NARUC
National Association of Regulatory Utility Commissioners

PBR State Working Group Examination of Examples PIMs: AMI, Resilience, Energy Efficiency

Introduction

In 2024, the Performance-Based Regulation State Working Group conducted written and verbal case studies of three state implementations of PBR. Each case study addressed a different underlying topic: advanced metering infrastructure effectiveness (Hawaii); reliability, resilience, and customer service (Illinois); and energy efficiency and demand side management (New York). A template of seven questions was created to facilitate a common structure among the three case studies. Each Working Group member participated in one case study and contributed to producing a "report-out" using the template. Some case studies were better equipped to follow the template than others, so the seven questions are addressed in the report-outs to varying degrees. Nevertheless, each case study generally includes a summary of the PBR case's goals, barriers to an effective PBR framework, the value and limitations of the PBR approach in this instance, and how the specific implementation compared to a "state-of-the-art" PBR approach framework.

Each of the three case studies is summarized below in a consistent format. The individual report-outs are included as appendices for readers interested in more detail. The team assigned to the New York case chose not to complete the template but instead prepared a presentation with much of the same information. The attached version of their presentation also captures additional remarks made by the presenters in the "Notes" field, as well as a summary of a subsequent question and answer discussion.

Hawaii

Overview: The case study on Hawaii's performance-based regulation (PBR) approach focused on Advanced Metering Infrastructure (AMI) effectiveness. The study utilized Decision and Order

37787, which aimed to accelerate the utilization of AMI technology and ordered a suite of new performance mechanisms for the PBR framework for the Hawaiian Electric Company.

PIMs: Three upside-only Performance Incentive Mechanisms (PIMs) were approved:

1. Critical Load Reported Metrics (Resilience)
   This metric served as a starting point to begin tracking the resilience of the utility company's system and focuses on the system's resilience in preserving service to critical loads. The metric is measured as the aggregated total sum of hours that critical loads are without power from Hawaiian Electric in a year.
2. Green Button Connect My Data Scorecard
   This metric incentivizes the utility company to track the number and percent of customers that have used Green Button Connect My Data (energy portal data) to enable the sharing of information and compare it to the percentage of all customers with AMI installed. This metric is measured as the number and percent of customers that have used Green Button Connect My Data to enable sharing of information.
3. AMI Opt-Out Reported Metric
   This metric evaluates the percentage of customers who decline to receive an AMI meter once Hawaiian Electric modified its advanced meter deployment approach from an opt-in approach to an opt-out program. This metric is measured as the percentage of customers opting out of advanced meters

Barriers: Key barriers that prevented a more effective PBR framework and implementation were identified in the case study as a lack of baseline data from which to set targets and issues with third-party data sharing and customer education.

Value and Limitations of PBR Approach: The Hawaii case study team found that the PBR approach was valuable in determining the actions necessary to maximize the value of advanced meters and incentivizing utility actions beyond the core functionality of advanced meters or business as usual practice. However, the lack of experience is a limitation of the effectiveness of the PBR approach.

"State-of-the- Art" PBR Approach: The Hawaii case study team concluded that an ideal PBR approach should include reliable data, measurable metrics, target, financial incentive, transparent collaboration among stakeholders, explanations in plain language of the benefits to ratepayers, evaluation, and refinement.

Illinois

Overview: The case study on Illinois' performance-based regulation (PBR) approach focused on reliability, resilience, and customer service. The study utilized Final Order 22-0067, which aimed to solidify performance metrics for Commonwealth Edison (ComEd) as mandated by the Climate and Equitable Jobs Act. The Commission focused on three general areas: the proposed performance metrics, the basis points assigned to each performance metric, and the proposed tracking metrics.

PIMs: ComEd proposed systemwide metrics that contain two components: (1) a systemwide SAIDI metric, and (2) a four-part metric that measures SAIDI, SAIFI, CEMI4, and CELID12 performance in Equity Investment Eligible Communities ("EIECs"), which is comprised of Environmental Justice ("EJ") communities and low-income communities eligible for grant funding ("R3"). The systemwide SAIDI metric is designed to ensure that the utility maintains and improves overall reliability and resilience. ComEd's proposal included three performance metrics for the "reliability, resilience, and power quality" category:

1. SAIDI excluding up to nine major event days and excluding events for interruptions of less than one minute.
2. Number of customers who experience four or more interruptions per year for three consecutive years; or at least one 12-hour interruption per year for three consecutive years.
3. Power quality metrics: percent of system visible (60%); percent of network uptime (20%); percent of segments controllable with communication times qualified below a power quality actionable threshold (20%)

Basis Points: A symmetrical incentive or penalty of up to +/- 5 basis points annually will be applied if ComEd meets (or fails to meet) its incremental annual target for the systemwide SAIDI metric. ComEd's proposed overall basis point allocation is provided in the following table:

Proposed Performance Metric	Final ComEd Proposal (60 bps total)
1. Overall Reliability Based on System Average Interruption Duration Index ("SAIDI")	+/-15 bps
2. EJ and R3 Communities Reliability and Resiliency Based on SAIDI	+/-10 bps
3. System Visibility Index	+/-5 bps
4. Load Reduction Capability	+/-2 bps
5. Supplier Diversity	0 bps
6. Affordability	+/-13 bps
7. Interconnection Timeliness	+/-10 bps
8. Customer Service	+/-5 bps

Barriers: Key barriers that prevented a more effective PBR framework and implementation were identified in the case study as a lack of data to assess the costs and benefits of many metrics to customers and proposed basis point allocations. Unspecified benchmarking data, cost benefit analysis methodology, and structure for incentive/disincentive basis point allocation across different performance metrics also caused issues.

Value of PBR Approach: The Illinois case study team determined that the PBR approach was valuable in allowing for incremental improvements above the baseline and encouraging equitable outcomes and advances energy policy goals that are not directly aligned with a distribution company's public service obligations or existing financial incentives. However, the team also identified potential drawbacks to the PBR approach, such as cost ineffectiveness, increased utility spending to hit threshold, increased financial incentives for providing basic services, data gaps in determined basis points, and balance of risk.

"State-of-the- Art" PBR Approach: The Illinois case study team concluded that an ideal PBR approach should:

- Attempt to decrease the gap in the traditional regulatory and rate case framework brought about by changing industry conditions
- Address negative regulatory lag
- Increase regulatory efficiencies, reduce costs, promote better collaboration between intervening parties
- Align the interests of the utility, ratepayers and shareholders

New York

Overview: The case study on New York's performance-based regulation (PBR) approach focused on energy efficiency and demand side management. The study utilized Case 19-E-0065 on peak reduction EAM (earning adjustment mechanism) incentives, which aimed to incentivize Con Edison to deliver coincident electric system peak reductions that provide additional system benefits and lower supply costs for customers. This order approved the adoption of program-achievement based and outcome-based EAMs to incent achievement of State policy objectives beyond current baseline expectations.

EAMs: The joint gas and electric service proposal included three categories of EAMs: a peak reduction program, locational system relief value (LSRV) load factor, and energy efficiency programs.

1. Peak Reduction
   This metric is based on actual weather normalized coincident system peak for Con Edison's service territory measured in MW as reported in the Load Forecasting Task Force in December prior to the rate year.
2. LSRV Factor
   This metric is based on the load factor improvements in 9 LSRV areas and achievement is based on the number of LSRV areas that maintain or improve their load factor each year. The percent change of the substation load factor is calculated annually based on the previous year's baseline. The EAM is based on the number of areas that maintain or improve load factor.
3. Energy Efficiency (EE)
   a. Deeper Energy Efficiency Lifetime Savings
      This metric is a cross-commodity metric (looking at both gas and electric savings) that encourages the utility company to undertake longer lead time, longer

lasting, deeper energy efficiency and beneficial electrification programs (such as building envelope measures, HVAC, heat pumps) in an effort to meet clean energy goals. It is measured on lifetime energy savings provided by deeper energy efficiency measures in the company's entire efficiency portfolio expressed in lifetime MMBtu.

b. <u>Share-the-Savings</u>
This metric was designed to reduce unit costs for Con Edison's combined electric and gas EE portfolio by reducing the unit cost of lifetime energy savings below the previously approved unit cost levels while increasing the overall achievement level of energy savings. The goal of the EAM is for the cost to come in below the cost to be determined in a separate commission case based on the utility company's efficiency portfolio. The utility company only achieves awards when they achieve the minimum amount of lifetime energy savings which is calculated by subtracting the achieved cost from the baseline cost and multiplying the savings and savings factor.

Barriers: The key barrier that prevented a more effective PBR framework and implementation was identified in the case study as the use of a broad-based outcome measures approach rather than a specific programmatic outcome or achievement approach. Due to the broad outcome-based approach, utilities were focused only on peak demand in their service area. Recently, both the peak reduction and EE EAMs completed changed and are now more programmatic and focused on very specific programs the utility would implement

Value and Limitations of PBR Approach: The New York case study team determined the PBR approach was valuable in incenting Con Edison to reduce peak load which will avoid peak transmission line loss, decrease peak generating assets, and reduce ancillary services as well as reduce wholesale and bulk transmission system costs paid by its customers.

Appendices

1. Hawaii: AMI Effectiveness
2. Illinois: Reliability, Resilience, Customer Service
3. New York: Energy Efficiency and Demand Side Management

Group 1: AMI Effectiveness

Subgroup Members:
- Hon. Abigail Anthony, Rhode Island
- Donn English, Idaho
- Amy Andrews, Washington (Team Lead)
- Kim Lighthart, Nevada
- Tim White, Connecticut
- Hon. Staci Rubin, Massachusetts

Report Out Date: May 2

Selected Case and Summary: Hawaii – Decision and Order 37787

On May 17, 2021, the Hawaii Public Utilities Commission issued a decision and order approving the final details of a suite of new performance mechanisms for the performance-based regulatory framework (PBR Framework) for the Hawaiian Electric Companies established last December.

The suite of new performance mechanisms includes an Interconnection Approval performance incentive mechanism ("PIM"), which incentivizes faster interconnection timelines for small-scale solar and storage systems, and an LMI Energy Efficiency PIM, which incentivizes increased collaboration between the utility and the energy efficiency program administrator to provide low-to-moderate income customers with opportunities to better manage their energy consumption. The Commission also approved an AMI Utilization PIM, which incentivizes the utility to harness the opportunities offered by advanced meters to begin providing immediate customer benefits.

The Decision and Order also approves a portfolio of Scorecards and Reported Metrics, which will track and measure utility performance across a wide spectrum of categories to provide valuable data that can inform future planning and development efforts.

This decision is a continuation of the Commission's years-long efforts to transform Hawaii's energy sector, and builds on the successful collaboration of a diverse group of stakeholders, including the Hawaiian Electric Companies, State and County government agencies, clean energy companies, and non-profit organizations, who have continued to help propose, develop, and implement new ideas to facilitate this transformation.

Performance Incentive Mechanisms (See pages 39-43 of case)

Critical Load Reported Metric (Resilience): Hawaiian Electric PBR Scorecards and Metrics

The Critical Load Reported Metric was identified as a starting point to begin tracking the resilience of the company's system and focuses on the system's resilience in preserving service to critical loads. Although the metric will include catastrophic and non-catastrophic outage events, it may provide useful information to assess the level of readiness for a catastrophic event and help the company identify areas that are more vulnerable and warrant additional grid improvements.

This metric is defined as the aggregated total sum of hours that critical loads are without power from Hawaiian Electric in a year.

Data for this metric is currently not available as it is not quantifiable through reasonably available data until the Companies develop and test a mechanism to determine outage durations for AMI meter locations for critical loads, which the Companies plan to develop this year.

- **Metric**: Total amount of time that critical loads are without power in a year
- **Target**: N/A
- **Reporting Frequency**: Annual

Green Button Connect My Data Scorecard: Hawaiian Electric PBR Scorecards and Metrics

The company successfully launched its Energy Portal at the end of April 2021. Among its various functions, customers with an advanced meter installed will be able to authorize third-party vendors to access their Energy Portal data with Green Button Connect My Data. Once authorized, Green Button Connect My Data allows a vendor to gain easy access to customer electric usage data after consent from the customer. The vendor will need to be certified with Green Button Connect My Data to provide this option to its customers. The company tracks the number and percent of customers that have used Green Button Connect My Data to enable sharing of information and then compare it to the percentage of all customers with AMI installed.

- **Metric**: Number and percent of customers that have used Green Button Connect My Data to enable sharing of information
- **Target**: Equal to the percent of all customers with advanced meters installed
- **Reporting Frequency**: Quarterly

Green Button Download My Data Scorecard: Hawaiian Electric PBR Scorecards and Metrics

The company successfully launched its Energy Portal at the end of April 2021. Among its various functions, customers with an advanced meter installed will be able to authorize third-party vendors to access their Energy Portal data with Green Button Connect My Data. Once authorized, Green Button Connect My Data allows a vendor to gain easy access to customer electric usage data after consent from the customer. The vendor will need to be certified with Green Button Connect My Data to provide this option to its customers. The company tracks the number and percent of customers that have used Green Button Connect My Data to enable sharing of information and then compare it to the percentage of all customers with AMI installed.

- **Metric**: Number and percent of customers that have used Green Button Connect My Data to enable sharing of information
- **Target**: Equal to the percent of all customers with advanced meters installed
- **Reporting Frequency**: Quarterly

AMI Opt-Out Reported Metric: Hawaiian Electric PBR Scorecards and Metrics

On March 3, 2021, the Hawaii Public Utilities Commission approved Hawaiian Electric’s proposal to modify its advanced meter deployment approach from an opt-in approach to an opt-out approach. The AMI opt-out metric measures the percentage of customers who decline to receive an AMI meter. This metric is based on the total number of opt-outs divided by the total number of customers who received communications about their upcoming meter exchange.

- **Metric**: Percentage of customers opting out of advanced meters
- **Target**: N/A
- **Reporting Frequency**: Biannual

Template Questions

Upon individually reviewing the initial proposal, case discovery, development, and components of the final order, discuss and provide responses to the following questions as a group.

1. **Provide a summary of what issues the PBR case was attempting to address.**

   As part of Hawaii's PBR proceeding in Docket 2018-0088, the Hawaii PUC (Commission) desired to accelerate the utilization of AMI technology. While the utilities experienced meter deployment delays, the Commission directed a working group to draft a PIM that incentivized the enabling technology rather than a structure to simply promote an accelerated meter deployment process and business as usual benefits. For example, an initial metric included thresholds related to bills determined with AMI interval data, customer accessibility of data through a customer portal, and enrollment/participation in TOU rates, DER, DR, or other advanced programs. Our group observed that the Commission appears to be incentivizing the utility to realize benefits from established programs through the AMI investment.

   Additionally, the Commission reinforced its intention for PIMS to reward exemplary performance and overcome challenges already identified by the companies but recognized the concern regarding financial risks of this newer technology and created the finalized PIM as "upside only." Further, the Commission acknowledged the short-term nature of the need and limited the timeframe of the PIM to the first three years of a multi-year rate plan after which time a comprehensive review of the PIM would be performed.

   Through several iterations of the PIM, the Commission approved the following PIM structure:

   Percentage of total customers with advanced meters delivering at least two of the following three benefits:

- Customer Authorization Benefit - Customer authorization for the sharing of interval data with third parties (Green Button Connect My Data). The company tracks the number and percent of customers that have used Green Button Connect My Data to enable sharing of information and then compares it to the percentage of all customers with AMI installed. *Intended to incentivize companies' customer outreach and education while promoting easy and fast data sharing processes.*
- Energy Usage Alert Benefit - Customers with advanced meters who sign up for the alerts and select their preferred delivery method (e.g., text, email, phone call, etc.). Usage alerts do not include alerts or information delivered solely through appearance on the customer's energy portal display (i.e., requires the customer to self-initiate engagement with the portal). *Intended to promote active customer engagement rather than relying on customers to consistently visit the Energy Portal.*
- Program Participation Benefit - Customers with advanced meters who newly enroll in open existing time-varying tariffs or DER programs, or new program development from the Commission's ongoing DER Docket (2019-0323). *Encourage customer participation in programs more likely to leverage AMI investments rather than incent "enabled" enrollment.*

The incentive was capped at $2 million and allocated across the three companies based on total customers. Further, rewards were established using an upper target and lower target with linear interpolation to recognize incremental improvements. Following is the target/reward structure:

	2021	2022	2023
Upper Target ($2M max reward)	5%	15%	30%
Lower Target ($1M max reward)	2.5%	10%	20%

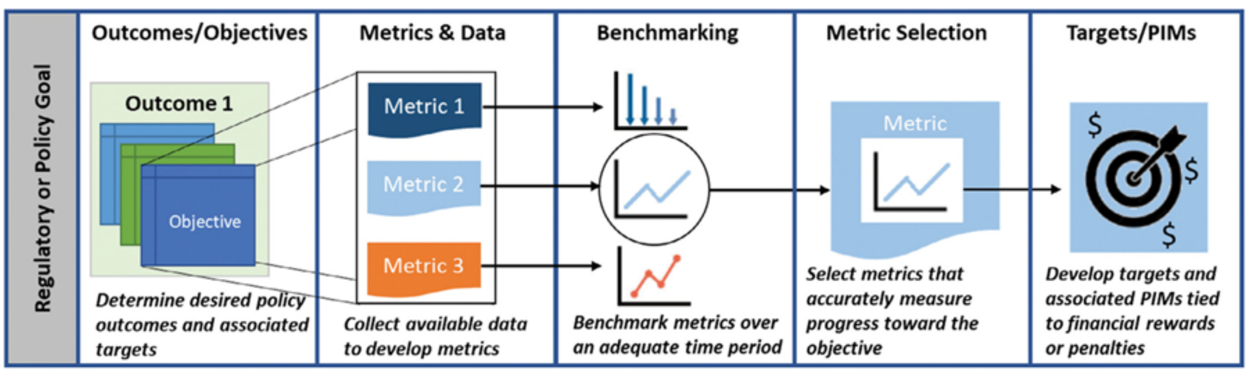
The group observed, from our own experiences, that one of the tricky things about AMI cases is that a lot of the value case is premised on enablement benefits. A relatively small part of the total value is utility O&M savings, and the majority of the value is presented as the meters will enable customers to save or shift electricity use, or facilitate adoption of DER, and if they do that there may be power system and participant benefits. This order shows the way the Hawaii PUC tried to get their hands around those enablement benefits and insert some accountability to the realization of those benefits.

2. **Upon review of the case, were there gaps or barriers identified by the Commission that prevented more effective PBR framework or implementation? Staci**
    - A barrier was simply the companies had experienced delays in meter deployment and there was no baseline data to evaluate prior to determining a target, which may have resulted in a more effective implementation (re: ability to create a more effective framework).
    - The Commission identified barriers to full enablement due to issues with third-party data sharing and customer education. While the PIM is designed to encourage data sharing, the Commission acknowledged that third party vendor recruitment and affirmative customer authorization present challenges that must be overcome during implementation. Further, the Commission directs the companies to educate customers; implementation will determine whether there is sufficient education to lead to increased customer participation in TOU and DER programs.
    - These PIMs seem designed to motivate the utility to engage in marketing the opportunities provided by the AMI investment. If the Commission didn’t think the AMI would be beneficial without marketing, did they consider including marketing in the project budget?
    - What evidence did the Commission have to establish a baseline for what a $1.4m incentive for marketing should deliver? What

information did they use to determine what the outcome would be without the incentive, and what outcomes the Commission should expect to see for this reward?

- The Commission indicated there are no penalties, which was intentional because the PIM is novel. Additional information about whether the incremental improvements are a better PBR design compared to a tiered structure may have led to a penalty component of the PBR
- The Commission understandably limited the metric development to their three PBR objectives. Could there have been another AMI use case that provided greater customer benefit? There is now some rethinking about AMI as a core functionality of utility business rather than the thing to be incentivized.

3. **A common PBR framework is provided below. In the case you reviewed, which of the five stages did regulators encounter the most significant challenges or had the most success? Tim**



- The Commission seemed to have the most success in the metric selection stage. The Commission directed the use of working groups, which appears effective, to assess and refine metrics. The results of the working group process led to refined metrics that are better aimed at achieving the intended objectives of accelerating the number of customers enabling the full benefits of advanced meters.
- It is not clear how much time was spent on benchmarking metrics over an adequate time period. There are likely additional materials beyond the order that describe the benchmarking process.
- While it may be obvious, there was no available data to set targets or introduce a full PIM (reward and penalty). It seems the percentages

reflected the nascent stage of meter deployment. However, the Commission did require dashboards/scorecards to help present the information over time. There is a current petition before the Hawaii PUC for modification of the AMI PIM.

4. **What kinds of other questions would group members have asked if they had been working on the case? Abigail**
    - High level, we are interested in how confident the Commission was in the reliability of the value case for the investment proposal? The AMI PIM was one of the most challenging to develop. Specifically, how to quantify the benefits with little to no baseline data.
    - We are also interested to understand whether the Commission considered service quality metrics or penalty-based incentives instead, or in addition to, the positive incentive plan. There was no consideration of a penalty structure. The PIM was created under the holistic view of PBR and desire to tie utility revenue to performance so they focused on upside only. In Rhode Island, the utility said, promised numerous enablement benefits (as well as operational benefits). Since the utility's case put so much weight on delivering these benefits, we said..ok, you have to deliver those functionalities. We did this by capping their capital budget yet requiring them to keep spending until they deliver the customer portal, outage alerts, green button connect, load disaggregation, etc. Then we made the approval take it or leave it…if you don't like the conditions you don't have to start the meter deployment. For the most significant enablements, we imposed penalties. For example, all of the benefits of TOU rates and customer information/portal were premised on being about to get data from the meter, through the MDMS, and back to the customer portal in 30-45 minutes. We require the utility to achieve the requisite network speed or face a penalty.
    - The Hawaii order said that a PIM isn't needed for investments or actions that the company said that they'll do, like billing customers using interval data once meters are deployed. What are the stakes here? How much value depends on the utility billing customers using interval data? Uncertain as the value case was not in front of the

Commission when the PIM was under development. In retrospect, PIM development in advance of baseline data or established programs was identified as a lesson learned.

- Did the Commission consider adopting standards or a data sharing protocol instead of the incentive for the customer authorization benefit? What evidence did they have that the number of customers sharing data is a sign of success that the utility should be paid for? I wonder if they considered holding the utility accountable to how quickly the data sharing requests are processed? How easy the utility makes it to share data? What are the alternatives to establishing a data sharing program? The data sharing portion of the PIM was put forward by the staff and vetted by others in the PBR Working Group but could not recall specifics (this would require a deeper dive into the docket).
- Are there additional barriers beyond advanced meters that prevent customers from participating in and benefiting from DER programs? Yes, Hawaii has experienced a few challenging years (COVID, wildfires, energy capacity issues) that delayed DER (and other) program development. Reliability is currently a significant issue before the Commission. A major plant has been offline (⅓ of generation), aging fossil fuel plant running in a way not originally intended (related to renewables being added to grid) which has caused increased maintenance, plus extreme weather events.
- How are the companies balancing customer privacy with the need to share sufficient data with third parties, following customer authorization, and aggregated data for the public? *Not asked.*
- Was there concern the initial targets were set too low and not realizing the maximum benefit for the reward dollars? Or, was there any consideration for an offramp (reset) if the targets were grossly over/under estimated during the three-year period? The PBR framework established a mechanism for parties to request a re-evaluation for any PIM at any time.
- How was the maximum $2M cap determined? Looked at the total PIM portfolio as a percentage of utility revenue, the expected costs and benefits, and what would be worthwhile for utility action.

- Is the Hawaii PUC hearing about interconnection (telecommunication backbone) challenges? If so, has there been a plan established to address those concerns? Just starting to investigate. The utilization of a mesh network versus individual locations, particularly in response to DER, seems to be of interest.
- Were the utilities initiating AMI as prior meters had reached end of life or were there also stranded asset costs to consider? Uncertain.

5. **In the work or research at your commission, have you identified any useful resources to consider for using PBR to address these gaps or barriers? Roundtable**
    - While the MA DPU has not necessarily directed the use of working groups to develop PBR frameworks, the agency has directed the use of working groups to work through complex matters where there is a wide spectrum of opinions. Effective stakeholder working groups that have guidance from PUCs can address complex issues, overcome barriers, and potentially lead to consensus.
    - Washington state is primarily working to establish reporting metrics prior to setting targets or creating PIMS. In our PBR docket, we are not necessarily looking to create a target/PIM specific to the advanced meters but trying to identify which performance measures can be informed by the meters or ADMS.
    - Consideration for holding utility accountable for baseline AMI (meter) performance as promised. As an example, Rhode Island established a penalty related to expected speed and availability of data. Not only is there a distinct dollar penalty but the utility must also use investor-funded for any work required to obtain the minimum thresholds.

6. **Was a PBR approach valuable in this case? What were the efficiencies and limitations (compared to traditional/COS ratemaking)? Amy**
    - Yes, the PBR approach was valuable in determining the actions necessary to maximize the value of advanced meters. Efficiencies are related to incentivizing year-over-year improvements in TOU and

DER program participation all within the total incentive cap for all three companies. There are inefficiencies in considering novel rate design concepts as part of rate cases that focus on traditional COS ratemaking, which are adjudicated in separate proceedings focused on one regulated entity at a time.

- Yes, specifically the intentional efforts to incentivize utility actions beyond the core functionality of advanced meters or business as usual practice.
- Limitations are the retrospective look provided with traditional COS regulation (evaluating definitive data rather than committing customer dollars for scaled benefits). However, particularly for Washington state, we recognize the changing energy landscape with both climate and equity mandates require more flexible and innovative regulatory design.

7. **What would a "state-of-the-art" PBR approach framework look like and what components were absent from this case? Abigail/Staci - revise for general reflections**
    - A state-of-the art PBR framework includes reliable data, measurable metrics, target, financial incentive, transparent collaboration among stakeholders, explanations in plain language of the benefits to ratepayers, evaluation, and refinement. The order has little discussion of benefits to ratepayers and a clear plan for evaluation and verification.
    - There is simply a lack (absence) of experience. We appreciate that Hawaii is limiting the scope of their docket to gain that experience, but it appears they have diverged from the "best practice" approach as outlined by numerous sources, such as NARUC, the Regulatory Assistance Program (RAP), and other industry leaders (*i.e.,* establishing baseline data from reporting metrics with no financial implications, transition to Target/Scorecard metrics without financial incentives or penalties, then move to PIM development).

Group 3: Reliability / Resilience / Customer Service

Subgroup Members:

- Hon. Dan Scripps, Michael Byrne, and Kayla Gibbs (comment color), Michigan
- Hayley E. Hinken, Pennsylvania (comment color)
- Stacy Schumacher, Wisconsin (comment color)
- Holly Forrest, Nevada
- Peter Kramer, Connecticut (comment color)
- Laura Storino, New Jersey
- Geoffrey Rush, Oklahoma (Group Lead) (comment color)

Report Out Date: August 1 (our next group meeting will be in June)

Selected Case and Summary: Illinois – Final Order 22-0067: Reliability and Resiliency – Systemwide metrics that contains two components: (1) a systemwide SAIDI metric, and (2) a four-part metric that measures SAIDI, SAIFI, CEMI4, and CELID12 performance in Equity Investment Eligible Communities ("EIECs"), which is comprised of Environmental Justice ("EJ") communities and low-income communities eligible for grant funding ("R3"). The systemwide SAIDI metric is designed to ensure the utility maintains and improves overall reliability and resilience. A symmetrical incentive or penalty of up to +/- 5 basis points annually will be applied if ComEd meets (or fails to meet) its incremental annual target for the systemwide SAIDI metric.

Background: On January 20, 2022, this docket was opened to solidify performance metrics for Commonwealth Edison as mandated by the Climate and Equitable Jobs Act. The proposed metrics include System Average Interruption Duration Index (SAIDI), Customers Exceeding Minimum Service Levels, System Visibility Index, Load Reduction Capability, Arrearages, Interconnection Timeliness, First Contact Resolution, and Percentage of Spend with Diversity-Certified Suppliers. ComEd also proposed 11 tracking metrics across five categories (emissions reductions, grid flexibility, cost savings, diversity and equity) to monitor performance to aid in the development of future performance metrics.

On October 13, 2022, the Illinois Commerce Commission (ICC) issued an order clarifying and amending its September 27, 2022 order approving ComEd's proposed performance and tracking metrics. Specifically, the amendatory order clarifies the percent improvement targets for four indices under Performance Metric 2, which is related to system interruption, and clarifies the approved penalty and incentive structure for ComEd's interconnection timeliness metric, Performance Metric 7.

Performance Incentive Mechanisms
Reliability and Resiliency – Systemwide metrics that contains two components: (1) a systemwide SAIDI metric, and (2) a four-part metric that measures SAIDI, SAIFI, CEMI4, and CELID12 performance in Equity Investment Eligible Communities ("EIECs"), which is comprised of Environmental Justice ("EJ") communities and low-income communities eligible for grant funding ("R3"). The systemwide SAIDI metric is designed to ensure the utility maintains and improves overall reliability and resilience. A symmetrical incentive or penalty of up to +/- 5 basis points annually will be applied if ComEd meets (or fails to meet) its incremental annual target for the systemwide SAIDI metric.

Proposed Performance Metric	Final ComEd Proposal (60 bps total)
1. Overall Reliability Based on System Average Interruption Duration Index ("SAIDI")	+/-15 bps
2. EJ and R3 Communities Reliability and Resiliency Based on SAIDI	+/-10 bps
3. System Visibility Index	+/-5 bps
4. Load Reduction Capability	+/-2 bps
5. Supplier Diversity	0 bps
6. Affordability	+/-13 bps
7. Interconnection Timeliness	+/-10 bps
8. Customer Service	+/-5 bps

Template Questions

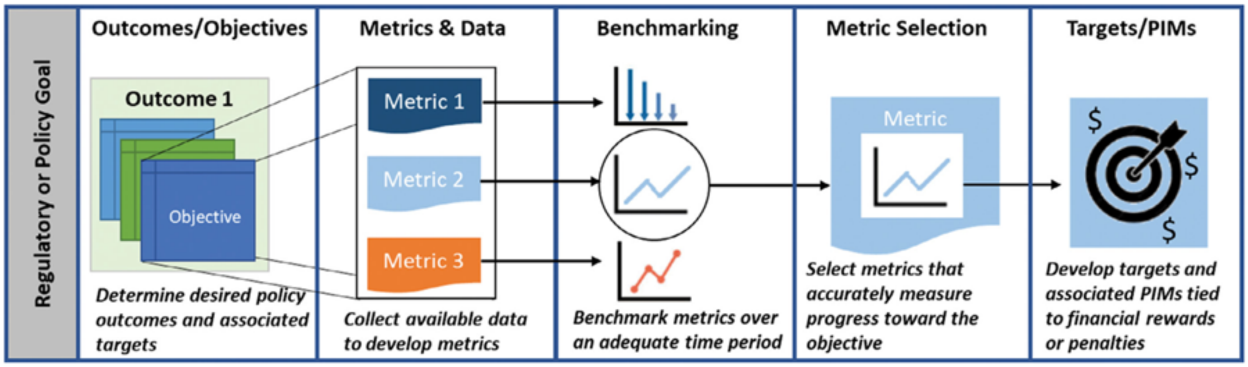
Upon individually reviewing the initial proposal, case discovery, development, and components of the final order, discuss and provide responses to the following questions as a group.

1. **Provide a summary of what issues the PBR case was attempting to address.**
    - 2021 IL law which directed: "…the Commission to establish performance incentive mechanisms in order to better tie utility revenues to **performance and customer benefits**, accelerate progress on Illinois energy and other goals, ensure equity and affordability of rates for all customers, including low-income customers, and hold utilities publicly accountable." - this set of performance metrics addresses system performance generally, and then when considering performance in EJ/low-income communities.
    - Specifically, the relevant statute directs the Commission to approve or approve with modification, the utility's proposed performance metrics by September 30, 2022. In doing so, the Commission chose to focus on whether specific performance metrics further the goals of P.A. 102-0662 and should be approved. Per statute, the Commission could approve no more than 8 performance metrics and such performance metrics must advance the following categories: (1) reliability, resiliency, and power quality; (2) peak load reductions; (3) supplier diversity; (4) affordability; (5) interconnection; (6) customer service.
    - In this proceeding the Commission needed to approve or approve with modification, ComEd's proposed PBR metrics. In doing so, the Commission focused on three general areas:
        1. the proposed performance metrics;
        2. the basis points assigned to each performance metric;
        3. the proposed tracking metrics.
    - ComEd's proposal included three performance metrics for the "reliability, resilience, and power quality" category:
        - **Metric 1:** SAIDI, excluding up to nine Major Event Days and excluding events for interruptions of less than one minute.
        - **Metric 2:** Number of customers who experience four or more interruptions per year for three consecutive years; or at least one 12-hour interruption per year for three consecutive years.
        - **Metric 3**: Power quality metrics: percent of system visible (60%); percent of network uptime (20%); percent of segments controllable with communication times qualified below a power quality actionable threshold (20%)
    - The Commission was faced with several performance metric design issues including:

    - Metric calculation methodologies: Exclusions of Major Event Days
    - Level of utility control
    - Cost-effectiveness; Benefits to ratepayers
    - Target setting
    - Incentive design, including the appropriate assignment of basis points

2. **Upon review of the case, were there gaps or barriers identified by the Commission that prevented more effective PBR framework or implementation?**
    - Total number of basis points: According to Staff, there was a lack of data to assess the costs and benefits of many metrics and the utility's cost-benefit analysis did not attempt to characterize potential costs associated with the proposed performance metrics. For instance, the utility experienced challenges in estimating costs and did not quantify the costs of programs that would be employed to achieve the peak load metric, stating that they would not be known until the programs are implemented. Order at 29. The Commission considered "the current uncertainty in the effectiveness of ComEd's PBR structure due in part to data gaps and lack of information regarding costs and benefits" in reaching its decision. Order at 35.
    - Proposed overall BPS allocation: Parties were concerned regarding a lack of information regarding potential benefits for customers, including a lack of information to determine which metrics will provide the most benefits and should be assigned more basis points. Order at 40-41. The Commission recognized these concerns and the potential risks to ratepayers in making its determination. Order at 44.
    - There had not been benchmarking data agreed to as part of the proceeding, with the company proposing two years, and intervenors arguing for a longer benchmarking, because the utility may be chose a period to make initial success in meeting targets easier to achieve.
    - There was not an agreed upon cost-benefit analysis methodology at the start of the proceeding. The utility proposed their own suggestions but admitted that its analysis "is necessarily limited by certain factors in this docket, including the need for consideration of customer and societal benefits, some of which are qualitative or not practically quantifiable at this time."
    - There was not an agreed upon structure for how incentives/disincentive basis points would be allocated across the different performance metrics.

3. **A common PBR framework is provided below. In the case you reviewed, which of the five stages did regulators encounter the most significant challenges or had the most success?**



- Outcomes/Objectives
    - Symmetry vs. asymmetry: There was disagreement among the parties on how the PA read. Could a penalty only mechanism be offset with a separate incentive only mechanism to be symmetrical.
    - Implementation of PBR framework: utility receiving a financial incentive for providing basic and other services to ratepayers and essentially maintains the status quo.
        - Metrics less ambitious for the needs of customers thus less beneficial.
        - Only rewarded for investments utility would not have made absent PBR framework
- Metrics & Data
    - Determining the baseline for metrics.
    - Qualitative CBA data missing for some of the metrics- unable to determine customer benefits
- Metric Selection
    - Customer service metric: improving customer services stems from improving customers' reliability at reasonable rates. Customer service won't be adequate if rates are unaffordable.
    - According to some parties the peak demand reduction metric doesn't pass the cost benefit analysis test.
        - Forecasting error when determining peak reduction metric.
        - Doesn't acknowledge EV charging.
    - Including or Excluding MEDs in SAIDI metric(s) vs. EWEDs
        - Controllable vs. uncontrollable interruptions.
        - Capping MEDs
    - Reliability metrics focus on EJ/disadvantaged communities vs. non-EJ communities
    - Interconnection metric- timeliness/ days saved- what's appropriate

- Targets/PIMs
    - Number of basis points to link incentives/penalties and the specific basis points for each metric.
    - Linear vs. stair step approach structure.
        - Adjusted in the second round of the proposal- all parties agreed on linear.

4. **What kinds of other questions would group members have asked if they had been working on the case?**
    - Does IL have rules/regulations that require the utilities to maintain a certain reliability standard and they penalized for not doing so?
    - Is there going to be a cap on the penalties a utility can receive?
    - How were the basis points that were recommended from parties determined? Unsure if a thorough analysis was conducted to provide the Commission with sufficient information to make a decision.
        - ComEd recommended 60 because the PA allowed that to be the max.
        - Staff recommended 36 because it was easily divisible by the 6 metrics they were proposing and ensuring room for adjustment depending on how the metrics perform upon implementation.
        - CUB recommended 42- unsure the reasoning.
        - Utilized the ICE calculator but outlined some discrepancies/ miscalculations.
            - "Input-Output analysis" is the best method to estimate the benefits of the metric but lacks sufficient time to perform.
    - Has a cost analysis been completed to show how the different basis points affect ratepayers? How much additional cost will ratepayers be responsible for if the utility earns an incentive?
        - Yes, IIEC conducted an analysis of what 1 basis point equals for ratepayers.
    - Was a "backtest" done to the metrics to show how the utility would be affected in regards to incentives/penalties.
    - Curious to hear more from Staff on their reasoning for having the same basis points for all metrics- they were not weighted differently.
        - How come Staff was unable to determine net benefits of each metric to weigh each differently? What data/reporting was missing from the utility?
    - What was missing for a customer and societal cost benefit analysis to be conducted? Qualitative cost benefit analysis conducted by not quantitative?
    - How do you determine which MEDs to include in the cap and which are eliminated?
        - Are the MEDs the first 9 that occur, or determined by some other criteria on which ones to include?
    - Is there any data missing to track/enhance these metrics or to establish an accurate baseline?

- Allotting zero basis points for a metric- doesn't that make the incentive/penalty moot? Only allowing for a deadband- no incentive or penalty.

5. **In the work or research at your commission, have you identified any useful resources to consider for using PBR to address these gaps or barriers?**
    - Stakeholder groups can provide valuable input on areas explored in PBR development. Some of this can be granular and give areas for staff to explore that may be lost in more generalized information on PBR. However, some work may be needed to give a general understanding of what PBR is, what metrics/outcomes/incentives are, and this can take additional time in the process that must be accounted for.
    - WI PSC has an investigation docket open specific to PBR items and has been working with consultants on PBR process items, as well as digging into more specific options for data sources that could inform metrics - balance of staff time is one consideration - managing the information to and from external organization vs. doing primary research work. Other investigation dockets (affordability, reliability) are likely to provide useful information, which is useful, but can affect the PBR investigation timeline.
    - Notice of Inquiry. The Oklahoma Commission currently has an NOI open which allows the utilities and interested parties to opine as to both the necessity of a PBR, the pros and cons of a PBR, and if one was mandated - how would it need to look to provide benefits, and how could it be structured to properly align goals of the utility, ratepayers and shareholders.

6. **Was a PBR approach valuable in this case? What were the efficiencies and limitations (compared to traditional/COS ratemaking)?**
    - Pros of PBR approach:
        - P.A. 102-0662 gave guidance to the PBR approach and what is expected of the utilities in regards to their multi-year rate plan and performance metrics.
        - Metrics include, "a description of the metric, a calculation method, a data collection method, annual performance targets, and any incentives or penalties for the utility's achievement of, or failure to achieve, their performance targets, provided that the total amount of potential incentives and penalties shall be symmetrical."
        - Allows for incremental improvements above the baseline.
        - Encourages equitable outcomes and advances energy policy goals that are not directly aligned with a distribution company's public service obligations or existing financial incentives.
    - Cons of PBR approach:

- Could not be cost effective for ratepayers.
- Utility spending more to hit the incentive threshold. Evaluation of expenditures necessary during applicable proceedings to make sure this won't happen.
    - Could economically affect disadvantaged communities and communities of color the most.
    - Multi-year rate plans cost projections rely heavily on estimates.
- Utility companies would receive additional financial incentives for providing basic and other services to ratepayers and essentially maintain the status quo.
- Guaranteed profits without meaningful improvements
- When calculating the basis points to apply to the incentives/disincentives there were significant data gaps (ICE Calculation, Input/Output analysis), and costs and benefits could be fully assessed at this time.
    - Do you want to implement something that does have the time or the ability to be assessed in the available ways.
- Difficult to balance the risk to the utility vs. risk to customers.
- Metrics could be less ambitious and provide less benefit to customers.
- Metrics could provide the utility an opportunity to double recover.

7. What would a "state-of-the-art" PBR approach framework look like and what components were absent from this case?

- A "state-of-the-art" PBR framework would accomplish several things.
    1. Address the gap in the traditional regulatory and rate case framework which is brought about by changing industry conditions.

    2. When utilities operate in an environment characterized by increasing costs and declining sales growth, there is a strong possibility of negative regulatory lag, which can result in utilities filing frequent rate cases to "catch up." Alternative Regulation will allow efficient management of regulatory lag and reduce the frequency of rate cases.

- Increase regulatory efficiencies, reduce costs and promotes better collaboration between intervening parties.
- Aligns the interests of the utility, ratepayers and shareholders
    a. Annual scrutiny of investments and expenses would allow for more frequent discussion and collaboration around issues most impactful to customers.
    b. Cost transparency for customers.
    c. Aligns the utility's revenues and performance with metrics and customer centric goals through various performance incentive mechanisms.

Group 2: Energy Efficiency and Demand Side Management

Deeper EE Lifetime Savings (DEEL) EAM

Results

	2020 (3/31/22 Report)	2021 (6/14/23 Report)	2022 (4/1/24 Report)
Minimum Target	8.7M LMMBtu	10.1M LMMBtu	11.5M LMMBtu
Maximum Target	11.6M LMMBtu	14.6M LMMBtu	15.3M LMMBtu
Achievement	10.5M LMMBtu	18.9M LMMBtu	27.94M LMMBtu
EAM Earned	**$14.5 million**	**$31.9 million**	**$28.34 million**

Note: LMMBtu = Lifetime MMBtu

1

Share-the-Savings (STS) EAM

Metrics

- Designed to reduce unit costs for Con Edison’s combined electric and gas EE portfolio by reducing the unit cost of lifetime energy savings below the unit cost levels as approved in Case 18-M-0084, while increasing the overall achievement level of energy savings.
- Awarded 30% of unit cost savings realized from its acquired non-LMI EE savings once the minimum non-LMI EE lifetime savings targets are met.
- STS EAM ($) = [RYx Baseline LMMBtu Unit Cost – RYx Acquired LMMBtu Unit Cost] ∗ RYx Acquired LMMBtu ∗ S%

2

- The STS EAM was designed to reduce unit cost for the utility company’s combined electric and gas efficiency portfolio but excluding the low and moderate income efficiency portfolio by reducing the unit cost of savings on a dollar per lifetime of mmbtus. The goal of the EAM is for the cost to come in below the cost to be determined in a separate commission case based on the utility company’s efficiency portfolio. The utility company only achieves awards when they achieve the minimum amount of lifetime energy savings which is calculated by subtracting the achieved cost from the baseline cost and multiplying the savings and savings factor. The utility company could earn 30% of any achieved savings and the rest stays with customers
- Key Takeaways:

1. The commission’s proposal and joint proposal did not articulate lowering unit cost of savings as a policy goal but has a general goal of lowering total costs. This EAM seems like a reasonable thing for the NY commission to require the utility to measure and serves as a way to incent them to lower their yield rate.

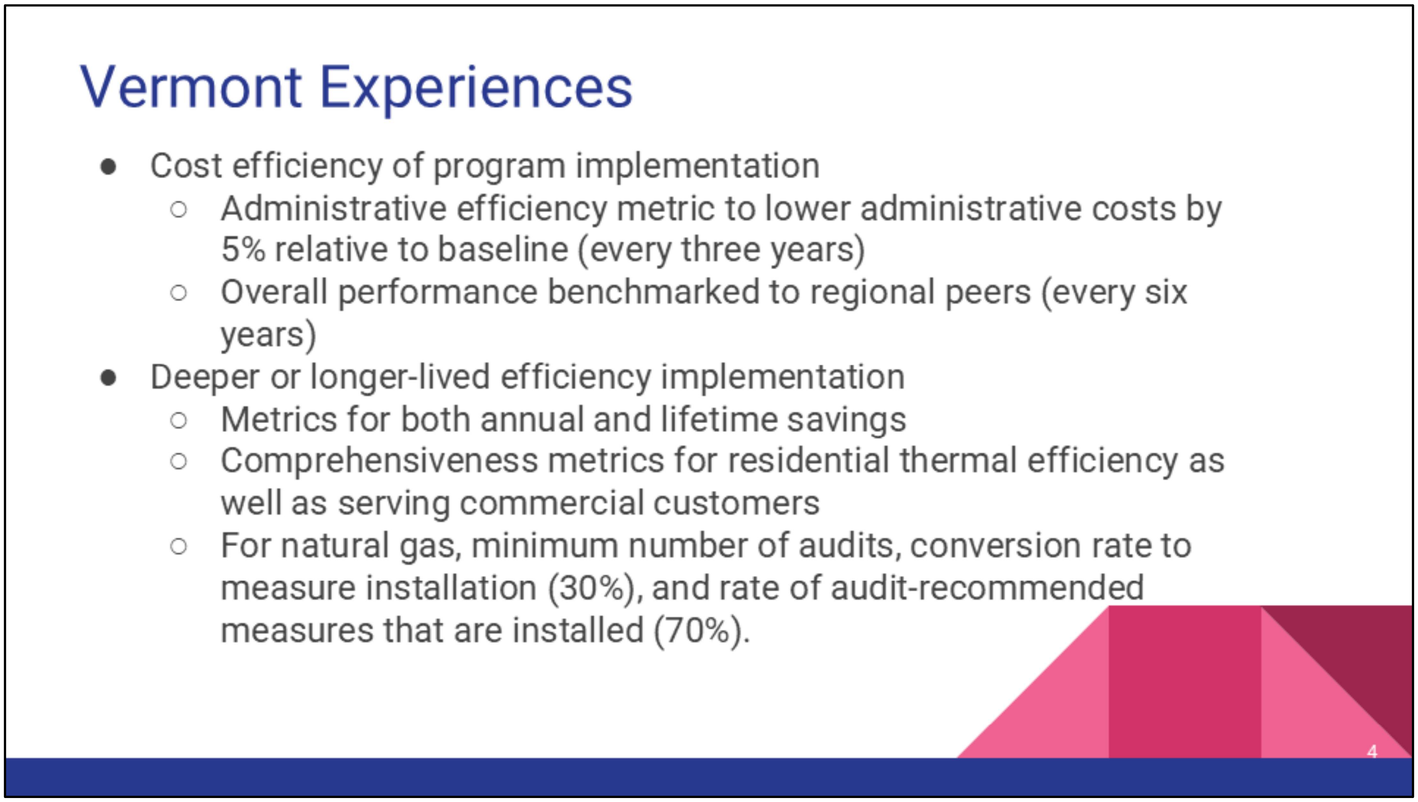
Share-the-Savings (STS) EAM

Results

	2020 (3/31/22 Report)	2021 (6/14/23 Report)	2022 (4/1/24 Report)
Target	20.4M LMMBtu	24.3M LMMBtu	29.9M LMMBtu
Budget	$172.2 M	$208.0 M	$237.3 M
Expected Weighted Avg EUL	10.4	10.4	10.99
Budget Unit Cost	$8.45 per LMMBtu	$8.57 per LMMBtu	$7.94 per LMMBtu
Achievement	26.4M LMMBtu	34.6M LMMBtu	41.2M LMMBtu
Resulting Unit Cost	$5.82 per LMMBtu	$6.41per LMMBtu	$10.99 per LMMBtu
EAM Earned	**$18.3 million**	**$22.4 million**	**$0.00**

3

- In 2022, the company's unit cost was almost $11 per LMMBTU. This increase happens over time as efficiency programs mature, cost of savings goes up. The reason behind this jump from $6 to $11 from 2021 to 2022 is unknown.



Compares efficiency metrics in NY to VT

- Deeper savings
    - There is nothing similar to NY's deeper, longer-lived measures in VT. In VT, a combination of multiple metrics achieve the same policy goal
    - There are distinct metrics for both annual efficiency and lifetime savings, and lifetime savings goals can't be achieved unless longer-lived measures are implemented.
    - VT doesn't allow behavioral type efficiency in programs and instead has a bias towards deeper type efficiency
    - For thermal efficiency, there are comprehensiveness metrics. One utility has to achieve a certain number of comprehensive residential weatherization projects each year, reduce air leakage by an average of 34%, and add insulation to an average of 50% of finished floor area
    - There is also a comprehensiveness metric for commercial customers for heating systems and building shell improvements
    - Metrics are weighted for each utility
    - Weighting for the gas utility is 20% of the potential earnings mechanism dedicated to comprehensive and deeper levels of energy savings

2. Share the savings

- This metric is directionally similar to two different ways of measuring efficiency programs in VT
- The administrative efficiency performance metric is achieved if the utility

decreases administrative costs by 5% relative to a baseline target over a few year period

- NY looks at total costs of savings while VT only looks at administrative costs
- VT looks at overall program costs every 6 years, not in comparison to a predetermined benchmark but relative compared to similarly situated efficiency program administrators in the region. There is no financial incentive attachment but instead is part of the consideration whether the incumbent should keep its job in administering efficiency programs or VT should look for someone else to administer efficiency programs
- This metric is only somewhat helpful because looking at different program administrators causes all sorts of asterisks, because different program administrators account for costs differently. Therefore, cross jurisdictional comparisons only have so much meaning. Resultingly, the NY way is somewhat superior

Relative Financial Impact of EAM

Results

Year	EE and PR EAMs	Con Edison Revenue (Electric Only)	Operating Income (Electric Only)	Percentage of Operating Income
2020	$44.41 M	$8,103 M	$1,731 M	2.57%
2021	$66.5 M	$8,806 M	$1,802 M	3.69%
2022	$28.34 M	$9,751 M	$1,496 M	1.89%

2020 EAM: $11.61-PR, $0.0-LSRV, $14.5-DEEL, and $18.3-STS - Total $44.41 million
2021 EAM: $12.2-PR, $0.0-LSRV, $31.9-DEEL, and $22.4-STS - Total $66.5 million
2022 EAM: $0.0-PR, $0.0-LSRV, $28.34-DEEL, and $0.0-STS - Total $28.34 million

Note: Con Edison Electric only Revenue and Operating Income from:

- 2022 Annual Report, p. 64
- 2021 Annual Report, p. 62

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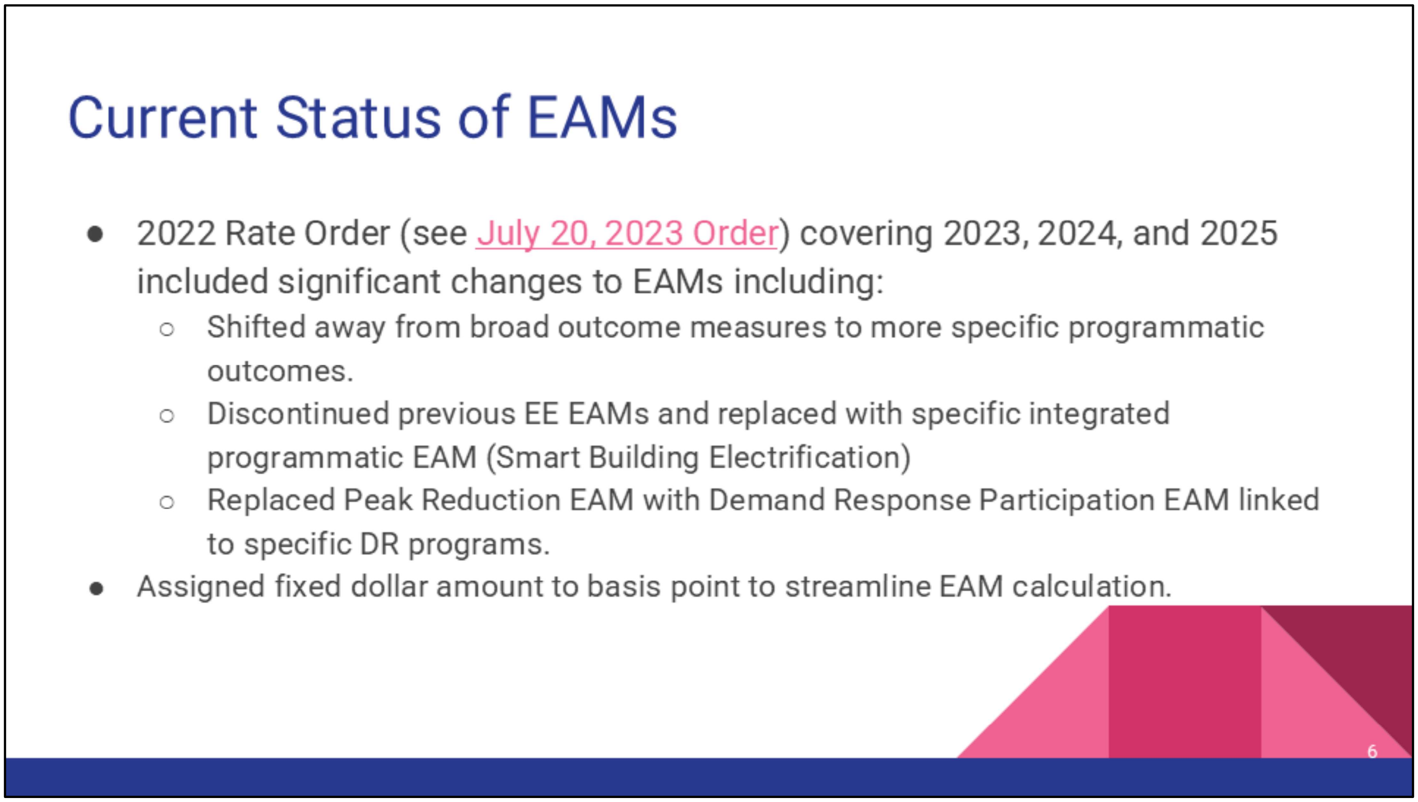
Summary comments

- One thing that has come up a lot of with PBR is the component of selectinig the right measures and targets but also are awards enough economically to promote changes at the utility level
- Comm. Hughes was personally surprised that the awards seem sizable compared to some PBR in NC (with a caveat that NC is just starting with PBR)
- The amounts of awards and penalties were much lower in NC
- Con Edison was fairly successful at getting significant positive EAM adjustments to the level of 2.5% of operating income. Magnitude wise, utilities Comm. Hughes has worked with fight tooth and nail for much lower percentages for much smaller positive upside, so this is a sizable number
- Jumped to over 3.5% in 2021
- Fell a little bit in 2022

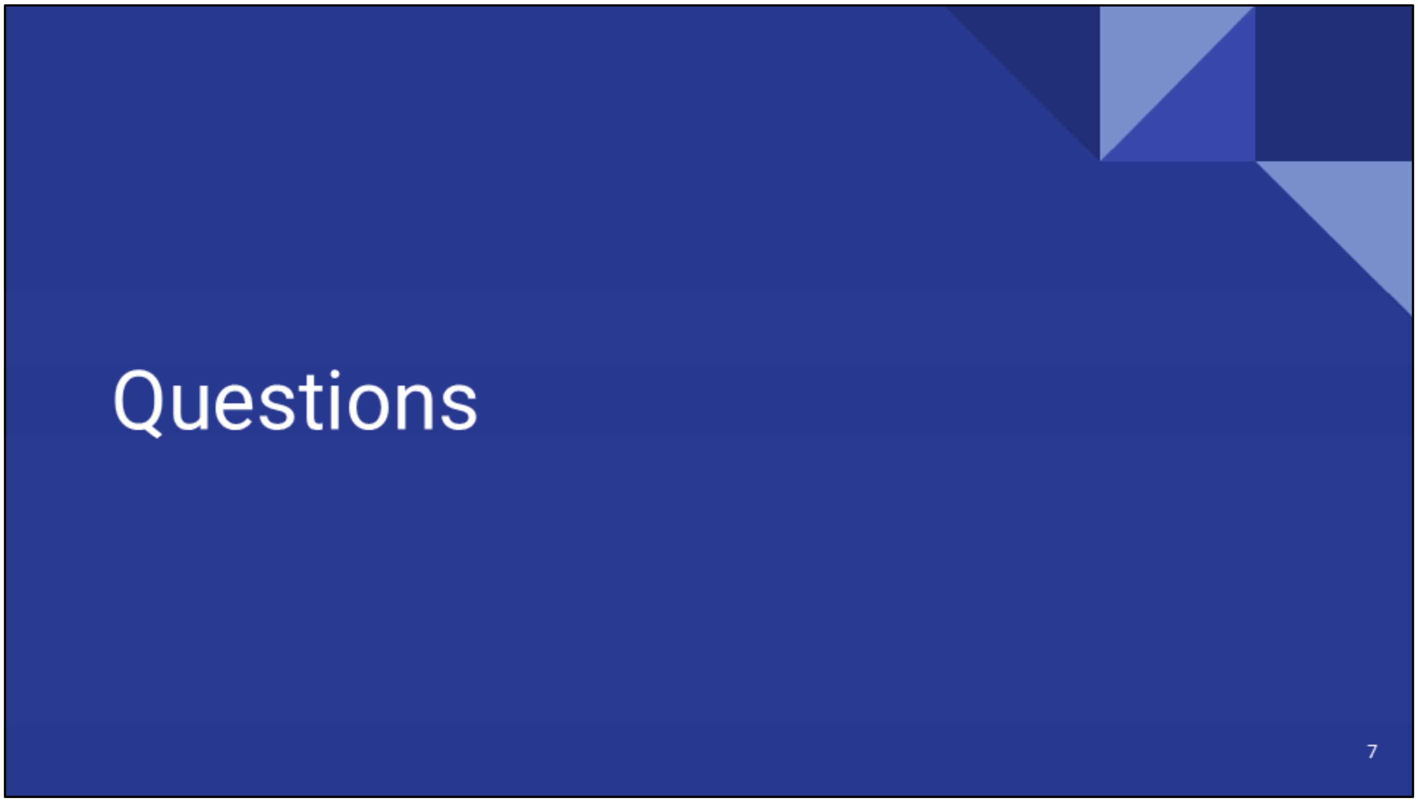


Comments combine what happened in NY and the current status of EAMs
- Comm. Hughes stated that they heard from a team in the NY Commission this past week and he wished they got them on a call earlier
- NY looked at the impact of their EAMs and made very significant changes when charged with approving new EAMs for a new period (2023-2025 done in a 2022 rate order). Concerning points mentioned previously in this presentation were echoed by NY staff

- Comm. Hughes stated that the broadest change is a shift away from broad outcome measures to specific programmatic outcomes and achievements. The idea of looking at broad outcomes and giving utilities discretion on achieving an outcome sounds good, but what they found in NY particularly in peak reduction was that utilities were just focused on looking at peak demands in their service area. The pandemic caused peak demands to drop significantly and the utility was rewarded very significantly for that outcome. This scared commission staff away from having broad outcome measures
- Recently, both the peak reduction and EE EAMs completed changed. They are now more programmatic and focused on very specific programs the utility would implement. There is also now a more traditional measurement of how the program achieved and rewards are given based on that achievement
- One factor that influenced changes is that NY passed major decarbonization legislation in 2019 and from a policy perspective, it took energy efficiency from more of an aspirational goal to rigid policy target codified in statutes
- Therefore, the NY Commission pulled back in rewarding run of the mill energy

efficiency, because it is now law that utilities met these energy efficiency standards. Awards went toward beyond a compliance approach

- Testimony related to the rate order referenced this law and stated that the NY Commission can no longer support PBR approaches that are now requirements in the law
- Continued status of EAMs
    - EAMS continue to only have positive upside rewards and no penalties
    - Comm. Hughes found it interesting that within the same rate order, there are other PBR aspects to revenue recovery. Customer service is covered in a large way in PBR outside of the current EAM approach but included very significant penalties
    - ConEdison had several years of sizable penalties on customer service, and they weren't happy. The utility has really pushed back on any downside performance-based approach. The NY Staff told us that it has been a perpetual back and forth
    - The NY Commission conceded to only having upsides to energy efficiency and DSM
    - Comm. Hughes speculated that a more balanced, downside approach is in the future for EE and DSM



Q1: Comm. Anthony- Was there anything that NY was doing that would solve a problem in your state?

1. A: Comm. Hughes- The first thing that comes to mind is that NC has long rewarded energy efficiency, so while NC is new to PBR, EE has had sizable incentives for years. He was struck by the framework for positive benefit cost ratio in that once established, it is full steam ahead and the commission doesn't look at it after that. Some incentives increase as benefits increase, but NC does not reward a utility for coming up with really efficient ways for saving energy vs run of the mill just hit the minimum threshold and walk away with an incentive. Meanwhile, it pleased Comm. Hughes to see NY has an efficiency of energy efficiency metric that measures how the cost effectiveness of implementation, which is what struck him the most
2. A: Tom- This is a useful metric, and a good way to keep the utility focused on the cost of implementing energy efficiency programs. The baseline was not determined in this rate case order but instead in an efficiency case. It is useful as long as a careful review of utility's budget and projected savings is conducted to determine the baseline and whether those baselines are based on solid, historic costs. It could be a useful substitute metric in VT, as VT already has performance metrics in the teens for energy efficiency programs. Utilities are already pulled in several different directions,

so he is not sure if the addition of another metric would be helpful in efficiently serving customers.

Q2: Comm. Anthony- The RI Commission recently discovered that they can't really determine whether metrics/tool/money are effective. Does NY have the evidence to make this decision on effectiveness of incentives? What else would you need to see to approve these proposals?

1. A: Comm. Hughes- If you read testimony of 2022, you can read in between the lines and we got this point blank from NY staff, this was a big concern of theirs from 2020-2022. The NY Commission didn't think there was evidence particularly with peak reduction. Instead, they felt that a lot of money went out due to the pandemic. Therefore, the 3rd round of EAMs are more stingy. Comm. Hughes is impressed with the complexity but also these EAMs are complicated. The new metrics are clear in the way they are designed that they can determine impact on the customer base, In sum, Comm. Hughes does not feel there was sufficient evidence for a lot of these metrics, but NY checked and corrected and are moving forward with a different approach
2. A: Tom- This serves as a reminder to colleagues that if you are setting a performance metric, make sure to understand how it is measured. If you are offering a utility millions of dollars, make sure you are comfortable with the metrics such as net vs gross savings. Heat pumps is a classic example in that the net to gross factor keeps going down over time.
3. A: Comm. Anthony- Comm. Anthony had a similar experience in RI for their EE and peak reduction EAMs. Performance incentives were based on net benefits and how much a utility spends to get net benefits (dollar benefits per dollar spent). For energy efficiency, costs are set at beginning of the performance period, which is ever 3 years, but avoided cost values are volatile and can majorly change in one year so much so that they might be no where near the value when it was approved. This is a riskier proposition for rate payers because value can be volatile over the 3 year period.

Q3: Jeff Loiter- 3 years seems to be a common cadence for efficiency programs in PBR. Is there a sense that this might be too long? That 3 years is too slow to adapt to volatility, avoided costs, and pandemics? Is that a conversation in this group?

1. A: Comm. Hughes- Comm. Hughes can feel the NY Commission staff cringing at the suggestion to do it more often than every 3 years. NY has 6 large utilities they regulate and each has different metrics, and the NY Commission staff felt they didn't have resources to look into it every 3 years nonetheless even more frequent. On the energy efficiency side, it is difficult to make sizable

changes in incentives. It is a nice idea to do more recurring incentives but not practical

2. A: Comm. Anthony: RI looks at them every year. The utility files proposals every year. The one time RI didn't, it was a disaster. It was badly designed, because the RI Commission didn't have enough time to look into it in the context of rate case and it ended up being a give away to utility that the RI Commission was stuck with for 4-5 years. Comm. Anthony thinks that if setting for more than a year, the commission should feel very confident in it and know how it's going to work.
3. A: Hughes: That's one of the reasons NY got so conservative in this round due to what happened in the last round, because they knew they were giving away for peak reduction but were stuck with it for as long as the pandemic lasted

Q4: Comm. Hughes- Question for CT: The NY staff said CT has significant downside incentives for PBR and NY made it seem like it was a difficult process for CT politically. Would you stand by having negative downside penalties?

1. A: Comm. Anthony: RI uses penalties differently than CT, but RI has penalties for service quality. When the RI Commission updated the energy efficiency performance incentive to make it a function of net benefits per dollar spent, it turned out that low income and residential programs don't have net benefits, so they couldn't give a performance incentive as a function of net benefits. The RI Commission wanted the utility to implement the energy efficiency program they were approving, so they gave penalties associated with not delivering the program the utility said they were going to deliver even though it will have net costs for customers. Comm. Anthony is more amused by the utility's advanced metering proposal, which is a penalty only performance plan for achieving functionalities the utility company said they would achieve like network speed, calculated vs estimated bills, and outage notifications. The RI Commission gave the utility parameters and asked them to propose penalty-only performance parameters. The RO Commission gave financial ranges and parameters. In response, the utility was out of compliance of the order by lowering the maximum penalty in every proposal. What became clear is the utility didn't understand what the RI commissioners wanted. The RI Commission wanted to hold the utility accountable for implementation through penalties. The RI Commission us still working through that, and Comm. Anthon finds it interesting how averse the utility is to penalties
2. A: Comm. Hughes- NC PBRs have some negative downside but they are minuscule in comparison to the significant penalties in NY


Appendix
8

Peak Reduction EAM

Achievement - Basis Points Awarded			
Level	**2020**	**2021**	**2022**
Minimum	3	3	3
Midpoint	5	5	5
Maximum	8	8	8
Value of an EAM basis point			
Electric	$1.45 million	$1.53 million	$1.60 million

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LSRV Load Factor EAM

Achievement - Basis Points Awarded

Level	2020	2021	2022
Minimum	1	1	1
Midpoint	3	3	3
Maximum	5	5	5

DEEL EAM

Achievement - Basis Points Awarded

Level	2020	2021	2022
Minimum	2	2.5	3
Maximum	11	12+BP carryover from 2020	13+BP carryover from 2021

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Share-the-Savings (STS) EAM

Achievement - Basis Points Awarded

Level	2020	2021	2022
Minimum	30% of $/Lifetime MMBTU Savings applied to acquired non-LMI EE savings		
Midpoint			
Maximum			

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Insights from New York Public Services Commission Staff Discussion

- Created a general framework that allowed PBR details to be established during general rate cases. Established a cap of 100 basis points.
- PBR implementation in the EE and DSM areas have not included negative (punitive) earnings adjustments as do other types of PBR such as customer service, which includes a “downside.” Utilities have consistently pushed back on the use of “downside” EAMs.
- EE and DSM PBR approach has evolved over time and broader output EAMs such as Peak Reduction to more specific programmatic EAMs.
- Lack of consistency across the different utilities and rate cases allows for customization and adaption but increases staff resource needs.

Impact of the Passage of the Climate Leadership and Community Production Act (CLCPA)

Program targets are no longer aspirational goals within the context of a Commission-led initiative. With the passage of the CLCPA, the achievement of these goals is now a statutory mandate, the achievement of which the Commission must impose upon utilities, and the Company has an obligation to do so at least cost. (Page 22, Staff Panel EAM Testimony Case 22-E-0064)

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Focus on “beyond compliance”

We are concerned that providing the Company with a monetary award for mandated EE and Heating Electrification achievement on top of the increased investment in EE and Heating Electrification required by the CLCPA will negatively impact ratepayers. (Page 39, Staff EAM Panel Testimony Case 22-E-0064)

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