STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE-ENERGY CLOUD ("CEF-EC") PROGRAM ON A REGULATED BASIS	**))))))**	**BPU DOCKET NO. EO18101115**

DIRECT TESTIMONY OF

PAUL J. ALVAREZ

ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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DIRECT TESTIMONY OF PAUL J. ALVAREZ

I. Introduction, Qualifications, Purpose, and Perspective

Q. Please state your name and business address.

A. My name is Paul J. Alvarez. My business address is PO Box 620756, Littleton, CO 80162.

Q. What is your occupation?

A. I am the President of the Wired Group, a consultancy specializing in electric distribution business planning, investment, and performance measurement, including smart meters.

Q. On whose behalf are you submitting testimony?

A. I am testifying on behalf of the New Jersey Division of Rate Counsel (Rate Counsel).

Q. Please describe your work experience and educational background.

A. My career began in 1984 in a series of finance and marketing roles of progressive responsibility for large corporations, including Motorola's Communications Division (now Android/Google), Baxter Healthcare, Searle Pharmaceuticals (now owned by Pfizer), and Option Care (now owned by Walgreens). My experience in finance and marketing led to my first job in the utility industry in 2001, developing demand-side management programs for Xcel Energy, one of the largest investor-owned utilities in the U.S.

At Xcel Energy I served as product development manager, overseeing the development of new energy efficiency and demand response programs for residential, commercial, and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance (including distributed solar incentive program design and metering policies). There I learned the economics of traditional monopoly ratemaking and associated utility incentives, as well as the impact of customer self-generation, energy efficiency, and demand response on utility profits and management decisions. I also learned a great deal about utility program benefit quantification (measurement and verification, or "M&V").

I left Xcel Energy to lead the utility practice for sustainability consulting firm MetaVu in 2008. At MetaVu I employed my M&V experience to lead two comprehensive, comprehensive evaluations of smart grid deployment performance. The results of both were part of regulatory proceedings in the public domain and include an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for Xcel Energy in 2010,[1] and an evaluation of Duke Energy's Cincinnati-area deployment for the Ohio Public Utilities Commission in 2011.[2]

[1] Alvarez et al, MetaVu. "SmartGridCity™ Demonstration Project Evaluation Summary". Report submitted to the Colorado Public Utilities Commission in the testimony of Michael G. Lamb, Exhibit MGL-1, proceeding 11A-1001E. Report dated October 21, 2011; filed December 14, 2011.

[2] Alvarez et al, MetaVu. "Duke Energy Ohio Smart Grid Audit and Assessment". Report to the Staff of the Public Utilities Commission of Ohio in proceeding 10-2326-GE-RDR. June 30, 2011.

In 2012 I started the Wired Group to focus exclusively on distribution utility businesses and operations. In addition, I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach an elective graduate course on electric technologies, markets, and policy. I have also taught at Michigan State University's Institute for Public Utilities, where I have educated new regulators and PUC staff on grid modernization and distribution utility performance measurement.

Finally, I am the author of Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment, a book that helps laypersons understand smart grid capabilities, optimum designs, and post-deployment performance optimization. I am also the developer of the Utility Evaluator, an Internet-based software program which benchmarks distribution utility performance against peers with like characteristics using publicly available financial and operating performance data.

I received an undergraduate degree from Indiana University's Kelley School of Business in 1983, and a master's degree in Management from the Kellogg School at Northwestern University in 1991. Both degrees featured concentrations in Finance and Marketing.

Q. Have you appeared before the New Jersey Board of Public Utilities previously?

A. Yes. I submitted testimony regarding Rockland Electric Company's advanced metering infrastructure ("AMI") implementation in Docket No. ER19050552 (Rockland Electric Company's most recent rate case) on behalf of Rate Counsel. In addition, I have testified in, or served as a consultant to clients in support of, cases before state utility regulatory commissions on "smart meters", associated rate designs, grid modernization, distribution planning processes, and distribution utility performance measures in 20 different states in dozens of cases in the last five years. Brief descriptions of submitted testimony or reports, and case numbers for each, are provided in the "Regulatory Appearances" section of my Curriculum Vitae, attached as Appendix PJA-1.

Q. What is the purpose of your testimony in this proceeding?

A. I provide testimony recommending that the Board reject the petition ("Petition") by Public Service Electric and Gas Company (PSE&G) to deploy advanced metering infrastructure ("AMI") and recover its costs through the Infrastructure Investment Program ("IIP"). My testimony supports this recommendation through several arguments organized as follows:

- The benefits to customers of the AMI deployment PSE&G has planned will not exceed AMI costs to customers;
- AMI is not the prerequisite for distribution automation that PSE&G would have the Board believe, as an evaluation of Releases 2-4 makes clear;
- Given questionable customer value, current economic conditions, and questionable qualifications, the Board should not allow IIP recovery for AMI;
- The AMI reports prepared for the Board overlook critical AMI issues.

Q. Before you present these arguments, can you please provide your overall impression of the state of AMI in the United States today?

A. I understand the Board is anxious to secure the potential benefits available from AMI, and to use AMI capabilities to make progress on New Jersey's Energy Master Plan. I would like to see New Jersey and PSE&G customers get those benefits too. But I believe technology deployment plans which do not appear likely to deliver benefits in excess of costs to customers must be rejected.

Unlike the benefits of most types of utility investments, AMI benefits are uncertain. My research indicates that the benefits from AMI deployments vary widely from utility to utility based on the types of programs utilities implement and the design of those programs. The fact that some optimized capabilities made available by AMI can make it more difficult for an investor-owned utility to earn its authorized rate of return should be inconsequential. In my informed opinion, no AMI deployment should proceed without 1) a clear plan to maximize all available AMI benefits; 2) a clear understanding of conservatively-estimated customer costs and customer benefits; and 3) a clearly-defined performance measurement program.

I understand that some AMI benefits are not quantifiable. This observation, however, does not imply that deployment plans which fail to maximize available, quantifiable benefits in a way that exceeds costs should be approved. Further, the notion that AMI is a pre-requisite for distribution automation and other future benefits is simply not accurate. While there are a few grid modernization capabilities which can be made marginally better with AMI data, the vast majority of the benefits from these capabilities are available without AMI data, and I have seen few utilities with AMI actually use their AMI data to secure those last few increments of value.[3]

Q. So, you do not oppose AMI investments?

A. Not categorically, no. I oppose AMI proposals which underestimate costs to customers, which fail to maximize available benefits on behalf of customers, and which rely on unsubstantiated and vague promises of what AMI might be able to deliver in the future. In many utility proposals I find that the need and timelines for AMI data and capabilities are exaggerated. I also find that many AMI "use cases" utilities tout appear to be implausible products of brainstorming sessions, not based on any customer or utility need. These "use cases" are often not subjected to any type of critical evaluation, nor are they accompanied by any serious implementation plan.

Q. Does PSE&G's Energy Cloud proposal fall into this category?

A. Yes, in every respect. PSE&G's petition asks the Board to approve its AMI deployment in advance, and to recover costs through the Infrastructure Investment Program mechanism. PSE&G justifies the need for its AMI deployment by describing 70 "use cases" for AMI data and capabilities. The PSE&G petition provides implementation timelines which indicate that 22 of the use cases will be implemented in Release 1, with 48 additional use cases implemented in a staged roll-

[3] Trabish, H. *Slowed Pay-off From Billions in AMI Investment Puts the Technology's Future in Doubt.* Blog Post, Utility Dive, February 20, 2020 (https://www.utilitydive.com/news/slowed-pay-off-from-billions-in-ami-investment-put-the-technologys-future/570274/). Also, *Utilities Vastly Underutilizing Smart Meter Technology – Report*. Blog Post. Smart Energy International. January 13, 2020 (https://www.smart-energy.com/industry-sectors/smart-meters/utilities-vastly-underutilising-smart-meter-technology-report/). Also, Walton, R. *Most Utilities Aren't Getting Full Value from Smart Meters, Report Warns*. Blog Post. Utility Dive, January 13, 2020. (https://www.utilitydive.com/news/most-utilities-arent-getting-full-value-from-smart-meters-report-warns/570249/).

out of use cases from 2023 to 2027 (Releases 2, 3, and 4). However, in discovery, PSE&G admitted that it had not estimated the incremental costs or incremental benefits of any of the use cases beyond Release 1,[4] nor had it developed implementation plans for any use case beyond Release 1.[5] Nor would PSE&G commit to implementing any of the use cases beyond Release 1.[6] These are the first indications that the implied benefits and use cases beyond Release 1 are of the "brainstormed" variety, and that the Board should critically challenge the validity and credibility of the 48 use cases PSE&G presents in Releases 2-4.

I will discuss these use cases in more detail in Section III of this testimony. As a result of the inflated expectations, lack of validity, and lack of credibility PSE&G exhibits in use cases scheduled for Releases 2 through 4, I encourage the Board to base its decision on the Company's petition on Release 1 only, which I will examine presently.

II. The benefits to customers of the AMI deployment PSE&G has planned will not exceed AMI costs to customers

Q. Please summarize this section of testimony.

A. The AMI deployment as proposed by PSE&G will not deliver benefits to customers in excess of costs to customers. In this section I will focus on the benefits and costs of Energy Cloud Release 1 because PSE&G claims that Release 1 benefits alone will

[4] New Jersey BPU Docket EO18051115. PSE&G response to DR RCR-E-0035
[5] Ibid.
[6] Ibid.

exceed AMI costs to customers.[7] I also focus on Release 1 benefits because I do not agree that AMI is a prerequisite for Releases 2-4, as PSE&G's Energy Cloud business case implies. I also believe customers will receive few if any incremental benefits related to AMI from Releases 2-4. I will describe my concerns about Energy Cloud Releases 2-4 in Section III.

This section of my testimony is organized into two parts. The first part addresses the total cost of the AMI deployment to customers, which PSE&G's petition never discloses. The cost information PSE&G does provide in its petition is misleading, and understates the total cost of the AMI deployment to customers by over one billion dollars over 20 years. The second part will address the Release 1 benefits PSE&G anticipates, which are overstated by over $600 million dollars. I will conclude this section of testimony with a realistic assessment of Release 1 benefits and costs, discuss the implications of PSE&G's flawed Release 1 benefit-cost analysis, and provide other thoughts on AMI for the Board's consideration.

Q. Before you begin, please explain the concepts of Releases and use cases.

A. In its Petition, PSE&G describes 70 potential use cases. Each "use case" represents a particular application of "smart" technology, which PSE&G's Energy Cloud business case implies require AMI technology and data, using words such as "foundational", "core", and "fundamental" to describe what PSE&G calls its "iESP" (meaning AMI meters, communications, software, and data, which I refer to as AMI throughout this testimony). Twenty-two use cases are included in Release 1, and

[7] New Jersey BPU Docket EO18051115. Confidential workpapers on customer benefits ("Use Case Mapping") and operational benefits provided by PSE&G in response to RCR-E-0001. The total benefits presented in these two workpapers equal the benefits provided in Figure 5-2 of Schedule FGD-CEF-EC-2, p. 68.

PSE&G's Energy Cloud business case compares Release 1 benefits to AMI deployment costs. *Cost Information PSE&G Provides for Release 1 Is Misleading, and Understates Total Costs to Customers*.

Q. Describe the cost information PSE&G provides in its Petition for Release 1.

A. PSE&G provides two pieces of cost information in its Petition which are illustrative, but which understate the total costs to customers of the AMI deployment. One piece of information is the revenue requirement associated with AMI cost recovery through the IIP rider. This information indicates that the IIP rider will require revenues of $85 million annually by the completion of the AMI deployment,[8] or an increase in the current rates for residential customer on the RS rate of about $3.36 per month.[9] However, this is only the amount of the AMI deployment PSE&G proposes to collect through the IIP rider. It does not include AMI-related costs PSE&G intends to collect through other means.

The Board should not consider the $3.36 per month IIP incremental rate increase estimated by PSE&G to represent the incremental costs to customers of the PSE&G AMI deployment. The $3.36 per month amount does not include the 10% of IIP project capital which must be excluded from IIP recovery per IIP rule, which amounts to another $71.4 million in AMI capital to be recovered from customers.

Q. What is the second piece of AMI-related cost information PSE&G includes in its petition?

[8] New Jersey BPU Docket EO18051115. Updated workpaper provided by PSE&G Witness Swetz, WP-SS-CEF-EC-1 UPDATE.xlsx, tab "SS-CEF-EC-2" (Schedule SS-CEF-EC-2), Cell O24.
[9] Ibid, tab "SS-CEF-EC-3"Cell I40 (Rider amount 10/1/2025) minus Cell C40 (Current Rider amount).

A. PSE&G also states in its petition that it estimates the total cost to implement AMI at $785 million.[10] This figure includes the capital associated with the $3.36 rider amount, and the $71.4 million in IIP project capital excluded from IIP cost recovery by IIP rule. It also includes $70.8 million in AMI-related O&M costs the Company proposes to defer and collect in the next rate case. Yet the $785 million cost is also misleading and understated, because two other significant AMI-related costs customers will incur are still excluded from the PSE&G cost estimate: 1) $216 million in book value for meters removed prematurely to make way for smart meters; and 2) the carrying charges customers will pay on all AMI spending not included in the IIP rider amounts, plus all carrying charges customers will pay on AMI capital once the IIP rider is incorporated into base rates until the AMI investments are amortized (20 years). I estimate these two items combined to be approximately $1.1 billion.[11] The total of all customer payments, which I estimate at $1.884 billion, should serve as a basis of comparison to AMI-related benefits, thereby representing the minimum amount of benefit the PSE&G AMI deployment to be cost effective.

Q. Why should the cost of meters removed prematurely to make way for AMI be considered a cost PSE&G must cover through benefits to customers?

A. I submit that PSE&G should have been installing AMI meters in the normal course of business (i.e., as older meters fail) since AMI meters became the de-facto meter installed in the US. It is likely that AMI meter installations surpassed standard meter

[10] New Jersey BPU Docket EO18101115. Daum Testimony, AMI Business Case, Figure 1-5. Page 18.
[11] See Appendix PJA-2, “Rate Counsel AMI Cost Estimate Adjustments” for calculation details.

installations as early as 2010, but certainly by 2012. Had PSE&G been doing so, the cost to customers of AMI deployment could have been drastically reduced.

Q. Validate your assertion that AMI meter installations had become the standard by 2012.

A. The Edison Electric Institute estimated that by 2012, 42 million AMI meters had been installed across the U.S.,[12] or about 8.4 million per year since their introduction in 2007. Using PSE&G's historical meter replacement rate as a guide (1.9% annually),[13] and considering that there were probably 126.6 million residential electric customers in the U.S. at year-end 2011,[14] 2.4 million meters were probably replaced in the U.S. in 2012 due to malfunction (126.6 million x 1.9%). Even if all these meters were replaced with non-AMI meters (unlikely), it appears that at least 3.5 AMI meters were being installed in the U.S. for each non-AMI meter (8.4 million vs. 2.4 million) as early as 2012.

Q. So PSE&G should have been installing AMI meters since 2012?

A. To be consistent with industry norms, yes. But the PSE&G situation is even more concerning. Beginning in about 2011, PSE&G began to accelerate the pace at which it replaced older electric meters. From 2000 through 2011, PSE&G electric meter replacements averaged 39,555 annually, or about 1.9% per year in the routine course of business; from 2012 through 2019, electric meter replacements averaged 71,619

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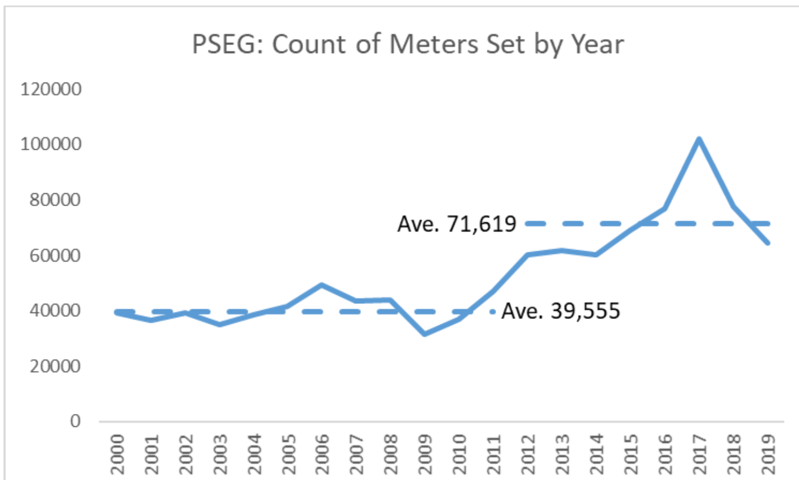
[12] Cooper, A. *Electric Company Smart Meter Deployments*. The Edison Foundation' Institute for Electric Innovation. October, 2016. Figure 1, Page 2.
[13] New Jersey BPU Docket EO18101115. PSE&G response to DR RCR-E_0088, "RCR-E_0088-Update_PSE&G Meter Count by Set Year 2020-05-1.xlsx." Percentage assumes a count of 2.1 million residential and small commercial customers.
[14] U.S. Energy Information Administration Electricity Data Browser. Count of residential customer accounts December, 2011 (https://www.eia.gov/electricity/data/browser/)

annually, or about 3.4% per year.[15] From 2012-2019, PSE&G replaced almost 573,000 electric meters, for about ¼ of its electric customers. Almost none of these new meters were AMI meters.[16] Figure 1 illustrates meter installation data by year from 2000 through 2019.

Figure 1: PSE&G Meter Installations by Year, 2020-2019



Despite the fact that AMI meters have been the industry standard since at least 2012, PSE&G continued replacing older electric meters with new ones which were not AMI up through today (literally). Had PSE&G been replacing older electric meters with AMI meters in the normal course of business since 2012, the AMI deployment would have been at least 25% complete by now, and the book value of meters to be retired prematurely would be a fraction of today's $216 million balance. The AMI costs PSE&G is now asking the Board to consider would also be lower by approximately 25%. When replacing older distribution equipment, from circuit breakers to fuses, I believe the use of industry-standard models to be a reasonable

[15] New Jersey BPU Docket EO18101115. PSE&G response to DR RCR-E_0088.
[16] Ibid.

expectation. Replacing older electric meters with new meters which are not industry-standard AMI makes absolutely no sense to me.

Q. Did you ask PSE&G about this in discovery?

A. I did. PSE&G claims it did not begin using AMI meters as replacements in the routine course of business due to a lack of compliance with its meter data collection technology (one-way, short-range, walk-by or drive-by wireless meter data collection).[17] When questioned further in discovery, PSE&G representatives claimed no knowledge of "upgradable" AMI meters.[18] Such AMI meters are readable by walk-by or drive-by wireless data collection methods in the short term, and are upgradable to full two-way, remote wireless meter communications in the future. However, I am aware that at least one major meter manufacturer (Itron, PSE&G's walk-by/drive by communication system vendor)[19] did indeed offer AMI meters upgradable in this manner.[20] My conclusion is that PSE&G simply did not fully consider the cost to customers of installing non-standard (non-AMI) meter technology from 2012-2020. Further, other AMI meter communications technologies were (and are) available to read standard-issue (i.e., not upgradable) AMI meters located randomly throughout a utility's service territory. The installation of AMI meters in the normal course of business, when older meters fail, results in AMI meters dispersed randomly throughout a service territory. The interim

[17] New Jersey BPU Docket EO18101115. PSE&G response to DR RCR-E-0135(a).
[18] New Jersey BPU Docket EO18101115. Discovery conference call between Staff, Rate Counsel, and PSE&G. July 8, 2020, 1pm-3pm ET.
[19] New Jersey BPU Docket EO18101115. PSE&G response to DR RCR-E-0135(b).
[20] *Itron Expands Functionality of its OpenWay Centron Smart Meter.* Post at T&D (Transmission & Distribution) World website September 24, 2009. Accessed via Internet at https://www.tdworld.com/smart-utility/article/20962125/itron-expands-functionality-of-its-openway-centron-smart-meter. Also, Itron press release dated September 15, 2009.

communications technology would be public carrier cellular networks. Yet PSE&G appears not to have fully considered either upgradable AMI meters or the use of public carrier cellular networks. What's more, since PSE&G submitted its first petition in this docket, in October 2018, PSE&G has continued to install new meters which are not AMI meters – over 63,000 of them.[21] All this information indicates that despite PSE&G's interest in AMI meters, it apparently disregarded options which could have reduced the AMI roll-out cost to customers.

Q. Are there any precedents for installing wireless meter communications over time, in the "routine course of business"?

A. Yes. PSE&G has been replacing its gas meters with wireless communicating versions (called "AMR" meters, for automated meter reading) in the routine course of business since 2010. It plans to finish its deployment by the time the planned AMI deployment is completed (2025).[22] I note this gas meter deployment will require 15-years, no accelerated cost recovery, no pre-approval, and no significant increases in customer rates. This limited rate impact is the result of graduated, "in the routine course of business" deployment PSE&G is pursuing with regards to gas AMR meters.

Q Are you suggesting cost recovery for the meters installed since 2012 which were not AMI meters be disallowed?

A. It would be reasonable for the Board to ask shareholders to pay for those costs if it approves PSE&G's AMI proposal.

[21] New Jersey BPU Docket EO18101115. PSE&G updated response to DR RCR-E-0088. Landis + Gyr ALF and ALFR meters, plus Aclara I-210 meters, installed in 2019 and 2020 (through May).
[22] New Jersey BPU Docket EO18101115. PSE&G response to DR RCR-E-0090(c)

Q. Let's turn to your estimate that PSE&G has understated the cost to customers of its AMI deployment by $1.1 billion. Explain how you arrived at that estimate.

A. As indicated in the introduction to this section, PSE&G never estimates the total amount customers will pay for the AMI deployment in its petition. This is obviously a critical piece of information, suitable for comparison against customer benefits and the basis for any benefit-cost analysis. I requested a total payment estimate in discovery, which PSE&G failed to provide, stating it has prepared no such estimate.[23] While a failure to estimate such a critical number is a meaningful indictment in its own right, I responded by calculating my own estimate, the details of which are provided in Appendix PJA-2. In estimating total customer payments for AMI over time, I assume that PSE&G will be filing a rate case every five years as implied by IIP regulations,[24] consistent with the expectation that any temporary rates the Board might approve be tied periodically to the fundamental rate case process the Board is obliged to oversee.[25] Following this assumption, five rate case intervals can be defined over the life of the AMI investment, which ends with the AMI benefit period PSE&G defines (through 2040). Beginning with the first rate case test year cited in the PSE&G petition (2023),[26] these periods, and the payments PSE&G will collect from customers in each, are summarized in the Table below.

[23] New Jersey BPU Docket EO18101115. PSE&G response to DR RCR-E-0005 (c).
[24] New Jersey Administrative Code 14:3-2A.4(a), which states "A utility may petition the Board for approval of an Infrastructure Investment Program extending for a period of five years or less."
[25] New Jersey Supreme Court. 66 N.J. 12 (1974), IMO Proposed Increased Intrastate Industrial Sand Rates by the Central Railroad Company of New Jersey. Decision dated October 23, 2974.
[26] New Jersey BPU Docket EO18101115. PSE&G petition dated April 1, 2020, page 14.

Table 1: Rate Counsel's Approach to Estimating Total Customer Payments for PSE&G AMI Proposal

Period	Test Year	Customer Payments Consisting of:
Approval through Dec. 31, 2023	Not applicable	IIP Rider increase PSE&G estimates from inception through Dec. 31, 2023
Jan. 1, 2024 through Dec 31, 2028	2023	• Amounts determined by the 2023 test year • IIP Rider increases PSE&G estimates from Jan 1, 2024 through Dec 31, 2028 • Amortization of book value of old meters retired as of Dec 31, 2023 (part 1) begins • Recovery of deferred AMI O&M costs begins July, 2024
Jan 1, 2029 through Dec 31, 2033	2028	• Amounts determined by the 2028 test year • Amortization of book value of old meters retired after Dec 31, 2023 (part 2) • Recovery of deferred AMI O&M costs ends June, 2029
Jan 1, 2034 through Dec 31, 2038	2033	• Amounts determined by the 2033 test year
Jan 1, 2039 through end of AMI benefit period (2040 per PSE&G)	2038	• Amounts determined by the 2038 test year

Q. And the total of customer payments in each of these periods amounted to $1.099 billion more than PSE&G's estimate?

A. On a nominal basis, yes. I estimate the total payments by PSE&G customers for AMI through 2040 will be $1.884 billion, or $1.099 billion more than PSE&G's cost estimate of $785 million.[27] On a present value basis, discounted at PSE&G's current

[27] New Jersey BPU EO18101115. Schedule FGD-CEF-EC-2, page 68. Total nominal costs $785 million.

weighted average cost of capital (6.48%)[28], I came up with an estimated customer cost of $1.085 billion, or $444 million more than PSE&G's estimate of $641 million.[29] I provide the details of my estimate in Appendix PJA-2.

The Customer Benefits PSE&G Estimates from its AMI Deployment Are Dramatically Overstated.

Q. Explain how the benefits PSE&G anticipates from its AMI deployment are overstated.

A. PSE&G overstates AMI benefit estimates in two ways. First, PSE&G's O&M spending reductions in many business functions are estimated using operational "rules of thumb" dollar cost amounts per activity. As these "rule of thumb" spending estimates are not supported by any cost reduction plans, such as headcount reductions, I have no confidence PSE&G will be able to deliver O&M spending reductions in these business functions from AMI.

Second, timing differences between when PSE&G experiences an AMI-related operational improvement, and when those improvements are actually reflected in customer rates via a rate case, result in a significant overstatement of the benefits customers will actually receive. PSE&G estimates its benefits based on the percentage of smart meters deployed by year, for example [**BEGIN CONFIDENTIAL**] [redacted]

[28] New Jersey BPU EO18101115. Schedule SS-CEF-EC-1 Update, tab "SS-CEF-EC-1", cell H15.
[29] Ibid. Total present value costs $641 million.

[redacted] [**END CONFIDENTIAL**].[30] PSE&G's petition indicates it will file a rate case by December 31, 2023,[31] using 2023 as a test year, and PSE&G projects no operational benefits from AMI until 2024. Thus, the rate case test year of 2023 will not include any operational benefits at all from AMI, nor will customer rates reflect any such benefits. As in the customer cost calculation discussed earlier, I will assume the first rate case following the 2023 test year PSE&G specifies in its petition will be held in 2029 (using a 2028 test year). In such a scenario, I estimate that PSE&G customers will miss out on, and shareholders will enjoy, more than [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in operational benefits from 2024 through 2028.

Q. Let's start with the overstated O&M spending reductions. How did PSE&G estimate O&M spending reductions?

A. PSE&G estimated most O&M spending reductions based on headcount reductions, for example in meter reading, billing, or customer care, as well as for reductions in leased space. These O&M spending reduction estimates are relatively straightforward, i.e., headcount reduction x annual cost per headcount = annual O&M expense reduction. However, some O&M spending reductions were based on reductions in activities, multiplied by a "rule of thumb" dollar amount per activity.[32]

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[30] New Jersey BPU EO18101115. Confidential attachments provided by PSE&G in response to RCR-E-0001. "Operational Benefits" and "Customer Benefits" for years 2024-2028, excluding TOU Rate benefits.
[31] New Jersey BPU EO18101115. Petition Page 14.
[32] New Jersey BPU EO18101115. Confidential attachment provided by PSE&G in response to RCR-E-0001, "RCR-E_001PSEG Energy Cloud Workpapers – Operational Benefits – Confidential.xlsx", tabs OB14 through OB24.

In my experience, activity-based spending reductions not backed-up by planned resource reductions (for example, personnel or equipment) cannot be relied upon.

Q. What is a "rule of thumb" dollar amount per activity?

A. A "rule of thumb" dollar amount per activity is a short-hand way to estimate resource costs. For example, a utility might establish a "rule of thumb" that each time a truck is dispatched, the utility incurs a cost of $250. Rules of thumb are generally established by dividing total costs in a year (generally labor and vehicle) by total activities in a year (like truck rolls). When estimating a cost reduction, a utility's logic might be "We had 100,000 truck rolls last year, but because of AMI, we expect those to fall 5%. So, 5,000 truck rolls multiplied by $250 per truck roll will yield a savings of $1,250,000 per year." (Note that all numbers are hypothetical, and used for illustrative purposes only. The dollar amounts or activities do not relate to PSE&G).

Q. That seems logical. What's wrong with that logic?

A. Nothing, as long as headcount reductions and vehicle reductions amounting to 5% are actually executed. However, if no actual resource reductions are executed, no actual cost savings are delivered. Employees can always find other things to do with 5% of their time. It is impossible to know whether that time will be more productive, of whether employee productivity will simply fall by 5%. This is why I find it prudent to discount activity-based spending reduction estimates not backed by resource reductions..

Q. So you believe the activity-based PSE&G AMI spending reduction estimates to be exaggerated?

A. Yes, because they are not backed by resource reduction plans. PSE&G used this approach to estimate O&M spending reductions for skilled positions in electric and gas operations. Such employees are historically utilized for some amount of service turn-ons and turn-offs, some amount of move-ins and move-outs, etc., the volume of which PSE&G projects will fall if AMI is deployed. Of the [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in annual O&M savings PSE&G projects from the full AMI roll-out in 2028, for example, [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] of it was estimated using the rule of thumb approach. In discovery, I asked for headcount reductions in gas and electric operations from AMI,[33] and reductions in trucks,[34] associated with these activity reductions. PSE&G replied that no such headcount or truck reductions were planned from the AMI deployment.

Q. So, you believe O&M spending reduction estimates to be overstated by the amount of the reductions estimated in the rule of thumb manner?

A. Absolutely. I have no confidence that PSE&G will reduce O&M spending by [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in electric and gas operations annually without a single planned headcount or truck reduction in these business functions. These reductions are reflected in Appendix PJA-3, “Rate Counsel AMI Benefit Estimate Adjustments”.

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[33] New Jersey BPU EO18101115. PSE&G response to RCR-E-0137.
[34] New Jersey BPU EO18101115. PSE&G response to RCR-E-0122(d).

Q. Are the timing differences you described earlier reflected in this Appendix as well?

A. Yes. Appendix PJA-3 includes all operational benefits PSE&G estimates by year but one, time-varying rates, as these benefits will be reflected on customers' bills as customers take the actions required to secure time-varying rate benefits. All other operational benefits PSE&G projects are not reflected in customers' bills until they are included in a rate case test year. Examples include O&M expense reductions, but also revenue-assurance benefits like reductions in unbilled usage, reductions in theft, and improvements in meter accuracy. My calculation assumes PSE&G requests a rate case on December 31, 2023, and a subsequent rate case on December 31, 2028. My analysis indicates more than [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in operational benefits PSE&G includes in its business case will never be recognized by customers in rates as a result of the 5-year delay in operational benefit recognition between the 2023 test year and the 2028 test year. The figure below highlights the difference between the benefits PSE&G is projecting and the recognition of benefits projected by Rate Counsel in rates through rate cases processed every five years during the AMI benefit period defined in the PSE&G business case.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Rate Counsel's Benefit and Cost Adjustments and Implications

Q. Please summarize the adjustment you would make to the benefits and costs PSE&G provides in its business case.

A. The table below summarizes my recommended adjustments in nominal dollars, and the subsequent table summarizes my recommended adjustments in present value dollars (discounted at PSE&G's weighted average cost of capital, 6.48%). The recommended benefit adjustments include reductions for timing differences in operational benefit rate recognition and O&M expenses not backed by headcount and truck reductions. The recommended cost adjustments include increases for the cost of meters removed prematurely and carrying charges customers must pay.

Table 2: Rate Counsel Adjustments to the PSE&G AMI Business Case, Nominal Values

($ in millions)	Per PSE&G	Adjustments	Per Rate Counsel
Benefits (PJA-3)	2,054	(604)	1,450
Costs (PJA-2)	785	1,099	1,884
Benefits in Excess of Costs (costs in excess of benefits)	1,269	(1,703)	(434)

Table 3: Rate Counsel Adjustments to the PSE&G AMI Business Case, Present Values

($ in millions; 6.48% discount rate)	Per PSE&G	Adjustments	Per Rate Counsel
Benefits (PJA-3)	887	(260)	627
Costs (PJA-2)	641	444	1,085
Benefits in Excess of Costs (costs in excess of benefits)	246	(704)	(458)

Q. What are the implications of the PSE&G cost understatements you have identified?

A. The implication of understated cost is that it lowers the hurdle of benefits PSE&G's AMI deployment must deliver in order to provide benefits in excess of costs for customers.

Q. What are the implications of the PSE&G benefit overstatements you have identified?

A. The timing of rate cases so that operational benefits can accrue to shareholders for five years before such benefits are captured in rates is a significant issue. The combination of understated costs to customers and overstated benefits makes it extremely unlikely PSE&G's AMI deployment will deliver benefits to customers in excess of costs, and extremely likely that customer costs will exceed benefits.

Q. How might the Board address the operational benefit timing issue?

A. The Board has already addressed the operational benefit timing issue in PSE&G's Gas IIP case. In that case, the Board required PSE&G to credit estimated operational and maintenance (O&M) spending reductions to customers before approving the IIP revenue requirement.[35] The same situation exists with AMI, except that AMI offers more benefits than just O&M spending reductions. Other AMI operational benefits beyond O&M spending reductions that PSE&G describes in its business case require a rate case to be recognized as benefits to customers. These include claimed revenue assurance benefits like reductions in usage on inactive accounts, reductions in theft, improvements in meter accuracy, and reductions in bad debt.

A number of state utility regulators have recognized this problem and enacted related protections for customers. Regulators in Ohio[36] and Oklahoma[37] have ordered that the operating benefits utilities reflected in their AMI business cases be deducted from AMI-related revenue requirements until the next rate case. I recommend this approach, as it holds utilities accountable for both the timing and the size of the operational benefits estimated by the utilities in their business cases, at least until the next rate case. The Ohio order further specifies the timing of the next rate case, such that operating benefits available at the conclusion of the AMI deployment are

[35] New Jersey BPU Docket No. GR 17070776. Order dated May 22, 2018. Item 33.a, page 8.
[36] Ohio Public Utilities Commission Case No. 10-2326-GE-RDR. Order dated February 24, 2012.
[37] Oklahoma Corporation Commission Cause No. PUD 201000029. Order 576595 dated July 1, 2010.

reflected in the test year. I would support such a requirement in New Jersey as well. I would go further, however, as neither of these orders clearly specifies that an audit be conducted to measure the actual operational benefits delivered to customers following the AMI deployment. Given the variability in AMI-related benefits I described earlier, I believe this to be a critical requirement.

Q. Doesn't AMI offer improvements in reliability?

A. Yes, but the reliability benefits from AMI are extremely small. In fact, other than a small reduction in storm repair labor costs,[38] PSE&G does not attempt to quantify the economic customer benefits associated with AMI reliability improvements in its business case. PSE&G claims it will get a 2% improvement in SAIDI[39] from AMI, but the economic value of such a small improvement, particularly to residential customers, is negligible. The U.S. Department of Energy's online Value of Reliability Improvement estimation tool, given input assumptions based on PSE&G actual data, delivered a present-value economic benefit to residential customers of just $1.38 million.[40] Even if the reliability-related benefits to an estimated 95,000 small commercial customers are added, the present value is still only $22.2 million – just 2.5% of PSE&G's $887 million present value AMI benefit estimate. I also have significant reason to believe the small commercial customer benefits calculated by

[38] New Jersey BPU EO18101115. According to confidential workpapers provided in response to RCR-E-0001, PSE&G estimates the annual reduction in storm repair labor costs at just [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] upon full AMI deployment in 2028.

[39] New Jersey BPU EO18101115. PSE&G petition dated April 1, 2020. Page 8.

[40] U.S. Department of Energy Interruption Cost Estimator available at https://icecalculator.com/reliability-improvement. Inputs: SAIDI (with storms) 89.0 (5-year PSE&G average 2013-2018, 2% improvement after AMI); SAIFI (with storms) .799 (5-year PSE&G average 2013-2018, no improvement after AMI); Residential customer count 2.1 million; non-residential customer count 0.1 million; inflation rate 2.5%; discount rate 6.48%; AMI improvement lifetime 20 years starting in 2024; state = New Jersey.

the Department of Energy's online tool are exaggerated, for all the reasons cited by Dr. David Dismukes in his testimony on behalf of Rate Counsel regarding PSE&G's Energy Strong II petition,[41] which I adopt in their entirety.

Q. Reliability benefits from AMI are minor? How can that be?

A. The notion that AMI delivers big reliability benefits is a popular misconception. While AMI meters can report that power has been lost, customers are not generally shy about notifying their utilities about power outages. The question becomes, how much better are AMI meters at reporting outages than customers? My primary research indicates two situations where AMI meters can be helpful. One situation is faults in underground lines, which are notoriously time-consuming to find. While AMI meters can speed underground fault location,[42] underground lines are rarely disrupted by storms, meaning that this capability is of limited benefit during storms.

The other situation is relevant in storm situations, but the reliability benefit is relatively small. Sometimes, in post-storm restoration, grid damage which prevents electricity from being delivered can be "masked" within damage impacting a larger geography. In such situations, which utilities generally call "trouble within trouble" or "nested outages", a crew will repair the damage to the grid impacting the larger geography. Once the damage impacting the larger geography is repaired, the crew moves on to the next priority, unaware of the nested damage. Customers within the nested damage area then experience delayed restoration.

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[41] New Jersey BPU EO18060629. Direct Testimony of David E. Dismukes dated March 1, 2019. Pp 22-27.
[42] "SmartGridCity™ Demonstration Project Evaluation Summary", Page 80.

Smart meters can be "pinged" for power status. If mass meter pinging is performed after a repair, a utility can be immediately made aware that nested damage exists, and can direct the repair crew to the nested outage before the crew leaves the area. The ability to direct a crew to a nested outage before leaving an area improves repair crew efficiency, as time spent traveling around is reduced. But overall, this capability is not likely to significantly improve reliability.[43] Nested outages are not an everyday occurrence. I would classify any SAIDI reliability improvement estimate from this capability over 5% as an exaggeration; PSE&G's estimate of a 2% SAIDI improvement sounds about right to me.

Q. Is there other evidence AMI fails to significantly improve reliability?

A. Yes. Earlier this month, Tropical Storm Isaias resulted in lengthy outages in both Westchester County and Long Island, with some customers out of service for more than five days. Yet Con Ed reports 100% AMI deployment in Westchester County,[44] and New York's Newsday website reports that PSE&G is about 50% complete with its AMI deployment on Long Island.[45] Perhaps more disturbing is Newsday's report that New York State Senator Jim Gaughran's office fielded numerous calls from PSEG Long Island customers with smart meters whose power was out "but was listed by PSEG as being on."[46] This can only mean one thing: that the smart meter installed on premise A is incorrectly associated in PSEG Long Island customer

[43] Ibid, page 82.
[44] Con Ed website. https://www.coned.com/en/our-energy-future/technology-innovation/smart-meters/when-will-i-get-my-smart-meter
[45] Harrington, M. "PSEG Long Island Considering No-Call Policy for Non-emergencies". Newsday blog post August 23, 2020. Available via Internet at https://www newsday.com/long-island/pseg-fixes-for-next-storm-1.48387937
[46] Ibid.

systems with premise B. While this is a problem for smart meter outage reporting, it is an even bigger problem for smart meter billing. Incorrect meter assignments mean that PSEG Long Island is billing the customer at premise B for the usage being recorded by the meter installed at premise A.

Q. Do you have other concerns with PSE&G's proposed AMI deployment?

A. Yes. As big as the issues I have described are, I have an overriding concern about PSE&G's proposed AMI deployment, and specifically with the proposed IIP cost recovery. Because PSE&G seeks to have the AMI investment reviewed in advance, the possibility of cost disallowance at a later date is very low. In effect, the request for preapproval transfers the risk of paying for imprudent investments from shareholders to customers. PSE&G admitted as much when it said it would not deploy AMI without prior Board approval.[47] To me, this indicates that PSE&G is indeed concerned it will not be able to quantify benefits in excess of costs after AMI is deployed, and that its AMI investment will be deemed imprudent.

In the next section of testimony, I'll discuss the unlikely prospects that AMI will deliver any benefits beyond those estimated in Release 1.

III. AMI Is Not the Prerequisite to Distribution Automation PSE&G Would Have the Board Believe, as an Evaluation of Releases 2 through 4 Makes Clear

Q. Please preview this section of testimony.

[47] New Jersey BPU EO18101555. PSE&G response to RCR-E-0134.

A. PSE&G asks the Board to approve AMI deployments based in large part on the future potential offered by the technology. However, this section provides information which casts doubt on potential future AMI benefits beyond Release 1, as well as any requirement to install AMI before distribution automation can proceed.

As cited above in the introduction to this testimony, my overall concerns about Releases 2 through 4 include: 1) PSE&G has not developed plans to implement any of these use cases; 2) PSE&G has not estimated the incremental costs or incremental benefits of any of these use cases; and 3) PSE&G makes no commitment to implement any of these use cases. I will not revisit those significant concerns here, but will discuss the limited information PSE&G provides on the 48 use cases it describes in Release 2 through 4. My review, which I summarize in Appendix PJA-4, reveals:

- For 75% of these use cases there is no research that supports a technical need or economic benefit of the use case, or of the use of AMI data.
- For all but one use case (meter pinging), universal AMI deployment is not required to secure the majority of benefits of the use case, nor is AMI required for any of the 18 use cases which could be categorized as distribution automation.
- AMI capabilities offer potential, small incremental benefits in half of the use cases, but alternatives to AMI are available, and in many cases PSE&G already performs the activities described in the use case without AMI.
- About a third of the use cases relate to services already available in the market, or which should be market-based, or for which no market need exists.

- About an eighth of the use cases could prove valuable in the future, but could likely be accommodated by a "normal course of business" AMI roll-out.
- The use cases with the greatest potential benefit-to-cost ratio for customers are either missing from Release 1, or missing entirely.
- About half the use cases describe the same capability applied to different situations, and are therefore duplicates. The Board should not perceive the volume of use cases as impressive or convincing.

These categorizations are not mutually exclusive; for example, a use case which does not require universal AMI, but for which AMI data could potentially offer some value, and for which that value won't be needed until the future, could all apply to a single use case. To help the Board gain an understanding of my perspectives, I will discuss each of these findings, including examples, in this section of testimony.

Q. Explain your finding that there is no research for 75% of the use cases that supports a technical need or economic benefit of the use case, or of the use of AMI data.

A. One cannot assume that every use case PSE&G's consultant describes satisfies an unmet technical need, or that the use of AMI data will increase use case benefits, or that the use case itself will deliver benefits in excess of costs. Consider, as an example, use case 2-2, *Asset Management & Health*, which states "Using advanced asset analytics to enable smart asset management capabilities and become increasingly more focused on monitoring and predicting system health and deficiencies, and ensuring that all operations, investments and maintenance decisions are correct based on in-depth analysis and evaluation of detailed asset-level health and risk data." This description, combined with the description of use case 3-14, Asset Risk Analysis and Scoring, seems to suggest that by recording asset-specific operating data (note that there is no mention of AMI data) over time, maintenance costs and grid investments can be reduced.

While these implied benefits appear attractive, neither maintenance costs nor grid investments are likely to fall as a result of these use cases. Asset maintenance schedules are driven by manufacturers' recommendations. No utility is going to skip an asset's scheduled maintenance tasks as a result of "light" operating demands recorded in historical asset operating data, and headcount reductions based on any such maintenance reductions are even less likely. Of course no utility with capital bias is truly interested in reducing grid investments, and the subjective "Risk Analysis and Scoring" use case is not really intended to secure this outcome.

Objective tests are available to identify assets at risk of failure so that they can be replaced in advance. Utilities have been testing substation assets (transformers, circuit breakers, and relays) which serve large numbers of customers on a regular schedule for decades as a standard industry practice. The risk-based approach to which these use cases refer involves the use of subjective estimates of historical asset stress to identify assets for replacement instead of objective test results. One of the heavily weighted inputs to these subjective models – asset age – virtually ensures that the assets which will be identified and replaced by these models have zero book value (and are therefore earning no rate of return for the utility). Furthermore, age is a poor predictor of asset failure, which is why the objective test results became standard industry practice in the first place. In my experience, subjective health assessments result in the identification of a lot more assets for replacement than objective testing. This use case accelerates capital spending rather than defers it, and is thus a detriment, not a benefit, for customers.[48] There are 34 other use cases not supported by research from technical, AMI data, or economic benefit perspectives.

Q. Explain your finding that for all but one use case, universal AMI deployment is not required to secure the majority of benefits of the use case, and that AMI is not required for any of the 18 use cases which could be categorized as distribution automation.

A. For all use cases but one (meter "pinging"), AMI capabilities or data are not required at all, or, for use cases which do require AMI data, AMI meters can be installed on specific loads or resources. Consider control of customers' loads, for example, which PSE&G's consultant describes in four different use cases (two residential, 2-1 and 2-10, and two commercial, 4-1 and 4-2). AMI capabilities are not required for demand response programs. Residential load control programs have existed for decades without any AMI meters. In the early days of residential load control, wireless radios were used to control the compressors on residential customers' air-conditioning units, cycling them on and off during peak demand periods. More recently, such programs have benefitted from customers' installations of remote-controllable thermostats. In such instances, customers simply provide secure access to such

[48] Alvarez P et al. Asset Replacement Based on Risk Modeling – Emerging Best Practice? Public Utilities Fortnightly. August, 2020. Pages 58-62.

thermostats directly to utilities or third parties, which then increase air-conditioning set points (in degrees) to reduce customers' loads during periods of peak demand. Control units are also available for other residential customer loads, from electric water heaters to pool and hot-tub pumps, which could permit wireless load control by utilities or third parties upon customer authorization. Commercial customers' loads have been controlled by third parties as part of PJM's Curtailment Service Provider program for many years despite the lack of AMI.

Q. But what about the need for AMI capabilities and/or data related to distributed generation, or energy storage, or microgrids, or for time-based rates. AMI capabilities and data are certainly necessary for those use cases, are they not?

A. It is true that AMI capabilities and/or data are required for many use cases – 16 by my estimate. However, in none of these circumstances does AMI need to be deployed universally. In each of these 16 use cases, AMI could be installed only on specific loads or resources, or only for those customers taking advantage of time-based rates, to secure the benefits of the use case. The Hawaii PUC recently ordered just such an AMI deployment.[49] PSE&G will likely argue that the AMI communications network it has decided upon makes such a deployment difficult, but as described earlier, several AMI communication network options are available to address this concern.

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[49] Hawaii PUC Docket 2018-0141. Application of (Hawaiian Electric Companies) for Grid Modernization Strategy Phase 1, dated June 21, 2018. Section IX.E, pages 32-38, "Anticipated Implementation Schedule". Also Decision and Order 36230 dated March 25, 2019. Section 2, "Cost Recovery Caps", pages 25-27, "Variable Cost Recovery".

Q. Explain your finding that AMI data offers potential, small incremental benefits in about half the use cases, but alternatives to AMI are available, and in many cases PSE&G already performs the activities described in the use case without AMI.

A. In half the use cases AMI data could conceivably offer some small, incremental benefit if utilized in the use case. But in each such use case, alternatives to AMI are available. Indeed, PSE&G already conducts the activities described by many of the use case without any AMI data at all.

Q. What kind of alternatives to AMI are available?

A. Twenty four use cases imply that AMI is required as a data source for many capabilities, such as asset-specific utilization (voltage or current history by hour, for example); grid-state conditions in near-real time (voltage, current, power factor, frequency, etc.); or reliability (historical counts of operations for fuses, circuit breakers, switches, or reclosers on the distribution grid, as examples). However, AMI meters are not needed to provide such data. Let us start with asset-specific utilization data history. Many types of grid assets listed are already available with sensors which can monitor and wirelessly communicate grid condition data in near-real time to grid operators. Line sensors are a type of equipment dedicated solely to monitoring and reporting grid conditions in near-real time wherever they are installed. Line sensors are a proven technology, and are relatively inexpensive to purchase or install. Utilities routinely record data from all of these sources for later analysis.[50] In fact, PSE&G's Contingency Reconfiguration Subprogram of the Energy Strong II Petition offers precisely such grid monitoring and reporting capabilities without AMI.[51]

Q. And you say PSE&G already performs the activities described in many use cases without AMI today?

A. Yes. Today, almost all large utilities conduct reliability analyses by circuit, section, and asset, using historical data from outage management and geographic information systems, for example (use cases 2-3 and 4-4). This is called worst performing circuit analysis, and is standard practice in the industry. In fact, PSE&G's Grid Modernization Subprogram of the Energy Strong II Petition offers precisely such capabilities without AMI.[52] Today, all utilities monitor the loads on circuits and assets for distribution planning (also known as capacity planning, use cases 2-5, 3-6, and 4-12). Today, all utilities reconfigure their grids from time to time, to complete planned maintenance and testing, to reduce the number of customers impacted by a service outage (called fault isolation and service restoration), or in emergency situations (use cases 2-6, 3-7, 3-8, 3-9, 3-16, 4-8, and 4-15). Today, all utilities must decide the best places for placing equipment like switches, reclosers, and capacitor banks (use cases 3-15 and 4-14). Today, all utilities manage grid voltage and power factor (use cases 3-10 and 4-13). Utilities with and without AMI perform all these activities today. Of those utilities with AMI data and capabilities, I know of almost none that use AMI to improve these activities.

[50] Most large utilities employ the PI System from OSISoft to record data histories of field devices.
[51] New Jersey BPU EO18060629. PSE&G Petition dated June 8, 2018. Pages 4-5.
[52] Ibid. Pages 5-6.

Another use case, smart street lighting (2-7), assumes the use of the AMI communications network, though such communications services could easily be secured from AT&T or Verizon Wireless.

Q. So, AMI data and capabilities are worthless for such use cases?

A. I would not go that far. Engineers typically prefer more data than less, all else being equal. The question is, does the availability and use of additional data result in improved decisions, or different decisions, than those made without the additional data? Further, if such decisions were actually better, were they sufficiently better to justify the time and effort the engineer spent incorporating the additional data, or to justify the cost of collecting that data? Given the limited use of AMI data in such decision-making I have seen to date, I think the answer to these questions is no.

Q. Explain your finding that about a third of the use cases relate to services already available in the market, or which should be market-based, or for which no market need exists.

A. Many use cases developed by PSE&G's consultant, PA Consulting, describe services which are already available in the market, or which do not constitute a regulated (natural monopoly) service. Simply because an AMI system *can* be employed to support a use case does not necessarily mean it *should* be employed in that manner. Let us refer again to multiple load control use cases PSE&G's consultant describes with future potential. Residential customers in Toronto and the San Francisco Bay Area can already sign up with smart phone apps (third parties OhmConnect and Chai Energy, respectively) that pay rebates for demand response. Commercial customers have their choice of over 50 curtailment service providers. But customer load control represents just a few of the use cases subject to market forces which should not be cornered by a regulated utility like PSE&G.

Two use cases (2-11 "network as a service", and 3-1 "Smart Cities") would employ AMI communications network services to deliver commercial wireless data communications services. Not only would such use cases require PSE&G to become a licensed supplier of telecommunications services in New Jersey, PSE&G would be competing against companies like AT&T and Verizon Wireless for such business. Use case 2-12 is essentially meter data management software as a service, or distribution management software as a service; and there are already several established competitors for each. Use case 3-4, involving loyalty programs, is certainly market-oriented, and I note that the other component of this use case – customer contests (which PSE&G's consultant calls "gamification") – do not require AMI. Nothing prevents PSE&G from offering loyalty programs or customer contests today. Use case 3-11, "Customer Safety", consists of services offered today by leading home security providers such as ADT (CO2, natural gas, and flood detection), and such detectors are available on Amazon.com today for purchase as optional parts of home security systems. Use case 3-12 offers commercial customers power quality management services; not only is AMI not required for this, PSE&G customers can likely choose from dozens of large electrical contractors in New Jersey to secure such services. Use cases 4-9, 4-10, and 4-16, regarding distributed generation, distributed energy storage, and ancillary services aggregation and management, respectively, should likely all be market, rather than regulated, services.

Q. Explain your finding that about an eighth of the use cases could prove valuable in the future, but could likely be accommodated by a " normal course of business" roll-out.

A. Seven use cases describe what I perceive to be a legitimate benefit from at least some level (not necessarily universal) of AMI deployment, but which will not be needed for many years. In service areas with very high levels of distributed generation, or storage, or microgrids, such as California and Hawaii, I am just beginning to see situations in which AMI data could be helpful. But given that PSE&G customers are years away from such high levels of distributed generation, or storage, or microgrids, there is no associated urgency behind AMI deployment. As a result, installation of AMI through the routine course of business, such as ordered by state utility regulators in Hawaii, or as demonstrated by PSE&G in its gas AMR meter deployment, will be adequate to meet these future needs.

Q. You mentioned that use cases with the greatest potential benefit-to-cost ratio for customers are either missing from Release 1, or missing entirely. Which might those be?

A. My research indicates that one of the best potential benefit-to-cost ratios of any grid modernization capability is automated conservation voltage reduction, particularly when operated 24 hours a day, 365 days a year. Two associated use cases, including one designed to reduce demand (2-14) and one designed to reduce energy use (2-15) through voltage reduction are included in Release 2. Yet, like all other use cases in Releases 2, 3, and 4, PSE&G makes no commitment to implementing them. I understand the Board is currently reviewing studies on Conservation Voltage Reduction in docket EO19040499.

Q. Are there other use cases missing from the PSE&G Energy Cloud business case?

A. Not with the kind of potential economic benefits for customers offered by automated conservation voltage reduction, but yes. I believe three sound use cases are missing from PSE&G's AMI Plan, including default Peak-Time Rebate; improved demand-side management program impact measurement; and Connect-My-Data standard compliance.

Q. What is default Peak-Time Rebate?

A. Peak-Time Rebate is a time-based rate structure which rewards customers for conserving energy during peak demand periods. Customers who do not, or who cannot, conserve energy during peak demand periods are not charged a higher rate; instead, those who do conserve are provided with a rebate on their bills. As such, the program delivers much of the benefit of time-based rates with none of the drawbacks for low-income customers (who are less likely to be able to conserve energy during peak demand periods.) With experience over time, such programs reduce the amount of capacity a utility must procure, reducing costs for all customers.

"Default" refers to the fact that all customers are eligible for rebates without having to complete any kind of enrollment. Default Peak-Time Rebate was employed in Maryland as a way to maximize AMI benefits.[53]

Q. How can AMI improve demand-side management program impact measurement?

A. The detailed energy usage data AMI meters record can be used to improve demand-side management (DSM) program impact measurement. As just one example, changes in the usage data of all participants in a particular DSM program pre- and post-enrollment can be compared to the data of non-participants, who serve as a baseline over the same time periods. Such comparisons are helpful in determining the actual impact of a DSM program. Today, impact measurement (called EM&V, for evaluation, measurement, and validation) is based on estimated program benefits. Improved DSM program impact measurement benefits customers by ensuring that ineffective DSM programs are discontinued, and by reducing overcompensation in DSM program lost revenue adjustment mechanisms.

Q. What is the Connect-My-Data standard?

A. Connect-My-Data is a set of protocols a utility can follow which standardizes how customers authorize third party access to their energy usage data, and which provides authorized third parties with secure and automated access to that data. Though not limited to AMI, Connect-My-Data is particularly valuable for customers who wish to utilize the services of third-party home energy managers and smart phone app

[53] Baltimore Gas & Electric Company. Energy Savings Days. (https://www.bge.com/WaysToSave/ForYourHome/Pages/EnergySavingsDays.aspx)

developers, such as Chai Energy and Ohm Connect mentioned earlier. Connect-My-Data standard compliance thereby allows a utility customer to pick the home energy management services provider which best meets his or her needs. This expands consumer options and stimulates service innovation while preventing monopoly advantages from expanding into unregulated markets for consumer energy services.

Q. You also mentioned that there is a lot of duplication among the use cases?

A. Correct. By my count, 26 of the use cases are duplicates of other use cases. As just a few examples, at least four use cases involve the control of customers' loads; four use cases involve time-based rates; and seven use cases involve grid reconfiguration in some way, shape, or form. In general, PSE&G's consultant applies the same basic "smart" capability in multiple contexts and situations, thereby creating multiple use cases from a single capability.

Q. Have other state utility regulators approved distribution automation investments absent AMI?

A. Absolutely. In 2009 the U.S. Department of Energy announced $487 million in distribution automation grants to 12 utilities with no AMI as part of the Smart Grid Investment Grant program (part of Great Recession recovery spending). More recently, the Massachusetts DPU approved three utilities' grid modernization proposals while rejecting their AMI deployment proposals.[54] The North Carolina Utilities Commission is currently considering a $2.3 billion Grid Improvement Plan proposal from Duke Energy. Though Duke Energy is installing AMI in North

[54] Massachusetts DPU 15-120 to DPU 15-122. Order dated May 10, 2018. Pages 1-5.

Carolina, and has significant experience with AMI going back to 2010 in Ohio (the utility was among the original Smart Grid Investment Grant award winners for AMI), Duke Energy's Grid Improvement Plan includes no mention of AMI capabilities or data integration.[55]

My testimony on this subject could be even lengthier, but I believe the illustrative examples provided amply make several points: 1) The Board should not be swayed by the large number of use cases in PSE&G's Energy Cloud business case; 2) The Board should not assume that all use cases benefit customers; and 3) The Board should not assume that AMI is a requirement for distribution automation or other grid modernization investments.

IV. Given Questionable Customer Value, Current Economic Conditions, and Questionable Qualifications, the Board Should Not Allow IIP Recovery for AMI

Q. Please summarize this section of testimony

A. In the previous two sections of testimony I provided evidence that the AMI deployment proposed by PSE&G will not deliver benefits in excess of costs to customers. I also provided evidence that AMI is not the prerequisite for distribution automation that PSE&G would have the Board believe. These challenges to the customer value of AMI alone should be reason for the Board to reject PSE&G's petition to install AMI and recover the costs through the IIP rider. But extenuating

[55] North Carolina UC Docket Nos E-7 Sub 1214. Direct testimony of Jay W. Oliver dated Sept 30, 2019.

circumstances provide additional rationale for such rejection. In this section I will make the case that times of challenging economic conditions, as we are experiencing now, are times for belt-tightening, not for making large investments which will deliver rate increases in excess of benefits. Further, while I understand the Board has broad discretion regarding the application of the IIP program, I identify the characteristics of AMI which make it inappropriate for IIP cost recovery.

Q. Why do you categorize current economic conditions as challenging?

A. New Jersey's unemployment rate for June, at 16.6%, was the highest level since the US Bureau of Labor Statistics started keeping local area unemployment data in 1976.[56] The New Jersey Chamber of Commerce reports that as many as one in four workers in New Jersey applied for unemployment benefits since the start of the pandemic.[57] These numbers dwarf those of recent recessions, including the Great Recession of 2008 and the dot-com bubble of the early 2000s, when New Jersey's unemployment rate peaked at 9.8% and 6% respectively.[58] Both of these recessions were characterized by slow recoveries, which experts fear are the new norm. For example, though the near-collapse of the financial system in the autumn of 2008 which caused the Great Recession had been clearly averted within nine months, it took six years for total employment to return to pre-crisis levels.[59] All signs point to

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[56] U.S. Bureau of Labor Statistics, *Current Unemployment Rates for States and Historical Highs/Lows, Seasonally Adjusted* (New Jersey). (https://www.bls.gov/web/laus/lauhsthl.htm)

[57] New Jersey Chamber of Commerce. *Pandemic Update for New Jersey Businesses*. July 30, 2020. (https://njchamber.com/news/njchambernow/901-2020-07-30-latest-coronavirus-news-for-new-jersey-businesses)

[58] Munoz, D. *New Jersey Unemployment Could Blow Past Great Recession Levels*. Blog post at NJBiz. May 1, 2020. (https://njbiz.com/report-nj-unemployment-blow-past-great-recession-levels/)

the pandemic lasting far longer than 9 months, with some experts optimistically targeting the end of 2021.[60] Even then there is much uncertainty.[61] An extended pandemic is likely to deepen and extend challenging economic conditions.

Q. Why should current and prospective economic conditions preclude approval of PSE&G's AMI proposal?

A. Many New Jersey families are already making difficult choices, such as buying food or medicine versus paying the electric and/or gas bill. While there is never a good time to approve utility investment proposals for which customer benefits are unlikely to exceed customer costs, increasing rates during extremely challenging and uncertain economic conditions is the worst time to do so.

Yet there are other extenuating circumstances the Board should take into account when considering PSE&G's AMI investment and cost recovery proposal. There are so many investments a distribution utility could make, and so many PSE&G might need to make in coming years. Tropical Storm Isaias proved that utilities' ability to invest their way to storm resilience is limited, to say the least. But PSE&G may need to make grid investments in coming years for reasons other than reliability and resilience. Investments may be needed to accommodate growing distributed and renewable generation, electrification, conservation, peak demand management, and other aspects of the New Jersey Energy Master Plan. The Board

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[59] Yglesias, M. *Will the Worst Downturn Since the Great Depression Last Long?* Blog post at Vox.com April 22, 2020. (https://www.vox.com/2020/4/22/21225333/how-long-will-recession-last-great-depression

[60] A Return to Normal: How Long Will the Pandemic Last"? University of Pennsylvania blog post at Medical Express.com July 20, 2020. (https://medicalxpress.com/news/2020-07-pandemic.html)
[61] Ibid.

may wish to consider if the AMI investment should be prioritized over other potential uses of capital. I argue that rate increases should be considered a precious resource to be called upon only when necessary. As the pandemic recession's impact on the State's budgets has clearly indicated, having some "gas in the tank" is a really good idea, and I believe the concept extends to rate increases. A poorly designed and executed AMI deployment plan has no place in any economy, but should certainly not be approved, in advance, for accelerated cost recovery in an economy as precarious as the current one.

Q. Why do you believe PSE&G's proposed AMI investment to be inappropriate for approval and cost recovery under the IIP program?

A. I understand and fully appreciate that the Board has broad discretion regarding the application of IIP cost recovery. This testimony has already revealed why the PSE&G proposal currently before the Board does not merit approval, including:

- Pre-approval via IIP transfers the risk of excess, ineffective, or imprudent investments from shareholders to ratepayers;
- IIP cost recovery reduces the need for rate cases, prompting the significant timing issue somewhat unique to AMI which will preclude more than $350 million dollars in operational benefits from reaching customers;
- AMI is not the prerequisite to "distribution automation" PSE&G would have the Board believe (IIP is authorized for distribution automation).

While I feel that any of these should disqualify AMI from IIP approval and cost recovery, there are additional arguments against IIP for AMI, including:

- AMI is not "needed for continued system safety, reliability, and resiliency, and sustained economic growth in the State of New Jersey";[62]
- AMI is not "Non-revenue producing"[63] (PSE&G's AMI proposal will grow revenues, benefitting shareholders until recognized in rates though a rate case);
- AMI does not constitute "necessary accelerated installation" of utility plants and equipment.[64]

Q. Explain why AMI is not "needed for continued system safety . . ." as specified by IIP guidelines.

A. PSE&G provides only three use case which suggest any safety improvement from AMI. Only one of these use cases (1-10) is in Release 1, meaning that PSE&G has committed to implement it. It involves the use of smart meters to detect hot sockets, and smart devices (not smart meters) to identify wires down. I know of no utilities with AMI that have implemented the hot socket customer service, and both customers and smart devices (other than smart meters) can alert utilities to downed wires.

The other two safety-related use cases are in Releases 2-4, meaning that PSE&G has not committed to implement them. One of these, Customer Safety (3-14), is already available from home security service providers like ADT, and should not be a regulated utility service. The other, related to employee safety (4-15), will result in marginal safety improvements at best, due to two reasons. First, over a five-year period from 2015-2019, PSE&G provided only 10 instances when a distribution

[62] New Jersey Administrative Code 14:3-2A.1 (b).
[63] New Jersey Administrative Code 14:3-2A.2 (a)(2).
[64] New Jersey Administrative Code 14:3-2A.1 (b)

line which was supposedly de-energized for work was actually energized in error (the subject of use case 4-15).[65] Secondly, none of these 10 incidents resulted in an injury, as standard safety procedures routinely practiced by PSE&G avoided any such incidents.[66]

Q. Explain why AMI is not "needed for continued system . . . reliability, and resilience . . ." as specified by IIP guidelines.

A. PSE&G commits to completing only a single use-case (1-16, Outage Detection and Restoration) which could improve reliability. Primary research I have personally completed indicates that the reliability and resilience benefits from this use case are extremely small.[67] In addition, PSE&G provides no estimate of reductions in system average interruption duration index (SAIDI) as a result of its AMI deployment. While many use cases in Releases 2-4 relate to maintaining reliability in some way, none of these require AMI, nor has PSE&G committed to deploying them.

Q. Explain why AMI is not "needed for . . . sustained economic growth in the State of New Jersey."

A. As indicated in the earlier section of this testimony dedicated to the costs and benefits of PSE&G's AMI deployment, the costs to customers will exceed the benefits to customers by a wide margin if deployed by PSE&G as planned. Any utility investment which does not deliver benefits in excess of costs acts as a drag on

[65] New Jersey BPU EO18101115. PSE&G response to DR RCR-E-0097.
[66] Ibid.
[67] Colorado PUC 11A-1001E. Appendix MGL-1, *SmartGridCity™ Demonstration Project Evaluation Summary*. October 21, 2011. Page 81 and page 83.

the economy within its service territory. As a result, PSE&G's AMI deployment as planned cannot possibly contribute to or preserve economic growth in New Jersey.

Q. Explain why AMI is not "Non-revenue producing".

A. I believe the IIP, properly implemented, achieves a reasonable balance between the Board's goal of reducing regulatory lag, and the Board's goal of avoiding undue shareholder enrichment at customer expense. An indication of this can be found in the IIP condition that eligible investments not produce revenues or (by implication) profits for shareholders.

As indicated earlier operational benefits, including revenue-assurance benefits, will not be recognized by customers in rates until 2029, as PSE&G is unlikely to file a rate case based on a test year which reflects these benefits until it has to. PSE&G is unlikely to do so because, until the occasion of the follow-on rate case, these revenue assurance benefits will accrue to shareholders. Several of the AMI capabilities PSE&G touts in its business case will increase PSE&G revenues from 2024 through 2028, including reductions in usage on inactive accounts, reductions in theft, and improved meter accuracy. Combined, PSE&G estimates revenue assurance capabilities will deliver [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in benefits (nominal dollars) from 2024 through 2028.[68] This surely meets the definition of "revenue producing" as intended in the IIP regulation.

[68] New Jersey BPU EO18101115. PSE&G confidential response to DR RCR-E-0001. Attachment "RCR-E_0001_PSEG Use Case Mapping – Benefits – CONFIDENTIAL.xlsx, tab "Customer Benefits Summary". All Customer Benefits less TOU Rate Benefits, 2024-2028.

Q. Explain why AMI does not constitute "necessary accelerated installation" of utility plants and equipment.

A. Metering is a routine requirement of every commodity distributor. From time to time meters must be replaced, and PSE&G's existing business practices are adequately replacing meters as they fail. Indeed, as indicated earlier, PSE&G has been replacing meters at a rate averaging more than 70,000 annually in recent years without incident. This is typical base spend. Had the 573,000 meters PSE&G has replaced since 2012 been AMI meters (see testimony page 13), those installations would have been base spend. As a result, the first 573,000 AMI meters PSE&G installs, at a minimum, should be considered base spend and excluded from IIP cost recovery. However, due to the AMI business case weaknesses as described throughout this testimony, I argue that PSE&G has not made the case that AMI represents "necessary accelerated installation" per IIP regulations.

V. The AMI Reports Prepared for the Board Overlook Critical AMI Issues.

Q. Please preview this section of testimony

A. I understand the Board has reviewed two reports authored by Navigant Consulting. Navigant (now Guidehouse) is a consulting firm that works frequently for utilities and may not be an objective provider of information to the Board. While it is unclear whether Staff or PSE&G intend to rely on these reports in this case, or whether they will be introduced or allowed into evidence, I understand that the reports have been "accepted" by the Board, and I therefore I wish to briefly explain the omissions and deficiencies which cause them to be unreliable. In this section of testimony I will identify multiple shortcomings in the two recent AMI reports Navigant has provided to the Board: 1) Its review of the Rockland Electric Company's AMI business case; and 2) Its "AMI Gold Standards" report. As a result, I recommend the Board discount the information in these reports as it considers PSE&G's petition to deploy AMI and recover the costs through the IIP.

Q. Beginning with Navigant's assessment of the AMI landscape, in a Board report titled "AMI Gold Standards", what are the omissions and deficiencies?

A. There are many. First, while Navigant's Gold Standards report briefly mentions the rejection of an AMI business case by the Kentucky PSC, it fails to report several other high profile AMI business case rejections by state utility regulators, including the Massachusetts DPU (which was favorably pre-disposed to AMI prior to the proceeding),[69] the New Mexico PSC,[70] and the Virginia SCC.[71] All three rejections were the result of the regulators' assessments that insufficient benefits relative to costs were presented in utilities' AMI deployment plans. This information should have been included in any objective report on AMI and would have been very valuable to the Board.

Q. Were there other oversights?

A. Yes. For example, the Gold Standards report makes no mention of how to maximize the benefits of an AMI deployment, including best practices in the design and

[69] Massachusetts DPU 15-120 to 15-122. Order dated May 10, 2018. Pages 1-5.
[70] New Mexico PSC Case No. 15-00312-UT. Order dated April 11, 2018.
[71] Virginia SCC Case No. PUR-2018-00100. Order dated January 17, 2019. Pages 5-6 and pages 7-9.

marketing of AMI-related energy efficiency programs or time-based rates. Nor does the Gold Standards report provide any performance benchmarks on reliability improvements, operational benefits, or customer program participation related to AMI, or recommend any AMI performance measures. Also missing from the Gold Standards report are the use cases I described earlier as missing from the PSE&G AMI deployment plan, including compliance with Green Button's Connect My Data standard, the use of AMI data in DSM program impact measurement, and default Peak-Time Rebate.

Q. Do you have other critiques of the Gold Standards report?

A. Yes. For a review ostensibly directed at AMI, the Gold Standards report seems to spend a lot of time on distribution automation. Like PSE&G's AMI proposal, the Gold Standards report appears to imply that AMI is a prerequisite to distribution automation, and none of the alternatives available to deploy distribution automation without AMI, as I described earlier in this testimony, are presented. Nor does the Gold Standard report make any mention of how to address the stranded costs created by rapid smart meter deployments, though the stranded cost issue is significant in this proceeding, as it is in many AMI proceedings. Finally, for a report that appears to focus significantly on AMI technologies, I note not a single sentence devoted to AMI communication network options and decisions. Such decisions are a significant aspect of any AMI deployment plan. In my experience, the communications network is a critical limiter or enabler of AMI capabilities and benefits. Further, I believe that utility communications network choices are unduly influenced by capital bias, particularly as we enter the "internet of things" era, with more advanced offerings from public network providers announced almost daily. That this issue was completely avoided by the Navigant report is one more piece of evidence that the report fails to provide a complete picture of the AMI landscape.

Q. You have also reviewed Navigant's report on Rockland Electric's AMI business case, correct?

A. Correct. I find multiple omissions and deficiencies in that report, referred to as the Capstone Report, as well. Perhaps most significant of these is Navigant's failure to examine the actual benefits delivered by Rockland Electric's AMI deployment. It seems to me that any evaluation of business case quality should compare the benefits projected in the business case to the benefits actually delivered.

Q. Could such a comparison have been outside the project scope authorized by the Board?

A. Possibly. But to not even reference the need to examine actual benefits delivered as part of a business case evaluation seems to me to be a deficiency. In addition, there are multiple other deficiencies. For example, Navigant's Capstone Report makes no mention of the understatement of costs due to the exclusion of the carrying charges Rockland Electric customers will pay for the AMI deployment over 20 years. As I discussed earlier in this testimony, a benefit-cost analysis supposedly developed from a customer perspective which fails to consider the significant carrying charges customers will pay on the investments over time is wholly inappropriate. The Capstone Report also ratifies the 20-year benefit period the business case associates with AMI meters, despite assertions in Navigant's contemporaneous Gold Standard report which indicates that a more appropriate benefit period for AMI meters is 12-15 years.[72]

Q. Do you have other criticisms of Navigant's Capstone Report?

A. Yes. There are other indicators that the Capstone Report was a less than rigorous examination of Rockland Electric's AMI business case. For example, my examination of the business case identified that projected meter reading cost reductions were 64% greater than actual meter reading department spending prior to the AMI deployment.[73] My testimony also identified that many operating expense reductions were unsupported by headcount reductions, making such reductions highly unlikely.[74] Navigant's examination of the Rockland AMI business case did not catch either of these clear deficiencies.

VI. Review and Recommendations

Q. Please review your testimony

A. This testimony demonstrates that:

1. The benefits to customers of the AMI deployment as proposed by PSE&G will not exceed AMI costs to customers;
2. AMI is not the prerequisite to distribution automation PSE&G would have the Board believe, as an evaluation of Releases 2 through 4 makes clear;

[72] Elberg R and Kelly M. *AMI Gold Standards Report*. Published 4Q 2019 by Navigant Research. Page 33.
[73] New Jersey BPU ER19050552. Direct Testimony of Paul J. Alvarez dated October 11, 2019. Page 12 at 13.
[74] Ibid, page 15 at 9.

3. Given questionable customer value, current economic conditions, and questionable qualifications, the Board should not allow IIP recovery for AMI;
4. The Navigant AMI reports to the Board overlook critical AMI issues.

Q. What do you conclude from these findings?

A. I recommend the Board reject PSE&G's request for prior approval to deploy advanced metering infrastructure (AMI) and recover the costs through the Infrastructure Investment Program (IIP). I understand the Board's inclination to get AMI installed in New Jersey, and to make progress on the Energy Master Plan among other goals. However, PSE&G proposes to roll out AMI in a manner that unduly increases costs to customers, and manages the timing of benefit delivery, to the point where the costs significantly outweigh the benefits of AMI. As a result, I believe the Board has no choice but to reject the request for preapproval of the AMI investment. While I do not believe the proposed program meets the eligibility requirements for IIP, PSE&G of course retains the ability to replace its existing meters with AMI in the normal course of business subject to prudency review in a rate case.

Q. How do you recommend the Board ensure AMI deployments in New Jersey are in the best interests of electric customers and the state's economy?

A. Guidelines for benefit-to-cost analyses would certainly be an excellent starting point. But I suggest the Board focus the bulk of its efforts on post-deployment, outcomesoriented performance measurement. IIP regulations provide for such efforts.[75]These would generally compare conditions and performance or benefit projections pre-deployment to conditions and performance post-deployment. This examination, essentially an audit, would quantify the extent to which AMI actually delivers:

- Operating expense reductions in various departments post-deployment
- Headcount reductions in various departments post deployment
- Improvements in reliability measures
- Various revenue assurance improvements, from reduced usage on inactive accounts and reduced bad debt write-offs to increases in theft detection.
- Program-specific benefits, such as customer participation in time-based rates, or average annual voltage reductions by circuit for automated conservation voltage reduction.

Given that Rockland Electric has already completed its AMI deployment, an excellent opportunity to conduct such an audit already exists. I cannot imagine why the Board would not want to fully understand the benefits delivered by an existing AMI deployment before pre-approving another AMI deployment, particularly one which I estimate will cost PSE&G customers $1.884 billion over the next 20 years.

Q. Are there actions beyond performance measurement you would recommend?

A. Yes. I recommend the conventions established by regulators in Ohio and Oklahoma regarding operational benefits which will not be recognized without a rate case be adopted in New Jersey, as the Board has already ordered in PSE&G's Gas IIP petition. As described earlier, this convention is to reduce the revenue requirement

[75] New Jersey Administrative Code 14:3-2A.5.2.

by the amount of the operational benefits a utility anticipates in its AMI business case by year. This approach holds utilities accountable for the timing and size of projected operational benefits, at least until the follow-on rate case, at which point the performance measurement efforts described above would be implemented.

In addition, for any AMI deployment which might be approved, I urge the Board to actively preserve in its orders all existing consumer protections, specifically including disconnection for non-payment protections. I think it critically important that the improved ease with which AMI enables utilities to disconnect service remotely does not result in any shortcuts. The in-person visit prior to disconnection for non-payment should be retained, for example, despite AMI's remote service disconnection capability.

I also recommend, for any AMI deployment which might be approved, restoration of the three missing use cases I described earlier, including compliance with the Connect My Data standard; the use of AMI data to improve DSM program impact measurement; and the implementation of a default Peak-Time Rebate program. Further, should any utility with AMI propose a pre-payment program (PSE&G use case 2-8), I believe distinct proceedings should be required such that stakeholder concerns regarding the design and administration of such programs can be adequately addressed.

Q. Does this conclude your testimony?

A. Yes, it does, though I would like to reserve the right to provide surrebuttal testimony for the Board's consideration in response to any rebuttal PSE&G might provide.

APPENDIX

Appendix PJA-1: Curriculum Vitae of Paul J. Alvarez

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer and environmental advocates, regulators, associations, and suppliers.

Appearances and Research Projects in Regulatory Proceedings

Critique of Oklahoma Gas & Electric's $810 Million Grid Enhancement Plan. Testimony before the Oklahoma Corporation Commission on behalf of AARP. OCC PUD 202000021 dated August 25, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017.

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 to be published September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Smart Grid Regulation: Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Appendix PJA-2: Rate Counsel AMI Cost Estimate Adjustment

Rate Counsel AMI Cost Estimate Adjustment			ESTIMATED CUSTOMER PAYMENTS		
	Nominal Value	Present value	Year	Estimated Customer Payments in Millions of $	Assumption
"Costs" per PSEG	785	641			
			2022	1.4	
Estimated Customer Pmts '22-'40*	1,884	1,085	2023	24.5	Rate Case test year ending 12/31/2023. IIP amounts added to rate base for new rates 1/1/2024.
Less: Costs per PSEG	(785)	(641)	2024	117.1	New rates 1/1/2024; amort of old meter book value part 1 begins; recovery of deferred O&M costs begins in July
Rate Counsel Cost Estimate Adjustment	1,099	444	2025	149.4	Last IIP increase hits in October (AMI deployment completed)
			2026	161.1	
Customer Costs per Rate Counsel	1,884	1,085	2027	161.1	
* Includes amortization of $216 million in stranded costs net of ADIT			2028	161.1	Rate case test year ending 12/31/2028; amort of old meter book value part 1 ends; remaining IIP added to rate base
			2029	131.4	New rates 1/1/2029; amort of old meter book value part 2 begins; recovery of deferred O&M costs ends in June
			2030	123.8	
Assumptions used for estimated customer payments			2031	123.8	
Weighted Ave. Cost of Debt	3.96%		2032	123.8	
Discount Rate:	6.48%		2033	123.8	Rate case test year ending 12/31/2033; amort of old meter boof value part 2 ends
Autorized Rate of Return	9.60%		2034	74.9	New Rates 1/1/2034
Debt to Equity Ratio	46.00%		2035	74.9	
Revenue Factor Applied to Authorized ROR	1.3946		2036	74.9	
New Jersey Sales and Use Tax	6.25%		2037	74.9	
Effective NJ + Federal Tax Rate	28.11%		2038	74.9	Rate case test year ending 12/31/2038
IIP rate increases per Swetz testimony workpaper schedule SS-CEF-EC-3			2039	53.7	New Rates 1/1/2039
Rate Cases called using test years 2023, 2028, 2033, and 2038			2040	53.7	
			TOTAL PAYMENTS	1,884.0	

Appendix PJA-3: Rate Counsel AMI Benefit Estimate Adjustment

Rate Counsel AMI Benefit Estimate Adjustment						
	Nominal Value	Present value				ESTIMATED CUSTOMER BENEFITS
					Estimated Customer	
Benefits per PSEG	2,054	887		Year	Benefits in Millions of $	Assumption
				2022	-	
Estimated Customer Benefits '22-'40*	1,450	627		2023	-	
Less: Benefits per PSEG	(2,054)	(887)		2024	[redacted]	Time-of-use rate benefits begin
Rate Counsel Benefit Estimate Adjustment	(604)	(260)		2025	[redacted]	
				2026	[redacted]	
Customer Benefits per Rate Counsel	1,450	627		2027	[redacted]	
* includes no operational benefits 2024-2033 due to rate case timing differences				2028	[redacted]	
				2029	[redacted]	Rate case using 2028 test year; operational benefits first recognized in rates
				2030	[redacted]	
Estimated customer benefit assumptions:				2031	[redacted]	
Discount Rate:	6.48%			2032	[redacted]	
Rate Cases called using test years 2023, 2028, 2033, and 2038				2033	[redacted]	
				2034	[redacted]	Rate case using 2033 test year (operational savings increase due to inflation)
				2035	[redacted]	
				2036	[redacted]	
				2037	[redacted]	
				2038	[redacted]	
				2039	[redacted]	Rate case using 2038 test year (operational savings increase due to inflation)
				2040	[redacted]	
			TOTAL BENEFITS		[redacted]	

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2	1	Customer demand response (control of residential customers' loads, duplicate of 2-10))	PSEG's iESP infrastructure can provide information on energy use as well as alerts and updates and price signals, which, in conjunction with customer displays, the internet, cell phones, email, and text can alert customers and control devices (thermostats, smart appliances, water heaters) based on their demand response set-up. This use case also deals with the analytics around calculating the real-time energy information (usage, pricing, etc.) to participating customers to enable better demand decisions. The information can also be used in home or commercial/industrial building automation applications. In this case PSE&G would send dynamic pricing or device signals (perhaps real-time) to respond to a variety of drivers (CO2, feeder loading, major event, etc.) to request a customer's response or curtailment service. This use case is designed to contribute to energy, fossil fuel and carbon reductions.		X		X		X
2	2	Asset Management & Health (Prospective Asset Replacement, same as 3-14)	Using advanced asset analytics to enable smart asset management capabilities and become increasingly more focused on monitoring and predicting system health and deficiencies, and ensuring that all operations, investments and maintenance decisions are correct based on in-depth analysis and evaluation of detailed asset-level health and risk data. Being able to manage assets and integrated data (asset, condition, load, voltage, maintenance, etc.) in real time from a health and risk point of view is now a significant area of development in the industry.	X	X	X			X
2	3	Reliability Analysis, Optimization, & Cost/Benefit (Outage Management System & Geo Information System; duplication of 1-6 & 4-7)	Reliability analysis and optimization uses the network model, outage and iESP data to provide planning and upgrade advice to improve system reliability. It provides the ability to analyze outages over specified timeframes, jurisdictions, asset hierarchy (substation, main line conductor or trunk, switches, transformers, laterals, fuses, meter), and outage types, to review the impacts of outages on SAIDI, SAIFI, provide improvement options based on cost or risk, and cost benefit analysis.	X	X	X			X
2	4	Distributed Generation Analysis	Various technical and economic issues occur in the integration of distributed generation resources into a grid. Technical problems arise in the areas of power quality, voltage stability, harmonics, reliability, protection, and control, which require detailed analysis. This use case covers the establishment of the process, applications and analytics required to manage the behavior of network assets on the grid for all combinations of distributed energy generation locations. iESP level data is now critical to the effectiveness of this use case.		X	X		X	
2	5	System Planning Investment Portfolio (distribution planning)	System Planning & Investment are a core part of a utility's business and would be deployed in the planning and development of the distribution networks. This use case and its analytics would use iESP data with other information to cater for the growth in DER connections and help manage/optimize the capital investment program to ensure that the electricity networks remain fully compliant with the technical and regulatory requirements. The objectives here are to continuously improve the safety, security, reliability and capacity of the distribution networks, optimize the performance and condition of the existing assets, analyze the capability of the network to accommodate both demand and high volume of generation connections, provide innovative technical solutions, and produce analytic outputs (plans, cost/benefits) to support design and delivery teams and ensure the network is developed in the most economic, efficient and coordinated manner to meet customer requirements.	X	X	X			

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2	6	Distribution Automation/ADMS (grid operations; duplicate of 3-9, 3-13, and 3-16)	The extension of intelligent monitoring and control over electrical power grid functions to the lowest network level (i.e., the iESP meter). The goal of Advanced Distribution Automation is real-time adjustment to changing loads, generation, and failure/outage conditions of the distribution system, usually without operator intervention. This necessitates control of field devices, which implies enough information technology (IT) development to enable automated decision making in the field and relaying of critical information to the utility control center. The IT infrastructure includes real-time data acquisition and communication with utility databases and other automated systems. Accurate modeling of distribution operations supports optimal decision making at the control center and in the field.	X	X	X			X
2	7	Street-Lighting Remote Operations ("Internet of Things" Communications Services)	Use of the iESP Infrastructure to enable: - Remote control of lumens output of networked streetlights allows for the streetlight operators to remotely increase or decrease the lumens output of streetlights depending on various operational considerations. For example, perimeter lights around malls may be dimmed after hours to save energy and reduce light pollution complaints. Conversely, lights around stadiums or popular late night meeting spots may be increased / strobed to assist in crowd control. Motion activated perimeter lights may also provide a certain level of deterrence against potential intrusions. - Remote monitoring of health leverages the communications capabilities of smart streetlights to allow operators to remotely determine the operating status of a particular streetlight without having to resort to either sending out night time patrol crews, or depending on customers to report particular outages.	X	X	X	X		
2	8	Customer Pre-Pay (AMI installed on specific loads or resources)	Customer service can use the ability of prepay programs to improve the customer choice and experience, and potentially assist deposit management. Prepay energy service allows consumers to pay in advance for utility services, to monitor their usage and account balance daily, and to manage their usage in a manner that is consistent with their household or property usage profile. Access to daily information can facilitate direct customer energy management. Pre-pay also allows customers the choice of when to consume in the case of transient properties – RV Parks, marinas, lake houses, etc... The spread of smart meters has resulted in opportunities for these new services.		X		X		
2	9	New Tariff Development (Time-based pricing; duplicate of TOU in Release 1 as well as 2-13 and 4-3)	Using customer segmentation, smart meter and market data - use pricing simulations to design and implement TOU rates that suit the regulated revenue frame, next generation and customer expectations. – Time-of-Use, Demand, DER specific pricing, market pass through, etc. This would also include support for new products and services and is heavily dependent on Customer Segmentation.		X				X

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2	10	Customer Smart Home/Appliances/Devices **(Control of residential customer's loads; duplicate of 2-1)**	This Use Case relates to potential contribution of iESP data and infrastructure to support Home Energy Management Systems (HEMS) and more broadly the Smart Home. This objective is to utilize iESP meter data in combination with other behind the meter communications and smart devices - outlets, home Assistants (Alexa, Google Home, Home Pad), thermostats, appliances, etc., in combination with advanced analytics and visualizations that help the customer better engage with and manage their energy usage and other smart home functions (security, internet, etc..). The iESP network could be leveraged here as long as capacity and connectivity is available. In the event of a demand response request from the Utility, this would also include potential infrastructural support for optimal control/scheduling of DERs and automatic control of smart devices/appliances (thermostats, dishwasher/washing machines, water heaters, etc.)		X		X		X
2	11	iESP Network as a Service ("Internet of Things" Communications Services)	This Use Case is intended to cover new business opportunities that could leverage the capabilities of the iESP data and infrastructure in an "as a service" mode to customers, other utilities, municipalities, communities or cities. Network as a Service – provision of the PSE&G iESP network capabilities to enable municipalities to connect their smart meters and provide smart services	X	X		X		
2	12	iESP Data as a Service (Meter data and distribution management software as a service)	This Use Case is intended to cover new business opportunities that could leverage the capabilities of the iESP data and infrastructure in an "as a service" mode to customers, other utilities, municipalities, communities or cities. Data as a Service – provide iESP network and data services that mange both the smart meter device and meter data on behalf of the municipality.	X	X		X		
2	13	Critical Peak Pricing **(Time-based pricing; duplicate of TOU in Release 1 as well as 2-9 and 4-13)**	• Critical Peak Pricing: is a construct under which a utility can call a critical event when it anticipates or experiences high wholesale market prices or emergency system conditions and raise the rate. CPP rates can be fixed at a predetermined rate for each critical event or vary based on system demand during the critical event. CPP rates are designed to reduce a customer's consumption on a limited number of days when critical events occur. • Critical Peak Rebates: these are offered when a utility calls a critical event during pre- specified time periods (e.g., 3 pm - 6 pm summer weekday afternoons) in response to anticipated or observed high wholesale market prices or emergency system conditions. The price for electricity remains the same during these periods but the customer is refunded at a single, predetermined value for any reduction in consumption as determined by the difference in what the utility deemed the customer was expected to consume and their actual consumption.		X				X
2	14	Demand Response Control **(Conservation Voltage Reduction utilized during peak demand; duplication of 2-14; should be in Release 1)**	Demand Response Control is the automation of control functions that control DR mechanisms and devices in the field (with appropriate oversight). It is heavily dependent on the Demand Response Planning.		X	X			X

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2	15	Conservation Voltage Reduction/Optimization (duplicate of 2-14; should be in Release 1)	Conservation Voltage Regulation (CVR) is a technique for improving the efficiency of the electrical grid by reducing voltage on the feeder lines that run from substations to homes and businesses. CVR permanently lowers the voltage at which electrical power is delivered and yields an average of 0.6-0.8% energy savings for each 1% in voltage reduction down to 114V. AMI plays an important role in CVR by providing end-point voltage data (with certain customer meters set up as bellwether meters) to help analyze, lower and then monitor voltage levels on the circuit/feeder. With AMI in place CVR can be implemented with manual adjustments to tap changers, voltage regulators and capacitors. This would be enhanced by VVO but is not dependent on it. VVO is an extension of CVR in that it is the dynamic management of voltage and power quality. Where CVR is focused on conservation and involves permanent changes, VVO is focused on power quality, is far more dynamic in nature and can be supported by some level of distribution automation. VVO can also result in increases or decreases in voltage depending on the power quality issue. VVO can provide the monitoring and adjusting role for CVR and would allow a more aggressive reduction approach given some level of automation. With new technology it is now far less expensive to save energy at the point of consumption, than it is to increase the capacity of the grid or create additional generation		X	X			X
3	1	Smart Cities ("Internet of Things" Communications Services)	This Use Case is intended to cover the iESP data and infrastructure support contribution for any NJ or PSE&G Smart City initiatives, which have data and infrastructure needs and dependencies far broader that iESP. A smart city is an urban area that uses different types of electronic data collection sensors to supply information which is used to manage assets and resources efficiently. This includes data collected from citizens, devices, IoT, and assets that is processed and analyzed to monitor or manage traffic and transportation systems, environmental issues, power plants, water supply networks, waste management, law enforcement, information systems, schools, libraries, hospitals, parking, lighting, floods, and other community services.	X	X		X		
3	2	Microgrids (Microgrid management; AMI installed on specific loads or resources; duplicate of 4-13)	This Use Case is intended to cover the iESP data and infrastructure support contribution for microgrid initiatives, which has data and infrastructure needs and dependencies far broader that iESP. A microgrid is a localized group of electricity sources and loads that normally operates connected to and synchronous with the traditional centralized electrical grid (macrogrid), but can also disconnect to "island mode" — and function autonomously as physical and/or economic conditions dictate.	X	X	X		X	X
3	3	Innovative Products & Services (Duplicates 2-1, 2-9, 2-10, 2-11, 2-12, 2-13, 3-1, 3-5, 3-12, 4-1, 4-2, and 4-3)	The introduction of new and innovative products/services that are either new, or an improved version of current offerings. These new PSE&G products and services will leverage IESP data and network and look to deliver these in the key areas of Smart Customer, Home and City areas.	X	X		X		X
3	5	Distribution/Bi-Directional Marketplaces	Support of a transparent and unified distribution (or peer to peer) market for customers, DERs and other third-party products & services across the state that are animated and fully transactive. The extent to which PSE&G can use its iESP platform to support these new markets will largely depend on the strength of its foundational capabilities to better understand customers and communities.	X	X			X	
3	4	Customer Gamification (contests) & Loyalty Programs	Customer side analytics and algorithms that use iESP and other market and household data to encourage education and gaming among customers. Analytics that assist in the design, management and evolution of customer loyalty programs (points, tiers, rewards)	X	X	X	X		X

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3	6	Asset Performance, Maintenance & Visualization **(Distribution equipment monitoring)**	Manufacturers' recommendations, models, estimates and visual inspection are typically used to determine when maintenance work should be done. However, it is not always known which assets are overloaded or often stressed on the distribution system. When iESP information is available and used to do asset loading analysis and other data analysis, work can be more accurately designed and scheduled. Predictive maintenance is a key component of a maintenance regime that involves using software for real-time monitoring of equipment health and comparing its current operational state to a model that defines normal or ideal operating conditions. Predictive analytics software uses advanced algorithms to detect subtle operational variances for each piece of equipment, which often warn of impending problems that might have gone unnoticed otherwise. Utilities can create automated alarm notifications and use the software to diagnose the source of equipment and system anomalies, in addition to prioritizing issues based on severity.	X	X	X			
3	7	Load Curtailment / Limiting **(Grid operations)**	An automated Load Curtailment Application detects predetermined trigger conditions in the network and performs predefined sets of control actions, such as opening or closing non- critical feeders, reconfiguring downstream transmission or sources of injections, or performing a tap control at a transformer. When a network is complex and covers a larger area, emergency actions taken downstream may reduce burden on upstream portions of the network. In a non-automated system, awareness and manual operator intervention play a key role in trouble mitigation. If the troubles are not addressed quickly enough, they can cascade exponentially and cause major catastrophic failure.	X	X	X			
3	8	Advanced (Automated) Outage Detection & Location (duplicate of 1-16, "Outage Detection and Analysis")	Uses the network model, advanced algorithms, and fault signals, SCADA (sensor) and smart device measurements to automatically identify possible outage locations, network sections that are out and protection devices that operated. E.g. fuse blowout, recloser operation. Data is geospatially displayed in real-time, to allow fast response and crew dispatch to the precise location with information on the cause of the outage in order to restore power quickly. Automatically identify the number of customers affected by the outage, verify the outage/restoration by automated pinging devices and track the restoration in real-time. Improves response time to outages as well as proactively notifying customers through integration to other systems such as IVR, CIS, and OMS.	X	X	X			X
3	9	Automated Fault Isolation & Restoration (FLISR) – Self Healing **(grid operations; duplicate of 2-6)**	Isolates faults, perform automated switching actions to isolate faults and restore maximum number of customers. Ensures switching actions during restoration are safe and do not cause overloads or extreme voltage conditions in the system. Generates and displays ranked, ordered restoration, system restoration solutions, together with specific sequenced steps in real-time. Integrates DER and storage dispatch with system constraints, and safe operations objectives, for a safer, more complete system restoration decision-making process. Allows for any combination of decentralized and centralized automation.	X	X	X			X
3	10	Volt/VAR Control	Volt/VAR Control or VVC refers to the process of managing voltage levels and reactive power throughout the power distribution system. Benefits: minimize feeder loss, maximize feeder power factor, minimize feeder voltage profile for variable consumption, and provide VAR support for transmission system. Volt/VAR application monitors system to determine if it's operating efficiently, and automatically operates field equipment to bring the system back into an optimized state if it goes out of the system parameters initially set by the operator.		X	X			

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3	11	Customer Safety (**"meter pinging" component duplicates 1-16, 3-8, and 4-7)**	Assess reliability, service and safety impacts at a customer or meter/sensor level (gas leaks, flooding, CO2, etc.). Allows proactive identification of premise level reliability and safety concerns. Direct grid investments to customers with greatest outages. Cost effectively monitor reliability and safety goals. With iESP systems, Customer Service Representatives at the call center may be able to ping a customer's meter to determine whether or not it has voltage or there is any safety issue. This allows the representative to offer better advice on what to do in the current situation. iESP can sense and report issues when no one is present on premises. Utilities can use this information to notify customers of interruptions, in a manner of the customer's choice.				X		X
3	12	Permanent Power Quality Management **(Power Factor Services for Customers)**	The purpose of the permanent power quality measurement enterprise activity is to provide long-term and continuous monitoring in order to provide reliability and benchmarking statistics. Many customers which can include utilities and large consumers of electric power have a need for an installed permanent power quality measurement system. Historically, power quality meters were portable and installed on a temporary basis in order to capture, diagnose and solve a specific problem that might be occurring in the facility. However, with increased demands for power quality and reliability benchmarking, power quality contracts, billing and energy use verification, predictive maintenance and others, the need and demand for permanent power quality monitoring has increased dramatically in recent years.	X	X		X		
3	13	Utility, Customer, & Community Energy Storage, grid Level (AMI installed on specific loads or resources; duplicate of 2-6, 3-9, and 3-16)	Grid energy storage (also called large-scale energy storage) is a collection of methods used to store electrical energy on a large scale within an electrical power grid. Electrical energy is stored during times when production (especially from intermittent (utility and customer) power plants such as renewable electricity sources such as wind power, solar power) exceeds consumption, and returned to the grid when production falls below consumption. iESP data and sensors can be utilized to manage and optimize the bi-directional flows inherent with this DER technology.	X	X	X		X	X
3	14	Asset Risk Analysis and Risk Scoring **(Prospective Asset Replacement; Duplicate of 2-2)**	Risk Based Asset Management (RBAM) is an optimal maintenance business process used to examine energy network equipment such as feeders, poles, transformers, etc. It examines the health, safety and environment and business risk of 'active' and 'potential' damage mechanisms to assess and rank failure probability and consequence. This ranking is used to optimize inspection intervals based on site-acceptable risk levels and operating limits, while mitigating risks as appropriate. RBAM analysis can be qualitative, quantitative or semi-quantitative in nature and may also include financial or market risk variables. Smart devices across the network provide key data into the analytics of this process.	X	X	X			X
3	15	Optimal Switch / Recloser Placement	Optimal placement of protection devices and DERs in radial feeders is important to ensure power system reliability. This use case has specific algorithms that determine the optimal position of ACR's (individual or as part of an ASR scheme) on feeders on the network.	X	X	X			

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3	16	Dynamic Circuit Reconfiguration **(grid operations, duplicate of 2-6, 3-9, and 3-13)**	In the use case, a fault occurs on the distribution system and the Fault Clearing Device clears the fault. The Fault Clearing Device sends the lock out signal to the Circuit Reconfiguration Controller (CRC). The CRC sends the lock out information to the Distribution SCADA (D-SCADA)/ Distribution Management System (DMS), the OMS, and Distribution Historian (SCADA history). The CRC sends an abnormal control area configuration status to any applicable Volt/VAR Controller. By polling the various smart devices, the CRC is able to perform a fault isolation calculation to isolate the fault. The CRC then sends a device command to the Isolation Device which acknowledges the command and performs the functions needed to isolate the fault. These events are monitored in the D-SCADA through regular polling of the devices. The CRC eventually calculates the reconfiguration scenario and sends the commands to the Reconfiguration Device which acknowledges the commands. After the Reconfiguration Device functions, it sends an update to the CRC which sends all equipment status updates to D-SCADA.	X	X	X			X
4	1	Load Control, Adjustment, Optimization, & Contingency **(Control of commercial customers' loads, duplicate of 4-2)**	This Use Case places the "on-off switch" in the hands of the consumer using devices such as a smart grid controlled load control switch. While many residential consumers pay a flat rate for electricity year-round, the utility's costs actually vary constantly, depending on demand, the distribution network, and composition of the company's electricity portfolio. The application of load control technology continues to grow today with the sale of both radio frequency and powerline communication based systems. Certain types of smart meter systems can also serve as load control systems. Charge control systems can prevent the **recharging of electric vehicles during peak hours. Vehicle-to-grid systems can return electricity from an electric vehicle's batteries to the utility, or they can throttle the recharging of the vehicle batteries to a slower rate.**	X	X		X		X
4	2	Customer Building Automation Optimization **(Control of commercial customers' loads, duplcage of 4-1)**	Managing the energy and other needs in buildings efficiently and intelligently can have considerable benefits. A building energy management system (BEMS) is a sophisticated use case to monitor and control the building's energy needs. Next to energy management, the system can control and monitor a large variety of other aspects of the building regardless of whether it is residential or commercial. Examples of these functions are HVAC, lighting or security measures. BEMS technology can be applied in both residential and commercial buildings. The effectiveness of BEMS are greatly enhanced by the availability of smart devices and data at the building and equipment level and enable demand response and other energy efficiency capabilities	X	X		X		X
4	3	Real-Time-Pricing **(Time-based rates; duplicate of TOU in Release 1 as well as 2-9 and 2-13)**	The purpose of the Real-Time Pricing use case is to implement and manage a full scale distributed computing system that integrates key industry operations and permits customers to plan and modify their load and generation in response to price signals in "real- time" (operational timeframe which can range from seconds to days ahead), received from an energy services provider who acts as a facilitator and platform provider for the market.		X				X
4	4	Storm/Lightning Analysis **(Outage Management System and Geographic Information System; duplicates 2-3)**	Leveraging investments in iESP Infrastructure that give utilities near-real-time readings on the health of their electric grid. The capability to use this and storm/lightning data in causal and predictive analysis can equip utility engineers and dispatchers to predict which assets will be affected by storms while optimizing the placement of crews, thus decreasing outage restoration times. Combined with geospatial visualization weather data and integrated statistical algorithms, the utility can be more prepared and shorten outages from weather events and identify weak points in the electrical distribution system thus preventing future outages.	X	X	X			X

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New Jersey BPU Docket 18101115
Exhibit PJA-4

Release	Use Case	PSEG Consultant Name (Rate Counsel Categorization If Different and/or Clarifying)	PSEG Consultant Description	Research support for the technical need or economic benefit of the use case, or AMI data, does not exist	(Universal) AMI not a prerequisite, or use distribution equipment to onitor and report grid state	AMI might help, but alternatives available and/or SEG already performs today	Service available in market, or should be market based, or no emonstrated market need.	Need may materialize, but if so, is far in future & can be met by gradual AMI deployment	Duplicate of another use case
4	5	Vegetation Management	"Predictive maintenance for trees". Factors such as annual growth rates, tree species, feeder construction type, and network configuration can be taken into account to achieve optimal reliability.	X	X				
4	6	Environmental / Sensitive Area Analysis	Analytics that assist the mapping of environmentally sensitive areas (flora, fauna, etc.) in combination with iESP for other key planning functions (reliability, voltage, etc.)	X	X				
4	7	Storm Prediction **(duplicates 1-16 and 3-8)**	See Storm Analysis - This Use case would operate in real time and allow pro-active planning of network and field resources, based on damage and outage assessments.	X	X	X			X
4	8	Advanced DER Planning & Management (DERMs -- AMI installed on specific loads or resources)	The Advanced Distribution Automation System Function performs a) data gathering, along with data consistency checking and correcting; b) integrity checking of the distribution power system model; c) periodic and event-driven system modeling and analysis; d) current and predictive alarming; e) contingency analysis; f) coordinated Volt/VAR optimization: g) fault location, isolation, and service restoration; h) multi-level feeder reconfiguration; i) pre-arming of RAS and coordination of emergency actions in distribution; j) pre-arming of restoration schemes and coordination of restorative actions in distribution, and k) logging and reporting. These processes are performed through direct interfaces with different databases and systems, (EMS, OMS, CIS, MOS, SCADA, AM/FM/GIS, AMS and WMS), comprehensive near real-time simulations of operating conditions, near real-time predictive optimization, and actual real-time control of distribution operations.	X	X	X		X	
4	9	Control of Customer DERs (AMI installed on specific loads or resources)	The purpose of this Use Case is to stabilize power quality in a power distribution system with a large percentage of PV output. Commercial buildings with large demand can contribute to stabilize power quality by controlling demand of the building. Building energy management systems (BEMS) can control DERs and HVACs in response to DR signals from a utility EMS. There are three scenarios: 1) BEMS makes an operation schedule for DERs and HVAC equipment based on PV output prediction and building load prediction, 2) BEMS controls DERs and HVACs or building loads according to the operation schedule planned in Scenario 1, and 3) when BEMS receives a DR signal for islanding operation during DR mode in scenario 2, BEMS switches the system to islanding operation.	X	X		X		
4	10	**Control of Customer HVAC Equipment (Control of commercial customer loads)**	The purpose of this Use Case is to stabilize power quality in a power distribution system with a large percentage of PV output. Commercial buildings with large demand can contribute to stabilize power quality by controlling demand of the building. Building energy management systems (BEMS) can control DERs and HVACs in response to DR signals from a utility EMS. There are three scenarios: 1) BEMS makes an operation schedule for DERs and HVAC equipment based on PV output prediction and building load prediction, 2) BEMS controls DERs and HVACs or building loads according to the operation schedule planned in Scenario 1, and 3) when BEMS receives a DR signal for islanding operation during DR mode in scenario 2, BEMS switches the system to islanding operation.	X	X		X		X
4	11	Battery Aggregation & Control **(AMI installed on specific loads or resources)**	In a future where there is a high penetration of fluctuating energy sources, the demands on temporary storage will tend to become intensified. This use case describes interactions between the Grid operator, Grid EMS, Battery SCADA, Battery SCADA Operator and Stationary Batteries during online power system control for Battery Aggregation. Battery SCADA is used to control distributed Stationary Batteries as a Virtual Battery in two scenarios: for load frequency control by battery aggregation and for reserve margin by battery aggregation. This Use Case uses interoperable communications protocols to control all the aggregated storage units on the grid.	X	X		X		

Summary Evaluation of AMI Use Cases Described, But Not Committed to, in PSEG Petition

New Jersey BPU Docket 18101115
Exhibit PJA-4

Release	Use Case	PSEG Consultant Name (Rate Counsel Categorization If Different and/or Clarifying)	PSEG Consultant Description	Research support for the technal need or economic benefit of the use case, or AMI data, does not exist	(Universal) AMI not a prerequisite, or use distribution equipment to onitor and report grid state	AMI might help, but alternatives available and/or SEG already performs today	Service available in market, or should be market based, or no emonstrated market need.	Need may materialize, but if so, is far in future & can be met by gradual AMI deployment	Duplicate of another use case
4	12	PV/DER Output Forecasting/Backcasting (AMI installed on specific loads or resources; distribution planning)	This Use Case describes the sequence of activities required for forecasting generation and load by segment on the distribution system. An accurate load/generation forecast is essential for the operation of the system at high penetration levels. The DER forecast is based primarily on a detailed weather forecast, since weather influences both the loads and the generation. But typical weather regional forecasts do not meet the needs of predicting energy flows on discrete distribution line segments. It will be necessary to do microclimate forecasts for smaller zones within the region. Actual implementation of this Use Case's equence may require multiple iterations in order for the system to converge on a solution, at which point the DERC at the substation or lower level have some autonomy to maintain stability and respect the limits of the power system (i.e. they will have a pick list by resource by segment with weighting). This use case will calculate the output for various behind the meter DER sources (i.e. solar panel installation) for given project specific modelling parameters (i.e. panel orientation, power factor corrections) and weather data (i.e. solar irradiation or wind speed). This generation output data, in conjunction with iESP load data (net load data), can be used to determine the gross load on a particular feeder. Gross load data may be more helpful to plan for the worst case scenarios for contingency / planning purposes.		X			X	
4	13	Real-Reactive Load-Voltage Management (Microgrid management; duplicate of 3-2)	This Use Case a) performs periodic and event-driven information exchanges between the EPS operator/DMS and microgrid operator/EMS about the aggregated reactive load and generation dependencies on voltage within the voltage ranges under normal operating conditions and b) provides the Electric Power System operator with relevant data for post- factum analyses, when needed. The information exchanges are performed through direct interfaces between DMS and EMS. Interfaces between the EMS and data aggregators may be used to meet the objective of the Function.	X	X	X		X	X
4	14	Optimal Capacitor Bank Design & Placement	Optimal location of Capacitor banks for deployment on the network to minimize voltage swells / sags. Optimization routine should be able to maximize cost/benefit, or other voltage stability metrics. The problem of Capacitor placement on a network system has a variety of complex multi- variable solution algorithms. The location, type, and size of capacitors, voltage constraints, and load variations are considered. The objective of Capacitor placement is peak power and energy loss reduction, taking into account the cost of the capacitors. The power flows in the system are explicitly represented, and the voltage constraints are incorporated. The master plan is used to determine the optimal location of the capacitors. Master plan sub-details lay out the type and size of the capacitors placed on the system.	X	X	X			
4	15	Switching Schedule & Safety Management	A core function of a DMS has always been to support safe switching and work on the networks. Control engineers prepare switching schedules to isolate and make safe a section of network before work is carried out, and the DMS validates these schedules using its network model. Switching schedules can combine tele-controlled and manual (on-site) switching operations. When the required section has been made safe, the DMS allows a Permit to Work (PTW) document to be issued. After its cancellation when the work has been finished, the switching schedule then facilitates restoration of the normal running arrangements. Switching components can also be tagged to reflect any operational restrictions that are in force.	X	X	X			

Summary Evaluation of AMI Use Cases Described, But Not Committed to, in PSEG Petition

New Jersey BPU Docket 18101115
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4	16	Ancillary Services **(PJM frequency regulation and capacity markets)**	Market Operations Energy Services, for the purposes of this use case, collects bid and offers into the ancillary services market from Energy Service Providers and other aggregators of distributed ancillary resources. Market Operations evaluates incoming bids against needs and accepts or rejects those offers.	X	X		X		
4	17	Energy Management & Frequency Control **(grid operations)**	This use case is a description of the information exchanges between a Data Acquisition subsystem and the load frequency control core of an Automatic Generation Control system. The calculation of economic dispatch and handling of generator schedules and production cost summaries form a separate use case [undocumented at present]. The AGC Load Frequency control subsystem receives new data values from the Data Acquisition subsystem (i.e. SCADA), calculates an Area Control Error and the required changes in generating unit set points. Set point controls are sent through the Data Acquisition subsystem to the power stations. The generating unit states can be made available for other applications.	X	X	X			X

RELEVANT DISCOVERY RESPONSES

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-E-0001
Date of Response: 5/7/2020
Witness: Daum, Frederick
Operational Benefits

Question:
Refer to PSE&G Witness Daum testimony, page 27, Figure 5, "Business Case Overview". Provide the detail of nominal Operational Benefits, $1,048 million, in the following manner:
a. Provide the detail by year from year 1 (likely 2021, or the year the first AMI meter is to be deployed) through year 25 (likely 2045, or the year the last AMI meter to be installed is fully depreciated).
b. Provide the detail by year by Release 1 use case, attributing benefits to each of the 22 Release 1 use cases with Operational Benefits individually as appropriate. Ensure the response is sufficiently detailed such that the sub-components add up to those listed in the "Benefits Overview": $669 million in Customer Operations, $232 million in Grid Operations - Gas; and $147 million in Grid Operations - Electric.
c. Cite the data sources, describe all assumptions, and explain the methodologies behind the calculation of each use case benefit estimate, for example, for a single year upon full deployment.
d. Provide the details of the calculations which translate the $1,048 million in Nominal Value into $450 million in present value.

Attachments Provided Herewith: 2
RCR-E_0001_PSEG Use Case Mapping - Benefits - CONFIDENTIAL
RCR-E_0001_PSEG Energy Cloud Workpapers - Operational Benefits - CONFIDENTIAL

Response:

a. Please see the attached CONFIDENTIAL Excel file "PSEG Energy Cloud Workpapers – Operational Benefits.xlsx". Each individual Operational Benefit is calculated, including year by year estimates for the period 2021 to 2040.

b. Please see the attached CONFIDENTIAL Excel file "PSEG Use Case Mapping - Benefits.xlsx." Operational Benefits for seven of the 22 Release 1 use cases (Use Cases 1-6, 8, 10,12,13,14, and 16) are mapped on the worksheet "Use Case Mapping". Columns A-B contain the Use Case Numbers and Names, Columns D-E-F provide the Operational Benefits index, description and projected benefit. Please see the Operational Benefits Workpapers provided in part (a) above as it displays how each individual Operational Benefit is calculated, including year-by-year estimates for the period 2021 to 2040.

c. Data sources, assumptions, and methodologies for nominal Operational Benefits are contained in the Operational Benefits Workpapers provided in part (a) above. All inputs and calculations are shown and data sources are identified in footnotes to the workpapers.

d. Please see the Operational Benefits Workpapers provided in part (a) above. The Operational Benefit pre-tax cash flows were estimated for each year 2021 to 2040. These annual cash flows were then discounted to present value at 6.85% discount rate per PSE&G's 12+0 rate case filing.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-E-0001-REVISED
Date of Response: 7/10/2020
Witness: Daum, Frederick
Operational Benefits

Question:

Refer to PSE&G Witness Daum testimony, page 27, Figure 5, "Business Case Overview". Provide the detail of nominal Operational Benefits, $1,048 million, in the following manner:

a. Provide the detail by year from year 1 (likely 2021, or the year the first AMI meter is to be deployed) through year 25 (likely 2045, or the year the last AMI meter to be installed is fully depreciated).

b. Provide the detail by year by Release 1 use case, attributing benefits to each of the 22 Release 1 use cases with Operational Benefits individually as appropriate. Ensure the response is sufficiently detailed such that the sub-components add up to those listed in the "Benefits Overview": $669 million in Customer Operations, $232 million in Grid Operations – Gas; and $147 million in Grid Operations – Electric.

c. Cite the data sources, describe all assumptions, and explain the methodologies behind the calculation of each use case benefit estimate, for example, for a single year upon full deployment.

d. Provide the details of the calculations which translate the $1,048 million in Nominal Value into $450 million in present value.

Attachments Provided Herewith: 3
RCR-E_0001-REVISED_PSEG Energy Cloud Workpapers - Operational Benefits - Confidential - REVISED.xlsx
RCR-E_0001-REVISED_PSEG Energy Cloud Workpapers - Operational Benefits - OB11-OB24 - REVISED.xlsx
RCR-E_0001-REVISED_PSEG Use Case Mapping - Benefits - Confidential.xlsx

Response:

a. Please see the attached CONFIDENTIAL Excel file "PSEG Energy Cloud Workpapers – Operational Benefits - REVISED.xlsx". The entire worksheet is marked as confidential because non-confidential worksheets are required to be included to allow the summary pages to calculate correctly, and the formula in the summary sheets could be used to back into the confidential information. Worksheets OB1 through OB10, and the Summary tabs specifically contain confidential data, and the tabs are shown in red. In addition, please see the attached Excel file “PSEG Energy Cloud Workpapers – Operational Benefits – OB11-OB24 - REVISED.xlsx” which provides worksheets OB11-OB24 as a non-confidential version of the workbook that excludes the confidential worksheets and summary tabs Each individual Operational Benefit is calculated, including year by year estimates for the period 2021 to 2040.

b. Please see the attached CONFIDENTIAL Excel file “PSEG Use Case Mapping - Benefits.xlsx.” Operational Benefits for seven of the 22 Release 1 use cases (Use Cases 1-6, 8, 10,12,13,14, and 16) are mapped on the worksheet “Use Case Mapping”. Columns A-B contain the Use Case Numbers and Names, Columns D-E-F provide the Operational Benefits index, description and projected benefit. Please see the Operational Benefits Workpapers provided in part (a) above as it displays how each individual Operational Benefit is calculated, including year-by-year estimates for the period 2021 to 2040.

c. Data sources, assumptions, and methodologies for nominal Operational Benefits are contained in the Operational Benefits Workpapers provided in part (a) above. All inputs and calculations are shown and data sources are identified in footnotes to the workpapers.

d. Please see the Operational Benefits Workpapers provided in part (a) above. The Operational Benefit pre-tax cash flows were estimated for each year 2021 to 2040. These annual cash flows were then discounted to present value at 6.85% discount rate per PSE&G’s 12+0 rate case filing.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-E-0035
Date of Response: 5/7/2020
Witness: Daum, Frederick
Release 1, Use Cases 8, 9, and 10

Question:
Refer to the Energy Cloud Plan prepared by PA Consulting for PSE&G (Schedule GD-CEF-EC-2). Provide the date by which PSE&G commits that all Release 2 use cases will be routinely in use/providing benefits for customers.

Attachments Provided Herewith: 0

Response:
As is stated in the testimony of Mr. Daum, the 22 use cases comprising Release 1 are fully-developed and not only provide short-term benefits that justify the Company's currently planned investments that are the subject of this proceeding, but also form a foundation for longer term opportunities to realize various additional potential benefits that either would be implemented in the normal course of business and recovered through a base rate proceeding, or would be the subject of future petitions by the Company for accelerated recovery, as appropriate. These future opportunities are described as the 48 use cases comprising Releases 2 through 4 of the longer-term plan. Detailed plans, including cost and benefit analyses, of the Release 2 through 4 initiative opportunities have not been conducted and if necessary, would be the subject of future proceedings to evaluate and approve additional investments.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-E-0088-UPDATE
Date of Response: 6/8/2020
Witness: Daum, Frederick
Old and Solid State Meters

Question:

With reference to PSE&G's response to RCR-E-0008(e), which indicates that PSE&G does not repair old meters, but replaces old meters as they fail with solid state meters which do not have a wireless communications capability:

a. For how long has PSE&G been replacing old meters as they fail with solid state meters without wireless communications?

b. How many solid state meters without wireless communications are currently installed in the PSE&G service area?

c. Please provide document RCR-E_0008_PSEG Meter Count by Set Year 2020-04-24.docx in a Microsoft Excel worksheet.

Attachments Provided Herewith: 1
RCR-E_0088-UPDATE_PSEG Meter Count by Set Year 2020-05-15.xlsx

Response:

a. PSE&G started buying solid state electric meters in 2004. PSE&G started buying electric ERT meters along with solid state meters in 2005. In 2018 PSE&G shifted meter purchases from AMR meters to solid-state meters essentially stopping AMR purchases. PSE&G did make an opportunity purchase of 1,536 AMR equipped network voltage meters in 2019. PSE&G was able to secure these meters for $70 each due to a canceled purchase order from another utility. At $70 the cost per unit was, and still is, just $22 above the cost of a non-communicating solid-state meter and less than half the current quote of an AMR equipped network voltage meter from the sole remaining supplier. This purchase allowed for an extension of the in kind replacement effort to avoid any decrement in performance while continuing to work down inventory and avoid stranded costs.

b. There are 341,060 solid state (digital non-communicating) electric meters without wireless communications currently installed in the PSE&G service territory.

c. Please see the attached Excel file "PSEG Meter Count by Set Year 2020-05-15.xlsx" previously provided in response to RCR-E-0088.