PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

Received
Records Management
08/05/19 15:22
State Of WASH.
UTIL. AND TRANSP.
COMMISSION

August 5, 2019

VIA ELECTRONIC FILING

Mark L. Johnson
Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

RE: Docket U-190531—Pacific Power & Light Company's Comments

The Washington Utilities and Transportation Commission requested comments as part of "an inquiry into the appropriate process for identifying property that becomes used and useful for service in Washington."[1] Pacific Power & Light Company (Pacific Power), a division of PacifiCorp, provides these comments to address the issues raised by the Commission in the July 5, 2019 Notice of Opportunity to file written comments.

I. Background

The state of Washington recently enacted E2SSB 5116, which includes the Clean Energy Transformation Act (CETA),[2] which, among many other provisions, provides for the Commission to have "sufficient and flexible authority to determine the value of utility property for rate making purposes…"[3] Specifically, this legislation allowed for the inclusion of property that is used and useful for service in Washington rates during the rate effective period of a general rate case.[4] This legislation additionally allows for rate changes forty-eight months after the rate effective date and ensures the Commission has the authority to implement "incentive-based regulation, multi-year rate plans, and other flexible regulatory mechanisms."[5]

To implement these revised provisions of Washington law, the Commission opened an investigation and requested comments on certain specific questions. Pacific Power provides responses to these questions below.

[1] *Notice of Opportunity to file Written Comments* (July 5, 2019).
[2] S.B. 5116, 66th Leg., Reg. Sess. (Wash. 2019) (enacted).
[3] *Id.* at Sec. 20.
[4] *Id.*
[5] *Id.*

II. Pacific Power's Response

1. *In order for property to be considered for inclusion in rates during the rate effective period, should such property specifically be identified in the general rate case giving rise to those rates, or can specific property be identified in a subsequent proceeding? If such property may be identified in a subsequent proceeding, what proceeding would that be and why?*

   Pacific Power recommends that the Commission consider and evaluate multiple avenues for property to be included in rates. For example, the process used for including in rates larger assets, such as a generation asset, may be different than the process used for including in rates smaller, cumulative assets, such as distribution assets. Consistent with Pacific Power's 2015 limited-issue rate case, utilities should be able to present information on future investments within a general rate case, and provide an avenue for staff to review in-service dates and actual costs after the completion. This has worked well for Pacific Power, and is a simple way to include known and significant future investments, allow appropriate review time, and reduce regulatory lag. This approach, however, is only one of many options.

   In California, Pacific Power has a Post Test Year Adjustment Mechanism (PTAM), which allows for the timely recovery of "prudently incurred cost increases related to inflation, new plant, general operating cost increases, unforeseen events, and changes in capital structure."[6] The PTAM allows for cost recovery of major capital addition to plant-in-service that are greater than $50 million on a total-company basis.[7] Pacific Power submits an advice letter containing significant information about the proposed capital addition to the California Public Utilities Commission (CPUC). This filing is open to protest and is reviewed by the Energy Division of the CPUC. Pacific Power's process in California allows for significant capital investments to be included in rates with minimal regulatory lag. However, Pacific Power's mechanism utilizes unique California precedent to allow post-test year ratemaking that has historically been unavailable within the regulatory structure in Washington.[8] Pacific Power has been able to use the PTAM to include wind facilities[9] and new transmission assets.[10]

   The Renewable Adjustment Clause (RAC) in Oregon allows for recovery of prudently incurred costs "to construct or otherwise acquire facilities that generate electricity from renewable energy sources, costs related to associated electricity transmission and costs related to associated energy storage."[11] The RAC is specifically authorized by statute

---

[6] *In Re PacifiCorp*, Case No. A. 05-11-022, D. 06-12-011 at 3 (Dec. 14, 2006).
[7] *In Re PacifiCorp*, Case No. A. 05-11-022, D. 06-12-011 at Attachment A §2.3.2 (Dec. 14, 2006).
[8] "Whether called attrition or known by some other name, proposals such as SCE's [Post-test year ratemaking] mechanism have been approved in utility rate proceedings on several occasions over the past 20 years[.]" *In Re Southern California Edison Co.*, Docket A.02-05-004, D. 04-07-022 at 204 (July 8, 2004).
[9] PacifiCorp Advice Letter No. 428-E, Cal. Pub. Util. Comm'n (Nov. 29, 2010).
[10] PacifiCorp Advice Letter No. 492-E, Cal. Publ. Util. Comm'n (Jun. 10, 2013).
[11] ORS 469A.120.

and was adopted by the legislature to ensure minimal regulatory lag for resource acquisitions associated with compliance with the state's renewable portfolio standard. This process allows for the creation of an automatic adjustment mechanism (separate tariff) for the incremental costs and capital that is necessary for investment in renewable energy sources. The automatic adjustment clause is updated annually and continues until the incremental costs are included in base rates during a general rate case. Pacific Power is currently seeking to recover the costs associated with repowering the company's wind fleet through the RAC.[12]

Both of these mechanisms in Pacific Power's states allow for the inclusion of significant and specific assets into utility rates outside of a general rate case. Additionally, there are mechanisms that are used in other parts of the country to include investments that are individually smaller projects but cumulatively larger amounts that occur in between general rate cases.

Ohio provides an example of a mechanism that allows for the inclusion of incremental capital investment in distribution to be recovered in between rate cases. Specifically, it allows for the recovery of costs related to infrastructure modernization "including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization."[13] Referred to by different names for different electric utilities, these distribution investment riders are structured in a manner where specific caps are set in each year for the total distribution investment that may be recovered in a given year. The rates in this rider are updated quarterly to include distribution investment as it is placed in service and audited in an expedited proceeding annually for accounting accuracy, prudence, and compliance with an approved distribution modernization plan.[14]

Massachusetts has a similar mechanism that allows for investments in distribution infrastructure for gas utilities. Specifically, the Massachusetts Department of Public Utilities began approving, on a case-by-case basis, a targeted infrastructure replacement factor for natural gas distribution companies in 2009.[15] These targeted infrastructure replacement factors (TIRF) allowed for the replacement of gas pipeline infrastructure. Without approval of the TIRFs, the Massachusetts Department of Public Utilities noted that recovery of the capital investments would be delayed until a future rate case, and found that providing more certainty and more timely recovery of the revenue requirement associated with certain capital expenditures to be appropriate.[16]

---

[12] *See In the Matter of PacifiCorp d/b/a Pacific Power 2019 Renewable Adjustment Clause*, Docket UE 352, Advice No. 18-011 (Dec. 28, 2018).
[13] *See* Ohio Rev. Code §4928.143.
[14] *See In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer pursuant to Section 4928.143, Revised Code, in the form of an Electric Security Plan*, Docket No. 11-346-EL-SSO, Opinion and Order at 42-47 (Aug. 8, 2012).
[15] Bay State Gas Company, D.P.U. 09-30; see also National Grid, D.P.U. 10-55.
[16] National Grid, D.P.U. 10-55, at 120 (November 2, 2010).

The TIRF mechanism was replaced in 2014 by the Act Relative to Natural Gas Leaks.[17] Natural gas distribution companies in Massachusetts now file annual Gas System Enhancement Plans on October 31st of each year, setting forth plans to replace leaking and aging infrastructure during the next calendar year; these plans include a timeline and prioritization method for addressing these replacement projects. The GSEP includes a cost estimate for the following year based on average actual GSEP costs during the prior year and includes a GSEP that represents the three-year weighted average cost of leak repairs multiplied by the total miles replaced during the annual GSEP investment period. This offset is used to determine the savings credited to customers in the annual GSEP revenue requirement. Each May 1, utilities file for recovery under the GSEP based on actual investment closed to plant during the prior year. These filings update data associated with the program including O&M leak repair costs and leak rate data.

Texas also has a mechanism that allows for cost recovery of utility investment in distribution infrastructure in between rate cases.[18] It allows for the accelerated recovery of distribution plant.[19] Vertically integrated electric utilities file a distribution cost recovery factor (DCRF) on an as-needed basis, and the regulations allow for a 145 day review period after the application was filed and informal proceedings may be held to approve the application.[20]

Requests for recovery under a DCRF must first be offset by total load-growth related distribution revenues, and then will be allocated using the billing determinant allocation factors from the most recent base-rate proceeding.[21] Additionally the capital structure and cost of debt that was approved in the utility's most recent rate case is used for the mechanism.[22] Costs are reconciled in the utility's next base-rate proceeding.[23]

Pacific Power provides a number of examples to show how much flexibility there is in these mechanisms across the country. In light of the additional risks and difficulties that utilities face as a result of CETA, the Commission should allow multiple approaches and flexibility in how utility costs and investments are reviewed and approved.

2. *How should plant-in-service be valued (for determination of rate base) for each year of a rate plan? Does this valuation depend on prospectively identifying specific plant investments across the rate plan during the general rate case giving rise to the rates? Why or why not?*

   CETA authorizes the Commission to determine rates for "up to forty-eight months after the rate effective date using any standard, formula, method, or theory of valuation

[17] Massachusetts Acts of 2014, Chapter 149, Section 2, codified at M.G.L. c. 164, §§ 144 and 145.
[18] *See* Tex. Utilities Code §36.210.
[19] *See* 16 Tex. Admin. Code §25.243.
[20] *Id.*
[21] 36 Tex. Reg. 6728, 6747 (Oct. 7, 2011).
[22] *Id.* at 6753.
[23] 16 Tex. Admin. Code §25.243(f).

reasonably calculated to arrive at fair, just, reasonable, and sufficient rates." Given the flexibility granted under the new law, the Commission now has the power to set rates using everything from attrition mechanisms to future test periods and flexibility even within those constructs. Pacific Power has identified a number of mechanisms used by other states that do not require prospectively identifying specific plant investments during a general rate case. In practice, an approach that incorporates both elements may be the best option. For significant, identifiable investments, an approach that allows for prudence review of those investments so that they may be incorporated into a rate plan may be effective. For smaller projects that are cumulatively significant, actual identification of specific plant may not be practical.

3. *What should be the review process for property included in rates that becomes used and useful after the rate effective date? Is this review process the same for plant placed in service both up to and during the rate-effective date?*

   If investments and projects are reviewed in the context of a rate case (as discussed in 1), a limited post-case review may be appropriate for plant placed in service after the rate effective date. In the company's 2015 case, the company supplemented the record with actual costs and an affidavit stating that the projects were in service. While those specific projects were reviewed as part of a second-step rate increase, the company believes a similar process could be used even after the new rates have gone into effect.

   If projects are reviewed outside the context of a rate case, a more flexible approach where the level of review is commensurate to the significance of the projects may be appropriate. Pacific Power would point to many of the mechanisms in other states that have been discussed earlier in these comments as examples.

4. *Should pro forma plant additions placed in service after the test year but before the rate effective date be considered using the same process that the Commission will use to identify, review, and approve property that becomes used and useful after the rate effective date? Or should these post-test year plant additions be considered under a separate process? What is the best way to incorporate the participation of all the parties to the underlying rate proceeding in the process of reviewing the prudence of these post-test year plant additions?*

   With the use of a historical test-year, projects and plant additions that are placed in-service after the test year but before the rate effective date could be reviewed as known and measurable additions in a general rate case or other rate setting proceeding. In the past, Pacific Power has used a simple process in its rate case for a rate plan where these projects beyond the rate effective date are identified in the rate proceeding and reviewed for prudence.[24] Once the projects come into service, an attestation is provided and the final costs can be reviewed by Commission staff, and revised rates are subject to

[24] *WUTC v. Pac. Power & Light Co.*, Docket UE-152253, Order 12 at ¶9 (Sept. 1, 2016).

Commission approval.[25] Since a second rate change would not be necessary if the rate additions occur before the rate effective date, then only a simple attestation from the company the project or plant addition has been placed in-service may be necessary. Alternatively, a future test year could be used to solve this issue.

5. *If the rate base used to establish rates for a multi-year rate plan relies on a formula or plant-in-service projections (rather than a prospective identification of specific investments), what is the appropriate process for identifying, reviewing, and approving property that becomes used and useful for service after the initial rate-effective date? How should actual plant-in-service relate to the plant-in-service used to establish rates?*

Pacific Power does not have direct experience using formula rates or projections of investment levels that are not specifically tied to investments in the state regulatory context.

However Illinois does have a formula rate mechanism that sets the revenue requirement for utilities. The revenue requirement calculation inputs include costs recorded in a particular year's FERC Form 1 with certain ratemaking adjustments.[26] Certain inputs are mandated by statute, such as, actual capital structure (excluding goodwill) and a cost of capital methodology that is based on the sum of the applicable calendar year average of 30-year U.S. Treasury Bonds and 580 basis points.[27] There is also a Return on Equity (ROE) collar in the event that the utility actually earns a rate of return more than 50 basis points higher or lower than the rate determined based on the methodology contained in the statute.[28] Finally, there is an annual reconciliation between the revenue requirement determined pursuant to the formula rate and the revenue requirement that would have been determined if actual cost information from the rate year itself had been available at the filing date.[29] Thus, following the initial formula rate filing, an annual filing is made that is comprised of the setting of the new annual rates and the reconciliation of the previous year's rates.

This is just one example of a methodology used by a commission to identify, review and approve property that comes into service after the initial rate effective date. The examples cited above from Ohio, Massachusetts and Texas also provide an example of how these rates are included in service by identifying, reviewing and approving these costs on an expedited basis. The uniting factor in these mechanisms are an expedited process that provides standardized information to enable an efficient review by parties.

---

[25] *Id.*
[26] 220 Ill. Comp. Stat. 5/16-108.5 (d)(1).
[27] *Id.*
[28] *Id.* at (c)(5).
[29] *Id.* at (c)(6).

III. Conclusion

Under the revised language in CETA, the Commission now has the ability to craft mechanisms with a great deal of flexibility. Pacific Power would also note that the utilities in Washington all have different geographic and demographic customer bases. As a result Pacific Power would recommend the Commission take an approach that allows for tailored solutions to specific needs as opposed to a single mechanism for all utilities. It may be more efficient for the utilities to develop mechanisms and standards that work for each utility individually, and utilities may propose those for adoption to the Commission.

Pacific Power remains committed to extensively participating in this proceeding and working with the Commission and stakeholders through this process. Pacific Power further appreciates the continued opportunity to provide written comments as this investigation has progressed.

/s/

Etta Lockey
Vice President, Regulation
Pacific Power & Light Company
825 NE Multnomah St., Suite 2000
Portland, Oregon 97232
(503) 813-5701
etta.lockey@pacificorp.com