manufacturer resistance to sharing de-anonymized customer data reflecting specific device usage because device manufacturers often view it as intellectual property and have concerns about their own liability to our mutual customers. If these solution providers experience a change in ownership[86], the terms and conditions governing this data can also change. This complicates PGE's operation and analysis of existing flexible load resources. PGE seeks a solution that enables PGE to access common electric measures as detailed in specifications such as IEEE-1547-2018[87] and IEEE 2030.5[88] for DERs interconnection, with as-close-to-real-time communication as possible, and with the granularly and frequency of which the device is capable. PGE's need for this information is a key requirement for the utility to support our customers' energy journey while developing cost-effective flexible load resources. In making this request, PGE recognizes the inherent commitment to protect customer data, and to follow best practices to protect customer data privacy. PGE accepts its responsibility to keep this data safe and secure while in use, and to ensure that it is not kept beyond its useful life.

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[85] See PGE Advice No 20-46 for the discussion of uses of data in the Multi-family water heater pilot.

[86] For example, when a startup technology is procured by or merges with another company. Such as when Nest was purchased by Google.

[87] Available at https://standards.ieee.org/standard/1547-2018.html The technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems and DERs are the focus of this standard. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. It also includes general requirements, response to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests. The stated requirements are universally needed for interconnection of DER, including synchronous machines, induction machines, or power inverters/converters, and will be sufficient for most installations. The criteria and requirements are applicable to all DER technologies interconnected to EPSs at typical primary and/or secondary distribution voltages. Installation of DER on radial primary and secondary distribution systems is the main emphasis of this document, although installation of DERs on primary and secondary network distribution systems is considered. This standard is written considering that the DER is a 60 Hz source.

[88] Available at https://standards.ieee.org/standard/2030_5-2018.html The application layer, with TCP/IP providing functions in the transport and Internet layers to enable utility management of the end user energy environment, including demand response, load control, time of day pricing, management of distributed generation, electric vehicles, etc. is defined in this standard. Depending on the physical layer in use (e.g., IEEE 802.15.4™, IEEE 802.11™, IEEE 1901™, IEEE 1901.2™), a variety of lower layer protocols may be involved in providing a complete solution. Generally, lower layer protocols are not discussed in this standard except where there is direct interaction with the application protocol. The mechanisms for exchanging application messages, the exact messages exchanged including error messages, and the security features used to protect the application messages are defined in this standard. With respect to the Open Systems Interconnection (OSI) network model, this standard is built using the four-layer Internet stack model. The defined application profile sources elements from many existing standards, including IEC 61968 and IEC 61850, and follows a RESTful architecture (Fielding [B3]) using IETF protocols such as HTTP.

3.10.2 Problem Statement

PGE's flexible load plan is dependent on our ability to dispatch connected devices (e.g., smart thermostats, water heater controls, and behind-the-meter batteries). While often subsidized or incented by PGE, these devices are typically owned by the customer and registered for use with the device manufacturer by signing a lengthy list of terms and conditions. These terms and conditions establish an agreement between the manufacturer and the customer about how the data is owned and managed by the manufacturer, including which data points PGE can obtain from the manufacturer, how the data can be used or not used, how it is to be stored, and when the data must be destroyed. This creates a challenge for PGE as this approach not only sidelines PGE's relationship with the customer and their experience, but also effects our flexible load resource development.

3.10.3 Enabling the Best Customer Experience

For PGE to have effective relationships with customers and their devices, PGE must have direct access to the data from these devices.

Fundamentally, for flexible load programs to be successful, PGE requires certain information about when and how each customer participated. This information is correlated to individual event performance, and thus the overall performance of the flexible load resource. As noted in the grid services section, each grid service has specific performance criteria, including some criteria that is auditable under NERC and WECC standards. Data is needed to demonstrate resource performance to inform decision-making in the pursuit of a decentralized, dynamic, and decarbonized grid that continues to operate to the highest standards of safety and reliability. Today, access to and use of this data is controlled by the manufacturers. PGE may only use the data provided in a very limited capacity. Presently, PGE does not have a mechanism whereby the customer can assign data access.

3.10.4 What is Needed

Customers must have the ability to assign access to data directly to a third party such as a utility for use in the deploying and enhancing flexible load programs. PGE seeks to work with the Commission to further define these requirements to support this initiative[89].

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[89] California has addressed this issue with the following language.

> *A business that receives a verifiable consumer request from a consumer to access personal information shall promptly take steps to disclose and deliver, free of charge to the consumer, the personal information required by this section. The information may be delivered by mail or electronically, and if provided electronically, the information shall be in a portable and, to the extent technically feasible, readily useable format that allows the consumer to transmit this information to another entity without hindrance. A business may provide personal information to a consumer at any time but shall not be required to provide personal information to a consumer more than twice in a 12-month period.*

3.11 Demonstration Work in PGE's Smart Grid Testbed

PGE is operating and using the Testbed as envisioned by the Commission and communicated in the Staff whitepaper in docket LC 66.[90] As the following figure shows, PGE is using the Testbed to test and deliver the customer value propositions envisioned and proposed in the PGE Testbed proposal in ADV 859[91] and as requested by Chair Decker in her comments during the Commission meeting approving the Testbed proposal.[92]

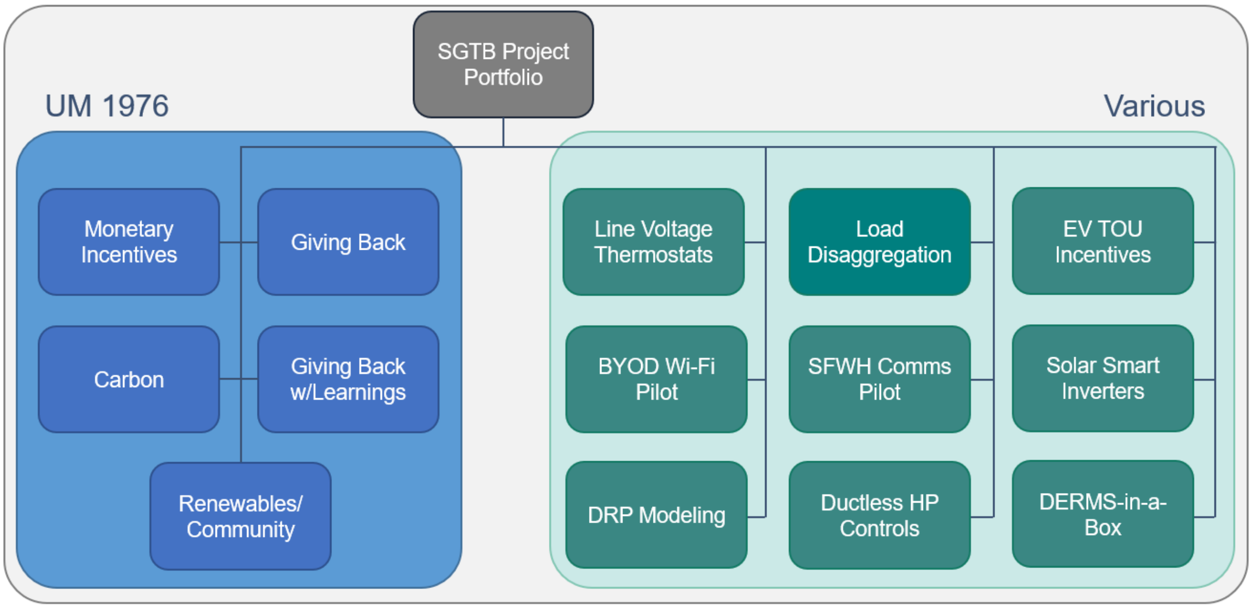

Figure 29 – Smart Grid Testbed Portfolio

The items labeled "Various" on the right side of Figure 29 are demonstration efforts being undertaken within the Testbed based on input from the Demand Response Review Committee. These activities include the following items.

California code: Title 1.81.5, sec 1798.100(d)

This language provides a starting place for an open discussion with the Commission to address data sharing.

[90] LC 66, Staff's Final Comments, Appendix A Demand Response Testbed Overview
[91] Docket No. ADV 859, Advice No. 18-14
[92] Oregon Public Utility Commission, Public Meeting April 9, 2019, where Chair Decker requested PGE conduct work inside the Testbed to advance DER development. Available at https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=387.

3.11.1 DR/DER Locational Value

The PGE Testbed Team is currently working with contractor Kevala Analytics to quantify distribution level value from DR/DER starting with the Island substation in the Testbed.[93] The goal of this work is to help ramp up distribution resource planning activity and refine program cost effectiveness valuations. This work began in Q3 of 2019 and will continue through Q2 of 2020.

3.11.2 Load Disaggregation

The PGE Testbed Team is currently working with contractor Bidgley to conduct a customer asset inventory. PGE is using AMI and building inventory data to predict residential mechanical systems such as home heating and cooling type and water heater fuel type. This work will also provide information on usage patterns and other large loads.

The goal of this work is to help quantify technical DR/DER potential, identify product portfolio roadmap gaps and more effectively target programs and pilots. The work began in Q4 2019 and was completed Q1 2020. We are currently assessing the results of the work and will share the information with the Demand Response Review Committee (DRRC) prior to making a decision to continue with further investment.

3.11.3 Electric Vehicle Time- of-Use Incentives

The PGE Testbed Team is working with the PGE EV Team to conduct research on how time-of-use rate structures affect EV charging behavior[94]. The scope of this work will be to roll out TOU incentives for 400 EVs in the Testbed. PGE will use 100 EVs outside the Testbed as a control group. Contractor FleetCarma will install data loggers in 500 EVs and then enroll these customers in specific Time-of-Use rates over the course of two years.

The goal of the work is to collect information on baseline charging behaviors and vehicle use to inform our understanding of how TOU, event based, and locational value influences charging. The work began in Q1 2020 and will run through Q4 2022.

3.11.4 Communication Study Opportunities

Establishing and maintaining reliable communications with flexible load devices is one of the main challenges with scaling programs and achieving cost effectiveness. PGE's current options for connectivity include cellular, Wi-Fi and local mesh networks. Each of these options has benefits and drawbacks in terms of communications stability, latency, and cost.

PGE is leveraging the multifamily water heaters demonstration to assess the total value of cellular, Wi-Fi and local mesh networks. The demonstration project targets 150 customers to test communication protocols for single family water heaters to inform future pilots and programs. PGE

[93] If successful, this effort will be expanded to the two additional substations in the Testbed, Roseway and Delaware

[94] This work is funded through UM 1826 Clean Fuels.

is partnering with the Energy Trust to identify clusters of heat pump water heaters which have the necessary controls to operate as a DR resource.

The demonstration project is scheduled to launch in later Q2 early Q3 of 2020 and run through Q4 of 2021.

PGE also has an opportunity to study the deployment of local area networks to control Wi-Fi-based control switches as part of a DR demonstration bundle within the Testbed. These utility-owned networks provide a unique opportunity to deploy and test the value of Wi-Fi-based communications for direct load control devices. This project is described in more detail in Section 3.11.8, below.

3.11.5 Energy Efficiency Alignment with Ductless Mini-split Control

Ductless mini-split heat pumps offer another opportunity to expand the types of devices eligible for flexible load program while aligning with EE priorities. Pursuant to Commission Order 19-301 in Docket UM 1696, PGE and Energy Trust are working on a demonstration project to assess the demand response value of ductless mini-split systems.[95] The Energy Trust's goal is to assess whether add on controls can increase EE performance, while at the same time delivering DR/flex load benefit to PGE. Min-split controls research provides an opportunity to explore the measure, while sharing the costs of that activity with Energy Trust.

The demonstration project would launch in Q3 2020 and run through Q3 of 2021, including two cooling seasons and one heating season.

3.11.6 Expanding DR Opportunities with Line Voltage Thermostats

PGE is leveraging one multifamily site in the Hillsboro Test Bed to demonstrate DR controls for line voltage thermostats that are capable of controlling radiant baseboard heat. The 136 units in the Park Village Apartments are all electric and use radiant baseboard systems to heat the units. PGE currently does not have a line voltage thermostat solution in market capable of controlling radiant baseboard heat, nor does it have accurate estimates of the DR value of such controls in our service territory.

As noted above, PGE also has an opportunity to study the deployment of local area networks to control Wi-Fi-based DLC switches. Developing a line voltage thermostat demonstration project at Park Village, enables PGE to explore the flexible load value of this control strategy without the need to deploy a new, dedicated network or rely on those operated by the tenants themselves, thereby reducing pilot costs and improving reliability. Additionally, this project offers an opportunity to test PGE's bundling approach to product development, described in Section 3.3 as this site is also participating in PGE's multifamily water heating pilot.

Due to the Covid-19 outbreak, this project is on hold until such time as PGE and Park Village Apartments are able to reconnect regarding installation or an alternative site can be established.

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[95] Commission Order 19-301, Docket UM 1626, available at https://apps.puc.state.or.us/orders/2019ords/19-301.pdf.

This project may be pushed to a potential Phase II if market conditions continue to present installation barriers.

3.11.7 Leveraging the Capability of Smart Inverters

Smart inverter capabilities currently exist on many inverters already interconnected into PGE's distribution system. With the passing of IEEE1547-2018,[96] it is reasonable to expect that Oregon will soon adopt the standard and all new smart inverters will adhere to the standardized functionality and control prescribed in IEEE1547-2018. This availability will pave the way for a more streamlined process for utilities to access and utilize smart inverter features. Smart inverter capabilities include voltage regulation, frequency support, and relief of distribution constraints through direct load control.

Conducting a smart inverter demonstration in the Testbed provides PGE an opportunity to test the effectiveness of these functions on a small scale, limited duration basis. This project will also inform a potential future regulatory requirement and provide insights into how smart inverter settings can be optimized to meet the needs of our system.

The Testbed team has engaged in preliminary conversations with the Energy Trust of Oregon and secured a list of existing interconnections in the Testbed that can be enabled. The timing of launch would be contingent on the development of a tariff (or modification of Sch. 13), contractual negotiations, and associated IT processes (e.g. security screening) related to the inverter original equipment manufacturers (OEMs). This projects status is placed on hold until a market approach can be identified. The current market is challenging due to Covid-19 restrictions.

3.11.8 Bring Your Own Device

The PGE Testbed team is working with contractor Virtual Peaker on a Bring Your Own Device demonstration project in the Testbed. Virtual Peaker has established appliance cloud-based controls with a host of companies such as General Electric, Rheem, Honeywell, Chargepoint and others. The demonstration project seeks to deploy a flexible DR/DER program platform to test new technology and program design.

The goal of the demonstration project is to evaluate the grid value of a "bring your own" DR program structure that covers a range of Wi-Fi based DR technologies. The idea is to test the viability of a device agnostic flexible load program which pays participants based on the service they can provide to the grid. This demonstration project is the first step in understanding how to develop a platform like approach to flexible load.

[96] The technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems (EPSs) and distributed energy resources (DERs) are the focus of this standard. Available at https://standards.ieee.org/standard/1547-2018.html

PGE and Commission Staff discussed this approach in June 2020. At that time it was decided that a Bring Your Own Device approach is complex and would require additional work on PGE's part and additional conversation with regulatory Staff.

3.11.9 Distributed Energy Resource Management System

A standalone Distributed Energy Resource Management System or DERMS solution with a preliminary Optimal Power Flow model offers a multifaceted opportunity to advance PGE's ability to build the Virtual Power Plant.

PGE is partnering with Open Systems International, Inc. (OSI) to build a DERMS that can model power flow for the three Testbed substations (Island, Roseway and Delaware). OSI also provides PGE's Energy Management System (EMS) that supports PGE's bulk electric activities, including automated generation control and integration with the Energy Imbalance Market. PGE hopes to leverage integration opportunities available across the OSI platform to provide both bulk electric and distribution level grid services. This integrated approach will allow PGE to maximize the value of the distribution cited Virtual Power Plant in ways that would not be available without system integration.

The goal of the demonstration project is to evaluate the flexible load opportunity, to capture the capacity value of DR, to establish distribution deferral values, to determine local distribution power losses, and to identify tools for reducing losses. The demonstration project will enable PGE to improve the management of both front of the meter and behind the meter flexible loads including distributed generation (DG), energy storage, DR, and EVs.

The demonstration project leverages existing work done for ADMS and data from PGE's geographic information system (GIS) for Testbed circuits. Additionally, the demonstration work with a discrete DERMS will enable PGE to integrate multiple Testbed elements into a demonstration Virtual Power Plant.

This demonstration project is expected to launch in Q3 2020 and run through Q1 2021.

Chapter 4 Cost Effectiveness

Chapter Summary

Chapter 4 is not a request for action from the Commission, but rather a recitation of our cost effectiveness practices. This chapter also defines and discusses the various grid services that flexible load does, or may be able to, provide in the future. This chapter is offered for transparency and to demonstrate the maturity of our practice in identifying and validating flexible load values and cost effectiveness.

4.1 Introduction

This chapter lays the foundation for conversations with the OPUC around measuring flexible load cost-effectiveness. It first focuses on the cost effectiveness methodology in place today, and then discusses the current status of the portfolio and actions being taken to improve portfolio results.

The value of flexible load will continue to grow as our grid rapidly transforms into a decentralized, low-carbon energy system; flexible load is a vital component in meeting our decarbonization goals. Along with growing and improving our flexible load portfolio, PGE is building the quantitative analysis to support this investment. We are pursuing improvements in both programs and quantitative evaluation simultaneously. Program development and refinement, market adoption, and participant education is a multiyear journey, and only through sustained commitment will this resource be ready for our transforming electrical system. PGE recognizes that successful demand response programs share a common feature: consistent, sustained commitment to the resource over time. PGE is committed to building and maintaining flexible load resources that mature into long-running programs. PGE looks forward to Staff's partnership in both program evolution and cost effectiveness evaluation.

4.2 Regulatory Background

The OPUC adopted the current cost effectiveness methodology in 2015 through Commission Order 15-203 (UM 1708)[97]. This approach is based on California protocols, now updated via its Standard Practices Manual[98]. In April 2016, PGE submitted *A Proposed Cost Effectiveness Approach to Demand Response* to the OPUC outlining this methodology[99]. The 2016 proposal, prepared by Navigant, was informed by PGE's unique system, stakeholder feedback, as well as Navigant's 2015 work on BPA's *Smart Grid Regional Business Case*. Beginning in 2015, each pilot filing has included a cost effectiveness forecast based on the California protocols.

[97] Commission Order 15-203, UM 1708, PGE Compliance Filing April 28, 2016, "A proposed Cost Effectiveness Approach for Demand Response."
[98] 2016 Demand Response Cost-Effectiveness Protocols, California Public Utility Commission, Available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11573
[99] Commission Order 15-203, UM 1708, PGE Compliance Filing April 28, 2016, "A proposed Cost Effectiveness Approach for Demand Response."

Since its first analysis, PGE has grappled with appropriate value assignment and which of the four tests is most applicable. The cost effectiveness analyses accompanying PGE's pilot filings in Appendix A reflect this ongoing analytical work. System values are updated as our understanding of flexible load products, deployment, and impact evolves. The California protocols are applied to all flexible load pilots and programs, populating the values applicable to each specific application. In February of 2020, Commission Staff commented on the Company's IRP and provided three recommendations on cost-effectiveness for DR, below[100]. Each recommendation is explored within the chapter's discussion of current practice. The location of that discussion is identified below each recommendation:

- **Staff recommendation 1:** The use in all calculations of the same base values as those employed for EE, specifically found in UM 1893.

  FLP location: The distinction between EE and flexible load, and the historic basis of their distinct valuation, is discussed in section 4.3.3.

- **Staff recommendation 2:** Reflect the benefit of DR as a zero-emission, dispatchable capacity resource. One such method could be to assign DR a capacity value equivalent to a non-emitting, dispatchable resource, not the current proxy resource.

  FLP location: Capacity resource selection and impact is discussed in section 4.3.2 of this chapter.

- **Staff recommendation 3:** Discontinue the use decrementing value assumptions that assume a value of lost service until PGE has the data to establish such a penalty.

  FLP location: Value of lost service assumptions and impact is discussed in section 4.2 of this chapter.

In April of 2020, Commission Staff requested that the Company provide data comparing DR avoided costs to the Commission Order No. 19-430 avoided cost methodology for energy efficiency[101]. Subsequently, in May of 2020, the Commission highlighted the importance of PGE's Flexible Load Plan to "sufficiently advance stakeholder understanding of PGE's approach to demand-side resources as a comparable resource to supply-side capacity".

This chapter seeks both to advance stakeholder understanding and to lay the foundation for ongoing collaboration.

4.3 Current Practice Inventory

Chapter Two describes how DERs have been treated within IRP system planning to date: cost effectiveness has been determined exogenously, by a third-party consultant, and reflects generic

[100] Staff's Final Report LC 73 Docket LC 73 PGE's 2019 IRP at p. 14 available at https://edocs.puc.state.or.us/efdocs/HAU/lc73hau163412.pdf.

[101] OPUC Information Request 001, Dated April 10, 2020 providing table from Order No. 19-430 in Docket UM1893.

program cost and benefit assumptions. Forecasted MW of flex load adoption has also reflected these generic assumptions. At the program level, in contrast, program design attempts great specificity in the costs and benefits unique to each program, and these details are reflected in the program-specific cost effectiveness results. As PGE gains experience with flexible load deployments, inputs are refined to reflect the costs and load impacts realized.

The OPUC and PGE has emphasized the Total Resource Cost (TRC) Test result in its pilot filings. The TRC test is expressed as a single benefit-to-cost ratio, and necessarily describes a snapshot in time. For programs in flight, ratios reflect both past actuals and projected future conditions over the anticipated program life. This is expressed as a single dollar amount on a net present value basis. The snapshot reflects:

- Past enrollment + future enrollment assumptions;
- Past costs realized + future cost assumptions;
- Current load impact + future load impact assumptions, if expected to change, and
- System benefits values as modeled per IRP

4.3.1 PGE's Flexible Load Cost Effectiveness Framework: Four Perspectives

PGE's analytic approach to cost-effectiveness is based on Commission Order 15-203 and California protocols, now updated via its Standard Practices Manual[102]. A cost-effectiveness test measures whether an investment's benefit exceeds its cost and is one tool in ensuring that PGE makes well-informed investment decisions. Typically, a cost-effectiveness test calculates the net present value (NPV) of both benefit and cost streams over the post-pilot lifetime of the program. The result is presented as a benefit-to-cost ratio.

Since investments are often "lumpy", cost effectiveness measurements require a forecast of both costs and benefits over the life of the program. For instance, some programs have substantial start-up costs such as initial equipment investment or IT enablement. For in-flight pilots and programs, PGE's application of the cost effectiveness tests includes both realized results and future estimates, including program enrollment assumptions.

Historically, the primary benefit stream associated with flexible load programs has been the avoided cost of capacity. PGE continues to explore and quantify values beyond capacity as technology improves and costs decline. The primary cost streams are equipment purchases, program implementation costs, and incentive payments.

PGE employs a four-test framework common throughout the country. Each provides a distinct stakeholder perspective and includes a distinct set of benefit and cost streams. The four tests are

[102] 2016 Demand Response Cost-Effectiveness Protocols, California Public Utility Commission, Available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11573

the Total Resource Cost (TRC) test, the Program Administrator Cost (PAC) test, the Rate Impact Measure (RIM) test, and the Participant Cost Test (PCT).

4.3.1.1 Total Resource Cost Test

The TRC adopts a summary perspective for all stakeholders: the utility and its customers. While not a full societal test – which might attempt to quantify externalities such as the health impacts of carbon – the TRC attempts to holistically answer whether the program's benefits justify its costs. This test is widely accepted by the stakeholder community and has been emphasized in PGE's pilot DR filings to date.

Because the TRC strives for a holistic lens, it excludes transfers between the utility and its customers; a benefit to one party is a cost to the other, and they cancel one another out. These transfers include incentive payments, bill savings, and bill increases.

The second noteworthy element of the TRC is the inclusion of participant cost categories: Transactional Cost to Participant (dollars spent to enable participation) and Value of Service Lost (quantification in dollars any inconvenience a customer may experience during a DR event).

4.3.1.2 Program Administrator Cost Test

The PAC test measures the net benefits of a program from the perspective of the program implementer, in this case, PGE. All financial costs borne by the administrator are included, including participant incentive payments. The customer's Transactional Cost and Value of Service Lost are excluded.

The PAC test reflects the perspective of the program administrator as a financial entity. A program that achieves a benefit to cost ratio of 1.0 will reduce costs for that entity. For a Cost of Service utility such as PGE, this means reducing customer costs.

4.3.1.3 Rate Impact Measure Test

The RIM test measures the net benefits of a program from the perspective of non-participating customers. It is largely similar to the PAC test, but includes decreased energy sales as a cost, and increased energy sales as a benefit. If a program achieves a 1.0 benefit-to-cost ratio on the RIM test, its benefits outweigh its costs for non-participating customers. A result less than 1.0 indicates that cost shifting will occur.

As part of UM 2003, PGE submitted a cost-effectiveness methodology for EV programs based on the RIM test. EV programs by themselves are not flexible load programs. However, some EV programs have an associated grid services program. Like other EV programs, these EV DR program are evaluated using the RIM test.

4.3.1.4 Participant Cost Test

The PCT test measures the net benefits of a program from the perspective of customers participating in DR programs. Program costs and energy system benefits are excluded; only

Transactional Cost to Participants and Value of Service Lost are included as costs; incentives are included as benefits.

4.3.2 Test Elements

Table 5, compares the cost and benefit streams included in the different cost-effectiveness tests. Each category is then discussed in more detail.

Table 5 – Cost and Benefit Streams of Cost Effectiveness Tests

Cost/Benefit Category	Total Resource Cost (TRC) Test	Program Administrator Cost (PAC) Test	Rate Impact Measure (RIM) Test	Participant Cost Test (PCT)
Administrative costs	Cost	Cost	Cost	
Avoided costs of supplying electricity	Benefit	Benefit	Benefit	
Bill Increases				Cost
Bill Reductions				Benefit
Capital costs to utility	Cost	Cost	Cost	
Capital costs to participant	Cost			Cost
Environmental benefits	Benefit			
Incentives		Cost	Cost	Benefit
Increased supply costs	Cost	Cost	Cost	
Revenue gain from increased sales			Benefit	
Revenue loss from reduced sales			Cost	
Transaction costs to participant	Cost			Cost
Value of service lost	Cost			Cost

Categories not currently utilized:

Market benefits	Benefit	Benefit	Benefit	
Non-energy/monetary benefits	Benefit			Benefit
Tax credits	Benefit			Benefit

4.3.2.1 Benefit Categories

The system benefits of flexible load are largely determined through modeling. Inputs and assumptions that drive this modeling are regularly updated via the IRP and other dockets, which leads to fluctuations in value. Programs do not determine these values; the values are inputs to which program design and management must respond. PGE recognizes that building successful, mature flexible load programs requires consistent, sustained investment even as these values fluctuate. Over time, PGE intends that our investments in flexible load are cost effective.

Avoided Cost of Supply Electricity is the largest category of benefits. As PGE moves down the pathway to decarbonization and electrification, our need for these services will increase[103]. Flexible load is a key source for these grid services, as evidenced by the findings in PGE's "Pathways to Deep Decarbonization" Study. As technology advances and costs decline, flexible load's role in providing these services will grow. Services will expand as flexible load's ability to provide grid services evolves, along with PGE's ability to model the financial value of those services.

For PGE's existing portfolio, the largest value stream currently is capacity, which reflects the historic design intent of DR and the capital-intensive nature of new generation. The valuation of capacity is established in PGE IRP dockets, and also outlined in the California Standard Practices Manual.

The following sections provide detail on benefit categories.

4.3.2.2 Avoided Cost of Capacity

The value in the avoided cost of capacity is derived from flexible load's ability to contribute to Resource Adequacy (RA). RA is deliberately planning one to four years ahead to ensure there are enough resources – generation, efficiency measures, and DR including flexible load – to serve loads across a wide range of conditions with a sufficient degree of reliability.[6] The value of reliable capacity continues to grow as the region sees increasing thermal plant retirements, limited available long-term transmission capacity, and the expansion of new loads[104].

Capacity needs typically cluster in certain seasons and hours in which demand for electricity is highest and resource availability[105] is limited. As the penetration of variable energy resources (VER) grows, PGE may see emerging capacity needs for periods when renewable supply is limited. In some ways, a capacity product is like an insurance policy: its value does not derive from its use, but from the policyholder's ability to call on it if necessary. Because of this, a capacity product with limited availability (such as some forms of demand response) can be useful when its availability aligns with periods of system constraint.

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[103] These services include regulation and frequency response; reactive supply and voltage control; and contingency reserves. These services are described in detail in this chapter.
The grid service section of this chapter reviews the possible grid services flexible load might be capable of providing.

[104] This approach is similar to that employed by the Northwest Power and Conservation Plan Seventh Power Plan where the Resource Plan therein called for the development of 600MW of demand response by 2021 to satisfy regional resource adequacy standards and meet additional winter peaking capacity. Here the Power Council found that, "The least-cost solution for providing new peaking capacity is to develop cost -effective demand response resources the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed." Seventh Northwest Conservation and Electric Power Plan, Chapter 1: Executive Summary, available at https://www.nwcouncil.org/sites/default/files/7thplanfinal_chap01_execsummary_6.pdf.

[105] For example, hydroelectric resources may be de-rated in late summer.

PGE models the value of capacity as the long-term avoided cost of acquiring a capacity resource. The identification of this resource (the ‘proxy resource’) and its costs are determined via PGE’s IRP process. In the 2016 IRP, the generic capacity resource was identified as a Simple Cycle Combustion Turbine and valued at $131.11/kW-yr (2020 dollars)[106]. This value is held consistent across a variety of dockets and pricing mechanisms.

Flexible load varies from the proxy capacity resource in important ways, including:

- Frequency with which the resource can be called;
- Days and hours in which the resource is available;
- Number of consecutive hours it is available; and
- Whether energy is avoided or shifted.

These differences typically decrease the value of capacity that a use limited resource such as a VER or flexible load, brings to the system relative to the proxy capacity resource. In 2019, PGE began modeling DR programs to quantify (rather than estimate) a DR Effective Load Carrying Capacity (ELCC). This modeling is done via the Renewable Energy Capacity Planning Model (RECAP).

Prior to 2019 RECAP modeling, PGE estimated the capacity value of DR through a series of five adjustment factors in alignment with the California Public Utilities Commission. Those adjustment factors will be familiar to DR stakeholders.

All of PGE’s current DR pilot proposals initially utilized estimated adjustment factors. 2019 modeling resulted in an increased ELCC for some programs (meaning a smaller adjustment or de-rate), and a decreased ELCC for others. Across the portfolio, pilot proposals estimated an average ELCC of 72%. RECAP modeling resulted in a lower portfolio average ELCC of 60%. RECAP modeling will be refined over time, as program characteristics - such as the extent that energy is shifted rather than reduced - are better quantified based on PGE’s operational experience.

Table 6 – Pilot Assumption and Modeled ELCC across the Flexible Load Portfolio

Pilot Proposal	2025 MW Target	Pilot ELCC	Modeled ELCC
Time of use	19	100%	90%
Water heaters	22	82%	73%
Electric vehicles	16	100%	79%
Energy Partner	30	44%	63%
Thermostat	74	77%	60%
Peak Time Rebate	26	42%	44%
Portfolio	**186**	**72%**	**65%**

106 Current programs were designed to meet the 2016 IRP objective of 77 MW in winter by the end of 2020, and initially profiled with 2016 IRP values. We have held those values steady within this document.

The complete calculation for a program's annual capacity value is as follows:

Cost of proxy resource	X	Program-specific ELCC	x	Load reduction per enrollee	x	Number of enrollees	X	1+ T&D peak line loss

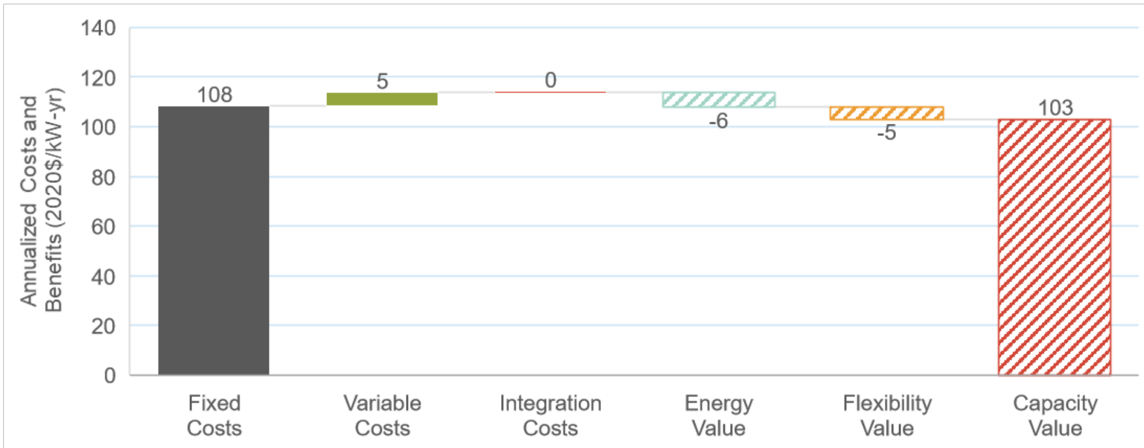
For a single Thermostat DR customer, this looks like:

$131/kW-yr	X	60%	X	0.80 kW-yr	X	1	x	1.08	=	$67.97

This is the annual capacity value of a single, two-season thermostat DR participant to PGE's system (in 2020 dollars; value inflates annually). A benefits-based budget would use this value as a cap on program expenditures (for thermostats, 98% of program value is capacity).

Staff recommendation: Reflect the benefit of DR as a zero-emission, dispatchable capacity resource. One such method could be to assign DR a capacity value equivalent to a non-emitting, dispatchable resource, not the current proxy resource.

In LC 73, Staff recommended that PGE explore the use of a non-emitting capacity resource to value the capacity provided by demand response and flexible load programs. PGE appreciates this recommendation and provides additional information here to inform future discussions about evaluating the capacity value of demand response and flexible load programs. First, it is important to consider that the cost of capacity is intended to reflect the cost that PGE and PGE customers would otherwise incur to specifically provide an equivalent amount of capacity to the system, which is separate and distinct from potential benefits associated with avoided emissions or other attributes of a flexible load. The benefits associated with avoided emissions are captured within the energy value of each program, to the extent that the forward energy prices used in that determination incorporate a price on carbon, as is the current practice in the IRP. To isolate these types of benefits from the value of capacity, PGE calculates the net cost of capacity from a proxy capacity resource by subtracting all non-capacity benefits from levelized cost of the proxy resource, as shown in Figure 6-7 in the 2019 IRP.



From PGE's perspective, the question that Staff raises is not necessarily about the non-emitting nature of the proxy resource but is instead about the alignment of the proxy capacity resource with the actions that PGE would otherwise be taking specifically to meet capacity needs. PGE's 2019 IRP Action Plan lays out the Company's plan to secure capacity that is not provided by flexible loads through a combination of bilateral negotiations for existing resources in the region and through a non-emitting capacity RFP or RFPs[107]. The outcomes of these competitive processes provide a better indication of true avoided costs than the estimates provided in the IRP, especially when the proxy resources in the IRP rely upon technologies with rapidly evolving costs, such as renewables and battery storage.

The IRP necessarily estimates costs associated with capacity resources several years in advance in order to inform a robust long-term plan. In the 2019 IRP, cost estimates for energy storage in 2025, the year of focus for PGE's capacity acquisitions, were developed in 2018, seven years before those resources would potentially come online. To address this time lag, the IRP considers wide ranges of potential costs. For example, the 2019 IRP estimates that annualized fixed costs for a 6-hour battery in 2025 could fall below $150/kW-yr or could exceed $250/kW-yr.

While it is necessary and important that long term planning considers market estimates with wide ranges of uncertainty when technology costs are evolving so quickly, these estimates do not lend themselves well to direct application in tariffs, cost effectiveness evaluations, and other decisions and determinations that have an unfiltered impact on customer prices. This filtering occurs when the Company conducts a competitive solicitation for a specified need to determine the actual cost of these technologies in the market and whether those costs are aligned with the interests of our customers.

PGE is open to Staff's suggestion to consider non-emitting resources when valuing the capacity provided by flexible load to the extent that such consideration focuses on the outcomes of recent

[107] The acknowledged 2019 IRP Action Plan describes two RFPs, which, per Order 20-152, must allow for co-optimization between them or be combined into a single RFP. At this time, PGE has not put forward an RFP design proposal.

competitive solicitations and allows for frequent updates as technologies mature, rather than the infrequent and time-lagged estimates as currently provided through the IRP.

4.3.2.2.1 Avoided Cost of Energy

If a Flexible Load program results in net energy savings, the value of that energy is considered a benefit. Many flexible load programs involve minimal energy reduction: DR programs may operate less than 50 hours per year, and they may *shift* energy rather than *reduce* overall energy consumption. Energy is therefore typically a far smaller component of the benefit stream.

Energy is valued at PGE's long-term wholesale energy forecast, Aurora. Programs are attributed with avoiding the on-peak cost under the carbon pricing forecast scenario. For some programs, energy cost estimates target the months and hours the program is available. In today's DR portfolio, energy is less than 5% of the program benefit. For emerging flexible load such as batteries and electric vehicles, with their greater call frequency, energy may be a more significant benefit stream.

4.3.2.2.2 Avoided Cost of Transmission & Distribution

Several Grid Services are described in Section 4.4.1, below. To date, PGE's flexible load programs have not been administered to provide PGE with grid services. PGE will explore grid services as program deployment and operations stabilizes and matures, and for those programs with appropriate attributes (such as direct load control). The behind-the-meter residential battery and water heater pilots will likely be the first pilots to supply grid services.

Additionally, as discussed in Chapter 2 on the DRP, PGE's investment in ADMS and ongoing R&D efforts will inform the valuation of distributed flexibility in providing grid services such as volt var and reactive power. PGE plans to include T&D value streams as they become available via R&D efforts that pursue both the technical application and the quantification of financial value.

Broadly speaking, the most commonly applied T&D value in utility pricing has been the avoided cost of infrastructure investment. This value is applied to Energy Efficiency per PGE's Marginal Cost Study. For flexible load, PGE's current working proposal is that programs should be credited with T&D deferred investment under the following conditions:

- A specific transmission or distribution system constraint has been identified;
- The cost of and required timeframe for the traditional solution has been estimated;
- The non-wires alternative is deemed capable of deferring or avoiding all, or a portion of, the traditional investment;
- If deferred, the timeframe associated with the deferral has been estimated; and
- Results are unitized: e.g. a non-wires alternative that solves half of the need is attributed with half of the cost/value of the traditional solution.

The necessary correlation to attributing flexible load programs with deferred or avoided capital investment is to reduce capital investment. PGE is working towards applying this lens consistently and holistically in its product development and capital investment processes.

4.3.2.2.3 Avoided Cost of Flexibility Services

Flexibility services encompass generation system needs other than energy and capacity, specifically, Contingency Reserves and Regulating Reserves. As described in Section 3.3.2 flexible loads with response times that meet specific integration, communication, and performance criteria can provide flexibility services. PGE includes these values when appropriate and expects flexible load to provide more flexibility services as technology improves, costs decline, and PGE's need increases.

4.3.2.2.4 Environmental Benefits

The TRC is the only test where environmental benefits are highlighted. PGE has quantified this value as the cost of carbon in energy prices. This was done by modeling the difference between two scenarios in the Aurora forecast: the "with-carbon-pricing" scenario; and the "without-carbon-pricing" scenario. The cost of carbon is applied on a per MWh basis. Because many flexible load programs have minimal energy impact, the modeled environmental benefit of those programs is also minimal.

The 2016 Navigant/PGE white paper describes additional benefits beyond carbon pricing, including reduced emissions of sulfur dioxide, nitrogen oxides, and particulate matter[108].

4.3.2.2.5 Bill Reductions

Bill reductions are included as a benefit within the Participant Cost Test. Reductions typically correlate to total energy consumption, which has been noted as minimally impacted by most existing flexible load programs. Bill reductions are directly related to the number of events called, the customer's participation in each event, and the incentive structure. These bill reductions are generally, inconsistent dependent on grid conditions requiring an event be called. Exceptions include the in-flight Time of Use pricing proposal, which has the potential to produce persistent customer bill savings.

4.3.2.2.6 Lower Per-Unit Costs from Increased Sales

Within a certain bandwidth this is the inverse of bill reductions and can be a benefit from the ratepayer's perspective. For a Cost of Service utility, there are certain fixed costs[109] that must be collected from all customers. While some of these costs are collected through basic service charges, the majority of these costs are collected through volumetric charges on a per-kWh basis. As a utility's customer base (sales in kWh) grows, these fixed costs are spread across more customers, lowering the per-unit cost of service. In other words, increased sales grow the denominator (kWh) across which system costs are spread. For a Cost of Service utility, increased usage increases can lower customer prices assuming the increasing load does not require

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[108] UM 1708 PGE's Application for Deferral of Expenses Associated with Two Residential Demand Response Pilots, April 28, 2016 Compliance Filing, A Proposed Cost -Effectiveness Approach for Demand Response, at Page 11. Available at: https://edocs.puc.state.or.us/efdocs/HAD/um1708had113843.pdf.

[109] For example, substation equipment; transmission and distribution lines; fixed costs of generation.

additional investment above the increase to revenue. An example of this is flexible load partnered with transportation electrification, which has the potential to measurably increase electricity sales while spreading fixed costs across a greater volume of sales.

4.3.2.3 Cost categories

Program costs are the primary lever with which program management can impact cost effectiveness and are the focus of deferral filings and program reporting. The following sub-sections provide detail on cost categories.

4.3.2.3.1 Administrative Costs

Administrative costs encompass all costs to run a program other than capital costs and incentives. They are included in all tests except the Participant Cost Test. Administrative costs typically include:

- Program marketing and management
- Program evaluation
- Distributed Energy Management Systems
    - Platform provisioning
    - Data costs
    - Equipment manufacturer licensing costs
    - One-time integration costs
- Data network costs, if not included in above
- Third-party administrator, if applicable

With a continually evolving understanding of program and customer needs, PGE is actively managing administrative costs and contracts across the portfolio to improve cost effectiveness. The Flexible Load Plan represents PGE's proposal to measurably reduce administrative costs.

4.3.2.3.2 Capital Costs

PGE distinguishes capital costs from O&M in alignment with California protocols. The significance of this distinction lies with utility budgeting: O&M and capital typically have distinct budgeting processes, and capital requires more nuanced forecasting to model its impact on annual revenue requirement. Under Generally Accepted Accounting Principles ("GAAP"), capital describes an investment in which the asset life is greater than one year; recovery of that investment is thus spread over more than one year in alignment with the useful life of the asset. The undepreciated portion of a capital investment appears on the utility balance sheet. In the Cost of Service regulated model, capital investment is also the mechanism by which shareholders earn a return.

To date, DR programs have included minimal capital investment. An exception is the IT investment required to support Peak Time Rebate data integration. When PGE contributes to the purchase of a long-lived asset but does not retain ownership (e.g. Energy Partner investments or Thermostat Direct Install), the purchase is expensed.

Cost effectiveness modeling incorporates both program administrator capital investment and program participant capital investment. For the program participant, PGE interprets this as a capital investment required for participation in the flexible load program. For instance, for Bring Your Own thermostat DR, the participant's purchase of the thermostat is not included. This is because the thermostat serves a primary role of regulating heat; it was not purchased primarily to enable DR program participation.

4.3.2.3.3 Incentives

Incentives are the financial payment to participants and are included in all tests other than the TRC test. In the TRC, incentives are considered a transfer payment and thus excluded. Incentives can be structured in a variety of ways, including a per-season, per-event, or per-kWh basis. Some incentives are up-front to encourage customers to join a program. Others are on-going payments designed to encourage continued participation in events. PGE incentive levels were developed through national review of similar programing, market research, PGE system values, and pilot results, and can be adjusted if deemed necessary through tariff updates. For PGE's current DR portfolio, incentives range from 30-50% of annual programs costs.

4.3.2.3.4 Transaction Costs to Participants

This captures any dollar cost to the participant. PGE does not currently utilize this cost category, as programs have been designed without this requirement. To date, any investment that programs that require – such as a thermostat – has a primary purpose other than enabling DR participation.

4.3.2.3.5 Value of Service Lost

This is a qualitative cost intended to capture the inconvenience of participating in a flexible load program. It attempts to translate into dollars the customer experience of a turned-down air conditioner on a hot summer night, or an industrial process curtailment. It appears in the TRC and PCT only. Per the California Protocol, PGE has calculated this value as a share of the incentive the participant receives, under the theory that if the value of service lost exceeded the incentive, the participant would leave the program. The TRC looks at costs and benefits across the utility and the program participant. Loss of service is a new "cost" introduced by the flexible load program, and, as such, the TRC attempts to capture its impact.

Because the Value of Service Lost is a subjective measure, PGE applies it generically according to program type, as do other utilities. PGE assigns this value according to three levels of customer impact:

- No intended service level impact: lost service = 10% of incentive value
- Residential program with service level impact: lost service = 25% of incentive value
- Commercial program with service level impact: lost service = 50% of incentive value

The impact on TRC results varies by program, as illustrated below (all dollars are in millions, on 10-year NPV basis):

Table 7 – Impact of Test Results by Program

	Total Program Cost	Incentive Cost	Value of Service Lost	Resulting TRC Cost Reduction	B:C Ratio Impact
No intended customer impact					
Water Heater	$26.42	$11.86	10%	$11.86 x (1-10%) = $10.86 cost reduction	+37%
Visible customer impact (residential)					
PTR	$24.11	$10.77	25%	$10.77 x (1- 25%) = $8.08 cost reduction	+50%
Visible customer impact (commercial)					
Energy Partner	$20.90	$12.55	50%	$12.55 x (1-50%) = $6.28 cost reduction	+30%

PGE originally adopted this cost line item in alignment with the California protocol. It has retained its use because it brings TRC test results into closer alignment with the PAC and RIM tests. The table above shows the impacts of the value of lost service on the TRC test. Without the Value of Service Lost, the TRC lens would be less balanced giving outweighed affect to incentives calculated in the participant cost test. With the Value of Service Lost in place a better balance is struck.

Staff recommendation: Discontinue the use decrementing value assumptions that assume a value of lost service until PGE has the data to establish such a penalty.

PGE agrees that the decrementing value assumption is not grounded in research. However, the decrementing value assumption does bring the results of the four tests into closer alignment. One alternative PGE has considered is utilizing the Test Bed to conduct research on program-specific Value of Service Lost for our customers. Because the TRC excludes the cost of incentives, it produces significantly (30-50%) higher ratios that the PAC and RIM tests, even with the Loss of Service adjustment. PGE has continued to use Value of Service Lost because it is an established part of the TRC test and it brings the tests into closer alignment, as PGE internally focuses on the RIM in order to reduce customer cost shifting. This is however a suboptimal solution.

PGE recognizes that cost effectiveness is evolving both regionally and nationally; PGE is monitoring these conversations and is interested in continued dialogue with the Commission and Staff. For instance, a National Standard Practice Manual is in its final stages of development, sponsored by a consortium of groups, that attempts to evolve the California standards and allow for tailoring to each jurisdiction’s circumstances and priorities. PGE supports the transparent treatment of all costs and benefits associated with flexible load and looks forward to continued exploration in this area.

4.3.2.4 Test Elements Not Utilized

The following categories were included in the 2016 Navigant white paper and reflect the national landscape review that supported that work. Oregon's market conditions and PGE program/market data do not support the current inclusion of these categories in our cost effectiveness analyses. They are included in this document for awareness and can be rolled into test results should conditions change.

4.3.2.4.1 Organized Wholesale Market Benefits

This benefit depends upon a competitive wholesale capacity market typically operated by an Independent System Operator (ISO) or a Regional Transmission Organization (RTO). As such, it is currently not used. The 2016 Navigant/PGE white paper describes this benefit as follows:

This category of benefits includes increased market efficiency improvement in overall system load factors and improved market performance (e.g., decreasing price volatility). This benefit is often quantified as the price elasticity of demand market price effect, also known as demand reduction induced price effect (DRIPE).

In competitive electricity markets, lower demand for capacity yields lower overall prices. Therefore, a significant load reduction can have the effect of suppressing market capacity prices for all parties participating in the market. This price suppression is a benefit to all market participants, separate and additional to the avoided cost of capacity for a particular utility administering the DR program.

A competitive capacity market is a prerequisite to realizing any DRIPE benefits from DR, as well as a having a critical mass of DR resources in the market.

PGE notes that the Northwest Power Pool has undertaken an effort to establish a Regional Resource Adequacy program. This effort is examining the capacity contribution of flexible load and other emerging technologies as part of this effort[110]. PGE supports the inclusion of flexible load as an RA capacity resource and is actively participating in program development.

4.3.2.4.2 Non-Energy and Non-Monetary Benefits

Non-monetary benefits include participants' perception of helping to protect the environment, being good citizens through grid-engagement, improving their ability to manage their own energy usage, having a better public image (for commercial enterprises), and improving working conditions. This is a qualitative benefit that is difficult to quantify. PGE has not assigned this benefit to its flexible load offerings to date. In states such as California and Hawaii, it is included in the TRC test only.

While many people intuitively believe that these perceptions influence participation, they are difficult to quantify. In many ways this is a qualitative corollary to Value of Service Lost.

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[110] https://www.nwpp.org/adequacy

Participant interviews or surveys could provide a basis for including this benefit stream in the future. However, in the past, the Commission has not allowed non-energy benefits to filter into cost benefit calculation for customer programs such as energy efficiency.

4.3.2.4.3 Tax Credits

Oregon does not currently use tax credits for flexible load. HB 2618, passed in 2019, provides $30 million to the Oregon Department of Energy to create a program for providing rebates for the purchase, construction or installation of solar electric systems and paired solar and storage systems. These incentives may be included in future flexible load programs.

4.3.3 Flexible Load vs. Energy Efficiency

EE cost effectiveness protocol was first established with the Power Act and has had decades of stakeholder review and engagement. It is often suggested as a basis for or comparison to flexible load modeling. EE is a demand side program as is flexible load; however, the impact of EE on PGE’s system is more straightforward, particularly for permanent load reductions which lower the demand curve in every hour[111]. In contrast to flexible load, energy efficiency is not designed to respond to shifting system conditions, and it is not deployed.

Because EE reduces the total volume of system load during every hour, its capacity value is not discounted. Flexible load reduces system use periodically, rather than continuously. Because of this, capacity values for flexible load are discounted via an Effective Load Carrying Capacity (ELCC) assignment. The modeling of flexible load on PGE’s system currently produces ELCCs between 40% and 80%, which results in a discount of 20%-60% relative to EE.

EE is also credited with transmission and distribution deferral values per PGE’s Marginal Cost Study, a benefit PGE does not currently attribute to its flexible load programs. PGE’s proposed investments in ADMS and the DRP are a prerequisite for PGE capturing T&D deferral values for flexible load. The value credited to EE is measure-specific and reflects the hourly peak demand factor per the savings/load shape of that measure. The measure is apportioned value according to the peak coincidence of the savings shape. For EE, distribution deferral values are assigned using bulk system peak conditions as a proxy, as distribution values are not yet available. The full T&D deferral value provides a benefit of around 20% of the (undiscounted) value of capacity. Because flexible load programs have not yet been designed or dispatched to respond to distribution-level system conditions, to date PGE has not attributed these programs with T&D deferral values.

The following table compares the most current values available for flexible load cost effectiveness modeling, with the values PGE provides to ETO for energy efficiency cost effectiveness modeling.

[111] EE also distinguishes time-varying savings shapes, or EE that both reduces overall energy consumption and shifts the time of consumption.

Note that for the existing portfolio, values reflect 2016 IRP outputs, for consistency with program pilot filings.

Table 8 – Cost Effectiveness for Flexible Load vs. Energy Efficiency

Modeling Category	Flexible Load		Energy Efficiency	
	Value	***Source***	***Value***	***Source***
Capacity				
Value	$103	2019 IRP. 2020 $	$103	2019 IRP. 2020 $
ELCC	Varies	RECAP modeling	N/A	
Deficiency	NA		2021	2016 IRP Update
Line Loss Factors				
PGE transmission	NA		1.6%	PGE OATT
Distribution, primary, (industrial)	2.85%	Internal Loss Factor, 2015 GRC Line Loss Study	2.85%	Internal Loss Factor, 2015 GRC Line Loss Study
Distribution, secondary, average (commercial and residential)	4.74%	Internal Loss Factor, 2015 GRC Line Loss Study	4.74%	Internal Loss Factor, 2015 GRC Line Loss Study
Distribution, sub transmission	1.45%			Internal Loss Factor, 2015 GRC Line Loss Study
Distribution marginal to average line loss ratio	70%	Applied to applicable distribution line loss. RAP Marginal Line Loss Study 2011	varies	Power Council's marginal loss formula applied to a generic system load shape
BPA line factor	1.90%	Wholesale market purchase: 1 leg of BPA		
Transmission				
Deferral credit	NA		$9.38	Per kW-yr. 2019 GRC. 2019 $
Winter value			100%	
Summer value			0%	
Distribution				
Deferral credit	NA		$24.39	Per kW-yr. 2019 GRC Marginal Cost Study for sub transmission and substation. Shaped 12x24. 2019 $
Winter value			100%	
Summer value			0%	
Energy		Per MWh. Aurora on-peak forecast. Annual, monthly, or hourly		Per MWh. Aurora forecast, on and off-peak, monthly
Risk Reduction Value	NA		$3.00	Per MWh. 2016 IRP; not updated in 2016 IRP Update. Describes forward price exposure. 2016 $
RPS Compliance	NA		$0.00	Per MWh. In the 2016 IRP Update, no incremental cost of PNW wind net of capacity value and energy value
Regional Act Credit	NA		10%	1978 Power Act. Demand side can be 110% of cost of supply side proxy

Other benefits categories unique to EE are the Risk Reduction Value and the Regional Act Credit. The Risk Reduction Value reflects the hedging value of avoiding future price spikes due to reduced energy market purchases. This value is modeled in the IRP process by modeling scenarios with and without EE.

Lastly, the Regional Act Credit provides a 10% "benefits adder" to EE. This adder is in statute per the Power Act[112]. It defines EE as cost effective if it is within 110% of supply side alternatives. This adder was included to preference demand side resources over sources of electric generation, to approximate the value of non-energy and non-monetary benefits.

While DR does not enjoy a "benefits adder", it does privilege demand side resources through the TRC by reducing program costs (rather than increasing program benefits). The following table compares costs included in the RIM test (cost shifting view) and the TRC test (partial societal view) for the December 2018 DR Flex pilot filing. The adjustments result in a 37% decrease in costs under the TRC test:

Table 9 – Comparison of Costs between the RIM and TRC Tests

Cost Categories	Ratepayer Impact Test	Total Resource Cost Test
Administrative	$14.8	$14.8
Capital	$3.1	$3.1
Reduced sales	$0.0	$0.0
Incentives	$26.2	$0.0
Transaction costs	NA	$0.0
Value of Service Lost	NA	$8.3
Total	$44.1	$26.2
Total program cost delta		*($17.9)*

Unlike EE, the four test protocol results in a demand side advantage that varies by program. The larger incentives are as a share of the total program budget, the greater the impact of their exclusion from the TRC test.

Staff recommendation 1: The use in all calculations of the same base values as those employed for EE, specifically found in UM 1893.

The primary differences between the two valuations is the assignment of T&D deferral values, and the greater demand-side premium that flexible load is assigned via the TRC. EE reduces energy consumption and thereby alleviates system constraints. However, even with EE, there is locational and operational uncertainty at the distribution level as to whether the measure actually leads to a capital deferral. The T&D deferral value is applied as a simplification. For EE that reduces but also shapes consumption, EE stakeholders have assigned T&D deferral value in alignment with bulk system conditions, as distribution level conditions – and installation location

[112] Northwest Power Act §3(4)(D), 95 Stat. 2699.

of EE investments – are not yet detailed. The second scenario – energy shaping – is akin to flexible load.

The assignment of values not yet known is a difficult subject that PGE has grappled with internally. Across all program design and grid services, PGE has not assigned values that cannot be verified. For flexible load, we are building programs for a future distribution system that we are not yet able to model. However, we continue to believe that defensible assignment of financial value is crucial. We look forward to bringing stakeholders into this conversation.

4.4 Results

In the planning phase, PGE's pilot proposals all exceeded a TRC Test of 1.0. PGE has invested in flexible load resources with the expectation that they will mature into cost-effective programs. As proposals moved into field testing, however, some TRC results have fallen below 1.0, reflecting the differences between PNW and national results that informed planning values, and the many technological, user education, and other challenges that pilots work through once deployed in the field. PGE is working to improve cost effectiveness through both specific priority actions tailored to each pilot and through portfolio-wide efficiency improvements.

Table 10 – Current Cost Effectiveness Test Results for Flexible Load Initiatives

Initiative	TRC	PAC	RIM	PCT	Date of Estimate	Key Actions to Improve C:E
MF Water Heaters	0.82	0.49	0.49	9.74	May 2020	Increase connectivity, decrease over-rides, decrease costs
Energy Partner	1.23	0.86	0.85	2.04	May 2020	Increase participation
Thermostat	1.06	.64	.62	4.17	March 2020	Reduce costs (vendor, thermostat purchase and installation), increase participation
Peak Time Rebate	0.85	0.56	0.56	4.00	Feb 2020	Increase load impact, improve baselining, decrease costs

PGE has launched several flexible load pilots over the past four years with the goal of delivering carbon-free grid services, while meeting PGE's DR capacity goals[113]. All of PGE's flexible load projects are planned and managed to be cost effective over the life of the project. However, the process of translating planning assumptions into operational programs means that achieving programmatic cost effectiveness is a process of continuous improvement.

Since initiation, PGE has 1) field tested planning assumptions and market acceptance; 2) vetted alternative technological solutions; 3) incorporated vendor expertise into PGE implementation teams; 4) experimented with multiple communication networks; 5) integrated with data and billing systems; and 5) generated process maps to integrate programs into real time operations. Through

[113] See Order 17-386, Docket LC 66 where the Commission set demand response goals of 77MW winter and 69MW summer capacity. These goals were set as a floor.

this process, the Company is building expertise in the flexible load lifecycle that ultimately result in a cost-effective portfolio. PGE's work is an ongoing iterative process.

PGE's current DR activities are not just new applications of flexible load technology for the company but also new in the Northwest[114]. Because of this, PGE launched these activities as demonstrations or pilots. Over the last four years, PGE has ramped efforts quickly to meet MW targets, stood up new organizational functionality, and field-tested a range of program concepts and technologies within PGE's unique market and operational context.

PGE understands and supports the expectation that our investment in DR will mature into a cost-effective resource. Cost-effectiveness is a Commission imperative and is crucial to limiting rate pressure upon our customers. The learnings from the last four years of program growth are incorporated into this proposal's recommendations to reduce program cost and improve performance in an effort to evolve PGE's flexible load program to achieve cost effective resource build[115].

[114] Even where DR programs have long histories, such as DLC programs in Florida, each climate produces unique results, with unique customer impacts. While some learnings can be translated across geographic regions and climates, demonstrations or pilots are necessary to understand the application of each flexible load technology to the Northwest.

[115] Demand response is not entirely similar to energy efficiency. The Commission recognized the difference in 2015 when the Commission directed PGE to the California's Demand Response Cost Effectiveness Protocols in UM 1708. The Commission then furthered their policy on DR resource builds through Order No. 17-386 in LC 66 PGE's 2016 IRP, which required several actions on DR including building a 77MW DR resource by 2021.
In response, PGE made several changes to program development, supporting infrastructure and the DR resource build processes. These start-up costs are reflected in our activities' current expenses and budgets. PGE built each pilot individually because we did not have the regulatory framework that has been developed for EE through years of trial and error. To assure resource build, PGE used the latitude afforded under the Commission definition of pilot activity - including the exceptions to cost effectiveness found in UM 551 - coupled with close and regular reporting to the Commission and Commission Staff. Many of the investments made through our initiation of the DR resource build will be shared across a portfolio of activity; these start-up investments make the evolution to cost effectiveness easier for the next iteration of activity. PGE has been transparent in our efforts to meet the DR goals set by the Commission.

PGE has identified six lanes within the journey to a cost-effective flexible load portfolio. Some we are driving; others we are tracking and ready for engagement with the changing context in which we work, as seen in Figure 25 and Figure 26, respectively:

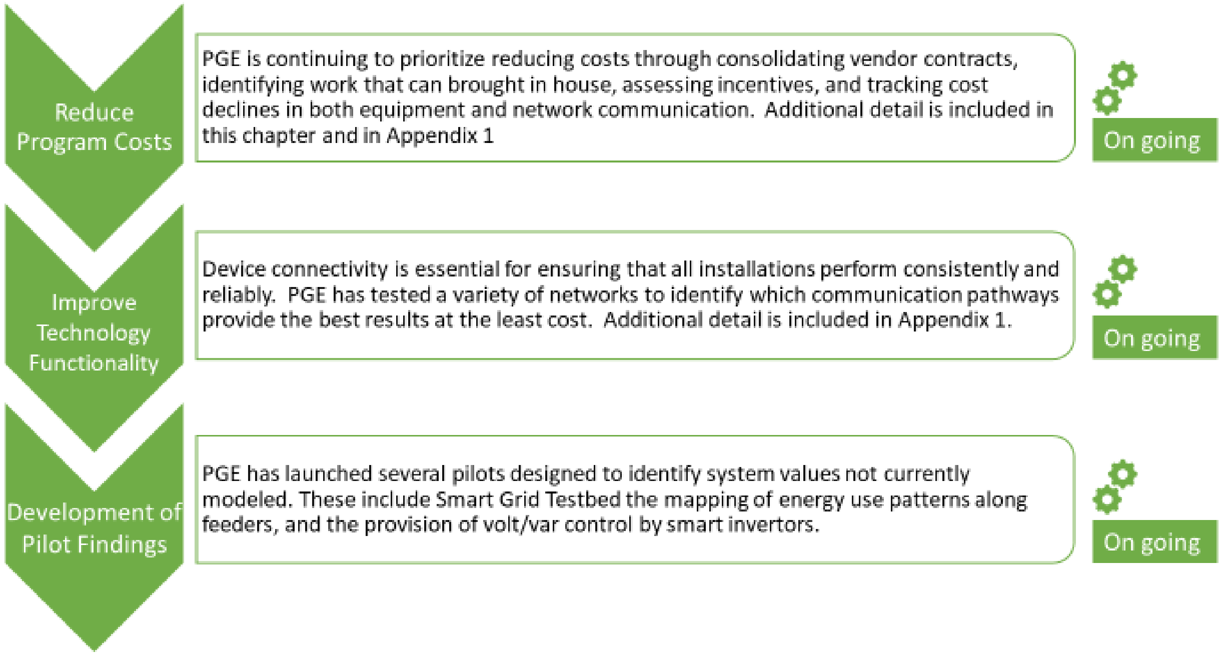

Figure 25 – Current Efforts toward a Cost-Effective Flexible Load Portfolio

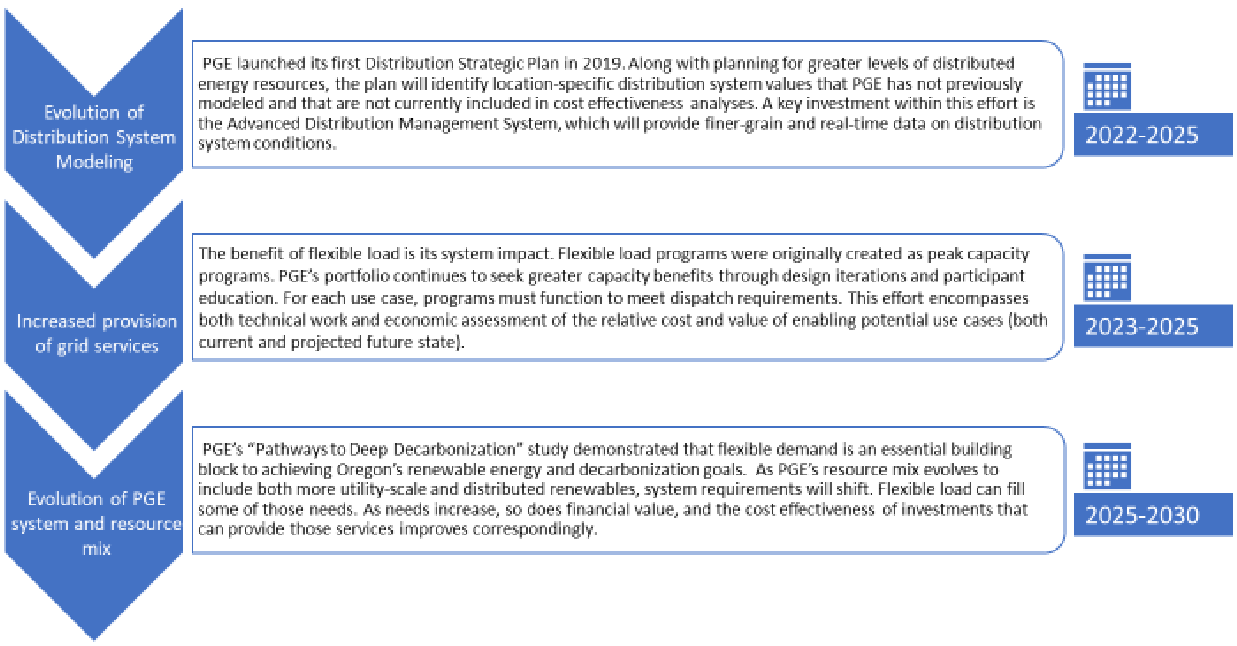

Figure 26 – Anticipated Efforts toward a Cost-Effective Flexible Load Portfolio

4.4.1 Flexible Loads as a Grid Service

Cost effectiveness compares benefits and costs. Expanding the benefits that flexible load provides to grid services beyond capacity can improve benefit cost ratios. This section provides an overview of services that flexible load can provide today or may provide in the future.

The ability of any technology to provide these services reflects many factors, including response time, cycle duration, and ability to integrate within the relevant dispatch entity. This high-level summary of those factors is intended to inform explorations of how flexible load can be optimized in support of PGE’s operational needs.

PGE envisions a future in which flexible load resources are co-optimized across the transmission and distribution systems through Virtual Power Plants. As noted above, PGE sees these emerging “shimmy” resources as a key opportunity to maximize the value of flexible load and as a key tool for reliability in a decarbonized future. PGE is still learning about the capabilities, customer impacts, and value of these emerging flexible load opportunities. Even as these demonstrations and pilots progress, PGE recognizes that the core value in DR and flexible load is providing reliable capacity to meet resource adequacy needs. Flexible load has a real, proven ability to replace peaking capacity; even as PGE explores the opportunity for flexible load to provide the grid services described below, PGE recognizes that resource adequacy capacity is the core value of flexible load programs.

PGE also recognizes that the value that flexible load offers to the grid as a whole must be co-optimized on a locational basis. Through the DRP, PGE is exploring both locational value and opportunities to co-optimize across various grid services. PGE recognizes that flexible load offers multiple value streams; PGE is working diligently to assess the ability to stack these products to produce optimized, least cost solutions for our customers.

4.4.1.1 Current Grid Services Program Capabilities

Table 11, illustrates grid services capabilities of PGE's current and planned portfolio.

Table 11 – Grid Service Capabilities of Current and Planned Portfolio

	Resources						
Grid Service	**DLC Daily**	**DLC Seasonal**	**Behavioral DR**	**Res Battery**	**C&I Battery**	**EV**	**PV Smart Inverters**
Distribution Services							
Volt/Var control				Current	Current		
Frequency response				Current	Current	Near-term	
Outage Mitigation and Upgrade Deferral	Near-term	Near-term	Near-term	Near-term	Near-term	Near-term	
Transmission Services							
Congestion and Upgrade Deferral	Near-term	Near-term	Near-term	Near-term	Near-term	Near-term	
Generation Services							
Capacity	Current	Current	Current	Current	Current	Current	
Value of Energy	Current	Near-term	Near-term	Current	Current	Current	
Flexibility services							
Contingency Reserves							
Spinning reserves	Current			Current	Current		
Non-spinning reserves	Current	Near-term		Current	Current		
Load following / Energy Imbalance	Longer-term	Longer-term		Near-term	Current	Near-term	
Regulation				Near-term	Current	Near-term	
Voltage support	Current				Current		Current
Black start	Current			Current	Current		
Participant Benefits							
Power reliability	Current	Current	Current	Current	Current		
Outage mitigation				Current	Current	Longer-term	Current
TOU charge reduction				Current			
Demand charge reduction					Current		

4.4.1.2 Distribution Services

4.4.1.2.1 Autonomous Volt/Var Support

Definition: Autonomous Volt/VAr support is a local, distribution level function in which a DER adjusts VArs to support local voltage within a prescribed band. Advanced VAr management is one tool a utility can use to manage system voltage and power factor[116].

Requirements:

- Response time: within seconds
- Call frequency: continuous
- Duration: minutes to hours. Most events are less than 3 minutes.
- Exclusive assignment: no, can occur concurrently

Dispatch: This service is enabled rather than dispatched. For instance, residential batteries will include Volt/VAr support as a built-in feature that PGE can turn on and off via a central control. PGE will turn this on when appropriate and the device will provide services autonomously. This use case will be more valuable when Advanced Distribution Management System (ADMS) is in place (anticipated in 2022). Post-ADMS this service will be enabled and managed by the Distribution System Operator.

Applicability to flex load: As PGE advances our understanding and capabilities of flexible load we will address the potential value of this service when and if provided by flexible load.

4.4.1.2.2 Autonomous Frequency Response (Freq/Watt)

Definition: The entire WECC system needs to maintain frequency within a certain band both during normal operations and in response to a disturbance or major event. The NERC requires PGE to contribute to maintaining this frequency following a major event. PGE meets this requirement by dispatching energy resources (e.g. sourcing or sinking kW from the system) to help maintain interconnection frequency within the predefined bounds in response to a system frequency deviation.

Requirements:

- Response time: within seconds
- Call frequency: once every few months
- Duration: 15 minutes
- Exclusive assignment: has limited ability to be combined with other opportunities

Dispatch: Scheduled by Grid Operations[117]; dispatched automatically. This use case is enabled rather than dispatched. For energy storage, it is responsive to local monitoring and control functions.

[117] PGE is required to supply sufficient frequency response to comply with NERC Reliability Standard BAL-003-1.1: Frequency Response and Frequency Bias Setting. PGE's Frequency Response Obligation is the amount of frequency response that PGE's Balancing Authority is expected to provide to the interconnection, measured in MW of response per 0.1 hz. PGE's Frequency Response Obligation for 2019 was -16.9 MW / 0.1 hz. In other words, for every 0.1 hz of frequency loss, PGE is required to response with -16.9 MW. A 0.2 hz loss would require PGE to respond with 33.8 MW.

Applicability to flex load: Primary frequency response is typically provided by the governor droop setting on a generator, typically set at 5%. PGE has also successfully experimented with providing frequency response with battery storage at the Salem Smart Energy Center.

Flexible Loads including water heaters and battery storage are capable of providing autonomous frequency response under certain conditions[118].

4.4.1.2.3 Distribution Outage Mitigation and Upgrade Deferral

Definition: This service is the avoidance or deferral of distribution system investment. PGE's management of and investment in its distribution system is driven primarily by reliability targets: PGE plans for N-1 resiliency, meaning all components have some form of redundancy[119]. Flexible load can defer investment in system upgrades specific to each to each system constraint.

Requirements:

- Each application is uniquely tailored to address the specific constraint.
- Exclusive assignment; some feeders will align with PGE's overall system peak.

Dispatch: Primarily dispatched manually by Distribution System Operation solution rather than autonomous; long-term, this function could be automated.

Applicability to flex load: Traditionally, distribution equipment upgrades have been utilized in response to load growth. However, flexible load can be utilized to defer to mitigate this investment. An example of using DER to manage congestion and defer additional distribution investments is National Grid's Island Ready project that installed a 48 MWh battery, upgraded distributed generation, and installed substation automation to defer the need to build a third undersea cable to serve Nantucket Island[120].

4.4.1.2.4 Distribution Congestion and Upgrade Deferral

Definition: Electric power distribution is the final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers. When load growth exceeds the capability of the distribution equipment to meet the demand for electricity, equipment must be replaced or upgraded. Flexible load can offset the need for distribution system investment with custom solutions targeting the specific constraint.

Requirements:

- Response time: depends on required upgrade
- Call frequency: depends on required upgrade

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[118] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-21152.pdf

[119] An N-1 planning standard ensures that the system can withstand a "primary contingency," or a loss of one or more system elements through a planned or unplanned event and maintain uninterrupted service. PGE currently performs in the top quartile for the primary reliability metrics.

[120] National Grid's IslandReady: A Nantucket Electricity Initiative Factsheet. Available at: https://islandreadynantucket.com/wp-content/uploads/2019/08/IslandReady-Fact-Sheet_August-2019.pdf

- Duration: depends on required upgrade
- Exclusive assignment: No

Dispatch: The dispatch depends on the resource type. Manual by System Control Center via EMS. Long-term, this function could be automated.

Applicability to flex load: Distribution upgrades are traditionally done by replacing/upgrading existing equipment. Flexible loads, including batteries, DR, and EE can defer or mitigate the need for these upgrades in certain circumstances.

4.4.1.3 Transmission Services

4.4.1.3.1 Transmission Congestion and Upgrade Deferral

Definition: Transmission is distinguished from distribution by the operational characteristics of the facility as defined by the FERC's Seven Factor Test. For PGE, voltage above 115 kV is classified as transmission. Similar to distribution system deferrals, flexible load can offset the need for transmission system investment with custom solutions targeting the specific constraint. Transmission system services require larger scale solutions than distribution system services.

Requirements:

- Response time: depends on required upgrade
- Call frequency: depends on required upgrade
- Duration: depends on required upgrade
- Exclusive assignment: No

Dispatch: The dispatch depends on the resource type. Manual by System Control Center via EMS. Long-term, this function could be automated.

Applicability to flex load: Transmission upgrades are traditionally done by constructing new transmission lines or replacing/upgrading existing transmission equipment. Flexible load can defer or mitigate the need for these upgrades in certain circumstances. For example, the New England Independent System Operator has identified more than $400 million in previously planned transmission investments in New Hampshire and Vermont that are now deferred beyond its ten-year planning horizon due to energy efficiency.

4.4.1.3.2 Voltage Support

Definition: Nearly all power system loads require a combination of real power (watts) and reactive power (VArs). Real power is supplied by a generator, but reactive power can be supplied either by a generator or a local VAr supply. Most of the loads connected to the grid distribution system such as motors, transformers and cables are inductive in nature and cause a reactive component of current to flow in the circuit supplying them as well as a resistive current flow feeding the device. The energy to supply this reactive current (whether for inductive or capacitive loads) has to be supplied by the generator which must divert some of its available energy to satisfy this demand. Additionally, because the traditional generators supply a multiplicity of loads, the voltage can vary widely across different areas of the distribution system. Smart inverters and batteries are capable of supplying local VArs where they are needed. This improves local power quality. Additionally, a generator that provides VArs sees a reduction in energy output. PGE values the increased generation efficiency that would result from providing local VArs.

Requirements:

- Response time: autonomously responsive to local voltage needs
- Call frequency: continuous
- Duration: continuous, when providing the service
- Exclusive assignment: no

Applicability to flex load: Today, reactive power is supplied by generators and capacitor banks that adjust the phase shift or phase angle between the voltage and the current. Smart inverters and batteries are able to supply reactive power.

4.4.1.3.3 Black Start

Definition: Black start is the process of restoring an electric power station or a part of an electric grid to operation without relying on the external electric power transmission network to recover from a total or partial shutdown. PGE is required by NERC to maintain a restoration plan that enables PGE to recover from a variety of outage scenarios. Batteries are particularly well suited to assist with black start restoration. Additionally, DR can alleviate some of the challenges with system restoration caused by cold load pickup by phasing in load in a more controlled manner[121].

Requirements:

- Response time: N/A.
- Call frequency: called during outages
- Duration: application dependent
- Exclusive assignment: no

Applicability to flex load: Black Start is provided by generators specifically configured to restore areas of the electrical grid in a specific sequence. Batteries could be utilized to provide the initial start-up energy to initiate a Black Start sequence. Additionally, DR could be deployed to mitigate cold load pickup and facilitate system restoration.

4.4.1.4 Generation Services

4.4.1.4.1 Generation Capacity

Definition: Capacity represents the ability of a resource to contribute to meeting a resource adequacy target. For example, PGE plans to a Loss of Load Expectation (LOLE) of 1 day in 10

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[121] Cold load pickup is the well-known problem defined as excessive inrush current drawn by loads when the distribution circuits are re-energized after extended outages. During extreme weather conditions, these currents can be high enough to appear as faults and/or overload, resulting in blown fuses or breaker re-trips, further extending the outage duration.

years. The capacity contribution of a resource, such as a flexible load program, is the amount of MW of a conventional proxy capacity resource that can be avoided. Generation capacity value represents the potential to avoid costs associated with new resources. The capacity value of the resource is calculated as the net cost of new entry (net CONE) for a new proxy capacity resource multiplied by the resource capacity contribution. PGE performs this analysis within the IRP.

The term capacity most frequently appears in a long term planning context as is associated with Resource Adequacy. Resource adequacy is deliberately planning one to four years ahead to ensure there are enough resources – generation, efficiency measures, and DR including flexible load – to serve loads across a wide range of conditions with a sufficient degree of reliability At dispatch, PGE's ability to serve its load is measured by resource sufficiency: does PGE have sufficient energy, flexibility, and reserves to meet its load service and reliability obligations?

Requirements:

- Response time: Either day ahead or hour ahead.
- Call frequency: No threshold, but response time may affect capacity contribution.
- Duration:1-6 hours.
- Exclusive assignment: No. A resource can provide capacity while providing other services.

Dispatch: Scheduled and dispatched by PGE Power Operations either day-ahead or hour ahead to meet forecast load.

Applicability to flex load: Capacity is traditionally provided by dispatchable generation, energy efficiency, and flexible load. Most existing flexible load programs provide capacity; all of PGE's current flexible load pilots provide capacity.

4.4.1.4.2 Value of Energy

Definition: Value of Energy is the ability to shift some of the required energy from higher priced periods to lower price periods. In Docket No 1751, the Commission defined this service as "[t]rading in the wholesale market by buying energy during low-price periods and selling it during high price periods."

PGE forecasts energy value for resources over the long term within the IRP based on the ability of the resource to avoid or better optimize wholesale market purchases. In the near term, this use case is realized as a reduction in power costs.

Requirements: Not prescriptive, but energy value will depend on how the resource dispatches under different market conditions.

Dispatch: Scheduled by Power Operations according to forecasted energy price. The schedule can be modified to respond to reliability needs.

Applicability to flex load: PGE's Power Operations group optimizes PGE's generation portfolio and makes purchases and sales in the bilateral market to capture this value. Flexible load that shifts energy out of high-priced periods and into lower priced periods can capture this value.

4.4.1.5 Flexibility Services

As flexible load pilots mature into programs, PGE is working with power operations and the balancing authority to incorporate flexible load programs and the grid services they are capable of providing into PGE's daily operations.

In order to balance generation and load on a second-to-second basis and to respond to unexpected conditions, PGE is required to carry a certain amount of online capacity that is able to respond to these moment-to-moment fluctuations and contingency events at all times. Operationally, this flexibility is broken into "operating" reserves and "contingency" reserves. Operating reserves are used to account for the *expected* moment-to-moment variations between supply and demand, and to account for forecast error. Additionally, PGE carries contingency reserves to ensure that PGE is able to recover from *unexpected* events. PGE must carry sufficient reserves to consistently meet North American Energy Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC) reliability standards.

While each grid service has its own performance criteria and operational obligation, from a real-time perspective, PGE also co-optimizes these services across PGE's portfolio. If a resource is held "in reserve" to provide a flexibility service, then it is not available to generate the energy needed to serve load. The difference between the market price and the resource's incremental cost to generate is considered an "opportunity cost." For example, if the market price is $30, and a resource's cost to generate is $25, the lost opportunity cost is $5. PGE power operations continually re-optimizes PGE's resources on a week-ahead, day-ahead, and real-time basis in order to reliably serve load at the least cost.

Co-optimization in long-term planning is done differently than co-optimization for real-time operations. For long term planning purposes in the IRP, PGE groups multiple services related to system flexibility into a broad category of "flexibility services." These include load following, regulation, and contingency reserves. These services are grouped together within the IRP because the evaluation of their value to the system occurs on a portfolio basis and requires co-optimization in a manner that accounts for the interactions between each service. In IRP modeling, regulation and load following have both an energy and a capacity component; however, from an operational perspective, the capacity associated with these services is billed under regulation[122] while the energy is billed under energy imbalance.[123] Additionally, PGE considers the value associated with operating the system more efficiently due to the ability to provide a portfolio of flexibility reserves as part of the Flexibility Value quantified within the IRP.

While PGE plans for and co-optimizes these services together from a planning perspective, within each operating hour, PGE is required to carry each service separately in order to meet NERC and WECC reliability obligations. Each service has specific operational and performance criteria. Therefore, while there is a co-optimization opportunity when considering PGE's flexibility reserve

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[122] OATT Schedule 3: Regulation and Frequency Response Service

[123] OATT Schedule 4: Energy Imbalance Service and OATT Schedule 4a: Retail Energy Imbalance Service

portfolio holistically, PGE must be able to provide each service independently in real time operations.

Finally, it is important to differentiate between the definition of flexible load used within this document and the definition of the flexibility or flexible service used by the IRP and power operations. Flexible load is a categorization of behind the meter, grid-enabled, customer-sited activities. These activities can vary from customer behavioral changes to advanced, autonomous grid-connected devices that provide any of the services described in this section. The definition of flexible load in this document aligns with national discussions of services that are provided from the behind the meter resources found on the distribution system.

This does not mean that the programs group is defining a new type of service called flexible load. The definitions of grid services beyond energy and capacity are defined by NERC, WECC and FERC to ensure regional consistency and cost allocation. PGE's flexible load programs will need to provide services that meet existing definitions and requirements in accordance with PGE's load service and reliability obligations.

4.4.1.5.1 Contingency Reserves

Definition: Contingency reserves refers to both spinning and non-spinning reserves. NERC requires that each Balancing Authority provide resources on a stand-by basis to respond to unplanned events. PGE is required to carry reserves to cover three percent of system load plus three percent of online generation. Reserves are distinguished between spinning reserves (synchronized to the grid) and non-spinning reserves (not synchronized to the grid). Load is always considered synchronized to the grid and is therefore considered a spinning reserve.

Requirements:

- Response time: within 10 minutes
- Call frequency: Up to a few times per month
- Duration: minimum of 60 minutes
- Exclusive assignment: The ability of a resource to provide contingency reserves will depend on the extent to which the resource is also scheduled to provide other services, including energy, load following, and regulation.

Dispatch: PGE's Balancing Authority Operators dispatch operating reserves in response to unplanned events. Currently, Distributed Standby Generation (non-spinning reserves) is dispatched via GenOnSys, PGE's Distributed Energy Resource Management System (DERMS). Spinning reserves are provided by PGE's online generating resources.

Applicability to flex load: PGE meets half of its reserve requirement with Distributed Standby Generation, which provides non-spinning reserves. The remaining requirement is met through the available capacity of online generation[124]. Flexible loads that are online and capable of responding

[124] For a generator to supply spinning reserves, it must be online, with additional upward dispatch capability, limited by the generator's 10-minute ramp rate. For example, consider a generation plant

within 10 minutes are able to provide spinning reserves. Demand Response, electric vehicles, and storage can all provide spinning reserves. DR from interruptible loads participates in ancillary service markets for contingency reserves in several different markets, including ERCOT, MISO, PJM, and NYISO. Usually, these programs call on interruptible loads solely under contingency events (though NYISO co-optimizes contingency reserves into energy markets under certain conditions) and based on a low frequency threshold or system operator command[125]. Because PGE already meets 100% of its non-spinning obligation with the Distributed Standby Generation program, PGE has no current need for additional non-spinning reserves.

4.4.1.5.2 Regulation and Load Following Reserves[126]

Definition: Regulation is the online capacity necessary to maintain the balance between generation, load, and exports, in real time. Regulating reserves are governed by NERC regional reliability standard BAL-001-2. Regulation Up describes an increase in energy production or decrease in consumption; Regulation Down describes a decrease in production or increase in consumption. PGE meets this obligation by reserving capacity on specific units to respond to upward or downward fluctuations within each operating hour. Currently, PGE bids regulation capacity into the Energy Imbalance Market[127].

Requirements:

- Response time: four seconds
- Call frequency: continuous while in regulation mode
- Duration: seconds to minutes

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was online and generating at 100 MW, but had a nameplate capacity of 200 MW. If the generator's ramp rate is 1 MW/minute, the generator could supply 10 MW of spinning reserves. If the generator's ramp rate is 5 MW/minute, the generator could supply 50 MW. Because of the ramp rate requirements, PGE typically carries spinning reserves on its most flexible generation, especially hydro and gas generation.

[125] https://pdfs.semanticscholar.org/f0fc/f6962bf9eb10e34ef0939c59274997899809.pdf

[126] PGE models Regulation and Load Following with both an energy and a capacity component; however, under the PGE OATT, the capacity associated with these services is billed under regulation while the energy is billed under energy imbalance. While PGE models regulation (a fast product, needed to address fluctuations under 5 minutes) and load following (a slower product, needed to address fluctuations greater than 5 minutes) separately, the PGE OATT uses the single term "regulation" to mean all capacity needed to meet intra-hour variation. Post FERC Order 764: Integrating Variable Energy Resources, regulating reserve rates typically include "fast" "slow" and "replacement" regulating reserves that are generally analogous to PGE's differentiation between regulation and load following.

[127] The Energy Imbalance Market requires PGE to meet a series of Resource Sufficiency Tests, including a flexible ramping test that ensures each balancing authority area has sufficient ramp capability to meet it fifteen-minute forecasted energy and flexible ramping product requirement. PGE uses regulation capacity to meet PGE's obligations in this test. PGE uses the "available balancing capacity" tool to ensure sufficient regulation capacity is available to meet PGE's internal balancing authority needs. When needed, PGE's balancing authority operators will also dispatch generators that are providing regulation outside of the EIM market dispatch instructions based on system conditions.

- Exclusive assignment: The ability of a resource to provide regulation will depend on the extent to which the resource is also scheduled to provide other services, including energy and contingency reserves.

Dispatch: Automated Generation Control Center (via PGE's Energy Management System)

Applicability to flex load: Historically, regulation has been provided by online generation capable of responding quickly and accurately to an automated signal from PGE's Energy Management System. Hydroelectric generation and natural gas generation provide the majority of regulation reserves in the Northwest. Flexible load resources, including batteries, EVs and DR are capable of providing regulation.

4.4.1.5.3 Energy Imbalance

Definition: Energy Imbalance refers to the ability to respond to fluctuations in loads and generation to mitigate imbalances between scheduled energy, delivered energy, and load. PGE manages imbalance on this time scale through participation in the Energy Imbalance Market.

Requirements:

- Response time: 5 minutes ("fast" resources) or 15 minutes.
- Call frequency: Called via market signal; call is responsive to bid price and market conditions
- Duration: Award is based on a 5-minute or 15-minute interval
- Exclusive assignment: The ability of a resource to provide energy imbalance will depend on the extent to which the resource is also scheduled to provide other services, including energy, contingency reserves, and regulation.

Dispatch: Energy Imbalance is dispatched through the California Independent System Operator Energy Imbalance Market. Resources participating in this market must meet EIM qualifications.

Applicability to flex load: Today, the majority of PGE's generating resources, including VERs, are bid into the Energy Imbalance Market as "participating resources"[128]. While all flexible load resources are eligible to participate in the Energy Imbalance Market, this participation must weigh the costs of participation, such as communications and metering requirements, against the projected market revenues.

4.4.1.6 Participant Benefits

4.4.1.7 Outage Mitigation

Definition: Providing reliable, safe, clean, and affordable power is at the core of PGE's customer proposition. Flexible loads are an emerging tool to enhance the value to the customer across these metrics. Flexible loads can be a part of supporting outage mitigation for a customer or in a

[128] Qualified Facilities (QFs), Colstrip and Westside Hydro are currently non-participating resources due contractual or regulatory restrictions.

microgrid. If an energy resource or battery provides backup power, load modifiers can extend the duration of that power. Flexible load can effectively support customer loads when there is a total loss of power from the source utility. This support requires the flexible load system to island during a utility outage and resynchronize with the utility when power is restored. The energy capacity of the flexible load system relative to the size of the load it is protecting determines the time duration that the storage can serve that load[129].

Dispatch: Establishment of customer or microgrid islanding is an automatic service. Ensuing load adjustments can be automated or manual.

4.4.1.8 TOU Charge Reduction

Definition: Time-of-use is a rate plan in which rates vary according to the time of day, season, and day type (weekday or weekend/holiday). Higher rates are charged during the peak demand hours and lower rates during off-peak demand hours. This rate structure provides price signals to energy users to shift energy use from peak hours to off-peak hours and encourages the most efficient use of the system.

Time-of-use pricing incorporates the expected variability in wholesale energy prices into retail rates, offering customers a lower rate during periods where overall demand, and therefore price, is lower.

Time-of-use rates can be coupled with technology to automate customer response to the price signal.

Dispatch: None; Technology-enabled Time-of-Use can be dispatched on a day-ahead or hour-ahead basis.

4.4.1.9 Demand Charge Reduction

Definition: Demand charges reflect the peak power demand (kW) of the customer each month, as opposed to the amount of energy (kWh) used over the course of the month. Flexible load can be used to manage a customer's peak usage, thereby lowering the customer's demand charge. Demand charges apply to some commercial and industrial customers.

Dispatch: The customer would dispatch the flexible load to manage their own peak demand. The customer could perform this dispatch automatically, through their building energy management system, or manually.

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[129] Akhil, A.A., G. Huff, A.B. Currier, B.C. Kaun, D. M. Rastler, S.B. Chen, A.L. Cotter, D.T. Bradshaw, and W. D. Gauntlett. 2013. DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA. SAND2015-1002. Albuquerque: Sandia National Laboratories. http://www.sandia.gov/ess/publications/SAND2013-5131.pdf.

Chapter 5 Regulatory Alignment

Chapter Summary

Chapter 5 is not a request for action from the Commission, but is rather provided for informational purposes, and to share with the Commission and stakeholders that PGE looks forward to a discussion about regulatory alignment regarding the investment in flexible load.

Discussion

As prior chapters demonstrate, PGE views Flexible Load Resources as having a significant and growing role in our strategic vision to partner with customers in order to deliver a clean energy future for all. Therefore, PGE is committed to fully embrace and expedite the incorporation of Flexible Load resources into our portfolio.

Historically and across the industry, Flexible Load has not been incorporated into core utility operations, to the detriment of efficiency, customer experience and potential carbon reductions. This is because the traditional utility model lacks financial incentives for utilities to pursue Flexible Load Resources at scale. For PGE, this issue has not deterred our efforts towards meeting established 2016 IRP goals. However, we would be remiss is we did not recognize the need to align incentives as programs mature.

The American Council for an Energy-Efficient Economy (ACEEE) posits a solution to the business model barriers that utilities face when evaluating Flexible Load Resources at scale, writing, "To make SDR [Strategic Demand Reduction] a core part of the utility business model, incentives and other policies can continue to strengthen the link between utility performance on SDR and investor returns."[130] PGE raises this as a potential area for regulatory model evolution.

The current economic climate requires sensitivity in prioritization. In light of this, PGE is not seeking an earnings mechanism at this time. However, we are ready, when the Commission signals, to open a discussion on regulatory earnings mechanisms for Flexible Load.

Several states have sought to better align utility incentives by introducing new regulatory mechanisms for flexible load. Regulatory mechanisms introduced across the country vary from simple – for example, applications of the cost-plus model to flexible load expenditures – to more complex, value-based approaches. States such as Hawaii and Michigan have approached the issue cautiously by introducing a single new regulatory mechanism initially, while other states simultaneously introduced a suite of new regulatory mechanisms that vary in structure and magnitude. For example, New York's Reforming the Energy Vision ("REV") created four types of new regulatory mechanisms. The simplest and most widely adopted was cost-plus, regulatory asset treatment for energy efficiency program spend. Performance Incentive Mechanisms (PIMs)

[130] ACEEE report https://www.aceee.org/research-report/u2003 page 7

in the form of Earnings Adjustment Mechanisms, both programmatic and outcome-based, were also introduced as well as Non-Wires Solutions incentives based on administratively calculated shared benefits. Lastly, policy enabling Platform Service Revenues was introduced but has had limited adoption by New York utilities to date.

Evaluating the various forms of regulatory incentive mechanisms for flexible load is outside the scope of this filing, however, PGE offers the following design principles[131] to help the Commission streamline an investigation into the topic, should it be pursued:

1. Evaluate investment *__based on established need__*, in alignment with IRP practices.
2. Keep incentive structures as *__simple and transparent__* as possible.
3. Aim to achieve *__investor indifference__* between the quality of earnings opportunities associated with traditional rate base and new regulatory mechanisms for flexible load, including balanced reward for increased regulatory and/or execution risk.
4. Commit to multiyear programs that ensure *__durable policy signals__* that allow utilities to plan and invest over long-time horizons.
5. Enable an *__adaptive process__* that promotes continuous improvement and allows regulators and stakeholders the opportunity to iterate and expand the complexity and diversity of regulatory incentive mechanisms.[132]

We offer this introductory discussion of new regulatory mechanisms for flexible load resources in response to perceived interest in the topic by the Commission and stakeholders. It is PGE's view that evolving the regulatory framework to align incentives for utilities to embrace flexible load resources is in customers' interest and is in line with the clean energy vision articulated by the Governor and the OPUC. PGE would welcome the opportunity to explore the topic more in-depth with the OPUC and stakeholders, within the broader context of how the regulatory framework should evolve to best serve customers.

[131] Following these principles may result in vintages of regulatory incentive mechanisms that evolve over time to allow for incorporation of learnings while not violating retroactive ratemaking.

[132] https://rmi.org/wp-content/uploads/2018/10/RMI_Navigating_Utility_Business_Model_Reform_2018-1.pdf
https://info.aee.net/hubfs/AEE%20Institute_Utility%20Earnings%20FINAL_Rpt_1.30.18.pdf
https://www.aceee.org/research-report/u2003

Appendix A

A.1 Portfolio View and Summary

Existing Demand Response Pilots:

PGE Opportunities

- The cost to acquire MW is trending downwards as programs independently achieve economies of scale, negotiate cost reductions, as well as continually approve operational efficiencies. As the pilots evolve, the team is increasing focus on a portfolio management approach to identify opportunities for further reductions. This includes a review of internal resources dedicated to pilots, third party services, centralized IT infrastructure, and process synergies.
- As the pilots evolve to deliver more reliable results and are integrated as deployable resources into Power Operations, PGE will be able to drive maximum benefit: ensuring direct alignment of dispatch with price, performance and grid stability needs. Overall, PGE DR portfolio will be leveraged to reduce pressure on electricity rates.

Regulatory Opportunities

- Flexibility to adjust existing pilots:
  - Each pilot has a budget, procedures, and reporting requirements that have been developed uniquely in support of PGE’s 2016 IRP goal and filed with the OPUC independently. This created arbitrary siloes in how PGE must manage development costs, 3rd party costs (and contracts), operating costs, and evaluation costs. This also bears out in the customer experience as each separate pilot may have very different eligibility and participation requirements.
  - In the future, PGE could create better cost efficiencies if there was portfolio level flexibility to share funding, development costs, and be more agile to respond to dynamic market changes. These areas include
    - Shared development costs
    - DRMS provider consolidation
    - Shared customer outreach and recruitment
    - Asset management consistency
    - Evaluation
- Flexibility to grow the overall portfolio:
  - By managing the demand response product development and pilot deployment at the portfolio level, PGE would have greater flexibility to leverage investments and shift resources to maximize the greatest benefits for the customer and grid reliability.

Table 12 – Flexible Load Portfolio Budgets (Actual $000's)

Demand Response						
Project	Current Status	**2017 and prior** Actuals	**2018** Actuals	**2019** Actuals	**2020** Actuals plus Forecast	**2021** Forecast
Residential DR						
- Flex	Pilot	$ 1,405,259	$ 398,756	$ 2,052,173	$ 2,106,841	$ 3,674,000
- DLCT	Pilot	$ 752,962	$ 1,109,041	$ 3,643,917	$ 1,993,738	$ 3,860,961
- MFWH	Pilot	$ 60,583	$ 1,073,623	$ 2,999,211	$ 1,904,967	$ 4,149,283
Sub-Total Residential DR		*$ 2,218,804*	*$ 2,581,420*	*$ 8,695,301*	*$6,005,546*	*$ 11,684,244*
Non-Residential DR						
- Energy Partner	Pilot approaching Program	$ 4,374,045	$ 2,722,772	$ 2,660,926	$ 4,049,570	$ 3,720,000
Sub-Total Demand Response		*$ 6,592,849*	*$ 5,304,192*	*$ 11,356,227*	*$ 10,055,116*	*$ 15,404,244*
Testbed DR				**Nov '18 - Oct '19** Actuals	**Nov '19 - Oct '20** Actuals plus Forecast	**Nov '20 - Oct '21** Forecast
- Testbed	Project with Demonstrations			$ 265,120	$ 1,721,163	$ 3,779,938
Demand Response Portfolio Total		$ 6,592,849	$ 5,304,192	$ 11,621,347	$ 11,776,279	$ 19,184,182

Transportation Electrification		**2017 and prior** Actuals	**2018** Actuals	**2019** Actuals	**2020** Actuals plus Forecast	**2021** Forecast
- Residential EV Charging	Pilot	N/A	N/A	N/A	N/A	$ 1,559,000
Energy Storage Pilot						
- Residential Energy Storage	Pilot	N/A	N/A	N/A	$ 66,204	$ 761,563

Savings Reporting

- Load impact forecasts reflect both current results and our current best projection for how those results will improve in the future. Much of the measure work PGE is conducting is new to the utility and the region. This means we are developing best known measure savings for our demand response efforts. We also see how measure savings can increase by addressing measure performance and are pursuing those changes. This plays out differently for each of our programs. For Multifamily Water Heater, initial low load impact results are improving due to new technology selection delivering improved device connectivity. For Flex 2.0, the winter 2019-2020 evaluation has just been released, and the program has adjusted its baselining methodology in response to summer 2019 events. These trajectories are expressed as a range of MW savings. The range is a reflection of the process of adjusting planning savings assumptions based on evaluated savings. In contrast, Energy Partner is more mature and by nature more stable. That program is reported as a single MW savings target.

- Two significant market conditions have impacted our portfolio in the first half of 2020, COVID-19 outbreak impacts on our customers and Google Nest's recent decision to not provide demand response management services in support of the Nest Thermostat. In response to COVID in March, PGE made the decision to pause marketing of PTR and Thermostat programs out of sensitivity to customers. That pause lasted approximately three months, and marketing activities have begun again though delivery has been adjusted for safety purposes (for example, technology-enabled virtual thermostat installation assistance). Additionally, we have undertaken significant customer outreach efforts to minimize losses from the Google decision. For the Energy Partner program, we have seen reductions in customer participation commensurate with customers' business operations contracting or closing altogether. At present PGE estimates these market conditions have slowed acquisition to meet our 2019 IRP demand response by about 6 months, though there is uncertainty in that timing due to unknowns related to economic recovery from COVID.

Table 13 – Flexible Load Portfolio MW Savings

Cumulative MW by Program	2017 and prior Results	2018 Results	2019 Results	2020 Forecast		2021 Forecast	
	Average Summer & Winter			Summer	Winter	Summer	Winter
Residential- Flex	1.5	1.5	6.9	14.7	11.0	18.0	12.0
Residential- Thermostats	4.0	7.3	13.7	24.1	7.0	32.4	10.5
Commercial- Energy Partner	3.0	15.2	21.8	20.2	14.9	26.5	22.3
Commercial- MFWH	0.0	0.9	3.4	3.9	5.9	5.0	7.5
	8.6	**24.9**	**45.8**	**62.9**	**38.8**	**81.9**	**52.3**

A.2 Program Detail

A.3 Multifamily Water Heater Pilot

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$4.1M (EOY 2019)	3.4 MW	0.82	Summer 2020-21 (due in March 2022)

A.3.1 Program Description

The Multifamily Water Heater pilot aims to enable and operate electric water heaters for demand flexibility. This program provides capacity as well as intra-hour energy and lays the foundation for PGE's DR programs to offer intra-hour grid services to support reliability and renewables integration. The approach is relatively novel as it capitalizes on the density of electric water heaters found in multifamily dwellings. Density is necessary for several reasons. First, broadly distributed assets are more expensive per unit installation thus concentrations of units enable water heaters for a fraction of enabling the same number of units across a broader area. Second, because many multifamily units install the water heater within the living space electric resistance water heaters are used. This niche allows PGE to test advanced use cases from water heaters without affecting Energy Trust and the Northwest Energy Efficiency Alliance's efforts to promote adoption of more efficient heat pump water heaters. Third, having a concentration of these units granted PGE an opportunity to begin working with water heaters as a flexible resource sooner than if we had to wait for higher adoption and concentration rates in the field. Our learnings from this pilot will help inform our approach to single family water heaters. To be clear, PGE supports Energy Trust and the NEEA's effort to increase adoption of heat pump water heaters. However, given the importance of water heaters as a cost-effective approach to supplying flexible services, PGE developed the Multifamily Water Heater Program to learn about developing a flexible load resource from a highly dynamic, ubiquitous appliance.

In addition, PGE is operating the MFWH pilot to evaluate the various modes of device connectivity and different Operating Equipment Manufacturer (OEM) solutions as a means to optimize cost effective program implementation and event performance. Throughout the pilot period PGE will evaluate two approaches to connectivity -- Local Area Network or Wi-Fi communication. This can be done several ways, all of which rely on the presence of a local area network.

The MFWH pilot is structured in phases *designed to move it from* pilot to cost effective program. The first 8,000 installed units took 22 months to install (May 2018-Feb 2020) and will be capable of shifting up to 4MW of energy. We expect to add 2,000 installs in 2020 and 2,500 in 2021, which will create up to 5.0 MW and 7.5MW of shifted energy for summer and winter 2021, respectively.

Table 14 – Multifamily Water Heater Pilot Stages

Timeline	Units installed	Total Capacity
February 2020	8,000 (Program total)	Roughly 4MW (Covid-19 has delayed installations)
EOY 2020	2,000 (Incremental)	3.9MW Summer, 5.9MW Winter
EOY 2021	2,500	5.0MW Summer, 7.5MW Winter
Total	**12,500 retrofit switched units**	**5.0MW Summer, 7.5MW Winter**

PGE expects the per unit install cost for water heaters to continue declining as we install more cell-enabled switches, add mesh or field area networks switches, and add more smart water heaters through the new construction channel. The on-going maintenance costs will also continue to decline as we discontinue installing Wi-Fi switches, which are expensive to maintain connectivity. Conversely, cell-enabled, mesh or field area networks, and smart water heaters cost pennies to maintain connectivity. The project serves as a backbone to provide water heater solutions in new and existing construction markets for single family housing, as well as in owner-occupied MFR housing as early as Q3/2020.

A.3.2 *Multifamily Water Heaters as part of PGE's Decarbonization Strategy*

Water heaters serve every customer in PGE's service territory. Though a large percentage of this market heats their water with end use natural gas, PGE anticipates that as the State pursues carbon reduction strategies the percentage of electrically heated water heaters will grow. Unlike home batteries, roof top storage and electric vehicles, home water heaters are considered a necessary home appliance. Additionally, the cost of electric water heaters is considerably less than the aforementioned. Water heaters are able to shift energy usage, storage energy, and respond to intra-hour event calls without customer hot water service interruptions. This makes the water heater a prime, strategic flexible load resource to help develop a grid flexible enough to integrate variable energy resources while controlling integration costs.

Water heater DR is a critical component to PGE's portfolio because it uniquely represents flexible load. Within the multifamily market, it is estimated that nearly 90% of water heaters are electrically heated and represent 50% of the residential market. Additionally, this type of firm resource can be dispatched daily without affecting customer comfort or disrupting behavior. The fact that within the multifamily market 90% of water heaters are electrically heated, makes this market an excellent space fora flexible water heater program. Multifamily sites allow us to install DR capabilities to several units swiftly, minimizing costs associated with outreach and the costs of establishing service at disparate sites. Additionally, having several units within a single multifamily site allows us to see how the water heaters operate in concert to address capacity and delivery constraints. Moreover, the geographic aggregation of the water heaters creates natural communication and dispatch cost savings. The lessons learned around device installation, device performance and communication will inform development of a single-family water heater program.

A.3.3 *Primary Goals*

The goals for PGE's Multifamily Water Heaters pilot are as follows:

- Successfully operationalize and field deploy retrofit devices that allow for successfully controlling existing water heaters in PGE's DR platform. Operationalize and field deploy
- DR-enabled new water heaters that can be controlled via PGE's DR platform.
- Operationalize communications technology that provides uptime of 90+% for the PGE water heater fleet.
- Reduce costs for hardware, installation, maintenance, and operations down to cost-effective levels while scaling up the program during the pilot period.
- Test, modify, and proof business model with MFR property owners and their agents (MFR property managers).
- Successful dispatch of PGE water heater fleet in DR events with an average capacity of .5KW per water heater during the DR event period.
- Expansion of operation of PGE water heater fleet from DR to daily load shifting. Demonstration of load following capability.

Market potential (opportunity):

- This project targets the large scale / non-owner occupied MFR market: 50 units/site.
- The total number of eligible apartments in large scale MFR housing is 100,000 units. The achievable potential is **50,000 units** corresponding to **25 MW by 2027**.

A.3.3.1 Switch costs

PGE's original start-up budgeted costs per switch installed was roughly $545. Through the pilot we have explored different switch types and vendors. We have improved the effectiveness of our installations. Our third-party contractor negotiated better installation terms thereby lowering overall program costs. Installation work includes not only the switch mounting to the water heater but the communications infrastructure. We have been able to bring down the cost of the communication equipment placement and connectivity resolutions as we learn more about how the water heaters and switch devices operate in the field. We have been successful in bringing down the per unit installation costs to $330. This is a 35% cost savings per switch installed.

A.3.3.2 Communications

There are currently two switch communication methods being explored. Just over 4,400 wi-fi enabled switches with another 3,700 cell-enabled switches. We expect overall installation costs to decrease (due to less equipment needing to be installed – no routers or repeaters) and connectivity to increase (cell-enabled connectivity doesn't have nearly the outages as wi-fi does). We are also looking to explore a second cell-enabled vendor as well as mesh network and field area network options. Cost, latency, telemetry data, installation process lessons (router, repeaters) all play a role in choosing the right vendors.

A.3.3.3 Algorithms

There have been numerous issues with the data from the first winter season. Due to the second switch vendor supply issues, splitting the assets into two groups for control, and the wi-fi connectivity issues we had a very small, callable set per event to analyze. This created a lot of noise within the AMI data as well as inconsistencies between the AMI data, our data management system and our third-party data platform. Being able to increase our fleet will greatly improve our ability to decipher the data between AMI and telemetry. We are also exploring ways to create control sets outside the current fleet to increase the number of available callable switches.

A.3.3.4 Customer/Participation comfort

Our customer participation has been excellent. With almost 8,000 switches installed to date we have less than a 1% opt-out rate (4 customers in total have opted-out of this program). As for customer comfort, we have had less than 15 out of 3500 participating customers over 58 total events experience cold water calls. Of those 15 calls, not all have been directly attributed to the switch. There are four categories the calls have fallen into:

- 5-unknown issues (further tests being conducted)
- 4-faulty switches (repairman went out and removed old switch and installed a new one, problem did not continue)

- 3-installation issue (terminal connection lost, ground wire fell out, etc.)
- 3-water heater issue (dip-tube replaced, heating element not stable, etc.)

In the future we are looking to add maintenance monitoring to try and help detect water heater issues before they become a bigger problem. The monitoring is expected to help detect a burnt-out heater element or a leaking unit. This is a feature that the Maintenance Mangers are eager for us to deliver.

A.3.3.5 Availability of resources

This program has very few limitations on calling events: not for longer than 8-hours and not on weekends or holidays. Nor are we required to notify customers of the scheduled event. We can call events 5-days a week and multiple times a day.

For the winter 2018-19 season we called a total of 58 events from Dec 12th, 2018 through March 1, 2019. Some of those were as short as 2 hours and some as long as 5 hours. Most days we called two events (6-9 A.M. and 4-9 P.M.)

For the summer 2019 season we called a total of 68 events from June 3rd to Sept 30th, 2019. All of those were 4 hour events from 4 P.M. to 8 P.M.

For the Winter 2019-20 season we called a total of 179 events from Dec 2nd, 2019 through Feb 27th, 2020. All events were 3 hours each and called twice a day, from 6-9 A.M. and 5-9 P.M.

These calling structures have allowed us to use the resource for more than peak load reduction capacity. This program is explicitly testing an early evolution of flexible load. Given the poor connectivity rate of the wi-fi switches we are very pleased to see the increase in connectivity with the cell-enabled switches. We are working with our third-party DERMS vendor to continue to get a better report on the uncontrolled units per event.

A.3.3.6 Building configurations

PGE has found that different building types have different mesh network challenges. PGE working to address this challenge. Another obstacle is building configuration. Building configuration can challenge wi-fi connectivity. Cement walls and oddly shaped and spaced buildings are requiring additional routers and repeaters. This increases costs but may not always address the underline connectivity issue. Cell-enabled, mesh network and field area networks are all expected to address costs and improve connectivity. Expanding the fleet and adding cell-enabled switches will help determine the best switch for each building type.

A.3.4 Managing Cost and Cost Effectiveness

PGE is actively managing total costs of the program in order to positively affect cost effectiveness. PGE is focusing on a few select cost categories to better manage the overall cost of the pilot while not negatively affecting pilot performance. Install and hardware costs are the largest controllable cost centers. As stated above, we have seen a significant installed cost decline since the pilot began. New mobile enabled switches negate the need for PGE to create local area networks within each building site. Mobile switches require less investment from PGE in supporting infrastructure such as Wi-Fi routers and repeaters. This translates to less operations and maintenance costs. We are also actively managing contractor costs for each install.

Another way to manage to cost effectiveness is to increase utilization of the units, uptime or availability of the units and the total verifiable load drop from the unit. Recent cell enabled chips, installed in late 2019 are demonstrating better connectivity, as well as better load drop performance.

Table 15 – Cost Effectiveness: Multifamily Water Heater Pilot

	TRC		PAT		RIM		PCT	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Administrative costs	$14.56		$14.56		$14.56			
Avoided costs of supplying electricity		$12.78		$12.78		$12.58		
Bill reductions								$0.00
Capital costs to the utility	$0.00		$0.00		$0.00			
Environmental benefits		$0.14						
Incentives paid			$11.55		$11.55			$11.55
Revenue loss from reduced sales					0.00			
Transaction costs to participant	$0.00						$0.00	
Value of service lost	$1.19						$1.19	
Sum of costs and benefits	$15.7\5	$17.60	$26.11	$12.78	$26.11	$12.78	$1.19	$11.55
Benefit Cost Ratio	0.82		0.49		0.49		9.74	

A.3.5 *Evaluation*

The process evaluation has sought to assess how well the Multi-Family Water Heaters pilot is operating and to identify potential improvements to program processes, including recruitment, enrollment, data management, installation, and event management. Navigant's Summer 2019 evaluation report was submitted to the Commission through Docket UM 1827 February 12, 2020. The evaluation report highlighted several issues. These included customer acquisition, customer experience, system integration and event results. PGE Staff worked actively in December 2019 and Q1 of 2020 to address these items and gave updates to Commission Staff on the progress of our work.

A.3.6 Moving from Pilot to program

PGE has identified five build factors that a pilot moves through on its evolution to program. Stability of the customer experience, infrastructure stability, grid performance, financial performance and dispatch integration. As each program is individual the assessment of program versus pilot status can be individualistic. For example, the multifamily water heater pilot need not focus its attention on the stability the customer experience as the affected unit dwellers have not demonstrated customer friction with the program and how it interacts with their home appliance. However, multifamily water heaters do need to concentrate on infrastructure stability.

A.3.7 Customer experience

This part of the Multifamily Water Heater program is stable. There are two types of participants in the program. Those who take service from the water heater and those property owners and property managers who enroll their property into the program. In response to Navigant's Summer 2019 Pilot Evaluation PGE will be working to improve communications with property owners and centering communications on the benefits of the program and the technology. PGE will also be working to better inform tenant dwellers that the pilot is operating and what they might notice a box connected to their water heater.

A.3.8 Infrastructure Stability

Infrastructure stability is the primary challenge of the program and once addressed and stabilized can transition to dispatch integration the last factor PGE uses to determine pilot to program maturity.

Several infrastructure stability challenges are being addressed and are addressable. These include communications stability and load drop performance in accordance with planning values. Thus far in Q4 2019 and Q1 2020 PGE has been able to address these two infrastructure stability challenges through the installation and utilization of a new type of hot water heater switch which operates on different load drop protocols and a new cellular communications network.

A subfactor of infrastructure stability is tariff stability meaning that PGE through implementation of the pilot has not received feedback from the operation of the pilot that the tariff needs revision in order to provide optimal service. The Multifamily Water Heater pilot tariff operationally is sufficient however in order to assure controlled growth and Commission oversight of costs the program tariff limits the number of installation and regularly updated with each deferral filing. This approach for now is reasonable until such time as the pilot evolves to address the and stabilize some of the technology challenges and has begun the process of dispatch integration.

A.3.9 Stability of Performance

For multifamily water heaters stability of performance is closely tied to infrastructure stability. As PGE is able to address communication and event performance from the field units.

The PGE team is now working to address water heater performance during the events. The new cellular switches being installed are resulting in better performance per unit.

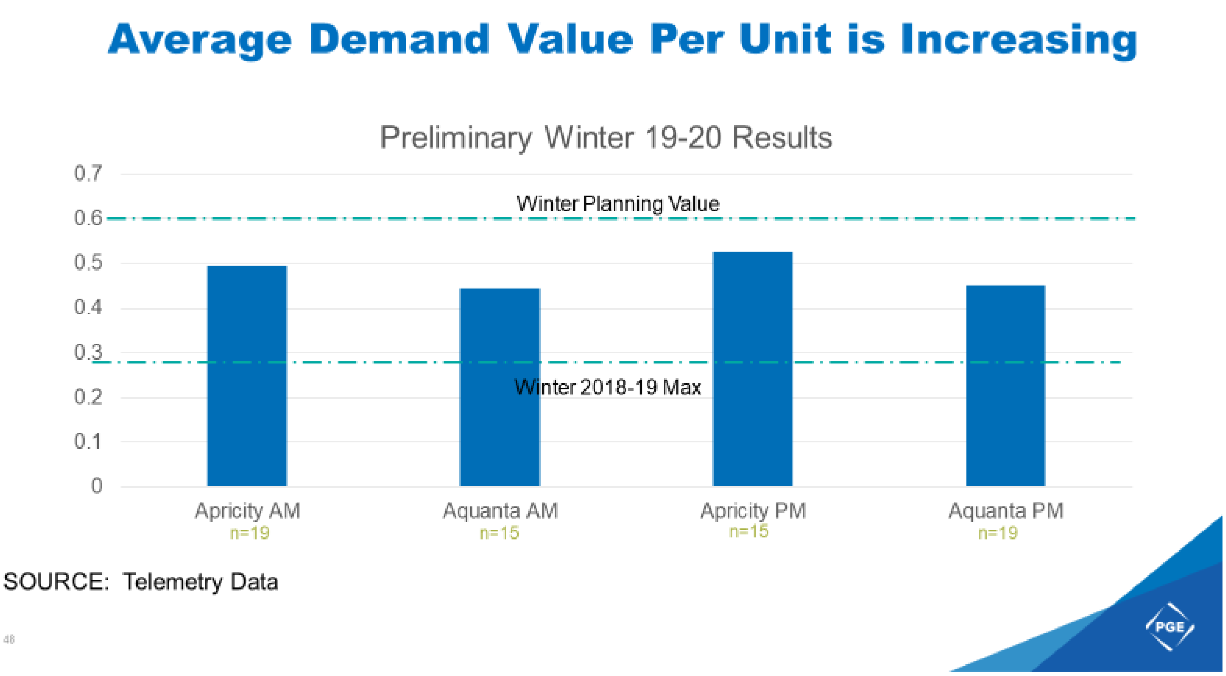

Figure 27 – PGE's Residential Demand Response Pilot Update, January 27, 2020

The figure above demonstrates the increased load drop seen with new approaches to water heater switch performance both for legacy Wi-Fi enabled units and new cellular enabled units. One can see an increase in performance. Additional performance improvements are necessary to meet the original filed planning value.

Dispatch Integration

Events are called daily (Monday-Friday, non-Holidays). Winter events are typically called twice per day for 3 hours each, from 6am-9am and 5pm-8pm. Summer events are typically called once per day for 4 hours from 4pm-8pm. We have found that we need to start and stop all events on the hour to prevent partial event recording.

It should be noted that events are not presently called by power operations. While there is coordination with the PGE Balancing Authority about when events are called and for what duration the pilot at present is too small a resource to hand over dispatch to power operations. Additionally, once the pilot team is able to stabilize the communications and technology performance issues the Multifamily Water Heater team will need to work with Power Operations to create a Mater File and dispatch protocols for utilization of the resource. Once this work begins, the threshold from Pilot to Program has been crossed. The Power Operation team has let the Demand Response team know that the resource must perform within a 12-15% accuracy of the nominated capacity. Thus, multifamily water heaters will need to identify with this same level of accuracy the reliable performance of the total aggregate resource. This means that connectivity of the water heaters needs to be closer to 85% and event participation must similarly in the aggregate meet 85% of the total nominated capacity whether used for multi-hour service or sub-hourly services.

A.3.10 Pathway to Flexible Load

The Multifamily water heater program is PGE’s most dynamic demand response resource and is capable of providing true load flexibility with minimal customer service interruptions. Additionally, because of the ubiquity and low entry level cost of the resource the Multifamily Water Heater Program holds significant promise as large service territory wide resource. The lessons learned from the multifamily water heater program will inform our single-family water heater program. It is likely that as the multifamily water heater program is incorporated into power operations it will be the first of PGE’s flexible load customer sited residential programs.

A.3.11 Activity within the Testbed

Multifamily Water heater pilot is present in the Testbed. PGE will be using the pilots’ presence in the Testbed to help identify the locational value of the resource. PGE will also be looking into how the multifamily water heater program will inform thermostat programs for multifamily units within the Testbed.

A.4 Residential Direct Load Control Smart Thermostat Pilot

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$5.5M (EOY 2019)	13.7MW	1.06	Summer 2020 (due July 2021)

A.4.1 Pilot Description

The Residential Direct Load Control Smart Thermostat Pilot aims to enroll and operate connected residential thermostats to control electric heating and cooling load. This pilot provides firm capacity; PGE is working with the Energy Trust to explore how thermostats and other efficacy measures can be paired to provide longer duration energy optimization. To participate in the pilot, PGE customers must operate either a ducted heat pump, electric forced-air furnace, or central air conditioner. The pillars of the pilot rest on three delivery channels:

1. **Bring Your Own Thermostat.** Customers may enroll online in PGE's demand response offer by A) purchasing a new qualifying thermostat, or B) using an existing qualifying thermostat attached to a qualifying HVAC system. Customers receive a $25 enrollment incentive and $25 for each DR season that they participate in (defined as 50% of the DR hours called within a season). Customers are permitted to opt-out of any or all events.

2. **Residential Thermostat Direct Installation.** Customers with a qualifying HVAC-system can participate by receiving a qualified thermostat, installed, provisioned, and enrolled into PGE's DR platform by a PGE contractor. This channel provides a no cost thermostat for customers with a ducted heat pumps or electric forced air furnaces, due to the high DR capacity value. Customers with central air conditioners are charged an incremental cost of $50. Customers from this channel are excluded from receiving PGE enrollment or seasonal participation incentives.

3. **Residential Thermostat Direct Ship.** PGE's roadmap for residential thermostat includes a possible new channel in 2020. This new channel would allow PGE customers to go online and order a thermostat free or at a reduced charge. In return, customers are required to self-install and enroll into PGE's DR pilot. Participating customers coming through this channel are excluded from receiving PGE enrollment and seasonal incentives. This channel is currently not yet active or approved–it is scheduled to be available in the Winter 2020 season.

A.4.2 Primary Goals

- The pilot aims having a total of 20,000 residential thermostats by 12/31/2019
- Determine and verify customer acceptance of the above delivery channels
- Build a minimum of 20 MW summer capacity and 2 MW winter capacity,

- Successfully operationalize and maintain or increase customer satisfaction for all three delivery channels
- Dispatch and control enrolled thermostats and obtain DR capacity at or above planning estimates
- Minimize customer drop-outs from *the pilot* (not event-based overrides) to increase customer retention

A.4.3 Market Potential

- This pilot's primary targets are PGE customers with and without existing connected qualifying thermostats that live in single-family residences with ducted heat pumps, electric forced air furnaces, or central air conditioners.
- Based on the best available information, PGE estimates the total number of eligible households is about 326,000 units (total addressable market). This number is increasing due to increasing installations of central air conditioners. The achievable potential is estimated at 149,000 units, which represents approximately **82.5 MW**. PGE continues to refine these estimations by improving our customer heating and cooling data, analyzing which types of customers are likely to be most successful in the pilot (not override their devices during an event) and implementing efforts that support customer participation.

A.4.4 Lessons learned

The Smart Thermostat pilot has identified several lessons learned which have translated into performance and structural items which are being addressed during 2020. Addressing these performance and structural items will advance the pilot toward the program phase. These lessons learned include:

A.4.4.1 Increasing Performance Levels for Direct Install Channel

PGE has identified that enrollees into the direct install channel have demonstrated a higher event override propensity than the Bring Your own Thermostat channel. This may be due to the type of customers who enrolls in the direct install offer. We are conducting further research to determine how best to engage with these non-performers before engaging in claw back activity outlined within the tariff. Our research indicates that customers utilizing this channel are older, typically on a fixed or lower income (retirees). As inability to pay utility bills is an advanced indicator of homelessness, we want to make sure that we are not placing non-performers on a claw back list, taking such action which may have deepen longer lasting negative lifestyle implications. To enhance participation and reduce overrides, PGE is commencing in follow-up educational efforts with Direct Install customers to refresh them on participation requirements and revising the claw back provision to reflect a more equitable solution.

A.4.4.2 Manage the Device Communications Interface

PGE launched the BYOT Smart Thermostat channel in 2015 with Google Nest, the provider of the Nest thermostat, by utilizing Nest's program, Rush Hour Rewards, to recruit customers and control Nest thermostats when PGE scheduled demand response events. This service to control the thermostats is generically referred to as "Distributed Energy Resource Management" or DERMs. This was a relatively turnkey solution for PGE. However, in late 2019, Google Nest informed PGE that they would not be providing their demand response management services in support of the Nest Thermostat following the winter 2019-2020 season. Google Nest provided little explanation stating, "due to Nest's integration with Google and our desire to help these programs scale, Google is shifting the way that RHR programs will be managed". PGE has contracted with Resideo, the current DERMs provider for ecobee and Honeywell thermostats in PGE's Smart Thermostat Demand Response Program to also provide DERMs services for Nest thermostats.

While this transition should have been seamless for the customer, Google Nest has further complicated it by updating their terms and conditions for the Rush Hour Rewards Program. This change requires active acceptance by every existing customer to remain enrolled in the program. If customers decline or fail to accept the new terms and conditions by September 15th, 2020, they will be unenrolled by Google Nest. These events have two implications for the PGE Smart Thermostat pilot: 1) the pilot is likely to see some enrollment reduction this will in turn cost the program in re-recruitment dollars. 2) this has taught PGE that partnerships with a device manufacturer who has so much market power must be approached with a contingency plan. To retain customers, PGE has provided advanced and direct communication to customers about these changes and the actions they must take to stay in PGE's program and retain the benefits. This has created additional administrative costs for the program for customer engagement as well as data management through the migration. For the longer term, PGE is currently investigating ways to create a direct relationship with the customer in support of these programs, rather than relay on third parties own those relationships.

A.4.4.3 Data and Customer Enrollment Management

The PGE customer data management system was not prepared the for the popularity of the Smart Thermostat pilot. IT upgrades needed to collect and track participation, enrollment, event performance and customer incentives did not happen in the necessary succession in order to support the growing enrollment. PGE's IT team is presently working to include these pilot activities into the meter data management system and the customer information and billing system that will allow more automated data management and reduce implementation costs internally (reduce manual data management) and externally (e.g., incentives have been administered through a third-party contractor). Ultimately, this will create a better customer experience as enrollment processes will be more expedient and incentives will be provided more quickly and "on-bill".

A.4.4.4 Low Income Approach

PGE is working to identify how to service low income customers with smart thermostats because the demand response program requires a qualified electric heating and cooling system, a smart thermostat, and reliable internet connectivity. There are two main hurdles to adoption for low income customers:

1) Low income customers may not be able to afford a Smart Thermostat or accommodate an appointment during regular business hours for a direct install offer. PGE is designing the “direct ship” channel to specifically target these customers with a free thermostat that they can install themselves and take advantage of energy efficiency and demand response events.
2) Low income customers experience the technology divide, as 35% or more do not have home internet, lagging behind the national average by 13%[133], and tend to rely on smart phones to access the internet. Through PGE’s Smart Grid Testbed project, PGE is working with the City of Hillsboro to leverage the City’s Low Income free and lower cost internet program. Progress on this work will be presented to the Demand Response Review Committee the group of stakeholders established by the Commission and PGE to help direct the work of the PGE Testbed.

A.4.5 Managing Costs and Cost Effectiveness

The pilot is continuously working to improve cost effectiveness through managing pilot costs and through identifying ways to increase the demand response performance. Here is a list of key initiatives completed or in process:

- PGE Leveraged the DERMs provider migration from Google Nest to Resideo to negotiate a 10% overall cost reduction for DERMs services across the pilot (assuming a 90% retention rate of Google Nest devices by September 15, 2020)
- Renegotiate Direct Install vendor contract to reflect recent drop in thermostat prices as well as restructure pilot to offer Nest E as no cost offer for all heating systems, reducing overall implementation costs by 12% in second half of 2020
- As previously mentioned, progressively introduce IT upgrades to reduce the amount of manual labor required to manage pilot processes and data as well as eliminate reliance on 3rd party vendor for check cutting services
- Investigate and trial mid-season engagement strategies and increased customer education to create higher participation rates and reduce customer event “override” (planned for Summer 2020)
- Alert customers with “offline” devices to root cause and repair their connections to enable future participation
- Enable automated “moves” process to re-engage customers who move within PGE’s territory in the pilot and to ensure that new occupants of previously participating residences are also enrolled in the pilot

[133] https://www.census.gov/library/stories/2018/12/rural-and-lower-income-counties-lag-nation-internet-subscription.html

Table 16 – Cost Effectiveness: Residential Direct Load Control Smart Thermostat Pilot

	TRC		PAT		RIM		PCT	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Administrative costs	18,610		18,610		18,610			
Avoided costs of supplying electricity		25,193		205,195		25,195		
Bill reductions								889
Capital costs to the utility								
Environmental benefits		82						
Incentives paid			20,962		20,962			20,962
Revenue loss from reduced sales					889			
Transaction costs to participant								
Value of service lost	5,243						5,243	
Sum of costs and benefits	23,853	25,277	39,572	25,195	40,460	25,195	5,243	21,850
Benefit Cost Ratio	1.06		.64		.62		4.17	

A.4.6 Evaluation

Evaluations are conducted by a third Party (Cadmus) in which they evaluate the following:

- Pilot Delivery/Enrollment – the how and how many customers who've enrolled
- Pilot Impacts – measuring the demand reductions during the dispatched Summer and Winter events.
- Customer experience – measuring customer satisfaction and comfort levels during dispatched events. Evaluations for the Bring Your own thermostat have been positive thus far which has been filed with the OPUC. An evaluation for the Direct Install channel should be completed and delivered prior to the end of 2019. Also, if approved, an evaluation for a Direct Ship model will follow in 2021

A.4.7 Moving from Pilot to Program

PGE has identified five build factors that a pilot moves through on its evolution to program. Stability of the customer experience, infrastructure stability, grid performance, financial performance and dispatch integration.

A.4.8 Customer Experience

PGE has gaps in the smart thermostat customer experience which need to be addressed. Due to the rapid adoption of the technology and number of units enrolled, PGE Staff have been focused on pilot build. The customer experience needs to be revisited in order to assure a quality customer experience going forward. The highest priority is conversion from separately mailed incentive checks to on-bill credits. This will provide a more expedient connection between customer participation and reward and help lower the administrative costs assisting with the cost effectiveness of the pilot. While much of PGE's outreach has been focused on customer recruitment, we are also working on-going engagement throughout the winter and summer seasons and education of customers, across a diverse set of demographics, to drive better customer satisfaction and success.

Additionally, PGE is working on a pathway to better verification of specific heating and cooling types for eligibility and currently seeking a solution for optimizing HVAC system verification. The Direct Install channels ensure that each customer is enrolled in the correct season, but the BYOT channel relies on a combination of customer testimonial, thermostat OEM data, and publicly available information to ensure eligibility and correct seasonal assignment. Many customers are not knowledgeable about their own HVAC systems so bridging this gap will enable more targeted customer recruitment and reduced customer confusion. Though the AMI meter data is informative of hourly usage it lends no verified insights into how the electricity is being used, thus verification of the HVAC type cannot be verified through the AMI meter data. We are presently work with Bigley and the Energy Trust's contractor Recurve to identify meter data analysis techniques which might better elucidate how customers are using their electricity and how to better enable their success in the pilot.

A.4.9 Infrastructure Stability

We were informed by Google Nest that will no longer be supporting their demand response management system for Nest Thermostats in late 2019, requiring PGE to contract with another provide for DR services. Additionally, , in early April, Google Nest communicated to Nest owners that they must actively accept new terms and conditions in order for Nest owners to remain enrolled in PGE's Rush Hour Rewards program. If the customer does not accept the new terms and conditions by September 15, 2020, Google Nest will unenroll the customer from the program. PGE responded to these changes by expanding the contract with Resideo, the current DERMs provider for Honeywell and ecobee thermostats and on the Google Nest approved list. PGE also alerted customers about this change in advance to better prepare them and supported acceptance through additional customer communications. This process has generated unplanned re-recruitment expenditures to re-capture customers who may have unknowingly unenrolled from the PGE pilot. This significant infrastructure adjustment will need to be addressed and stabilized in order to understand the total on-going cost when the pilot matures to a program.

A.4.10 Stability of performance

Currently we call events in the following manner:

- Review a daily report generated by PGE Power Operations that displays the forecasted load and what time(s) it will be at its peak, the Hi/Low temperature and regional weather, the Mid C Power Peak Price, and Power Plant conditions.
- We then record the above conditions with pre- determined parameters (from consulting with Power Operations) which then highlight/color code if the conditions warrant calling a demand response event.
- If the conditions warrant an event, we then consult with Power Operations to ensure it is okay to dispatch the event
- We then send out the decision report to all stake holders and inform them an event will be called and at what time so that ahead of time so that each area can take the necessary action to enable the dispatch of these resources .
-
- It is thought that once DR pilots become programs, power operations will assume the duties determining and dispatching events.

Predictability of load impact: 12-15% accuracy

A.4.11 Dispatch Integration

PGE will begin to address integration of the Smart Thermostat pilot with PGE's Power Operations and Balancing Authority once we have addressed the DRMS issues we are presently experiencing with Google Nest. Until then PGE will continue the practice of coordination with Power Operations and the Balancing Authority.

A.4.12 Pathway to flexible load

The pathway to Flexible Load for the Smart Thermostat pilot is presently less well defined and understood then the Energy Partner or the demand response enabled water heaters. Two options will need to be explored, likely through small demonstration projects or through model research activity conducted in the Testbed should the Testbed enter a second phase effort. Initially, the thermostat resource can be used for localized grid services in short event bursts (such as 1 hour). Dispatch could also be optimized to compliment renewable resources utilization. This aspect is being tested as a customer value proposition within the Testbed in 2020 and 2021.

Lastly, a combined energy efficiency and demand response measure whereby homes are better insulated may provide additional thermal mass for variable use of the thermostat throughout the day. This concept needs additional work, coordination and exploration with the Energy Trust.

A.4.13 Participation in the Testbed

The Smart Thermostat pilot is an anchor tenant of PGE's Smart Grid Testbed. Lessons learned from its inclusion in the Testbed will inform PGE program design for years to come.

A.5 Non-Residential Demand Response Energy Partner Program

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$9.8M (Jan 2017 EOY 2019)	21.8 MW	1.23	Q2-2021

A.5.1 Program Description

PGE is piloting a non-residential demand response program designed to reduce peak demand requirements during specific time windows in the winter and summer seasons by incenting customers to reduce their energy consumption during those times. PGE expects the primary source of this reduced demand (load) will be from large customers, with an option for small and medium customers to participate as well. The Energy Partner Program provides firm capacity; this program may evolve to provide intra-hour grid services to support reliability and renewables integration. The 2018 target was 14 MW of DR, increased to 20 MW for 2019, and ultimately to 27 MW by January 1, 2021.

PGE's non-residential DR program was launched in December of 2017, and was directly administered by PGE, with support from:

- CLEAResult for program implementation
- Enbala for technology integration via their Virtual Power Plant (VPP) software platform. PGE took a more active approach than the prior "turnkey" DR program administered by EnerNOC, as PGE found that third party aggregation fell far short of load goals.

The new arrangement offers the flexibility to offer a variety of products and potentially adjust them in the future. The secondary reason for PGE to work directly with customers is portfolio resiliency. With the loss of EnerNOC in 2017, PGE had to execute new contracts and deploy new technology to current participants. This presented customer retention risk. Directly administering the program should avoid such adverse operational risks should a third party exit the program. PGE administration of the program also allows for better bundling and / or cross-marketing of the program with other offerings such as EE, renewables, storage, and dispatchable standby generation.

Delivering an impactful business DR program and the associated flexible load is key to A) delivering upon PGE's IRP commitment, B) supporting Oregon's 50% renewables by 2040 (SB1547) target, and C) enabling PGE to achieve aggressive carbon reduction goals (carbon emissions reduced by 80% below 1990 levels). The program is expected to help us learn how to drive program adoption, optimize the DR software platform, and leverage the program value over time–evolving from a solely capacity resource to other use cases such as load following and renewable firming..

PGE's previous business DR program was initiated in 2013 and administered by EnerNOC. This prior iteration fell short of its 24 MW DR target, and by the end of 2016 had achieved only 10.6 MW. The volume gaps were attributed primarily to EnerNOC's approach to program design (inflexible and oriented solely to large customers) and their sales process, which lacked on-site account management. Their model delivered results in other geographies but was not adjusted to meet the needs of PGE's customer base. PGE's redesigned program offers customers flexible participation options during events, greater remuneration, options for both large and small-to-medium sized customers, and a "higher touch" sales approach.

In the prior program, customers had to enroll for 40 hours of event time per season and be on call from 7 am to 10 pm in the winter and noon to 10 pm in the summer. In the current program, customers can select from 20, 40, or 80 hours of events per season and customize their participation schedule by selecting one or more event windows such as 7-11 am (winter), and 11 am to 4 pm, 4-8 pm, 8-10 pm (summer and winter). Compensation is also more favorable: the same selections as the prior program now earns 22% more, and the maximum hour / maximum window option pays 76% more.

The EnerNOC program lacked participation options for small-to-medium size businesses. PGE's updated program offers a smart thermostat free of charge; this unit controls heating and cooling during DR events and pays customers $60 per season if they participate in a minimum of 50% of event hours. Larger Commercial and Industrial customers also benefit from this option, as many have office buildings on site.

Another gap addressed by the revamped business DR program is the addition of dedicated sales representatives and engineering staff (provided by CLEAResult) who can work on site with customers. EnerNOC predominantly serviced accounts over the phone and via email and were unable to build the customer insight and trust essential to success. Unlike residential DR programs which leverage a "mass market" approach, business customers require individualized, ongoing focus to ensure their operations are not disrupted by DR events (e.g. nominations may require adjustments, questions may arise as to how to optimize participation during events).

A final limitation of the EnerNOC program was their DR Management System (DRMS) which was acceptable for the prior pilot but lacked the technical capability to meet future requirements. The tool only supported an "all call" approach, which notified all participants during a multi-hour event. Compare this to Enbala's more sophisticated VPP, which can call devices based on constraints such as location (e.g. around a feeder), or customer sited set points (maximum and minimum pump set points). The Enbala VPP software used with PGE's new program provides the flexibility to meet these future needs.

Customer feedback on the redesigned program has been positive. Customers appreciate the flexible program design and dedicated / responsive sales and engineering staff as improvements. PGE is proud that the great majority of customers transitioned to the new program. When combined with additional customers that PGE has signed up for the program, PGE exceeded its 2018 & 2019 targets of 14 MW and 20 MW respectively. A comprehensive Measurement and Verification evaluation of event performance and customer satisfaction was completed in third quarter 2019 with favorable results.

A.5.2 Incremental Activities

The non-residential DR program is expected to entail bolstering several program design elements to accelerate the program's ability to refine and optimize its delivery activities. Specifically, PGE plans for the program's activities to include enhanced incentives, targeted marketing, and dedicated sales / outreach. We expect these efforts will be incremental to the program's "business as usual" operations, meaning that they leverage existing program activities. Furthermore, we expect these incremental efforts to be invaluable in defining optimal program delivery strategies and tactics, identifying customer segment-specific ceilings for program participation, and facilitating acceleration of significant load reduction capacity within the DR portfolio.

Examples of potential incremental program activities evaluated include:

- Incentives
  - Offering enhanced incentives at a to-be-determined level
  - If possible, testing multiple enhanced incentive levels is desirable due to ability to determine "incentive elasticity"
- Marketing
  - A/B testing of the same messaging delivered through different delivery mechanisms
  - A/B testing of customer segment-specific messaging
- Sales / outreach
  - dedicated sales / outreach staff
- Product design
  - Bundling of program offerings such as business demand response electric vehicle charging and Energy Trust's Strategic Energy Management.
  - New tariff designs that allow the customer to provide differentiated energy services throughout the year for a greater number of total hours of the year.
  - Tiered incentive levels tailored to the DR approach (e.g. manual, automated, or advanced)

PGE intends to leverage non-residential DR program activities to drive improved program performance on a territory-wide basis. To enable this, the program expects to have informed answers to the following questions:

- By customer size and segment:
  - What incentive levels are most cost-effective at driving program participation?

- Which product bundle and marketing messages are most compelling?
  - What is the maximum expected conversion rate given various incentive / marketing / sales / outreach configurations?
  - Are marketing, sales / outreach, or incentives most impactful in driving program participation?
- Which customer segments are extremely *unlikely* to participate (regardless of incentive level) due to operational challenges not conducive to DR participation?
- Is sales / outreach or targeted marketing more effective at converting small-to-medium sized customers?
- Do customers have a higher propensity to participate if businesses located near them are also participating?

PGE expects that evaluating the non-residential DR program's learnings will improve our ability to fine-tune DR offerings in both the small-to-medium business (SMB) and large commercial and industrial spaces.

A.5.3 Goals

The goal of the Energy Partner Program is to provide 27MW by end of year 2020. Additionally, the Energy Partner program is the most mature program in the PGE demand response/flexible load portfolio. PGE is currently working with our power operations team and our balancing authority team to incorporate Energy Partner into power operation dispatch practices, such that Energy Partner is seen agnostically, as a resource within the resource stack and dispatched based on its operating profile. The process for this integration has started. Below is a diagram which maps our current Energy Partner dispatch practices and protocols.

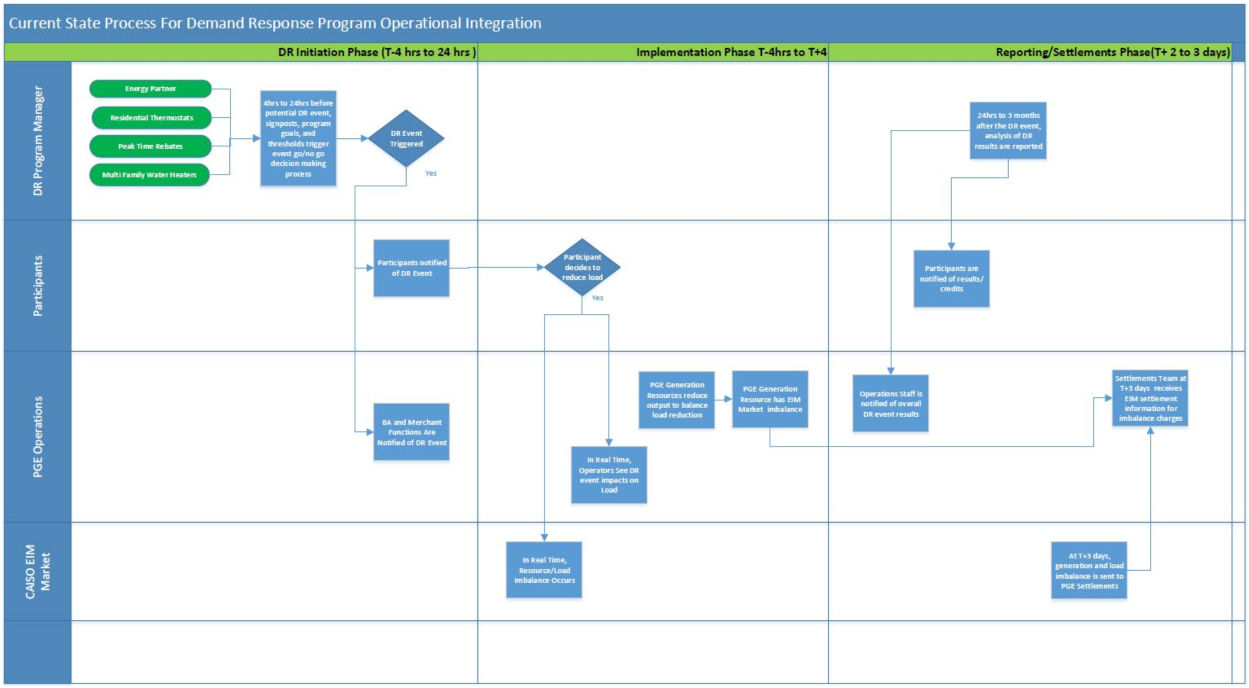

Figure 28 – Energy Partner Program Operation Integration – Current State

The most immediate takeaway from the diagram is that 1) Energy Partner is not dispatched by power operations but is dispatched by the program operations group. This practice is the result of an earlier Commission decision requiring dispatch of the program the for a certain number of times per year. This means the program is not dispatched economically but dispatched for program development purposes. While this practice serves an important purpose for both PGE and participant customers; after Energy Partner transitions to power operations this resource must be dispatch based on power operations set criteria for grid stability and economic efficiency. 2) Second the full integration of Energy Partner into power operations will require process changes to both power operations, the program operations group and Energy Partner. This would include communication to the participants about the change and how it may or may not affect them and their expectations.

PGE has been working cross functionally with the Power Operations Team and the Balance Authority Team to develop an approach to flexible load dispatch. Using the process graphic above as the current state; the following graphic was developed to show necessary process changes. These would then guide the Teams work to include flexible load as a resource within the resource stack, operated as any other resource, dispatch to meet economic and grid stability needs.

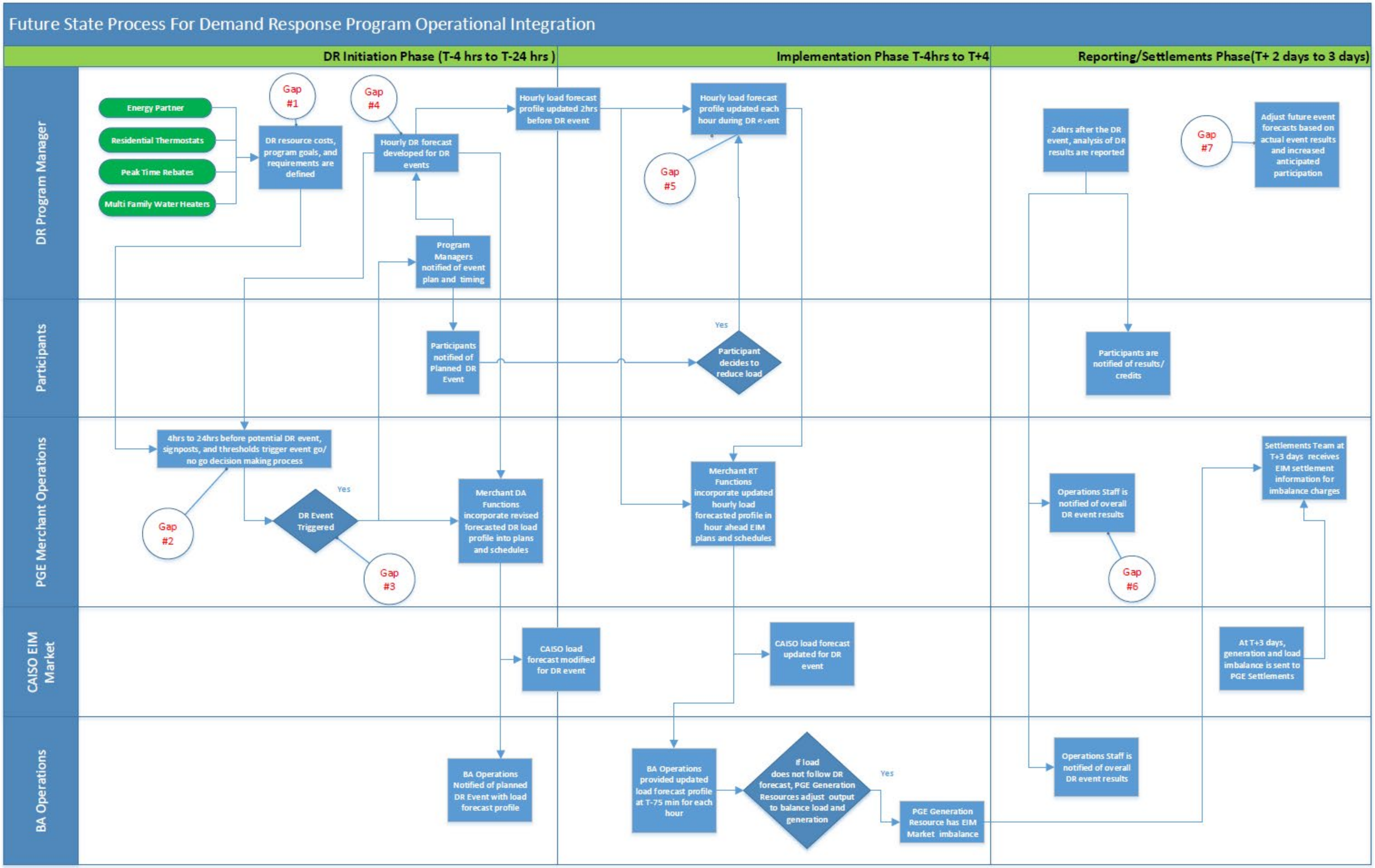

Figure 29 – Energy Partner Program Operation Integration – Future State

The above chart is meant to guide PGE's work to place flexible load into the power operation activity. The chart identifies seven gap areas and recommendations for action.

A.5.4 Demand Response Operational Integration Gaps Summary

Gap #1: DR program operations parameters need better definition, clarity and visibility.

Recommendation: DR Program Managers define overall program costs, incremental dispatch cost, must run requirements, and other program goals, and sign-posts important to the economic dispatch trigger process.

Gap #2: The DR event trigger process should be better defined for economic dispatch and the go/no go decision-making process should lie with Merchant Operations.

Recommendation: DR Program Managers and Operations Leads partner to define the economic dispatch signposts and thresholds that will be used to trigger DR event go/no go decision-making process.

Gap #3: The final decision to trigger a DR event for economic dispatch should be made by Merchant Operations using the appropriate parameters, thresholds, and sign-posts.

Recommendation: Merchant Operations partners with DR Program Managers to stand up decision-making process for economic dispatch of DR event.

Gap #4: DR load reduction hourly forecasts for each event are not part of the current process.

Recommendation: DR Program Managers work to develop process for providing hourly DR forecasts for the entire event duration of planned and future DR events.

Gap #5: DR event load reduction real time monitoring is not part of current process.

Recommendation: DR Program Managers work to develop process for gathering real time information on actual load reduction and provide updated forecast for remaining duration of the event.

Gap #6: After the DR Event Results Summary is needed to provide program managers and operations staff updated information for settlements analysis and next event planning.

Recommendation: DR Program Managers develop process for providing complete DR event results summary a minimum of 48 hours after the conclusion of the event.

Gap #7: Past event results and changing customer participation should be used to modify DR Program parameters and forecasts to enhance the future DR event trigger process.

Recommendation: DR Program Managers to develop process for updating key DR parameters for future program enhancement.

A.5.5 Market Potential

Energy Partner is a two-tariff program operating under both Schedule 25 and 26.

The chart below is from the 2016 ‘Demand Response Market Research: Portland General Electric 2016 to 2035’ report prepared by the Brattle Group. The chart shows the potential MW reduction for various DR program designs in PGE's service territory. The load reduction potential of each program design was evaluated in isolation from each of the other options; they do not account for potential overlap in participation that may occur if several DR options were simultaneously offered. What also should be noted is that the potential MW reduction estimates include all customers in PGE's service territory and do not account for direct access customers who currently are not eligible to participate in PGE's demand response programs. This will have a significant impact on the market size for programs targeting the large C&I customers. In addition, the chart has been updated from the original report to show the current level of enrollments for the Schedule 26 (20.7 MW) and Schedule 25 (0.2 MW).

For Schedule 26, the program design on the chart that most closely correlates to the current Energy Partner program is the ‘Large C&I Curtailable Tariff, Opt-In’ (second from left) which is estimated to grow to 70 MW. Derating that number by 50% to account for non-qualified direct access customers would indicate a market size of approximately 35 MW.

For Schedule 25, the 'Medium C&I' program designs on the chart do not correlate with the current Schedule 25 program design, which makes it difficult to estimate market size. However, the number of small and medium business in PGE service territory is a known quantity, approximately 95,000, assuming we enroll half those customers and applying a conservative KW impact of .3 KW for each one, the potential market size would be around 15 MW.

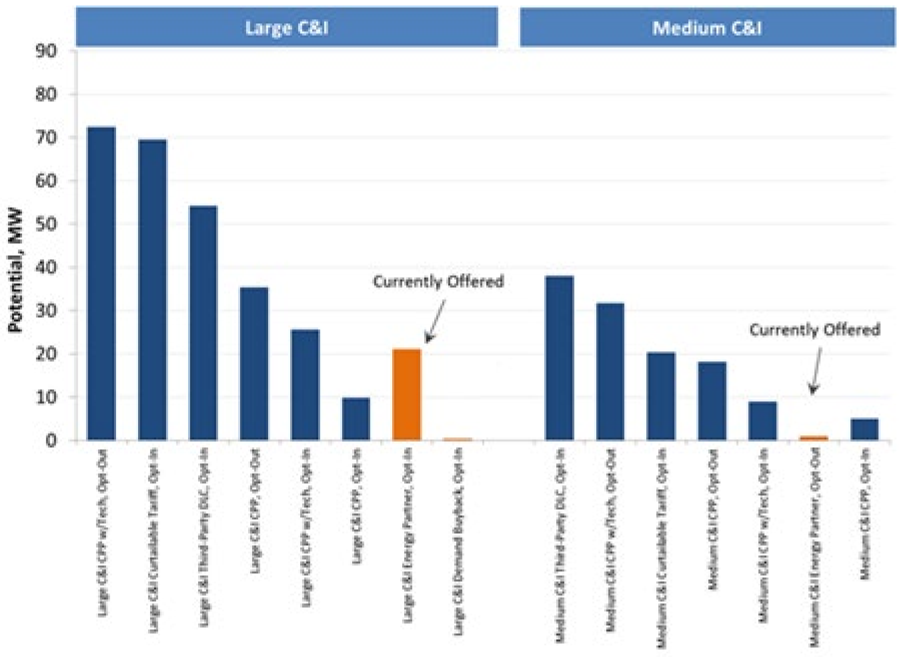

Figure 30 – Potential MW Reduction for Various DR Program Designs

A.5.6 Lessons Learned

A.5.6.1 Pilot Performance can be affected by one customer

In summer 2016 customer nominations ranged from 50 KW to 1.1 MW and the six customers with the highest nominated load reductions accounted for 48% of the total. Enrollment and nomination changes from these larger customers have a greater impact on the total nominated load than an average per participant number suggests. For example, one of the customers that we lost due to direct access was a national retailer with ten stores in our service territory. When that one customer transitioned to direct access at the end of 2016, we lost all ten stores, 1.1 MW of nominated load or about 12% of total load at that time. Adjustments and unenrollment's to a single nomination from a large customer will cause much greater impacts to the total nominated load than an average load per customer would suggest.

A.5.6.2 Program Stability should not be in the control of contractors

The previous program implementer, EnerNOC, opted to leave the program at the end of the summer 2017 season". Updated information on the subject was included in the 2019 report; "EnerNOC, Inc. and PGE ended the aggregator contract in September 2017" and "PGE contracted with CLEAResult Consulting Inc. to coordinate the customer enrollment and enablement process and with Enbala Power Networks, Inc. to provide the demand response management system (DRMS)". It's was a mutually agreed transition because EnerNoc acted as an aggregator focused only on load and could not deliver the required realization rates. Under the new format, PGE modified the tariff (Schedule 26) to provide more options to customers and assure delivery of both load and realization.

During the winter 2017 season a significant load reduction was caused by the transitioning of the program away from EnerNoc to new implementors, CLEAResult and Enbala. On September 30, 2017, the end of the summer season, every participant was automatically unenrolled from Energy Partner and then PGE, along with the CLEAResult, reached out to each customer to re-enroll them in the program. At the end of 2017 PGE had re-enrolled 3 MW. By the summer season 2018 PGE had enrolled 12.5 MW back into the program. At no time under the EnerNoc contract did this program see such rapid growth

A.5.6.3 Tracking Enrollments based on nominated MWs per customer is a poor metric

Although tracking the pilot using a MW per participant metric is a reasonable way to identify early trends and inflection points (i.e. the program transition it doesn't effectively capture details that have impacts to enrollments and total load. Moving forward this metric will become even less effective because of the way enrollments are targeted. The initial focus of the program was to target and enroll customers with the largest loads to get the biggest initial impact, once those large opportunities are exhausted customers with smaller loads will be targeted. As enrollments for smaller customers increase the MW per participant metric will decrease and may lead to an assumption that there is a problem with the program when it's just a reflection of the way nominated loads are distributed among customers.

A.5.6.4 Moving from Pilot to Program

As noted above efforts are underway internally to transition Energy Partner to power operations and PGE has identified the factors indicative of a pilot to program transition. Discussion of the additional factors can be found below.

A.5.6.5 Customer Experience

The customers enrolled in Energy Partner are larger sophisticated energy consumers. Many have been part of the program for the last several years. These customers have responded to events and have demonstrated very stable performance and understanding of how to respond to events and signals. As Energy Partner is transitioned there will be a need to communicate any program changes to these customers.

A.5.6.6 Infrastructure Stability

The Energy Partner program has a well-known and operating supporting infrastructure which includes a third-party Demand Response Management System. Additionally, through the PGE portal Energy Partner participants can view their performance in near real-time. Dispatch call protocols are well practiced with customers. Our contractor CLEAResult has worked with each customer to perform performance audits.

A.5.6.7 Grid Performance

Since program revisions in 2017 Energy Partner has demonstrated load drop stability. Performance of the resource has remained within the 15-20% of nominated capacity.

Financial Performance

The resource is cost effective as presently constructed and operated.

Table 17 – Cost Effectiveness: Non-Residential Demand Response Energy Partner Program

	TRC		PAT		RIM		PCT	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Administrative costs	$8.21		$8.21		$8.21			
Avoided costs of supplying electricity		$17.79		$17.79		$17.79		
Bill reductions								$0.22
Capital costs to the utility	$0.00		$0.00		$0.00			
Environmental benefits		$0.01						
Incentives paid			$12.55		$12.55			$12.55
Revenue loss from reduced sales					$0.22			
Transaction costs to participant	$0.00						$0.00	
Value of service lost	$6.28						$6.28	
Sum of costs and benefits	$14.48	$17.81	$20.76	$17.79	$20.98	$17.79	$6.28	$12.77
Benefit Cost Ratio		1.23		0.86		0.85		2.04

Dispatch Integration

As noted in the above sections PGE is actively working internally to incorporate Energy Partner directly into power operation such that the resource can be economically dispatched.

A.6 Flex 2.0 - Peak Time Rebate & Time of Use

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$3.9M (2020)	6.9MW	0.84	Estimated March 2022

A.6.1 Pilot Description

In 2016, PGE launched a two-year Residential Pricing Pilot (Flex 1.0) in which a combination of 12 opt-in and opt-out TOU, PTR, and Behavioral DR scenarios were tested. Flex provides energy optimization by shifting use out of high demand periods and provides peak reduction through a modification of the demand forecast. In all, approximately 14,000 customers were enrolled in control or treatment groups and provided valuable insights into customer response to, and expectations of, programs of this nature. In June 2018, Cadmus completed an independent evaluation of the Flex 1.0 pilot and confirmed that PGE can cost-effectively obtain demand savings through pricing and behavior-based DR programs and offered specific recommendations on those scenarios that delivered the highest value and levels of customer satisfaction.

Based on those findings, PGE worked with OPUC staff and stakeholders to develop the Flex 2.0 "Residential Pricing Program" that we believe will achieve high customer satisfaction and support PGE's DR goals. The goals for Flex 2.0 are as follows:

- Design and deploy a large-scale DR program that equitably and cost-effectively contributes a substantial DR amount to our IRP goals.
- Offer easy-to-engage-in DR offerings that serve as gateways for adoption of other DLC offerings such as Smart Thermostat.

The first step of Flex 2.0 was launch of a PTR pilot in April 2019. The vast majority of PGE's residential customer base is eligible to participate in this voluntary pilot, and 77,000 residential customers have chosen to enroll in the past year (opt-in basis) exceeding our Year 1 enrollment goal by 40 percent. The PTR pilot provides educational energy saving tips and rewards customers for shifting their energy use during 3-4 hour "event" periods when energy costs are higher and renewable energy sources are less plentiful. Customers are notified a day prior to the event via text and/or e-mail, based on their preference, and encouraged to shift usage during the event hours the next day. After the event, they are notified of the result of their specific effort and, if applicable, their earned incentive. Customers earn $1.00 for every kWh they shift during an event, and the rebate appears as a credit on their next monthly bill. There is no "penalty" should a customer use more than expected energy during an event, making PTR a no-risk, "win-only" offering for our customers. The pilot uses to third party service providers: Oracle delivers the pre- and post-event information to customers and Trove Analytics calculates aggregate and per customer load shift for each PTR event.

PGE is working with OPUC Staff on design of a new TOU rate and plans to submit a revised Schedule 7 tariff to include the new pricing structure in Q2/Q3 2020. The TOU pricing plan could be combined with the PTR to enhance year-round savings and provide daily load shift value to PGE.

A.6.2 PTR is Foundation of PGE's Smart Grid Test Bed

In July 2019, approximately 13,400 customers within the Test Bed were automatically enrolled (opt-out) in PTR as part of Schedule 13. The primary reasoning for this approach was to allow PGE to study customer engagement and participation by testing several customer value propositions. This work is overseen by the Demand Response Review Committee established by the Commission in Order 17-386. Additionally, the Test Bed provides an opportunity for PGE to learn if PTR incentives serve as a "gateway" to other DLC options by fostering behavioral changes that encourage adoption of additional DR offerings.

If an opt-out strategy proves successful within the Test Bed, PGE may explore an opt-out PTR offering with targeted customers or geographic areas. Large-scale participation in programs of this nature provides the opportunity for significant DR load shift, an alternative to additional fossil fuel-based energy plants, as well as supporting PGE's DR goals.

A.6.3 PTR as Part of PGE Decarbonization Strategy

PTR, though a behavior-based load shifting strategy, is part of PGE's decarbonization strategy as it allows us to communicate with customers about when the costliest time to use electricity occurs. These times generally correlate with high carbon content resource procurement or dispatch. Within the Test Bed, PGE is testing Customer Value Propositions in which customers are informed of the carbon resource dispatch deferral they affected through their action. This is communicated as carbon abatement resulting from the aggregate action of Test Bed participants.

A.6.4 Enrollment Goals

Flex 2.0, including enrollment across PTR and TOU treatments in the Flex 1.0 pilot ranged from 3% to 6% despite restricted marketing efforts given the nature of the pilot. In setting enrollment targets for Flex 2.0, PGE assumed increased marketing outreach while still using a conservative adoption rate of 7% year 1 (2019), with 9% growth in year 2 (2020), 4% growth in year 3 (2021) and a more modest 3% growth year-over-year thereafter. Other utilities, such as Sacramento Municipal Utility District, achieved enrollment targets as high as 16% for its TOU program. Enrollment goals are also designed to support our IRP goals for residential DR with more aggressive marketing occurring in the first two years of the program to support that DR goal.

During the first year of broad-scale pilot operations (2019), PGE worked with TROVE Predictive Data Science to analyze *customer-level* earning potential and created Demand Response-specific customer profiles or personas based on that data. While the Flex 1.0 evaluation looked at load shift and DR value at the *aggregate,* averaging performance across the enrolled population, we now have greater insights into *customer-level* load shift and savings potential. We discovered that customers cluster into five unique "savings" groups based on household construct and behavioral factors. We also learned that customers in the highest saving persona classification have potential to shift approximately three times the kWh per event as does customers categorized as a lower saving persona. These lower-saving customers, who were recruited via our Call Center, are over-represented in our current enrollment mix while higher-saving customers are underrepresented, and all customer segments are currently under performing based on their savings potential.

This concept of potential is incredibly important as it points to opportunities where customers *could* earn higher rebates if they had better savings tips and remembered about the event on the event day – both of which PGE can help influence. Given what is now known about these personas, we can tailor more personalized, relevant tips to help customers in each of these segments maximize their potential savings. Additionally, while Flex 2.0 is all-inclusive open to all (unlike Flex 1.0 that enrolled only those customers who would be known savers), we are targeting more high-saving customers through targeted recruitment channels to join to increase overall DR value and improve our cost effectiveness. We believe controlled growth and helping all customers achieve their savings potential will improve customer satisfaction, DR value, and cost effectiveness. PGE has submitted a tariff update to OPUC requesting an enrollment cap extension to 160,000 customers to help support that goal.

PGE had expected to launch the new TOU rate shortly after the PTR in 2019. Feedback from the OPUC and continued collaboration on the rate design has delayed that introduction. Enrollment targets for TOU will be reassessed once the proposed rate design has been approved by the OPUC and market introduction date can be reset.

After initial DR education and awareness, PGE will communicate information about TOU+PTR and encourage customers to stay on PTR or move to a DLC offerings, specifically our Smart Thermostat offering. DLC programs capture larger DR loads and are automated, which presents fewer hurdles to event participation, a more streamlined customer experience, and have energy efficiency benefits. Therefore, transitioning customers to DLC will be key to prove the resource capability of DR. DR initiatives such as PTR, TOU and BDR - with relatively low barriers to entry for customers - can serve as a launching point for drawing residential customers into deeper DR engagement over time.

A.6.5 Market Potential

PGE has identified the achievable potential for PTR and is working to meet the enrollment and saving targets found in the following table.

Table 18 – PTR Market Potential

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
TOU + PTR	19,000	43,000	57,000	66,000	75,000	80,000	84,000	88,000	93,000	97,000
PTR	36,000	87,000	111,000	125,000	139,000	146,000	152,000	159,000	166,000	172,000
Total	55,000	130,000	168,000	191,000	214,000	226,000	236,000	247,000	259,000	269,000
AAGR		136%	29%	14%	12%	6%	4%	5%	5%	4%
% of Res Acounts	7%	16%	20%	23%	26%	27%	28%	29%	30%	31%
MW Impact	16.3	38.8	50.3	57.4	64.3	67.7	71.0	74.3	77.6	80.9

In 2019 PGE was unable to launch the TOU + PTR option found in the table above as filed in ADV. 19-03. The megawatt, although current enrollment in PTR is closer to 90,000 the capacity demonstrated is closer to 14MW. PGE is actively working to launch the TOU and TOU + PTR option in 2020. We have kept Commission Staff updated as to challenges identified since launch and how we are addressing those challenges.

A.6.6 Lessons Learned

To date, Flex 2.0 is not demonstrating the expected load shift reduction/savings per customer as seen in the Flex 1.0 pilot. For the summer 2019 season, PTR events achieved average demand savings per participant between 0.05 kW (5%) and 0.14 kW (8%) for non-Test Bed participants, and 0.02 kW (2%) and 0.08 kW (4%) for TB participants over the season. Overall, load shift is about 60% less than expected based on Flex 1.0 performance results. In analyzing the information received through the summer 2019 and winter 2019/2020 events, PGE has determined several factors contributed to the lower performance results and has already implemented several changes in preparation for the summer 2020 season. Here we describe our findings as well as the improvements we have or will be implementing for summer 2020.

A.6.6.1 Customer Event Notifications

Survey and participation data from summer 2019 indicated that the lack of two specific features offered in Flex 1.0 but not in Flex 2.0 contributed to that decline: enrolling multiple household members for event notifications and same-day event reminders. An end-of-season summer 2019 survey found 25% of customers forget about the event on the event day without a reminder. While PGE is still working to identify a technology solution for enrolling multiple customers in the same household and for dispatching same-day text messages, we do plan to introduce same-day email notifications in summer 2020 and expect this will increase participation and overall load shift.

A.6.6.2 Customer Experience

Cadmus conducted an end of season experience survey following the inaugural 2019 PTR summer season that indicated customers have high satisfaction: 76% of customers who responded (n=953) said they were satisfied, while 34% said they were delighted with PTR. However, when asked more detailed questions about their experience, some customers indicated confusion over how their rebates were calculated and confusion as they perceived that like actions did not yield like results between events. In partnership with our analytics vendor, Trove, PGE reset the baseline approach for winter 2019/2020 to provide a more explainable methodology and create better customer consistency. Customers will feel more encouraged to continue participating in events when they are repeatedly rewarded for their efforts, event to event.

In our surveys, customers also cited that more education and recommendations about how they could shift their load would be beneficial. Some customers reported taking “low impact” actions such as turning off lights or unplugging cell phones as their primary load shift strategies. PGE conducted virtual focus groups in April to gain additional insights about how customers may be able to benefit from more information. As a result, PGE has created new collateral to better explain what specific actions to take during a Flex event. This collateral provides savings tips for both low-impact and high-impact customers and delivers the information in a way that allows the customer to select the tips that apply to their specific household. This approach will enable customers to adjust their energy use based on the options they have within their household and help them achieve their maximum savings potential.

A.6.6.3 Customer recruitment

As mentioned above in the enrollment section, we have learned that our recruitment strategy needs to be tailored to attract customers with the highest propensity for successful participation. While Flex 2.0 will remain open to all customers, PGE is tailoring its marketing approach to focus on customers with the highest propensity to save energy through making event based behavioral changes.

A.6.6.4 Vendor performance

One additional area that affected event performance were errors in issuing event notices by our vendor, Oracle early in the summer 2019 season. Oracle has assured PGE that they have put the proper measures in place to avoid such errors going forward and provide event by event metrics.

A.6.6.5 *Investigate other rebate models*

PGE is exploring new customer value propositions within the Smart Grid Test Bed that reward customers for behavioral change in different ways such as ability to donate rebates to a charitable organization and through gamification and contests to see if these additional approaches yield more DR savings and better customer satisfaction

We will be monitoring the impact of the above actions by analyzing per-customer DR value closely in the coming seasons and are focusing our efforts on continuous improvement to help each customer reach their savings potential.

A.6.7 Managing costs and cost effectiveness

The table below shows the present state of Cost Effectiveness for PTR and the pilot is currently falling short of our cost effectiveness goals driven mainly by the lower DR value per participant from Flex 2.0 as compared to Flex 1.0. The Flex 2.0 PTR pilot, having only one season at scale with multiple events, is still in development. We have used the information and results achieved to implement multiple measures that should improve pilot performance starting summer 2020, as described in the “Lesson Learned” section and also summarized here:

1) Improved event notifications (adding same day)
2) Increased baseline “explainability” and event to event consistency
3) Updated customer collateral, customized for the audience
4) Revamped customer recruitment strategy
5) Managing vendors for increased performance
6) Testing additional motivational strategies in the PGE Test Bed

In addition to the measures implemented to benefit DR value, PGE is also continuing to manage costs. As noted in PGE’s original proposal in ADV 19-03 PGE has employed TROVE and Oracle to deliver 3rd party services for PTR. On an ongoing basis, PGE evaluates those vendor contracts and looks for opportunities to identify cost-saving measures.

Table 19 – Cost Effectiveness: Peak Time Rebate

	TRC		PAT		RIM		PCT	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Administrative costs	$10.68		$10.68		$12.92			
Avoided costs of supplying electricity		$13.48		$13.48		$13.48		
Bill reductions								
Capital costs to the utility	$2.66		$2.66		$2.66			
Environmental benefits		$0.00						
Incentives paid			$10.77		$10.77			$10.77
Revenue loss from reduced sales								
Transaction costs to participant	$0.00						$0.00	
Value of service lost	$2.69						$2.69	
Sum of costs and benefits	$16.03	$13.48	$24.11	$13.48	$24.11	$13.48	$2.69	$10.77
Benefit Cost Ratio	0.84		0.56		0.56		4.00	

A.6.8 Evaluation

PGE has contracted with Cadmus to provide seasonal evaluations during the first two year of both PTR and TOU. As those evaluations are finalized, a copy of the reports will be filed with the Commission and PGE staff, and Commission Staff will meet to share results and open discussion regarding the findings and potential next steps.

A.6.9 Moving from Pilot to Program

PTR is our newest system-wide customer offer. It is also our first behavior-based DR resource. At present, as stated in the above Lesson Learned subsection, PGE is working to address several challenges associated with the market release of a large behavioral-based offer. The factors associated with pilot to program migration center on: Customer Experience, Infrastructure Stability, Grid Performance, Financial Performance, and Dispatch Integration. Our Residential Team is actively working to address the main challenges such as communication to the customer to enhance event performance and baseline performance and accuracy.

A.6.9.1 Infrastructure Stability

The Team has been able to address a sub-factor of Infrastructure Stability as the billing and data management are well understood and are presently operating well. PGE is exploring how it might reduce costs here by internalizing some of the data management activity which is currently outsourced.

A.6.9.2 Grid Performance and Dispatch Integration

PTR has a 2019 savings goal of 16MW, per the proposal in ADV 19-03. Despite delay in releasing a TOU+PTR offering, baseline accuracy and day-of notification challenges, PTR did acquire 14.1MW by 2019 year end. PTR is PGE's only behavior-based resource. As has been noted in many of PGE's DR and Smart Grid Test Bed filings, behavior-based resources are not the preferred DER resource structure or characteristic power operations prefers. Behavior-based programs are excellent customer inclusive offerings. However, they do not offer power operators the control and certainty power operators prefer. Thus, integration into power operation dispatch will present novel challenges. PTR has several structural challenges which need to be addressed prior to contemplating integration into power operations, but it is PGE intention to integrate each of our Flexible Load offerings.

A.6.9.3 Financial Performance

Peak Time Rebate is a cost-effective resource. We'll need to be careful to assure that changes made to meet challenges faced in the field or offer structure do not jeopardize cost effectiveness.

A.6.10 Pathway to Flexible Load

PTR is a demand response pilot used to address peak usage hours. At present, there is not a known pathway to increase the number of usage hours or to transition the grid service provided, capacity, to a more dynamic energy service. The Test Bed is exploring ways that PTR can be the launch pad of a customer migration strategy to more dynamic flexible load offerings such as thermostats, behind the meter energy storage, and advanced smart water heaters. The Test Bed activity is being evaluated on a rolling basis the lessons learned and the evaluations are shared with the Test Bed's Demand Response Review Committee. If the approach of using PTR as part of customer migration strategy proves valid within the Test Bed, PGE will work to incorporate such into the broad portfolio strategy.

A.6.11 Activity within the Test Bed

PTR operates on an opt-out or automatic enrollment pilot within the geographic boundaries of the Testbed. All residential customers who qualify (do not have a do not communicate requirement on their account or have communicating meter) are enrolled in Peak Time Rebate. Of the roughly 19,000 residential accounts in the Test Bed roughly 15,500 are eligible to participate in PTR.

The Test Bed, across its three substations and cities, has 15,542 residential customers enrolled in PTR. PGE has been working to learn more about who these customers are and how they are motivated to take action during events. Directly connected to PTR in the Test Bed is the Test Bed Team's work to test several customer value propositions to garner insights into customer engagement and performance. For those roughly 15,500 customers enrolled, they will be exposed to four customer value proposition treatments; monetary incentives, carbon reduction, renewable power, and giving back. If any of these value propositions prove effective PGE will use them throughout the service territory first through Flex 2.0. Test Bed is also using PTR because the offer is inclusive as the customer need not purchase any enabling technology to participate. Additionally, PTR does not harm those who are unable to take action or actually use more than expected during an event.

A.7 Residential Battery Energy Storage Pilot

Total Costs	Megawatts Procured	Cost Effectiveness Score	Next Evaluation
$66K (EOY 2020)	160kW	N/A	Est. June 2021

A.7.1 Program description

In April 2020 PGE filed a tariff to leverage battery energy storage systems installed on residential customer homes behind the utility electric meter as a dispatchable resource. PGE is utilizing the pilot to test the capability of residential battery storage to provide a variety of grid and customer services.

As a fleet, the batteries will act in aggregate to provide system services and individually for customer services. PGE has modeled the value of some services; for others, the pilot will seek to establish a value. Each battery will provide between 3 to 6 kW of power output and 12 to 16 kWh of energy storage. The pilot intends to aggregate 525 residential batteries totaling 2 to 4 MW in size and 6 to 8 MWh in duration.

PGE will have full control over battery operations and will charge and dispatch the fleet according to system needs, except in the event of an outage when the batteries will autonomously island to provide home energy back-up. PGE will deploy batteries for the following use cases:

- Distribution use cases:
    - Localized demand response
    - Autonomous Volt/Var support
- Generation use cases:
    - Generation capacity
    - Energy resource optimization
    - Contingency reserves
    - Autonomous frequency response
- Customer use case:
    - Outage mitigation

PGE has selected EPRI's open-source Storage Value Estimation Tool (StorageVET®) software for evaluation and will share modeling results and data. The software co-optimizes bulk system and locational benefits based on provided inputs. This modeling will inform PGE's operation of the batteries.

A customer who applies to participate with a qualified battery and who is accepted into the Pilot will be compensated $40 per month, or $20 if the battery is restricted to rooftop photovoltaic charging only, in exchange for allowing PGE to operate the battery for grid services. All batteries will be owned by the customer. PGE will make the pilot offer available to Community Emergency Response Team ("CERT")/Neighborhood Emergency Team ("NET") volunteers. These trained volunteers have committed to assisting their community in the event of a major disaster.

Customers living within the Test Bed, as defined in PGE rate Schedule 13, with a newly installed qualified battery are also eligible to receive a rebate at time of purchase, in addition to the monthly payments. This offer seeks to drive density within select substations to achieve sufficient technology penetration to test locational benefits.

PGE is also partnering with the Energy Trust to address potential barriers to residential storage for income-constrained customers. Income-qualified customers participating in the Energy Trust's Solar Within Reach program and who install a qualified battery, are eligible for a $5,000 rebate in addition to the monthly payments. These customers may reside anywhere within PGE's service territory.

A.7.2 Residential Energy Storage as Part of PGE Decarbonization Strategy

Battery storage is a potential gamechanger for deep decarbonization of the electric gird. They are capable of providing all the grid services necessary to balance high renewable penetration. Additionally batteries imbedded in the distribution system are able to provide location specific services.

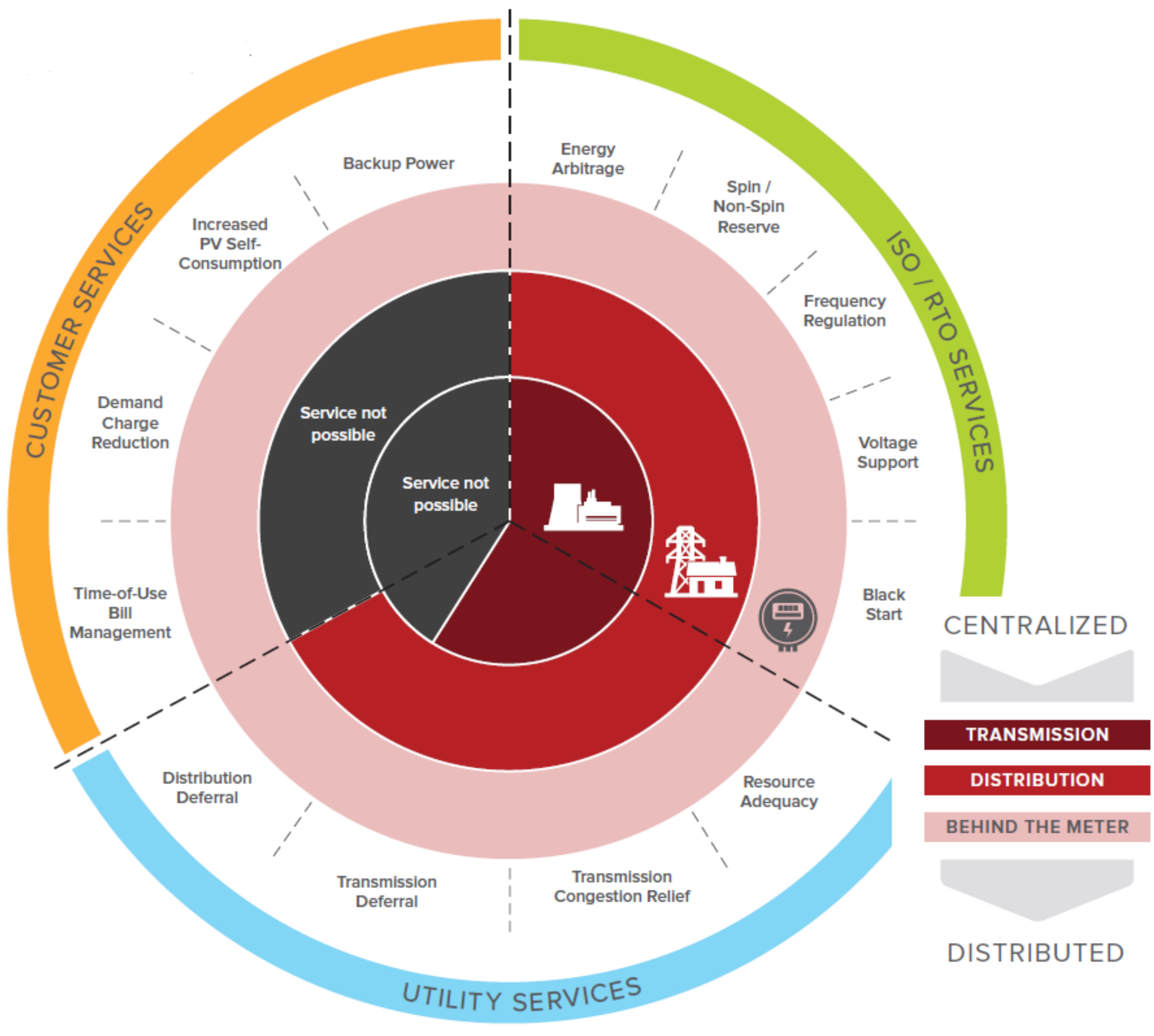

Figure 31 – Energy Storage Services

A.7.3 *Goals*

The key objective of the Residential Battery Storage Pilot is to collect as much information as possible about the impact of residential battery storage in four categories: The Energy Portfolio, the Grid, the Customer, and the Program. These learnings are explored in further detail in the section: Lessons to be Learned.

A.7.4 *Market potential*

PGE's goal is to enroll 525 units for the Pilot in order to have sufficient storage capacity to provide 1 MW for a 4-hour period to act as a Virtual Power Plant. This will include a target of 200 units within the test bed substations, 25 income qualified installations, and 300 units anywhere in the service territory.

Using assumptions from a Tesla Powerwall 2, it would take approximately 570 operational units to meet the minimum desired capacity of 1 MW on the darkest day of the year.[134] However, at the proposed level of 525 units PGE will be able to meet the desired 1 MW of capacity for four hours 80 percent of the year using the same assumptions as above and with historically average weather. The eventual proportion of devices restricted to solar charging (due to receipt of the Federal Solar Investment Tax Credit, or “ITC”) will impact the required number of units, as batteries that can grid charge average over double the discharge capacity during Portland’s rainy months.

To ensure PGE can test locational value, a concentration of devices will be required to test impacts on the distribution system. For this reason, additional incentives will be provided to customers within the three PGE Test Beds to achieve a measurable effects on a single distribution feeder. A single residential battery system fully charged may deliver 5 kW at any given point in time, which represents about 0.05% of a distribution feeder’s typical load. To have a measurable impact on a distribution feeder’s performance, concentrations that affect the power flow of at least 3%, or 0.2-0.3 MW of energy storage per distribution feeder, are necessary. Anything less than this impact is lost within the margin of error, and the opportunity to explore location-specific value diminishes. Using the same math as above, to reach 0.3 MW of capacity during the lowest production solar month on a single feeder requires a minimum of 171 batteries. PGE will pursue other methods of inducing density beyond just the Test Bed, including working with new home builders who may want to include battery storage in a subdivision.

PGE will easily stay within the stipulated capital restriction of $1.5M, as there is close to no capital projected for this Pilot, and the Company has designed the Pilot to stay well within the operations and maintenance (O&M) targets set in UM 1856.

A.7.5 Market Trends

In PGE’s service territory, there are approximately 150 residential battery installations and about 15,000 rooftop solar installations.[135] PGE’s Test Bed currently has 407 rooftop solar installations and three homes with a battery installed.[136] Achieving the targets outlined above will require more than tripling the existing battery installations in PGE’s territory within three years. Current market trends support these projections, with the most recent Wood Mackenzie Energy Storage Monitor forecasting a tripling of residential energy storage capacity nationwide from 2020 to 2024, as shown in Figure 32.[137]

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[134] Assuming 100% of usable energy capacity is used for a 4-hour discharge in aggregate, and is optimized for the average production in the lowest solar production month with solar size of 4.87 kW nameplate (the median residential solar installation on our system), then ITC-restricted batteries have 5.4 kWh of usable capacity on an average December day per PV Watts. If 80% of installed batteries are ITC-restricted, with the other 20% being able to charge from the grid (thus having 13.5 kWh of usable capacity), then we need 570 batteries to achieve 1MW discharge for 4 hours. The math goes as follows- Solve for n: (0.2 * 13.5kWh / 4h + 0.8 * 5.4kWh / 4h) * n = 1000kW

[135] PGE (2020)

[136] Id.

[137] Wood Mackenzie P&R/ESA U S energy storage monitor Q 4 2019

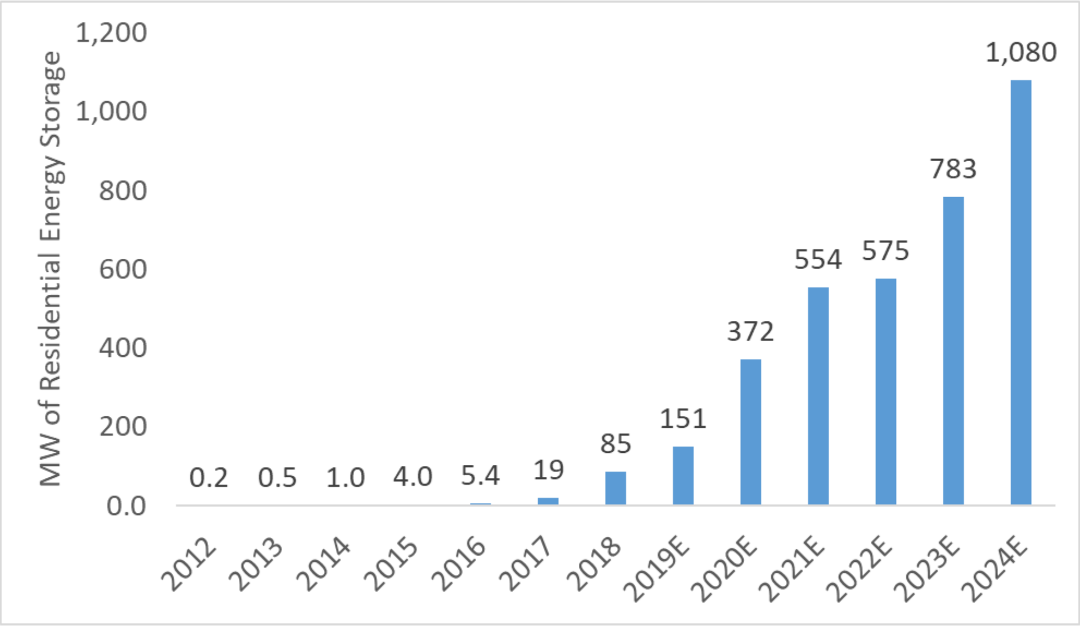

Figure 32 – U.S. Residential Energy Storage Deployment Forecast (MW)

Research by Navigant Consulting that forecasts residential energy storage adoption in PGE's service territory shows similar strong projected growth, with a base case of nearly 700 batteries in PGE's service territory by 2023 and a high case forecast of nearly 2,500 installed batteries, as shown in Figure 33.[138]

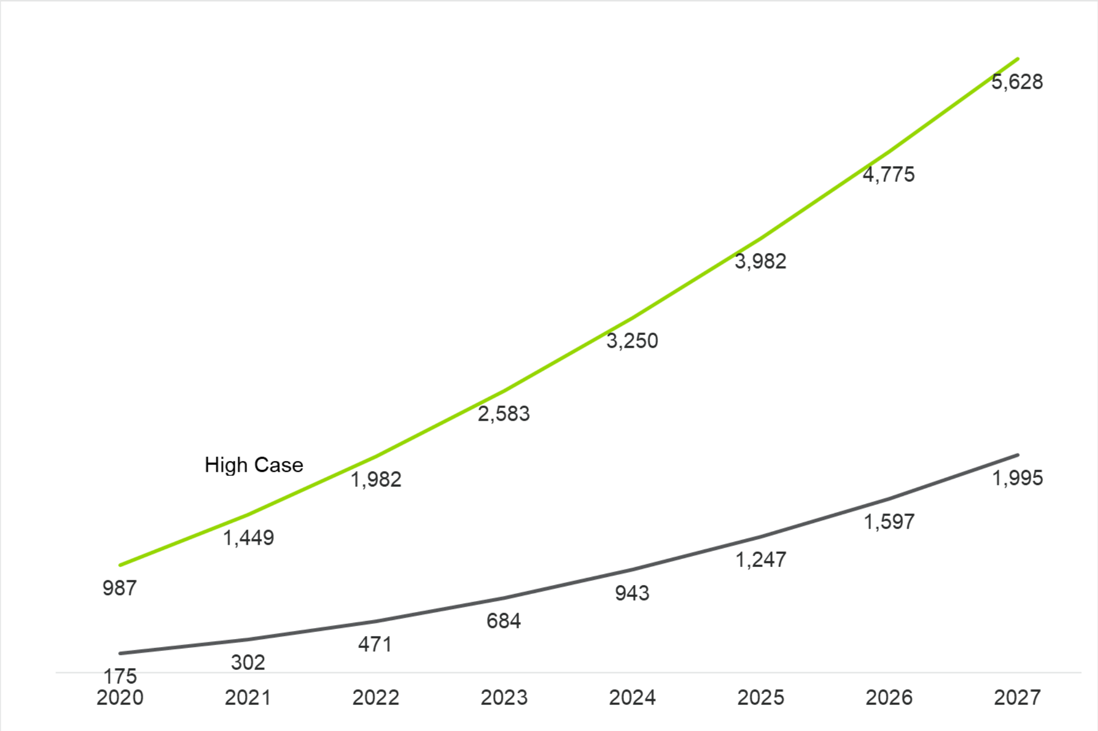

Figure 33 – Navigant Residential Storage Forecasted Installations

One of the drivers of adoption considered by Navigant was the customer's value of resiliency. This may increase due to the public safety power shutoffs in California and extreme weather events in the Northeast and Southeast.

Regarding financial drivers, the Wood Mackenzie report states:

> *In the future, factors including battery price reductions, declining hardware and controls costs, product standardization and process optimization will drive system-level price declines in the residential and non-residential BTM markets. Beyond just component-cost reductions, improvements in soft costs will also be realized as the market attains further maturity and policy changes drive improvements in permitting and interconnection processes.*

Additionally, the continued decline in lithium-ion battery pack prices will aid residential storage adoption. Since 2010, the price of lithium-ion battery packs has declined over 85% from 1,183

[138] Navigant PGE DER Forecast (2019)

$/kWh to 156 $/kWh in 2019[139]. Nationwide, the decline in lithium-ion battery prices resulted in a 500% increase in residential storage from 2017 to 2018. Battery prices are expected to drop below $100/kWh by 2024[140].

These market trends, paired with well-designed incentives and an increased awareness of resiliency among Oregonians, will allow this Pilot to meet its enrollment goals. The Company conducted a market research study in January 2020[141] with 1,432 customers completing the survey. Results showed that almost half (45%) of survey respondents are familiar with battery storage systems, with 63% interested in learning more. Twenty of the 37 customers surveyed who already have a battery system would consider allowing PGE to manage their battery charging and discharging without any mention of an incentive, while three-quarters (76%) of customers without a battery system would hypothetically consider allowing PGE to manage their battery charging and discharging without any mention of an incentive.

A.7.6 *Lessons to be Learned*

The key objective of the Residential Battery Storage Pilot is to collect as much information as possible about the impact of residential battery storage in four categories: The Energy Portfolio, the Grid, the Customer, and the Program.

A.7.6.1 The Grid

The primary goal of the pilot is to evaluate the ability of residential batteries to deliver locational value in support to PGE's electrical system. The grid value questions this pilot seeks to explore are:

- Explore the effectiveness in shaping load, and the potential for distribution upgrade deferrals
- Evaluate and refine setpoints and settings for advanced inverter capabilities to maximize locational value while maintaining local system reliability and retaining battery longevity
- Understand the effectiveness of batteries to support Volt-Var optimization
- Understand the ability of residential batteries to relieve hosting capacity constraints
- Understand the compatibility of stacked services, and the frequency of conflicting dispatch priorities between locational Grid services and Bulk Energy services

A key pilot finding will be the determination of values for each tested use case, including both generation and locational values. Modeling is useful to estimate these values, but this pilot will serve as a field test to assess the accuracy of the modeling and the actual experiences in customers' homes. Accurate valuation must also reflect the batteries' ability to integrate with the markets and dispatch entities relevant to each use case. The pilot will explore all value streams and remains open to any learnings obtained through this project. The specific use cases that PGE will be evaluating are autonomous Volt/Var support, autonomous frequency response, BAO

[139] BNEF (2019)
[140] BNEF (2019)
[141] PGE PV/Battery Survey, 2020

dispatch of contingency reserve, and bulk generation capacity deferral, however PGE will also pursue any additional use cases that arise as technically feasible over the course of the pilot.

PGE will explore the services and attendant values agreed to in Order 17-118, Appendix A[142]. Additionally, PGE will investigate the value of these distributed distribution system-sited resources to the bulk grid. Similarly, PGE will explore distribution system values from operating this fleet of batteries—including both local distribution system value and systemwide generation values.

These grid and operational learnings will be captured through quantitative analysis of the batteries' performance, evaluated internally through the EPRI StorageVet tool and externally through a third-party evaluation consultant. All batteries will be integrated into GenOnSys, which is PGE's control software package currently used for the Dispatchable Standby Generation (DSG) program. GenOnSys will provide PGE and the evaluator with access to all the relevant historical data about inverter charge/discharge times, state of charge, and current and voltage levels. Should PGE opt to not dispatch the batteries through GenOnSys for any reason, data will also be stored by the aggregation platform in the utility portal.

Actual dispatch of the battery will be subject to uncertain grid conditions and limitations in real performance. PGE will evaluate the actual dispatch for the grid benefits provided and will use the results to inform future StorageVET® evaluation and modeling. This feedback loop will refine PGE's ability to make informed, economic, and transparent decisions for future storage-related pilots and programs. The grid value learnings are intended to inform PGE's Integrated Resource Plan (IRP) so that residential battery energy storage can be properly valued, and a cost-effective scalable program may be developed.

A.7.6.2 The Energy Portfolio

The pilot has the potential to stack values relevant to PGE's bulk energy portfolio. The bulk energy value questions this pilot seeks to explore are:

- Evaluate the cumulative number of hours the aggregate residential energy storage resource is dispatched to serve Bulk Energy use cases, and total value accrued for those services
- Test base assumptions around Bulk Energy resources such as load following and primary frequency response
- Determine the accuracy of PGE's modeling inputs to the EPRI StorageVET and its suitability as a planning tool (inform IRP values for use cases)

A.7.6.3 The Customer

The pilot will allow PGE to develop operating protocols that balance the needs of the grid with those of individual customers. It will specifically identify how best to extract the greatest value for PGE's investment without jeopardizing customer participation in the pilot. PGE will evaluate

[142] OPUC UM 1751 Order 17-118 https://apps.puc.state.or.us/orders/2017ords/17-118.pdf

Customer Needs around battery energy storage through a combination of qualitative and quantitative analysis. Topics PGE seeks to explore include:

- Acceptance of PGE control of the battery
- Preference for up-front rebate or ongoing compensation
- Hurdles to battery adoption
- Target market most likely to purchase battery storage
- Messaging that customers relate to for value proposition of utility control
- Identification of gaps between battery performance and customer expectation (especially when it comes to longer-duration outages)
- Balancing use of the battery for grid services with customer reserve in the event of an outage
- Device communication performance, uptime, hurdles
- Frequency of opting-out of dispatch
- Average battery state of charge and availability to provide customer backup
- Average number of cycles per year, and effect on battery degradation
- Customer economics of battery usage, potential of TOU optimization

PGE will do this through:

- Baselining customer surveys of awareness, interest, and consideration testing prior to pilot launch
- A/B testing of messaging and outreach
- Ongoing customer surveys of those who enroll in the pilot on their experiences and satisfaction
- Surveys of those who do not enroll in the pilot (identified as those who install solar panels through the Energy Trust program but do not purchase a battery) to better understand their barriers, and
- Interviews and/or surveys with installers to understand what questions customers are asking, barriers to installation, and ideas they might have for increased adoption.

The pilot will test the willingness of customers to allow PGE to operate their battery in exchange for payment, and whether PGE’s proposed payment is sufficient to encourage pilot participation. A key pilot learning will be whether the monthly payment and up-front rebate amounts are appropriate. PGE is employing a tiered, up-front rebate that will start higher and reduce as customers are enrolled—allowing PGE to test the efficacy of various incentive levels on customer uptake. If the pilot struggles to enroll customers, a second phase of the pilot may involve re-working the offers. Conversely, if the pilot reaches capacity faster than anticipated and has a robust waitlist of interested customers, PGE may consider reducing the incentives in any future pilot expansion.

PGE will work to ensure that the financial design is a favorable alternative to bill management. To that end, PGE will evaluate time of use (TOU) rate optimization and general customer economics throughout the pilot. While a battery controlled by the customer and programmed for TOU rates can effectively shift energy load from one time period to another and provide customer bill management, the full spectrum of use cases diminishes without utility operation of the battery.

A.7.6.4 The Program

In addition to learning about customer needs and grid value of battery storage, PGE will utilize the pilot to inform a future recommendation on scalable future program design and the most appropriate business model for PGE in the residential battery storage market. This includes understanding efficiencies that can be achieved through program design, unanticipated costs and hurdles of battery storage implementation, the best practices for aggregated control & dispatch, balancing cost with operations, understanding the full value streams available from batteries so a cost-effective program can be developed, and the ability to strategically select locations for storage to create a program that best utilizes distribution upgrade deferral. Specific questions PGE seeks to address to inform future program design include:

- Study reliability and efficacy of various communications protocols, LTE cellular data vs. Wi-Fi
- Understand cost versus benefits of communications methods
- What is the best way to manage integrations of multiple APIs?
- Determine actual financial impacts on customer bills, appropriate way to utilize non-utility measurement and metering devices
- Quantify actual Round-Trip Efficiency (RTE) losses of interconnected batteries- vendors report efficiencies under “ideal conditions,” how do customer homes compare to ideal conditions, what is the range of field efficiencies that are observed
- Quantify what increased value is available due to direct control/dispatch from the utility versus passive measures to incent customer behaviors (e.g., TOU)
- Set effective incentive levels to develop a cost-effective scalable program
- Tolerable use cases and battery usage for customer acceptance

While the default option for battery storage communications will be customer-hosted internet (Wi-Fi or ethernet), some (though not all) of the batteries on the qualified products list (QPL) have LTE capability that can be activated. PGE will track the effectiveness and availability of customer hosted internet and has selected an aggregation platform with multi-modal messaging to customers whose batteries go offline to remind them to reconnect their device to the internet if they wish to remain in PGE’s pilot. PGE may opt to offer LTE cellular communications to income qualified participants and other customers who are deemed to have insufficient internet coverage and will evaluate the costs versus benefits of utilizing customer internet versus PGE hosted LTE cellular data.

A.7.6.4.1 Development of Integration Best Practices

A key research objective is the development of best practices for integrating distributed resources into existing asset control systems, and to measure the acceptance of battery storage systems as a tool for renewable power integration. In PGE's Proposal and in the Stipulation approved in Commission Order No. 18-290, PGE committed to aggregate and dispatch residential energy storage as a fleet. Aggregated dispatch will allow PGE to evaluate battery impact on generation services and transmission & distribution (T&D) services,[143] while also allowing the resources to be used by PGE Power Operations for generation capacity, energy resource optimization, and contingency reserves.

A.7.6.5 Generation Services

The intent of dispatching the residential energy storage devices as a fleet is to evaluate each of the potential use cases which include bulk energy and ancillary services. PGE intends to also collect learnings for localized T&D grid services, which can respond to localized controls/settings or a coordinated dispatch at the feeder/substation level. These values can be co-optimized to enhance the total potential value represented by a residential energy storage device, but only to the degree that the resource is of sufficient size to participate in delivering Bulk Energy and Ancillary Services or Distribution Capacity Deferral (PGE Power Operations dispatches in 1 MW increments). If aggregated and dispatched as a Virtual Power Plant of 1 MW or larger, PGE will gain learnings in co-optimizing the Bulk Energy and Ancillary Services along with the localized T&D services.

A.7.6.6 T&D Services

In aggregate, fleet operation should be significant enough for grid operations to see the effects of the resource as it moves from the grid edge to distribution operations to the bulk system. Once PGE understands how best to design a controls hierarchy which co-optimizes the aggregate resource while retaining appropriate localized value for individual units, the Company will be better positioned to further incorporate residential programs into T&D planning. This represents a major learning for PGE which can also inform our efforts to value and effectively integrate other distributed energy resources (DERs) into T&D grid planning and operations.

PGE will test location-specific functions like the ability to manage distribution feeder voltage, or the ability to reliably influence distribution power flow. In understanding how reliably these devices can deliver these services, and how much impact they are able to have on the distribution system, it will help calculate what theoretical locational value may exist. PGE may then establish settings for the devices to operate based on location-specific needs while also co-optimizing grid services around them and learn to what degree those services conflict with each other or are compatible with each other. Finally, PGE will compare performance for direct-control over the storage assets versus what we anticipate performance to look like for passive-control (e.g., Time of Use) to determine which is more cost effective.

A.7.7 *Managing Costs and Cost Effectiveness*

Pilot capital costs fall within the stipulated maximum of $1.5M overnight capital. The only portion of the Pilot that qualifies as a capital expense at this time is the purchase of test batteries that will

[143] See page 5 of Commission Order 18-290 in Docket UM 1856

be installed in PGE locations for training and dispatch testing purposes at an estimated cost of $33,000 (five-year NPV of $40,000).

The O&M costs outlined below are the costs that PGE will include in its deferral request. Per the stipulation of UM 1856[144], evaluation costs are not included in this budget. The costs specific to operating this residential pilot will be included as part of the deferral, though in accordance with the stipulation no administrative costs of operating the entire portfolio of battery storage projects are requested.

PGE will stay within the guidelines of $5.7M NPV of revenue requirement and a year one revenue requirement of $700k. O&M costs are comprised of incentives (monthly + Test Bed and income qualified upfront rebates), program operations (Energy Trust contract, PGE program management, customer outreach), and the cost to dispatch the batteries as a fleet.

The table below reports pilot costs on a Net Present Value basis over the five-year pilot life. This is the amount (excluding the capital costs) that will be requested in the deferral application.

Table 20 – Pilot Budget: five-year NPV, 2020$

Budget Item	Rounded ,000
Incentives	$1,290
Monthly incentives; Grid Charging	$547
Monthly incentives; PV Restricted	$272
Test Bed Rebates	$362
Income Qualified Rebates	$109
Pilot costs	$926
PGE Program Manager	$376
PGE Customer Outreach	$61
ETO implementation	$423
Energy losses	$66
Aggregation & Dispatch	$604
Aggregation platform	$354
GenOnSys API Integration	$88
Vendor communications fee	$162
Total Requested Deferral	$2,820
UM 1856 O&M Budget	$5,700
Capital costs to utility	$40
Test batteries	$40
UM 1856 Capital Budget	$1,500
Total Budget	$2,860

[144] UM 1856 Partial Stipulation

A.7.8 *Cost Effectiveness*

The activity in the residential battery demonstration project is not cost effective. The primary objective is to learn as much as possible in a small-scale R&D type pilot to understand the appropriate pathway to cost-effectiveness, and to inform IRP values that will be required to appropriately quantify the benefits for a future cost-effective battery storage program. PGE has worked hard to limit the total spend and thus the cost risk to which ratepayer, the utility and participants are exposed. One of the primary reasons the project does not include an option for PGE to own the batteries is because the costs were simply too high and primary lessons to be learned could be acquired at less cost through the approached filed with the Commission March 12, 2020.

A.7.9 *Evaluation*

Under the stipulation in Order 18-290, PGE must file an annual compliance evaluation report and comprehensive evaluations in years 3, 6, and 10 of the pilot—looking at all five of the battery pilots approved under the order. PGE proposes to file a comprehensive evaluation in year 3 after the recruiting phase is complete, and the final evaluation in year 6, after the pilot is complete. Table 21 outlines the evaluation schedule.

Table 21 – Evaluation Schedule

Year	Activity	EOY Projected Capacity
1	Pilot Launch	175 customers, between 0.2MW-0.6MW for 4 hours
	Year 1 Recruitment Activities	
	Compliance Evaluation Report	
2	Year 2 Recruitment Activities	350 customers, between 0.4MW-0.2MW for 4 hours
	Compliance Evaluation Report	
3	Final Year of Recruitment	Full subscription: 525 customers, between 0.57MW-1.77MW for 4 hours
	Comprehensive Mid-Pilot Evaluation	
4	Recruitment closed, pilot operations	
	Compliance Evaluation Report	
5	Final Year of pilot Operations	
	Comprehensive Final-Pilot Evaluation	

A.7.9.1 *Comprehensive Reports*

The comprehensive mid-pilot and final evaluation reports will be completed by a third-party, and PGE will issue a competitive request for proposal (RFP). The evaluation should conform with established industry standards (e.g., the Department of Energy's Protocol for Uniformly Measuring and Expressing the Performance of Energy Storage)[145]. This protocol outlines how to perform baseline and duty cycle tests to ensure a battery storage system can perform at the required response times for various grid services. PGE will require selected evaluators to note and justify any deviations from this protocol.

[145] https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=8274603

PGE will use GenOnSys to integrate all the batteries. GenOnSys as well as the aggregation platform will capture and provide historical access to all the relevant data about inverter charge/discharge times, state of charge, and current and voltage levels.

The comprehensive reports will seek to answer the questions laid out in the “Lessons to be Learned” section, and to quantify the IRP values of any tested use cases that PGE was able to execute.

More details on the evaluation plan are available in PGE’s January 25, 2019 Addendum filed in UM 1856[146]

A.7.9.2 Annual Compliance Reports

Between comprehensive filings PGE will complete annual compliance filings. Compliance evaluation reports will be prepared by internal PGE resources, and will include qualitative and quantitative updates on pilot’s progress, including:

- Participation metrics – customers recruited, enrolled, who have dropped out, etc.
- Demographic profile of participating customers
- Budget update – projected and actual spend
- Available capacity
- Any in-house modeling results that have been conducted
- Any in-house calculations on RTE losses, actual TOU billing impacts
- Integration and dispatch methods, what’s going well and what needs improvement
- Communications metrics – Wi-Fi uptime, LTE metrics, lessons learned
- Results of any customer and/or installer surveys and/or interviews

Below is a table of the detailed learnings that PGE committed to studying through this pilot in its compliance filing, along with the learnings hoped to gain and the method for achieving the learning.

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[146] UM 1856, Addendum to PGE’s Residential Storage Pilot, filed Jan. 25, 2019, at 16-18, https://edocs.puc.state.or.us/efdocs/HAD/um1856had123254.pdf.

Table 22 – Evaluation Risk Management Plan

Risks	Learnings	Method
Risks of Personal Injury and Property Damage	Document issues in installation, maintenance, and decommissioning of units, as well as resolution strategy.	Internal project tracking; stakeholder interviews
Risk of Power Quality or Reliability Impacts	Capture incidence and trajectory of issues to inform PGE on what to expect from systems in the field and understand what level of support needed to ensure power quality is appropriately maintained.	Data historian for management system (GenOnSys) made available to evaluator
Integration Risk	Can be both infrastructural barriers and software integration issues: • (Power systems side) PGE will continue to develop expertise in performing hosting capacity assessments as-needed to support pilot deployment. • (Communications) PGE will monitor communications uptime through its management platform • (Software) What kind of integrations are required between management system at customer site and central control system? In the course of sustained operations, what are the relative firmware upgrades or updates to relevant APIs? • PGE will gain applicable learnings around smart inverter settings for customer-connected devices and how these can affect hosting capacity.	• (Hosting capacity): captured in project documentation and stakeholder interviews. • Communications downtime monitored through PGE's management platform and recorded in data historian. • Software integration issues documented as necessary.
Risk of Inopportune Timing	How does deployment timeline relate to customer and/or system needs, and what are the implications if exogenous drivers occur during the pilot timeframe? (E.g., additional rebates or community initiatives, or large concentrations through new construction).	PGE will monitor these events and document in the process evaluation.
Risk of Low/High Enrollment	Need a representative sample to the extent possible to ensure enough diversity of load profiles to understand various use cases. In addition, PGE is interested in determining what tools are effective (or not) at marketing energy storage to residential customers? How does the ownership model affect participation, decision making to enroll, and satisfaction?	Process evaluation will review marketing materials, benchmark similar programs, conduct stakeholder interviews, and include customer surveys.
Risk of Partner Failure	By requiring adherence to open communications protocols, PGE hopes to mitigate risk due to vendor changeout in a quickly evolving market. PGE will assess performance of hardware, software, aggregations, and O&M vendors contracted through the pilot.	Conduct post-failure analysis to understand cause of failure (for cases when vendors fail to perform duties). Also through stakeholder interviews with key program staff at PGE and with implementation partners.
Risk of Supply Chain Failure	PGE will seek to engage early with vendors to plan deployment and secure delivery guarantees. PGE will pursue alternate vendors as appropriate if supply chain problems exist. Learnings will inform program planning assumptions for future offerings.	Reasons for delays will be recorded and mitigated where possible. Stakeholder interviews will capture issues and recommend strategies for mitigation on wider rollout.

A.7.10 Moving from Pilot to Program

The purpose of the Residential Battery Pilot is to learn how to control a geographically diverse, distributed energy resourced situated behind the meter for various co-optimized energy services. The resource as it will be dispatch in the aggregate so that power operations can control and extract services will meet at least one important program factor, Dispatch Integration. However, because the residential battery effort is very new PGE at present needs to explore the other factors before being able to communicate with confidence the pathway of the effort to a formal program. For example, one of the primary learnings to be explored in the Residential Battery Project is to better understand infrastructure stability of behind the meter residential batteries. PGE will keep the Commission updated through regular check-ins as proposed in the planning chapter of this document.

A.7.11 Pathway to Flexible Load

Behind the meter batteries are the ultimate flexible load capable of provide a host of co-optimized grid services. Through this project we will explore how flexible and how well the resource can be leveraged by the PGE system for flexible load services.

A.7.12 Activity within the Testbed

Customers living within one of the PGE Test Beds[147] are eligible for an up-front rebate in addition to the monthly bill credit. This is to encourage density on the three select substations of the Test Bed and to allow PGE to study locational T&D impacts. To encourage prompt action as well as to test the impact of varying incentive levels on uptake, PGE will employ a tiered incentive that steps down after a certain level of uptake. Among the targeted 200 Test Bed participants, the first third will receive $3,000, the second third will receive $2,000, and the last third to enroll in the pilot will receive $1,000.

Customers receiving the up-front rebate will sign an agreement to participate in the entire pilot, or PGE has the option to require re-payment of the unamortized portion[148] of the rebate.

To ensure PGE can test locational value, a concentration of devices will be required to recognize impact on the distribution system. A single residential battery system fully charged may deliver 5 kW at any given point in time, which represents about 0.05% of a distribution feeder's typical load. To have a measurable impact on a distribution feeder's performance, concentrations that affect the power flow of at least 3%, or 0.2-0.3 MW of energy storage per distribution feeder, are necessary. Anything less than this impact is lost within the margin of error, and the opportunity to explore location-specific value diminishes. To reach 0.3 MW of capacity during the lowest production solar month on a single feeder requires a minimum of 171 batteries. PGE will pursue other methods of inducing density beyond just the Test Bed, including working with new home builders who may want to include battery storage in a subdivision.

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[147] As defined by PGE Rate Schedule 13.

[148] This is calculated as the proportion of the unpaid amount when calculated over the potential length of time the customer would have been eligible to participate in the Pilot.

A.8 Single Family Water Heater Testbed Demonstration

A.8.1 Description

PGE is leveraging R&D funding to perform a demonstration project for interconnecting single-family water heaters for demand response, and specifically heat pump water heaters. The objective of the research is to test varied communications protocols beyond customer hosted Wi-Fi, assess the demand response potential of heat pump water heaters, test incentive mechanisms, and better understand the options for a future scalable cost-effective single-family water heater program.

The communications protocols PGE seeks to employ for this demonstration are customer-hosted Wi-Fi, cellular LTE, and a mesh radio frequency network. The customer hosted Wi-Fi will use water heaters with onboard Wi-Fi chips for a “bring your own appliance” method of enrollment, while the LTE and mesh network controls will rely on water heaters with CTA-2045 capabilities and will be a much higher touch effort. The goal is to enroll 150 water heaters, 50 for each communication protocol. The demonstration may target existing homes as well as new construction single family homes.

An incentive may be provided to customers who enroll in the demonstration, as well as an ongoing incentive for continued participation. Builders in new construction may receive the enrollment incentive and potentially some or all of the ongoing incentive for purchasing a compliant heat pump water heater and enrolling the device in the demand response program.

The single-family water heater demonstration project will differ from the multifamily water heater pilot in an important distinction. PGE is committed to energy efficiency as the first fuel. To this end, it is important that where possible PGE flexible load resource building endeavors not complete with energy efficiency procurement. Thus, the single-family water heater demonstration will be working to connect heat pump water heaters, the most efficient electric water heat option. This is also why the endeavor is demonstration within the Testbed. PGE needs to explore the capabilities of these units to provide load shed.

A.8.2 Learnings

Enabling water heaters for DR purposes in single family settings has not historically been cost-effective for a few primary reasons.

Historically water heaters have been demand response enabled by having a licensed contractor install an intelligent switch on a water heater’s control panel. In a multi-family scenario economies of scale can be achieved with regards to installation labor, but having contractors spend time travelling between installation sites for specific installation windows with specific customers at least doubles the installation costs. This pilot will test newer technologies that don’t require a licensed contractor.

The cost to enable a water heater with communications devices independent of the customer’s own Wi-Fi has been prohibitive in the past. PGE has found that an alternative communications protocol to Wi-Fi is preferred due to disconnects from router reboots, energy outages, etc. This study will evaluate the costs of alternatives versus the benefits of improved reliability. Cellular

LTE data costs have been declining and may be approaching a cost that is appropriate for dispersed water heater controls. A mesh network operating radio frequency does not have ongoing costs to operate, but PGE must understand the cost and complexity of erecting a network and understand the limitations to reaching devices that may be located in customer basements or other out of the way locations. And finally, while PGE has historically found that customer Wi-Fi is unreliable for appliance controls, will the emergence of the “internet of things” and increasingly connected lifestyles improve that reliability? Can incentive design paired with prevalent appliance apps encourage customers to re-connect a device that has fallen offline? Understanding these questions will enable PGE to move forward with a cost-effective and scalable program for the future.

A.8.3 Single Family Water Heaters as Part of PGE Decarbonization Strategy

Single family water heaters are is a top priority for PGE’s decarbonization strategy as water heating is typically the second largest energy use in a home, only behind space heating. Testing in the multifamily water heater pilot shows that most customers do not notice when their water heater is being controlled by the utility for grid services, and thus demand response activities and grid services can be performed much more frequently than other events that may require more customer involvement or potential discomfort for customers. Additionally, water heaters, like batteries, are able to store and release energy. While the energy cannot be released back on to the grid like batteries, water heaters do demonstrate the ability to take service from the grid in sub-hour and possibly sub-fifteen minute increments.

A.8.4 Goals

The goals of the demonstration pilot are to:

- Understand the costs and benefits of various communications protocols for demand response of single-family water heaters
- Quantify the potential value of demand response in heat pump water heaters
- Understand the complexities, costs, and efficacy of a mesh network using radio frequency communications
- Pilot the use of CTA 2045 communications technology with customers

A.8.5 Roadmap to a Scalable Program

By gathering the learnings outlined above, in conjunction with the experience of the multifamily water heater demand response pilot, PGE will develop a cost-effective and scalable program that correctly values the incentive structure for customers, utilities cost-effective communications protocols and dispatch strategy, and employs a streamlined interconnection strategy.

PGE and the Energy Trust will collaborate to explore a joint incentive structure for heat pump water heaters supporting this key technology. Because heat pumps are so highly efficient they have a lower potential for demand response, and collaboration with energy efficiency partners is required to send proper market signals to customers and pursue a cost-effective program.

UE 394 PGE/1103
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Through incentive data collected by PGE, Energy Trust, and the state of Oregon from the RETC, PGE is able to identify homes with the specific models of heat pump water heaters that are able to be interconnected into a demand response program. Until a code requirement is in place that mandates all water heaters have demand response capabilities PGE will perform targeted outreach to customers for existing appliances, and work with installers and home builders to incent the installation of new water heaters with DR capabilities.

Customers surveys and focus groups consistently convey that customers want to participate in clean and advanced energy programs that provide an environmental benefit and are eager to participate in programs that have either non-existent or relatively low up-front costs for participation. PGE plans to provide this program at no cost to participating customers and may provide a one-time enrollment incentive as well as performance / participation incentives, dependent on the costs to operate the program and the value streams that emerge.

The ultimate goal of the pilot is to identify a path to a cost-effective demand response program for a multitude of single-family water heaters, including both electric resistance and heat pump. Electric resistance water heaters comprise a significant proportion of water heaters within the single-family housing market and have high levels of demand response capacity, however, are more difficult to interconnect. Heat pump water heaters are increasingly being sold with demand response capabilities built-in, and pair with energy efficiency goals.

The target market for single family housing with electric water heating is estimated to encompass 148K households, with an achievable potential of 74,000 households that represents 37 MW (assuming a capacity of 0.5 KW per water heater). Successfully establishing both the Single-Family Water Heater program and the CTA2045 standard may allow for water heaters to be DR-enabled by code by 2025.

A.9 Residential Smart Charging Pilot

A.9.1 Program Description

In March 2020 PGE proposed a Residential EV Charging pilot ("Pilot") to encourage customers to deploy connected Level 2 EV Charging (L2) infrastructure at their homes. The program, which targets single family homes, aims to provide rebates for approximately 3,600 charging stations over a three-year period. Participants will receive a rebate ranging from $500-1,000 per charger, and EV dealers will receive a $100 mid-stream rebate for referring a qualified successful EV charger installation. Further, the pilot will test the effectiveness of providing grid services, specifically demand response (DR) using home chargers, by offering customers a $50 annual incentive for participating in grid services events.

A.9.2 Program as part of Decarbonization

The program will support Oregon's climate goals, accelerate TE, and encourage efficient grid integration by:

- Reducing customer costs: Decrease costs associated with deploying charging infrastructure at home and at businesses;
- Enhancing customer experience: Simplify and standardize the EV charger buying and installation process;
- Enabling efficient grid integration: Ensure that future charging stations deployed in PGE's service territory are connected and participating or have the ability to participate in smart charging programs; and
- Supporting greater EV adoption in moderate-income and low-income communities: By offering larger incentives for qualifying individuals and facilities and by supporting transit agencies in electrifying their fleets.

A program like this one is likely to help accelerate Oregon's transition to a clean energy future. The proposed pilot wholly supports the state's goals to decarbonize the transportation sector while ensuring that we are building a grid that can maximize value from these new distributed energy resources (DERs). As our customers' trusted energy partner, PGE brings a balance of technical knowledge and customer acumen to deliver programs to accelerate TE and create value to the grid. We believe that this pilot will make charging more affordable, simplify the experience around installing charging infrastructure, increase the number of charging points in PGE's service territory, and create a pathway to capture and quantify new flexible energy resources.

A.9.3 Goals

PGE proposes to launch a Residential EV Charging pilot to encourage customers to deploy connected L2 infrastructure at their homes. The pilot targets single-family homes and aims to provide rebates for approximately 3,600 charging stations over approximately a three-year period. The Residential EV Charging pilot aims to:

- Encourage EV adoption by reducing the cost and complexity of installing qualified connected charging stations; and

- Explore and establish mechanisms to realize the value of the delivery of grid services (DR, daily load shifting, and load following) from connected chargers.

Table 23 – Residential Smart Charging Pilot Structure

Incentive	Projected Participation
Standard EV charger installation incentives	3,250 incentivized installations
Income-eligible EV charger installation incentives	360 incentivized installations
Grid Services	2,800 participating EV chargers

A.9.4 Market Potential

Through customer interviews, PGE found that EV buyers exhibit several key needs and wants. Many customers don't know how to navigate the transition from gas-fueled vehicles to EVs. While customers want green affordable transportation[149], they struggle to quantify the benefit of EVs when considering the purchase of a vehicle.

Customers want charging that is fast, easy, and convenient enough to compete with traditional fuel. The pilot is designed to address the fact that most homes do not have an available 220 volt / 30-40 amp circuit installed in their garage or driveway to accommodate a L2 charger.

EV chargers represent an incremental cost[150] for EV buyers to move from fossil fuels to electric. Financing of charger and installation costs are often not addressed by EV manufacturers or dealers during the EV sales process. As a result, customers face many home charging options and often choose the lowest cost option, which is often not connected and has no opportunity for grid integration.

Many customers simply lack the information they need to figure out that EVs are affordable, reliable, and can make financial sense for them. Finally, early EV adopters and potential EV buyers indicate that they desire to be perceived as smart and knowledgeable within their community (e.g. friends, family, co-workers) when transitioning from gas-powered vehicles to EVs.

Through customer interviews, PGE found that typical buyers of EVs fall into the annual household income category of greater than $60,000. Despite this, PGE found that all the buying groups desire to drive green, eliminate the use of fossil fuel to meet their transportation needs, and are

[149] Edmonds, Ellen. (2018, May 8). *1-in-5 U.S Drivers Want an Electric Vehicle*. AAA. Retrieved from https://newsroom.aaa.com/2018/05/1-in-5-us-drivers-want-electric-vehicle/
[150] Agenbroad, Josh (2014, April). *Pulling Back the Veil on EV Charging Station Costs*. Rocky Mountain Power Institute. Retrieved from https://rmi.org/pulling-back-veil-ev-charging-station-costs/

generally supportive of and/or are existing participants in PGE green programs (e. g. renewable power, DR, paperless billing).

The market size of potential EV adopters (innovators through early majority) in PGE's service territory is estimated at 240,000 households. Roughly 30% of these prospective customers are not able to install a home charger because they live in non-owner-occupied housing or have a physical/legal barrier to installing an off-street charger. This leads to a potential target market size of 160,000 installed home chargers (participating households).

The Residential EV Charging program addresses the need for convenient and fast home charging for the 100,000 electric passenger vehicles that are expected to be registered in Oregon by the end of 2025. PGE recently conducted a DER Potential Study[151] through the Integrated Resource Plan (IRP) process, which suggests that Battery Electric Vehicle[152] sales will reach a velocity of 10,600 new registrations per year in PGE service territory in 2025.

As shown in Table 24, research data suggests annual EV sales will accelerate from 1,900 cars per year to 5,500 cars per year during the timeframe that we propose for this pilot. The cumulative number of EVs sold in the period from 2019-2022 are estimated at 15,000.

To forecast program participation, PGE estimates approximately 15,000 new EV sales in our service area by 2022[153]. Adjusting for 1) fleet sales, 2) non-qualifying new installations of EV chargers, and 3) customers that do not have the option to install an EV home charger (among other factors), PGE estimates that 6,300 qualifying EV home chargers will be installed during the approximately three-year term of the pilot (see Table 24 for details).

PGE expects that some of these EV chargers, despite being the correct model, will not receive incentives for the installation of the equipment and/or participation in DR events due to lack of awareness for the pilot and/or non-timely submission of incentive applications, among other factors.

[151] Navigant (2019). DER Potential Study.

[152] The estimate does not include registrations of plug-in hybrid electric vehicles (PHEVs) in PGE's service territory. PHEVs have lower battery capacities than BEVs. BEV owners are also less likely to install L2 home chargers.

[153] The forecast model uses high-level macroeconomic factors like gross domestic product and population as well as vehicle density and historic sales data to project overall light duty vehicle market growth. These forecasts are helpful for sizing program adoption but are not intended to suggest that there is not a need to accelerate TE. There is a need to accelerate TE as the forecasted levels of EV adoption are not on pace to meet the Governor's 50,000 EV goal by 2020, nor are they sufficient to meet the state's greenhouse gas reduction goals. PGE expects that programs like this one will add to the customers' value proposition when considering an EV and, in turn, will accelerate transportation electrification.

Table 24 – Estimated Annual EV Sales and Installations of Eligible EV Home Chargers in PGE's Service Territory

Sales by Year	2019	2020	2021	2022	Total	2025
Annual New EV Sales[154]	1,937	3,537	4,296	5,461	15,231	10,613
Annual Installations of Qualifying Charging Stations	700	1,350	1,800	2,500	6,300	NA

Adjusting for fleet sales, non-qualifying new installations of EV chargers, and customers that do not have the option to install an EV home charger (among other factors) PGE estimates 6,300 qualifying EV home chargers will be installed during the approximately three-year pilot period.

PGE expects that some of these EV chargers, despite being the correct model, will not receive incentives for the installation of the equipment and/or participation in DR events due to lack of awareness for the pilot and/or non-timely submission of incentive applications, among other factors.

A.9.5 Lessons Learned

The program will undergo an evaluation to measure the effectiveness of the approach in meeting its objectives, areas for continuous improvements, and energy impacts on PGE's system. The following are some of the high-level learning objectives:

- Track customer participation and satisfaction levels with pilot offerings (grid service events, rebates, dealership assistance, and referrals);
- Understand the level of PGE's influence in customers' decisions to procure an EV and install charging;
- Document charging installation successes and challenges;
- Document and understand the successes and challenges of managed charging for PGE and customers;
- Measure customer load impacts on PGE's system; and

Identify pilot implementation successes and challenges, and improvement opportunities.

A.9.6 Managing Cost and Cost Effectiveness

PGE estimated that the residential and nonresidential customer pilots will have a 14-year net present value (NPV) net cost of $2.4M (which includes $34.7M in benefits and $37.1M in costs).

[154] Ibid.

The table below describes the incentives that the pilot will offer to facilitate the above aims.

Table 25 – Residential Smart Charging Pilot Incentives

Incentive Type	Amount	Frequency	Description
Standard Installation Incentive	$500	One-time	For the installation of a qualified connected L2 EV charging station at a single family residential home.
Income-Eligible Installation Incentive	$1,000	One-time	For qualifying income-eligible households, towards the installation of a qualified connected L2 EV charging station at a single family residential home.
Grid Services Incentive	$50	Annual	For customers that are participating in grid services (initially DR, later daily load shifting, and later load following) via the connected charging stations and/or connected vehicle.
Re-Connection and Grid Services Enrollment Incentive	$25-50	Promotional One-time	To encourage enrolled customers whose chargers have lost Wi-Fi connectivity[155] to reconnect their charger. Available at PGE's discretion. For customers with an existing charger who have not received an installation incentive and are enrolling into grid services.

[155] If Wi-Fi connectivity drops below necessary thresholds, PGE will offer this incentive as needed to ensure the operationalization and evaluation of grid services.

Table 26 shows the benefits and costs of the total pilot which includes charger installation rebate and grid services rebate. The combined benefit/cost ratio (rebate + grid services components) of the Residential EV Charging pilot is 0.95.

Table 26 – Blended Cost/Benefit Ratio Based on Combined Pilot Components (Residential EV Charging)

RIM Summary – NPV ($000's)	EV	DR	Total	%
Market Participation Revenue	-	-	-	-
Avoided Cost of Supply	-	1,210	1,210	10%
Revenue Gain from Increased Sales	10,434	-	10,434	90%
Benefits	**10,434**	**1,210**	**11,645**	**100%**
Administrative Costs	2,636	1,530	4,167	34%
Capital Costs to Utility	704	-	704	6%
Incentives Paid	2,276	920	3,196	26%
Increased Supply Costs	4,251	-	4,251	35%
Costs	**9,868**	**2,450**	**12,318**	**100%**
Benefit/Cost Ratio	**1.06**	**0.49**	**0.95**	

The pilot is designed to be in the field for approximately three years. Each charger is assumed to have a life of 10 years. The total pilot period stops 10 years after the last charger has been installed. While the initial number of participating chargers is increasing during the installation period (three years) the number of chargers participating in the pilot is assumed to drop over time. Participation levels drop due to customers moving-in and moving-out out, the charger losing its Wi-Fi connectivity, and other reasons.

A.9.7 Evaluation

PGE expects to submit evaluation findings in an interim report to the OPUC after the winter season spanning 2020 and a final report to the OPUC in the spring of 2023.

A.9.8 Pathway to Flexible Load

The Residential EV Charging program is a flexible load program. As PGE demonstrated in its Transportation Electrification Plan and again the Residential EV Charging Program proposal Time of Use charging is valuable, but a demand response component is needed to address grid constraints, local gird integrity and the ability to manage EV charging load directly. This comports with the criteria found in SB 1547, Section 20 where any program be expected to improve grid efficiency and operational flexibility including renewable integration. The Residential EV Charging Program is structured to address this criteria by the fact that PGE will work to enable new chargers to provide grid services such as DR, load shifting, and load following. These tools will support the integration of renewables on the grid.

A.9.9 Activity in the Testbed

The Residential EV Charging Program will be offered in the Testbed at the same time as the program is offered in the remainder of the service territory.

A.10 Fleet Electric Vehicle - Charging Program

A.10.1 Program Description

PGE is working to develop a program for public (transit, municipal and school bus) and private fleets to minimize the cost and complexity of fleet electrification by offering services that may include fleet planning (vehicle and charging infrastructure) and a turnkey approach to charging, where PGE builds, owns and maintains infrastructure in support of electric fueling. PGE envisions enabling this through modification to our existing line extensions policies. The charging equipment would be grid enabled, meaning it could participate in flexible load grid events (such as demand response). It is anticipated Energy Partner schedule 26 will be adjusted to dispatch these loads over time. Another service being considered is transacting Clean Fuels Credits on a customer's behalf for an administrative fee and crediting the proceeds to participants.

Fleet and transit operators are interested in electrifying their fleets to be more sustainable, and over time lower their operating costs. The vehicle and charging decision are made simultaneously and fueling companies often provide all fueling infrastructure (i.e. own, operate and maintain the fueling source). These businesses need a solution customized to meet their needs. Installing charging infrastructure is time consuming, expensive (especially capacity upgrades) and complex, and is a key barrier to fleet electrification[156]. Customers often want to focus on vehicles, where they have more knowledge, and they find charging presents a steep learning curve.

A.10.2 Program as part of Decarbonization

The program will support Oregon's climate goals, accelerate TE, and encourage efficient grid integration by:

- Reducing customer costs: Decrease costs associated with deploying charging infrastructure;
- Enhancing customer experience: Simplify EV charger implementation and operations
- Enabling efficient grid integration: Ensure that future charging stations deployed in PGE's service territory are connected and participating or have the ability to participate in smart charging programs; and
- Accelerating fleet electrification: By providing tools to support fleet electrification efforts and reducing the cost and complexity of deploying EV charging infrastructure, which is critical to the operation of EVs.

A.10.3 Activity in the Testbed

This program would be offered in the Testbed at the same time as the program is offered in the remainder of the service territory.

[156] Mortenson.2019. EV Industry Trends. 48% of fleet owners ranked charging infrastructure as the biggest barrier to EV adoption. 55% of fleet owners anticipate lead time for charging infrastructure is 1 year or more. 16% of fleet owners ranked financing as the biggest barrier to EV adoption. 46% of fleet owners say substantially more incentives are needed to stimulate widespread adoption.

A.11 Business EV Charging

A.11.1 Program Description

PGE is working to develop a program for business customers to reduce the cost and complexity of installing Level 2 EV charging stations. PGE plans to build, own and maintain the infrastructure up to the parking space, and offer a rebate for the customer's purchase of a qualified charger. An enhanced line extension allowance is envisioned, covering most (or all) of the cost of the distribution system upgrades and the make-ready infrastructure; any costs above the allowance will be paid by the customer.

A.11.2 Program as part of Decarbonization

The program will allow PGE to invest in our customers to decarbonize the transportation sector. Planful investments in EV charging infrastructure will support market growth and charging control, which will enable flexible loads that will be needed in a high-renewables future.

A.11.3 Market Potential

From 2021 through 2023, PGE anticipates engaging ~200 customer sites in the program, for a total of ~1000 charging ports.

A.11.4 Lessons Learned

PGE has leveraged numerous lessons learned from the Electric Avenue expansion and TriMet pilots to understand financial and operational needs to support this type of offering for customers. Ongoing lessons learned will be integrated to strengthen the offering for customers, as well as inform future programs.

A.11.5 Managing Cost and Cost-Effectiveness

Costs for the rebate portion of the offering will be limited to $1 million. Costs for the make-ready portion of the offering will be accounted for using PGE's typical line extension process.

A.11.6 Evaluation

Evaluation will measure the effectiveness of the offering in meeting its objectives and identify areas for enhancement. PGE may measure the energy impacts on PGE's system as part of additional research with separate funding. Learning objectives include, but are not limited to:

- Track customer participation and satisfaction levels with offering (e.g. value proposition, rebates, equipment choices, process);
- Understand PGE's ability to influence customers' decisions to install charging equipment and/or (as appropriate) operate EV fleets;
- Document charging installation successes and challenges, and customers' perceptions of working with PGE; and
- Identify pilot implementation successes and challenges, and improvement opportunities.

Expected process evaluation activities include:

- Logic model

- Data analytics
- PGE administrator interviews
- Participant web surveys
- Attribution analysis (for future program design purposes only)

A.11.7 Pathway to Flexible Load

Participation in demand response will not be a requirement of the offering; however, all chargers deployed through the program will be DR-enabled. A demand response component may be developed and offered to participants in future years.

A.11.8 Activity in the Test Bed

This program will be offered in the Testbed at the same time as the program is offered in the remainder of the service territory.

Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory

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PREPARED FOR

Portland General Electric

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EVOLVED ENERGY RESEARCH

Contents

Executive Summary

Background

Portland General Electric (PGE) retained Evolved Energy Research to undertake an independent study exploring pathways to deep decarbonization for its service territory. This study comes amidst a broad interest in decarbonization from customers and stakeholders, as well as policies and goals to promote clean energy and emissions reductions.

Since 2007, Oregon has had a goal of reducing statewide greenhouse gas (GHG) emissions by 75 percent below 1990 levels by 2050. Recently proposed legislation seeking to establish a cap-and-trade program in Oregon also proposes to tighten the statewide GHG reduction goal to 80 percent below 1990 levels by 2050. At the local level, the City of Portland and Multnomah County passed resolutions in June 2017 committing to 100 percent renewable electricity by 2035 and a complete transition to carbon-free energy by 2050.

These drivers to deeply decarbonize the economy would require a transformation of the energy system, and major choices will need to be made about which technologies play a role and how aggressively to pursue carbon reductions across different sectors. A substantial body of existing technical work shows that the electricity sector plays a pivotal role in a low-carbon transition, but the extent and type of role depends on choices made in other sectors.[1] For example, the level of electrification pursued in buildings and the decision to produce fuels from electricity, such as hydrogen from electrolysis, will have implications for electricity demand and the quantity of renewable electricity generation that will need to be developed.

Due to the potential impact on long-term planning, PGE sponsored this study to inform its Integrated Resource Planning (IRP) efforts. This study is intended to provide an understanding of: (1) the opportunities and challenges of achieving economy-wide deep decarbonization; and (2) the resulting implications for electricity system operations and planning.

Approach

The overarching emissions target for this study is an 80 percent reduction below 1990 levels by 2050 in energy-related CO_2 emissions. CO_2 emissions from fossil fuel combustion have been the predominant source of Oregon's historical GHG emissions, and, since 1990, they have accounted for approximately four-fifths of total GHG emissions in the state. This target would allow for fossil fuel combustion emissions of no more than 9.2 $MMTCO_2$ in 2050 for the state of Oregon. We allocate the statewide carbon budget to PGE's service territory using its projected share of Oregon's population, which is estimated to be 47 percent in 2050.[2] This results in a carbon budget of 4.3 $MMTCO_2$ in 2050 for the PGE service territory.

We designed three future energy scenarios that reduce emissions to comply with the 4.3 $MMTCO_2$ target. These scenarios are referred to as "deep decarbonization pathways" or "pathways", and they provide alternative blueprints for achieving deep decarbonization of the energy system.

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[1] For example, see Williams, et al. (2014) and Haley, et al. (2016).
[2] Population growth rate projections from OEA (2013).

For each sector of the energy economy, we developed a range of measures to replace today's energy infrastructure with efficient and low-carbon technologies over the next three decades. For example, passenger travel currently provided by a gasoline vehicle is replaced by an electric vehicle, and a compact fluorescent (CFL) light bulb is replaced by a light emitting diode (LED) light bulb. Each pathway combines measures across sectors at the scale and rate necessary to meet the study's emissions target.

We use EnergyPATHWAYS, a bottom-up energy systems model, to estimate energy demand, emissions and costs for each pathway. Our analysis starts with the same model and approach we have previously used to evaluate deep decarbonization for the United States, the State of Washington and other jurisdictions. We developed a detailed representation of the PGE service territory energy system, including infrastructure stocks and energy demands for buildings, industry, and transportation. Our analysis incorporates an hourly dispatch of PGE's electricity system, which allows us to better understand fundamental changes to electricity supply and demand, such as how to balance very high levels of intermittent renewables and the impact of electrification on hourly electricity demand.

Pathways

Our study aims to provide an understanding of the broad choices available to achieve deep decarbonization across the economy and the potential implications on the electricity sector. To inform this understanding, we develop three plausible energy futures for PGE's service territory that achieve steep reductions in energy-related CO_2 emissions between now and 2050. These future energy scenarios outline: (1) potential sources and demands for energy types over time; and (2) the scale and timing of change over the next three decades.

Table 1 provides a high-level summary of the three pathways included in this study, where each scenario incorporates alternative emissions reduction strategies and technologies. One of the primary objectives of our scenario design was to reflect a broad range of outcomes for the electricity sector. The High Electrification pathway relies on electrifying space and water heating in buildings and deploying bulk energy storage to balance high levels of renewable generation. Passenger transportation is characterized by high levels of battery electric vehicles (BEV), while freight transportation includes both battery electric and hybrid diesel trucks. The Low Electrification pathway decarbonizes energy supply with a variety of renewable fuels, and electrolysis and power-to-gas facilities provide both electricity balancing services and decarbonized pipeline gas. Passenger transportation is primarily BEV, while compressed and liquefied natural gas trucks are incorporated in the freight transportation sector. The High DER pathway is highly electrified and distributed, with increased rooftop solar PV and distributed energy storage in buildings and industry. The Reference Case projects business-as-usual conditions, including the Oregon Clean Electricity and Coal Transition (OCEP) and Clean Fuels Program (CFP).

Table 1 Scenario Summary

Scenario	Description
High Electrification	Fossil fuel consumption is reduced by electrifying end-uses to the extent possible and increasing renewable electricity generation
Low Electrification	Greater use of renewable fuels, notably biofuels and synthetic electric fuels, to satisfy energy demand and reduce emissions
High DER	Distributed energy resources proliferate in homes and businesses, which also realize higher levels of electrification
Reference	A continuation of current and planned policy, and provides a benchmark against the deep decarbonization pathways

We are not choosing or recommending a pathway to 2050, and the scenarios presented above are not exhaustive. However, the pathways we have included in this study illustrate possible routes to a deeply decarbonized energy system and provide an understanding of trade-offs between complex decisions made by consumers and producers across the energy economy.

Key Findings

The three pathways evaluated in this study demonstrate that achieving deep decarbonization is both possible and there are multiple ways of doing so. Through this analytical exercise, we have identified a number of key findings, which we describe in detail below.

Common Elements to Achieve Deep Decarbonization

Although our pathways demonstrate that a variety of technologies and approaches are possible to realize a low-carbon economy, they also share common strategies, including: energy efficiency, decarbonization of electricity generation and electrification. These *three pillars* are common themes in all pathways, and the energy transformation from today to 2050 reflects: (1) a decline in per capita final energy consumption by approximately 40 percent; (2) a decrease in the carbon intensity of electricity generation to near zero; and (3) an increase in the share of energy coming from electricity or fuels produced from electricity from approximately one-quarter today to at least half by 2050. All three strategies are required and pursuing only one is insufficient.

Planning for a 2050 Energy System

In order to facilitate a pathway to 2050, new energy infrastructure will be required that is low-carbon and efficient. Transformation is required across all sectors with consumers and energy suppliers both playing a key role. The analysis identifies the scale and rate of change for each pathway, and highlights trade-offs between choices made to achieve deep decarbonization. One example is the choice of decarbonizing heat in buildings. Electrification of heat with heat pumps may require electricity distribution network upgrades to allow for growth in electricity demand, but they also provide a source of flexibility and efficient cooling services during the summer. The alternative is decarbonized pipeline gas that requires new central-station fuel production facilities, additional renewable generation and transmission network upgrades. *Both* choices require new infrastructure and highlight how long-term planning will need to address several uncertainties.

Energy Demand and Electricity Demand

Energy efficiency plays a crucial role in all pathways, and *total energy demand* in 2050 is approximately 10 to 20 percent below today's level, while the population grows by more than 40 percent. Despite overall energy demand decreasing, *electricity consumption* increases in all pathways. By 2050, retail electricity sales are projected to increase by 60 to 75 percent relative to today's level. As a result, electricity's share of overall energy demand is projected to increase in a deeply decarbonized future.

Transportation Electrification

Electrification of passenger transportation is a critical component of decarbonizing the energy system, and passenger vehicles are at least 90 percent BEV by 2050 across all pathways. To ensure these vehicles are on the road by 2050 requires consumer adoption to be near 100 percent of vehicle sales during the mid-2030s. Delays in adoption increase the likelihood of missing the 2050 target.

Widespread adoption of electric vehicles (EVs) is projected to be the largest source of increased electricity consumption, and, left unmanaged, would increase peak demand. However, the fleet of EVs across PGE's service territory can employ smart charging by shifting their demand to more efficient times of day. Charging off peak, such as when renewable generation is high or during the middle of the night can mitigate peak load impacts while ensuring that passengers complete all of their intended trips.

Scale of Renewable Resources

Oregon's existing renewable portfolio standard (RPS) requires half of the energy PGE delivers to its customers to come from qualifying renewable resources by 2040. Deep decarbonization extends that ambition in two ways. First, the overall electricity generation mix is more than 90 percent carbon-free by 2050, including onshore wind, solar PV, hydro and geothermal resources. Second, the total quantity that must be generated (in average megawatts) increases due to: (a) electrification of end-use demand, such as heating and transportation; and (b) producing fuels from electricity, such as hydrogen and synthetic natural gas. As a result, the installed capacity of renewables is substantially higher than what's anticipated in any current planning proceedings and is more than double the quantity we would expect under current RPS policy.

Rooftop solar PV can play a key role in electricity supply, but its share of the overall electricity generation mix in a deeply decarbonized energy system is limited by the resource quality in Northwest Oregon (i.e., low capacity factors) and growth in electricity consumption. Distributed solar reduces the need for, but does not completely replace, transmission-connected renewables. Although the Low Electrification pathway has the lowest retail energy deliveries by 2050, the pathway requires the highest level of transmission-connected renewable generation due to electric loads from producing hydrogen and synthetic natural gas.

The scale of renewable resource development present in all scenarios highlights the need for proactive planning to ensure that these resources are available to come online in a timely fashion. This includes identifying promising areas for resource development, possible transmission network upgrades to ensure renewable generation is delivered to load, and operational considerations to balance a highly renewable electricity grid.

Balancing the Electricity System

Electricity systems must be continually balanced across several timescales, from seconds to daily, weekly and seasonal changes. Today, generation from thermal and hydro resources is varied to meet changes in demand. However, balancing electricity supply and demand becomes more challenging when inflexible, variable renewable generation is the principal source of electricity supply. For example, renewable generation exceeds load in approximately half of all hours in 2050 in our pathways.

This operational paradigm necessitates a transition to new forms of balancing resources to integrate renewables and avoid curtailment. New sources of flexibility, including energy storage and flexible demand, can complement traditional sources of flexibility. Flexible demand includes both: (a) flexible end-use loads, such as smart EV charging and water heating; and (b) flexible transmission-connected loads, such as electrolysis and power-to-gas facilities that produce low-carbon fuels. The portfolio of available balancing options depends on choices made across the energy economy.

I. Background

Portland General Electric (PGE) retained Evolved Energy Research to undertake an independent study exploring pathways to deep decarbonization for its service territory. This study comes amidst a broad interest in decarbonization from customers and stakeholders, as well as policies and goals to promote clean energy and emissions reductions at the state and local level. Transitioning towards a low-carbon energy economy will have significant implications for electricity supply and demand, and the various technologies and strategies deployed during this transformation can result in broad outcomes for the electricity sector. Due to the potential impact on long-term planning, PGE sponsored this study to inform its Integrated Resource Planning (IRP) efforts and provide an understanding of: (1) the opportunities and challenges of achieving economy-wide deep decarbonization across its service territory; and (2) the resulting implications for electricity system operations and planning.

A. Motivation and Context

Oregon has long been at the forefront of recognizing the risks imposed by climate change. In 2007, the Oregon legislature passed House Bill 3543 (HB 3543), which established GHG reduction goals, including: (a) 10 percent reduction below 1990 levels by 2020; and (b) 75 percent reduction below 1990 levels by 2050. The Oregon Global Warming Commission (OGWC) was established through the same bill, and later recommended an interim goal of a 40 percent reduction below 1990 levels by 2035.

Recently proposed legislation seeking to establish a cap-and-trade program in Oregon also proposes to tighten the statewide GHG reduction goal. The proposed legislation would require a reduction in statewide GHG emissions to: (a) a goal of 20 percent below 1990 levels by 2025; (b) a limit of 45 percent below 1990 levels by 2035; and (c) a limit of 80 percent below 1990 levels by 2050.

Oregon has existing climate policies targeting specific sectors. The Clean Fuels Program requires the average carbon intensity of transportation fuels to be reduced by 10 percent between 2015 and 2025. The state adopted a Renewable Portfolio Standard (RPS) in 2007, which requires a percentage of retail electricity sales to be met by qualifying renewable electricity generation. This policy originally required 25 percent of load to be met by renewables by 2025. Senate Bill 1547 (SB 1547), also known as the Oregon Clean Electricity and Coal Transition (OCEP), was passed in March 2016 and requires: (1) an increase in the RPS to 50 percent renewables by 2040; and (2) removing coal-fired electricity generation from the state’s electricity supply by 2035.

PGE’s 2016 IRP reflected the increase in renewable energy requirements and transition from coal generation called for in the OCEP. Throughout the IRP process, stakeholders and customers have expressed interest in low-carbon portfolios and exploring deep emissions reductions. In addition, the City of Portland and Multnomah County passed resolutions committing to ambitious clean energy goals shortly after, including: (a) 100 percent renewable electricity by 2035; and (b) a complete transition to carbon-free energy by 2050.

These drivers to deeply decarbonize the economy would require ambitious energy system transformation. Prior studies examining similar levels of GHG reductions for the states of Washington and California, the United States and countries representing more than 75 percent of global GHG emissions have all identified the following required changes to their future energy systems: (1) highly efficient use of energy; (2) generating electricity with low- and zero-carbon resources; and (3) substituting fossil fuels with electricity and electricity-derived fuel.[3] Pursuing only one change, such as decarbonizing electricity generation, is insufficient to meet economy-wide goals and all three strategies are needed.

In addition to these common themes, there are a range of alternative strategies that make it possible to achieve the same GHG goal. Different technologies and fuels can be deployed to decarbonize energy supply and demand, and the extent of decarbonization by end-use sector may vary. Key differences between pathways identified in prior studies include the level of end-use electrification and the allocation of limited bioenergy resources to decarbonize gaseous and liquid fuels.

As a result, long-term planning for the electricity sector will need to account for decarbonization efforts in other sectors and the complex mix of choices that may be pursued. Examples of actions that would affect long-term electricity planning include: (a) adoption of high levels of electric vehicles in the transportation sector, which affects overall electricity demand and its shape; (2) production of synthetic electric fuels, such as hydrogen from electrolysis, which will increase the demand for clean electricity generation; and (3) deployment of distributed energy resources across homes and businesses. However, the likelihood and timing of these developments and other potential decarbonization efforts is uncertain.

Our study aims to provide an understanding of the broad choices available to achieve deep decarbonization across the economy and the potential implications on the electricity sector. To inform this understanding, we develop a range of plausible energy futures for PGE's service territory that achieve steep reductions in energy-related CO_2 emissions between now and 2050. These future energy scenarios outline: (1) potential sources and demands for energy types over time; and (2) the scale and timing of change over the next three decades.

B. Study Scope

Our study scope includes designing and evaluating three future energy scenarios that deeply decarbonize the PGE service territory's energy system. We refer to these scenarios throughout the report as "deep decarbonization pathways" or simply "pathways". We also developed a Reference Case reflecting current policy to provide a benchmark against the pathways scenarios.

The primary results of our study include projections from today to 2050 of: (1) energy demand by sector and type; (2) energy supply; (3) energy-related CO_2 emissions; and (4) energy system-related costs. This is supplemented by detailed results for the electricity sector, including electricity demand, installed capacity, generation, and hourly dispatch results for PGE's bulk power system.

Given our focus on exploring energy system transformation, we account for all forms of energy (e.g., gasoline, pipeline gas, hydrogen) and our analysis is not limited to electricity. We include CO_2 emissions from energy use, but we do not track non-energy CO_2 and non-CO_2 GHGs. The geography for our analysis is confined to PGE's service territory and excludes the rest of Oregon. Since one of the primary objectives of the study is to explore economy-wide compliance with a GHG target, we include load from customers that are currently under direct access to account for all energy use.

[3] These strategies are commonly referred to as the "three pillars".

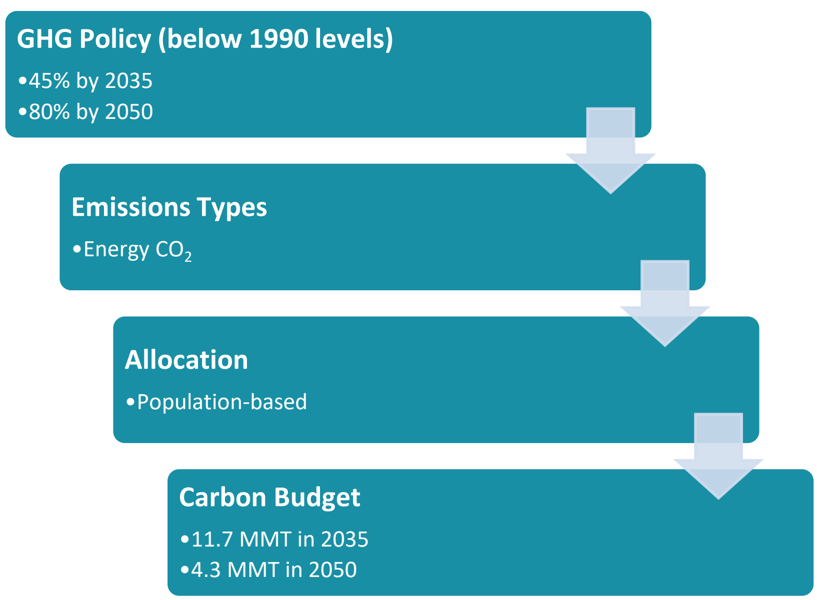
Given the exploratory nature of this study, it is important to emphasize what this study *is not*:

- Our scenarios are not a forecast of the future;
- We are not predicting future outcomes or assigning probabilities to scenarios;
- We are not choosing or recommending a pathway to 2050;
- Scenarios assessed here are not exhaustive and thousands of plausible alternatives exist;
- Scenarios do not reflect PGE's business plan or future resource acquisitions; and
- This study's modeling approach and results do not replace existing tools or processes used in IRP, such as defining "need" for resource adequacy or identifying optimal portfolios, nor do they replace cost-effectiveness evaluation, etc.

C. Study Emissions Target

For the purposes of this study, the energy-related CO_2 emissions budget for PGE's service territory is 11.7 million metric tons ($MMTCO_2$) in 2035 and 4.3 $MMTCO_2$ in 2050. Developing an appropriate emissions budget to evaluate deep decarbonization requires numerous assumptions to account for: (a) the fact that currently there is no binding, economy-wide GHG policy covering PGE's service territory; (b) any state-wide emissions limit must be translated into a budget for PGE's service territory; and (c) the scope of our work includes energy-related CO_2 emissions and excludes non-energy CO_2 and non-CO_2 GHGs. Our approach for deriving the study's emissions budget is summarized in Figure 1 and further described below:

Figure 1 Approach to Develop Study's CO_2 Target



- **GHG Policy**. The context for emission reductions, discussed in the proposed cap-and-trade legislation, requires a reduction in statewide GHG emissions to: (a) 45 percent below 1990 levels by 2035; and (b) 80 percent below 1990 levels by 2050.

- **Emissions Types**. CO_2 emissions from fossil fuel combustion have been the predominant source of Oregon's historical GHG emissions, and, since 1990, energy-related CO_2 emissions have accounted for four-fifths of total gross GHG emissions in the state. For simplicity, we apply the emissions reductions from the above GHG policy to Oregon's 1990 energy-related CO_2 emissions, which were approximately 46 $MMTCO_2$.[4] This results in a state-wide budget for CO_2 emissions from fossil fuel combustion of approximately 25.2 $MMTCO_2$ in 2035 and 9.2 $MMTCO_2$ in 2050. Based on a state population forecast of 5.59 million in 2050, this results in a per capita emissions budget of 1.6 tCO_2 per person, which is consistent with prior decarbonization studies.
- **Budget Allocation**. We allocate the state-wide emissions budget to PGE's service territory using its projected share of Oregon's population. In 2015, the PGE service territory included approximately 1.8 million people or 45 percent of Oregon's population. Projections of long-term population growth show counties within PGE's service territory growing at a slightly faster rate than the state as a whole. PGE's share of the state's population is projected to increase to 46.3 percent in 2035 and 47 percent by 2050. This translates into a carbon budget of 11.7 $MMTCO_2$ in 2035 and 4.3 $MMTCO_2$ in 2050.

The carbon budget we have developed for PGE's service territory is specific to this study. Any future policy mechanisms used to achieve emissions reductions, such as a price on carbon or complementary measures, may result in alternative emissions outcomes than those modeled here. In other words, the *total* statewide GHG emissions target may be compliant in the future, but *where* mitigation occurs is not definite. For example, more or less mitigation may occur between: (a) PGE's service territory and the rest of Oregon; (b) buildings and the industrial sector; and (c) sources of energy CO_2 and other GHGs.

[4] We note that our approach implicitly assumes that non-energy CO_2 and non-CO_2 GHGs will be reduced on an equivalent percentage basis in order to achieve the overall GHG targets. Historical emissions data from DEQ (2016).

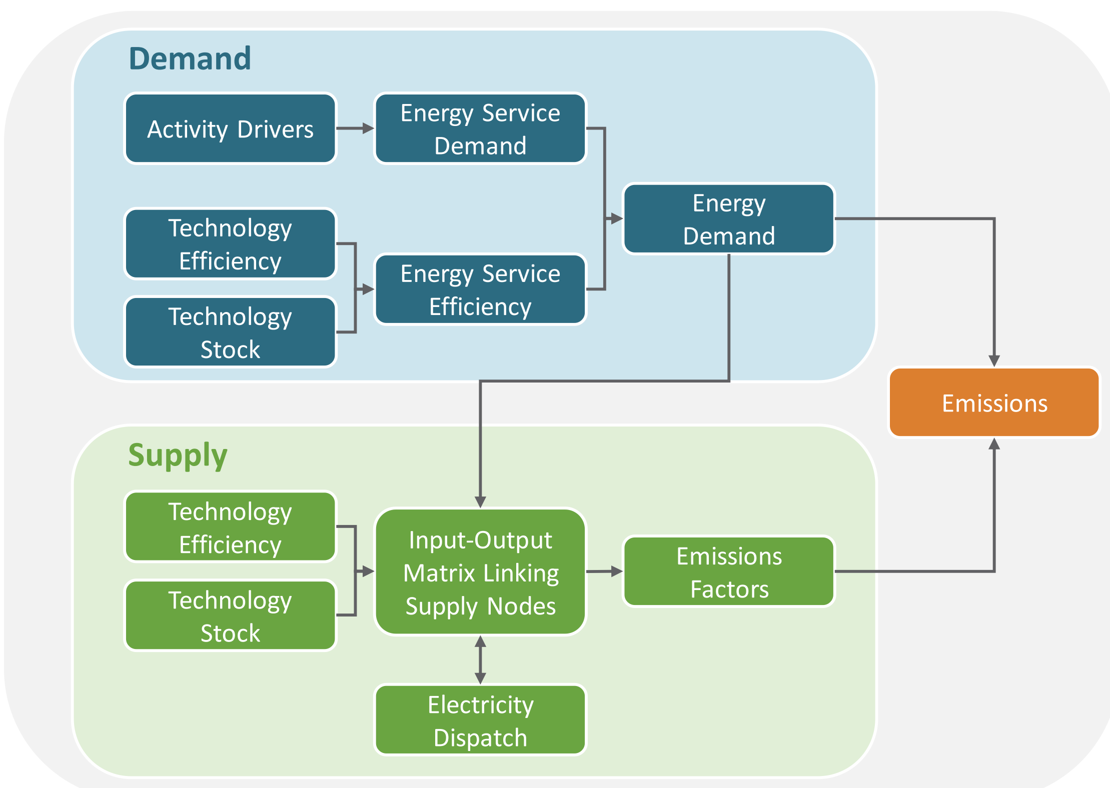
II. Study Assumptions and Approach

A. EnergyPATHWAYS Modeling Framework

We use EnergyPATHWAYS, a bottom-up energy systems model, to estimate energy demand, emissions and costs for each future energy scenario. Our analysis starts with the same model and approach we have previously used to evaluate deep decarbonization for the United States, the State of Washington and other jurisdictions. We developed a detailed representation of the PGE service territory's energy system, including infrastructure stocks and energy demands for buildings, industry, and transportation. Our analysis incorporates an hourly dispatch of PGE's electricity system, which allows us to better understand fundamental changes to electricity supply and demand, such as how to balance very high levels of intermittent renewables and the impact of electrification on hourly load.

Figure 2 depicts the general structure of EnergyPATHWAYS with the demand- and supply-side of the energy system shown separately. The demand-side calculates the quantity of energy demanded by different services at the technology level, such as the kWh of electricity and therms of pipeline gas demanded by water heaters in the residential sector. The supply-side determines how energy demand is met, such as the share of electricity provided by gas-fired combined cycle power plants, onshore wind power plants and rooftop solar PV. The energy system is simulated in sequence with the demand-side run prior to the supply-side.

Figure 2 General Structure of EnergyPATHWAYS



The demand-side starts with exogenous projections of activity drivers, such as population, households, commercial floorspace and industrial value of output. These drivers serve as the basis for projecting demand for energy services. For example, as the number of total residential households and square footage increases, then the demand for lighting will similarly increase. The technology composition of the stock along with the efficiency of each technology creates a service efficiency. In the lighting example, a transition from incandescent to CFL and LED light bulbs would improve service efficiency. Energy service demand and service efficiency are then combined to calculate the demand for energy, while the fuel type depends on the stock of technologies used to satisfy the demand for energy services.[5]

The supply-side is characterized by an input-output (IO) matrix that specifies the flow of energy between "supply nodes" that produce or deliver energy. Examples of supply nodes include power plants and transmission and distribution infrastructure. The coefficients in the matrix specify the amount of input energy required to produce one unit of output energy. For example, a gas-fired combined cycle power plant with a heat rate of 6,824 Btu/kWh (50% efficiency) would require 2.0 units of natural gas to generate 1.0 unit of electricity. These coefficients are dynamic and reflect: (1) changes in the composition and efficiency of supply-side technologies; and (2) outputs from an hourly electricity dispatch (i.e., the generation mix). From this process, emission factors are developed for each fuel. Finally, the emission factors from the supply-side are combined with final energy demand from the demand-side to estimate system-wide emissions.

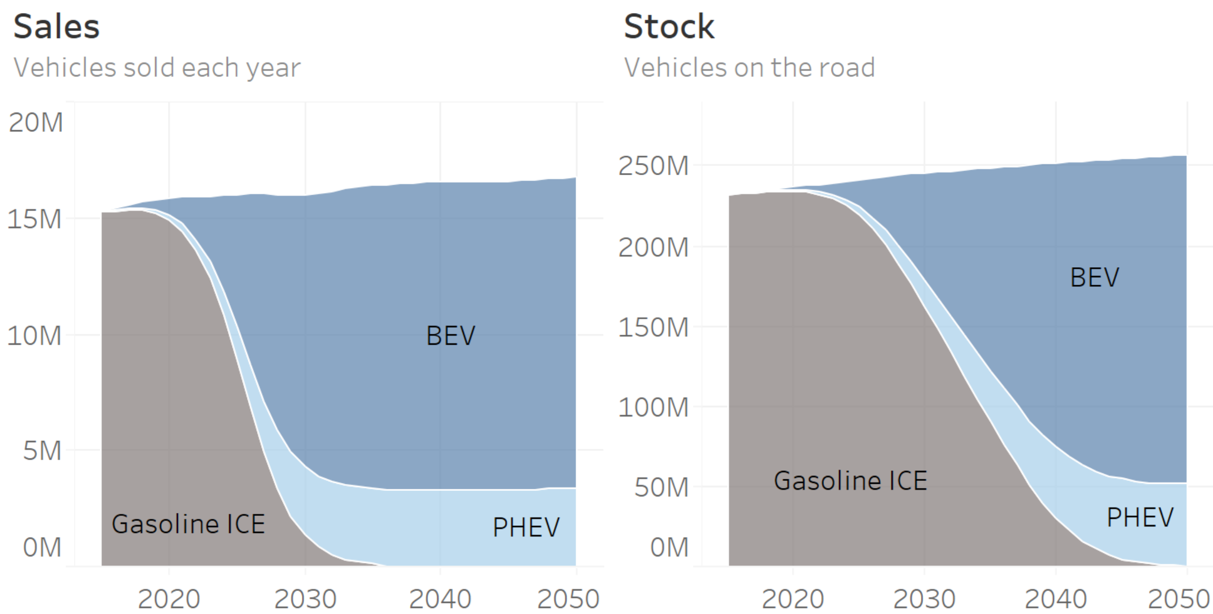
To reduce emissions, we develop measures to replace existing demand- and supply-side equipment and infrastructure with efficient and low-carbon technologies. For example, passenger travel currently provided by a gasoline vehicle is replaced by an EV, and a CFL light bulb is replaced by an LED light bulb. Future energy scenarios are designed by combining measures across sectors at the scale and rate necessary to meet the study's emissions target.

We implement measures through a stock rollover process, where a portion of energy infrastructure retires in each year and must be replaced by new energy infrastructure. In a baseline scenario, retiring infrastructure is generally replaced with the same category of technology, but the cost and performance characteristics reflect the more recent installation year (e.g., a retiring reference dishwasher is replaced by a new reference dishwasher). Alternatively, measures specify the composition of new energy infrastructure (e.g., half of vehicle sales are plug-in hybrid electric vehicles by 2025).

The stock rollover process is illustrated for light-duty vehicles in Figure 3, where the measure shown on the left-hand side of the chart specifies that sales of new light-duty vehicles are 80 percent BEV and 20 percent PHEV by 2035. Changes to the vehicle stock, shown on the right-hand side, are moderated by this process and BEV/ZEV vehicles do not make up all vehicles on the road until 2050. All scenarios in this study assume that infrastructure is retired naturally (i.e., at the end of its lifetime), and there are no early retirements.

[5] A portion of electric energy can be dispatched (i.e., flexible load), and this process is modeled on the supply-side.

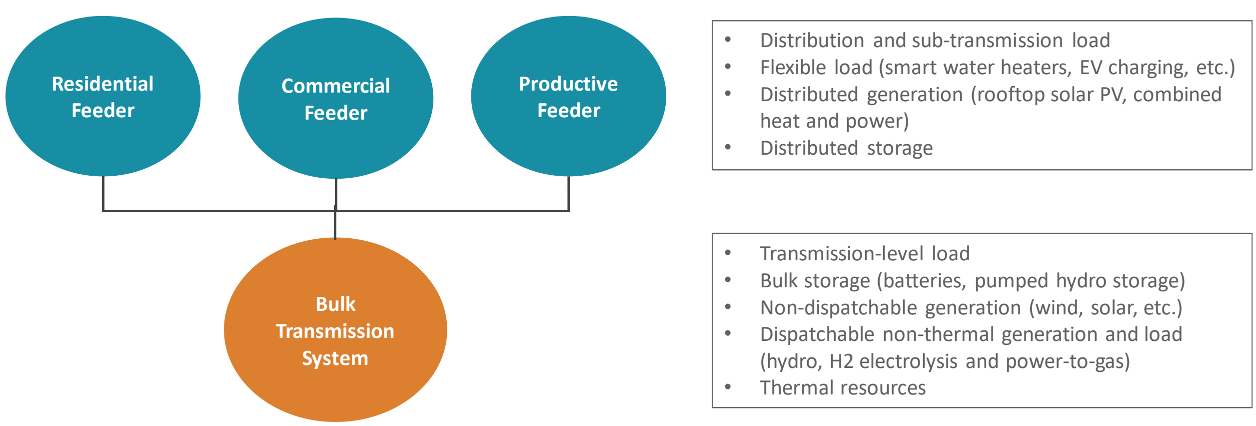
Figure 3 Illustrative Example of Stock Rollover in EnergyPATHWAYS



B. Electricity Sector Modeling

Electricity system operations in EnergyPATHWAYS are modeled on an hourly basis for each year through 2050. This includes a detailed representation of loads and resources at the feeder-level and the bulk transmission system. The structure of the electric system is shown in Figure 4 below, with the boxes illustrating the type of resources included within each node. Electricity dispatch and the development of load shapes are further described below, and we illustrate our approach for a three-day period (February 6-8, 2050).

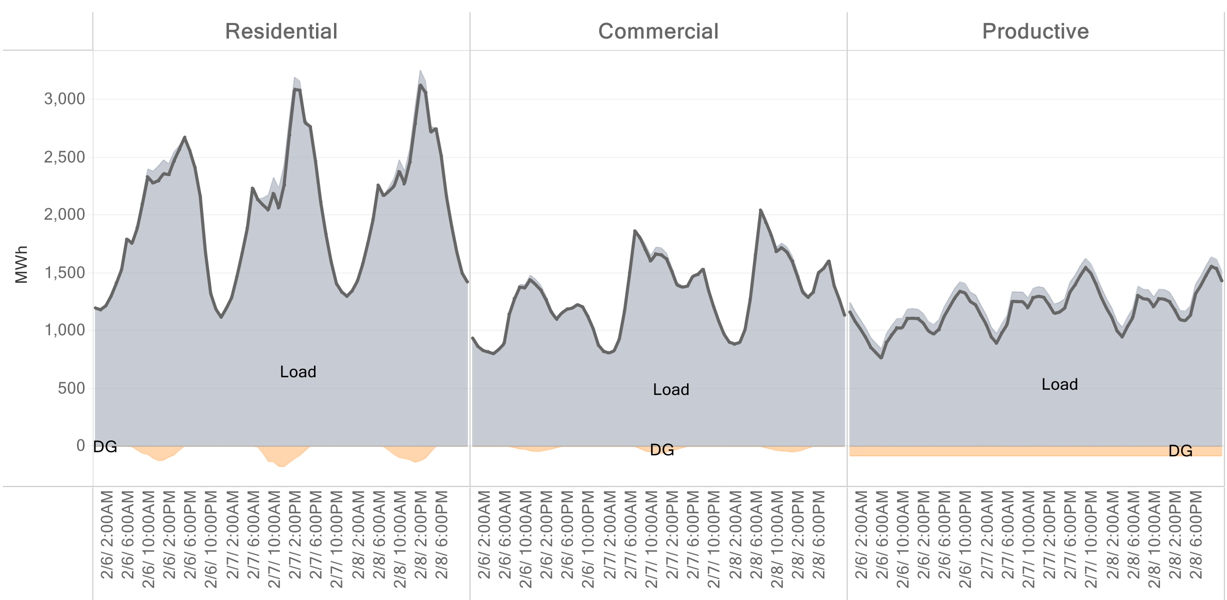
Figure 4 EnergyPATHWAYS Electricity System Structure



System load shapes are developed from the “bottom-up” by multiplying hourly sector, sub-sector, and technology-specific load shapes by the associated annual electricity consumption.[6] The bottom-up shape is then calibrated against a historical, top-down system load shape. Going forward, the system load shape changes in each year as the contribution from end-uses evolves. For example, as LED lighting penetration increases, then night-time demand will decrease due to their higher efficiency relative to incandescent and CFL light bulbs. In addition, the electrification of space heating will increase electric load during winter hours to account for the contribution of heating during winter months.

Sub-sector loads are aggregated to sectors and mapped to a “stylized” residential, commercial and/or productive (industrial) feeder, which models customer type at the distribution level. This is primarily to allocate electric vehicle charging, which could take place at home or at the workplace, onto the electricity distribution system. Distributed generation, such as combined heat and power (CHP) and rooftop solar PV resources are modeled across feeders. Figure 5 shows load and distributed generation for three feeders with the net load shown as the black line.

Figure 5 Distribution System: Net Load

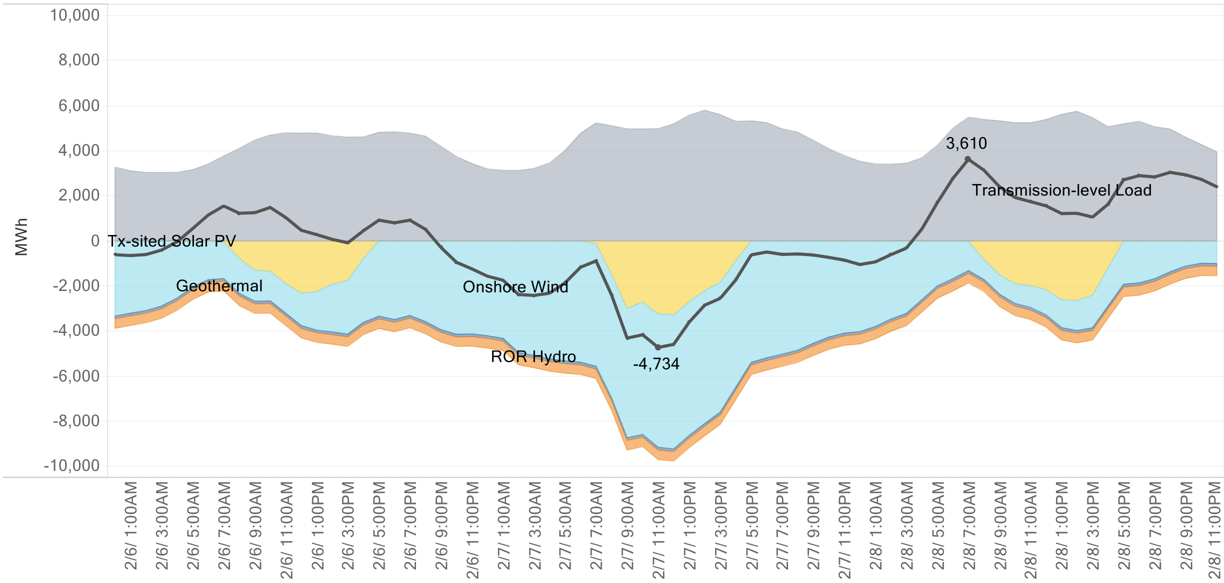


Note: figure is illustrative.

The bulk transmission system receives the distribution-level net load and combines them with transmission-level loads, such as electrolysis and power-to-gas facilities. Output from non-dispatchable resources on the transmission system, such as wind, solar, geothermal and run-of-river hydro, is then accounted for to produce an initial system net load signal, as shown in Figure 6 below. During this three-day snapshot, the minimum net load in a single hour is -4,734 MW due to the coincidence of high wind and solar generation.

[6] Load and resource shapes reflect 2011 weather conditions.

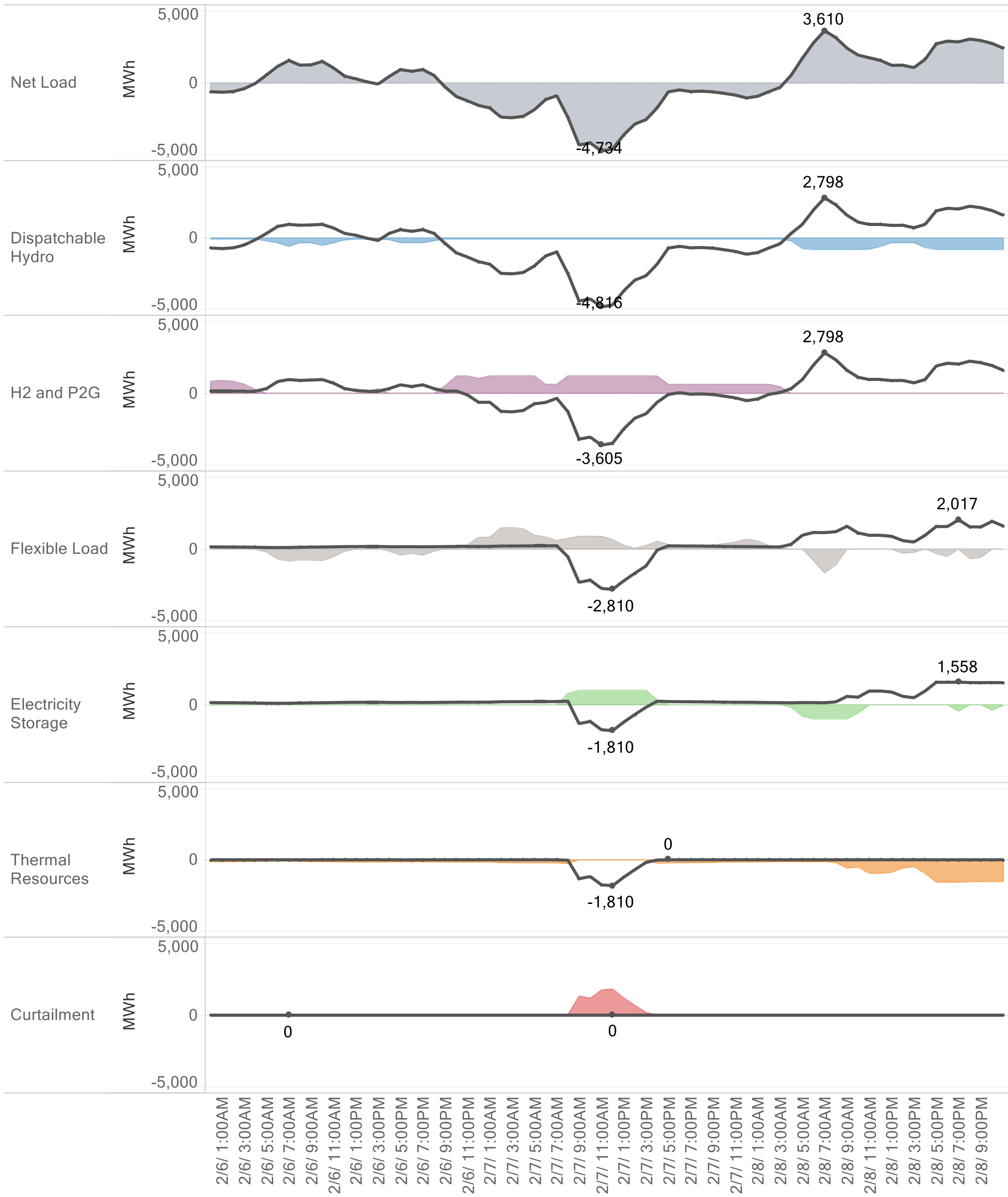
Figure 6 Transmission System: Net Load



Note: figure is illustrative.

Figure 7 illustrates the dispatch of flexible resources in sequence, with each resource dispatching to minimize the net load peaks and valleys. During the three-day period, net load starts with a maximum of 3,610 MW and and a minimum of -4,734 MW. Flexible, carbon-free resources, including dispatchable hydro plants, electric fuel production facilities, flexible loads and energy storage, flatten the net load to a maximum of 1,558 MW and a minimum of -1,810 MW. Thermal generators are dispatched in order of marginal cost to serve the remaining positive net load, while the remaining negative net load is curtailed.

Figure 7 Flexible Resource Dispatch



Note: figure is illustrative.

We model all generation resources in PGE's system, including existing power plants and contracts. The capacity of these resources was provided by PGE, and we developed plant heat rates (efficiencies) for thermal resources based on historical generation and fuel input data from Form EIA-923. Hydro resources are differentiated between dispatchable (e.g., Pelton-Round Butte) and run-of-river, and both resources types are constrained by a monthly energy budget. For imports, we use projected electricity market prices (in $/MWh) and natural gas prices (in $/MMBtu) provided by PGE to develop market heat rates (in MMBtu/MWh) to both cost and assign an emissions intensity.

We use the following heuristic to ensure the quantity of installed generating capacity meets system load in every hour of the year. First, "annual capacity need" is estimated as the maximum hourly net load plus operating reserves. Next, the installed capacity of dispatchable resources is de-rated by their forced outage rate to estimate their contribution. Finally, generic capacity resources are added to fill any gap between "annual capacity need" and the contribution of dispatchable resources. We assume generic capacity resources have the cost and performance characteristics of a frame type combustion turbine, which is consistent with PGE's IRP.

We note that our modeling results may differ from PGE's IRP due to the use of alternative models and the inclusion of direct access loads in our scope. We describe the electricity resources for each scenario in Section III.B.1 below.

C. Energy Demand and Supply

EnergyPATHWAYS was originally developed to assess deep decarbonization for the United States, and most of the energy demand and supply inputs are drawn from the EIA's National Energy Modeling System (NEMS) that produces the *Annual Energy Outlook*.[7] NEMS input data is comprehensive of the U.S. energy system and internally consistent. The primary geography for energy demand in NEMS is the census division, which each include a collection of states. For example, the Pacific census division includes Washington, Oregon and California, while the Mountain census division aggregates the remaining states in the West.

Given the common input data and energy system representation, EnergyPATHWAYS also uses census division as the primary geography. However, the model is geographically flexible by accepting energy demand and supply input data at a variety of geographical resolutions (e.g., state-level) and mapping these together onto one consistent geography. We used this geographic mapping feature to develop the underlying energy system representation for PGE's service territory. Figure 8 illustrates this process, where energy system data for a variety of geographies is mapped to PGE's service territory. This "downscaled" energy data is combined with direct inputs of PGE's service territory to characterize the entire energy system. To allocate input data at various geographical resolutions to PGE's service territory, we used: (1) households by county in PGE's service territory; (2) land area (in square miles) by county in PGE's service territory; and (3) value of shipments of products by industrial sector by state of origin, which allows us to estimate the quantity of industrial activity within a given subsector and state.[8]

[7] For example, see Risky Business Project (2016).

[8] PGE provided county-level households and land area. Value of shipments data is from the Bureau of Transportation Statistics and Federal Highway Administration's 2015 Freight Analysis Framework.

Figure 8 Geographic Downscaling

Table 2 summarizes the primary input data sources for energy demand by subsector. We use the 2013 PGE Residential Appliance Saturation Survey (RASS) to characterize the existing stock of the residential space heating, air conditioning and water heating subsectors. This includes the composition of technologies and fuels used in single-family, multi-family and manufactured homes. Energy use intensity (energy consumption per stock) is derived from the EIA's Residential Energy Consumption Survey (RECS) and the Northwest Energy Efficiency Alliance's (NEEA) Residential Building Stock Assessment. Energy demand for the remaining residential subsectors (e.g., refrigerators, dishwashers, etc.) is from the EIA AEO 2017. Vehicle miles traveled (VMT) for light-, medium- and heavy-duty vehicles are from Oregon's 2017 Highway Cost Allocation Study (HCAS), while the remaining energy demand is primarily from the EIA's AEO 2017.

Table 2 Summary of Energy Demand Input Data

Demand Subsector	Input Data Sources	Input Data Geography
Residential Space Conditioning and Water Heating	PGE 2013 RASS Study: existing stocks	Service Territory
	EIA RECS and NEEA: energy use intensity	State
Other Residential Subsectors	EIA AEO 2017: energy demand	Census Division
Commercial Subsectors	NWPCC 7th Power Plan: square footage	State
	EIA AEO 2017: energy demand	Census Division
Industrial Subsectors	EIA AEO 2017: energy demand	Census Region
Passenger and Freight Transportation	2017 Oregon HCAS: vehicle miles traveled	State

We compared the initial bottom-up energy demand projections against top-down energy demand data from the EIA's State Energy Data System (SEDS), which includes historical energy demand by fuel and sector. We calibrated EnergyPATHWAYS to reconcile any differences between our near-term modeling outputs and historical data by scaling energy service demand or energy demand. We further calibrated electricity consumption by sector to ensure consistency with PGE's load forecast through 2050.

Energy demand projections are developed separately for a variety of final energy types, which can broadly be categorized as: (1) electricity; (2) pipeline gas; and (3) liquid fuels.[9] Table 3 summarizes the types of resources that can supply each final energy type, and the supply mix determines the emissions intensity of fuels. For example, electricity can be supplied by a variety of fossil and carbon-free

[9] Additional final energy types are modeled, but these represent the vast majority of final energy demand.

resources, and Section III.B.1 details electricity supply assumptions for PGE's service territory. Pipeline gas can be supplied with a mix of natural gas, renewable natural gas (RNG) produced from bioenergy, hydrogen (H2) produced through electrolysis, and synthetic natural gas (SNG) produced though power-to-gas (P2G). Liquid fuels are supplied by refined fossil sources, as well as fuels developed using bioenergy (i.e., renewable diesel and jet fuel).

Table 3 Final Energy Types and Supply Sources

Category	Final Energy Type	Supply Sources
Electricity	Electricity	Coal and natural gas (fossil); hydro; wind; solar PV; geothermal
Pipeline Gas	Pipeline Gas	Natural gas (fossil); RNG (biomethane); H2; SNG
	Compressed Pipeline Gas (CNG)	
	Liquefied Pipeline Gas (LNG)	
Liquid Fuels	Gasoline	Fossil gasoline; ethanol
	Diesel	Fossil diesel; renewable diesel
	Jet Fuel	Fossil jet fuel; renewable jet fuel

D. Biomass

Biomass is key resource for decarbonizing energy systems due to its versality, which allows for biofuels to directly replace both liquid and gaseous fossil fuels. Examples of conversion routes include renewable natural gas (RNG) that replaces natural gas and renewable diesel that replaces diesel. However, the supply of sustainable or net-zero carbon bioenergy resources is limited, and, in prior analyses, scarce bioenergy resources are allocated to fuels and sectors that are challenging to electrify, such as jet fuel for aviation.

In this study, we use the U.S. Department of Energy's *2016 Billion-Ton Report* as the primary source for the availability and cost of bioenergy resources. Given that the supply curve is for the U.S., we make the following assumptions. First, the PGE service territory's allocation of the national supply is its population-weighted share, which is equal to 7.3 million dry tons (MDT), as shown below:

$$PGE's\ share = \frac{PGE\ population}{U.S. population} \times U.S. supply\ of\ sustainable\ biomass\ feedstocks$$

$$7.3\ MDT = \frac{1.8\ million}{320.9\ million} \times 1{,}300\ MDT$$

Second, we assume that other jurisdictions pursue similar bioenergy-related actions, which means that the cost of producing and consuming biofuels reflects movement up the national supply curve. This assumption addresses two considerations: (1) for sub-national (e.g., state or utility service territory) deep decarbonization analyses, it would be unrealistic to assume individual jurisdictions all consume the same (low-cost) portion of the bioenergy supply curve; and (2) given the high cost of transporting biomass across long distances, it's likely that biofuels would be developed close to their source and transported across the country via the same networks that currently transport fossil fuels. Finally, we assume that the biomass feedstock is net-zero carbon, which results in biofuels with very low emissions rates due to some emissions from non-bioenergy use in conversion and refining processes.

E. Key Data Sources

Table 4 summarizes the key data sources used in our energy system modeling. We use data from PGE's 2016 IRP to characterize the cost and performance of electricity supply technologies and rely on the 2013 PGE RASS study to characterize the existing stock of residential appliances, as described above. This is supplemented by state and regional data sources, such as Oregon's Office of Economic Analysis (OEA) and the Northwest Energy Efficiency Alliance (NEEA). Most of the remaining sources are publicly-available reports produced by national laboratories, such as the U.S. Department of Energy (DOE).

Table 4 Overview of Key Data Sources

Category	Sources
Energy Supply Technology Cost and Performance	• PGE 2016 Integrated Resource Plan • NREL Annual Technology Baseline 2017 • EIA Form 923 • DOE Hydrogen Analysis (H2A) Project • ENEA Consulting (2016)
End-Use Technology Cost and Performance	• Input data for EIA's National Energy Modeling System (NEMS) used to produce the Annual Energy Outlook • NREL Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections
Building Stock Characteristics	• PGE 2013 Residential Appliance Saturation Study • NEEA Building Stock Assessment reports
Fossil Fuel Prices	• EIA Annual Energy Outlook 2017
Miscellaneous	• DOE 2017 Billion-Ton Report • FERC Form 714 • 2017 Oregon Highway Cost Allocation Study • OEA Forecasts of Oregon's County Populations and Components of Change, 2010 – 2050

Note: DOE is the U.S. Department of Energy; EIA is the U.S. Energy Information Administration; FERC is the Federal Energy Regulatory Commission; NEEA is the Northwest Energy Efficiency Alliance; NREL is National Renewable Energy Laboratory; and OEA is Oregon's Office of Economic Analysis.

III. Scenarios

A. Overview

Table 5 provides an overview of the three pathways included in this study, which each incorporate alternative emissions reduction strategies and technologies. One of the primary objectives of our scenario design was to reflect a broad range of outcomes for the electricity sector.

The **High Electrification** pathway relies on electrifying space and water heating in buildings and deploying bulk energy storage to balance high levels of renewable generation. Passenger transportation is characterized by high levels of battery electric vehicles (BEV), while freight transportation includes both battery electric and hybrid diesel trucks. The **Low Electrification** pathway decarbonizes energy supply with a variety of renewable fuels, and electrolysis and power-to-gas facilities provide both electricity balancing services and decarbonized pipeline gas. Passenger transportation is primarily BEV, while compressed and liquefied natural gas trucks are incorporated in the freight transportation sector. The **High DER** pathway is highly electrified and distributed, with increased rooftop solar PV and distributed energy storage in buildings and industry.

To provide a benchmark to compare the pathways against, we developed a **Reference Case** that projects business-as-usual conditions. This includes compliance with state-level policy such as the OCEP and CFP, as well as major federal policy such as improvements in corporate average fuel economy standards. The scenario is not designed to achieve an emissions target.

Table 5 Overview of Scenarios

Scenario	Description
High Electrification	Fossil fuel consumption is reduced by electrifying end-uses to the extent possible and increasing renewable electricity generation
Low Electrification	Greater use of renewable fuels, notably biofuels and synthetic electric fuels, to satisfy energy demand and reduce emissions
High DER	Distributed energy resources proliferate in homes and businesses, which also realize higher levels of electrification
Reference	A continuation of current and planned policy, and provides a benchmark against the deep decarbonization pathways

Although the future energy scenarios are characterized by alternative mitigation strategies, they are all constrained by a set of common scenario design principles. This conservative approach allays a broad range of concerns surrounding the technical feasibility and economic affordability of realizing a deeply decarbonized energy system, such as the need for revolutionary technological improvements or disruptive lifestyle changes. The scenario design principles in this analysis include: (a) applying the same demand for energy services; (b) replacing energy infrastructure at the end of its natural life (i.e., there are no early retirements); (c) using commercial or near-commercial technologies; (d) limiting the supply of sustainable bioenergy use; and (e) ensuring there are sufficient electricity resources to serve load in all hours. The sections below describe the energy supply and demand assumptions for each pathway.

B. Energy Supply

1. Electricity Resources

Table 6 summarizes our electricity supply assumptions for each pathway. Coal-fired resource assumptions are consistent with PGE's 2016 IRP and OCEP, where Boardman ceases operations by the end of 2020 and Colstrip units 3 and 4 are out of the resource mix by 2035. We assume the capacity of PGE's existing gas-fired resource fleet is online through 2050, while the amount of energy generated from these resources is a function of our electricity dispatch.

Hydroelectric resources include Pelton-Round Butte, run-of-river (ROR) hydro, Mid-C hydro and other contracts. We assume projected hydro resources and contracts are extended through 2050 (a total of 933 MW), and an additional 23 MW of small hydro is placed on-line in 2035. We assume new geothermal resources of 100 MW in 2035 and growing to 500 MW by 2050. Prior studies have identified 832 MW of conventional geothermal potential in Oregon with a further undiscovered enhanced geothermal system potential of 1,800 MW.[10]

The High DER pathway includes approximately 2,500 MW of behind-the-meter (BTM) solar PV resources across buildings and industry by 2050. We developed this target based on the technical potential of distributed solar PV across PGE's service territory identified in the 2016 IRP.[11] The High and Low Electrification pathways assume approximately 400 MW of BTM solar PV, which is two times the highest level of adoption from the same study.

Pathways rely on high levels of transmission-connected wind and solar PV to decarbonize electricity generation, including: (a) onshore wind located in the Pacific Northwest (PNW); (b) onshore wind located in central Montana; and (c) solar PV located in central Oregon. Approximately 75 percent of electricity generation comes from these resources in the High and Low Electrification pathways, and this level is lower in the High DER pathway due to the quantity of BTM solar PV resources. The installed capacity of these resources depends on the level of transmission-connected load.

Our Reference Case reflects current RPS policy (i.e., 50% in 2040) and any gap between the RPS obligation and generation from existing/projected qualifying resources is met with an equal amount of energy from PNW onshore wind and central Oregon utility-scale solar PV resources. Our analysis did not consider low-carbon generation from new carbon capture and storage (CCS) or nuclear resources.

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[10] See Pletka and Finn (2009).

[11] See Table 1-3 of Black and Veatch (2015). Technical potential of 2,810 MW_{dc} translated to 2,555 MW_{ac} assuming an inverter loading ratio of 1.1.

Table 6 Electricity Supply

	High Electrification	Low Electrification	High DER
Coal	Boardman ceases operations by the end of 2020 Colstrip 3 and 4 out of the resource mix by 2035		
Gas	Maintain current fleet		
Hydro	Extend projected hydro contracts through 2050 (933 MW) Additional 23 MW of small hydro		
Geothermal	500 MW additional		
Behind-the-meter Solar PV	405 MW_{ac}		2,555 MW_{ac}
Utility-scale Wind and Solar PV	75% of electricity generation		67% of electricity generation

Note: values for 2050 unless specified otherwise.

The high levels of variable renewable generation included in the pathways necessitate balancing resources to ensure renewables are sufficiently integrated. Table 7 summarizes the flexible resource assumptions for each pathway, all of which include 36 MW/160 MWh of energy storage that comes online in 2021 to approximate PGE's proposed energy storage projects. Balancing in the High Electrification pathway is accomplished through 1,000 MW of bulk 8-hour energy storage, whereas the High DER pathway relies on 2,555 MW of distributed 6-hour storage, which is sized to the same capacity of distributed solar PV. No additional energy storage is developed in the Low Electrification pathway, which alternatively relies on flexible electrolysis and P2G loads. The size of these facilities depends on demand for hydrogen and synthetic natural gas, respectively.

All pathways incorporate flexible demand from select end-use sectors where: (a) load automatically shifts with changing electricity grid conditions; and (b) total electricity consumption does not change.[12] For example, the owner of an EV may wish to charge his or her vehicle when they arrive home, but they're willing to delay charging to later in the evening without affecting the ability to take future trips. Two promising electric loads to operate flexibility include: (1) loads that have a thermal storage medium (i.e., hot water heater) that can operate within a range and allow for flexible operation without service degradation; and (2) transportation loads that require battery storage, which can allow for flexible charging and state-of-charge management without degrading service.

We assume 75 percent of load from light-duty vehicles and water heaters in buildings is flexible by 2050, and 50 percent is flexible in residential space conditioning, residential clothes washing and drying, and commercial space heating subsectors. The amount of flexible load in each pathway depends on the level of electrification, and the higher quantity of electric appliances (e.g., heat pump water heaters) in the High Electrification and High DER pathways provides higher end-use demand flexibility relative to the Low Electrification pathway.

[12] Flexible load is further constrained by the number of hours load can be delayed and advanced in time.

Table 7 Balancing Resources

	High Electrification	Low Electrification	High DER
Energy storage	Proposed energy storage resources (36 MW / 160 MWh)		
	1,000 MW bulk 8-hour storage	No additional	2,555 MW distributed 6-hour storage
Flexible Electric Fuel Loads	Excluded	H2 electrolysis and P2G facilities	Excluded
Flexible End-Use Loads	Percent of electric load that is flexible by 2050: • Light duty vehicles = 75% • Residential and commercial water heating = 75% • Residential space conditioning = 50% • Residential clothes washing and drying = 50% • Commercial space heating = 50%		

2. Liquid and Pipeline Gas Fuel Blends

Table 8 summarizes our assumptions about the composition of pipeline gas, diesel and jet fuel in 2050. The Low Electrification pathway is characterized by several renewable fuels to decarbonize energy supply. Pipeline gas for buildings and industry is assumed to contain 15 percent renewable natural gas (RNG) and 15 percent synthetic electric fuels (H2 and SNG). The share of RNG is 85 percent in pipeline gas that is further liquefied or compressed for transportation vehicles, while the share of H2 and SNG is the same. Biomass is further used to produce liquid transportation fuels (e.g., renewable diesel). The High Electrification and High DER pathways assume no change to the supply of pipeline gas, with all biomass resources allocated to liquid transportation fuels.

Table 8 Liquid and Pipeline Gas Fuel Blend Assumptions in 2050

Type	Blend	High Electrification and High DER	Low Electrification	
		All Sectors	Res/Com/Ind	Transportation
Pipeline Gas	Natural Gas	100%	70%	0%
	RNG	0%	15%	85%
	SNG	0%	8%	8%
	H2	0%	7%	7%
Diesel	Fossil Diesel	0%	0%	0%
	Renewable Diesel	100%	100%	100%
Jet Fuel	Fossil Jet Fuel	0%	0%	0%
	Renewable Jet Fuel	100%	100%	100%

C. Energy Demand

1. Buildings and Industry

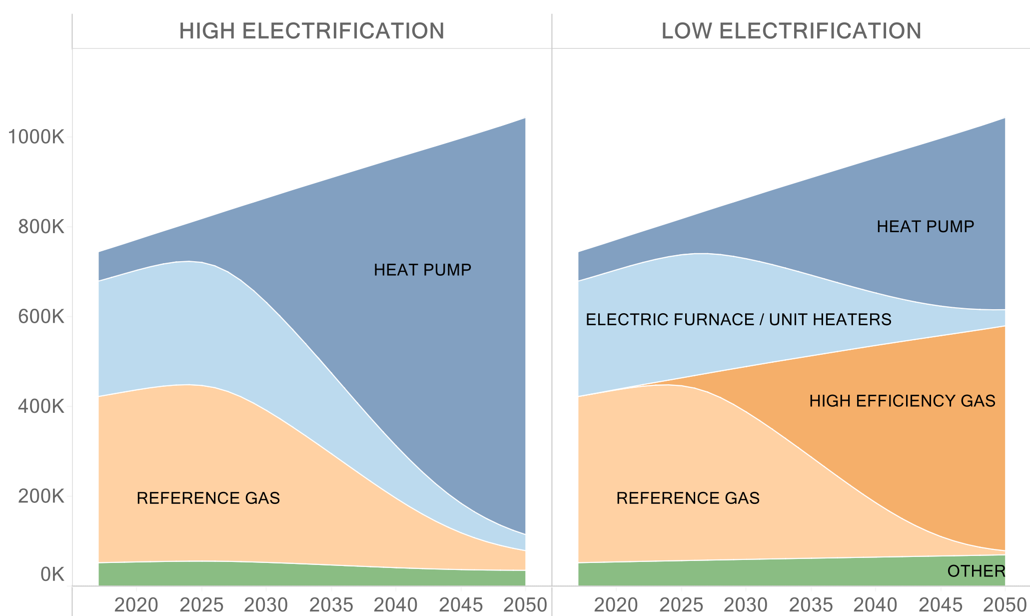
Table 9 summarizes the major low-carbon and efficient technologies in residential and commercial buildings. The High Electrification and High DER pathways are characterized by high levels of air source heat pump (ASHP) adoption for space heating and cooling needs, as well as efficient heat pump water heaters. The Low Electrification pathway relies on high efficiency gas-fired equipment to service space and water heating loads. In both pathways, lighting is provided by LEDs and the best available technology is adopted for other appliances, such as clothes washers, clothes dryers, refrigerators, etc.

Table 9 Predominant End-use Technologies in Buildings

	High Electrification and High DER	Low Electrification
Space Conditioning	Air source heat pump	High efficiency gas furnace High efficiency air conditioner
Water Heating	Heat pump water heater	High efficiency gas water heater
Lighting	LED	
Other Appliances	Best available technology	

We illustrate the change in today's building equipment by showing the evolution of the residential space heating stock through 2050 in Figure 9. Heat in the High Electrification and High DER pathways is largely provided by heat pumps, which includes both standard systems and ductless, mini-split heat pumps. In contrast, heat in the Low Electrification pathway is met by adopting high-efficiency natural gas furnaces, as well as pursuing electric energy efficiency by replacing electric furnaces and heaters with heat pumps.

Figure 9 Residential Space Heating Stock



We incorporated electrification measures in the High Electrification and High DER pathways for a limited number of industrial end-uses, including process heat and boilers. This was informed by NREL's Electrification Futures Study and includes adoption of electrotechnologies such as industrial heat pumps, resistance heating, induction furnaces and electric boilers.[13] These measures translate into electricity representing slightly less than 10 percent of final energy demand for industrial boilers and process heat by 2050.

2. Transportation

Table 10 summarizes our assumptions for vehicle sales shares in 2035 for passenger transportation and freight trucks. In all pathways, battery electric vehicles (BEV) are 90 percent of light-duty vehicle sales, while the remaining 10 percent is: (a) plug-in hybrid electric vehicles (PHEV) in the High Electrification and Higher DER pathways; and (b) hydrogen fuel cell vehicles (HFCV) in the Low Electrification pathway. We assume battery electric trucks account for half of freight truck sales, while the remaining 50 percent is: (a) hybrid diesel trucks consuming renewable diesel fuel in the High Electrification and High DER pathways; and (b) CNG and LNG trucks consuming decarbonized gas in the Low Electrification pathway.

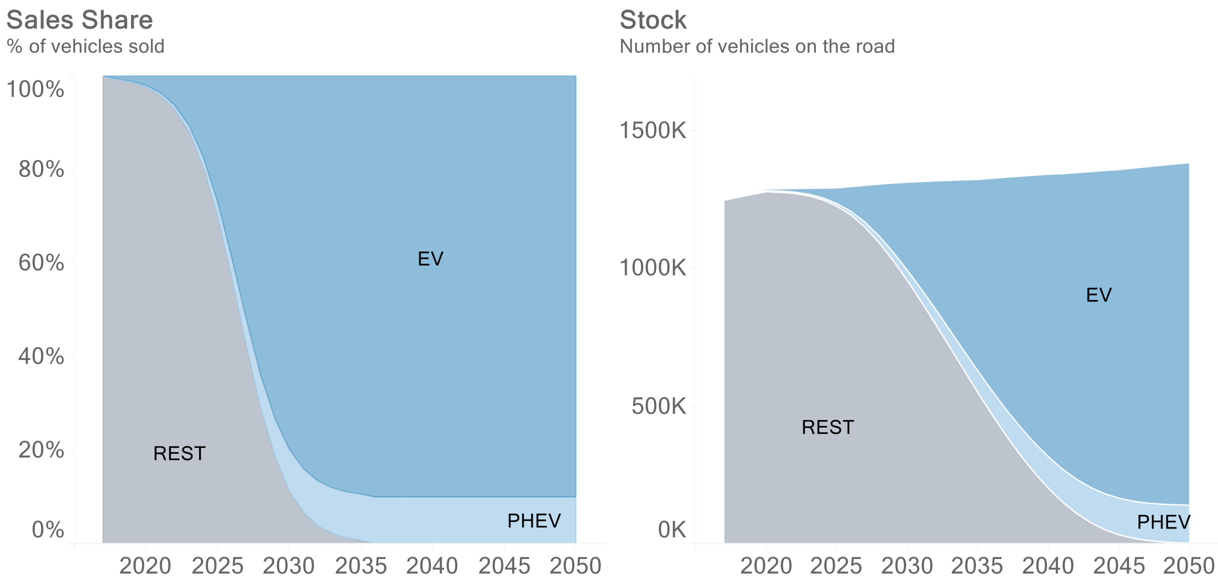
Table 10 On-Road Transportation Vehicle Sales Shares in 2035

Subsector	Technology Type	High Electrification and High DER	Low Electrification
Light-Duty Vehicles	Battery Electric	90%	90%
	Plug-in Hybrid Electric	10%	0%
	Hydrogen Fuel Cell	0%	10%
Medium-Duty Vehicles	Battery Electric	50%	50%
	Hybrid Diesel	50%	0%
	Hybrid CNG	0%	50%
Heavy-Duty Vehicles	Battery Electric	50%	50%
	Hybrid Diesel	50%	0%
	Hybrid LNG	0%	50%

Figure 10 shows how the assumptions in Table 10 change the stock of infrastructure over time, with light-duty vehicle sales shown on the left-hand side and the light-duty stock shown on the right-hand side. In the near-term, EV and PHEV light-duty autos and trucks make up a small portion of sales, but then increase to all vehicle sales in 2035. By the early 2030s, there are more than half a million EVs and PHEVs on the road, but the stock of vehicles does not completely turn-over to ZEVs until the mid-century.

[13] See Section 4 of P. Jadun, et al. (2017).

Figure 10 Light-Duty Vehicle Stock-Rollover: High Electrification Pathway



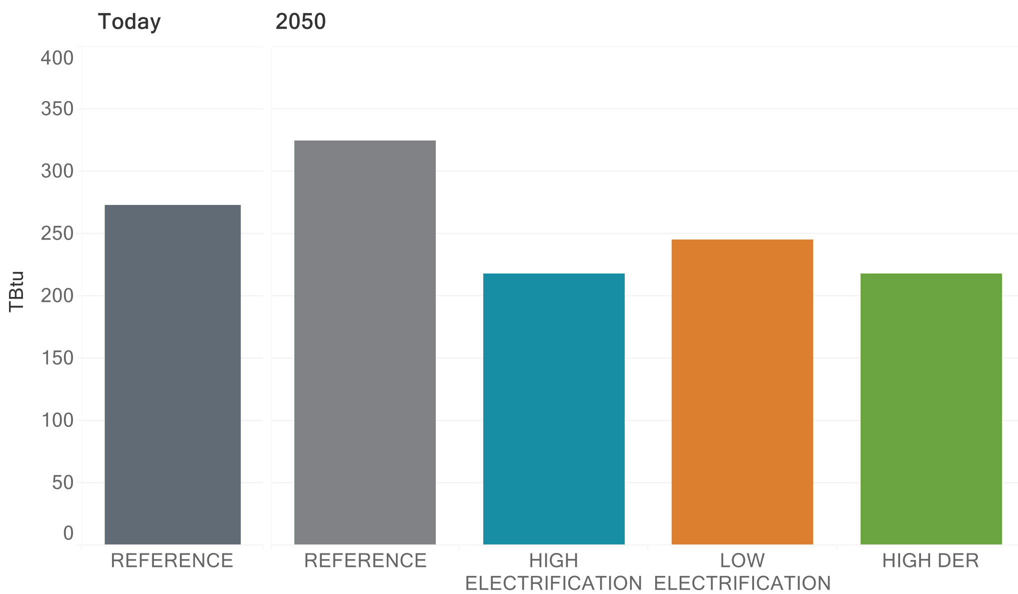
IV. Results: Energy System

In this section, we summarize the changes in the energy system for our future energy scenarios. We report several metrics for the energy system, including final energy demand, energy supply, energy related CO_2 emissions, and incremental energy system costs.

A. High-Level Summary

Reference Case final energy demand is projected to increase from 272 TBtu today to 325 TBtu, approximately a 20 percent increase, as shown in Figure 11 below. End-use demand is projected to increase as the drivers of energy use, such as population and economic activity, all grow through 2050. Final energy is used more efficiently in the pathways scenarios with a range of 218 to 245 TBtu by 2050, which represents a decrease of 25 to 33 percent below the Reference Case in 2050, and 11 to 19 percent below today's level.

Figure 11 Final Energy Demand



Energy-related CO_2 emissions are projected to slightly decrease (-4%) in the Reference Case between 2017 and 2050, as shown in Figure 12. This is largely due to existing policies decarbonizing electricity generation and transportation fuels being offset by growth in overall electricity consumption and vehicle miles traveled. Emissions for all three pathways are below the study's 2050 GHG target of 4.3 $MMTCO_2$. Emissions per capita decrease from 10.9 tCO_2 per person in 2017 to 1.6 tCO_2 per person in 2050, an 85 percent decrease.

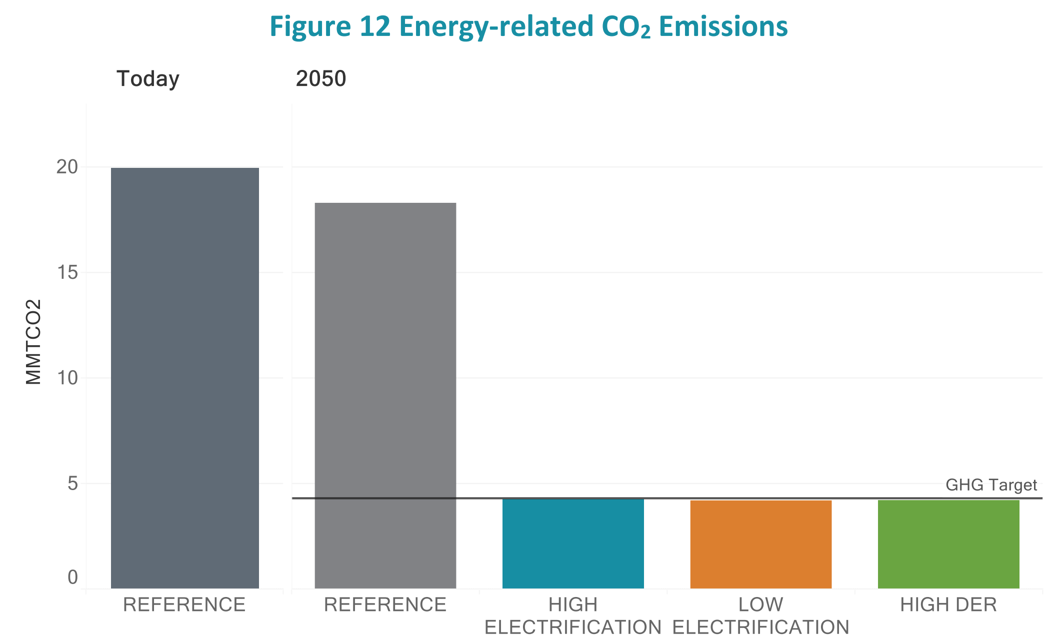
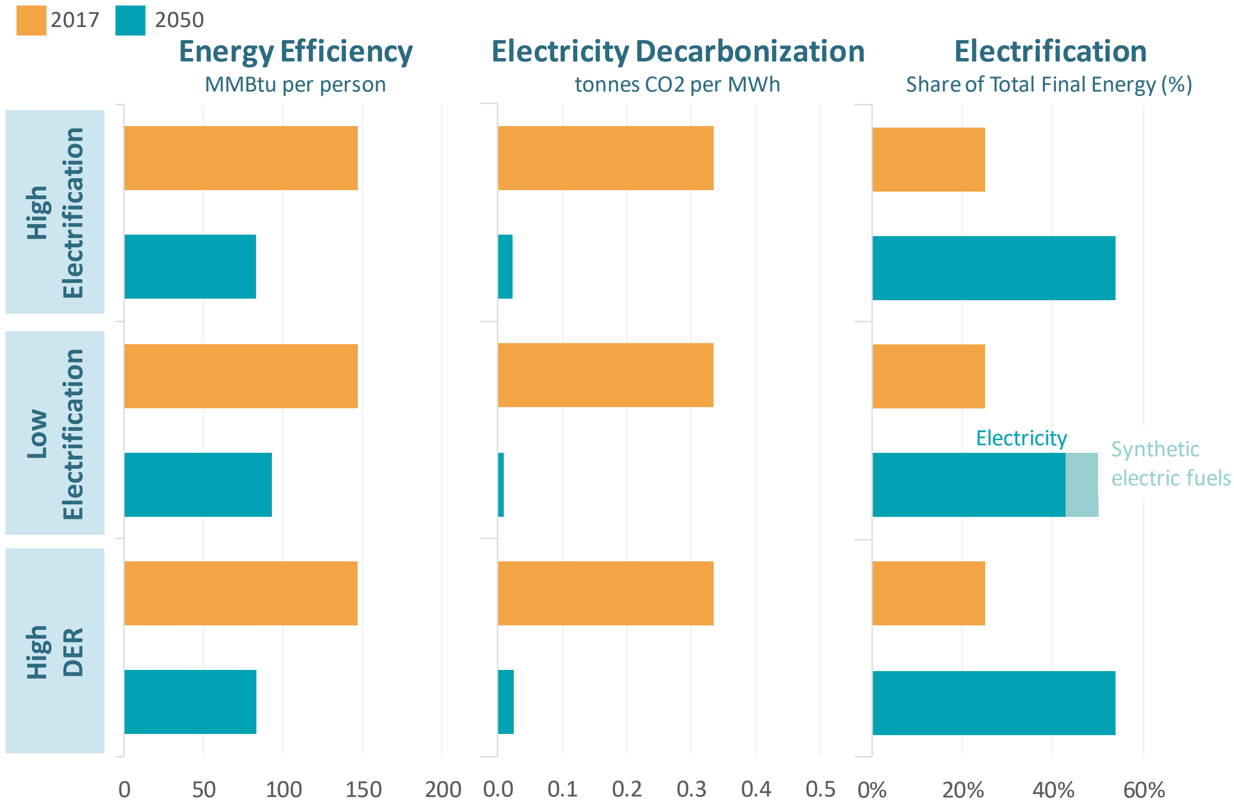


Figure 13 shows three metrics for decarbonization strategies ("three pillars"): (1) energy efficiency, which is estimated as final energy consumed per person; (2) electricity decarbonization, which is measured in tCO_2 emitted per MWh of generation; and (3) electrification, which is expressed as the share of total final energy that is electricity and electric fuels. Per capita energy consumption decreases from approximately 150 MMBtu per person today to between 83 and 93 MMBtu per person, a 37 to 44 percent decrease. This is accomplished without explicit reductions from baseline (Reference Case) energy service demand (e.g., vehicle miles traveled). The carbon intensity of electricity generation decreases by more than 90 percent and is below 0.03 tCO_2/MWh (300 kg CO_2/MWh) in all pathways. The percentage of electricity and electric fuels in total final energy increases from one-quarter today to at least half by 2050. In the Low Electrification pathway, the share of electricity is 43 percent (11 percentage points below the High Electrification pathway), but electric fuels make up 7 percent of total final energy, resulting in a total of 50 percent.

Figure 13 Three Pillars of Decarbonization



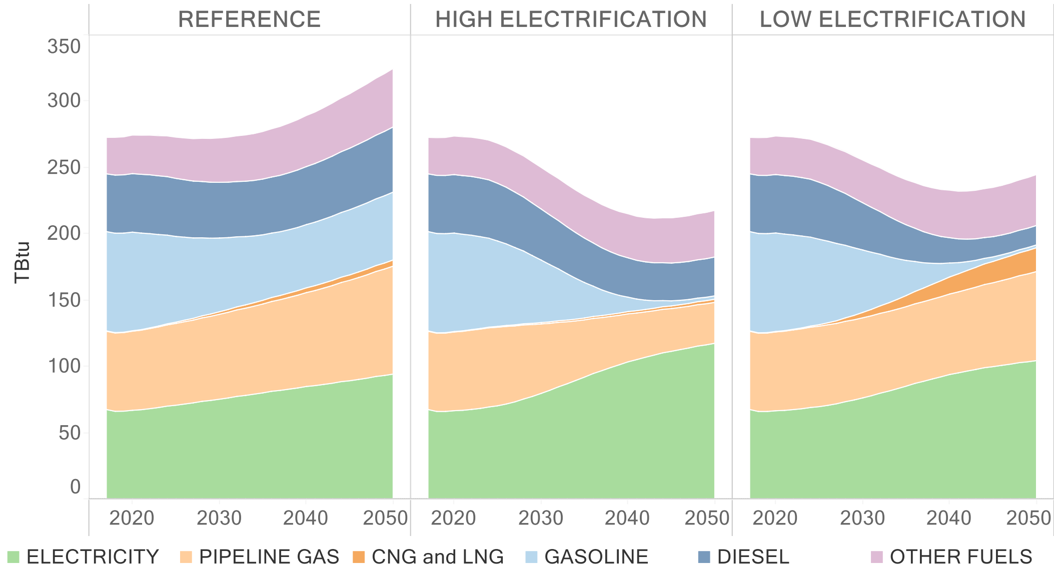
B. Energy Demand

Figure 14 shows end-use demand disaggregated by final energy type for each energy future.[14] The role of electricity expands across all pathways and increases from 25 percent of total end-use demand to 43 to 54 percent in 2050.[15] For comparison, the share of electricity only increases to 29 percent by 2050 in the Reference Case. Demand for liquid transportation fuels, such as gasoline and diesel, sharply decrease in all pathways. This decrease is compensated by higher demand for electricity, as well as CNG and LNG demand in freight transportation in the Low Electrification pathway.

[14] In this section, results for the High DER scenario are not shown, because final energy demand is equivalent to the High Electrification scenario. The impact of increased rooftop solar PV is accounted for when we show retail energy deliveries, which is discussed in Section V.A.

[15] This excludes synthetic electric fuels, which are categorized as "intermediate energy carriers".

Figure 14 Final Energy Demand by Type



Note: "Other Fuels" includes final energy types such as jet fuel, liquefied petroleum gas, biomass, and steam.

Figure 15 summarizes final energy demand for the residential, commercial, productive and transportation sectors. The figure shows Reference Case final energy demand growing over time, with decreases in the transportation sector (primarily due to fuel economy standards) offset by increases in buildings and industry. Total end-use demand decreases by 2050 for all pathways largely due to the efficiency improvements in passenger transportation related to adopting battery electric vehicles. As a result, the transportation sector's share of end-use demand decreases from approximately 46 percent today to 30 percent in 2050. Energy is used more efficiently in residential and commercial buildings, but the level of change varies across pathways based on technology adoption, which we discuss in more detail below.

Figure 15 Final Energy Demand by Sector

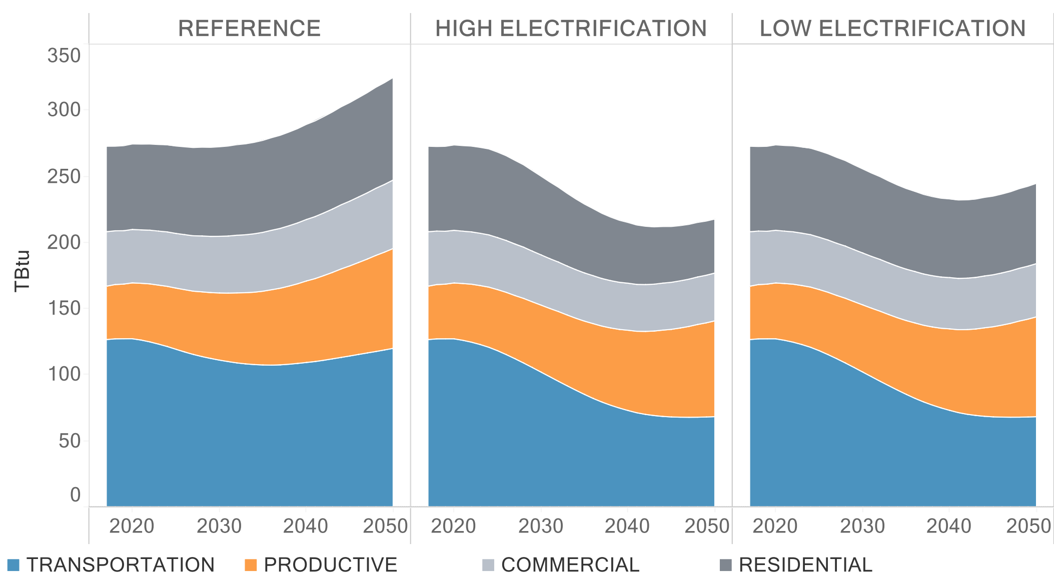
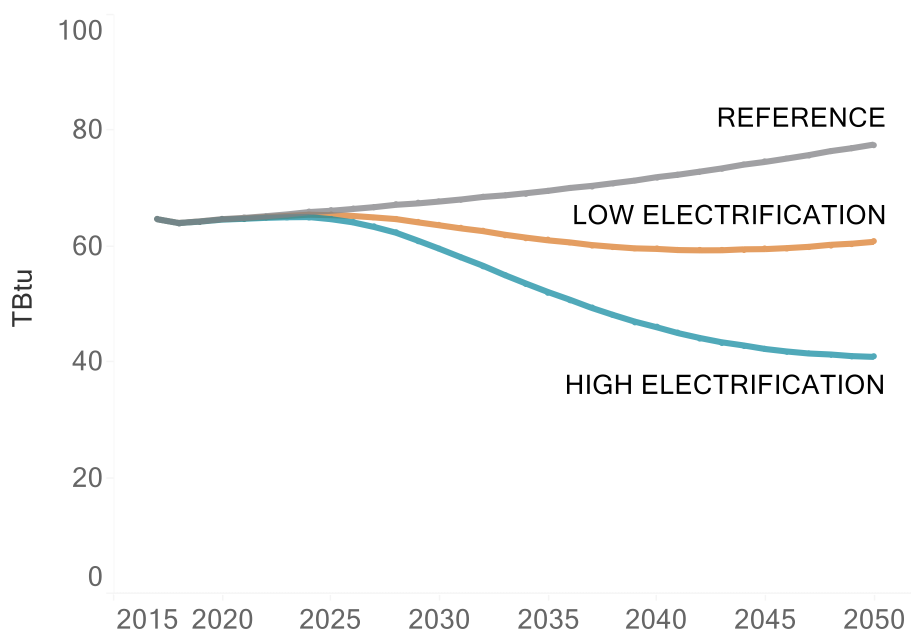


Figure 16 compares projections of residential energy demand and illustrates the improved use of energy in homes in the pathways scenarios relative to the Reference Case. All pathways include several electric energy efficiency measures, such as more efficient clothes washers and dryers, refrigerators, dishwashers and LED lighting. However, the large difference in final energy demand by 2050 between the High and Low Electrification scenarios is due to choices in space and water heating. The High Electrification pathway represents a world where households replace combustion-based furnaces and water heaters with air source heat pumps and heat pump water heaters, respectively. In the Low Electrification pathway, households adopt the most efficient gas furnaces and gas water heaters. However, the efficiency of heat pump technology relative to the best-in-class combustion equipment translates into deeper energy demand reductions.[16]

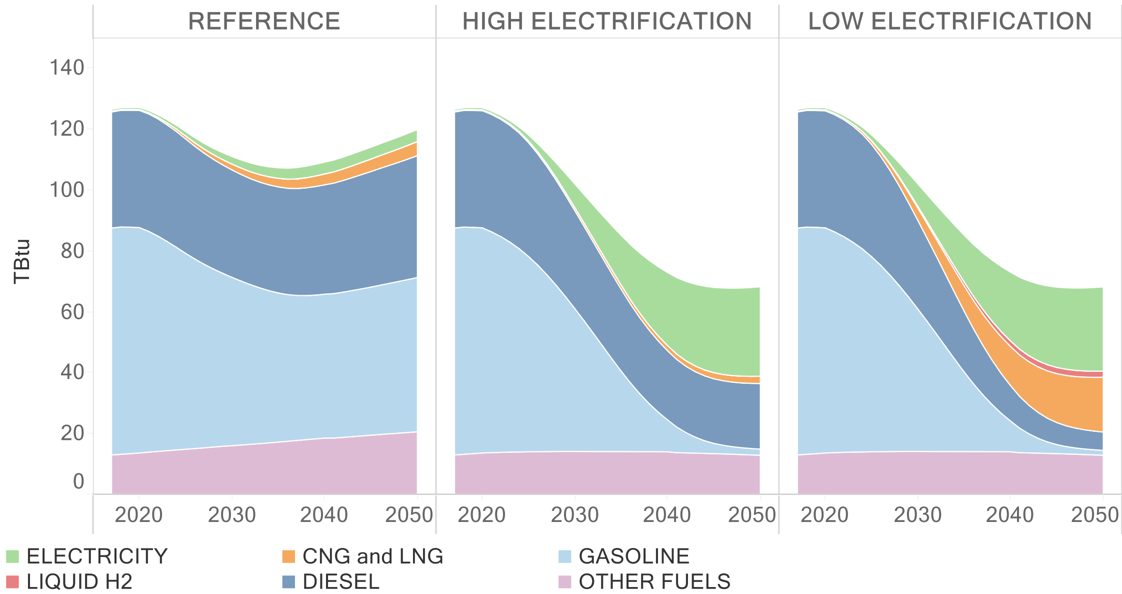
Figure 16 Residential Sector Energy Demand



The projections of energy demand for the transportation sector shown in Figure 17 reflect the changing composition of vehicles on the road. By 2050, the light-duty vehicle fleet is almost entirely electric vehicles, which results in significant decreases in gasoline fuel consumption and only modest increases in electricity consumption, because battery electric powertrains are more efficient than internal combustion engines. In all pathways, half of all freight trucks are electric by 2050, resulting in electricity becoming the largest transportation fuel type. The High Electrification pathway continues to use diesel fuel for the remainder of its freight trucks, but the supply is increasingly renewable diesel (100 percent by 2050). The Low Electrification pathway alternatively relies on hybrid CNG medium-duty trucks and LNG hybrid heavy-duty trucks. By 2050, demand from the CNG and LNG trucks in the Low Electrification pathway accounts for over 20 percent of total pipeline gas demand.

[16] For example, a high efficiency gas furnace has an annual fuel utilization efficiency (AFUE) of 0.98, whereas a standard air source heat pump installed in 2015 in the U.S. has a seasonal coefficient of performance (COP) of 2.45 and this is projected to increase to 3.75 by 2030. See Navigant Consulting (2014) and Jadun, et al. (2017).

Figure 17 Transportation Sector Energy Demand by Final Energy Type



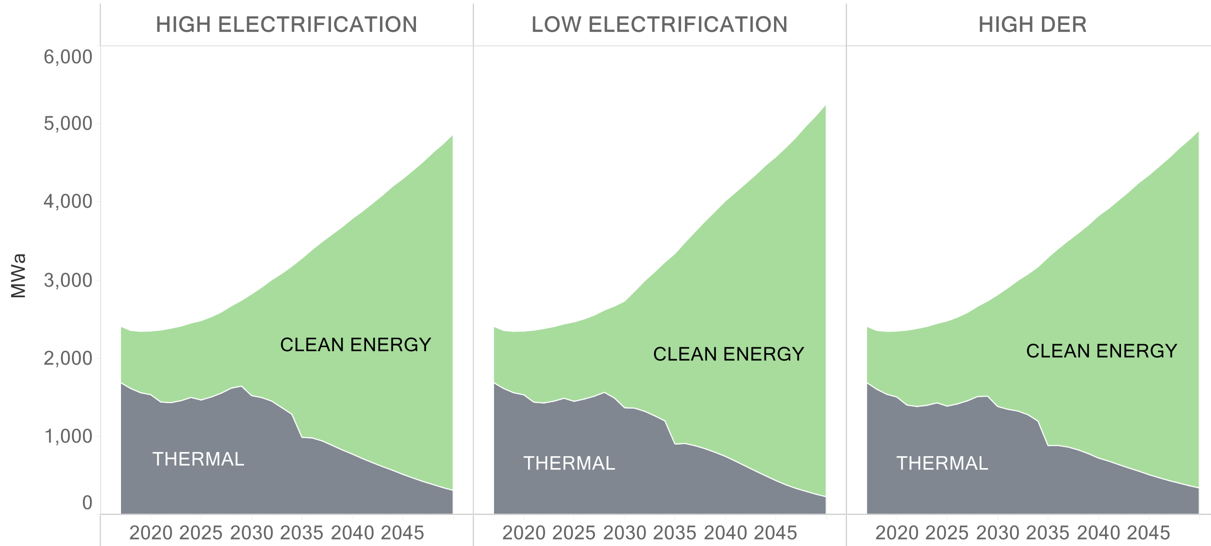
C. Energy Supply

1. Electricity

Figure 18 summarizes electricity supply through 2050, with generation from various resource types categorized as: (a) thermal, which includes generation from coal- and gas-fired resources, generic capacity and market purchases; and (b) clean energy, which includes generation from wind, solar, hydro and geothermal resources.[17] The figure shows that total electricity generation across all pathways grows rapidly, and total generation requirements in 2050 are more than double today's level. In all pathways, generation from non-emitting resources is more than 90 percent of the total and increases by 165 to 190 MWa per year between 2030 and 2050. Generation from thermal resources decreases significantly after 2035, and annual generation falls between 300 and 400 MWa by 2050.

[17] Our generation projections are not directly comparable to PGE's most recent IRP dispatch modeling due to the vintage of the load forecast provided for this study and the inclusion of direct access loads.

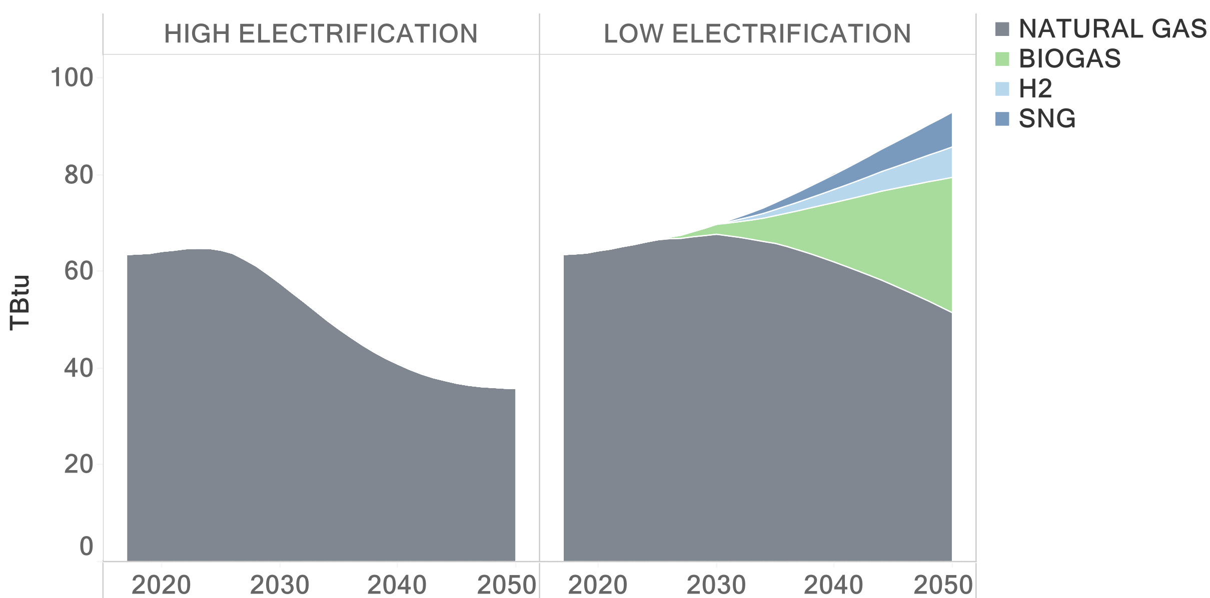
Figure 18 Electricity Supply



2. Pipeline Gas

Figure 19 compares pipeline gas supply for the High Electrification and Low Electrification pathways. In the High Electrification pathway, the pipeline gas supply remains entirely natural gas and total supply decreases by more than 40 percent relative to today due to electrification in buildings. Pipeline gas is decarbonized in the Low Electrification pathway with a combination of biogas and synthetic electric fuels, which reduces the share of natural gas to approximately 55 percent by 2050. Total gas supply increases by approximately 40 percent relative to today largely due to incremental gas demand from freight trucks with only a portion offset by more efficient use of pipeline gas in buildings.

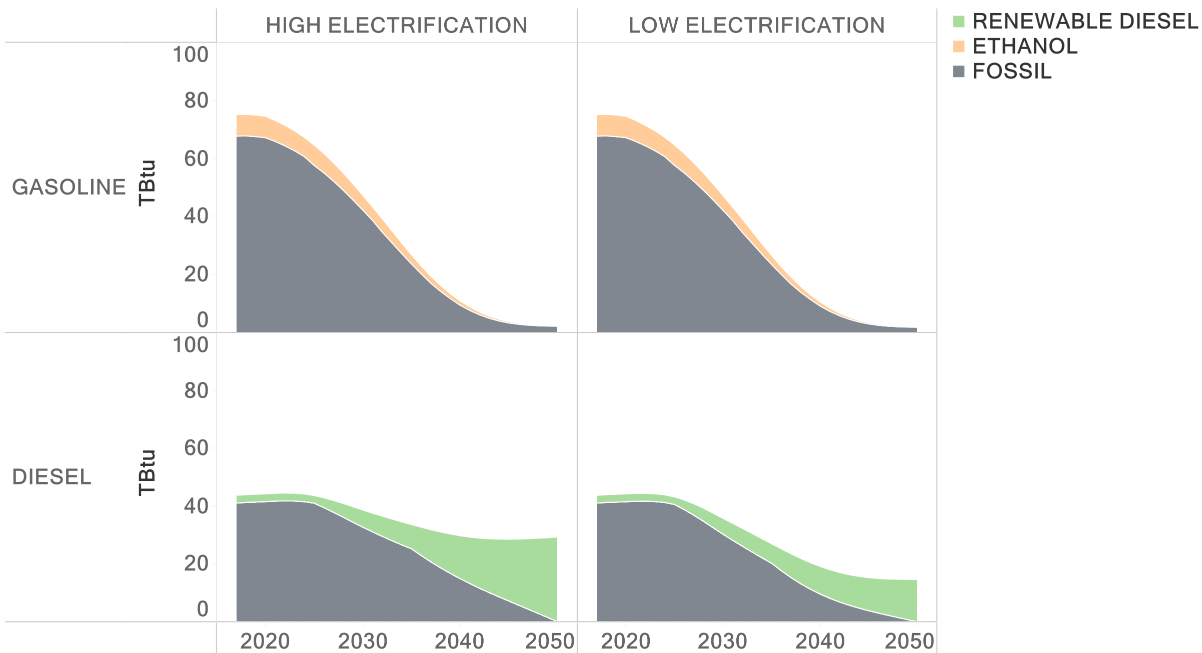
Figure 19 Pipeline Gas Supply



3. Liquid Fuels

Figure 20 summarizes the supply of today's two largest liquid fuels: gasoline and diesel. The supply of gasoline decreases by more than 95 percent by 2050 due to adoption of BEV, PHEV and HFCV vehicles in passenger transportation. Diesel remains a major fuel type in the High Electrification pathway, where half of freight trucks are hybrid diesel trucks. However, diesel supply transitions to 100 percent renewable diesel by 2050. The same supply transition occurs in the Low Electrification pathway, but total demand decreases by two-thirds by 2050 relative to today due to a shift from diesel trucks towards LNG and CNG freight trucks.

Figure 20 Liquid Fuels Supply



D. Energy-related CO_2 Emissions

Figure 21 and Figure 22 summarize energy-related CO_2 emissions by sector and energy type, respectively. The transportation sector's emissions, which is the largest source of emissions today, decrease by more than 90 percent across all pathways. This is the largest reduction by sector and total transportation emissions are less than the combined emissions from residential and commercial buildings by 2050. The transportation sector is primarily decarbonized through the following strategies: (1) electrification of passenger vehicles and freight trucks paired with very low-carbon electricity generation; and (2) decarbonization of liquid and gaseous fuels supplying the remaining fleet of freight trucks with bioenergy. The productive sector contains the largest remaining CO_2 emissions by 2050, and these are primarily from the direction combustion of fossil fuels, as opposed to emissions associated with electricity consumption. Most of the residual emissions in buildings are from combusting pipeline gas, and these are 50 percent higher in the Low Electrification pathway relative to the other pathways.

Figure 21 CO_2 Emissions by Sector

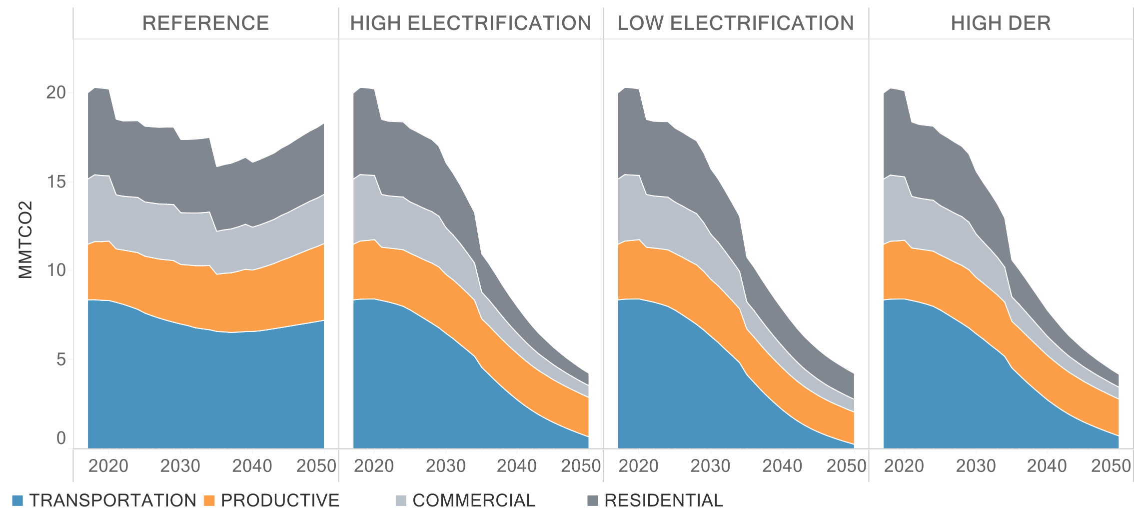


Figure 22 CO_2 Emissions by Energy Type

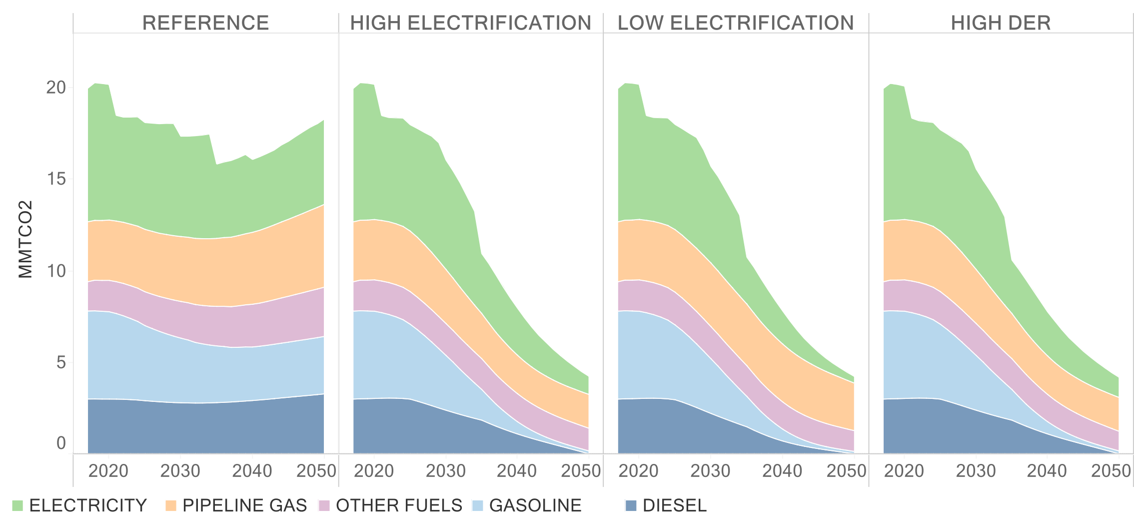
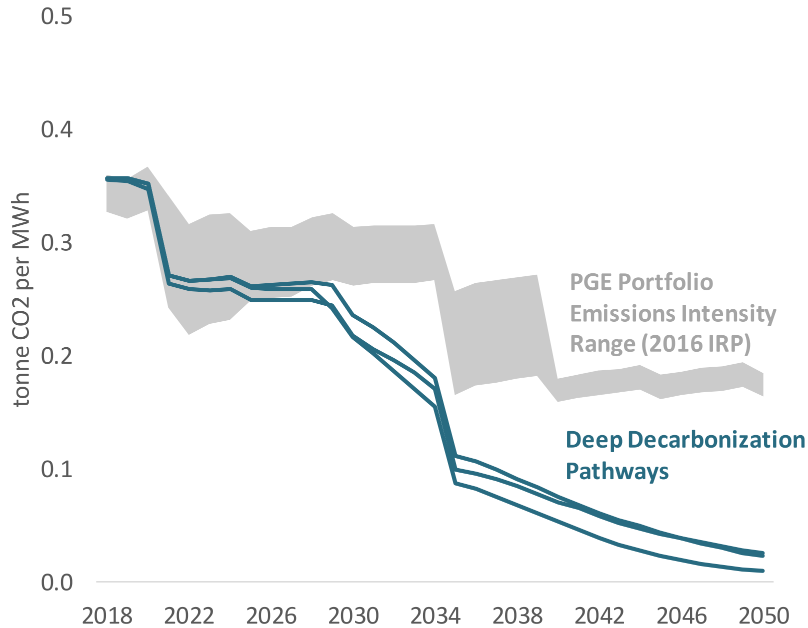


Figure 23 compares the emissions intensity of electricity generation from the three pathways against the range of PGE's portfolio from the 2016 IRP. Both projections decrease over time, with noticeable drops in 2020 and 2035 due to the assumed phase out of coal-fired electricity supply. The emissions intensity in the pathways scenarios begins to aggressively decrease beginning in the mid-2020s, and, relative to the minimum of the range, is at least 33 percent lower in 2035 and more than 85 percent lower by 2050. In 2050, the emissions intensity is below 0.03 tCO_2/MWh for all pathways, while the 2016 IRP ranges from 0.16 to 0.19 tCO_2/MWh.

Figure 23 Emissions Intensity of Electricity Generation



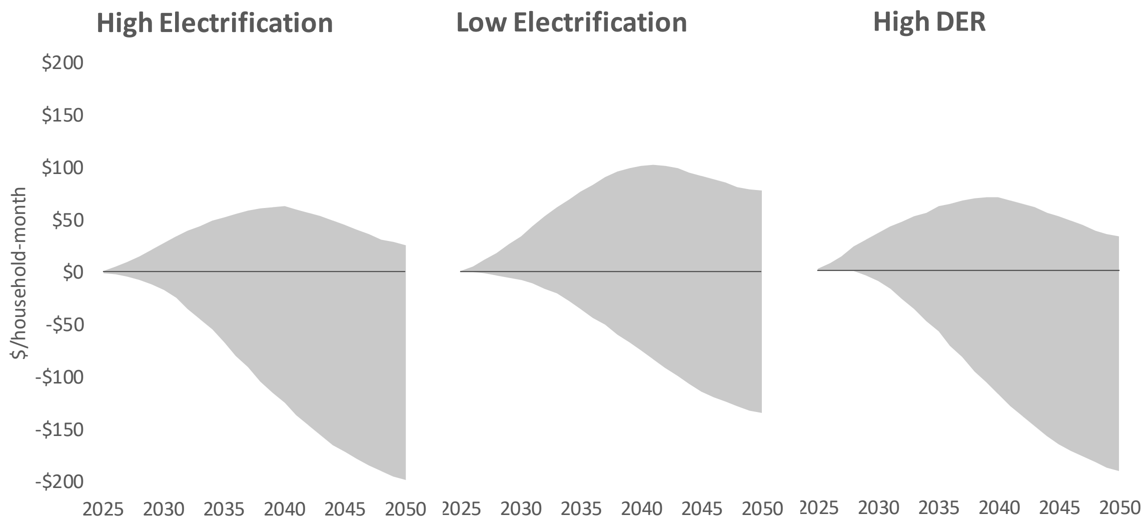
E. Energy System Costs

We measure the cost of transitioninig towards a low-carbon energy economy by comparing the incremental cost of investment in low-carbon and efficient equipment and infrastructure against the savings from avoiding fossil fuel purchases. This is calculated by taking the difference in energy system-related costs between a pathway scenario and the Reference Case. We exclude costs outside of the energy system, as well as benefits from avoiding climate change and air polution.

The annual, incremental cost for households is shown in Figure 24, which includes: (a) the annualized cost of appliances (e.g., high efficiency dishwasher); (b) the annualized cost associated with passenger transportation (e.g., electric vehicle); and (c) energy costs associated with using the equipment (e.g., gasoline for a vehicle and electricity for lighting). Given the challenge of projecting relative costs through a long study horizon (i.e., 2050), we show the results across a range of alternative fossil fuel price and end-use electric technology cost projections.[18] Year-to-year variations are due to: (a) the timing of investment needs; and (b) the assumed projections of technology costs and fuel prices. The range of uncertainties encompass both net cost increases and net cost decreases (savings) by 2050.

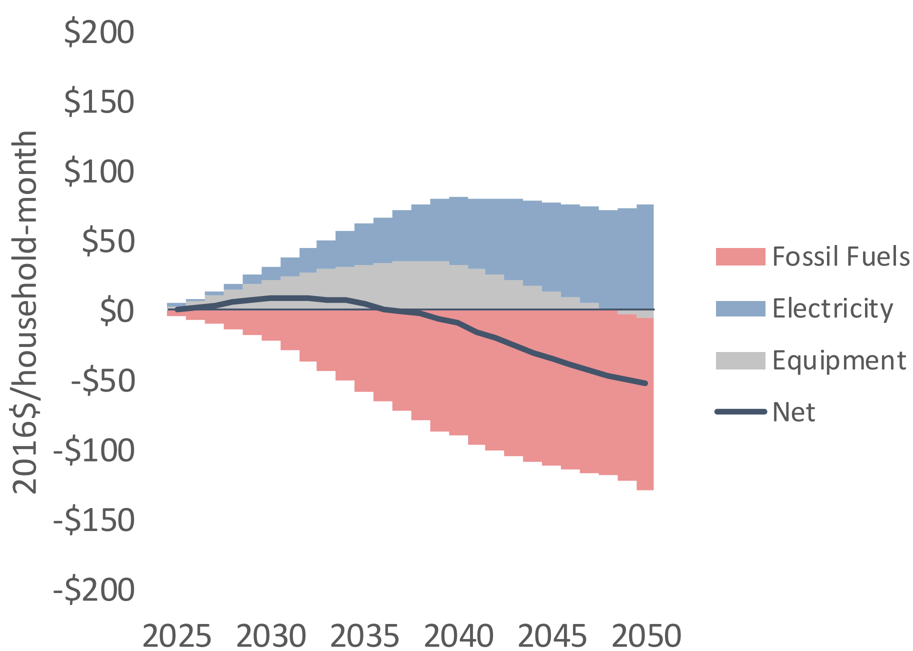
[18] Range of fossil fuel price projections are from the EIA's *Annual Energy Outlook 2017* and end-use electric technology cost projections are from NREL's *Electrification Futures Study*.

Figure 24 Range of Incremental Household Costs



Incremental household costs reflect the underlying changes in the energy system, such as: (a) increased spending on efficient end-use equipment (fixed costs); (b) increased spending on clean electricity infrastructure (fixed costs); and (c) decreased spending on fossil fuel costs (variable costs). Figure 25 illustrates how the structure of incremental household costs evolve over time for the High Electrification pathway under base fossil fuel price and end-use electric technology cost assumptions. Between 2025 and 2050, the average household spends additional money on equipment, such as an electric vehicle, air source heat pump and heat pump hot water heater, as well as additional money to power their equipment with clean electricity, including renewable power plants and transmission/distribution network upgrades. Meanwhile, households spend less money on fossil fuels, such as: (1) gasoline and diesel for their cars and trucks; and (2) natural gas for space and water heating.

Figure 25 Incremental Household Costs by Component: High Electrification Pathway

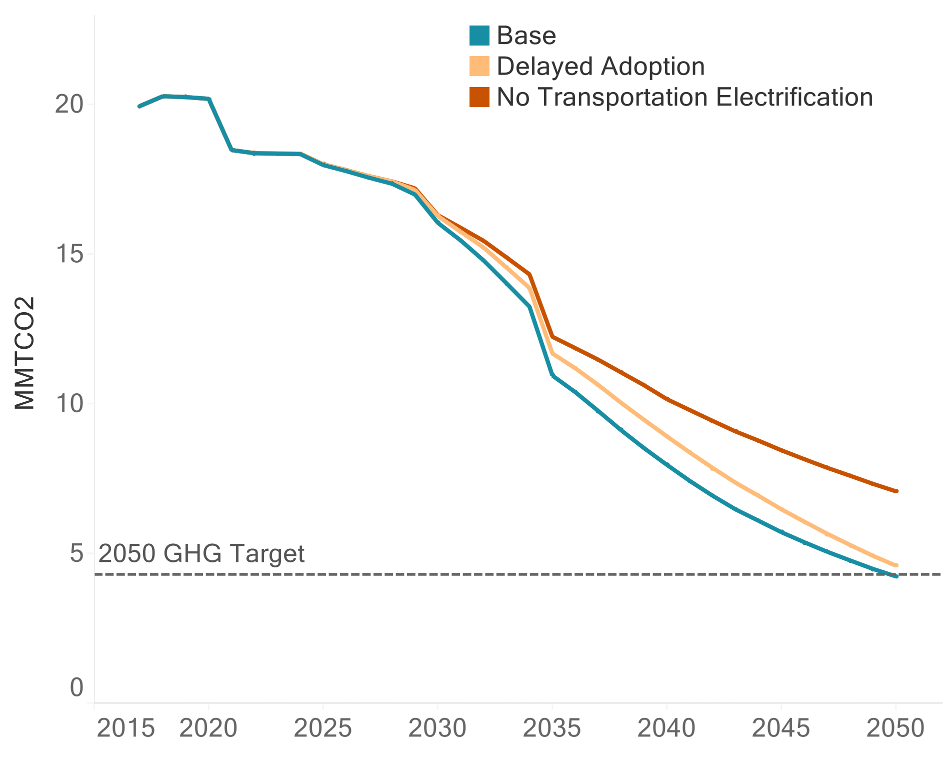


F. Transportation Electrification Sensitivity Analysis

Decarbonizing the transportation sector is essential to realizing economy-wide GHG reduction goals, and the pathways outlined above rely on passenger and freight transportation electrification. This requires aggressive consumer adoption by the mid-2030s for the fleet of vehicles on the road in 2050 to have the necessary low-carbon attributes. In the High Electrification pathway, 100 percent of light-duty vehicle sales are BEV or PHEV by 2035 and 50 percent of medium- and heavy-duty vehicle sales are BEV by 2035. To assess the importance of these aggressive transportation electrification strategies, we tested two sensitivities: (1) delay the assumed year of 100 percent BEV/PHEV adoption for light-duty vehicles from 2035 to 2050 ("Delayed Adoption"); and (2) remove all passenger and freight transportation electrification measures ("No Transportation Electrification").

Figure 26 shows the difference in CO_2 emissions between the High Electrification pathway ("Base") and the two sensitivities. The figure shows that delaying adoption of EVs in passenger transportation increases emissions in 2050 by 8 percent or 0.36 $MMTCO_2$, which results in the pathway no longer complying with the study's 2050 GHG target. This is because more than 10 percent of cars and trucks on the road in 2050 still consume petroleum rather than clean electricity as their fuel. CO_2 emissions increase by two-thirds without any transportation electrification (above 7 $MMTCO_2$) and the sensitivity does not achieve the emissions reductions necessary to meet the 2050 GHG target. We also note that the increase in emissions is partially mitigated through increased renewable diesel consumption by freight trucks (i.e., diesel freight trucks that transition to electric freight trucks in the base case now consume renewable diesel). However, the amount of bioenergy in this sensitivity exceeds the limit described in Section II.D, and, if strictly enforced, then emissions would be higher than shown here.

Figure 26 Energy-related CO_2 Emissions: Transportation Electrification Sensitivities



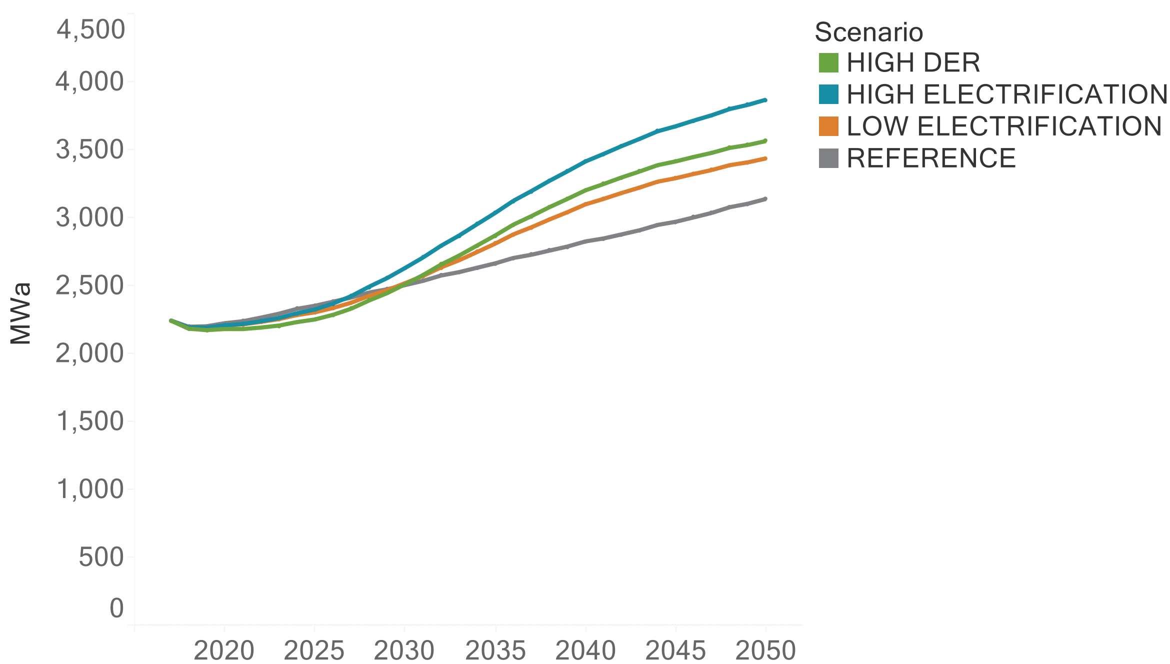
V. Results: Electricity System

This section summarizes results for the electricity system, including load, resources and hourly system operations. We also report the sensitivity of the results to variations in flexible end-use load, flexible electric fuel production, battery energy storage and pumped hydro storage assumptions.

A. Load

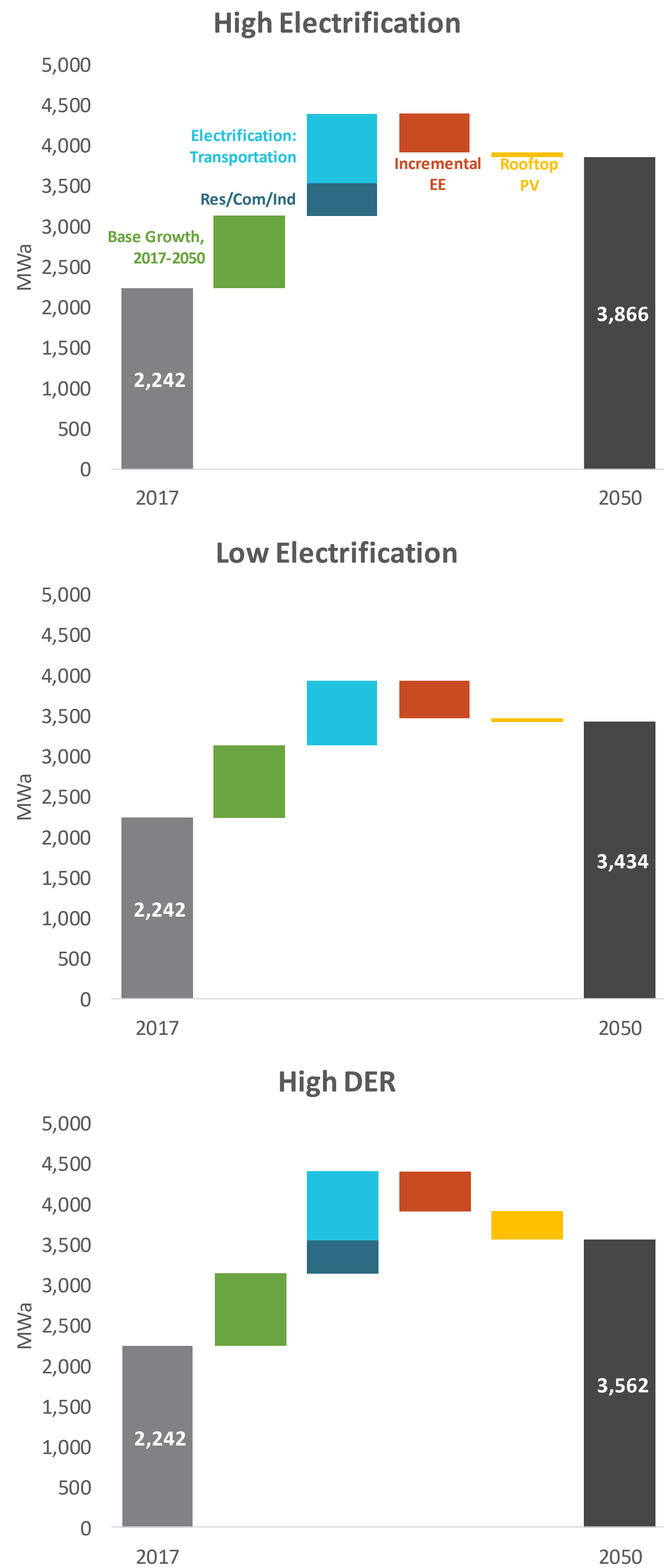
Figure 27 shows the trajectory of retail electricity sales for each scenario through 2050. In the long-run, retail sales in all pathways are higher than the Reference Case, and, as expected, the High Electrification pathway is the highest. Deployment of rooftop solar PV resources in the High DER pathway partially offsets end-use electrification measures, resulting in retail sales that are slightly above the Low Electrification pathway in 2050. Relative to today, retail sales increase by 50 to 70 percent by 2050.

Figure 27 Retail Electricity Sales



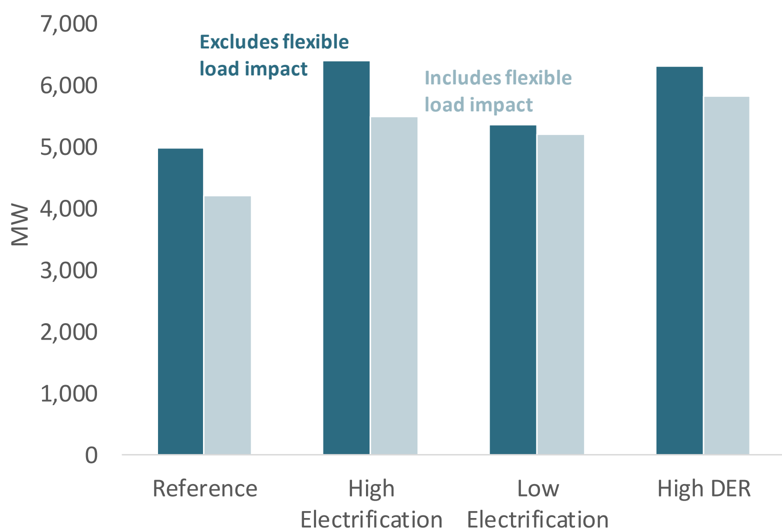
The components of the change in retail sales between 2017 and 2050 are shown in Figure 28, which separates: (a) baseline growth (i.e., growth that is embedded in the Reference Case); (b) electrification of buildings and industry; (c) transportation electrification; (d) incremental energy efficiency (EE measures beyond what's embedded in the Reference Case); and (e) rooftop solar PV generation. This figure highlights two key insights. First, transportation electrification is responsible for 50 to 65 percent of the net increase, as liquid fuels are replaced by electricity. Second, generation from rooftop solar PV has a smaller than expected *net* impact on retail sales. This is most apparent in the High DER scenario, where rooftop solar PV exceeds 2,500 MW (larger than today's average load). In this pathway, incremental electricity demand from end-use electrification still outweighs the directionally opposite impact from rooftop solar. This is a result of the lower-quality solar resource (i.e., low capacity factor) in PGE's service territory, and we would not expect similar conclusions to be drawn in geographies such as California or Arizona.

Figure 28 Evolution of Retail Electricity Sales, 2017-2050



We estimate the system peak load as the highest hourly load value from our simulations. As discussed in Section II.B, our hourly load (and resource) shapes reflect 2011 weather conditions, which means that the results we report here will not exactly match a 1-in-2 (weather-normalized) peak demand. Figure 29 plots the system peak load in 2050 in two ways. The first metric (in dark blue) represents "fixed demand" and excludes any impacts from load shifting, storage charge/discharge and flexible electric fuel production. The chart illustrates how widespread end-use electrification in the High Electrification and Higher DER pathways results in a system peak load of approximately 6,400 MW, which is about 1,400 MW higher than the Reference Case. Despite the proliferation of rooftop solar PV in the High DER pathway, the system peak load is nearly equivalent to the High Electrification pathway since it occurs during a winter morning before meaningful insolation. The second system peak load metric (in light blue) accounts for impacts from flexible end-use loads during the same hour, which moderates the impacts of electrification on peak loads.

Figure 29 2050 System Peak Load



B. Resources

1. Installed Capacity

Figure 30 shows the projection of installed capacity for thermal, generic capacity and renewable resources. Decarbonization of electricity generation and electrification requires renewable resource additions that far exceeds additions included in the Reference Case. The installed capacity of wind, solar, geothermal and hydro resources in the pathways is more than 2x the Reference Case quantity by 2050 and includes: (a) 5,100 to 5,900 MW of onshore wind in the Pacific Northwest; (b) 1,700 to 1,900 MW of onshore wind in Montana; and (c) 3,600 to 5,200 MW of utility-scale solar PV in central Oregon.[19] Rooftop solar PV in the High DER scenario reduces the amount of transmission-connected renewable generation, but its generation portfolio still requires utility-scale additions to reduce the carbon

[19] For context, NREL estimates technical potential of onshore wind resources in Oregon and Washington of approximately 45,480 MW and Black & Veatch estimates approximately 56,150 MW of utility-scale solar PV in Oregon alone. See Lopez et al. (2012) and Black & Veatch (2015).

intensity of electricity generation to levels consistent with the study's carbon budget. The Low Electrification pathway contains the highest installed capacity due to the amount of electricity required to serve synthetic electric fuel production loads.

Figure 30 Installed Generating Capacity

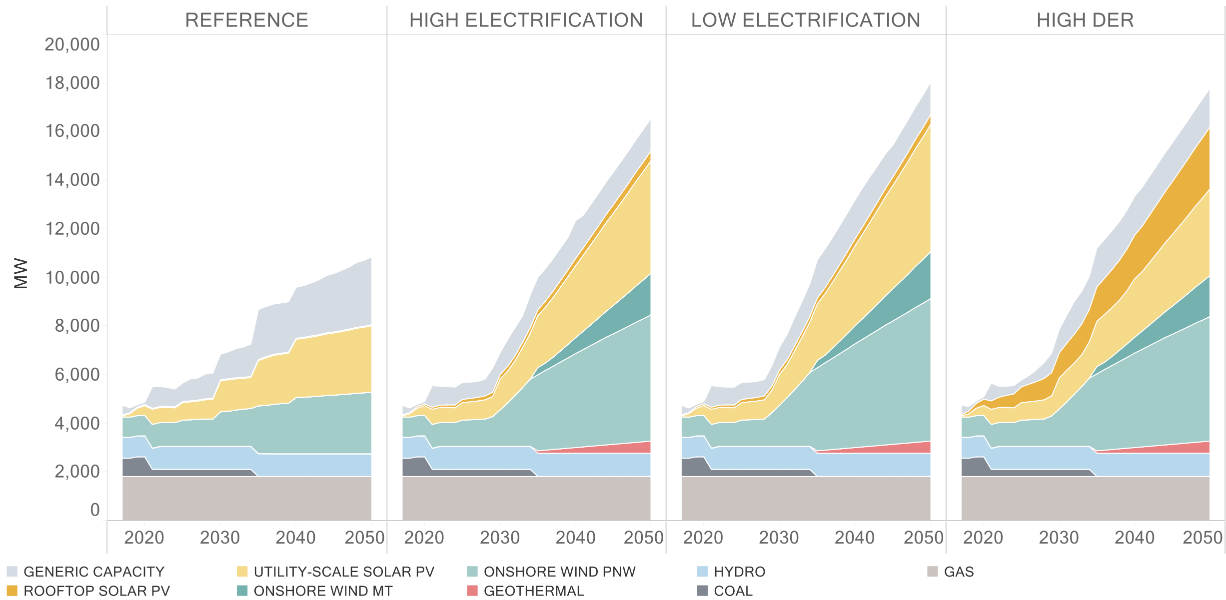
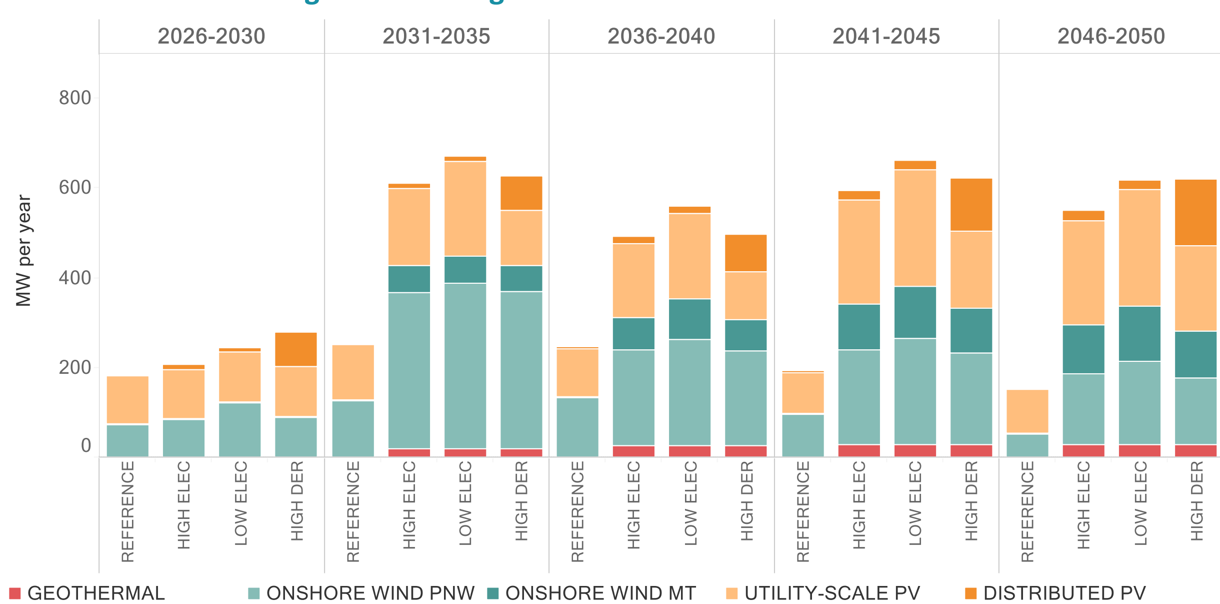


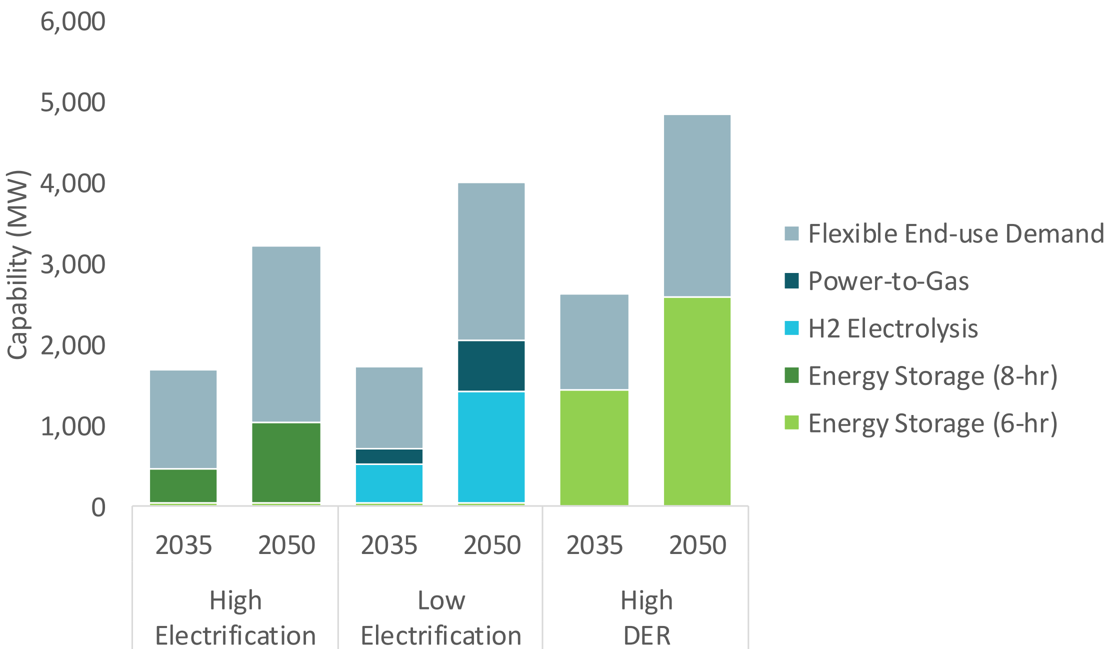
Figure 31 shows the annual average capacity additions of renewable resources, which are approximately 600 MW per year between 2030 and 2050 for the pathways scenarios. Annual renewable additions for the pathways scenarios are more than 2.0x Reference Case levels during the 2030s and more than 3.0x during the 2040s. For context, the amount of new onshore wind capacity beginning in 2030 is the equivalent to one to two Tucannon River (267 MW) wind power plants installed each year.

Figure 31 Average Annual Renewable Installations



The high penetrations of must-run renewable resources added across the pathways necessitate resources to balance electricity supply and demand. In addition to traditional sources of flexibility, such as hydro and thermal, the pathways incorporate a variety of new balancing resources to mitigate curtailment of renewable generation. Figure 32 shows the type and quantity of balancing resources incorporated in each pathway, including: (a) energy storage, which is differentiated between 6- and 8-hr duration; (b) hydrogen electrolysis facilities; (c) power-to-gas facilities; and (d) flexible end-use demand, which is estimated as the maximum hourly load shift in each year. The High Electrification and High DER pathways rely on a combination of flexible end-use demand and energy storage, while the Low Electrification pathway incorporates more than 2,000 MW of hydrogen electrolysis and P2G facilities by 2050 to consume excess renewable electricity generation and produce decarbonized pipeline gas. The High Electrification pathways contains the lowest quantity of physical / central-station balancing resources (i.e., 1000 MW of 8-hr energy storage) and relies on end-use loads to shift energy. The ability of these balancing fleets to minimize curtailment is further discussed in Section C.4 below.

Figure 32 Balancing Resources



2. Generation

The overall generation mix by resource type for each pathway is shown in Figure 33. Annual generation more than doubles from approximately 2,400 MWa today to between 4,900 and 5,300 MWa by 2050. Carbon-free generation is more than 90 percent of the total by 2050, including an approximate mix of: (a) 50 percent onshore wind in the Pacific Northwest and Montana; (b) 25 percent solar PV, including both utility-scale in central Oregon and rooftop PV resources located within PGE's service territory; (c) 9 percent hydro; and (d) 8 percent geothermal. Due to the increased penetrations of renewable resources, thermal generation decreases significantly over time and is between 4 to 7 percent of total generation by 2050.

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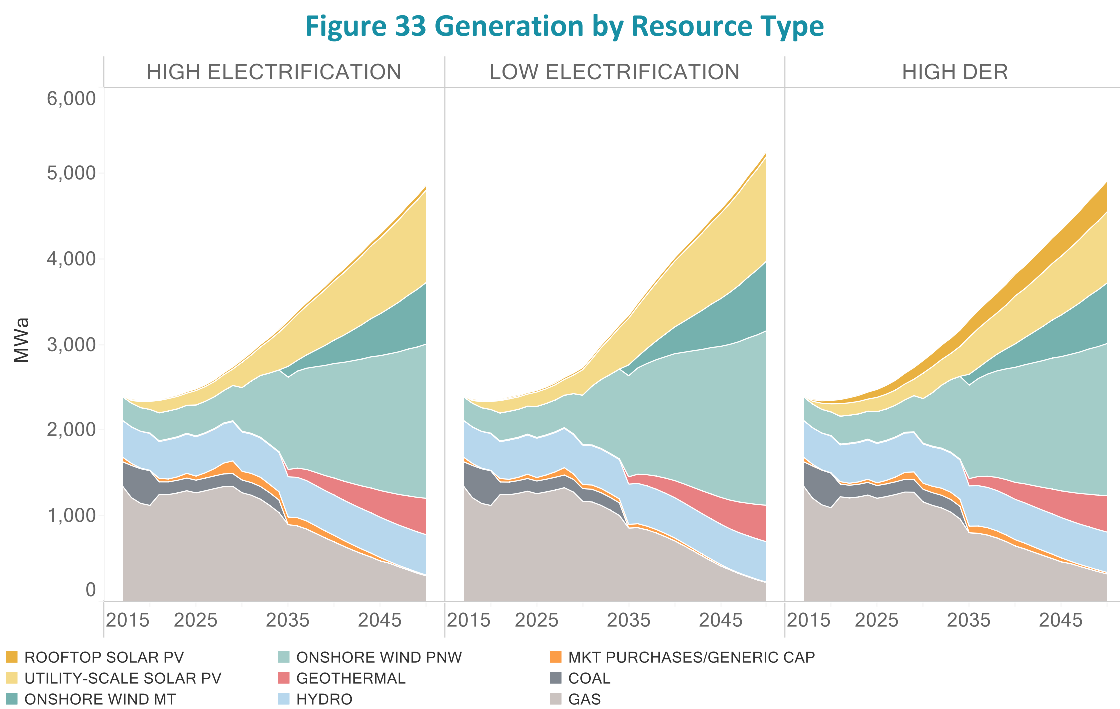
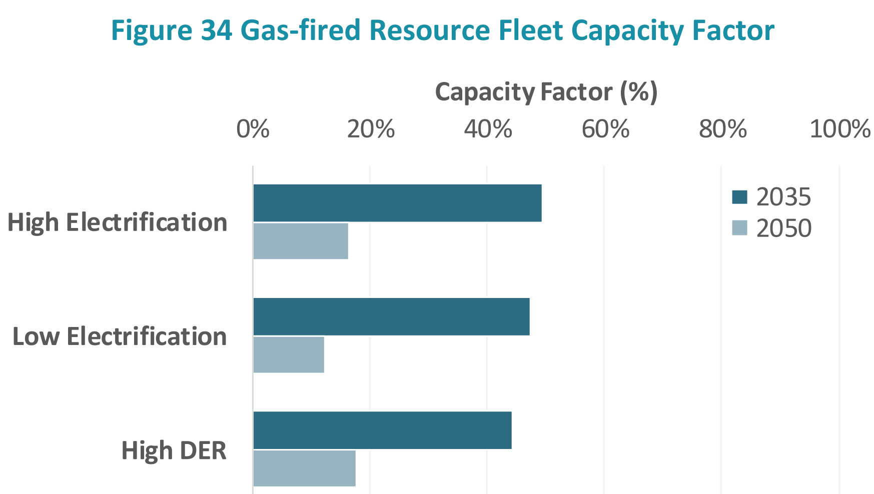


The capacity factor of PGE's existing gas-fired resource fleet is shown in Figure 34. The figure highlights how the growth in intermittent renewable generation between 2035 and 2050 decreases the utilization of these dispatchable resources from approximately 50 percent in 2035 to below 20 percent in 2050, a decrease of approximately 30 percentage points. The highly renewable power systems modeled in this study still require dispatchable resources to maintain reliability, and the gas-fired resource fleet, along with a variety of other balancing resources, have the characteristics to avoid unserved energy. The results here do indicate a shift in the role of these resources, particularly for combined cycle plants, from an energy to a capacity resource.



C. System Operations

1. Load and Net Load

We compare the distribution of hourly load and net load in 2050 for each scenario as histograms in Figure 35, and report summary statistics in Table 11. These two metrics are estimated as follows: (a) load includes inflexible, transmission-level load less behind-the-meter generation (e.g., rooftop solar PV); and (b) net load is load minus non-dispatchable generation, including onshore wind, utility-scale solar PV, geothermal and run-of-river hydro resources. Both exclude the impact of flexible loads and resources.

The load distributions show the expected impacts of electrification, with the High Electrification and High DER distributions shifting towards the right. The net load distributions provide a more meaningful benchmark in terms of assessing the amount of dispatchable capacity needed to reliably meet demand and the flexibility required to avoid curtailment. The net load distribution for the Reference Case, which includes a 50% RPS in 2050, shows net load below zero for 5 percent of hours in the year. The pathways scenarios, which include at least twice as many non-dispatchable renewables, have net load distributions that are much flatter than the Reference Case and frequently below zero.

The High Electrification net load distribution is below zero in approximately 50 percent of hours per year, and the minimum net load experienced is approximately -8,000 MW. During these hours, flexible resources are needed to consume additional load (e.g., energy storage charge) to avoid curtailment. The maximum net load is approximately 5,000 MW, which is about 4 percent higher than the Reference Case's maximum net load. The High DER pathway shows similar net load distribution results due to comparable levels of electrification and renewables.

Relative to the other pathways, the Low Electrification pathway's net load is distributed further left (i.e., more hours with negative net load). Net load is below zero for 64 percent of hours in the year and nearly reaches -10,000 MW in a single hour. This shape is due to different load and resource characteristics, including: (a) lower levels of end-use electrification; and (b) higher levels of inflexible renewable generation. Flexible hydrogen electrolysis and power-to-gas facilities consume load during these negative net load hours to produce low-carbon electric fuels and avoid curtailment.

Figure 35 Distribution of Hourly Load and Net Load in 2050

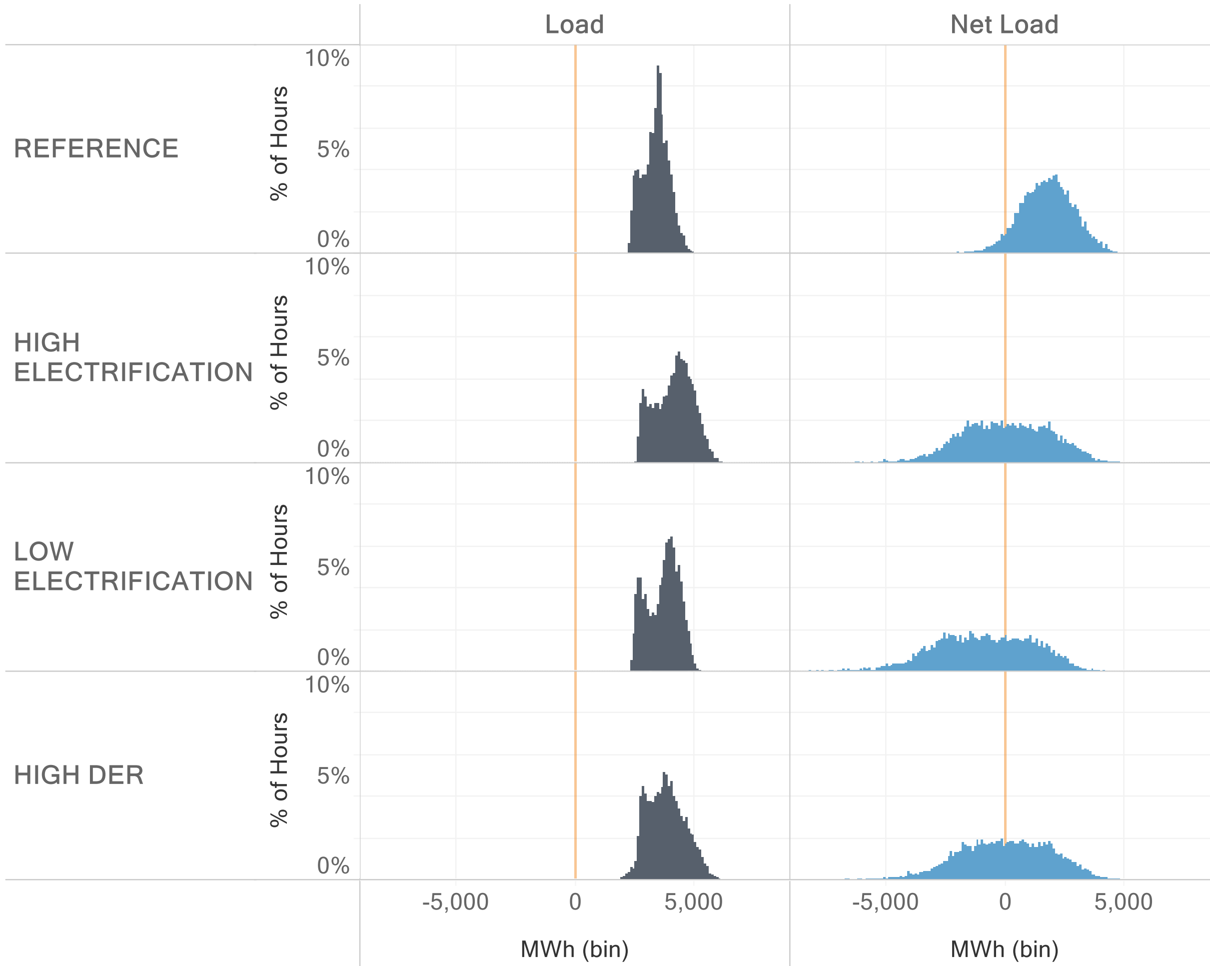


Table 11 Statistics for Hourly Load and Net Load in 2050

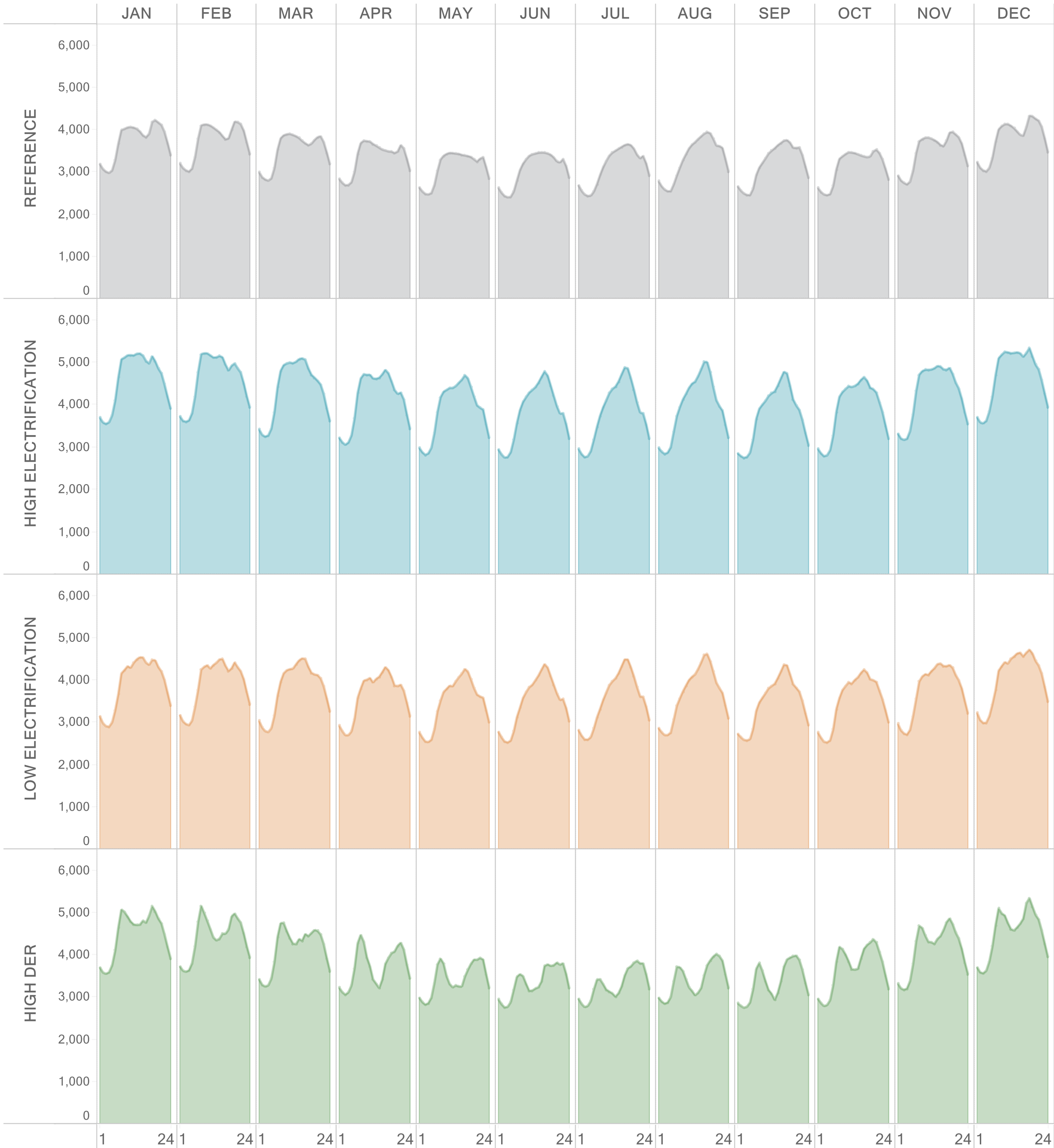
Scenario	**Load**		**Net Load**			
	Max	**Min**	**Max**	**Min**	**Frequency below 0 MW**	
	MW	MW	MW	MW	hrs	% of hrs
Reference	4,972	2,191	4,758	-2,392	457	5%
High Electrification	6,391	2,555	4,957	-7,942	4,346	50%
Low Electrification	5,351	2,273	4,261	-9,996	5,600	64%
High DER	6,310	1,920	4,961	-8,574	4,337	50%

2. Hourly System Load Shape

The average load by month and hour in 2050 for each scenario is summarized in Figure 36. The figure shows the system load shape prior to accounting for flexible loads and illustrates how the nature of electricity demand is affected by rooftop solar PV and varying levels of electrification.[20] The High Electrification pathway shows higher winter loads relative to the Reference Case primarily due to the electrification of space heating, but large new loads are also present in non-winter months largely due to transportation electrification. These non-heating related load increases are also present in the Low Electrification pathway and are most apparent in the early evening hours when most EV charging is assumed to take place. Although the High DER pathway contains the same electrification measures as the High Electrification pathway, the proliferation of rooftop solar PV changes both the daily and seasonal characteristics of electricity demand, including: (a) steep upward and downward ramps during the daylight hours across all months; and (b) large differences in daily energy requirements between winter and spring/summer months.

[20] The load shapes for the pathways also reflect high levels of electric energy efficiency.

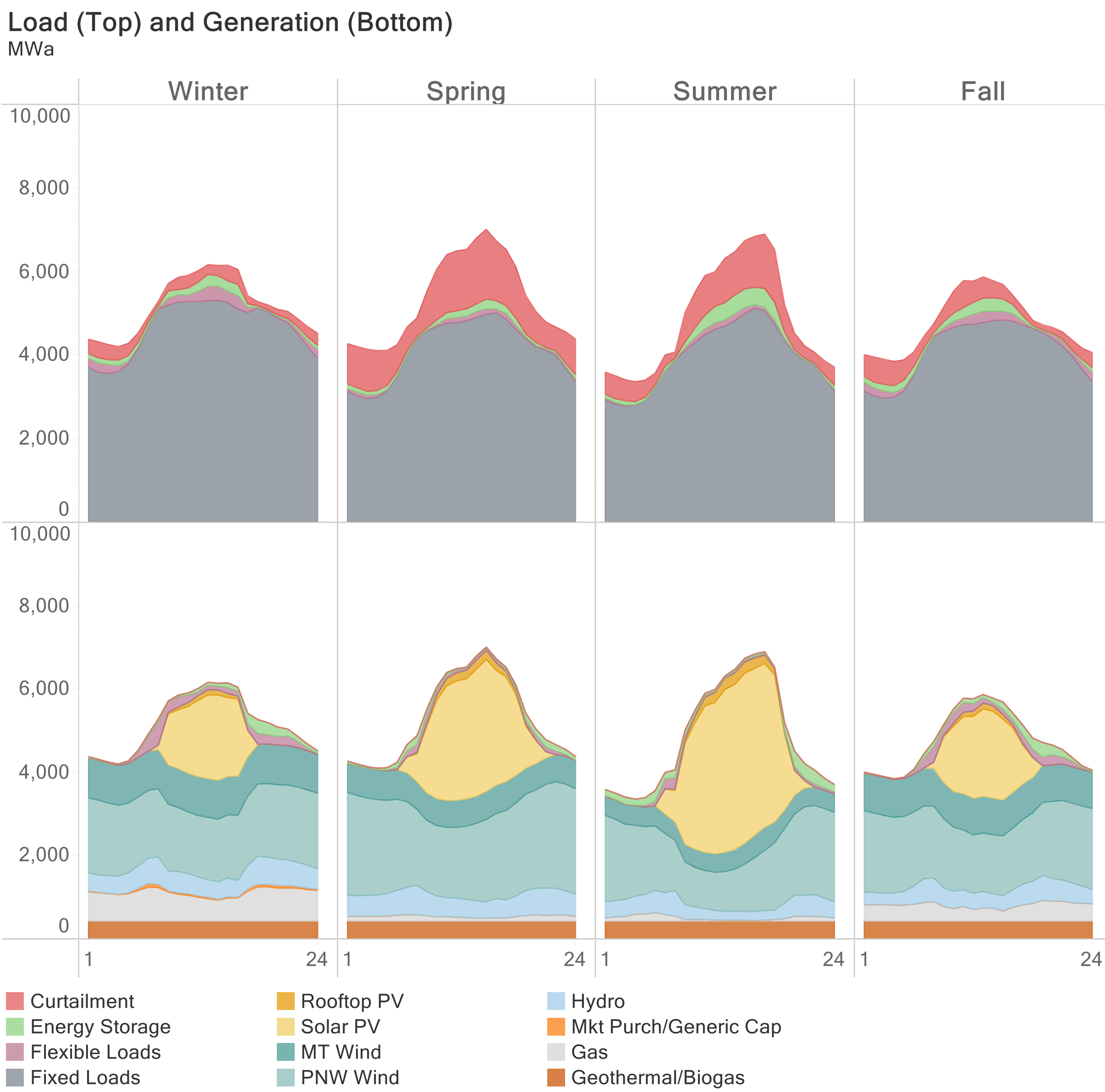
Figure 36 System Load Shape: Month-Hour Average in 2050



3. Month-Hour Electricity Dispatch

Figure 37 through Figure 39 show hourly average dispatch profiles by season for each pathway, where the top panel contains all sources of load and the bottom panel contains all sources of generation.[21] The figures illustrate how electricity supply and demand technologies combine across hours and seasons, and the operating profiles of flexible balancing resources.

Figure 37 Electricity Dispatch: High Electrification Pathway, 2050



[21] Seasons defined as: (a) winter includes December through February; (b) spring includes March through June; (c) summer includes July through September; and (d) fall includes October through November.

Figure 38 Electricity Dispatch: Low Electrification Pathway, 2050

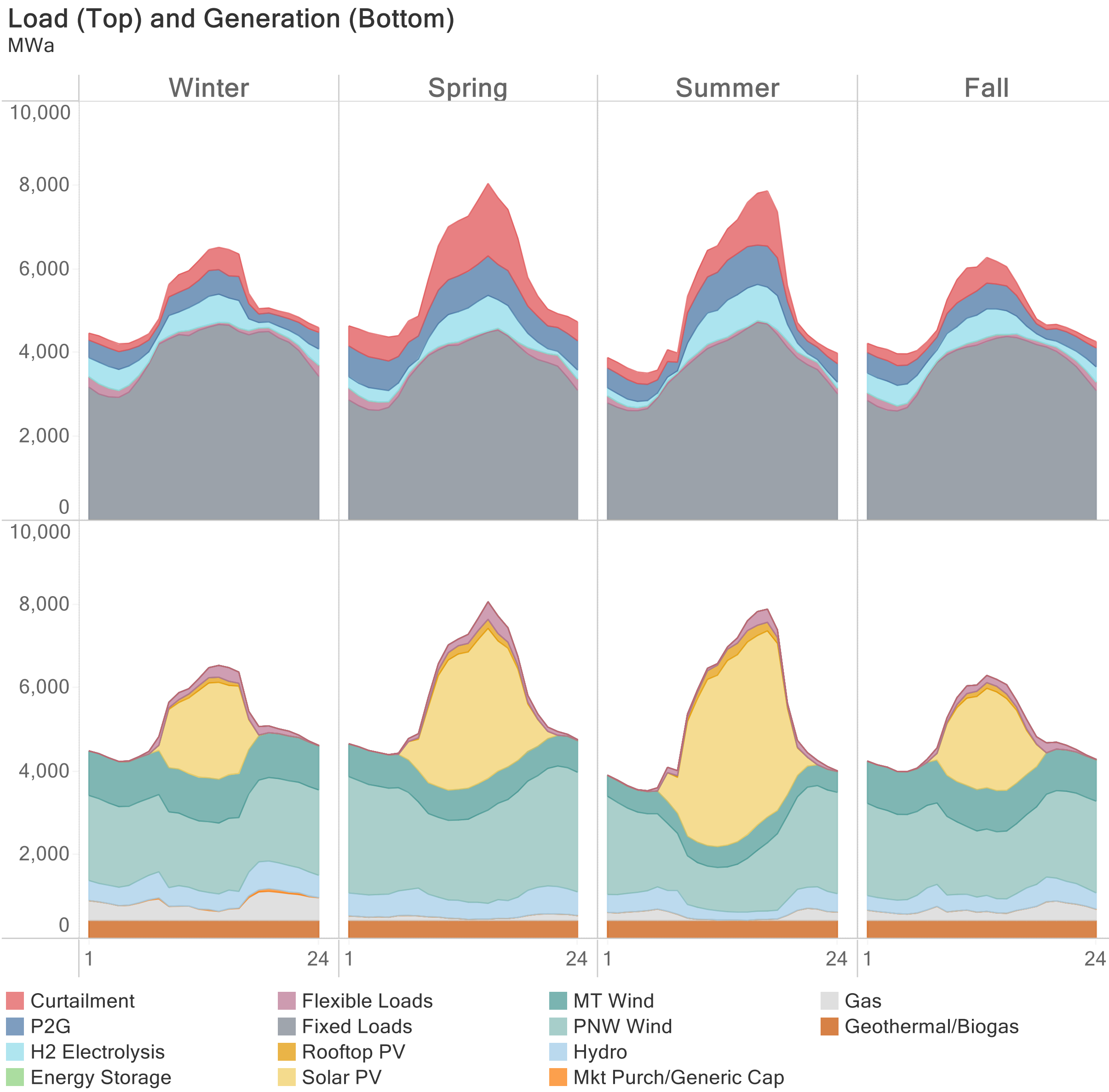
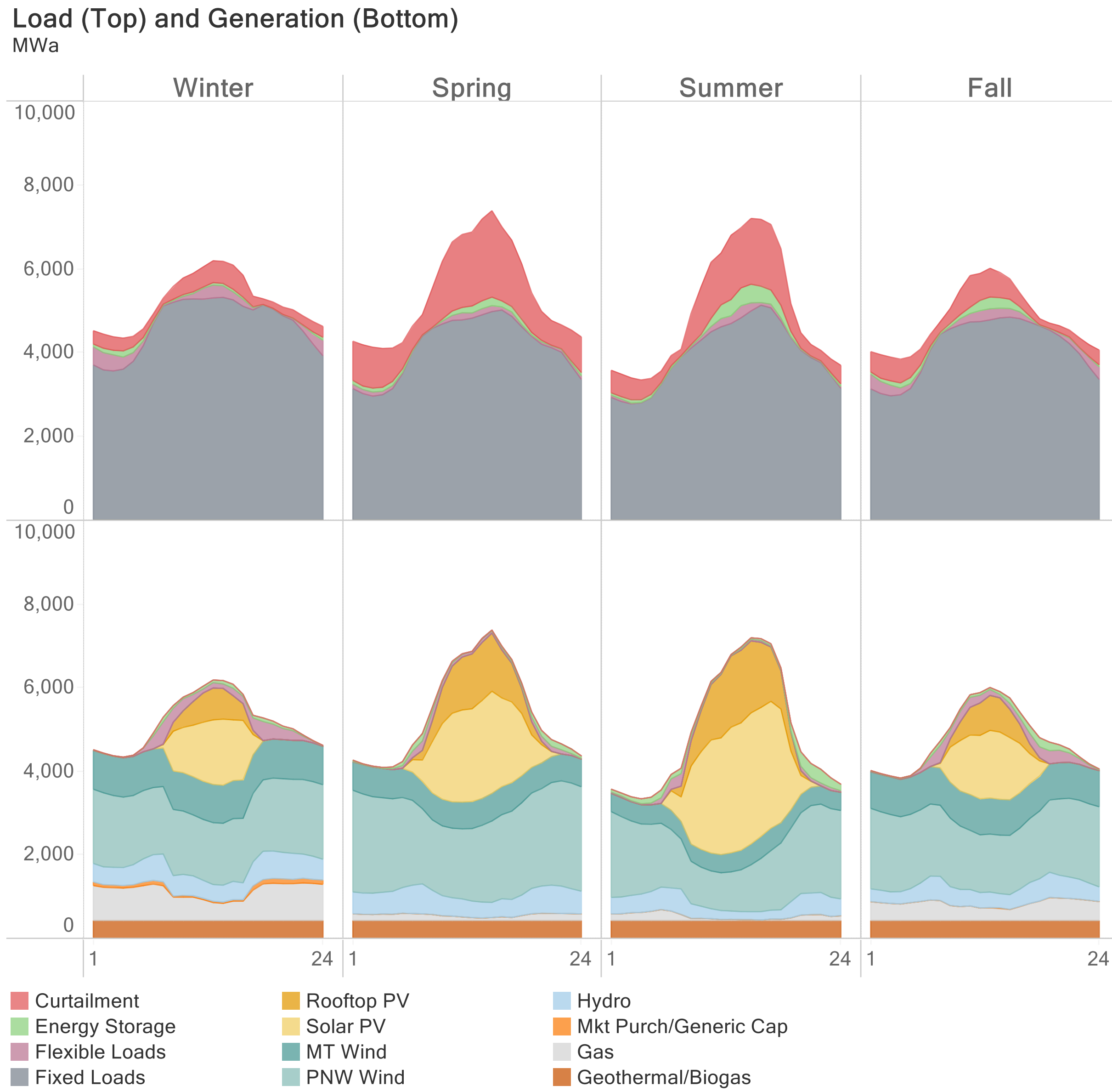


Figure 39 Electricity Dispatch: High Distributed Energy Resources Pathway, 2050



4. Curtailment

Curtailment of renewable generation occurs during periods where: (1) must-run generation exceeds load, resulting in an initial negative net load signal; and (2) balancing resources are unable to shift surplus energy to hours with energy deficits (i.e., positive net load signal). Figure 40 plots annual curtailment for each scenario and shows that curtailment does not become prevalent until the 2035 timeframe. As the share of inflexible, renewable generation increases above 85 percent by 2050, curtailment increases exponentially even after the impacts of balancing resource are accounted for.

Figure 40 Annual Curtailment

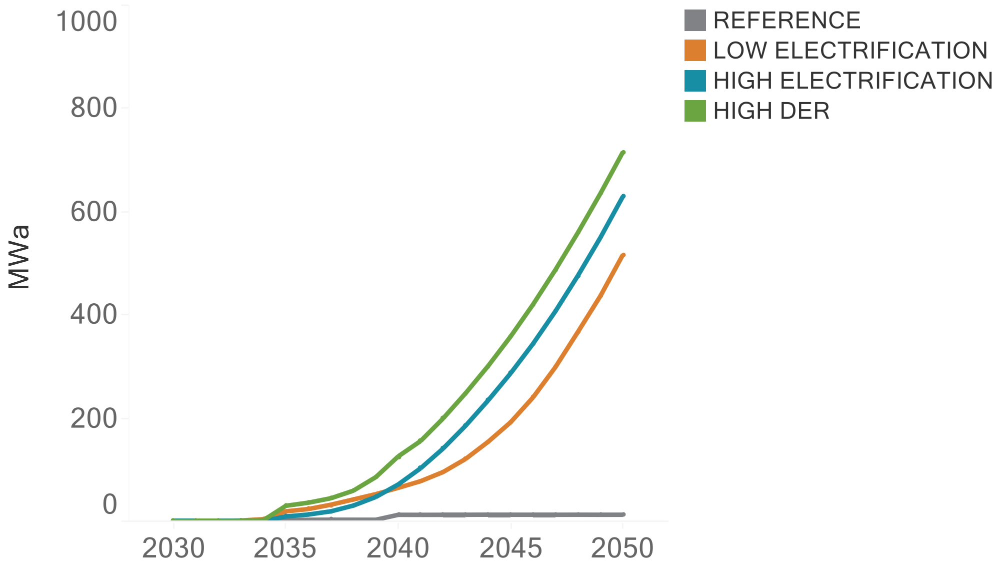


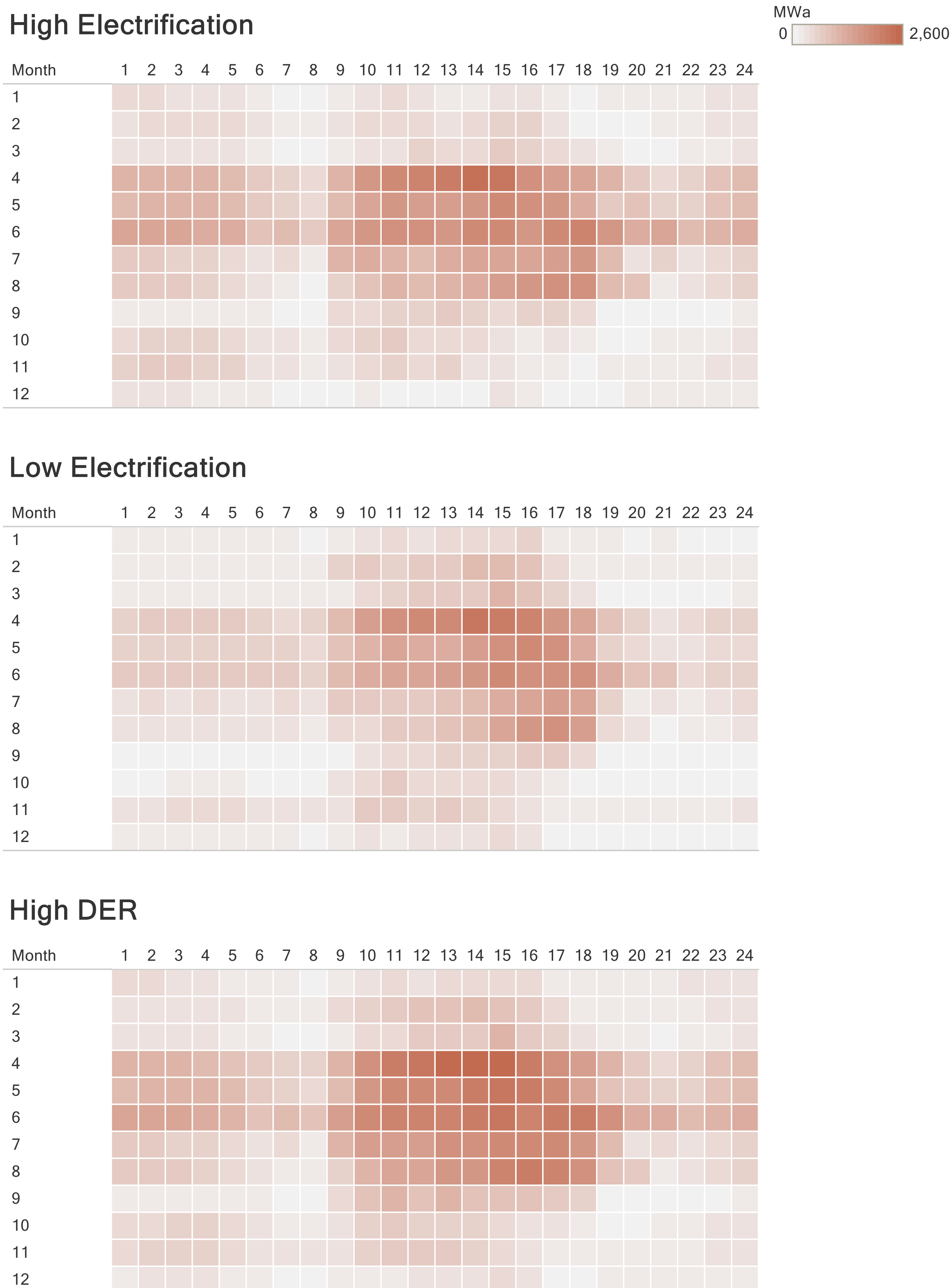
Table 12 summarizes several curtailment metrics for 2035 and 2050, including: (a) the amount of energy curtailed in average megawatts; (b) curtailment normalized as a percentage of available renewable energy; (c) maximum hourly observation; and (d) frequency, expressed in percentage of hours in a year. Curtailed generation is less than 2 percent of available renewable energy in 2035 across all pathways and increases to between 11 and 17 percent by 2050. Curtailment is experienced between 40 and 55 percent of hours in 2050, which is a decrease from the number of hours with negative net load (see Table 11) and reaches a maximum depth between 7,600 and 8,700 MW in a single hour. We explore the impact of alternative demand- and supply-side balancing resource assumptions on curtailment in the following section.

Table 12 Curtailment Metrics for 2035 and 2050

Scenario	Energy		Percent of Available RE		Hourly Maximum		Frequency	
	2035 MWa	2050 MWa	2035 %	2050 %	2035 MW	2050 MW	2035 % hours	2050 % hours
Reference	2	13	0.2%	0.8%	966	2,048	1%	3%
High Electrification	9	630	0.5%	15.0%	2,146	8,032	2%	39%
Low Electrification	19	517	0.9%	11.1%	2,378	7,597	4%	53%
High DER	30	716	1.5%	16.9%	3,121	8,663	5%	46%

The average amount of curtailment for each month and hour in 2050 is depicted as a heat map in Figure 41, with a darker red highlighting more extreme curtailment. The heat maps show that curtailment is concentrated during spring months when loads are low and renewable generation is high. Curtailment experienced during April through June makes up approximately half of annual curtailment, while only 11 to 13 percent occurs between December through February. Although most curtailment is concentrated during day-light hours, it is still experienced during the night-time and is up to 30 percent of the total in the High Electrification pathway.

Figure 41 Curtailment Heat Map for 2050



D. Sensitivity Analyses

In this section, we evaluate the sensitivity of our modeling results to alternative assumptions about the availability of demand- and supply-side resource flexibility. These sensitivities explore the impacts of alternative assumptions from the High Electrification pathway, including: (a) varying the availability of flexible end-use load; (b) including flexible electric fuel production (i.e., electrolysis); and (c) varying the quantity and type of energy storage. These sensitivities are summarized below.

Flexible End-use Load. In the High Electrification pathway, we assume a percentage of electric load is flexible in key end-uses: (a) 75 percent of light-duty vehicle electric load is flexible by 2050; (b) 75 percent of residential and commercial water heating electric load is flexible by 2050; and (c) 50 percent of electric load is flexible for residential space conditioning, residential clothes washing and drying and commercial space heating. We tested three cases designed to assess the importance of end-use flexibility: (a) no flexible end-use load; (b) only flexibility from electric vehicles; and (c) only flexibility from water heaters.

Flexible Electric Fuel Production. The results presented in the prior section highlight the seasonal imbalance between electricity supply and demand in a highly renewable power system. The base assumption in the High Electrification pathway is that energy storage and flexible end-use loads are the principal balancing resources. To assess the impact of long-term or seasonal storage, we conducted a sensitivity analysis where hydrogen produced from electrolysis facilities provides 3.5 percent of pipeline gas supply, which translates into more than 300 MW of electrolysis facilities.

Variation in Energy Storage. Varying the quantity of energy storage affects the ability of a power system to successful integrate inflexible renewable electricity generation. In the High Electrification pathway, the base assumption is that 1,000 MW of 8-hour energy storage is in-service by 2050. In this sensitivity, we assess the implications of: (a) increasing the quantity of 8-hour energy storage from 1,000 MW to 1,500 MW; and (b) assuming 500 MW of 24-hour pumped hydro storage (PHS) by 2050.

Table 13 summaries the results of our sensitivity analyses for 2050, which are shown as differences relative to the High Electrification pathway. We report changes in: (a) curtailment, in terms of average megawatts and percent difference; and (b) energy system CO_2 emissions, in million metric tonnes and percent difference. Removing flexibility from end-use loads increases curtailment by nearly 10 percent and emissions increase by 5 percent due to higher thermal generation, which results in the sensitivity exceeding the study's 2050 carbon budget. Including flexibility from electric vehicles and hot water heaters dampens the effect of losing other end-use flexibility, with curtailment and emissions rising modestly. The sheer volume of electric load from electric vehicles (more than 15 percent of total load in 2050) relative to water heaters allows for better curtailment and emissions outcomes. Electrolysis facilities and pumped hydro, both long-duration storage, show similar outcomes with curtailment decreasing by more than 10 percent. In contrast, increasing the quantity of 8-hour storage produces less than half the reductions in curtailment. The results of these sensitivity analyses highlight the importance of flexible end-use loads for integrating renewable generation, as well as the effectiveness of long-duration energy storage to reduce curtailment and address seasonal energy imbalances that occur in highly renewable electricity systems.

Table 13 Flexibility Sensitivity Analysis Results (Relative to Base Assumptions)

Sensitivity	Curtailment (MWa)	Curtailment (%)	Emissions ($MMTCO_2$)	Emissions (%)
Flexible End-Use Load				
None	+54	+9%	+0.21	+5%
Flexible EV Load Only	+14	+2%	+0.05	+1%
Flexible WH Load Only	+36	+6%	+0.14	+3%
Flexible Electric Fuel Production				
Add Electrolysis Facilities	-78	-12%	-0.08	-2%
Energy Storage				
Increase 8-hr energy storage	-31	-5%	-0.07	-2%
Add 24-hr PHS	-68	-11%	-0.15	-4%

Notes: values for 2050 and relative to High Electrification pathway base assumptions.

VI. Summary

We find that deep decarbonization of the PGE service territory's energy economy is possible and can be achieved using a variety of energy technologies and mitigation strategies. Our analysis of multiple pathways shows that they depend on a set of three pillars that are consistent with many studies examining deep decarbonization in the U.S. and abroad, including: (1) energy efficiency; (2) decarbonizing electricity generation; and (3) increasing the share of electricity and electric fuels. All three pillars are required and pursuing only one is insufficient.

The level of change to the energy system identified in this study is transformational and cannot be achieved with incremental improvements to energy supply and demand. In order to facilitate a pathway to 2050, both consumers and producers will need to participate to ensure that energy infrastructure is low-carbon and efficient. Although 2050 is more than three decades away, a successful transition to a low-carbon economy requires timely planning to account for: (a) the pace of consumer adoption; and (b) the fact that energy infrastructure is long-lasting and takes years to plan for. Despite the ambitious transformation of the energy system, the changes would not entail major lifestyle changes, but the structure of a household's energy bill will shift from fossil fuel expenditures to investments in technology.

Economy-wide decarbonization will profoundly change the way electricity systems are operated and planned for. In terms of power system operations, balancing electricity supply and demand becomes more challenging as inflexible, variable renewable generation becomes the principal source of supply. For example, the three pathways show renewable generation exceeding load in approximately half of all hours by 2050. This operational paradigm necessitates a transition to new forms of balancing resources to integrate renewables and avoid curtailment. New sources of flexibility, including energy storage and flexible demand, can complement traditional sources of flexibility, such as hydro and thermal resources. This also provides an opportunity for PGE's customers to facilitate renewable integration by playing a more active role through smart EV charging and water heating (among others), which expands upon traditional demand response programs.

Electricity system planning in the context of deep decarbonization will need to account for broad changes across the energy economy to ensure that infrastructure with the right attributes is available to come online in a timely fashion. For example, future resource adequacy analyses will need to address changes in: (a) overall load requirements; (b) the shape of hourly load; (c) the level of inflexible renewable resources; and (d) penetration of flexible demand. In addition, the scale of resource additions identified in this study exceeds historical levels due to: (1) reducing the carbon intensity of electricity generation to nearly zero; and (2) increased generation requirements from electrification and/or producing fuels from electricity (i.e., H2 and SNG). As a result, the installed capacity of renewables is substantially higher than what's anticipated in any current planning proceedings and is more than double the quantity we would expect under current RPS policy. If regulators pursue policies commensurate with the emissions reductions evaluated here, then the results of this study highlight a number of considerations that could be investigated in PGE's integrated resource planning efforts to ensure that near-term actions are consistent with a long-term decarbonized future.

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