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2022 PSE GENERAL RATE CASE
WITNESS: SANEM I. SERGICI

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-22____** **Docket UG-22____**

SECOND EXHIBIT (NONCONFIDENTIAL) TO THE
PREFILED DIRECT TESTIMONY OF

SANEM I. SERGICI

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

Maximizing Customer Benefits through PSE's Advanced Metering Infrastructure

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Executive Summary

In 2019, Puget Sound Energy ("PSE" or "the Company") filed an application before the Washington Utilities and Transportation Commission ("WUTC" or "the Commission") seeking recovery for its Advanced Metering Infrastructure ("AMI") investment. In its decision, the Commission approved PSE's recovery of all deferred depreciation expense for its AMI investment to date because PSE's decision to install AMI was prudent. However, in order to recover a return on its AMI investment, the Commission ruled that the Company's recovery of the return on its AMI investment is contingent on successfully deploying its AMI system and satisfactorily demonstrating the AMI-related customer benefits of the AMI system. The Commission cited six customer-facing use cases that it expected PSE to maximize: 1) time of use ("TOU") rates, 2) real-time energy use feedback for customers, 3) behavior-based programs, 4) data disaggregation, 5) grid-interactive efficient buildings,[1] and 6) conservation voltage reduction ("CVR") or volt/VAR optimization.

This report responds to the WUTC's request that PSE demonstrate the ways in which the Company is planning to maximize the customer-facing benefits of AMI. In this report, we present how the Company is planning to maximize AMI benefits through various customer programs and offerings that are enabled or facilitated by AMI, including benefits identified by the Commission as well as other benefits not quantified in the Company's previous filing. We then quantify the benefits along with the incremental cost of achieving these benefits.

To date, PSE's AMI deployment is on schedule. As of January 12, 2022, 838,085 AMI electric meters and 531,240 AMI gas modules have been installed in PSE's service territory, which is the largest deployment of AMI meters by a single utility in Washington. By the end of 2022, the Company will have installed more than 1 million electric meters and 757,000 gas AMI modules, representing about 90% of all electric and gas customers. The Company will deploy AMI meters to virtually all of its customers by 2023. Even though PSE has not yet completed its AMI deployment, the Company has already planned and launched a number of innovative pilot programs and other measures that will enable it to maximize AMI upon full deployment.

[1] We use the term "load flexibility" in the report instead of grid-interactive efficient buildings to denote the broader applications for this use case as envisioned by PSE. Load flexibility is also a more common industry term.

Following a systematic approach, PSE identified 38 AMI use cases. We reviewed all of these use cases and classified them into three tiers for analysis. "Tier 1" use cases are the six "customer-facing" use cases highlighted by the WUTC and therefore were prioritized for assessment and analysis. "Tier 2" use cases represent other AMI benefits that PSE has prioritized for implementation. "Tier 3" use cases refer to future use cases which are either difficult to quantify at this time, or initiatives that are in early stages of exploration. For these use cases, we present a select number of benefits qualitatively.

For the Tier 1 use cases, our analysis focuses on five main benefit categories:

- Avoided generation capacity costs
- Avoided transmission and distribution ("T&D") capacity costs
- Avoided energy costs
- Avoided emissions
- Avoided T&D losses

For each of the use cases, we quantified the expected annual benefits through 2037, which marks the end of the expected 20-year life of the AMI meters deployed in 2017.[2] After estimating the annual expected benefits through 2037, we calculated the total nominal benefits. Given the uncertainty involved in calculating expected benefits over a long time horizon (and while some of the programs are just being initiated), we defined Low, Base, and High cases to provide a range for the expected benefits that will be discussed further below.

The total Tier 1 Use Case benefits are estimated at $267 million for the Base case, $121 million for the Low case, and $424 million for the High case (see Figure 1 below). Benefits from load flexibility programs are the largest, followed by the time-varying rate ("TVR") use case and behavior-based programs.[3] The total Tier 2 benefits are driven chiefly by the remote connect/disconnect use case and the improved outage management use case. The total Tier 2 benefits are estimated at $358 million for the Base case, with the Low case and High case being $294 million and $494 million, respectively (see Figure 2). These benefits are incremental to the $668 million benefits presented in PSE's original business case.

We also estimated the incremental costs for the Tier 1 and Tier 2 use cases, above and beyond the AMI investment costs (see Figure 2). The costs associated with Tier 1 use cases are $52 million for Low case, $95 million for Base case, and $173 million for High case. The total Tier 2 costs are $16 million for Low case, $22 million for Base case, and $26 million for High case. As

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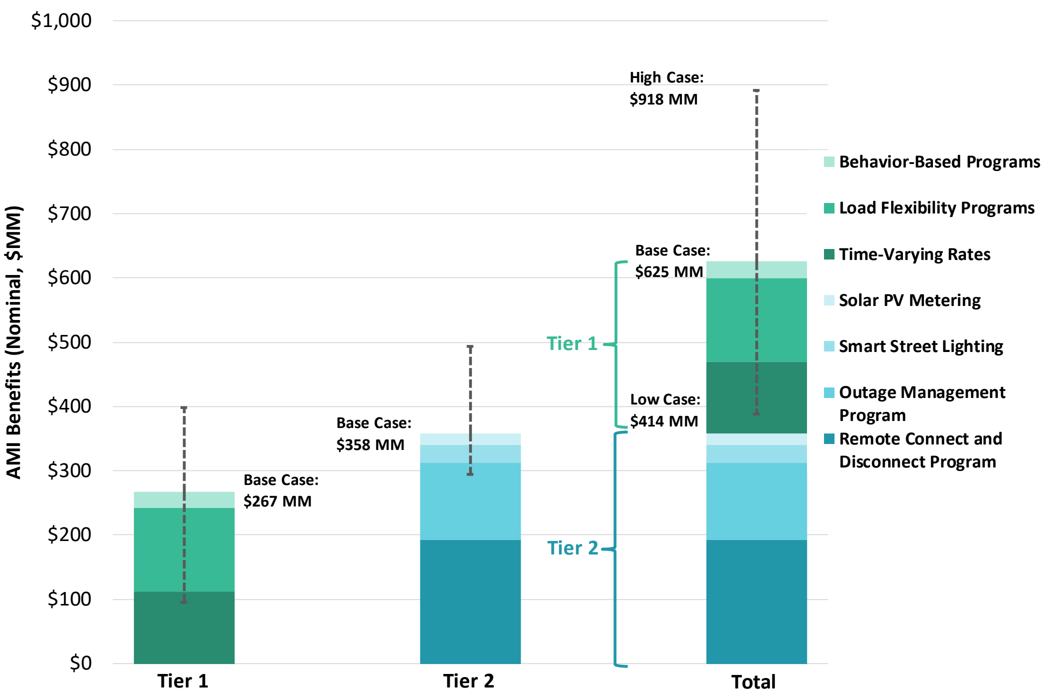
2 The first year of our benefit model for a particular program corresponds to when that program is launched or expected to launch.

3 Note that PSE presented the CVR use case benefits in the original business case.

noted, these costs are incremental to the $473 million costs estimated in PSE's original business case.

FIGURE 1: AMI USE CASE BENEFITS (NOMINAL, $ MILLION)



Note: The Bainbridge and Duvall Targeted Demand Response Programs are included in the Load Flexibility Programs

Accounting for the estimated benefits and costs in addition to those presented in the original business case leads to a benefit-cost ratio of 2.2 in the Base case. Compared to the previously reported ratio of 1.4, the higher ratio indicates that AMI will create more opportunities for PSE to introduce various new customer programs and offerings to benefit customers.

FIGURE 2: AMI USE CASE BENEFITS AND COSTS ($ MILLION)

	Tier 1		Tier 2		Original		Total		B/C Ratio
	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	
Low Case	$121	$52	$294	$16	$668	$473	$1,082	$541	2.0
Base Case	$267	$95	$358	$22	$668	$473	$1,293	$591	2.2
High Case	$424	$173	$494	$26	$668	$473	$1,586	$672	2.4

The benefit and cost estimates presented here are not meant to be comprehensive. These estimates are based on the best information and knowledge that we have of PSE's plans and efforts at this time. As PSE moves forward with the various use cases, and as more information becomes available, the Company will need to update assumptions in this report as appropriate.

I. Introduction

A. Background

Puget Sound Energy ("PSE" or "Company") initiated its Advanced Metering Infrastructure ("AMI") meter deployment in 2018, which, upon completion, will deploy 1.2 million AMI electric meters and 800,000 gas modules by the end of 2023.[4] As of January 12, 2022, 838,085 AMI electric meters and 531,240 AMI gas modules have been installed in PSE's service territory. By the end of 2022, the Company will have installed more than 1 million electric meters and 757,000 gas AMI modules, representing about 90% of all electric and gas customers.

In 2019, the Company filed an application before the Washington Utilities and Transportation Commission ("WUTC" or "the Commission") seeking recovery for its AMI investment by including the AMI costs in base rates. In its application, PSE quantified the costs and benefits associated with the AMI project.[5] The cost of the AMI project was projected at $473 million, while the benefits were projected at $668 million, yielding a benefit-cost ratio of 1.4.[6] PSE quantified three different benefit streams from AMI over the 20-year lifetime of the AMI assets: i) avoided costs associated with the replacement of its obsolescent Automated Meter Reading ("AMR") system; ii) benefits due to conservation voltage reduction ("CVR"); and iii) distribution automation benefits enabled by the AMI communication network. In addition to quantified benefits, PSE identified other benefits that would be enabled by AMI at the time of the cost recovery filing, such as advanced outage prediction, availability of load profile information, and the ability to remotely disconnect/reconnect. These benefits, however, were not quantified and included in the original PSE AMI cost-benefit analysis.

In its Final Order, issued in July 2020, the WUTC agreed that PSE's AMR system was obsolete and that PSE's operational decision to install AMI was prudent.[7] However, the WUTC granted PSE only cost recovery <u>of</u> all deferred depreciation expense incurred to date, and required PSE to defer *recovery of the return on* its AMI investments in a deferral account. The WUTC noted that,

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4 For the gas meters, the upgrade involves updating the AMR modules with AMI modules, while the physical meter stays.

5 *WUTC v. Puget Sound Energy*, Dockets UE-190529/UG-190530 *et al.*, Prefiled Direct Testimony of Catherine A. Koch, Exh. CAK-1T (June 20, 2019).

6 *Id.* at 1.

7 *WUTC v. Puget Sound Energy*, Dockets UE-190529/UG-190530 *et al.*, Final Order 08/05/03 (July 8, 2020).

> PSE has not yet satisfactorily demonstrated the benefits of the AMI system as a whole. The Company represented at hearing that it is planning to pursue additional benefits, but it has yet to put forth any formal plan or proposal. Instead, the only benefits the Company has cited are billing functions, voltage management—which cannot yet be adequately demonstrated—and remote disconnection capability. As such, PSE has not yet made a showing that would justify authorizing the Company to recover a return on any portion of its AMI investment made thus far.[8]

In its Final Order, the Commission also referred PSE to a *Utility Dive* article that is based on an American Council for an Energy-Efficient Economy ("ACEEE") report. The article concluded that "many utilities are underexploiting AMI capabilities and attendant benefits, thus missing a key tool to deliver value to their customers and systems."[9] The Commission indicated that it expected "PSE to take great strides to ensure that both the Company and its **customers receive maximum value from its AMI system** [emphasis added], and…to demonstrate that value to the Commission in the near future."[10] In the same order, the Commission noted,

> We encourage the Company to carefully review the report referenced in the Utility Dive article, which examined whether utilities are leveraging AMI by capturing data on six use cases: 1) time of use (TOU) rates, 2) real-time energy use feedback for customers, 3) behavior-based programs, 4) data disaggregation, 5) grid-interactive efficient buildings, and 6) CVR or volt/VAR optimization. The Commission is interested in PSE's analysis of the six use cases and whether or how they are applicable, as well additional information or metrics that demonstrate AMI's

8 *Id*. at ¶155.

9 Robert Walton, *Most Utilities Aren't Getting Full Value From Smart Meters, Report Warns* (Jan. 13, 2020), https://www.utilitydive.com/news/most-utilities-arent-getting-full-value-from-smart-meters-report-warns/570249/.

10 *WUTC v. Puget Sound Energy*, Dockets UE-190529/UG-190530 *et al.*, Final Order 08/05/03 at ¶157 (July 8, 2020).

> benefits to customers. Although we share PSE's optimism about the benefits AMI will ultimately produce, we reiterate our expectation that PSE will maximize those benefits.[11]

B. Purpose of This Report

This report is developed in response to the WUTC's request that PSE demonstrate the customer-facing benefits of AMI. Supporting PSE's renewed request as part of its 2022 general rate case that PSE be entitled to both recovery of and a return on its AMI investment, the report presents how the Company is maximizing or is planning to maximize AMI benefits through various customer programs and offerings that are enabled or facilitated by AMI—including those benefits identified by the Commission from the *Utility Dive* article.

PSE retained The Brattle Group ("Brattle") to assist the Company in quantifying the customer-facing benefits of AMI that it is currently achieving or planning to achieve. In all cases, the AMI investment either directly enables PSE to implement the use case (*e.g.*, time-varying rates, or "TVR") or allows PSE to maximize customer benefits by providing operational efficiencies and improved measurement and verification capabilities (*e.g.*, load flexibility programs).

As described later in the report, prior to Brattle's engagement, PSE had formed an internal working group of subject matter experts ("SME") to identify and coordinate the achievement of a wide range of AMI benefits for both electric and gas customers. The PSE working group identified 38 AMI use cases as well as the related initiatives, both current and planned. PSE and Brattle then followed a systematic approach to review all of the AMI use cases and classified them into three tiers for analysis:

- "Tier 1" use cases are the six customer-facing use cases highlighted by the WUTC and therefore were prioritized for assessment and analysis. The Brattle team, working with the PSE SMEs, documented PSE's progress in the six Tier 1 use cases and, when appropriate, quantified the expected benefits and costs associated with each of the use cases.
- "Tier 2" use cases represent other benefits PSE has prioritized and made progress on.
- "Tier 3" use cases refer to future use cases which are in early stages of development. At this time, we highlight a number of select Tier 3 use cases and present their benefits qualitatively.

[11] *Id.*

Laying the foundations and undertaking strong customer initiatives take time. It is notable then that PSE has planned and launched a number of innovative AMI-related pilot programs, even though the Company has not yet completed its AMI deployment. Progress to date underscores PSE's intent to maximize the capabilities provided by its AMI investment. PSE has identified a number of AMI use cases, has tasked multiple teams with delivering the benefits for these use cases, and has already started implementing some of these use case benefits. The Company's commitment to maximizing AMI benefits documented in this report stands in contrast with other utilities who have yet to maximize customer benefits many years after full AMI deployment, as referenced in the ACEEE report.[12]

We organize the remainder of the report as follows: Section II explains that PSE's implementation of AMI is consistent with industry standard and provides an overview of AMI deployments in Washington State and across the nation. Section III explains that AMI is necessary for customer empowerment and for achieving green energy and decarbonization initiatives. We describe our approach to quantifying AMI benefits in Section IV, and summarize PSE's efforts to maximize the benefits from its AMI investment and expected benefits from the different use cases in Sections V to VII. Section VIII concludes the report.

II. PSE's Deployment of AMI is Consistent with Industry Standard

PSE views AMI as a foundational technology that enables use cases throughout the organization to benefit customers directly and indirectly. AMI is also part of PSE's broader, company-wide initiative to modernize the grid and meet the objectives of the Washington Clean Energy Transformation Act ("CETA").[13] PSE is not alone in pursuing AMI investments to build the strong foundations for the energy requirements of the 21st century, and is joined by many utilities across the country and the globe who have done the same. Below, we present an overview of the status of AMI deployments in the U.S. and in the state of Washington.

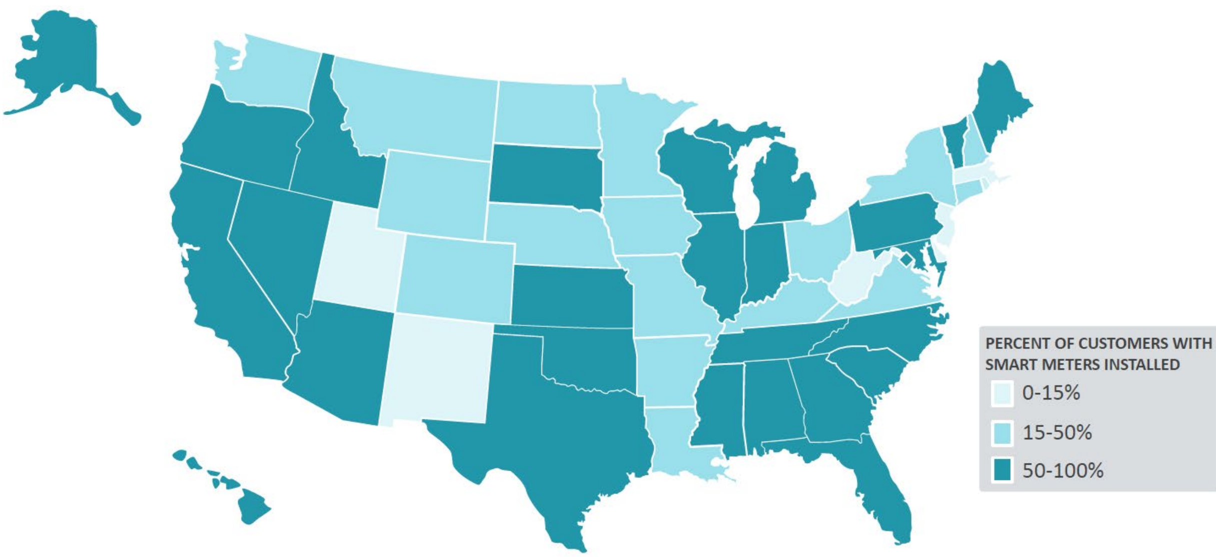
[12] Rachel Gold, Corri Waters, & Dan York, *Leveraging Advanced Metering Infrastructure To Save Energy*, ACEEE (Jan. 3, 2020).

[13] Chapter 19.405 RCW.

A. Status of AMI Deployments in the U.S.

The pace of smart meter deployment has accelerated in the past decade. As of 2020, 107 million smart meters were deployed, representing 75% of all households. According to a projection from the Edison Foundation, there would be about 115 million installed smart meters by the end of 2021, or about 80% of all U.S. residential customers.[14] As shown in Figure 3 below, AMI has been implemented in many of the U.S. states. At the current deployment rate, smart meters will reach almost all residential customers in five years.

FIGURE 3: SMART METER DEPLOYMENT BY STATE IN 2019[15]



Note: Reproduced from the IEI report.

Widespread deployment of smart meters in the last decade can be attributed to federal, state, and local policy incentives and requirements as well as the utilities' own initiatives to modernize and maximize their investments in grid infrastructure. For instance, the U.S. government, through the 2009 American Reinvestment and Recovery Act ("ARRA"), provided federal matching grants (up to one-half of project costs), funding 99 projects under the Smart Grid Investment Grant program.[16] In other places, utilities have modernized their metering infrastructure as the existing meters have reached the end of their useful lives and/or proven insufficient to enable customer-facing initiatives such as implementation of TVR.

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[14] Adam Cooper & Mike Shuster, "*Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2021 Update)*, The Edison Foundation Institute for Electric Innovation (Apr. 2021), https://www.edisonfoundation.net/-/media/Files/IEI/publications/IEI_Smart_Meter_Report_April_2021.ashx.

[15] *Id.*

[16] The ARRA provided $3.4 billion for this program. *See* Richard J. Campbell, *The Smart Grid: Status and Outlook* (April 10, 2018), https://fas.org/sgp/crs/misc/R45156.pdf.

It is important to note that it takes time to plan for and realize the full benefits of an AMI investment. There is usually delay between when AMI is first deployed and when AMI benefits can be maximized. This is because of the additional investments (such as system upgrades, system integration, data processing, and management tools) and new processes and standards (to address data privacy concerns, for example) needed to fully utilize AMI. At the same time, utilities need to obtain approval from regulators and invest significantly in customer engagement and marketing efforts to successfully implement any AMI-related programs. For example, Portland General Electric ("PGE") started its AMI deployment in 2008 and completed it in 2010.[17] In the subsequent years, PGE evaluated its pricing programs, performed market research and focus groups, and conducted load segmentation research.[18] The Oregon regulators approved PGE's request to run a TVR pilot in 2015, and customer recruitment began the following year. After the successful implementation of the pilot, PGE started to offer TVR to the full population in 2019, 11 years after the start of the AMI deployment.[19] Similarly, Consumers Energy started its AMI deployment in 2012 and concluded it in 2017.[20] It implemented two pricing pilots, one in 2010 prior to the AMI deployment, and another in 2019. Resulting from the success of these pilots, Consumers Energy deployed time of use ("TOU") rates to the full population in 2020.[21] In Consumer Energy's case, it took eight years for the Company to offer the TOU rates to the full population from the start of the deployment. In each of these cases, the companies built additional capabilities to leverage the AMI platform over time and tested them on a smaller scale to prove concept and ensure smooth transition, before offering them on a broader scale.

B. Status of AMI Deployments in Washington State

Introduction of smart meters in Washington State has historically been slow relative to neighboring states, as well as to the rest of the U.S. As of 2019, at least half of electric

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[17] Portland General Electric, *Smart Grid Report*, at 92 (June 2019), https://edocs.puc.state.or.us/efdocs/HAQ/um1657haq15635.pdf.

[18] Portland General Electric, *Portland General Electric Signs Contracts for Advanced Metering Infrastructure System*, (Sept. 19, 2007), https://investors.portlandgeneral.com/news-releases/news-release-details/portland-general-electric-signs-contracts-advanced-metering.

[19] Portland General Electric, *Smart Grid Report*, at 94.

[20] T&D WORLD, *Consumers Energy to Finish Installing Upgraded Meters in 2017* (Jan. 4, 2017), https://www.tdworld.com/smart-utility/metering/article/20967551/consumers-energy-to-finish-installing-upgraded-meters-in-2017.

[21] Ahmad Faruqui, *Moving Ahead with Time-Varying Rates (TVR)*, THE BRATTLE GROUP (Apr. 6, 2020), https://brattlefiles.blob.core.windows.net/files/18500_moving_ahead_with_time-varying_rates_tvr_-_us_and_global_perspectives.pdf.

customers had installed smart meters in more than half of the U.S. states.[22] Smart meter deployment was widespread in many Western states, including Arizona, California, Idaho, Nevada, and Oregon. In comparison, less than 50% of customers in Washington had smart meters at the time.

However, the number of customers in Washington with smart meters has increased in recent years as utilities across the state have accelerated the pace of AMI rollout. Inland Power and Light was the first Washington utility to complete its AMI rollout, installing 39,000 meters across its Washington and Idaho service area by 2015 (see Figure 4 below).[23] Seattle City Light and Avista initiated their meter deployment projects shortly after, and both projects have completed or are near completion.[24] Tacoma Public Utility District recently began their smart meter deployment effort in 2020, and the project is scheduled for completion in 2022.

PSE began to transition away from its obsolete AMR system in 2016. Since then, the Company has made steady progress and is on track for universal deployment of smart electric meters and gas modules by 2023. By then, more than 90% of electric customers in Washington State will be equipped with AMI meters. It is important to note that PSE is the largest utility in the State with over 1.2 million electric and gas customers and therefore has an extended deployment timeline relative to other utilities in the state.

FIGURE 4: STATUS OF AMI DEPLOYMENT IN WASHINGTON STATE

Company	Deployment Date	Number of Meters Installed	Notes
Puget Sound Energy	2017-2023	838,085 electric meters 531,240 AMI gas modules	Ongoing deployment; estimated 90% completion by December 2022
Avista	2017-2020	249,391 electric meters 160,166 AMI gas modules	
Inland Power & Light	2013-2015	39,000 electric meters	
Seattle City Light	2016-2019	461,496 electric meters	
Tacoma PUD	2018-2022	190,000 electric meters 110,000 water meters	Ongoing deployment

Notes and sources: Avista Utilities Advanced Metering Infrastructure (AMI) Project Report (Oct 2020).
PSE's installation data as of January 12, 2022.

22 Adam Cooper & Mike Shuster, "*Electric Company Smart Meter Deployments*

23 Avista Utilities Advanced Metering Infrastructure (AMI) Project Report (Oct. 2020).

24 According to Avista, about 0.1% of electric smart meters and 21% of gas modules remain to be installed. *WUTC v. Avista Corporation*, Dockets UE-200900/UG-200901 *et al.*, Final Order 08/05 (Sept. 27, 2021).

III. AMI Is Necessary for Customer Empowerment and Decarbonization

Customers are becoming increasingly engaged in their energy consumption decisions, desiring and demanding more information that can enable them to identify ways to lower their energy usage, reduce their carbon footprint, and effectively leverage new energy technologies. AMI's granular data and two-way communication capabilities unleash a multitude of possibilities for customers to become "empowered" through their participation in TVR, behavior-based, and load flexibility programs. These programs will help PSE to integrate more intermittent and variable renewable energy resources into the grid, allowing the utility to meet Washington State's clean energy goals.

Given these trends, AMI is essential to the development of any type of "smart grid" that would ultimately allow for distributed generation, lower costs, greater flexibility, and improved system-wide reliability and resilience. A smarter and more flexible grid would facilitate innovations in the industry by acting as a platform for customers and other market players to engage. If the state of the grid is not on a par with these innovations, then the customers who are served by that system will have limited access to these innovations.

A. AMI Enables Customer Empowerment

Customers have diverse tastes. Some want bill stability and are willing to pay more for it. Others want lower bills and are willing to modify their energy lifestyle to reduce their bills. To accommodate customers' diverse preferences, utilities need to offer different products and services, many of which are enabled by AMI.[25]

Another trend that has emerged in the past decade is the "greening" of customer tastes. For a variety of reasons, customers increasingly embrace organic products, and move away from anything that is perceived to be inorganic. When it comes to electricity, more and more customers wish to support the promotion of clean energy sources, a phenomenon called "organic conservation."[26] By providing customers with hourly energy usage information, AMI

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[25] Ahmad Faruqui & Cecile Bourbonnais, *The Tariffs of Tomorrow: Innovations in Rate Design*, IEEE Power and Energy Magazine (May-June 2020), https://ieeexplore.ieee.org/document/9069846.

[26] Ahmad Faruqui, Ryan Hledik & Wade Davis, *The Emergence of Organic Conservation*, The Electricity Journal (June 2015), https://www.sciencedirect.com/science/article/abs/pii/S1040619015001074.

allows customers to optimize their consumption based on the carbon emissions level of the power system. For example, customers can opt to limit their energy consumption during peak hours, when the electric grid is often most carbon intensive.

Customers want to know where their energy dollars are going. For example, customers want to know what the biggest end uses in their houses are, and which energy conservation behaviors may be the most cost effective and least inconvenient. To lower their bills, should customers focus on managing plug loads, appliances, HVAC systems, or lighting? AMI provides granular data that can be used to disaggregate total loads into end uses, helping customers make informed decisions about their energy usage and conservation. Furthermore, if a customer is eligible for multiple rate schedules, AMI data can help assess which rate schedule may lead to the lowest bill. Hourly AMI data from the previous year can be used to compute their bills on each of the rate schedules, helping to identify the most economic rate for the customer.

A small but growing group of customers goes a step further and makes their own decisions regarding how their energy is generated. These customers wish to go beyond changing energy usage patterns by modifying various end uses in their homes and are willing to invest in energy efficiency upgrades to lower their bills. To lower their bills beyond what can be achieved with energy efficiency, some customers install solar panels on their roofs. For these "prosumers," promoting the consumption of locally-sourced carbon-free electricity is a primary reason for pursuing distribution generation solutions. Finally, still others are willing to go yet one step further by pairing the solar panels with battery storage located on their premises. They are called "prosumagers." Batteries can give them the opportunity to further lower their bills if they are on a TVR and also to have resilience in the face of a power outage. AMI either facilitates or enhances all of these capabilities. For example, AMI meters will allow for more consistent and accurate meter readings for customers with distributed generation. Section VII provides more detail on AMI and distributed generation resources.

B. AMI Enables the Clean Energy Transition

AMI is a foundational technology that enables the modernization of utility operations, allowing utilities to meet the requirements of the 21st century grid and achieve clean energy goals and policy.[27] The rapidly evolving electricity grid increasingly relies on renewable generation on the utility side and has to manage a growing share of DERs on the customer side. At the same time, states and cities are setting aggressive goals to decarbonize the grid. Washington State signed

[27] U.S. Department of Energy, Office of Electricity. *AMI in Review: Informing the Conversation* (July 6, 2020), https://www.smartgrid.gov/document/voe-ami-in-review-informing-the-conversation.

into law its own clean energy commitment, CETA, in May 2019. Specifically, the state committed to achieving the following goals:

> By 2025, utilities must eliminate coal-fired electricity from their state portfolios. The first 100% clean standard applies in 2030. The 2030 standard is greenhouse gas neutral, which means utilities have flexibility to use limited amounts of electricity from natural gas if it is offset by other actions. By 2045, utilities must supply Washington customers with electricity that is 100% renewable or non-emitting, with no provision for offsets.[28]

In a decarbonized grid that will rely heavily on renewable energy resources such as solar and wind, load flexibility will be critical to preserving reliability and ensuring reliance in a cost-effective manner. To ensure the dynamic balancing of supply (which will fluctuate due to intermittent and variable wind and solar generation) and demand, such a grid will require loads to be flexible in real time. When there is an abundance of solar energy in the daytime and wind energy at nighttime, loads will need to surge in real time. When generation from solar energy wanes in the evenings, loads will need to reduce rapidly in real time. Otherwise, system reliability will be compromised.

The type of load flexibility required for dynamic system balancing in a decarbonized grid will need to go beyond the traditional energy efficiency or demand response programs that focus primarily on total energy or peak load reduction. Load flexibility would require loads to be raised or lowered in real time to offset the contractions and buildups of renewable supply resources in real time. The ability to modulate load can yield substantial benefits to all customers. A recent Brattle study has quantified that at the national level, load flexibility can reach a potential value of 200 GW, or 20% of peak demand, by 2030, creating more than $16 billion in benefits.[29]

Recent research shows that one of the most efficient and cost-effective ways to deploy load flexibility is through real-time pricing coupled with enabling technologies such as smart

[28] Washington State Department of Commerce, *CETA: A Brief Overview*, https://www.commerce.wa.gov/wp-content/uploads/2020/02/CETA-Overview.pdf.

[29] Ryan Hledik, Ahmad Faruqui, Tony Lee & John Higham, *The National Potential for Load Flexibility* (June 2019), https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf.

thermostats, smart appliances, and whole-house energy management systems.[30] By measuring hourly customer usage level, AMI can enable real-time pricing and other forms of time-varying pricing programs that can help power customer bills and help meet system needs. There are other pricing options that can be relied on in the interim, until enabling technologies start to communicate seamlessly with real-time prices.

In due course, as DERs such as rooftop solar panels and battery storage systems become more widely deployed, the grid may need to act as a platform to accommodate the two-way flow of power. The grid may also need to act as a platform to facilitate transactions between customers, such as those that were tested in the RATES pilot dealing with transactive energy that was carried out by Southern California Edison and funded by the California Energy Commission.[31] Without AMI, the grid will not be able to accommodate such transactions.

Furthermore, utilities are beginning to explore the role of non-wires alternatives ("NWAs") to reduce the need for investing in transmission and distribution assets. The rapid rate of electric vehicle ("EV") adoption is likely to over-burden the distribution system. Under normal conditions, an EV may raise the load of a house by anywhere from 25−50%. That could strain the service lines that serve the house. If multiple homes acquire EVs, the strain could be transmitted to distribution feeders; and if whole neighborhoods embrace EVs, the strain would travel upstream to distribution substations. AMI will facilitate the deployment of NWAs by providing utilities and/or third-party providers (who may work directly with customers on behalf of utilities) with data important to the planning and implementing process. NWA solutions can also leverage customer-side resources to contribute to the management of the grid constraints, thereby helping enhance grid reliability. To achieve the maximum impact, NWAs will require a combination of time-varying pricing, enabling technologies, and behavioral messaging, all of which can be facilitated or enhanced by the presence of AMI.

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30 William Driscoll, *Real-time pricing that integrates more solar power is proven to work in California*, PV MAGAZINE (June 30, 2020), https://pv-magazine-usa.com/2020/06/30/real-time-pricing-that-integrates-more-solar-power-is-proven-to-work-in-california/.

31 Rates: Retail Automated Transitive Energy System, *Rates Pilot Overview*, https://rates.energy/overview-1.

IV. Overview of Brattle's Quantification of PSE's AMI Benefits

The Company previously identified three categories of benefits and justified the cost of the AMI project based on the quantified benefits of these three categories: i) avoided investment to maintain the outdated AMR system; ii) distribution automation utilizing the AMI network; and iii) conservation benefits associated with CVR. The cost of the AMI project was estimated at $473 million, while the benefits were projected at $668 million, yielding a benefit-cost ratio of 1.4.[32]

The benefits quantified in PSE's original benefit-cost analysis alone provide a compelling basis for, and clearly justify, PSE's decision to implement AMI. Additionally, PSE's original AMI business case identified other AMI benefits but did not quantify them at the time. These benefits included improved customer service by leveraging technology and improved processes for certain services, such as remote connect and disconnects.[33]

In this section of the report, we summarize our approach to classifying and quantifying other benefits of AMI, which were not previously quantified as part of PSE's original AMI business case.

Prior to our engagement, PSE's AMI Working Group had already identified and begun developing 38 AMI use cases that are expected to generate customer and/or operational benefits. We evaluated each of these AMI use cases and classified them into three tiers:

1. **Tier 1 Use Cases** are the "customer-facing" use cases highlighted by the WUTC. They were prioritized for quantitative assessment and analysis. While the Final Order listed the six use cases, we consolidated some of these use cases into one category as they would be creating similar impacts. Figure 5 below presents our re-mapping of these six use cases into three use cases, the benefits of which are quantified in this report.

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[32] *See* Koch, Exh. CAK-7.

[33] *Id.*

FIGURE 5: TIER 1 USE CASES QUANTIFIED IN THIS REPORT

Commission Use Case[34]	Brattle's Tier-1 Classification	Status/Approach
1. TOU Rates	**1. Time-Varying Rates** • Time of Use Rates • Time of Use Rates with Peak-Time Rebates	PSE is currently planning a TVR pilot that will test TOU and PTR rates (including rates for customers with EVs, low income customers and small business customers).
2. Behavior-based Programs	**2. Behavior-based Programs** • Online Information Presentment • High Usage Notifications • Virtual Commissioning Pilot (small business)	PSE is currently implementing three programs that are intended to yield energy savings through effective provision of information to customers.
3. Real-time Informational Feedback for Customers	**2. Behavior-based Programs** • IHD Pilot Program (residential) • Online Information Presentment	PSE is currently implementing an in-home display pilot program. The information presentment is expected to yield behavior change and lead to conservation.
4. Data Disaggregation	**2. Behavior-based Programs** • Actionable Information, deployed with other behavior-based programs (online information presentment, high usage notifications) • Increased Marketing Effectiveness and Targeting for PSE Programs	While the primary benefit of data disaggregation is likely the increased marketing effectiveness of utility programs, we only quantify the customer benefits associated with conservation due to better information about appliance usage.
5. Grid-interactive Efficient Buildings (GEB)	**3. Load Flexibility Programs** • Smart thermostat programs for space heating (system-wide) • Grid-interactive water heating load control (system-wide) • Behavioral demand response (system-wide) • Bainbridge Island Targeted Demand Response ("DR") pilot (for reducing electricity peak demand) • City of Duvall Targeted DR pilot (for managing gas peak demand)	While the GEB use case is specifically about reducing the electricity usage and improving load flexibility in large buildings through smart controls, the PSE team has reinterpreted this use case as the broad umbrella of load flexibility programs more effectively enabled by AMI.
6. CVR or volt/VAR Optimization	1. **CVR/VVO**	This use case has been quantified in PSE's AMI business case and will be discussed in Witness Catherine Koch's testimony.

2. **Tier-2 Use Cases** represent other AMI benefits PSE has prioritized and have already made progress on achieving. Figure 6 below presents the Tier 2 benefits that are addressed in this study.

[34] Please refer to the Appendix for the definitions of the six ACEEE use cases.

FIGURE 6: TIER 2 USE CASES ADDRESSED IN THIS REPORT

Tier 2 Use Case	Description	Status/Approach
1. Solar PV-Customer Metering Costs	Bi-directional AMI meters reduce equipment costs for customers and improve investment planning.	PSE is already delivering this benefit.
2. Leveraging AMI Network for Smart Street Lighting	Connect devices by leveraging the AMI network. Smart Street Lighting use case is the initial implementation.	PSE is already in the process of deploying smart street lights.
3. Remote connect/disconnect	This use case refers to the ability to connect and disconnect service remotely, by avoiding a field visit to the service location.	PSE is already implementing the remote connect/disconnect capability.
4. Improved Outage Management	Earlier outage detection. Quicker outage restoration	PSE is planning to transition to a new OMS module that integrates AMI data by 2023.

3. **Tier-3 Use** Cases are use cases that have no well-established data at this time or are in early stages of planning and development. We discuss a select number of these benefits qualitatively. These use cases include improved bill generation, avoided metering issues, better visibility into asset utilization, and improved DER planning and integration, among others. Appendix C contains a complete list of Tier 3 use cases considered.

A. Approach

For each of the use cases, we worked with PSE SMEs to compile key data and information on the status of PSE's currently implemented programs, planned near-term pilots, and program implementation scenarios beyond pilot durations. Throughout the process, the Brattle team independently reviewed the relevant information for each use case and followed up with the PSE team to understand and clarify execution plans for the planned pilots and programs as needed.[35] To the extent that the PSE SMEs were able to provide inputs on the expected participation rates and expected program impacts, the Brattle team reviewed, confirmed, or proposed alternatives to these assumptions based on our experience from other jurisdictions. For those cases where the PSE team was not able to provide initial assumptions, the Brattle team helped populate these assumptions based on similar programs elsewhere, and then confirmed the reasonableness of those assumptions with the PSE SMEs. Throughout this process, the PSE and Brattle teams worked closely to parameterize each of the Tier 1 and Tier 2

35 Brattle reviewed 38 use cases proposed by the PSE teams. Please see the Appendix for a list of all proposed use cases.

use cases quantified in this report and leveraged our respective strengths: the PSE team's knowledge of its own customers and programs, and the Brattle team's knowledge of the national and global landscape in customer-facing AMI-enabled programs.

For each of the use cases, we quantified the expected annual benefits through 2037, which marks the end of the expected 20-year life of the AMI meters deployed in 2017.[36] After estimating the annual expected benefits through 2037, we calculated the total nominal benefits. Given the uncertainty involved in calculating expected benefits over a long time horizon (and while some of the programs are just being initiated), we defined Low, Base, and High cases to provide a range for the expected benefits that will be discussed further below.

We note that the programs presented in this report are based on PSE's latest plans and efforts to maximize AMI benefits at this time. As the Company further develops and pursues these programs, it may acquire new data and insights that will help inform and further shape the program designs and implementation. In addition, any programs PSE implements will need to comply with applicable laws and regulations. Accordingly, the AMI-enabled programs that PSE will eventually make available to customers may differ from what we present in this report. To address these uncertainties, at least in part, we constructed three cases, Low, Base, and High, for each major quantified benefit. While these three cases are meant to reasonably capture the range of uncertainty, program designs and implementation will need to be updated as more information becomes available.

B. Benefit Categories

Our analysis focuses on five main benefit categories associated with Tier 1 use cases:

- **Avoided generation capacity costs**: These refer to the avoided generation capacity costs due to reductions in system peak demand, which lowers the need to invest in new generation capacity and related infrastructure. We quantified the benefits by multiplying the total reduction in peak for eligible and participating customers by the generation capacity benefit ($95.27 per kW-year).[37]
- **Avoided T&D capacity costs**: Similar to the avoided generation capacity benefit, AMI-enabled programs can help defer the need to invest in T&D assets. The avoided T&D benefits were quantified similarly to the avoided generation capacity benefits, but we relied

[36] The first year of our benefit model for a particular program corresponds to when that program is launched or expected to launch.

[37] PSE Integrated Resource Plan 2021.

on the avoided T&D capacity cost value of $12.61 per kW-Year, based on PSE's 2021 Integrated Resource Plan ("IRP").[38]

- **Avoided energy costs**: These benefits result from conservation or load shifting from high price to low price hours. In the case of conservation, PSE can either generate less or procure less power resulting in lower power costs for customers. In the case of load shifting, as the load is shifted from higher price hours to lower price hours, PSE's generation or procurement costs decline, lowering costs for customers. To quantify the impact of energy conservation, we multiplied the total reduction in energy usage for all participating customers by Mid-Columbia energy prices. To quantify the benefit from load shifting, we calculate the difference between the energy cost in peak hours and off-peak hours for all participating customers. Savings related to natural gas consumption is derived using commodity costs, which are obtained from PSE's 2021 IRP.
- **Avoided emissions**: Less electricity generation translates to lower carbon emissions. This is quantified by multiplying the reduction in energy usage with the social cost of carbon ("SCC"), which is about $90/ton of CO_2 in 2021, based on PSE's 2021 IRP. When converted to $/MWh, the SCC accounts for PSE's progress in decarbonizing its grid in the next decades to reach its 100% clean energy goal by 2045. For natural gas emissions, the cost of carbon includes both the SCC (emissions during consumption) and the upstream emissions.
- **Avoided T&D losses**: There are losses associated with the process of transmitting electricity generated by large power plants over long distance to load centers. AMI-enabled programs can help reduce electricity usage at the customer's premise, which in turn leads to a proportionally greater reduction in electricity generation. For example, a reduction of one kW of demand at the meter avoids more than one kW of generation capacity. Note that this benefit is incorporated into benefits associated with reduction in peak and energy usage. We scaled up the above benefits using a line loss impact of 6.8%, based on the 2021 IRP.

Each use case involves different programs and targets, and is therefore associated with a different set of benefits. Figure 7 below presents each of the Tier 1 use cases, the programs addressed under each, and the benefit categories quantified.

[38] We applied a 70% adjustment factor to both generation and T&D capacity deferral benefits (i.e., reducing benefits by 30%) to account for potentially lower benefits from demand response due to availability and performance constraints.

FIGURE 7: TIER 1 USE CASE BENEFITS

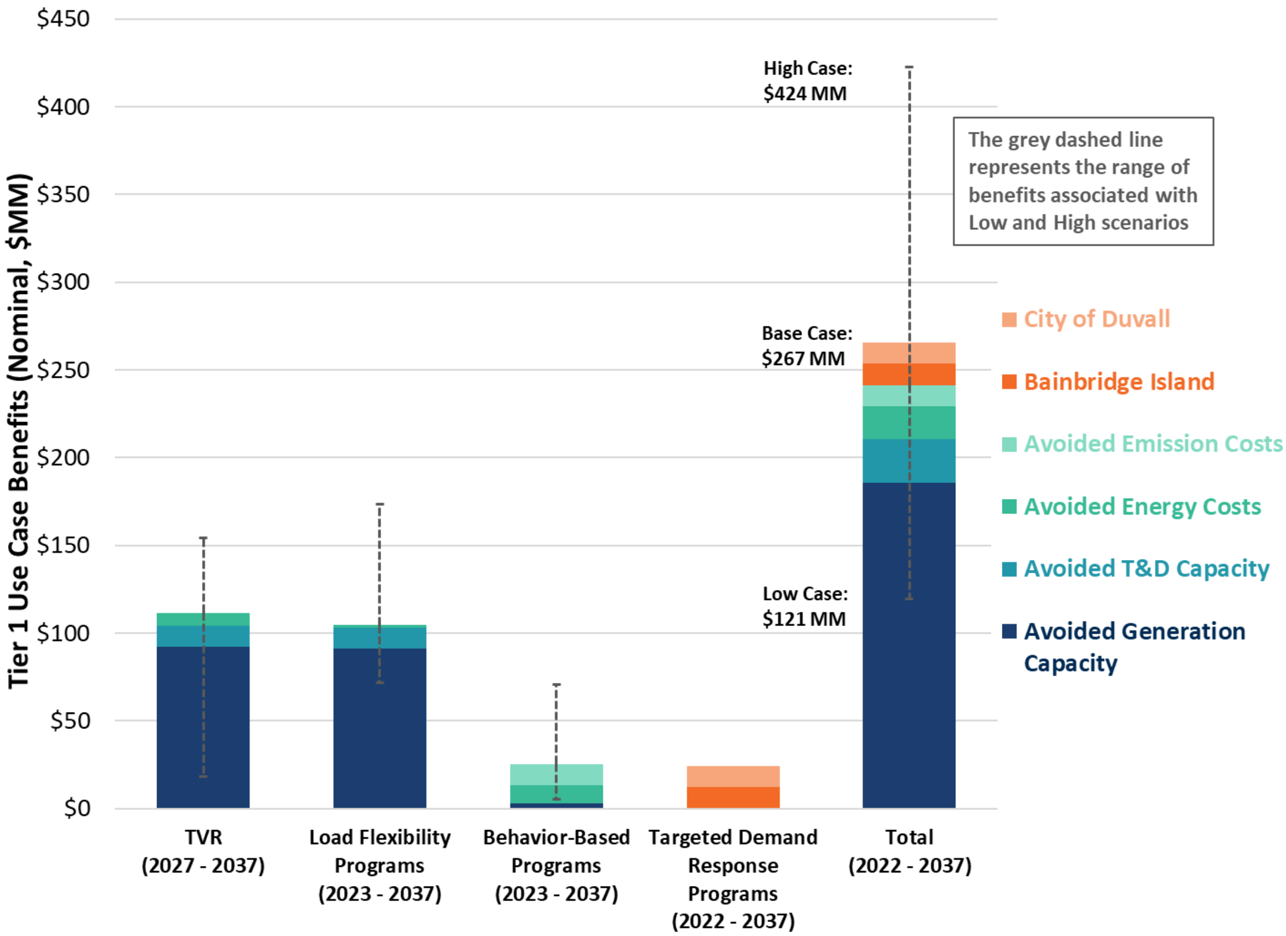
	Programs	Avoided Generation Capacity Costs	Avoided T&D Capacity Costs	Avoided T&D Losses	Avoided Energy Costs	Avoided Emissions
TVR	TOU	●	●	●	●	x
	TOU + PTR	●	●	●	●	x
	EV TOU	●	●	●	●	x
Behavior Based Programs	IHD Pilot	(Not Quantified)				
	Virtual Comissioning Pilot	(Not Quantified)				
	Online Information Presentment	●	●	●	●	●
	High Usage Notification	●	●	●	●	●
	Data Disggregation	●	●	●	●	●
Load Flexibility Programs	Smart Thermostat for Space Heating	●	●	●	x	x
	Behavioral Demand Response	●	●	●	x	x
	Grid-Interactive Water Heating	●	●	●	●	x
	Bainbridge Island Targeted DR Pilot	(Avoided Distribution Component of Wired Solution Deferral Benefit)				
	City of Duvall Targeted DR Pilot	(Avoided Pipeline Deferral Benefit)				

V. Tier 1 AMI Use Case Benefits

In this section, we discuss our approach and assumptions for developing the Tier 1 Use Case benefits as well as the results. Figure 8 below presents the total Tier 1 Use Case benefits quantified using inputs and methodology that were developed in close collaboration with PSE SMEs. The total Tier 1 Use Case benefits are estimated at $267 million for the Base case, with Low case being $121 million and High case $424 million. These benefits are incremental to the benefits estimated in PSE's original business case of $668 million.

In addition to these quantified benefits, some of the use cases are associated with unquantified benefits such as increased customer satisfaction, increased reliability and resilience, and local job benefits. When these unquantified benefits are applicable, we discuss them in each use case.

FIGURE 8: TIER 1 USE CASE BENEFITS



Note: Benefits associated with the avoided T&D loss are incorporated into the other benefit categories.

A. AMI Enables TVR

One of the leading benefits of AMI is the enablement of TVR and the harnessing of the load flexibility capability created by these rates. As of 2020, 107 million smart meters have been deployed, accounting for 75% of all U.S. homes.[39] Yet, TVRs are only deployed to 4% of U.S. residential customers, so there is a huge opportunity for expansion.[40]

TVRs feature variation in electricity prices by time period. TVRs allow customers to lower their bills by reducing their peak loads and possibly shifting some of their peak period energy to the off-peak period. The most common example is a TOU rate, which features variation in prices

[39] Jonathan Spencer Jones, *75% of US households have smart meters - report* (May 3, 2021), https://www.smart-energy.com/industry-sectors/smart-meters/75-of-us-households-have-smart-meters-report/#:~:text=107%20million%20smart%20meters%20are,for%20Electric%20Innovation%20has%20reported.

[40] Brattle analysis of EIA Form 861 (2020).

across two or more pricing periods in a day. The rates by pricing period are known in advance to the customer. A more complex example is critical-peak pricing ("CPP"). CPP prices are designed to lower peak demands during the highest demand hours of the year and usually target the top one percent of the hours of the year. The rates are known in advance to the customer but not the exact time, because when a CPP event is called depends on uncertain system conditions. Typically, the customer may be informed of a CPP event one day ahead. Under peak-time rebates ("PTR"), the customer pays the existing rate during certain critical hours but has an opportunity to earn a rebate equivalent to the CPP price by lowering his or her usage below their baseline.

Over the past two decades, there has been a gradual movement toward TVRs in North America and in other parts of the globe. Utilities, working closely with stakeholder groups under the guidance of appropriate regulatory bodies, have carried out nearly 400 tests of TVRs around the world. The empirical evidence from these tests reveals that a large percentage of customers accept and respond to TVRs by lowering peak demand and shifting it to off-peak periods.[41] By so doing, they can mitigate the need for capacity additions and reduce the energy costs by shifting their peak period usage, thereby effectively lowering utility bills for all customers, not just for themselves. Customers are becoming increasingly interested in managing their energy lifestyle not only to lower their bills but also to lower their carbon footprint. Some customers are installing emerging technologies, such as smart thermostats, electric vehicles, rooftop solar panels, and battery storage to further lower their bills and mitigate their carbon footprint. TVRs help them in making the best use of these technologies.

PSE has been working diligently to offer TVRs to its customers. PSE has developed a TVR pilot, which is anticipated to be fielded in the winter of 2023, if approved by the Commission. In preparation for the pilot, the PSE team has conducted focus groups to understand customer preferences towards TVRs, conducted detailed data analysis to inform the development of TVRs, and held collaborative meetings to incorporate stakeholders' feedback on the design of the rates and the design of the pilot.[42] To improve the customer participation in TVRs, PSE plans to continue this data-driven, customer-centric approach beyond the pilot, if and when the Company introduces TVRs on a system-wide basis.

At this point, PSE is planning to test three whole-house TVRs for its residential customers: a two-period TOU rate, a two-period TOU rate combined with PTR on event days ("TOU+PTR"),

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41 Ahman Faruqui, Sanem Sergici, & Cody Warner, *Arcturus 2.0: A meta-analysis of time-varying rates for electricity*, 30 THE ELECTRICITY JOURNAL 64 (Dec. 2017), https://www.sciencedirect.com/science/article/abs/pii/S1040619017302750.

42 At the time of the writing of this report, the PSE rates team has led three stakeholder meetings to inform the TVR pilot design decisions.

and a three-period TOU rate that targets residential customers with electric vehicles (three-period EV TOU). For its small commercial and industrial ("C&I") customers, PSE is planning to test a TOU+PTR rate. Under the current proposal, these rates will be offered to a random sample of customers who choose to be on these rates for two years. Depending on the results from the pilot, one or more of these rates may be extended to the broader population on an opt-in basis.

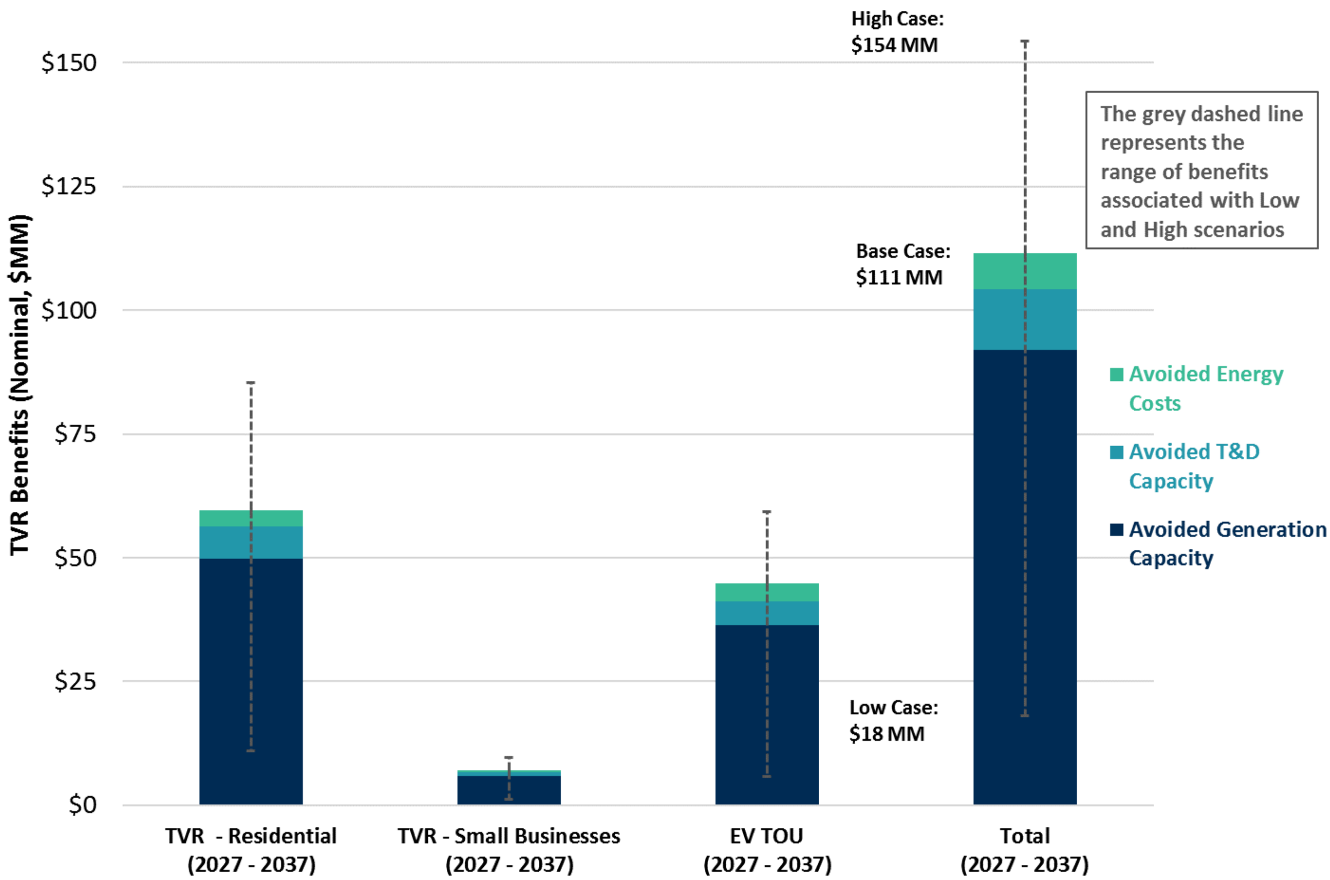
While the TVR Use Case is at the pilot planning stage at this time, the Company is fully committed to extending these rates to all customers if the pilot yields desirable results. For the purpose of quantifying the benefits of the TVR Use Case, we rely on the TVR rate offerings that PSE is proposing to test in the pilot.

We estimate the benefits associated with avoided capacity (generation, transmission, and distribution), avoided T&D losses, and avoided energy costs (load shifting) for each year in the study period. We assume that after piloting the rates in 2023 to 2025, the Company is likely to offer rates to the broader population thereafter on an opt-in basis if the impact evaluation yields favorable results.

As noted earlier, the TVR pilot will test both TOU and TOU+PTR rates for residential customers and TOU+PTR rates for the small C&I customers.[43] We expect that the Company will eventually offer only either the TOU or TOU+PTR rate to the broader residential class. Since it is not possible to predict the outcome at this time, we calculate the expected value of the TOU and TOU+PTR benefits assuming 50% probability for each scenario. For the small C&I customer class, we assume that the TOU+PTR rate will be offered to the broader, small C&I population on an opt-in basis. Figure 9 below presents the estimated TVR Use Case benefits.

[43] Pilot design also includes separate treatment cells for low-income residential customers, but those benefits were not separately identified in this report and were included in the broader residential class category.

FIGURE 9: TVR USE CASE BENEFITS



As seen in Figure 9 above, the majority of the benefit associated with TVR programs is derived from avoided generation capacity. This is consistent with previous findings and programs.[44] Across all the Low, Base, and High case for the residential TVR program, the generation capacity deferral benefit is about 80–85% of all benefits. The share of the avoided generation capacity benefit is around 85% for the TVR small business program.[45]

We note that there is a wide range in the total benefits. This has to do with the uncertainty associated with customer interest in and response to the TVR programs. Our work and experience in other jurisdictions inform the assumptions made in the Base case. With the Low and High cases, we aim to capture the scenarios in which PSE customers may behave differently

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[44] Ahmad Faruqui, Ryan Hledik, Sam Newell, & Hannes Pfeifenberger, *The Power of Five Percent*, THE ELECTRICITY JOURNAL (Oct. 2007).

[45] TVRs are generally limited in their direct emissions benefits as they largely involve load shifting, instead of conservation. The emissions benefits are associated with the difference in marginal emissions rates between peak and offpeak hours (assuming that offpeak emissions rates are lower). TVRs may also indirectly lead to emissions benefits as they can enable integration of renewables and help reduce curtailments. We did not quantify these benefits in our analysis.

than customers in other areas (*e.g.*, little or high interest in switching to dynamic rates; or lower/higher-than-expected peak reduction). Results from PSE's proposed TVR pilot will better inform these assumptions.

We estimate the total costs to fully deploy these TVR programs range from $15.5 million (in the Low case) to $63.4 million (High case). In the Base case, the total deployment costs are estimated to be about $44.6 million. The costs include capital investments (billing IT system upgrades, meter data management systems, and AMI integration), recruitment and marketing costs (including rebate amount for the PTR program), and administration costs. Of these, the recruitment and marketing costs are the highest, accounting for about 52% of the total costs in the Base case. Similar to the benefit evaluation, we calculated the expected cost of the TOU and TOU+PTR programs by assuming 50% probability for each scenario.

B. AMI Enhances Behavior-Based Programs

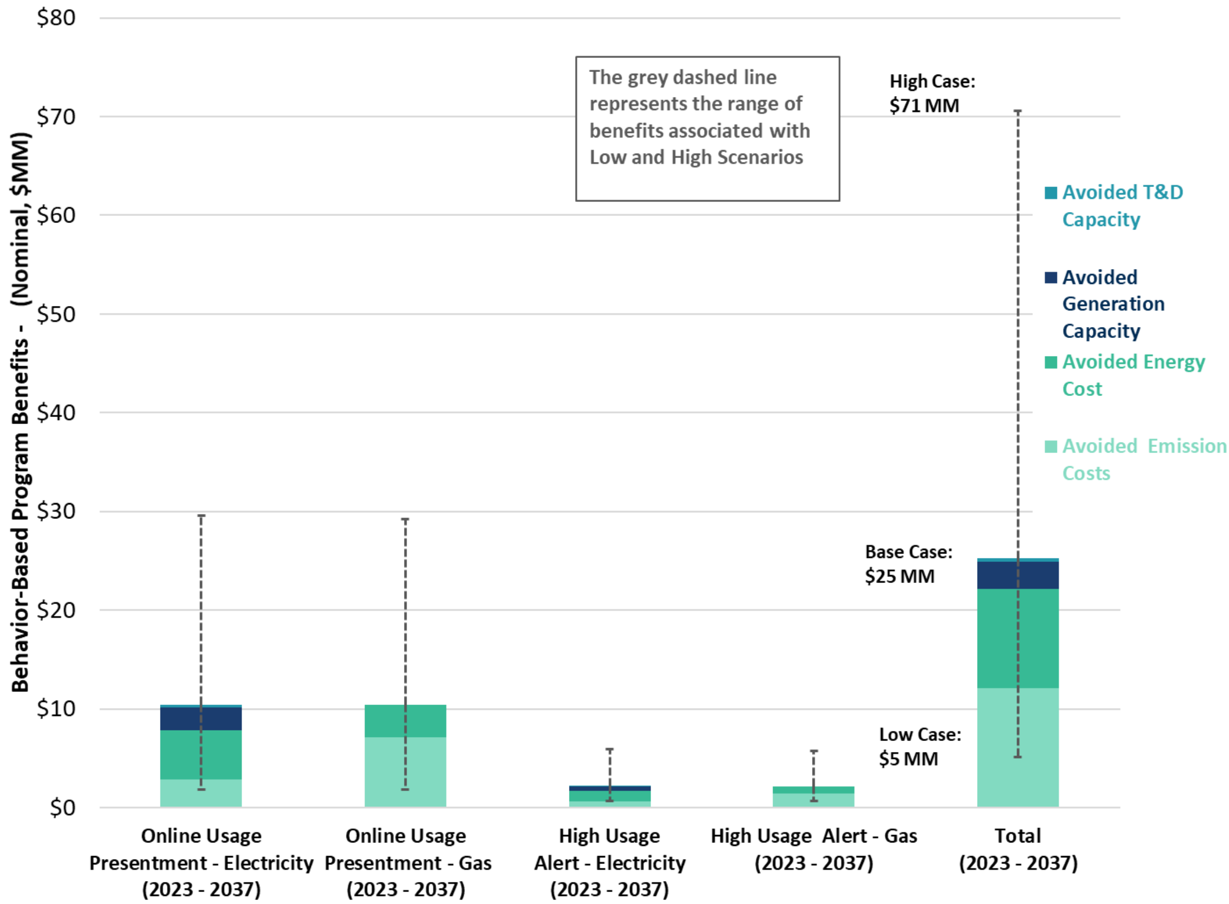
AMI creates more granular data availability on electricity and gas usage that can be utilized to offer customized programs and insights for the customers with the use of advanced data analytics. For example, PSE through AMI data can provide customers with personalized energy consumption reports, motivating them to alter their energy usage pattern. Other potential applications include disaggregated energy insights, highlighting which appliances are contributing more to usage and coaching on TVRs. In addition, AMI enables real-time or close-to-real-time informational feedback to the customers in the form of billing alerts and customer usage through in-home displays and smart devices. This timely feedback in turn can lead to more informed consumption decisions and typically energy conservation.[46] [47]

In this report, we examine the benefits of two system-wide behavior-based programs that are under implementation, online usage presentment and high usage alert programs, and two pilots that are under development. We find that the total benefits of behavior-based programs for electricity and gas over the study period is $25 million (see Figure 10). These benefits range from a Low case of $5 million to a High case of $71 million.

[46] As noted previously, we grouped three of the six ACEEE use cases (behavior-based program, real-time information feedback for customers, and data disaggregation) under the behavior-based program use case primarily because the three use cases listed in the ACEEE report are often implemented in combination, and they yield the same type of benefits to customers (often in the form of energy conservation). This is certainly how PSE plans to maximize AMI benefits through its current and planned initiatives.

[47] Ahmad Faruqui, Sanem Sergici, & Ahmed Sharif, *The Impact of Informational Feedback on Energy Consumption: A Survey of Experimental Evidence*, ENERGY (Apr. 2010).

FIGURE 10: BENEFITS OF BEHAVIOR-BASED PROGRAMS



The full deployment of the system-wide behavior-based programs is estimated to cost $3 million from the start of the program in 2023 until 2037, at this time. The two components of this cost are a one-time IT investment (including modifications of the current IT system to accommodate new AMI-enhanced services) and annual contract payments to a third-party service provider.

1. Online Usage Presentment

AMI data will expand offerings in PSE's online data presentment program, providing customers with more-customized energy management tips based on real-time energy consumption patterns (both for electricity and gas use) and estimated end-use load data disaggregation (for electric end uses).[48]

[48] This program implementation addresses both the real-time energy feedback use case and behavior-based program use case as described in the ACEEE report.

Currently, PSE makes available personalized household energy reports to all customers. When a PSE customer logs onto their PSE digital account, they can view their energy usage center to see graphs of usage, and estimated end use disaggregation. In addition, customers have the option to complete a self-assessment of their home energy usage, and view tips to be more energy efficient to help them save energy. This provides a behavioral incentive for households to benchmark and reduce their energy usage over time.

Energy and cost savings opportunities will increase due to the availability of highly granular and accurate AMI data, which will enable PSE to personalize energy management advice and tips for all customers. AMI data can be separated into groups based on the type of load being served. This type of load disaggregation analysis can further promote energy efficiency education and awareness and offer helpful tailored insights and advice. At the same time, these advanced tools and analytics can help customers reduce their energy use and costs in a manner that is most suitable to their preferences and lifestyle. PSE began to incorporate these AMI-enhanced features into its existing online customer portal in Q4 2021.

In our benefit model, we assume PSE will make available the online data presentment program to all customers. The program is available for both electric and gas customers. Based on data from PSE's existing home energy report program, we expect that about 75% of customers will be eligible to access the online portal (not all customers have their online accounts set up). Of these customers, up to 7% will take advantage of the online usage presentment data (Base case). The share of participating customers ranges from 2% (Low case) to 13% (High case). For those customers who would take additional steps to reduce electricity usage as a result of the AMI-enabled energy insights and tips, they will reduce their energy usage by 1.5−3% (2% for the Base case). For the electric program, the peak load reduction effect is about half of the energy conservation effect in percentage terms. Please refer Appendix B for our key assumptions.

We find that the total benefits of the online usage presentment program for electricity and gas over the study period is $21 million (see Figure 10). The overwhelming majority of the benefits come from the avoided energy and emission benefits for both electric and gas programs.

2. High Usage Alert

Currently, PSE issues high usage alerts for residential customers (both electric and gas). These messages are designed to help customers save energy and money when they are likely to use more than usual for a billing period. Available for residential customers with an AMR or AMI meter and 12 or more months of usage data at the current address, unusual usage alerts are triggered when a customer is trending to use more than 30% of what they used for the same billing cycle the year prior.

While AMR provides basic high usage alerts, granular, real-time AMI data will allow PSE to build more sophisticated energy usage prediction models that can alert customers more accurately and provide personalized insights to manage their consumption and lower bills. Models based on existing monthly AMR data may be limited as they rely on only 12 energy records over a one-year period. In contrast, AMI provides 8,760 data points over the same time period. More data means a higher accuracy level for the prediction models. Further, AMI data can offer insights into why certain customers experience high energy usage beyond the obvious reasons, pointing customers to AMI-enhanced energy conservation tools and customized insights that can help reduce energy costs.

In the benefit model, we assume that high usage alerts are available to all gas and electric customers.[49] Based on the data from the existing high usage alert program, about 15% of the customers will receive these alerts. In the Base case, we expect that about a quarter of those customers engage in the program, modify their behaviors and reduce their energy consumption. The per customer conservation effect is between 0.25−1% (0.5% for the Base case) for both gas and electric customers. In addition, the peak load reduction effect is about half. Our major assumptions are listed in the Appendix.

As seen in Figure 10 above, the combined benefits of the high usage alert program over the study period are about $4.4 million, the majority of which is derived from the avoided energy and emissions costs associated with electricity and gas usage.

3. Other Behavior-Based Program Pilots

PSE is launching a **virtual commissioning and tune-up pilot program** for small and medium business ("SMB") customers. Targeting customers under rate schedules 24 or 8 (with peak demand of 50 kW or less), the pilot will provide customized energy management tips and tune-up coaching through individual outreach. AMI data will be important during the benchmarking as well as the measurement and verification stages of the pilot, as it will allow both PSE and its customers to understand the starting point and gains attributable to the program. The SMB pilot will accrue benefits both to customers (in the form of avoided energy usage and lower bills), and to PSE. The pilot was budgeted in the 2020−2021 Biennial Conservation Plan.

49 Currently, PSE customers receive alerts when their energy consumption is unusually high. Customers can also opt to receive alerts when their usage exceeds a certain monetary threshold determined by the customers. Our benefit model addresses the first application, though improved data quality through AMI can enhance the second application as well.

Additional budget will be allocated in the 2022−2023 Biennial Conservation Plan. Over this time period, PSE plans to conduct outreach to 500 customers. Of these, an estimate of 100 customers will participate in the pilot program. If deemed successful, the SMB pilot may convert to a standardized program that expands to target specific SMB customer segments. The pilot may also be made available for PSE's more than 100,000 business customers.

Recently, PSE also launched Home Energy Monitor, an **in-home display ("IHD") pilot program,** for residential customers. Eligible customers have access to the dedicated storefront online where they can express their agreement to participate in the pilot and purchase an IHD unit at discount (customers receive an instant rebate). PSE, through a contractor, will provide a dedicated portal for pilot participants to receive ongoing information about tips on how to get the most out of the devices. The IHD devices will inform customers of their energy usage patterns and offer tailored tips for energy management. In the future, PSE may integrate this IHD program with its demand response and time-varying programs, offering customers greater control and savings opportunities. For instance, if the customer with an IHD device is enrolled in a peak-time rebate program, the device on the event day can remind the customer of event hours, and the customer can adjust their energy consumption accordingly. The device may also offer personalized insights during these events (*e.g.*, the customer may earn the most rebate by modifying a certain load type). Currently, the Company is planning to deploy 1,500 IHD units by early 2022. The pilot will conclude in 2023, at which point PSE will evaluate the program's cost effectiveness and determine whether to proceed with a full scale deployment of the program.

We have not quantified the benefits associated with these two pilots at this time, as they are currently limited in size.

C. AMI Facilitates Load Flexibility Programs

Load flexibility refers to the ability to modify residential or building load in real time in response to real-time conditions of the electricity grid.[50] In addition to providing grid services, load flexibility can also help optimize customer cost reduction, climate mitigation (by moving demand to periods when the grid is less carbon-intensive or by helping to integrate variable and intermittent renewable energy resources), and occupant needs and preferences. Load

[50] This use case is termed "grid-interactive efficient building" in the ACEEE report, and is defined as "incentivizing buildings that reduce energy waste and carbon emissions while offering flexible building loads to the grid. This may include integrating energy efficiency and demand response to better value the many benefits of grid-interactive efficient buildings." As discussed previously, we use the term "load flexibility" in this report to indicate the broad AMI-enabled application of this use case beyond large buildings. Further, load flexibility is more commonly used and understood in the industry.

flexibility can be accomplished with smart technologies to develop automated demand response capabilities, and can be coupled with DERs.

The major benefits associated with load flexibility programs include:

- Load shedding: Reduce specific loads (*e.g.*, lighting or heating) by a preset amount in response to grid signals can help reduce system peak load.
- Load shifting: Consume electricity at a different time in response to grid signals (*e.g.*, pre-heat water heaters during off-peak periods).

Load flexibility programs can reduce investments in generation and T&D capacity due to lower peak demand. They also reduce the costs of electricity generation and related greenhouse gas emissions.[51] For some of the load flexibility programs, there may be an additional benefit associated with reduced energy costs due to daily shifting of consumption to less expensive hours of the day.

Currently, PSE is pursuing a number of load flexibility initiatives, which are at various stages of development. In this report, we quantify the benefits of three initiatives: system-wide load flexibility programs and the Bainbridge and Duvall Targeted Demand Response Projects. It is important to note that TVR programs are also an effective load flexibility tool. For the purpose of this report, we quantified the time-varying program benefits separately, as they were singled out by the Commission in the six use cases that it encouraged PSE to explore and quantify.

1. System-wide Load Flexibility Programs

PSE is planning to pursue a system-wide load flexibility program with the goal of achieving 29 MW of capacity reduction by 2025 and 196 MW by 2031. Customer solicitation and acquisition are slated to begin in 2023 with 3,000 customers, expanding to 15,000 by 2025 and 100,000 by 2031.

Because PSE's system-wide load flexibility resource portfolio is currently under development,[52] we worked with the Company's SMEs to identify three load flexibility programs that are most likely to be pursued by the Company and are enhanced by AMI capabilities: smart thermostat,

[51] Load flexibility programs can also reduce ancillary services costs and improve integration of variable renewable energy resources (*e.g.*, wind and solar). We do not quantify these benefits in this report.

[52] An RFP for DER solicitations (including demand response/load flexibility) is scheduled to be released in early 2022 with vendors selected by the end of 2022.

grid-interactive water heater, and behavioral demand response programs.[53] At the moment, these programs will target primarily residential customers. However, the scope of these programs may widen to include C&I customers as program deployment and system needs evolve. The main benefits associated with these programs include benefits related to peak reduction (generation capacity and T&D deferral) as well as energy shifting (consuming electricity when prices are low). Once implemented, the system wide load flexibility programs could potentially evolve beyond capacity reduction and load shifting to allow for interaction with the Energy Imbalance Market.

Advancements in thermostat technology have increased the appeal of **thermostat-based demand response programs**. Wifi-enabled smart thermostats can include occupancy-sensing and learning capabilities, which can help optimize energy usage based on the user's behavior, proximity to their home, and local weather patterns, among other factors. In addition, smart thermostats continue to gain popularity among customers. Around 4.9% of residential customers in Washington had a smart thermostat installed in 2017.[54] According to recent research, the current share of smart thermostats is expected to increase to about 60% by the early 2040s.[55] [56] Because many customers are adopting thermostats for reasons other than participating in load flexibility programs, the thermostat-based approach also has the potential to be lower cost because PSE does not need to supply participants with the equipment.

We assume that PSE's smart thermostat program will be similar to a Bring Your Own Thermostat ("BOYT") program. A widely used smart thermostat program, BYOT provides customers with incentives for enrolling their existing qualified thermostats in a demand response program. The financial incentives can be in the form of a rebate or a bill credit for the demand reduction. In the Base case, we assume that of all eligible customers with electric space heating, 5% will participate in the program. The participation rate will increase to 30% by 2037. Please refer to the Appendix for our major load flexibility benefit assumptions.

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53 These programs are among the most popular residential load flexibility programs in the U.S. *See* SEPA, *2019 Utility Demand Response Snapshot* (Sept. 2019), https://sepapower.org/resource/2019-utility-demand-response-market-snapshot/. A/C switch is the most popular program, where a switch is installed on the compressor of the customer's air-conditioning unit, and the unit is cycled on and off during DR events. However, this capability is rapidly being transitioned to thermostat-based options, where the utility has the ability to control the thermostat set-point rather than cycling the unit. This provides more flexibility by allowing the DR operator to manage load in a more sophisticated way while maintaining a higher degree of customer comfort.

54 *Residential Building Stock Assessment II*, (accessed Oct. 24, 2021), https://neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Single-Family-Homes-Report-2016-2017.pdf.

55 *Technical Summary: Smart Thermostats*, Project Drawdown (accessed Oct. 24, 2021), https://drawdown.org/solutions/smart-thermostats/technical-summary.

56 *Over 40% of Thermostats sold in 2015 will be Smart Thermostats*, (accessed Oct. 24, 2021), http://www.parksassociates.com/blog/article/pr0715-smart-thermostats.

Grid-interactive water heating ("GIWH") program allows utilities or third-party aggregators to control customers' electric water heaters to respond to system needs and reduce costs. Water heaters can provide real-time, near instantaneous grid balancing service by increasing or decreasing the load on the grid as needed. In addition, heating load can be shifted away from peak periods, when energy prices are more expensive, by heating the water during low-priced off-peak periods. In essence, water heaters can act as low-cost energy-storage devices since they already exist in many homes.

Utilities have historically targeted direct load control of electric resistance water heaters to provide demand response services. Recently, grid-interactive heat pump water heaters with smart connected controls have emerged as an energy efficient technology solution that can provide a broader set of load flexibility benefits.

The current deployment rate of water heaters with smart controls in PSE's service area remains slow, though we anticipate the adoption rate will increase in the coming years thanks to the state's new communication standard requirements. In May 2019, Washington State passed legislation requiring all electric storage water heaters sold in the state to have ports compliant with ANSI/CTA-2045-A standard that enables two-way communication with the grid.[57] Assuming a turnover rate of 12% for water heaters, we estimate that about a third of PSE's customers will have smart water heaters by 2037.[58] Of these customers, we estimate that about 30% will participate in PSE's GIWH program by 2037 in the Base case. The program will initially focus on reducing peak demand, and will eventually expand to include daily load shifting capability in 2028.

In recent years, **behavioral demand response ("BDR")** has emerged as an economically appealing solution to reduce electricity usage during system peak periods. BDR allows utilities to directly communicate with customers, asking customers for voluntary demand reductions during times when the grid is experiencing stress. Customers in turn can participate by modifying their energy consumption through adjusting their thermostats or disconnecting major loads, and receive post-event feedback on their performance. BDR programs can be an attractive load flexibility option because they are less expensive to scale compared to hardware-based programs. According to one report, BDR provides about 800 MW of capacity in the U.S.[59]

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[57] RCW 19.260.080.

[58] According to PSE's 2017 Residential Characteristics Survey, about 38% of PSE customers have electric water heaters.

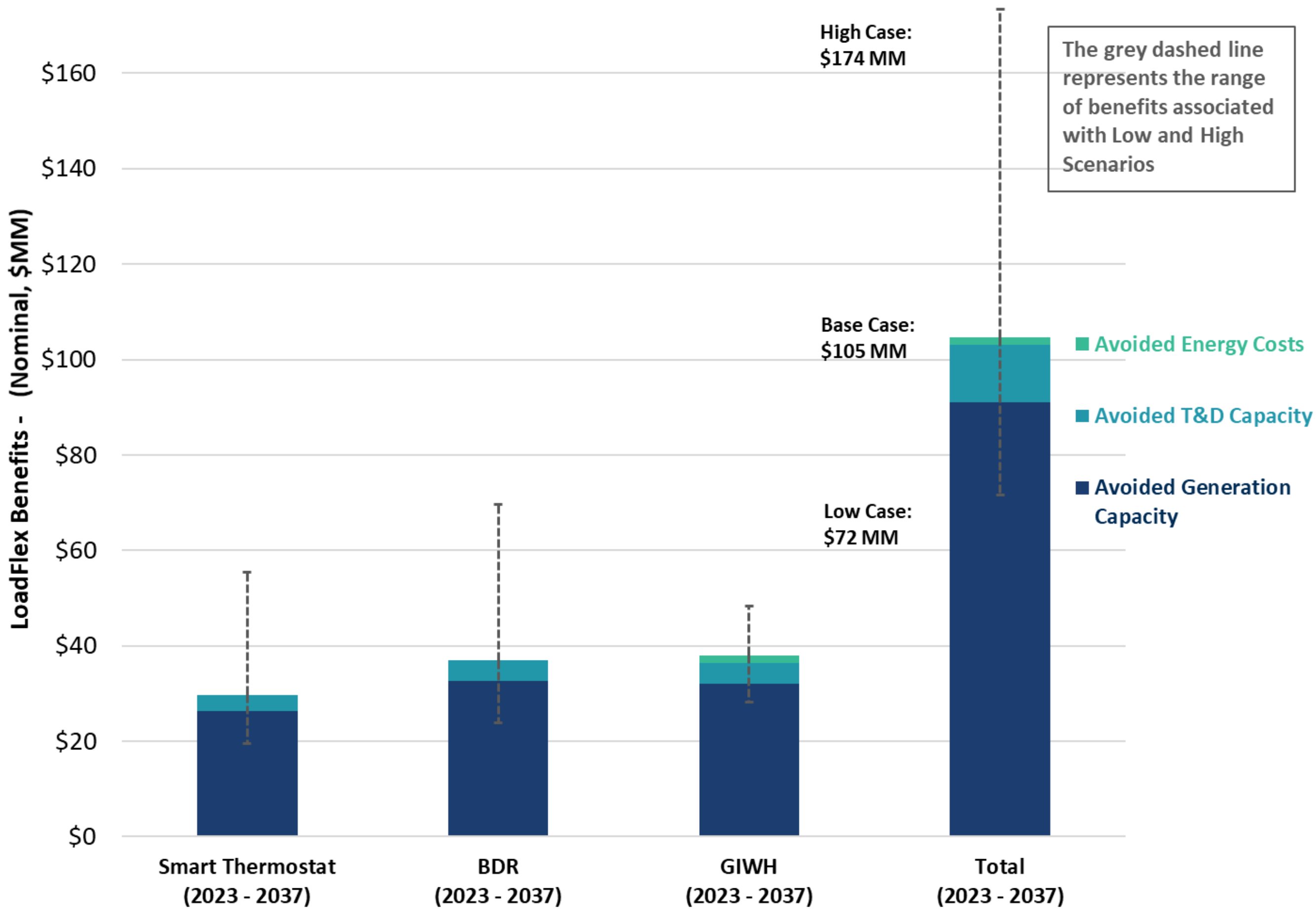
[59] SEPA, *2019 Utility Demand Response Snapshot* (Sept. 2019), https://sepapower.org/resource/2019-utility-demand-response-market-snapshot/.

In our benefit model, we assume that PSE's BDR program will be available for all electric customers in the service area on an opt-out basis. The program will begin in 2023, and initial participation rate will be 5% and after 10 years increase to 40% in the Base case. The primary benefits are associated with peak load reduction (generation capacity and T&D deferral).

Between 2023 and 2037, we estimate that the smart thermostat program could lead to a total benefit of about $30 million (see Figure 11 below). Again, the majority of the benefit comes from avoided generation capacity. Smart-thermostat-based air conditioning control is usually the largest load flexibility opportunity for most utilities, especially in summer peaking months, due to high eligibility rates and significant peak-coincident load reduction potential per participant. For PSE, the total smart thermostat benefit is lower than the benefit associated with GIWH and BDR (while the per customer impact for smart thermostat is significantly higher than the impact for GIWH and BDR programs). This is because only about 20% of PSE customers have electric space heating. In the Base case, the GIWH and BDR programs could result in $38 and $37 million in benefits, respectively. The range in the benefits between the Low and High cases reflects the uncertainty in customer eligibility rate (*e.g.*, how many customers will install smart thermostats) and the participation rate (of all customers with smart thermostats, how many will enroll in a load flexibility program).

The costs for the full deployment of the load flexibility programs are estimated to be about $24 million in the Low case, $39 million in the Base case, and $98 million in the High case. These costs consist of capital costs, annual implementation cost, and incentive payments. The capital costs include IT upgrades, which has a one-time cost of $1.4 million at the start of the program. The annual implementation costs are for customer education initiatives, customer marketing initiatives, program management, information technology cost, and customer interface and support. We expect PSE to incur these costs annually for the duration of the program. We also estimate that PSE will provide one-time payments to incentivize customers to sign up for the smart-thermostat and grid-interactive water heating program. The incentive payments per customer are $50 in the Low case, $100 in the Base case, and $200 in the High case for both programs.

FIGURE 11: SYSTEM WIDE LOAD FLEXIBILITY PROGRAM BENEFITS



2. Bainbridge and Duvall DR Programs

As part of a non-wires alternative solution to defer a new substation on Bainbridge Island, PSE seeks to reduce winter peak capacity needs on the island by 3.3 MW by 2029. To meet this goal, PSE is pursing the **Bainbridge Island Targeted Demand Response ("TDR") pilot**, along with the Targeted Energy Efficiency ("TEE") pilot. PSE plans to leverage AMI data to identify customers with high savings potential as initial participants in the TDR pilot program.

The Company issued an RFP at the end of December 2020, and is working with Energy 350 and their subcontractor Autogrid to implement the pilot. Targeting both residential and C&I customers, the pilot will include direct load control, commercial behavioral DR, and smart water heating (for both heat pump water heaters and electric resistance tanks). Initial pilot implementation is scheduled to begin Q2 2022, with a linear ramp-up (200–300 participants added annually) to full-scale program by 2028. The pilot will be evaluated annually beginning in 2023.

By using the existing electric infrastructure on the island instead of building new infrastructure, PSE estimates that it will save $13 million by 2030, the majority of which stems from generation and T&D capacity deferral.[60] The cost of the Bainbridge Island TDR pilot is budgeted to be approximately $250,000 annually.

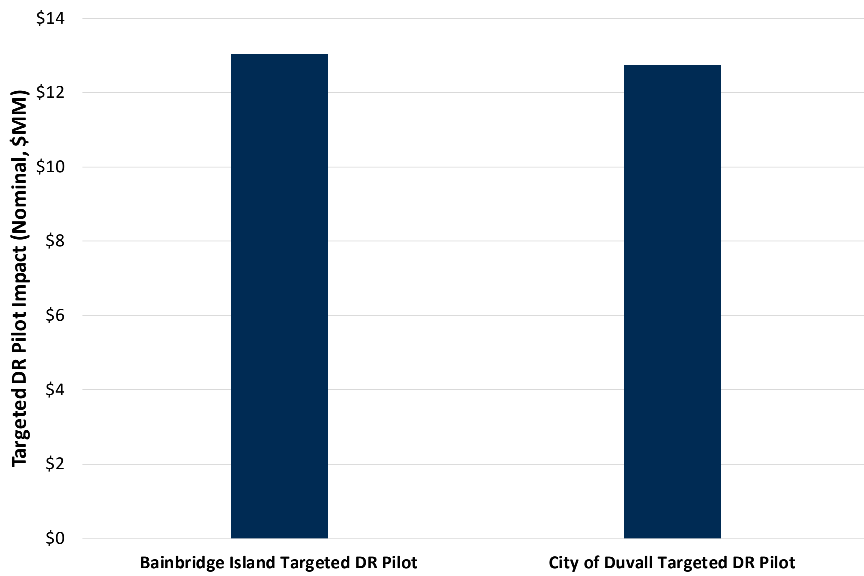
Similarly, in an effort to defer the installation of an additional natural gas pipeline to Duvall, PSE is implementing the **City of Duvall Targeted DR Program** to reduce winter peak natural gas usage by 30,000 MBH by 2029. PSE is implementing a residential and commercial smart thermostat pilot. The initial pilot implementation is scheduled to begin Q2 2022, with a linear ramp-up (50−70 participants added annually) to full-scale program by 2028.

The main benefit of the Duvall TDR program is the deferral of a new pipeline installation, which PSE estimates to be around $13 million. Cost of the Duvall TDR pilot is budgeted to be approximately $200,000 annually.

Both the Bainbridge Island and the Duvall TDR programs are planned to continue as long as the capacity constraints persist.

[60] Navigant, *Bainbridge Island Non-Wires Alternative Analysis* (July 9, 2019) (deferred costs are found in Table 2, items 4 and 5), https://psebainbridge.blob.core.windows.net/media/Default/images/AppendixD_BainbridgeIslandNon-WiresAlternativeAnalysis_NavigantConsulting_July_9_2019.pdf.

FIGURE 12: BAINBRIDGE AND DUVALL TARGETED DR PROGRAM BENEFITS



VI. Tier 2 AMI Use Case Benefits

In this section we quantify the benefits for four additional use cases which create value for PSE customers (though more indirect compared to Tier 1 benefits). These are mostly additional operational benefits (e.g., reduced O&M costs) over and beyond what was captured in the original business plan in relation to distribution automation and AMI network:

- **Leveraging AMI network for smart street lighting**. The AMI communication network can be leveraged to provide two-way communication between control center and smart street lighting. PSE is in the process of equipping 25,000 street lights in its service territory with smart controls, providing both the system and customers more visibility into the status of lights in their accounts. The primary benefits attributable to AMI include lower maintenance and related administrative expenses.
- **Remote connection and disconnection**. AMI provides PSE with the capability to turn meters on and off to support changes in occupancy, reoccurring non-payment issues, and prepaid service offerings. Benefits include reduced O&M costs and reduced unauthorized energy usage.
- **Outage management detection**. PSE will further integrate AMI data into its outage management system, using meter events to promptly identify and initiate outage reporting.

Earlier outage detection translates to shorter response time, decreasing customer outage minutes and improving customer satisfaction.

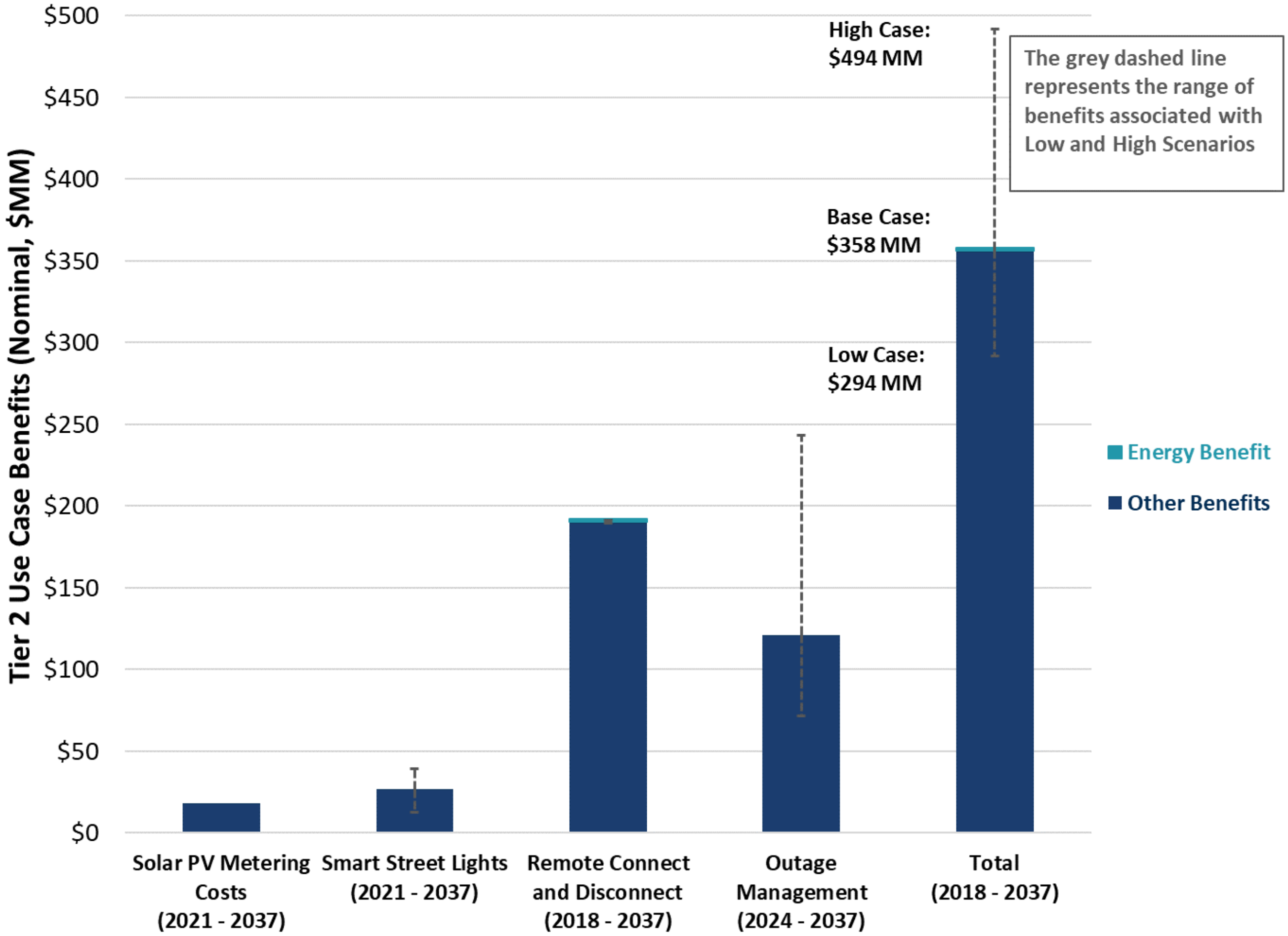
- **Lower metering costs for customers with distributed generation**. Customers with distributed generation (*e.g.*, rooftop solar) require advanced metering capabilities to measure billing determinants in order to enroll in net-metering programs. Customers already equipped with AMI meters do not need to upgrade their meters. PSE in turn avoids the costs of the additional metering upgrades.

Figure 13 and Figure 14 below show the benefits of these four Tier 2 use cases. The total benefits are estimated at $358 million for the Base case, with the Low case being $294 million and High case $494 million. Specific assumptions about each use case are included in the Appendix.

FIGURE 13: SUMMARY OF TIER 2 BENEFITS ($ MILLIONS)

Use Case	Low Case	Base Case	High Case
Solar PV Metering	$18	$18	$18
Smart Street Lighting	$12	$27	$39
Remote Connect and Disconnect	$191	$192	$193
Outage Management Programs	$72	$121	$243
Total	**$294**	**$358**	**$494**

FIGURE 14: SUMMARY OF TIER 2 BASE CASE BENEFITS ($ MILLIONS)



A. Leveraging AMI Network for Smart Street Lighting

Beyond providing granular data for metering purposes, the AMI communication network can be leveraged to provide two-way communication between the control center and distributed sensors, controllers, and switches. The AMI network can also be used for communicating with substations and feeder devices, smart inverters, and smart street lighting.

In the immediate term, PSE is developing a Smart Street Lighting program that leverages AMI to provide insight into the status and performance of the Company’s approximately 100,000 street lights and to enhance the street light system’s operational efficiency, reliability, and performance. Smart street light controls will communicate with PSE’s central operating platform through a secure network, enabling PSE to remotely monitor and manage the performance of each light in real time. These new advanced control systems will optimize the use of street light fixtures through a number of advanced features, including power consumption measurement, remote monitoring, and street light fault detection, among others.[61]

The primary benefit of Smart Street Lighting Controls is the reduction in operating expense that will accrue over time from reduced truck rolls, fewer street light outage calls, and improved asset management. Today, without any data on the performance of a particular street light, PSE must dispatch a truck to diagnose a reported issue, and often a secondary trip is required to fix the problem. With the AMI communication network, PSE can address lighting issues more efficiently.

Once smart street light controls are operational, any future maintenance issues will be detected automatically, removing the customer notification and compliance requirement, thus allowing PSE staff to assess the necessity for immediate repair. In addition, project data can be aggregated, and several maintenance activities can be dispatched together, therefore reducing single trip truck rolls and driving great cost efficiencies.[62]

PSE is preparing to deploy smart street light controls to 25,000 company-owned street lights by 2025. In the Low case, we assume that no additional installations will take place once this first wave of installations is complete. In the Base case, the deployment rate of 5,000 installations will continue until the rollout is complete. Finally, we assume in the High case that system-wide deployment will finish by 2030.

The total benefits for this use case over the first five years increase from $126,000 to $710,000. The majority of the benefits will come from lower maintenance expense (in the form of fewer truck rolls), as well as reduced administrative expense. Over the entire study period, the benefits are about $12 million for the Low case, $27 million for the Base case, and $39 million for the High case.

The implementation of this program is estimated to cost $5.8 million in the Low case, $11.9 million in the Base case, and $15.7 million in the High case. The costs include capital costs for

[61] Other advanced features include dimming capabilities yielding energy conservation benefits), scheduled and remote on/off operation, future demand response potential, and potential backbone network for additional smart city innovations.

[62] The street light conversion program will have an additional benefit of energy efficiency. The new LED lamps are more efficient, and their overall energy usage will be lower relative to the old high-pressure sodium bulbs. We estimate that this benefit is about $12.4 million over the study period (Base case). However, we exclude this benefit from this use case as it is not enabled by AMI.

the replacement of the current streetlights and for control hardware. They also include O&M costs, which incur annually for the duration of the program.

B. Remote Connect and Disconnect

AMI provides utilities the capability to turn meters on and off to support changes in occupancy, reoccurring non-payment issues, and prepaid service offerings. Remote connect/disconnect was implemented at PSE in October of 2019 for customer-initiated requests, safety and customer move in/move out. Remote connect/disconnect for non-payment was to be implemented in March of 2020. However, the program was deferred due to COVID-19 and the disconnect moratorium in Washington State. The moratorium ended on September 30, 2021, and PSE is currently working to implement the final phase of remote connect/disconnect.

There are two main associated benefits with remote connect/disconnect through AMI: reduced operations and maintenance cost savings (in the form of reduced number of service appointments, truck rolls, vehicle-miles traveled, and avoided postage and delivery costs) and reduced unauthorized energy usage ("UEU"). The latter benefit is related to lowering the amount of bad debt by reducing the amount of time between when a customer is eligible for disconnect and when the customer is actually disconnected. Without the ability to disconnect remotely, PSE currently experiences a lag between when a customer terminates their service (or when a customer is eligible for disconnect) and when service is actually disconnected. The AMI-enabled ability to immediately disconnect service shortens the lag, reducing the UEU. We observe a decline in the UEU level between 2017 and 2020, when AMI deployment was first initiated. Because the decline cannot be attributed to AMI entirely, we assume that in the Base case, 50% of the UEU reduction can be attributed to AMI. In the Low and High cases, the numbers are 25% and 75%.[63]

As PSE continues to deploy AMI meters, the remote connect/disconnect capability will be fully implemented in 2023. The associated benefits would increase from $3.1 million per year in 2021 to $9.8 million per year in 2023. Over the study period, the benefits are about $1 million for UEU reduction, $78 million for avoided O&M cost, and $113 million for reduction in bad debt, for a total of $192 million (see Figure 13 above). On the gas side, reduction in UEU will bring about $1 million in benefit during the study time frame. PSE allocated a budget of $10 million to invest in this remote and disconnect capability.

[63] The eviction moratorium in place during the COVID-19 reduced the move in/move out activity, and likely resulted in lower UEU over this period.

C. Improved Outage Management

Integrating information from monitoring devices and AMI with other real-time operating systems (such as the Outage Management System or the Geospatial Information System) enables utilities to quickly diagnose the location and extent of unplanned outages, and to provide customers with more accurate and timely information about the cause and status of outages. While this basic capability (providing power up and power down events and pinging of the meter collector can be pinged to gather information about a meter's status) is available with AMR meters, AMR meters rely on a 1-way pathway to collectors and have less reliable and less timely communication. In comparison, the individual AMI meters can be accessed to analyze meter status and operating voltage at the meter (positive confirmation of the power going directly to the customer's panel). In addition, the AMI mesh network improves communication pathways that increase the reliability and timeliness of communications. Utilities with AMI can configure smart meters to generate "last gasp" signals when they lose power, which provides a proactive, positive validation of the meter's loss of power. Without AMI, outages are typically identified by a customer call and require a service call to confirm. In addition, AMI can help to reduce costs by detecting "false positive" outages (when outage is due to the customer's internal electrical issues), avoiding field visits.

In addition, in 2023, as one component of PSE's fully-integrated Advanced Distribution Management System, a new Outage Management System will be implemented. The new OMS module will integrate AMI data and utilize meter events to help identify and initiate outage reporting (rather than relying solely on customer calls and logic), improving situational awareness of unplanned failures, enabling improved customer communication (including more proactive outage communication for outages and restoration), and identifying complex outage issues such as nested outages.[64]

We relied on the Department of Energy's ICE Calculator to compute the avoided interruption costs due to quicker detection and restoration of the outages enabled by AMI.[65] We assumed that the outage duration is 3% lower under the Base case, 1.5% lower for the Low case and 6% for the High case. We used the Company's SAIDI and SAIFI stats from 2017 and computed these benefits from reduced outage benefits only for the residential and small C&I customer

[64] PSE estimates that in 2020 the Company reduced the number of dispatched truck rolls to address single customer outages by about 600.

[65] United States Department of Energy, *Interrupted Cost Estimate (ICE) Calculator*, https://icecalculator.com/home.

classes.[66] The associated benefits range from $72 million for the Low case, $121 million for the Base case and $243 million for the High case. Because the AMI network already provides much of the equipment needed to implement this use case, PSE anticipates only a small cost of $41,000 to prepare for outage prediction and meter ping improvements.

D. Lower Metering Costs for Customers with Distributed Generation

The deployment of smart meters allows PSE to continue to serve customers adopting solar with the technology they need for net metering. Because bi-directional metering capabilities are necessary for net metering, customers with AMR meters normally would need to upgrade their meters when installing rooftop solar.[67] However, because all AMI meters are capable of measuring energy bi-directionally, when a customer with this meter adopts rooftop solar PV, equipment exchange is no longer necessary to convert the customer to net metering. This amounts to a savings of $350 per customer, or about $700,000 per year.[68] Assuming a steady increase rate of 2,000 new net-metering customers per year, the total 2021−2037 benefit of this use case is $15.2 million.

In addition, AMI meters will allow for more consistent and accurate meter readings for net-metered customers. Net-metered billing for customers with solar PV is more complicated than billing for standard delivery of power because the bill charges are calculated based on two separate meter registers, measuring energy delivered from and energy returned to the grid. The net energy purchase is a function of energy demand and solar energy generation and the coincidental timing of the two. AMI data can increase accuracy and effectiveness of net metering at customer sites.

The benefits enabled by AMI are especially pronounced for large industrial customers with onsite generation. Currently, PSE must serve these customers with an entirely different meter and meter data platform (MV90) in order to account for the four channels of meter data required when these customers enroll in net metering. These MV90 meters are more expensive

[66] While this benefit may also apply to the larger C&I customers, they are not quantified in our study. These large customers have more sophisticated energy management systems and, in most cases, dedicated energy managers. Therefore, one could imagine that the reduction in the notification times may not be as pronounced as the other two classes.

[67] In addition, the AMR bi-directional meters that PSE purchased and deployed to new solar customers prior to 2019 are no longer available.

[68] Going forward, PSE anticipates adding 2,000 new net-metered customers per year.

and have higher maintenance costs.[69] Capable of measuring the four separate billing determinants, AMI presents a more economical solution for large industrial customers enrolled in the net metering program.

Currently, PSE is developing plans to enhance its billing system to serve the growing number of large demand net-metered customers with standard AMI metering. With current adoption of solar energy among large demand customers, PSE is adding 24 MV90 meters in the field per year. Assuming steady to minimal growth in the adoption of solar among large demand customers, the replacement of MV90 metering with AMI metering would save PSE an estimated $3 million by 2040, with an associated one-time cost of $100,000 to modify the billing systems.

VII. Tier 3 AMI Use Case Benefits

In this section we describe use cases and initiatives enabled or enhanced by AMI that PSE is pursuing or plans to pursue. We have not quantified the benefits of these use cases because of a lack of well-established data at this time, or because the Company is in very early stages of exploring these use cases. Out of the 38 AMI use cases identified by PSE, we classified 22 use cases as the Tier 3 use cases. Below, we highlight and discuss a few of them, but the full list is provided in Appendix C.

A. Improved Bill Generation

AMI improves the accuracy of meter readings by automating activities that otherwise would be conducted manually, minimizing human error and equipment failures. AMI-enabled bill generation can lead to fewer customer complaints about inaccurate bills and allows utilities to resolve billing disputes faster. PSE anticipates that AMI data will have a 99% accuracy level (compared to 96% with existing AMR data).

For electric customers, the 3% improvement translates to more accurate billing for 375,000 transactions per year. Accordingly, the volume of bill inquiries is expected to decrease. In

[69] The setup of net metered billing using MV90 meters requires a different process and skillset. Further, customer-facing bill statements are difficult to understand and troubleshoot, resulting in the need for frequent specialized customer service including bill corrections. According to PSE, each MV90 meter costs about $2,000 more to install than an AMI meter, and has a 13% higher cost for ongoing maintenance.

addition, customer service representatives, enabled by detailed energy usage data from AMI, will be able to better assist customers during billing inquiries, providing them with timely and accurate billing information.

B. Avoided Metering Issues (Theft and Fraud Detection/Meter Failures)

AMI system can help to detect instances of meter tampering and electricity theft (also known as energy diversion) by issuing alarms or notifications when irregularities in consumption activity are identified. AMI data can also help identify faulty meters, register previously unregistered meters, and identify inactive meters or unoccupied premises. Together, these help to improve revenue and cost recovery.

Currently PSE's AMR-based algorithm uses daily meter readings as inputs and can detect irregular meter activities. Based on the detection results, PSE can conduct further investigation to determine whether energy diversion is present. However, AMI data will also enable PSE to identify more quickly when a meter disconnects, is reconnected and whether the reconnect was done by PSE personnel. In addition, the Company can rely on AMI meter functionality to monitor tamper meter alarms, overheat alarms and tilt alarms – all components that create diversion. PSE plans to evaluate potential improvements to the algorithm and estimate the potential benefits in 2024 after AMI is fully deployed.

C. Better Visibility into Asset Utilization

AMI data can support PSE in monitoring and improving awareness of grid assets and help the Company make operational or design decisions. For example, AMI data can be used to estimate the load on service transformers with much greater precision and to identify transformers that are at risk of failure due to overload. The main benefits associated with this use case include reduced operating and maintenance costs (planned equipment replacement is less expensive relative to unplanned replacement), a decrease in outage frequency, a decrease in the outage duration and customer interruption, as well as an increase in safety and customer satisfaction.

PSE is launching a pilot program that leverages AMI data to identify overloading transformers due to EV loading and schedule upgrades to appropriately serve the load they are assigned. The program will monitor residential and commercial transformers that are loaded above their nameplate value and identify the units most likely to fail. The pilot is currently planned for King, Kittitas, Pierce, Island, and Thurston Counties, where AMI data is currently available. If the pilot proves successful, PSE plans to create a system-wide program when AMI deployment is complete (currently scheduled for the end of 2023) that proactively replaces high-risk service transformers as planned work. PSE is currently in the data collection and validation phase of the pilot.

D. Improved DER Planning and Integration

As outlined in PSE's Transportation Electrification Plan ("TEP") and the Addendum filed on July 14, 2021, PSE is currently developing its next suite of EV programs to be offered to customers over the next five years.[70] These programs have a large focus on load management, depending heavily on PSE's AMI system for both measuring EV customer load profiles as well as implementing TVRs and other load management tools. Disaggregated EV load through AMI data can provide PSE with additional billing capabilities.

In addition, PSE will leverage AMI data to forecast how increased adoption of EVs might affect its system peak and overall demand in the future when the market for EVs is expected to grow. By combining the AMI load data with the findings of these EV programs, PSE will develop load disaggregation models that allow the Company to locate where EVs are charging in its service territory and incorporate that knowledge into the Company's system planning efforts. PSE plans to explore load disaggregation data for the purposes of implementing an EV-only TVR as appropriate.[71]

AMI data can also be utilized within PSE's EV programs to help customers further reduce carbon emissions by helping them understand how their charging corresponds to carbon emissions.

E. Other Tier 3 Use Cases

Beyond the four use cases discussed above, PSE is currently evaluating and pursuing a number of other Tier 3 use cases. We discuss several of these below. Please refer to the Appendix for a complete list.

Beyond billing benefits, AMI data allows utilities to analyze energy usage patterns to inform investment decisions. PSE is currently developing technology to provide internal and external understanding of hosting capacity for distributed generation. Awareness of hosting capacity will

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[70] *WUTC v. Puget Sound Energy*, Docket UE-210191, Puget Sound Energy 2021 Transportation Electrification Plan (March 19, 2021); *see also* Addendum to Puget Sound Energy 2021 Transportation Electrification Plan, July 14, 2021.

[71] *See* PSE TEP Addendum.

contribute to cost-effective deployment of renewables, increasing the pace and scalability of deployment. Data that contributes to hosting capacity includes circuit and transformer sizing as well as loads and generating capacity in place and time. When AMI deployment is complete, PSE will have access to interval data from customer-generation (kW power from customers to grid) for the first time. Within the next five years, this data will inform hosting capacity maps and will begin to help PSE refine standards for the study and development of individual distributed generation projects.

In addition to the load flexibility programs mentioned above, PSE is pursuing three clean energy technology demonstration projects that aim to make its grid more reliable, flexible, and resilient. Sponsored by the Washington State Department of Commerce, PSE is planning to deploy DERs at two separate sites. In partnership with the Tenino School District, PSE is installing an approximate 150kW photovoltaic generation system and a 1MW/2MWh Lithium Ion Battery Energy Storage System ("BESS") at and near the Blumaer Substation, providing grid services for Tenino High School. Providing the building blocks for a utility-scale microgrid, the project will transform how the high school's power load will interact with the grid under different circumstances. Specifically, the battery will be charged based on weather forecasts and circuit loading conditions, and discharged to back up the high school load during an outage in coordination with the PV generation and building load management. AMI data will provide an accurate understanding of the historical load pattern, informing the planning process.

The second DER deployment aims to provide enhanced reliability to a long circuit in the Bucoda area, a rural area that has experienced prolonged outages in the past. The project will provide back-up power to 235 residential and commercial customers through a BESS coupled with an advanced demand response program. During an outage event, this pilot project will utilize real-time feedback from AMI meters to inform the microgrid controller of the number of PSE customers the backup system can serve, and how much load curtailment is needed to preserve the back-up power. Both the Tenino High School and the Bucoda projects are planned to be operational by 2023.

Finally, PSE is in collaboration with the Electric Power Research Institute to develop a project that examines enhanced grid control capabilities. As currently proposed, the project will evaluate whether a substation can pick up critical loads (*e.g.*, emergency services) in the substation service area during an extreme event. The project will leverage the AMI connect and disconnect feature to help shed non-critical loads.

VIII. Conclusion

Across all Tier 1 and Tier 2 cases, we estimate that the total benefit of AMI use cases will be about $625 million over the 20-year period (Base case). The total costs for these use cases will be about $118 million over the same time period (see Figure 15 below). Combined with the original benefit ($668 million) and cost ($473 million), the total benefit and cost for PSE's AMI business case are $1,293 million and $591 million, yielding a benefit-cost ratio of 2.2 (compared to 1.4 in the original business case). The increase in the benefit-cost ratio is driven by Tier 2 use case benefits, especially for the outage management use case and the remote connection and disconnect use case, as well as the fact that the bulk of the capital investment cost (AMI network and meter deployment) is accounted for in the original AMI business case. The ratios in the Low case and High case are 2.0 and 2.4, respectively.

As we explained previously, the range of uncertainty reflects the unknown factors associated with the specific programs at this time. Key program parameters will need to be updated as PSE continues to develop and implement these programs, and as more information becomes available. However, given that the benefits are overwhelmingly greater than these quantified costs, it is reasonable to expect that even if the Tier 1 and Tier 2 use case costs are several times greater, there would still be net benefits from these use cases. The Company will quantify these costs with much improved accuracy in their programmatic filings.

FIGURE 15: AMI USE CASE BENEFITS AND COSTS ($ MILLION)

	Tier 1		Tier 2		Original		Total		B/C Ratio
	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	
Low Case	$121	$52	$294	$16	$668	$473	$1,082	$541	2.0
Base Case	$267	$95	$358	$22	$668	$473	$1,293	$591	2.2
High Case	$424	$173	$494	$26	$668	$473	$1,586	$672	2.4

APPENDIX

A. ACEEE Use Case Definitions

FIGURE 16: DEFINITIONS OF SIX ACEEE USE CASES

Commission Use Case	ACEEE's Definitions
1. TOU Rates	Charging different prices for electricity during different times of the day and year.
2. Behavior-based Programs	Reducing energy consumption through social science theories of behavior change by providing information to customers, by leveraging interpersonal interactions, or by providing consumer education. Excludes programs that rely on traditional program strategies such as incentives, rebates, or regulations.
3. Real-time Informational Feedback for Customers	Allowing consumers to better understand their behavior and adjust their energy usage to increase savings. Includes programs that provide feedback in near real time. Typically requires advanced metering infrastructure (AMI) installation
4. Data Disaggregation	Extracting end-use-level and/or appliance-level data from an aggregate or whole building energy signal to engage consumers and to target relevant programs to specific customers.
5. Grid-interactive Efficient Buildings (GEB)	Incentivizing buildings that reduce energy waste and carbon emissions while offering flexible building loads to the grid. This may include integrating energy efficiency and demand response to better value the many benefits of grid-interactive efficient buildings.
6. CVR or volt/VAR Optimization	Improving the efficiency of a utility's transmission and distribution system through voltage reduction systems, whether explicitly included in the utility's energy efficiency portfolio or not.

Source: Rachel Gold, Corri Waters, and Dan York, "Leveraging Advanced Metering Infrastructure To Save Energy." ACEEE, January 3, 2020

B. Tier 1 and Tier 2 Use Case Benefits Assumptions

FIGURE 17: RESIDENTIAL TVR USE CASE ASSUMPTIONS

Input	Scenario	TOU + PTR	TOU	EV TOU
P/OP Ratio (non-event, TOU)	All	2.3:1	5.2:1	7.5:1
P/OP Ratio (event day, PTR)	All	8.4:1		
Per Customer Peak Reduction (%, non-event)	Low Case	3%	5%	6%
	Base Case	6%	11%	13%
	High Case	6%	11%	13%
Per Customer Peak Reduction (%, event-day)	Low Case	6%		
	Base Case	11%		
	High Case	11%		
Per Customer Peak Reduction (kW)	Low Case	0.16 - 0.18 kW/Customer	0.16 - 0.18 kW/Customer	0.20 - 0.23 kW/Customer
	Base Case	0.33 - 0.39 kW/Customer	0.33 - 0.39 kW/Customer	0.41 - 0.48 kW/Customer
	High Case	0.34 - 0.41 kW/Customer	0.34 - 0.41 kW/Customer	0.42 - 0.51 kW/Customer
Participation Rate (%)	Low Case	5% - 10%	3 % - 5 %	3 % - 5 %
	Base Case	10% - 30%	5% - 25%	5% - 25%
	High Case	15% - 40%	10% - 30%	10% - 30%

Notes: Please refer to the modeling files for detailed assumptions and sources.

FIGURE 18: SMALL C&I TVR USE CASE ASSUMPTIONS

Input	Scenario	Small C&I Assumptions
P/OP Ratio (non-event, TOU)	All	2.3:1
P/OP Ratio (event day, PTR)	All	8.9:1
Per Customer Peak Reduction (%, non-event)	Low Case Base Case High Case	1% 3% 3%
Per Customer Peak Reduction (%, event-day)	Low Case Base Case High Case	3% 6% 6%
Per Customer Peak Reduction (kW)	Low Case Base Case High Case	0.15 - 0.16 kW/Customer 0.30 - 0.35 kW/Customer 0.30 - 0.37 kW/Customer
Participation Rate (%)	Low Case Base Case High Case	1% - 5% 5% - 18% 10% - 25%

Notes: Please refer to the modeling files for detailed assumptions and sources.

FIGURE 19: ONLINE USAGE PRESENTMENT ASSUMPTIONS

Inputs	Scenario	Electric Assumptions	Gas Assumptions
Per Customer Peak Reduction	Low Case	0.8%	
	Base Case	1.0%	
	High Case	1.5%	
Per Customer Peak Reduction	Low Case	0.02 - 0.024 kW/Customer	
	Base Case	0.027 - 0.033 kW/Customer	
	High Case	0.04 - 0.053 kW/Customer	
Per Customer Energy Conservation (%)	Low Case	1.5%	1.5%
	Base Case	2.0%	2.0%
	High Case	3.0%	3.0%
Per Customer Energy Conservation	Low Case	169 - 181 kWh/Customer	1.11 - 1.18 MMBtu/Customer
	Base Case	225 - 241 kWh/Customer	1.49 - 1.57 MMBtu/Customer
	High Case	338 - 362 kWh/Customer	2.23 - 2.35 MMBtu/Customer
Eligibility Rate	All	75%	75%
Participation Rate	Low Case	5% - 7%	5% - 7%
	Base Case	10% - 13%	10% - 13%
	High Case	1% - 2%	1% - 2%

Notes: Please refer to the modeling files for detailed assumptions and sources.

FIGURE 20: HIGH USAGE ALERT PROGRAM ASSUMPTIONS

Inputs	Scenario	Electric Assumptions	Gas Assumptions
Per Customer Peak Reduction	Low Case	0.13%	
	Base Case	0.25%	
	High Case	0.50%	
Per Customer Peak Reduction per Year (kW)	Low Case	0.003 - 0.004	
	Base Case	0.007 - 0.008	
	High Case	0.013 - 0.018	
Per Customer Energy Conservation (%)	Low Case	0.25%	0.25%
	Base Case	0.50%	0.50%
	High Case	1.00%	1.00%
Per Customer Energy Consevation per Year (kWh for electric, MMBtu for gas)	Low Case	28 - 30	0.19 - 0.20
	Base Case	56 - 60	0.37 - 0.39
	High Case	113 - 121	0.74 - 0.78
Eligibility Rate	All	15%	15%
Participation Rate	Low Case	17%	17%
	Base Case	26%	26%
	High Case	35%	35%

Notes: Please refer to the modeling files for detailed assumptions and sources.

FIGURE 21: ASSUMPTIONS FOR THERMOSTAT-BASED DEMAND RESPONSE PROGRAM

Input	Scenario	Assumptions
Per Customer Peak Reduction	All	27%
Per Customer Peak Reduction	Low Case	0.78 - 0.91 kW/Customer
	Base Case	0.78 - 0.96 kW/Customer
	High Case	0.79 - 1.01 kW/Customer
Eligibility Rate	All	4% - 13%
Participation Rate	Low Case	5% - 20%
	Base Case	5% - 30%
	High Case	5% - 55%

Notes: Please refer to the modeling files for detailed assumptions and sources.

FIGURE 22: ASSUMPTIONS FOR GRID-INTERACTIVE WATER HEATER PROGRAM

Input	Scenario	Assumptions
Per Customer Peak Reduction	All	50%
% of Consumption Attributable to Water Heating	All	20%
Per Customer Peak Reduction	Low Case Base Case High Case	0.29 - 0.34 kW/Customer 0.29 - 0.36 kW/Customer 0.29 - 0.38 kW/Customer
Eligibility Rate	All	9% - 35%
Participation Rate	Low Case Base Case High Case	5% - 20% 5% - 30% 5% - 55%

Notes: Please refer to the modeling files for detailed assumptions and sources.

FIGURE 23: ASSUMPTIONS FOR BEHAVIOR DEMAND RESPONSE PROGRAMS

Input	Scenario	Assumptions
Per Customer Peak Reduction	All	3%
Per Customer Peak Reduction	Low Case Base Case High Case	0.07 - 0.08 kW/Customer 0.07 - 0.09 kW/Customer 0.07 - 0.09 kW/Customer
Eligibility Rate	All	78% - 90%
Participation Rate	Low Case Base Case High Case	5% - 30% 5% - 40% 5% - 50%

Notes: Please refer to the modeling files for detailed assumptions and sources.

FIGURE 24: ASSUMPTIONS FOR LOWERING METER COSTS USE CASE

Input	Assumptions
Annual Increase in Net-Meter Customers	2,000
Benefit per Customer	$350

FIGURE 25: ASSUMPTIONS FOR LEVERAGING AMI NETWORK FOR SMART STREET LIGHTING USE CASE

Input	Scenario	Assumptions
Number of Installed Street Lights	Low Case	25,000
	Base Case	100,000
	High Case	100,000
Project Completion Date	Low Case	2025
	Base Case	2040
	High Case	2030
Avoided Admin Labor Cost	All	$72/Hour
Avoided PSE Labor Cost	All	$65/Truck Roll
Avoided Service Provider Labor Cost	All	$258/Truck Roll

FIGURE 26: ASSUMPTIONS FOR REMOTE CONNECT AND DISCONNECT USE CASE

Input	Scenario	Assumptions
Reduction in Unauthorized Energy Usage	Low Case	289,998 - 642,940 kWh/Year 11,888 - 20,986 CCF/Year
	Base Case	579,995 - 1,285,880 kWh/Year 23,777 - 41,973 CCF/Year
	High Case	869,993 - 1,928,820 kWh/Year 35,665 - 62,959 CCF/Year
Monthly Reduction in Postage	All	1,794
Monthly Reduction in Postage Cost	All	$10,290
Reduction in Field Visits for Reconnection	All	3,825
Monthly Labor Connection Reduction for Reconnection	All	$1,331,078
Reduction in Field Visits for Disconnection	All	5,375
Monthly Labor Connection Reduction for Disconnection	All	$1,969,912
Reduction in Bad Debt	All	61%
Monthly Total Reduction in Bad Debt	All	$5,431,129

FIGURE 27: ASSUMPTIONS FOR IMPROVED OUTAGE MANAGEMENT USE CASE

Input	Scenario	Assumptions
% Reduction in Outages	Low Case	1.5%
	Base Case	3.0%
	High Case	6.0%
Non-Med Saidi (Before AMI: 175)	Low Case	172
	Base Case	170
	High Case	165
Number of Residential Customer	All	1,066,293
Number of Small-Business Customers	All	144,402

C. PSE Identified Use Cases

Use Case Name	Final Classification	Tier
1. Controllable Customer Resources/Smart Consumer Devices (Grid-interactive Efficient Buildings)	Load Flexibility	1
2. Customer Load Disaggregation (Data Disaggregation)	Behavior-Based Programs	1
3. Demand Response/Demand Management (Grid-interactive Efficient Buildings)	Load Flexibility	1
4. Designing Rate Programs/Pricing (TOU Rates)	TVR	1
5. More information and control - Billing Alerts (Informational Feedback)	Behavior-Based Programs	1
6. More information and control - Customer Usage Data (Informational Feedback)	Behavior-Based Programs	1
7. More information and control - In Home Displays and Smart Devices (Informational Feedback)	Behavior-Based Programs	1
8. Volt/Var Optimization (CVR or Volt/Var Optimization)	VVO	1

Use Case Name	Final Classification	Tier
9. Outage Management - Detection (Earlier outage detection)	Outage Management	2
10. Distribution Automation (Quicker outage restoration)	Outage Management	2
11. Meter Ping Functionality (Quicker outage restoration)	Outage Management	2
12. Leveraging the Network (Connecting Devices)/SCADA (Quicker outage restoration)	Smart Street Lighting	2
13. Remote Connect and Disconnect	Remote Connect and Disconnect	2
14. Solar PV - Customer Billing and Utility Planning	Lower Metering Costs for Customers with Distributed Generation	2
15. Outage Management - Customer Communication	Outage Management	2
16. Outage Management - Nested Outages	Outage Management	2

Use Case Name	Final Classification	Tier
17. Metering Issues - Theft and Fraud Detection/Meter Failures (Avoiding metering issues)	Avoiding Metering Issues	3
18. Improved Customer Engagement with Additional Data (Reduced bill inquiries)	Improved Billing Generation	3
19. Improved Bill Generation (Improved billing)	Improved Billing Generation	3
20. EV Planning and Integration	Improved DER Planning and Integration	3
21. Support Non-Wires Solutions	Other Tier 3 Use Cases	3
22. Asset Health (utilization factor) - Under and Over Loaded Transformers	Visibility into Asset Utilization	3
23. Battery Incentive & Management	Other Tier 3 Use Cases	3
24. Bill Payment - Automated or Pre-Paid	Other Tier 3 Use Cases	3
25. Capacity Planning/Sizing Assets	Other Tier 3 Use Cases	3
26. Customized Engagement around Product/Services	Other Tier 3 Use Cases	3
27. Energy Efficiency Program Optimization	Other Tier 3 Use Cases	3
28. Grid Reliability/DERs integration/Hosting Capacity Analysis	Improved DER Planning and Integration	3
29. Identify customer-owned DER	Improved DER Planning and Integration	3
30. Identify Unsafe Working Conditions	Other Tier 3 Use Cases	3
31. Improved Customer Safety	Other Tier 3 Use Cases	3
32. Load Forecasting	Other Tier 3 Use Cases	3
33. Model Validation/Improved Data Quality	Other Tier 3 Use Cases	3
34. Momentary Outages/Power Quality	Other Tier 3 Use Cases	3
35. Monitor Asset Health (voltage anomalies)	Visibility into Asset Utilization	3
36. Power Quality/Voltage Compliance/Real-Time Operating Conditions	Other Tier 3 Use Cases	3
37. Predictive Analytics for Operations	Other Tier 3 Use Cases	3
38. Transformer Mapping/Phase Identification/Switching Analysis	Other Tier 3 Use Cases	3