AFFIDAVIT

THE FAIR TRADING COMMISSION

IN THE MATTER of the Application by the Barbados Light & Power Company (the BLPC) requests the approval of the Fair Trading Commission (the Commission) to establish a Clean Energy Transition Rider Mechanism to recover the cost associated with its Clean Energy Transition Programme (CETP).

AFFIDAVIT OF PEARL DONOHOO-VALLETT

I PEARL DONOHOO-VALLETT, of 1817 Bay Street Southeast, Washington, D.C. in the country of the United States, being duly sworn hereby **MAKE OATH** and say as follows:

1. I am a Senior Associate of The Brattle Group and specialize in regulatory and planning topics for electric and natural gas utilities as well as electric transmission planning. I have experience supporting utilities and regulators on issues of performance based regulation, performance incentive mechanisms, rate design, marginal cost of service, and cost-benefit analysis applied to energy efficiency, demand response, and non-wires alternatives.

2. I have co-authored reports submitted to regulatory dockets in the United States and internationally and submitted an expert report to the Circuit Court of White County, Arkansas, USA. My experience includes supporting

utilities in jurisdictions with deep decarbonisation goals including Hawai'i, New York, and Washington, D.C.

3. Prior to The Brattle Group, I was a post-doctoral researcher at Johns Hopkins University and a contractor at the National Renewable Energy Laboratory. I earned my Ph.D. in Engineering Systems: Technology, Management, and Policy at the Massachusetts Institute of Technology.

4. A copy of my resume is attached hereto and marked as Exhibit "**PD1**."

5. In October 2018, The Brattle Group was retained by BLPC to provide Rate Case Assistance, which included a review of performance incentive mechanisms. My colleagues, Mr. Bruce Tsuchida and Mr. Philip Q Hanser, of The Brattle Group and myself prepared the memorandum in Exhibit "**PD2**" which discusses the proposed design of the CETR.

6. The purpose of my testimony is to present our analysis of tracker design and the design of the Clean Energy Transition Rider (CETR) as proposed by the Barbados Light & Power Company Limited (BLPC) to recover expenses associated with the Clean Energy Transition Program (CETP), a 5-year bridging plan to support the Government's 100/100 Vision goals. The BLPC anticipates that the capital requirements of the CETP will be approximately $270 million, in addition to the sustaining capital required for normal system investments. Without an adjustment to the regulatory environment, the BLPC represents that it will not be able to make the investments supporting the 100/100 Vision while maintaining a reasonable opportunity to earn its regulated return on equity, partially due to regulatory lag. This, the increased capital investments required to enable the 100/100 Vision goals merit consideration of adapting the current regulatory environment to allow for timely recovery of investments and efficient customer price signals.

7. The structure of the CETR contains multiple opportunities for intervenors to review proposed expenditures and allows for the possibility of a cap on CETP

cost recovery, depending on the bill impact to customers. The proposed CETR includes pre-approval, before investments are made, for both broad categories allowed for recovery through the CETR and specific project projects. The CETR also includes a review of expenditures before added to the tracker for recovery. The BLPC anticipates that the CETP investments recovered through the CETR investments will be offset by fuel cost savings. If costs from the CETR exceed the fuel savings, the proposed design includes the possibility for the FTC to consider an annual rate increase cap, with revenues and appropriate interest delayed to subsequent years

8. The components of the CETR proposed by the BLPC generally follow regulatory acceptable precedents for trackers and are matched to the operating context of the BLPC. Alternatives to a tracker, including the use of formula rates, multi-year rate plans, or holding annual rate cases, could similarly enable the required 100/100 Vision investments, but would likely present greater regulatory burden to the FTC, the BLPC, and stakeholders.

SWORN TO by **PEARL DONOHOO-VALLETT**) Pearl E.D.

at the)
this 18th day of June, 2020)

Before me:

LEGAL ASSISTANT

<u>EXHIBIT “PD1”</u>

This is a copy of the document marked Exhibit “PD1” mentioned and referred to in paragraph 4 in the said Affidavit of Dr. Pearl Donohoo-Vallett

PEARL DONOHOO-VALLETT

Senior Associate

Washington, DC | +1.202.955.5050 | Pearl.Donohoo-Vallett@brattle.com

Dr. Pearl Donohoo-Vallett provides utilities and independent transmission companies strategic support on the increasing overlap of retail and wholesale regulatory and policy issues including the value of distribution resources, non-wires alternatives, and performance-based and alternative regulatory mechanisms. Her recent work for utilities, merchant transmission developers, and regulators focuses on:

- Performance based and alternative ratemaking,
- Distributed energy resources,
- Marginal cost of service,
- Clean energy policy, and
- Transmission planning.

Dr. Donohoo-Vallett brings her breadth of experience across alternative ratemaking mechanisms, performance incentive mechanisms, distributed energy resources, system operation, renewable portfolio standards, and transmission planning to help clients identify, understand and address emerging utility challenges. She also works with transmission developers to identify value propositions and estimate the economic footprint of projects. Dr. Donohoo-Vallett is active within the firm's pro bono practice currently working on criminal justice related issues.

EDUCATION

Dr. Donohoo-Vallett earned her Ph.D. from MIT in the field of Technology, Management and Policy; her doctoral dissertation explored transmission planning under uncertainty. She earned her S.M. from the Technology and Policy Program at MIT and a B.S. in Mechanical Engineering from the Franklin W. Olin College of Engineering.

AREAS OF EXPERTISE

- Performance Based Ratemaking
- Marginal Cost of Service
- Clean Energy Policy
- Transmission Planning and Evaluation

REPRESENTATIVE EXPERIENCE

Performance Based/Alternative Regulation

- For a U.S. utility, provided analysis on potential areas for shared savings mechanisms and performance incentive mechanisms and review of utility proposed responses. Analysis included review of best practices, discussion of alignment with commission goals, and benchmarking of O&M performance.

- For a U.S. utility, provided stakeholder and utility education on alternative regulation, including underlying economic concepts and current regulatory process. Presented an overview of alternative regulation to stakeholders and supported the utility in its ongoing stakeholder proceedings. Developed detailed case studies of multi-year rate plans for executives to demonstrate the variety of approaches to regulatory plans. Worked with the utility to identify potential performance incentives that would align with local policies and prioritize measures based on the utility's risk in implantation.
- For a U.S. utility, developed ten detailed state case studies on alternative regulation respond to commission questions in a docket on alternative regulation. Augmented case studies with an informal survey of select utility commissions in a report filed with the commission.
- For a U.S. utility, prepared a report demonstrating the wide-spread nature of alternative regulatory mechanisms including state-counts of different regulatory approaches.
- For a U.S. utility, supported filing of a new regulatory plan including formula-based rates and performance incentive mechanisms. Assisted the utility understanding industry standard and emergent performance incentive mechanisms and aided the utility in shaping its performance incentive mechanism portfolio. Supported preparation of direct testimony and discovery responses.
- For a Canadian utility, advised and supported new performance based metrics that were grounded in a survey of Canadian and U.S. reliability, customer service, and storm performance based regulations. Supported preparation of direct testimony and discovery responses.

Natural Gas Distribution

- For a large east-coast utility, reviewed benefit cost framework and model data to evaluate non-pipe options. The review included treatment of geographic differences in marginal costs due to pipeline access, and the Brattle team rebuilt the model from the ground-up to allow for intuitive use.
- For a U.S. based municipal natural gas distribution company, developed financial benchmarking to illustrate the company's performance relative to peers and industry trends during for a rate case. Developed integrated financial model to conduct scenario analysis on future health of the company including impact of increased borrowing. Supported direct testimony.
- For a proposed natural gas distribution company and electric utility merger, analyzed market power issues related to fuel-switching in home heating through census data and bottom-up technology models.

Cost of Service and Rate Design

- For a Canadian utility, developed a transmission rate design proposal to reflect evolution of the system, including the growth in distributed energy resources on bypass, changing generation types and needs, and differentiation in geographic load growth.
- For a state commission, reviewed and critiqued a utility sponsored distribution marginal cost of study analysis based premised on an engineering approach. Supported the use of a marginal cost approach that reflects the timing of investments and straightforward analysis of time-of-day marginal costing for T&D assets.
- For a state commission, reviewed proposed rate designs for two utilities against Bonbright's rate design principles.
- For a Canadian commission, reviewed and critiqued the marginal cost of study for generation and transmission using an engineering approach for going-forward costs. Critique included analysis of export potential and appropriate energy costs.

Value of Distributed Energy Resources and Non-Wires Alternatives

- For a U.S. utility, reviewed the utility's benefit cost assessment model used to evaluate distributed energy resources for alignment with commission orders and staff guidance. The assessment identified areas for refinement, including increasing the temporal and geographic granularity of the model. As part of the review, the Brattle team provided insights into potential misalignments between the valuation of transmission and distribution investment deferral within the model, customer value, and system value. The Brattle team rebuilt the model from the ground-up to allow for intuitive use and ensure that assumptions are clearly articulated and well-documented.
- For an independent transmission company, provided assessment intervener testimony regarding potential for non-wires alternatives to mimic benefits of proposed transmission line. Assessment included review of regulatory and practical barriers to implementation of proposed alternative based on jurisdictional requirements and existing regulatory models.
- For a U.S. utility with heterogeneous service territory, developed a granular distribution marginal cost of service model and study to provide improved pricing signals and reflect varied investment needs across the system. Worked collaboratively with the utility's engineering teams to classify investments, quantify capacity needs, and align forecasts.
- For a large U.S. utility with a dense urban service territory, developed a granular distribution marginal cost of service model to provide improved pricing signals for the location of distribute energy resources. The study differentiated areas of the system geographically, to reflect differing

costs, and network topology, to reflect the ability of distributed energy resources to offset multiple investments.

- For a U.S. utility, developed modeling to assess the value of commercial and industrial demand options across wholesale energy, ancillary service, and transmission and distribution value streams.

Clean Energy

- For a battery manufacturer, analyzed the ability of market stakeholders to anticipate changes to PJM's regulation market and explained the impact of those changes on battery performance.
- For the Massachusetts Attorney General's Office, reviewed the 83C offshore wind procurement process and developed analyses to support critiques of the solicitation process. Described potential benefits of including offshore wind transmission networks in future solicitations and potential distortion of project ranking due to scoring methodology used.
- For the Massachusetts Attorney General's Office, reviewed the 83D hydro and renewables procurement process. Reviewed and critiqued ability of power purchase agreements to procure incremental hydro generation for Massachusetts. Analyzed and described scoring improvements to remove potential distortions in future solicitations.
- For a trade group, reviewed clean energy policy differences by generator and vintage and developed an analysis of Tier 1 and Tier 2 renewable energy credit prices.
- For an investment group, provided strategic information related to potential future renewable energy and regional transmission needs through a review of policy drivers and procurement processes.
- For a consortium of Canadian entities, examined the potential for imported Canadian generation to qualify and participate in U.S. carbon mitigation programs. Analyzed Clean Power Plan legislation and provided insight into how participation may vary between different greenhouse gas policy implementation options. Developed framework for how Canadian generators could participate in state programs based on existing renewable portfolio tracking systems and eligibility requirements.
- For a large U.S. city, developed a comprehensive regional electricity generation capacity expansion model to evaluate options for greenhouse gas emission reductions to achieve economy-wide deep decarbonization under multiple scenarios developed in concert with stakeholders.
- Prior to joining The Brattle Group, compared current operating reserve definitions across timescales (frequency to replacement) and levels to modeled approaches in wind integrated studies in the U.S. and internationally.
- Prior to joining The Brattle Group, evaluated trade-offs between carbon dioxide emissions, water usage and cost for generation capacity planning in ERCOT.

Transmission

- For a large U.S. utility, analyzed the economic footprint of a new transmission project across four regions.
- For a large U.S. utility, analyzed the economic footprint of a generation tie line and wind farm using custom spending models to reflect geographic location of suppliers and work force.
- For a large U.S. utility, analyzed the economic footprint of its transmission investment portfolio across multiple states. As part of the engagement, benchmarked spending patterns to existing models and created custom spending models to reflect investment type, voltage level of equipment, and geographic location of suppliers and work force.
- For the WIRES organization, provided comments to the FERC on the resiliency benefits and challenges related to the transmission network.
- For a transmission development company, reviewed renewable energy credit markets and renewable portfolio standard eligibility requirements to develop an estimate of the potential value streams for users of an HVDC line.
- For a transmission development company, provided feedback and mock scoring of the company's bid for a FERC Order 1000 competitive transmission solicitation.
- For a Canadian transmission operator, reviewed Open Access Transmission Tariff requirements and NERC eTag practices to identify commonly applied practices.
- For a merchant transmission developer, analyzed the potential value of an HVDC line connecting the MISO and PJM markets.
- For a merchant transmission developer, synthesized transmission, natural gas and renewable generation studies to identify high-value transmission corridors.
- Prior to joining The Brattle Group, worked with a team to co-plan transmission and generation in WECC. Dr. Donohoo-Vallett developed a reduced-model of the WECC transmission network incorporating new transmission investments and existing reliability flow-constraints.

ACADEMIC HONORS AND FELLOWSHIPS

- Martin Family Society of Fellows for Sustainability (2012)
- National Science Foundation Graduate Research Fellowship (2009-2013)
- BP MIT Energy Fellowship (2009)

PUBLICATIONS

- "Comments on Commissioner Anthony's Principles for Performance Incentive Mechanisms," W. Zarakas and P. Donohoo-Vallett, prepared for Narragansett Electric Company d/b/a National Grid, submitted to RIPUC Docket No. 4943. February 28, 2020.
- "Review of Existing and Proposed Network Additions Policies for Newfoundland and Labrador Hydro," A. Ros, P. Hanser, and P. Donohoo-Vallett, prepared for the Newfoundland and Labrador Board of Commissioners of Public Utilities. November 19, 2019.
- "Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates: Response to PC51 Request for Comments," W. Zarakas, S. Sergici, P. Donohoo-Vallett, and N. Irwin, prepared for Joint Utilities of Maryland and filed in support of comments in PC51 for the Maryland Public Utilities Commission. March 29, 2019.
- "U.S. Alternative Regulatory Mechanisms: Scope, Status and Future," W. Zarakas, S. Sergici, and P. Donohoo-Vallett, prepared for Baltimore Gas & Electric, Delmarva Power & Light, and Pepco. February, 2019.
- "Recognizing the Role of Transmission in Electric System Resilience," M. Chupka and P. Donohoo-Vallett, prepared for WIRES and submitted to ERC Docket No. AD18-7-000. May 9, 2018.
- "Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals," S. Newell, R. Lueken, J. Weiss, K. Spees, and P. Donohoo-Vallett. August 2017.
- "Capricious Cables: Understanding Key Concepts in Transmission Expansion Planning and Its Models," by P. Donohoo and M. Milligan. NREL Research Report; TP-5D00-61680. Golden, Colorado, 2014.
  "Water-CO2 Tradeoffs in Electricity Generation Planning," by M. Webster, P. Donohoo and M. Palmintier. Nature Climate Change. Issue 3. October 2013. doi: 10.1038/nclimate2032
- "Algorithmic Investment Screening for Wide-Area Transmission Network Expansion Planning," by P. Donohoo, M. Webster and I. Perez-Arriaga. IEEE Power and Energy Society General Meeting; Vancouver, Canada. July 2013.
- "Stochastic Methods for Planning and Operating Power Systems with Large Amounts of Wind and Solar Power," by M. Milligan, P. Donohoo and M. O'Malley. 10th International Workshop on Large-Scale Integration of Wind Power into Power Systems; Porto, Portugal. November 2012.

- "Using Market-Based Dispatching with Environmental Price Signals to Reduce Emissions and Water Use at Power Plants in the Texas Grid," by N. Alhajeri, P. Donohoo, A. Stillwell, C. King, M. Webster, M. Webber and D. Allen. Environmental Research Letters, Vol. 6, 2011.
- "Operating Reserves and Wind Power Integration: An International Comparison," by M. Milligan, P. Donohoo, D. Lew, E. Ela, et al. 9th International Workshop on Large-Scale Integration of Wind Power into Power Systems; Quebec, Canada. October 2010.
- "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," by L. Bird, D. Hurlbut, P. Donohoo, K. Cory and C. Kreycik. NREL Technical Report. March 2009.

PRESENTATIONS

- "Panel 2: Implementation Experience of Other States" with W. Zarakas. Presented to the District of Columbia Public Service Commission Technical Conference FC 1156. October 18, 2019.
- "Washington D.C. Performance-Based Regulation Workshop" with W. Zarakas and S Sergici. September 19, 2018.
- "Debtor's Prisons in Faulkner County: Review of Issues & Analysis of Historical Data" with C. Bazelon, H. Green, N. Powers, M. Vinnakota, and M. Yoder A. (Brattle); Crawford, K. Johnson, A. Lynn, L. Reynolds, K. Robisch, and S. Rosenthal (Veneable LLP); and M. Huggins and M. Kelley (Lawyers' Committee for Civil Rights Under Law), presented to Arkansas Journal of Social Change and Public Service Symposium: "Life Beyond Bars." April 2018.
- "Lessons from Large Scale Transmission Planning using Stochastic Programming: Evaluation for WECC" with B. Hobbs, J. Ho, S. Kasina, Q. Xu and J. Ouyang, presented at the EPRI Risk Based Planning Workshop. Little Rock, Arkansas. November 19, 2015.
- "Transmission Planning for Renewables" presented at the Utility Variable-Generation Integration Group Spring Technical Workshop. Anchorage, Alaska. May, 2014.
- "Strategic Robust Transmission Planning" with M. Webster, and I. Perez-Arriaga, presented at the Western Electric Coordinating Council. Salt Lake City, Utah. May, 2012.
- "Robust Transmission Planning: Overview of Issues" with M. Webster. And I. Perez-Arriaga, presented to ABB Corporate Research Center. Raleigh, North Carolina. February, 2012.

- "Integrating Dynamics and Generator Location Uncertainty for Robust Electric Transmission Planning" presented at the INFORMS Annual Meeting. Charlotte, North Carolina, USA. November, 2011. Presented to Red Eléctrica. Madrid, Spain. July, 2011.

EXHIBIT “PD2”

This is a copy of the document marked Exhibit “PD2” mentioned and referred to in paragraph 5 in the said Affidavit of Dr. Pearl Donohoo-Vallett

Review of the Clean Energy Transition Rider

ENABLING THE 100/100 VISION

PREPARED FOR

THE BARBADOS LIGHT & POWER COMPANY LIMITED

PREPARED BY

Pearl Donohoo-Vallett

Philip Q Hanser

T. Bruce Tsuchida

THE Brattle GROUP

Table of Contents

I. Executive Summary

1. Achieving the 100/100 Vision will require a transformation of Barbados' electricity industry, replacing more than 90% of its existing generation with new clean, renewable resources. This transformation will need more than 600 MW of new clean energy and storage to replace the 300 MW of existing fossil generation.[1] One such portfolio includes 205 MW of centralized solar, 105 MW of distributed solar, 150 MW of onshore wind, 150 MW of offshore wind, 15 MW of biomass and waste-to-energy, and 200 MW of energy storage.[2] As these resources will likely be dispersed across the island, the transmission and distribution networks must be modernized to enable new flow patterns. This modernization includes new hardware and sensors to allow two-way flow from distributed resources and communication devices to control the increased number of resources.

2. The 100/100 Vision will place Barbados on the cutting edge of de-carbonization, and the Barbados Light and Power Company (the BLPC) will be a crucial partner in transforming the island electricity industry while continuing to provide safe and reliable service. To lay the groundwork for the 100/100 Vision, the BLPC has developed a bridging plan, the Clean Energy Transition Program (CETP)—a 5-year investment plan (2020-2024). The CETP includes the Clean Energy Resiliency Bridge, renewable generation (including a 10 MW wind farm at Lamberts St. Lucy and an additional 15 MW solar PV plant), energy storage, and grid modernization expenses.

3. The increased capital investments required to enable the 100/100 Vision represent a marked departure from business as usual and merit consideration of adapting the current regulatory environment to allow for timely recovery of investments and efficient customer price signals. The BLPC anticipates the first phase of electricity sector investments in the CETP will cost over $270 million, in addition to the sustaining capital required for normal

---

1 Ministry of Energy and Water Resources, "Barbados National Energy Policy 2019-2030," http://energy.gov.bb/web/national-energy-policy-for-barbados-2019-2030

2 *Id.*

system investments. To make these and other ongoing investments that enable the initial transition towards 100/100 Vision, the BLPC faces issues including:[3]

- **Timely recovery** of capital investments needed to transition towards the 100/100 Vision
- **Stranded assets** as investments needed today to transition towards the 100/100 Vision may become obsolete due to system evolution
- **Increased system operating expenses** due to increased flexibility needs (i.e., ancillary services, quick starts, cycling etc.) to accommodate the variable outputs of renewable resources

4. Given the need for these investments to enable the transition towards 100/100 Vision, the near term impacts related to the timely recovery of capital investments require the most immediate attention.

5. Without an adjustment to its regulatory environment, the BLPC represents that it will not be able to make the investments supporting the 100/100 Vision while maintaining a reasonable opportunity to earn its regulated return on equity, due to regulatory lag. Regulatory lag is the time between when expenditures are made and when the utility recovers the revenue requirement for the expenditures.[4] In this case, the regulatory lag between 100/100 Vision investments and recovery would likely cause the BLPC to under-earn relative to its allowed return on equity (AROE) because the utility would be unable to add the investments to its rate base promptly. Without a change in its regulatory environment, the BLPC estimates that its actual return on rate base would be 5.42% in 2020 (relative to a 10% allowed rate of return) and decrease further to -0.89% in 2024. Furthermore, the requirement for the BLPC to finance a capital campaign would likely impair the utility's liquidity due to substantial outflows of capital before recovery.

6. The primary mechanisms available to the BLPC to support increases in investment today are rate case filings requesting higher base rates. To keep up with the 100/100 Vision

---

[3] If the BLPC is responsible for resource adequacy in the local market, then the BLPC would further be required to supplement (or replace) third-party generation that may become unavailable. This may include independent power producer that exits the system with insufficient notice or projects that are delayed in coming on line.

[4] In other situations, regulatory lag can provide an incentive for utilities to be fiscally efficient as the utility must absorb any increases in costs between rate cases and cause the utility to under-earn relative to its allowed return on equity (AROE). If the overall expenses are increasing at a lower rate than revenues (i.e., the utility's revenues are outpacing expenditures), then regulatory lag can benefit the utility and the utility could over-earn relative to its AROE.

investment needs and its changing rate base, the BLPC anticipates filing annual general rate cases. These would strain the resources of the Fair Trading Commission (FTC) and the BLPC. Historically, the BLPC's base rate cases have been infrequent due to the financial health of the BLPC and the regulatory burden associated with filing rate cases. An annual rate case filing would require that the BLPC prepare, and parties review, updates to the cost of service model, rate design, and cost of capital, in addition to changes in capital expenditures and operations and maintenance. To avoid this regulatory burden for fuel costs, the Fuel Clause Adjustment (FCA), which allows the BLPC to pass through fuel costs without requiring a general rate case to adjust base rates, was developed. The FCA focuses on a narrow scope to support the pass-through of fuel costs, not a major multi-faceted capital campaign that requires the development of forward-looking plans and review. Therefore, neither of the two primary regulatory mechanisms available and in place today to the BLPC is structured to accommodate an expansion in the capital program.

7. The BLPC is proposing a capital rider, the Clean Energy Transition Rider (CETR), as an alternative mechanism to allow timely recovery for expenditures related to the 100/100 Vision, initially focused on the CETP. Before inclusion in the tracker, these investments would need approval by the relevant regulatory authorities, and the CETR would address the revenue requirement for the assets, including financing. The BLPC proposes to file annual adjustments to the CETR on March 1 with rate adjustments beginning approximately 90 days later on June 1. These yearly adjustments would include assets that are in service as of March 1. When BLPC files a general rate case, the non-depreciated portion of assets will transition from the rider to the rate base.

8. The BLPC estimates that the CETP investments will likely result in minimal customer bill impacts and has proposed additional customer protection. Specifically, the BLPC estimates that reduction in fuel costs will offset CETP investments through 2025. To provide further protection to customers, the BLPC has proposed that in the event the CETR adjustment is higher than the fuel cost avoided, the FTC may consider a cap on annual rate increases. To balance customer protection with the BLPC's need to recover its investments, any costs not included in the rider due to a yearly cap would be deferred and recovered in subsequent years.

9. The remainder of this memo follows in four sections. Section II provides an overview of trackers and riders, including design components and typical applications. Section III reviews balancing objectives in capital tracker designs. Section IV reviews the BLPC's

proposed CETR, and Section V provides concluding remarks. The Appendix contains examples of capital riders and trackers in the United States.

II. Overview of Trackers

10. Trackers supplement traditional utility regulation by allowing utilities to recover pre-specified costs or categories of expenses outside of a general rate case. A general rate case requires regulators, stakeholders, and utilities to grapple with a wide range of issues, including the revenue requirement, rate design, and cost of capital. By avoiding a full rate case, trackers (and riders, these terms are used interchangeably here) can streamline the regulatory process and focus on a more narrowly defined subject. The streamlined regulatory process reduces regulatory burden and allows for more timely decision making and revenue recovery. For example, a fuel adjustment clause that allows the utility to adjust the utility bill based on its incurred fuel cost (sometimes adjusted against the prevailing market price of fuel) used for its generation, is a well-known tracker. Since a tracker's review is narrower than a general rate case, it is typically more expedited than a full rate case. This shorter review timeline increases the importance of clearly articulating the tracker's specifications and all parties – regulator, stakeholders, and utility – agreeing to them in the initial design. This Section begins by describing four critical components of trackers (in Section II.A) followed by a review of typical applications (in Section II.B).

A. Tracker Design Components

11. As summarized in Figure 1, a tracker's design usually consists of four core components: 1) scope; 2) approval process; 3) performance incentives; and 4) cost containment. Each element should be specified in sufficient detail during the tracker's design phase to avoid subsequent lengthy regulatory processes following the tracker's approval. Failing to do so potentially increases the regulatory burden, thus reducing the tracker's goal of process efficiency improvements in comparison to a full rate case. The components outlined in Figure 1 are discussed individually in the following subsections.

Figure 1: Tracker Design Components

Component	Specifications	Indicative Examples
Scope	Types of capital and O&M costs includable in the tracker	• Fuel costs • Utility-installed solar capital costs • Targeted distribution system upgrades • Construction work in progress
Approval Process	Method and timing of tracker expenses	• Annual pre-approval of program budgets • Annual ex-post approval of expenditures • Quarterly pre-approval of specific expenditures
Performance Incentives	Rewards/penalties for over/underperformance on budget or timeline	• Basis point reward for coming in under budget • Penalty for delayed implementation
Cost Containment	Limits on tracker recovery	• Rate increases limited to a certain percentage per year • Disallowances of costs above budget

1. Scope

12. The scope defines the types of costs that a utility may include in the tracker's cost recovery. A tracker's scope may be broad and include multiple types of expenditures (e.g., grid modernization) or narrow and limited to a single project or investment type (e.g., installation of advanced metering infrastructure). Similarly, a tracker can be designed for ongoing use (e.g., a fuel adjustment clause) or designed to end following completion of a pre-specified project or period (e.g., construction of a generating station's scrubber). As in typical utility revenue requirement calculations, trackers may be designed to recover some combination of capital costs, O&M costs and construction-related costs (i.e., construction work in progress (CWIP) or allowance for funds used during construction (AFUDC)).

13. Broadly scoped trackers, which are inclusive of multiple project types, can provide regulators and utilities flexibility to implement complementary initiatives under a single umbrella. Under a broad tracker, the utility can have the flexibility to substitute more efficient or valuable investments than the one(s) original scoped without the need to develop a new regulatory mechanism. This can ease the regulatory burden relative to managing multiple trackers.[5] The flexibility of broad trackers can be especially

5 This presumes that the regulator would approve the proposed substitute expenditures.

advantageous in circumstances where the required investments are heterogeneous, uncertain, or not well-defined initially.

14. By contrast, narrowly scoped trackers are less flexible from an investment perspective but may provide greater transparency to the extent that only well-defined expenditures are included. If the expenditures for a tracker are targeted in nature (e.g., fuel costs), then the review of expenditures is more straightforward. This narrow approach and concomitant transparency can provide customer protection by removing uncertainty concerning allowable expenditures. The trade-off for this transparency is the potential requirement for a range of trackers to achieve similar objectives. Rather than passing through multiple projects or types of projects through a single broad tracker, the regulator may need to authorize a unique tracker for each specific expenditure category.

15. Trackers that involve capital expenditures may include provisions for outlays during construction through CWIP or AFUDC. If a tracker allows the utility to recover CWIP, then the utility can seek recovery for expenditures before a capital investment comes into use. CWIP provides the utility with increased cash flows during the investment period and can act as a further incentive for the company to invest capital. Some jurisdictions do not permit the use of CWIP as expenditures are recoverable only when the asset is deemed "used and useful." CWIP can be viewed as reducing the prudency review of expenses as outlays are recovered before such a review. As an alternative, AFUDC allows for the recovery of financing costs during construction, but the recovery of those costs does not take place until after the asset is in service. The relative value to the utility of using CWIP or AFUDC depends on the size of the capital investment and the length of the construction period.[6]

2. Approval Process

16. Trackers typically have multiple approval levels, ranging from the approval of the tracker itself to prudency reviews of individual investments following the asset placement into service. Unlike typical utility expenditures or capital investments that are reviewed during a general rate case, the review of tracker expenditures is primarily dealt with outside the

---

[6] Typically, higher value is associated with larger projects and longer construction periods.

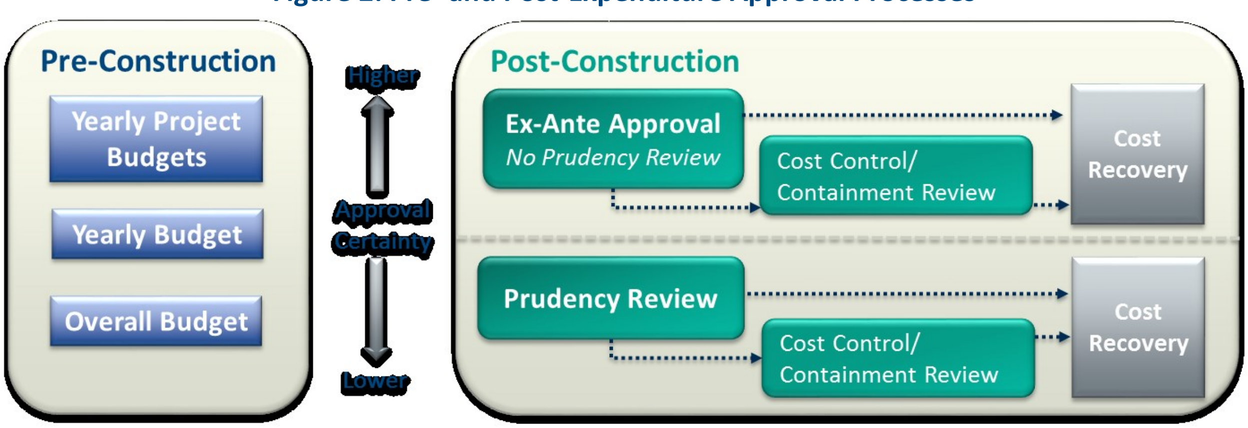
rate case process. The approval process can be viewed as comprising two stages: pre-expenditure and post-expenditure.

17. The pre-expenditure approval process can include approval of an overall (multi-year) budget, an annual budget, or budgets for specific projects to be recovered through the tracker. These pre-approval processes can also be combined. For example, an overall multi-year tracker budget approval could be paired with the subsequent approval of individual projects. More in-depth pre-approval processes provide greater certainty for customers and regulators on specific projects and their anticipated costs and give the utility greater confidence that expenditures will be treated as prudent.

18. The post-expenditure review can include prudency reviews or more formulaic audits or checks to see that the expenditures matched what was previously approved. These post-expenditure reviews can occur monthly, quarterly, or annually depending on the timing and magnitude of the expenditure within the tracker. The timing of the reviews should account for the likely investment or implementation schedule. For example, a monthly report of expenditures for a tracker related to the undergrounding of distribution lines may increase regulatory burdens without providing value as the undergrounding investments may take many months to make reviewable progress.

19. By shifting the amount of approval that takes place between pre- and post-construction approval, regulatory commissions can influence the relative risk of the investments, as illustrated in Figure 2. The more likely that the expenditures will be approved, the greater the utility's incentive to make those investments.

Figure 2: Pre- and Post-Expenditure Approval Processes



3. Performance Incentives

20. Performance incentives can be added to a tracker to incentivize cost-effective expenditures more forcefully and to deliver projects on or ahead of schedule. One critique of trackers is that with a pre-approved budget and without the customary regulatory lag between investments and recovery,[7] utilities lack incentives to make the most efficient expenditures. To counter these incentives, regulators can add performance incentives, such as modifications to the AROE and sharing of savings relative to the budget (i.e., the difference between the budgeted and actual expenditures). These incentives should only be applied to the extent that the utility has reasonable influence over the relevant expenses. If incentives are assigned to costs mostly out of the utility's control, such as purchased fuel, then the utility may earn rewards or receive penalties without changing its behaviour.

4. Cost Containment

21. The use of additional cost containment measures can mitigate cost overrun risks and, in combination with the approval processes, counteract the concern that trackers can act as a "blank check" to utilities. Cost containment measures related to approved project budgets include: 1) requiring any expenditures above the budget be subject to regulatory lag and considered in the next rate case; 2) sharing of expenditures above the budget between the utility and customers; and 3) disallowing from cost recovery all costs above the approved budget. For trackers with less project-specific budget certainty, cost containment can also be implemented through a cap on total expenditures or, equivalently, a cap on the rate impact (e.g., limit the year-over-year rate increase due to the tracker).

22. Cost containment mechanisms should take into account the relative certainty of the budget and the potential effect of stringent cost-containment approaches (e.g., disallowing cost recovery for expenditures above the budget) to delay utility investments to avoid disallowances. If the costs of a project are uncertain, the utility may slow its investment schedule to ensure that it remains at or below budget. Although in some circumstances,

---

7 Regulatory lag is the time between when expenditures are made and when the utility recovers the revenue requirement for the expenditures. Regulatory lag can provide an incentive for utilities to be fiscally efficient as the utility must absorb any increases in costs between rate cases and cause the utility to under-earn relative to its AROE. However, if the overall revenue expenditure is increasing at a lower rate than revenues (i.e., the utility's revenues are outpacing expenditures), then regulatory lag can benefit the utility and the utility could over-earn relative to its AROE.

this may be the desired outcome, in others, the regulator values the speed of investment. As with performance incentive mechanisms, cost containment is most appropriate when the utility has control over the costs.

B. TYPICAL APPLICATIONS

23. Trackers are applied to a variety of utility expenditures, such as fuel, purchased power, and capital expenditures, including those for renewable generation, transmission and distribution upgrades, and advanced metering infrastructure. As shown in Figure 3, nearly all of the electric utilities in the United States have at least one tracker (107 of a total of 128 utilities sampled). Approximately half have at least one capital expenditure tracker (68 of 128 sampled) with infrastructure (transmission and distribution) being more prevalent than generation capacity trackers.

Figure 3: Summary of US Electric Utility Trackers/Riders by Type

Type of Tracker/Rider	Number of Utilities
Renewables expense	70
Electric fuel/gas commodity/purchased power	107
Environmental compliance	52
New Capital	
Generation capacity	26
Generic infrastructure	68

Sources: 2018 RRA Adjustment Clauses
Notes: Count based on a maximum of 128 US electric utilities.

24. A range of infrastructure and renewable trackers have been used in the United States that address broad investment programs to specific renewable generation facilities. Figure 4 lists a few of these trackers. For example, in Arkansas and California, trackers have been used for "smart grid" technologies, in Arkansas on a system-wide basis and in California on a pilot basis. In Indiana, Massachusetts, and Pennsylvania, more broad transmission and distribution trackers have been used for capital investments. Similarly, both narrowly focused and broad approaches have been used for renewable energy projects. The Minnesota renewables tracker allows for recovery of costs associated with any renewable resource built meeting the Renewable Energy Standard. In contrast, the New Jersey solar generation tracker only covers costs associated with solar generation, and the Oklahoma

Crossroads tracker only covers costs of a specific wind farm. The Appendix contains an inventory of over 140 capital trackers.

Figure 4: Sample of Renewable and T&D Trackers in the United States[8]

State	Utility	Tracker Name	Eligible Investments
AR	Oklahoma Gas & Electric	Smart Grid Rider	System-wide smart grid implementation
CA	Pacific Gas & Electric	Smart Grid Pilot Deployment Project Balancing Account	Pilot programs for smart grid line sensors, volt/VAR optimization, detection and location of distribution line outages and faulted circuits, and information technology investments to improve short term demand forecasting for power procurement
IN	Northern Indiana Public Service	Transmission, Distribution & Storage System Improvement Charge	Investments to maintain the capacity deliverability of system and replacement of ageing infrastructure, economic development
MA	NSTAR Electric	Capital Projects Scheduling List	Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and maintenance hole inspection, repair, and upgrade
MN	Northern States Power (Xcel Energy)	Renewable Energy Standard Cost Recovery Rider	New renewable resources needed to meet Renewable Energy Standard
NJ	Public Service Electric and Gas	Solar Generation Investment Program	136 MW of utility-owned solar
OK	Oklahoma Gas & Electric	Crossroads Rider	Crossroads Wind Farm
PA	PECO	Distribution System Improvement Charge	Storm hardening and resiliency measures, underground cable replacement, substation retirements, and facility relocations

25. Since trackers remove expenditures from traditional regulatory frameworks, using trackers often requires justification. The National Regulatory Research Institute (NRRI) provides

---

8 EEI, Alternative Regulation for Emergency Utility Challenges: 2015 Update, Table 2, p. 12-19;

Xcel Energy, Minnesota Rate Riders – Electric, available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/MN/MinnesotaRateRiders.pdf;

State of New Jersey Board of Public Utilities, Order Approving Stipulation on Bilateral Sale Contract, available at: https://www.bpu.state.nj.us/bpu/pdf/boardorders/2011/20110518/5-16-11-8J.pdf;

three cost characteristics to justify a tracker: 1) largely outside the utility's control; 2) unpredictable and volatile; and 3) substantial and recurring such that "the difference between test-year costs and actual costs can materially affect a utility's rate of return."[9] While narrowly defining a tracker's scope to only those costs exogenously driven, "largely outside the utility's control" (e.g., fuel), it can be more broadly defined to include expenditures driven by policy requirements that are outside the utility's typical purview (e.g., environmental regulations).

26. Pragmatically, trackers are also used to induce utilities to make investments that would otherwise either not occur or occur on a slower timescale than the regulator prefers. Under a traditional ratemaking approach, when a utility undertakes a capital investment, it does not begin to recover its costs (or return) on the investment until included in the rate base through a general rate case process. A substantial capital investment or extended time lag between rate cases can lead to significant financial impacts on the utility. That is, the utility has a considerable outflow of expenditures with a concomitant increase in revenues that can affect cash flows and overall earnings. While regulatory lag can be considered appropriate in many circumstances, it can hinder the utility's ability to make investments that the policymakers would like to prioritize. Trackers, which allow for faster recovery, can induce utilities to make significant capital investments by minimizing the regulatory lag.

III. Balancing Objectives in Capital Tracker Designs

27. The design of trackers should reflect the underlying motivation while balancing the need for regulatory oversight with streamlined regulatory treatment and incentives to invest. For a tracker developed to enable capital investment, the approaches that lower hurdles for utility investment reduce regulatory oversight as well. For example, a tracker designed to maximize utility investment could allow pre-approval of expenditures, no ex-post

NJ PUC, Order for Docket No. EO12080721, available at: https://mseia.net/site/wp-content/uploads/2012/05/BPU-Board-Order-PSEG-Solar4All-Extension-5-29-13-2V.pdf.

9 National Regulatory Research Institute (K. Costello) "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives," Report No. 14-03, April 2014.

prudency review, performance incentives related to delivering investments early, and no cost-containment measures. Such a tracker would not balance the incentives to invest with reasonable regulatory oversight. Instead, regulators balance the motivations for the utility to invest with the ability of regulators and stakeholders to assess the prudence of the utility's expenditures and its incentives to invest efficiently.

28. Two capital investment tracker examples from Pennsylvania and New Jersey illustrate the distinct balance between regulatory oversight and the streamlined regulatory process balance discussed above. In both cases, the weight of the project approval process is toward pre-approval. The Pennsylvania tracker requires more formulaic checks before adding the asset to the tracker for recovery. In contrast, the New Jersey tracker requires a final prudency review during the next rate case. Though structured differently, both trackers also include cost-containment provisions.

29. The Pennsylvania Distribution System Improvement Charge (DSIC) is a capital tracker program available to electric, natural gas, and water utilities. The DSIC was initiated to attract investment for an aged water system in 1996[10]. It has since been held as a model program and replicated in other states.[11] In the electric sector, six of eight Pennsylvania utilities use the DSIC tracker to recover costs. The utility must first create a five-year Long Term Infrastructure Investment Plan (LTIIP) to make use of the DSIC, which is subject to stakeholder scrutiny and must be approved by the Pennsylvania Public Utilities Commission (PA PUC). The LTIIP defines the budgets and projects that the utility is authorized to recover through the DSIC mechanism. Once the LTIIP is approved, the utility can invest up to 5% of distribution rates billed to customers through the tracker. The tracker was developed explicitly as a way to encourage investment. In the view of the PA PUC, if a utility is over-earning (relative to its allowed ROE), then the tracker is no longer required to incentivize the utility to invest and consequently, the tracker is removed.

30. The most recently approved LTIIP for PECO Energy Company includes a broad range of programs, including storm hardening, underground cable replacement, and facility

---

10 PA PUC, PECO Long-Term Infrastructure Improvement Plan Opinion and Order, October 22, 2015.

11 PA PUC, "System Improvement Charges Distribution and Collection."

relocations. The total budget for these electric programs over the five years is $320 million, mainly in capital investments.

Figure 5: Pennsylvania Distribution System Improvement Charge Summary[12]

Pennsylvania's Distribution System Improvement Charge (DSIC)	
Motivation	• Accelerate investment in new utility plant to replace ageing distribution infrastructure; • Recover fixed costs (depreciation and pre-tax return) of certain non-revenue producing, non-expense reducing infrastructure improvement costs placed into service between base rate cases; • Reduce the number of base rate cases and the associated expenses, resulting in a more gradual increase in rates for consumers; • Better absorb increases in other categories of costs for a more extended period, particularly during times of relatively low-interest rates; • Facilitate compliance with evolving regulatory requirements; and • Implement solutions to regional supply problems.
Scope	• Revenue neutral projects (e.g., no new customer interconnections or generation facilities), consisting principally of replacement investments.
Sample Included Projects	**PECO Energy Company – 2016-2020** 1) Storm Hardening and Resiliency Measures; 2) Underground Cable Replacement; 3) Building Substation Retirements; and 4) Facility Relocations. **Total budget:** $320 million ($270 million for reliability projects and $50 million for facility relocation).
Approval Process	• Approval of 5-year long-term infrastructure improvement plan (can be renewed) • Annual reconciliation of and hearing on recoverable costs and revenues • Audit to ensure money is spent only on DSIC-eligible projects
Performance Incentives	• None
Cost Containment	• Cap on rate increases due to rider, typically 5% • DSIC is removed if the utility is over-earning

31. In New Jersey, the Public Service Enterprise Group (PSEG) can recover up to $1 billion through the Energy Strong Rider, which was developed for recovery from five major storms (including two hurricanes and a snowstorm) and to increase the resilience of the

12 PA PUC, System Improvement Charges Distribution and Collection, available at: http://www.puc.state.pa.us/general/consumer_ed/pdf/dsic_fs.pdf; PA PUC, Opinion and Order for Petition by PECO Energy Company for Approval of their Electric Distribution System Improvement Charge.

system to future storms.[13] As a broad tracker, the Energy Strong Rider includes flood mitigation and the installation of advanced communication technologies, among other measures. Unlike the DSIC program in Pennsylvania, which is renewable, the Energy Strong Rider was initially designed as a one-time, three-year investment program. The budget for the program was developed through a rate case process, and the total tracker budget across both electricity and gas is $1 billion. The investments are approved on a provisional basis and included in the tracker for recovery every six months. Final approval of the investments occurs during the next rate case. Investments over and above the $1 billion can be reviewed for recovery during the next rate case.

13 The New Jersey Public Utilities Commission has also approved a second phase of the Energy Strong program. See https://www.njspotlight.com/2019/09/19-09-11-pse-gs-scaled-back-proposal-for-gas-and-power-grid-upgrades-is-approved/

Figure 6: New Jersey Energy Strong Rider Summary[14]

New Jersey's Energy Strong Rider	
Motivation	• Recovery from storm damage and reinforcing resiliency of the grid
Scope	• Recovery of revenue requirement based on net plant costs calculated on a semi-annual basis • Includes AFUDC, depreciation, income taxes • Excludes O&M related to capital investments
Sample Included Projects	**PSE&G Electricity** 1) Electric station flood mitigation (raise, relocate, or protect 29 switching and substations damaged by storms) 2) Advanced Technologies (deploy expanded system communication and data collection) 3) Create system redundancies through smart switches, fuses, and adding redundancies in distribution loop designs. **Total electric budget:** $820 million.
Approval Process	• First $1 billion of total investments (electric and natural gas) recovered through rider; remaining planned $220 million recovered through a rate case • Approval of eligible programs • Provisional approval and recovery of investments on a semi-annual basis • Review of all investments in the following rate case
Performance Incentives	• None
Cost Containment	• Cap on total investments recovered through the program • Time limited, 3-year program (excluding substation relocation which is a 5-year program)

IV. Review of the BLPC's Proposed CETR

32. The BLPC is proposing the Clean Energy Transition Rider (CETR) to aid implementation of the Government's 100/100 Vision through the Clean Energy Transition Program (CETP) and ongoing investment needs. The CETP includes new generation, storage, and transmission and distribution investments, and the BLPC anticipates that the first phase of

[14] PSEG, "PSE&G Reaches $1.22 Billion Settlement in Energy Strong Proceeding with NJ BPU Staff," May 1, 2014. Available at: https://investor.pseg.com/investor-news-and-events/financial-news/financial-news-details/2014/PSEG-Reaches-122-Billion-Settlement-in-Energy-Strong-Proceeding-with-NJ-BPU-Staff/default.aspx.

electricity sector investments to enable the 100/100 Vision will cost over $270 million through 2024. These investments include:

- **The Clean Energy Resiliency Bridge**, a 33 MW medium-speed diesel plant;
- **Renewable Generation Resources**, including the 10 MW wind farm under development at Lamberts, St. Lucy and an additional 15 MW solar PV plant;
- **Energy Storage**, such as the existing 5 MW Energy Storage Device and an additional 10 MW of batteries; and
- **Grid Modernization Investments,** including expanded voltage management tools, sensors, and automated controls in addition to the expansion of the communication network.

33. These investments aim at facilitating the transition towards the 100/100 Vision directly through new renewable resources as well as increased flexibility and enhanced capabilities to accommodate two-way power flows from distributed energy resources such as rooftop solar. However, this is only one of the multiple stages of investments needed to fully transition the Barbados electric system to the renewable goals described in the 100/100 Vision.

34. This Section first reviews components of the proposed CETR and compares the overall design of the proposed CETR to the DSIC and Energy Strong Rider discussed previously. The Section then compares the use of a tracker to other regulatory treatments of the anticipated expenditures related to the 100/100 Vision.

A. The BLPC Proposed CETR Design

35. As summarized in Figure 7, the BLPC has proposed a framework for the CETR that encompasses each of the core design elements and enables it to transition towards the Government's 100/100 Vision goal. The BLPC designed the tracker components to balance the significant investments required to support the transition towards Government's 100/100 Vision goal while recognizing the limited resources available to the FTC, stakeholders, and the BLPC.

Figure 7: Summary of the BLPC Proposed CETR

Component	Specifications
Scope	• Depreciation expense, tax expense, allowed return, and operation and maintenance associated with the CETP
Approval Process	• Approval of broad categories in the CETP • Approval of specific project budgets • Annual approval of expenditures for recovery • Investments added to rate base during next rate case
Performance Incentives	• None
Cost Containment	• CETR investments are anticipated to be offset by fuel cost savings. • If costs from the CETR exceed the fuel savings, the FTC may consider an annual rate increase cap, with revenues and appropriate interest delayed to subsequent years

36. The BLPC tracker's scope includes the revenue requirements associated with generation, power purchase contracts, transmission, and distribution investments associated with transitioning towards the clean energy vision goal. Because the CETR is broadly defined, over the long-run, it can help accommodate the range of potential investments required (including those beyond the CETP) to achieve the 100/100 Vision without the need for the creation and administration of unique trackers for each expenditure type. However, the broad definition could raise concerns that the BLPC could include all of its expenditures (related to the 100/100 Vision or not) into the tracker to avoid delay on recovery. The BLPC's proposed approval process mitigates these concerns through approval of the investment types that includable in the CETR and explicit approval of specific project budgets. These two pre-approvals provide the FTC opportunities to agree (or disagree) that the expenditures should be eligible for recovery through the proposed CETR and provide the BLPC greater certainty that the expenditures will be treated as prudent.

37. Concerning cost containment, the proposed CETR provides multiple levels of review and measures to ensure that the incurred costs are reasonable. First, as previously discussed, the CETR includes two opportunities for the FTC or stakeholders to review the expenditure types proposed and then specific project budgets. Second, the BLPC anticipates that the CETP investments, recovered through the CETR, will reduce fuel costs such that customers will not see significant bill impacts. Should the CETR expenses exceed the fuel cost offsets on an annual basis, the BLPC proposal contemplates an annual cap on rate increases due to the CETR. Expenditures above that cap would be recovered in subsequent years, including interest.

38. The CETR's structure is similar to the DSIC in Pennsylvania and the Energy Strong Rider in New Jersey, discussed earlier in Section II and shown in Figure 8 below. All three trackers allow *broad* categories of costs to be recovered through the tracker. Similarly, all three require *pre-approval* of plans and budgets, including an annual (or semi-annual) review of expenditures before recovery. The DSIC mechanism requires less regulatory review than the proposed CETR or Energy Strong Rider with an audit to affirm that expenditure matched allowed projects rather than consideration of the projects themselves. None of the three trackers include *performance incentives*, and all three provide *cost-containment* mechanisms, predominantly through pre-approved budgets. Both the DSIC and the proposed CETR also contemplate *caps* on the amount that the tracker expenditures can affect customer base rates.

Figure 8: Comparison of CETP, Energy Strong, and DSIC Trackers

	CETP (Proposed)	Energy Strong, NJ	DSIC, PA
Scope	Broad	Broad	Broad
Approval	• Approval of broad categories and approval of the CETP • Approval of specific project budgets • Annual approval of expenditures for recovery • Investments added to rate base during next rate case	• Approval of eligible programs • Provisional approval and recovery of investments on a semi-annual basis • Review of all investments in the following rate case	• Approval of 5-year plan (can be renewed) • Annual reconciliation of and hearing on recoverable costs and revenues • Audit to ensure money is spent only on eligible projects
Performance Incentives	None	None	None
Cost Containment	• CETR investments are anticipated to be offset by fuel-cost savings. If costs from the CETR exceed the fuel savings, the FTC may consider an annual rate increase cap, with revenues and appropriate interest delayed to subsequent years	• Cap on total investments recovered through the program • Time limited program	• Cap on rate increases due to rider, typically 5% • DSIC is removed if the utility is over-earning

B. Other Regulatory Mechanisms to Enable 100/100 Investments

39. Three main factors characterize the operating environment for the 100/100 Vision investments: 1) the need for significant investments to enable the 100/100 Vision; 2) the constrained regulatory and utility resources; and 3) the considerable uncertainty associated with the technology, cost, and timing of 100/100 Vision investments. The investments needed to get to 100/100 Vision are also a single issue, to the extent that the BLPC does not need to resolve cost allocation, rate design, or the cost of capital issues on the same timeline as the need to invest.

40. Although utilities are typically incentivized to invest in order grow their rate base, the amount of investment that a utility is willing to undertake is limited by practical financial concerns, including regulatory lag. Utilities have responded to concerns of regulatory lag

by updating their revenue requirements through frequent rate cases, which impose substantial burdens on regulators, stakeholders and utilities. Historically, the BLPC has had widely spaced general rate cases, with the last rate case occurring in 2010. Alternatively, to enable utilities to invest while avoiding frequent rate cases, regulators have used a variety of adjuncts to traditional cost of service regulation. In addition to trackers, regulators have used: 1) future test years; 2) formula rate plans; and 3) multi-year rate plans with forecasted revenue requirements. Each of these regulatory approaches has strengths and weaknesses, and the selection of a regulatory approach is necessarily dependent upon the specific context of the jurisdiction.

41. Tailoring a regulatory approach to the BLPC will require collaboration between the BLPC and the FTC. However, based on a review of these alternative approaches, discussed one-by-one below and summarized in Figure 9, a tracker reasonably balances regulatory resource needs while enabling the required utility investments.

Figure 9: Relative Impact of Alternative Regulatory Approaches on Select Measures

	Decreased Regulatory Burden	Greater Investment Incentives	More Tailored to 100/100 Investments	Increased Regulatory Oversight
Tracker				
Annual Rate Cases	Worse	Lower	Lower	Higher
Future Test Year	Worse	Lower	Lower	Higher
Formula Rates	Worse	Same	Lower	Lower
Multi-Year Rate Plan *(stair-step)*	Worse	Same	Lower	Lower

Notes: These relative scorings are intended to provide a general and are not reflective of all possible design options, which can include different relative balancing of regulatory burden, oversight, and investment incentives.

1. Future (Forecasted) Test Years

42. Under a future test year, revenue requirement and rates for the upcoming rate period are calculated using projected costs and sales, rather than actual or historical values. By using a future test year, a utility can project investments for the next year and incorporate those expenditures into its revenue requirement. Typically, the first 12-months of the new rate period make up the forward test year. As a result, new rates should align well with the costs and sales during this period and mitigate any concerns due to the misalignment of revenue

collection and expenses, at least theoretically.[15] This approach also has the advantage of being transparent as stakeholders have an opportunity to review and examine projected investments, costs and sales before incurring the expenses.

43. Since BLPC anticipates varying annual expenditures over multiple years, a forecasted test year without an additional tracker may be insufficient for adequate cost recovery and result in the need for frequent rate cases. If the expenditures required to meet the 100/100 Vision goals increase over time, then the revenue requirement estimated for a forecasted test year may perennially lag the BLPC's actual incurred revenue requirement. The perennial lag, if significant, would result in the BLPC under-earning relative to its AROE and likely frequent rate cases. Unlike the forecasted test year approach, a tracker by its nature only captures incurred costs and mitigates the need for rate cases due to increased investments. The BLPC's current estimates result in an increasing rate base, indicating that the BLPC would experience regulatory lag and likely need to file frequent rate cases even with a forecasted test year.

2. Formula Rates

44. Formula rates refer to a regulatory mechanism through which rates are adjusted outside of a general rate case process based on the utility's realized return on equity according to a predefined formula. Typically, formula rates start with the setting of base rates and determining the authorized rate of return, both usually established as part of a general rate case. After that, the utility's realized return on equity is calculated (for the prior period) and compared to the authorized level.[16] Rate adjustments (either decreases or increases) are triggered when the realized return on equity differs from the AROE. The comparison of realized and authorized rates of return occurs annually and limits the regulatory lag that may arise between general rate cases. Similar to trackers, common concerns related to the use of formula rates include the ability to adequately review utility expenditures in annual expedited processes and the potential to shift investment risk from the utility to ratepayers.

---

[15] In reality, this may only be true to some extent, as forecasts (costs and/or sales) are inherently prone to error and may deviate from the actual values.

[16] There are other versions of formula rates that use the comparison of projected returns on equity to AROEs or a combination of projected and AROE comparisons.

45. Formula rate plans are generally used to address changing conditions in between rate cases, and thus reduce the frequency of rate cases.[17] Such changing conditions may include some combination of slow sales growth, increasing operating costs and increasing capital spending (e.g., asset replacements and upgrades), which result in an imbalance between costs and sales growth between rate cases. For example, in 2014, the Illinois Commerce Commission approved a formula rate plan for Commonwealth Edison (ComEd) to ensure that ComEd implemented its grid modernization plans expeditiously. Such an undertaking would require sizable capital expenditures not recoverable until the next rate case. The formula rate plan permitted ComEd to true-up rates to recover such costs on a backward- and forward-looking basis.

46. Formula rates, as described, could mitigate the need for frequent rate cases, but are more complicated to implement than a tracker. Developing a formula rate plan would require the BLPC to develop (and the FTC and stakeholders to review) a full regulatory approach, including how to treat over- and under-earnings (relative to the allowed ROE). Implementing a formula rate plan would require a review of utility earnings (rather than focus on the 100/100 investments, on an annual basis), albeit typically on an expedited basis.

3. Multi-Year Rate Plans

47. Multi-year rate plans (MRPs) are, in their most straightforward description, rate plans that extend over multiple years with formulaic or pre-determined revenue requirements. While frequently discussed for enhanced incentives for cost control, MRPs can be structured to enable investments through a series of consecutively forecasted revenue requirements referred to as the "stair-step" approach.[18] During the rate-case for an MRP using the stair-step approach, the utility proposes forecasted revenue requirements for, typically, the next 3-5 years. Once approved, the forecasted revenue requirements increase (or decrease) according to the projected test years without the need for a general rate case. To avoid over-earning from changes in expenditures or revenues (relative to the forecast), earning sharing

---

[17] Edison Electric Institute, Alternative Regulation for Emerging Utility Challenges: 2015 Update, prepared by Pacific Economics Group, November 11, 2015 (EEI 2015 Update).

[18] Under more formulaic approaches to setting revenue requirements for MRPs (such as inflation minus productivity or "I-X" approaches), increased capital investments can be incorporated through adjustments for exogenous expenditures.

mechanisms can be used. These mechanisms refund customers some portion of earnings over AROE. MRPs include a "stay-out" clause, which typically prevents the utility from refiling a rate case unless the earned return on equity is below a pre-determined level. By extending the time between rate cases and the use of forecasted revenue requirements, the use of an MRP could enable the investments to meet the 100/100 Vision.

48. Unlike a tracker, the use of an MRP is not tailored to a capital investment plan and would require BLPC to formulate (and the FTC to review) a full regulatory plan. The development of a stair-step MRP includes specification of components beyond the traditional rate case, including potential guardrails to mitigate the risks of over or under-earning and, in some cases, additional annual reconciliations. Concerning the revenue requirement, the BLPC would need to develop, and the FTC and stakeholders would need to review, forecasts for the full revenue requirement going out multiple years. The development of the revenue requirement would require the BLPC, the FTC, and stakeholders to develop new capabilities, which, while not necessarily difficult, would be an increased burden. The future capital costs required for the 100/100 Vision are uncertain, which would add to the difficulty of review.

V. Conclusion

49. The BLPC has proposed the Clean Energy Transition Rider to recover the investments associated with the transition towards the 100/100 Vision. The CETR will initially be used to recover the costs in the CETP, which includes investments through 2024. A tracker can provide an acceptable balance between regulatory oversight requirements and process burdens while enabling the utility to make investments significantly outside of its typical capital plan. Given the circumstances facing the BLPC, including significant investments beyond "business as usual," the potential for unsustainably low returns due to regulatory lag, and the regulatory burden of sequential rate cases, a tracker represents a reasonable approach to recover the CETP costs. The components of the CETR proposed by the BLPC generally follow regulatorily acceptable precedents for trackers and are matched to the operating context of the BLPC, as illustrated in Figure 10. Alternatives to a tracker, including the use of formula rates, multi-year rate plans, or holding annual rate cases, could similarly enable the required 100/100 Vision investments, but with a more significant regulatory burden to the FTC, the BLPC, and stakeholders. While the full set of

investments to enable the 100/100 Vision will require new regulatory processes, a tracker to support the CETP is a reasonable first step. In the long-run, an approach that perhaps combines these different alternatives but tailored towards Barbados' specific situations may need development.

Figure 10: Components of the CETR

Component	Description	Contextual Justification	Specifications
Scope	• Broad	• Investments are varied in type and uncertain concerning timing and scale	• Depreciation expense, tax expense, allowed return, and operation and maintenance associated with the CETP
Approval Process	• Multiple levels	• Provides multiple opportunities to review investments, which aligns with the broad scope included in the tracker	• Approval of broad categories and approval of the CETP • Approval of specific project budgets • Annual approval of expenditures for recovery • Investments added to rate base during next rate case
Cost Containment	• Multi-level investment review • Cap on rate increases (if required)	• Tracker is not anticipated to increase total customer bills • Provides flexibility to adapt with cost containment if required	• CETR investments are anticipated to be offset by fuel cost savings • If costs from the CETR exceed the fuel cost offsets, the FTC may consider an annual rate increase cap, with revenues and appropriate interest delayed to subsequent years

Appendix: Capital Tracker Examples in the United States

State	Company Name	Tracker Name	Eligible Investments
AL	Alabama Power	Rate Certificated New Plant	Any approved by Commission through CPCN
AR	Empire District Electric	Alternative Generation Environmental Recovery Rider	Environmental
AR	Oklahoma Gas & Electric	Smart Grid Rider	System-wide smart grid implementation
AR	SWEPCO	Alternative Generation Recovery Rider	New generation
AR	SWEPCO	Rider Environmental Compliance Surcharge	Environmental
AZ	Arizona Public Service	Renewable Energy Standard Adjustment Schedule	Renewables not recovered in base rates
AZ	Arizona Public Service	Environmental Improvement Surcharge	Environmental improvement projects
AZ	Arizona Public Service	Four Corners Rate Rider Surcharge	Generation
AZ	Tucson Electric Power	Environmental Compliance Adjustor	Miscellaneous environmental projects
CA	Pacific Gas & Electric	Smart Grid Memorandum Account	Smart grid projects that received DOE matching funds
CA	Pacific Gas & Electric	Smart Grid Pilot Deployment Project Balancing Account	Pilot programs for smart grid line sensors, volt/VAR optimization, detection and location of distribution line outages and faulted circuits, and information technology investments to improve short term demand forecasting for power procurement
CA	San Diego Gas & Electric	Energy Storage Balancing Account	Projects to store solar energy
CA	San Diego Gas & Electric	Advanced Metering Infrastructure Balancing Account	AMI
CA	Southern California Edison	SmartConnect Balancing Account	Advanced metering infrastructure project
CA	Southern California Edison	Solar PV Balancing Account	Solar generation
CO	Black Hills Colorado Electric	Transmission Cost Adjustment Rider	Transmission projects
CO	Black Hills Colorado Electric	Clean Air Clean Jobs Act Rider	Gas-fired generation
CO	Public Service Company of Colorado	Transmission Cost Adjustment	Transmission projects
CO	Public Service Company of Colorado	Clean Air Clean Jobs Act Rider	Miscellaneous environmental projects including gas-fired generation, scrubbers

CT	Connecticut Light & Power	System Resiliency Plan	Structural hardening
DC	Potomac Electric Power	Underground Project Charge	Undergrounding of specific feeders
DE	Delmarva Power & Light	Utility Facility Relocation Charge	Replacements due to mandated relocations not otherwise reimbursed
FL	Florida Power and Light	Environmental Cost Recovery Clause	Miscellaneous environmental projects
FL	Florida Power and Light	Capacity Cost Recovery Clause	Nuclear power
FL	Florida Power and Light	Generation Base Rate Adjustment	Generation
FL	Gulf Power	Environmental Cost Recovery Clause	Miscellaneous environmental projects
FL	Progress Energy Florida	Environmental Cost Recovery Clause	Miscellaneous environmental projects
FL	Progress Energy Florida	Capacity Cost Recovery Clause	Nuclear power
FL	Progress Energy Florida	Generation Base Rate Adjustment	Generation
FL	Tampa Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects
GA	Georgia Power Company	Environmental Compliance Cost Recovery	Miscellaneous environmental projects
GA	Georgia Power Company	Nuclear Construction Cost Recovery	Nuclear generation
HI	Hawaii Electric Light	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure
HI	Hawaiian Electric Company	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure
HI	Maui Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure
ID	PacifiCorp	Energy Cost Adjustment Mechanism	Lake Side II generation facility
IN	Duke Energy Indiana	Qualified Pollution Control Property	Miscellaneous environmental projects
IN	Duke Energy Indiana	Integrated Coal Gasification Combined Cycle Generating Facility Revenue Recovery Adjustment	Integrated gasification combined cycle generating plant
IN	Indiana Michigan Power	Clean Coal Technology Rider	Miscellaneous environmental projects
IN	Indianapolis Power & Light	Environmental Compliance Cost Recovery	Miscellaneous environmental projects
IN	Northern Indiana Public Service	Environmental Cost Recovery Mechanism	Miscellaneous environmental projects
IN	Northern Indiana Public Service	Transmission, Distribution & Storage System Improvement Charge	Investments to maintain the capacity deliverability of system and replacement of ageing infrastructure, economic development
KY	Kentucky Power	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects
KY	Kentucky Utilities	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects

KY	Louisville Gas & Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects
LA	Cleco Power	Infrastructure and Incremental Costs Recovery	Projects to be determined in subsequent filings to Commission
LA	Entergy Gulf States Louisiana	Formula Rate Plan-3	Acquisition of generating facility, new generating facility or refurbishment of an existing generating facility if the revenue requirement related to the project exceeds $10 million
LA	Entergy Louisiana	Formula Rate Plan 7	Cost of Ninemile 6 natural gas generating facility; New generating facility, acquisition of a generating facility, or refurbishment of an existing generating facility if the revenue requirement related to the project exceeds $10 million
MA	Massachusetts Electric	Net CapEx Factor	Potentially all distribution investments
MA	Massachusetts Electric	Solar Cost Adjustment Provision	Solar generation
MA	Massachusetts Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high-speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators
MA	Nantucket Electric	Solar Cost Adjustment Provision	Solar generation
MA	Nantucket Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high-speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators
MA	NSTAR Electric	Capital Projects Scheduling List	Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and maintenance hole inspection, repair, and upgrade
MA	NSTAR Electric	Smart Grid Adjustment Factor	Smart grid pilot
MA	Western Massachusetts Electric	Solar Program Cost Adjustment	Solar generation
MD	Baltimore Gas & Electric	Electric Reliability Investment Surcharge	Upgrades to improve poorest performing feeders, selective undergrounding, expanded recloser development on 13kV and 34 kV lines, diverse routing of 34 kV supply circuits
MD	Delmarva Power & Light	Grid Resiliency Charge	Feeder hardening
MD	Potomac Electric Power	Grid Resiliency Charge	Feeder hardening
ME	Central Maine Power	Customer Relationship Management & Billing Rate Adjustment	Customer relationship management & billing system replacement
MN	Interstate Power & Light	Renewable Energy Recovery Adjustment	Renewable generation

MN	Minnesota Power	Arrowhead Regional Emission Abatement Rider	Miscellaneous environmental projects
MN	Minnesota Power	Transmission Cost Recovery Rider	Incremental transmission investment
MN	Minnesota Power	Renewable Resource Rider	Renewable generation
MN	Minnesota Power	Rider for Boswell Unit 4 Emission Reduction	Miscellaneous environmental projects
MN	Northern States Power (Xcel Energy)	Metropolitan Emissions Reduction Project (later called Environmental Improvement Rider)	Miscellaneous environmental projects
MN	Northern States Power (Xcel Energy)	Transmission Cost Recovery Rider	Incremental transmission investment
MN	Northern States Power (Xcel Energy)	Renewable Energy Standard Cost Recovery Rider	Renewable generation
MN	Northern States Power (Xcel Energy)	Mercury Cost Recovery Rider	Miscellaneous environmental projects
MN	Otter Tail Power	Renewable Resource Cost Recovery Rider	Renewable generation
MN	Otter Tail Power	Transmission Cost Recovery Rider	Incremental transmission investment
MS	Mississippi Power	Environmental Compliance Overview Plan Rate	Miscellaneous environmental projects
ND	Montana-Dakota Utilities	Environmental Cost Recovery Tariff	Miscellaneous environmental projects
ND	Montana-Dakota Utilities	Generation Resource Recovery Rider Tariff	New Generation
ND	Northern States Power-MN	Transmission Cost Rider	Transmission projects
ND	Northern States Power-MN	Renewable Energy Rider	North Dakota based renewable generation
ND	Otter Tail Power	Renewable Resource Rider	Renewables
ND	Otter Tail Power	Transmission Facility Cost Recovery Tariff	Transmission investments required to serve retail customers
ND	Otter Tail Power	Environmental Cost Recovery Tariff	Miscellaneous environmental projects
NH	Granite State Electric	Reliability Enhancement Plan Capital Investment Allowance	Feeder hardening and asset replacement
NH	Public Service Company of New Hampshire	Energy Service	Miscellaneous environmental projects
NH	Public Service Company of New Hampshire	Reliability Enhancement Plan	Reliability improvements
NJ	Public Service Electric and Gas	Solar Generation Investment Program	Solar generation
NJ	Public Service Electric and Gas	Capital Infrastructure Investment Program	Reliability upgrades & feeder replacement
NJ	Public Service Electric and Gas	Energy Strong Adjustment Mechanism	Substation flood mitigation, gird reconfiguration strategies, and smart grid

OH	Cleveland Electric Illuminating	Rider AMI	Ohio Site Deployment
OH	Cleveland Electric Illuminating	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in the most recent rate case
OH	Duke Energy Ohio	Infrastructure Modernization Distribution Rider	Electric AMI
OH	Duke Energy Ohio	Distribution Capital Investment Rider	Distribution capital investments not recovered through other trackers
OH	Ohio Edison	Rider AMI	Ohio Site Deployment
OH	Ohio Edison	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)
OH	Ohio Power	Distribution Investment Rider	Net distribution capital additions since the date certain of most recent rate case not recovered through other riders
OH	Ohio Power	GridSMART Rider (Phase I)	Smart grid
OH	Toledo Edison	Rider AMI	Ohio Site Deployment
OH	Toledo Edison	Delivery Capital Recovery Rider	Power distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)
OK	Oklahoma Gas & Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening
OK	Oklahoma Gas & Electric	Smart Grid Rider	Smart grid
OK	Oklahoma Gas & Electric	Crossroads Rider	Crossroads Wind Farm
OK	Public Service Company of Oklahoma	Advanced Metering Infrastructure Tariff	Advanced metering infrastructure deployment
OK	Public Service Company of Oklahoma	System Reliability Rider	Grid resiliency projects
OR	PacifiCorp	Renewable Adjustment Clause	Renewable generation
OR	PacifiCorp	Lake Side 2 Tariff Rider	Generation
OR	PacifiCorp	M2O Transmission Rider	Mona to Oquirrh transmission line only if the line is placed into service within six months of May 31, 2013
OR	Portland General Electric	Renewable Adjustment Clause	Renewable generation
PA	Duquesne Light	Smart Meter Charge Rider	AMI
PA	Metropolitan Edison	Smart Meters Technologies Charge	AMI
PA	PECO	Smart Meter Cost Recovery Rider	AMI
PA	PECO	Distribution System Improvement Charge	Storm hardening and resiliency measures, underground cable replacement, substation retirements, and facility relocations
PA	Pennsylvania Electric	Smart Meters Technologies Charge	AMI
PA	Pennsylvania Power	Smart Meters Technologies Charge	AMI
PA	PPL Electric Utilities	Act 129 Compliance Rider	AMI

PA	PPL Electric Utilities	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., poles, wires)
PA	West Penn Power	Smart Meter Surcharge	AMI
RI	Narragansett Electric (electric operations)	Electric Infrastructure, Safety, and Reliability Plan Factor	Replacements and load growth
SC	South Carolina Electric & Gas	NA	Nuclear generation
SD	Black Hills Power	Environmental Improvement Adjustment tariff	Miscellaneous environmental projects
SD	Black Hills Power	Phase in plan rate	Gas-fired generation
SD	Northern States Power-MN	Environmental Cost Recovery Tariff	Miscellaneous environmental projects
SD	Northern States Power-MN	Transmission Cost Recovery Tariff	Transmission
SD	Northern States Power-MN	Infrastructure Rider	Generation
SD	Otter Tail Power	Transmission Cost Recovery Tariff	Retail sales portion of specific transmission projects
SD	Otter Tail Power	Environmental Quality Cost Recovery Tariff	Miscellaneous environmental projects
TX	AEP Texas Central	Advanced Metering System Surcharge	AMI
TX	AEP Texas North	Advanced Metering System Surcharge	AMI
TX	Centerpoint Energy Houston Electric	Advanced Metering System Surcharge	AMI
TX	Centerpoint Energy Houston Electric	Distribution Cost Recovery Factor	Change in net distribution rate base since last rate case
TX	Oncor Electric Delivery	Advanced Metering System Surcharge	AMI
TX	Texas-New Mexico Power	Advanced Metering System Surcharge	AMI
VA	Appalachian Power	Environmental & Reliability Cost Recovery Surcharge	Miscellaneous environmental & reliability projects
VA	Appalachian Power	Environmental Rate Adjustment Clause	Miscellaneous environmental projects
VA	Appalachian Power	Generation Rate Adjustment Clause	Dresden plant
VA	Virginia Electric Power	Rider S	Virginia City Hybrid Energy Center
VA	Virginia Electric Power	Rider R	Bear Garden Generating Station
VA	Virginia Electric Power	Rider W	Warren County Power Station
VA	Virginia Electric Power	Rider B	Biomass conversions
VA	Virginia Electric Power	Rider BW	Brunswick County Power Station (natural gas combined cycle generating station)
WV	Appalachian Power	Construction/765kW Surcharge	Generation, environmental
WV	Monongahela Power	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses

WV	Potomac Edison	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses
WV	Wheeling Power	Construction/765kW Surcharge	Generation, environmental
WY	Black Hills Power	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station
WY	Cheyenne Light, Fuel, & Power	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station

Sources: Edison Electric Institute, Alternative Regulation for Emerging Utility Challenges: 2015 Update, prepared by Pacific Economics Group, November 11, 2015 (EEI 2015 Update).

NORTH AMERICA | EUROPE | ASIA-PACIFIC

THE Brattle GROUP