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September 11, 2020

VIA ELECTRONIC FILING

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

RE: Dockets UE-191023 and UE-190698 (consolidated) Rulemaking to consider adoption of rules to implement chapter 19.405 RCW and revisions to chapter 80.28 RCW

The Washington Utilities and Transportation Commission (Commission) issued a Notice of Opportunity to Submit Written Comments on its draft rules considering changes to the its Integrated Resource Plan (IRP) and Clean Energy Implementation Plan (CEIP) rules as part of the Clean Energy Transformation Act (CETA) on August 13, 2020. In this notice, the Commission requested responses to specific questions about the draft rules. PacifiCorp dba Pacific Power & Light Company (PacifiCorp) respectfully submits its comments and responses to the Commission's specific questions on the draft rules.

INTRODUCTION

PacifiCorp is extremely concerned by several provisions of these draft rules. The draft rules have the potential to lead to exponential cost increases for Washington customers, will create significant operational challenges for the utility without creating meaningful benefit to customers, and likely exceed the Commission's statutory authority. PacifiCorp generally supports the intent of the draft rules, but recommends lower-cost and less burdensome approaches to meeting the requirements of CETA.

Most notably, PacifiCorp views interpretation two for incremental cost calculation (see question six) as legally unjustifiable and tremendously damaging for customers. If adopted, interpretation two would allow rates to rise by up to 45 percent eight years after a utility files its first Clean Energy Implementation Plan (CEIP). This approach renders CETA's customer protection provisions moot.

PacifiCorp strongly supports the legislative intent to balance the rate impacts with the important policy objectives of CETA. The ability for utilities to propose and pursue compliance options that are cost-effective, that capture economies of scale, and that reduce administrative burden could further enable compliance at a total cost below the cap envisioned by the legislature.

Finally, PacifiCorp is concerned that several sections of the draft rules include compliance obligations, penalties, and requirements that go beyond the plain text and legislative intent of CETA. While the Commission has authority to enact rules to carry out the direction of the legislature, its authority is constrained by the statute.

PACIFICORP'S RESPONSES TO THE COMMISSION'S QUESTIONS

1. **Do you agree with Staff's interpretation of RCW 19.405.060(1)(c) that Commission approval is contingent upon the utility justifying and supporting each specific action it takes or intends to take, including providing the business cases supporting each specific action identified in the CEIP? Please explain your response.**

   No. RCW 19.405.060(1)(c) requires the Commission to either "approve, reject, or approve with conditions" an investor-owned utility's CEIP. The standard for such approval must be the criteria set by CETA in RCW 19.405.060(1)(b). This section contains a lengthy description of how each "specific action" should be judged:

   > (iii) Identify specific actions to be taken by the investor-owned utility over the next four years, *consistent with the utility's long-range integrated resource plan and resource adequacy requirements*, that *demonstrate progress toward meeting the standards under RCW 19.405.040(1) and 19.405.050(1) and the interim targets proposed under (a)(i) of this subsection*. The specific actions identified must be *informed by the investor-owned utility's historic performance* under median water conditions and *resource capability and by the investor-owned utility's participation* in centralized markets. In identifying specific actions in its clean energy implementation plan, the investor-owned utility *may also take into consideration any significant and unplanned loss or addition of load* it experiences.

   The sections italicized above identify the statutory criteria that each "specific action" must meet. No section of the above statute obligates the Commission to require a business case if other evidence is sufficient. In addition, it is unclear what additional information a business case would include. This is not a defined term in the draft rules, and therefore creates an unclear expectation on the information provided in the utility's plan.

2. **Several comments submitted in response to the first draft CEIP rules proposed that the Commission require some form of funding to support equity-related public engagement. Specific proposals ranged from requiring utilities to provide funding support for participation in a utility's equity advisory group to utilities funding support for equity-focused intervenors.**

   a. **Does the Commission have the authority to require utilities to provide funding to support equity participation such as intervenor funding or direct payments to advisory group members?**

      PacifiCorp is unaware of specific statutory authority that would allow the Commission to require utilities to provide funding as described above. That said, PacifiCorp looks forward to discussions regarding such authority and possible methods to support this work.

b. If so, what type(s) of funding should the Commission require, and how would utilities implement such funding? For example, if you advocate direct payments to advisory group members, how would the utilities structure those payments (e.g., based on an hourly rate, per diem, etc.)?

In Oregon, PacifiCorp provides intervenor funding to a range of stakeholders under ORS 757.072, which allows the state's regulated utilities to enter into funding agreements with organizations that represent customer interests. The Public Utility Commission of Oregon must approve these agreements, assess eligibility of expenses for reimbursement, and oversee payments to organizations. These costs are tracked through a standing deferral and recovered through rates periodically. If the Commission finds that it has the authority to require funding as described above, the Oregon model, with oversight by the commission, is an effective model.

c. What other issues arise if the Commission were to require utilities to provide funding or direct payments to support equity advisory group members?

If the Commission concludes that it has the authority to require funding as described above, PacifiCorp recommends that the Commission oversee payments and assess the eligibility of expenses for reimbursement, as is the model in Oregon. However, to minimize the impact to customers, PacifiCorp would be interested in discussing a program structure that reserves funding support for new participants who truly could not participate without the support.

3. The Commission appreciates the value stakeholders have said they see in having commissioners and the agency participate in broad conversations about equity needs. Due to restrictions on commissioners taking part in ex parte conversations concerning items that are before the Commission to decide, the commissioners cannot engage in such conversations or otherwise participate in utility advisory groups to discuss issues related to particular CEIPs. However, the Commission will be involved in the process through workshops, special open-meetings, and other available proceedings with stakeholders to discuss important issues. The Commission additionally awaits guidance from the state Environmental Justice Task Force on agency engagement with equity issues and looks forward to addressing recommendations internally and throughout agency divisions as needed. The Commission is further committed to addressing agency awareness of equity issues and needs through continued agency-wide learning. The concerns stakeholders raised through their comments are beyond what this single rulemaking can address and may be better addressed outside of this docket. In preparation for future process and discussions, please provide a list of CETA-related topics the Commission should address immediately following or concurrent with this rulemaking.

PacifiCorp supports a parallel or subsequent process to provide additional guidance on equity issues, outreach expectations, and how equitable distribution of benefits can be shown both in CETA compliance and throughout regulatory processes generally. A process that initiates after the Phase I rules are adopted would be most helpful, as it would provide an opportunity to explore equity issues that would exist within the framework of adopted CETA rules.

At this time PacifiCorp does not have a specific list of questions to be undertaken within an equity rulemaking, but generally would appreciate guidance on how to more granularly apply the equity provisions of RCW 19.405.060(c).

4. **Draft WAC 480-100-610(6) requires each utility to adaptively manage its portfolio of activities to achieve the requirements in the section. Some commenters recommended that this section belongs in the section that describes the CEIP. Staff proposes to place this provision in section 610 because adaptive management is an expectation of all the utility's investments and operations for achieving the requirements of CETA. Please state whether you agree that this adaptive management requirement is appropriately placed in section 610 and explain your response.**

   PacifiCorp's June 2, 2020 comments recommended deletion of the "adaptive management" requirement from former draft WAC 480-100-650. There is no clear statutory authority for this section and it imposes unnecessary, duplicative requirements on utilities. PacifiCorp continues to recommend that this standard be deleted from the current draft for the same reasons.

   PacifiCorp also notes that the draft rules appear to include an "adaptive management" standard in WAC 480-107-640(11), discussing the CEIP, notwithstanding Staff's statement that it is better included in a more general section as it applies to all utility investments and operations. PacifiCorp's redline has deleted this section as well.

   Finally, "adaptive management" is exactly what utilities do every day. PacifiCorp's IRP is under almost continual development and refinement, for the precise purpose of adapting to changing market conditions and changing technologies. Other PacifiCorp employees are tasked exclusively with researching emerging technologies and assessing the potential for implementing those technologies to better serve customers. It is not clear if Staff expects utilities to do anything different than they currently are if this draft rule is adopted – but if so, more clarity is needed.

5. **When a utility files its CEIP, it will include an estimate of its incremental cost of compliance, which is the difference between the portfolio of actions it will take to comply with RCW 19.405.040 and RCW 19.405.050 and the portfolio of the alternative lowest reasonable cost and reasonably available actions (the baseline portfolio). At this stage, both portfolios will estimate inputs, such as natural gas prices, over the four-year period. When the utility files its CEIP compliance report and calculates the actual incremental cost at the end of the four years, the utility will**

use the actual costs for the portfolio of actions it took. However, for purposes of determining if the utility may rely on the incremental cost provision, the Commission must determine whether the utility should update the inputs to the baseline portfolio as well. If the utility does not update the inputs to the baseline portfolio, then it is not measuring the true incremental cost between the two portfolios because they use different input assumptions. However, updating the assumptions may leave the utilities exposed to unknowable changes in circumstances for which they could not reasonably plan, such as a rapid increase or decrease to natural gas prices.

In draft WAC 480-100-660(4)(c), Staff proposes to require the utility to update the verifiable inputs of the alternative lowest reasonable cost and reasonably available portfolio (baseline portfolio). Please respond if the utility should be required to update the assumptions in its baseline portfolio when reporting its actual incremental costs, or if it should not.

PacifiCorp is generally opposed to updates to the baseline portfolio, as the baseline is approved by the Commission and used to calculate incremental cost. Any modification to the baseline portfolio could distort the legislatively-directed incremental cost calculation. If the Commission feels that limited updates are necessary, PacifiCorp requests flexibility to ensure that any updates are streamlined, discussed in advance with stakeholders, and help accelerate the true-up of costs.

PacifiCorp is amenable to further discussing updates, but recognizes that there may be a difference between updating inputs and assumptions to support a cost true-up, and creating a new baseline portfolio that is materially different from what has been previously approved by the Commission, and developed through a robust and lengthy stakeholder process. PacifiCorp recommends that any framework for updating costs be designed to accelerate the review process, rather than to create additional administrative burden on stakeholders.

6. **The Commission is considering two alternative interpretations of the incremental cost of compliance option in RCW 19.405.060. First, both interpretations find the Directly Attributable Costs of compliance by finding the difference between the RCW 19.405.040 and RCW 19.405.050 Compliant Portfolio and the Baseline Portfolio.**

.040 & .050 Compliant Portfolio – Baseline Portfolio
= Directly Attributable Costs

To determine whether the utility can exercise the incremental cost compliance option, the Commission is considering two alternative interpretations. One interpretation calculates incremental cost as the directly attributable cost in any given year, and the other interpretation calculates incremental cost as the year-over-year change in directly attributable cost. The Department of Commerce's draft rule,

WAC 19-40-230(1)(b) – Compliance using 2% incremental cost of compliance, takes the second approach.

Interpretation 1:

$$\frac{\textbf{\textit{Directly Attributable Costs}}}{\textbf{\textit{Weather Adjusted Sales Revenue}}}$$

Interpretation 2:

$$\frac{\textbf{\textit{Change in Directly Attributable Costs from Previous Year}}}{\textbf{\textit{Weather Adjusted Sales Revenue}}}$$

Please respond with a recommendation for the appropriate calculation. See attachment C to the Notice for sample calculations of these two interpretations.

PacifiCorp supports interpretation one. CETA requires that any incremental cost methodology collect "the average annual incremental cost of meeting the standards or the interim targets established [in the utility's CEIP]." RCW 19.405.060(3)(a). The incremental cost must be derived from a comparison of the CEIP costs with "cost of an alternative lowest reasonable cost portfolio of investments that are reasonably available" (deemed the Baseline Portfolio in the question above). On the whole, Staff's draft rules appear to be consistent with this interpretation one. It is PacifiCorp's understanding that PacifiCorp, Avista, and Puget Sound Energy are in general agreement regarding incremental cost calculation.

Interpretation two is inconsistent with the statute

There is no statutory basis for a methodology that considers exclusively the "Change in Directly Attributable Costs from Previous Year" as a basis for determining incremental cost. This approach would not actually capture the "annual incremental cost of meeting the standards or the interim targets," because some portion of an annual cost (the amount "unchanged" from the previous year) would not be captured. All directly attributable costs – whether they change from a previous calendar year or not – are inherently incremental and must be captured by the incremental cost calculation.

This simplified example shows that interpretation two does not accurately capture incremental costs:

Year	*Directly Attributable Cost*	*Incremental Cost of Compliance*	
		Interpretation One	*Interpretation Two*
One	$20	$20	$20
Two	$30	$30	$10
Three	$20	$20	-$10
Four	$0	$0	-$20
TOTAL	$70	$70	$0
AVERAGE		$17.50	$0

In this example, the total four-year directly attributable cost is $70, the same amount that interpretation one shows as the total incremental cost, with the average being $17.50. However, interpretation two shows the four-year cost as $0, and the average cost as $0, simply because year four's directly attributable cost is $0, which creates a large "change in directly attributable costs from previous year."

The results of interpretation two are nonsensical. Under interpretation two, customers pay $70 of directly attributable costs in their rates over the course of four years – but interpretation two nonetheless indicates that they have not faced any incremental costs. It is not clear what those $70 are if they are not properly considered the "incremental costs of meeting the standards or incremental targets established in [the utility's CEIP]": after all, the utility could not have met those standards but for spending that $70 of customers' money, and would not have spent that money absent the requirements created by RCW 19.405.040(1) and 19.405.050(1).

Interpretation two does not provide meaningful protection for customers
Further, interpretation two fails to provide any meaningful protection for customers, in keeping with the Legislature's direction that the state must "provide safeguards to ensure that the achievement of this policy does not… impose unreasonable costs on utility customers."[1] As noted in the introduction to these Comments, interpretation two would allow rates to increase by up to 45 percent by 2030. In contrast, interpretation one caps increases due to costs directly attributable to RCW 19.405.040(1) and 19.405.050(1) at 17 percent.

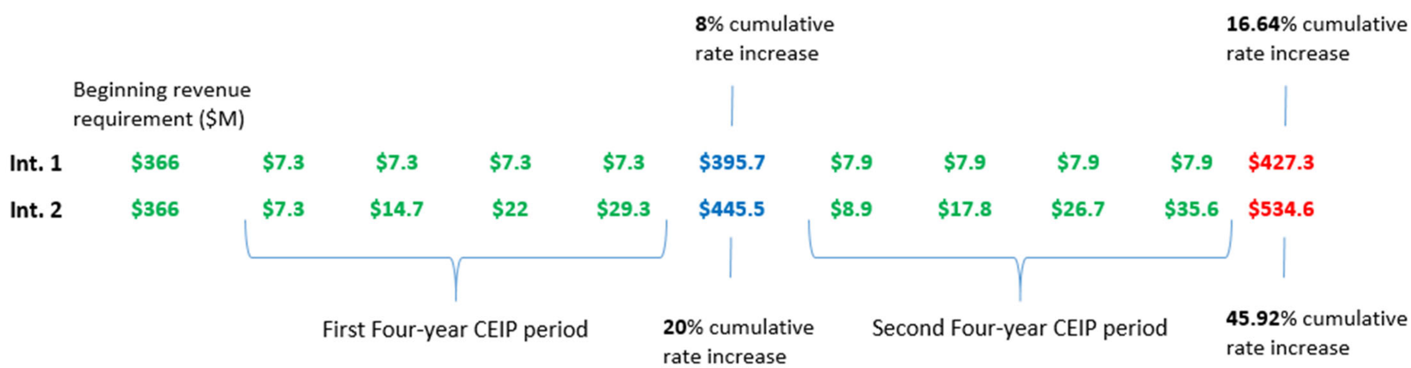

Figure 1 – Impact of interpretation one and interpretation two spending on PacifiCorp's revenue requirement over two CEIP periods. All numbers in $M, except percentages.

Interpretation two does not accurately address "above the previous year" in the statute
It may be that interpretation two is intended to be responsive to RCW 19.405.060(3)(a)'s discussion of costs "above the previous year," but this language is not intended to mandate a year-over-year comparison. In full, the section reads:

> (3)(a) An investor-owned utility must be considered to be in compliance with the standards under RCW 19.405.040(1) and 19.405.050(1) if, over the four-year compliance

[1] RCW 19.405.010(2).

> period, the average annual incremental cost of meeting the standards or the interim targets established under subsection (1) of this section equals a two percent increase of the investor-owned utility's weather-adjusted sales revenue to customers for electric operations *above the previous year*, as reported by the investor-owned utility in its most recent commission basis report."

(emphasis added). Here, "above the previous year" provides guidance to the Commission regarding which year's data the utility should use to determine the denominator in Staff's equations shown above. Specifically, the weather-adjusted sales revenue data used should be based on a utility's most recent Commission Basis Report (CBR) from "the previous year" before filing its CEIP. For the first CEIP, the most recent available CBR would be for calendar year 2020. This interpretation makes sense because the CEIP, including its incremental cost calculations, is filed one time for a prospective four-year period. A rolling "previous year," as seems to be contemplated in interpretation two, does not make sense in this case, because the underlying data – the CBR for those years – does not exist when the CEIP is developed. If the Legislature had expected utilities to use a forecast of weather-adjusted sales revenue, it could have required a data source that actually includes prospective estimates of that revenue, such as a utility's IRP, or at least could have left derivation of the data to the Commission's discretion.

PacifiCorp has proposed draft rule language in draft WAC 480-100-660(3) that is consistent with this interpretation. PacifiCorp looks forward to reviewing suggestions from other stakeholders, and it may be appropriate to conduct a workshop or request comments on this topic.

7. **Commenters have raised additional concerns about how utilities should demonstrate the elimination of coal from the allocation of electricity. Current draft rule language relies on attestations or audits and e-tags. Some commenters suggest waiting for the work of the markets workgroup to finish before developing rules for compliance with RCW 19.405.030(1)(a). Do stakeholders have concerns about whether e-tags are capable of tracking all electricity generated from coal-fired resources? Should the commission wait for recommendations or comments from the markets workgroup before addressing this issue in rule?**

   RCW 19.405.030(1)(a) requires coal-fired resources be removed from a utility's "allocation of electricity" by December 31, 2024. RCW 19.405.020(1) defines "allocation of electricity" as "for purposes of setting electricity, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state." Any interpretation of the requirement to remove coal-fired resources from a utility's allocation of electricity must take into consideration how coal-fired resources are put into a utility's allocation of electricity; in other words, traditional ratemaking informs how coal-fired resources are included in rates and should similarly inform how coal-fired resources are removed from rates. Removing the direct costs and benefits from rates (e.g., depreciation, operation and maintenance expense, net power cost benefits) through traditional rate-setting is consistent with the requirements of RCW 19.405.030(1)(a).

> Additionally, any rule should provide a framework for documenting the elimination of coal from Washington customers' allocation of electricity, while allowing for the future development of tools that provide additional support of such attestations.
>
> PacifiCorp disagrees that electronic tag review is an appropriate tool for determining whether Washington's allocation of electricity includes coal-fired resources. Notably, coal-fired resources are not currently included in rates on the basis of e-tag information. Electronic tags are a one-dimensional reflection of a transmission contract path for a transmitting electricity, not a representation of what resources were allocated to retail customers in individual jurisdictions for purposes of ratemaking. In the case of a multi-state utility such as PacifiCorp, it is the utility's interjurisdictional allocation protocol that determines what resources are included in Washington's allocation of electricity. The Commission should rely upon existing mechanisms, such as those used in net power cost proceedings, to establish the resources included in Washington's allocation of electricity. Based on the above, it is not necessary to wait for the Washington Markets Work Group to address this issue. PacifiCorp suggests the following edits to the proposed rule language for WAC 480-100-650(3)(a) for commission staff's consideration:
>
>> (a) Beginning in July 1, 2027, and each year thereafter, an annual attestation for the previous calendar year that: the utility does not use any coal-fired resource in its allocation of electricity to Washington customers ~~to serve retail electric customer load~~; and an appropriate company executive or qualified independent third party has reviewed relevant supporting ~~all e-tag~~ data for the prior calendar year. ~~and verified that no electricity from coal-fired resources was included in market purchases and therefore no such electricity was included in retail customer rates~~;

Other Comments

Resource Need should be redefined to provide additional flexibility to seek best outcomes for customers

PacifiCorp is concerned that the current definition of "resource need" in draft WAC 480-100-605 could be read to limit a utility's flexibility to provide its customers least cost, least risk portfolio resource solutions, because the definition limits "need" to what a utility needs to fill its resource deficit and meet operational requirements, including compliance with a variety of regulatory and reliability requirements. This definition essentially requires a utility to plan to meet needs with the resource portfolio it has today, unless there is a regulatory requirement for it to retire a portion of its resources.

This deficit framework for resource planning could have real implications for PacifiCorp's future IRPs and procurements. For example, PacifiCorp's most recent IRP preferred portfolio includes more than 6,500 MW of new renewables, nearly 600 MW of battery storage capacity, and over 700 MW of incremental energy efficiency and new direct load control resources, coupled with significant early coal retirements.[2] The draft rules might have prohibited this outcome because there was no simple "projected deficit to meet demand" when the most recent IRP process started, because PacifiCorp could theoretically have continued to serve load with those coal resources. Such retirements are a key component to an optimal portfolio, where all needs, whether created by load growth, resource retirements, the expiration of contracts, or regulatory requirements (present or future) are met by the best available proxy resources, inclusive of market purchases.

To some degree, Washington's aggressive coal retirement and clean energy mandates ensure that utilities will need to procure significant quantities of new renewable generation, regardless of whether their existing resource portfolios are actually short the physical energy or capacity needed to meet load. However, PacifiCorp would appreciate clarification regarding Staff's view of when "resources required for regulatory compliance" should be acquired (or retired). Would aggressive acquisition of renewables in 2023 meet a "resource need" even if a utility has sufficient gas-powered generation to provide equivalent energy and capacity until 2030? In PacifiCorp's view, this type of acquisition should fit Staff's definition, but there should be clarification that a known future regulatory requirement (such as 2030 and/or 2045 compliance targets) is considered sufficient to show resource need, even in years before those dates, if Staff's current definition is not changed. Otherwise, a reasonable case could be made that a utility does not actually have a "resource need" until just before 3030 and 2045, which would run counter to the state's policy goals and likely make compliance more costly.
Even if the meaning of "regulatory compliance" is clarified as requested, PacifiCorp is concerned that the draft definition may inadvertently restrict its ability to retire resources early when it is in the best interests of customers. As noted above, most of those retirements in the near term are likely to be coal-fired resources. However, CETA's timeline extends 25 years into the future. It is possible, even likely, that new technology will emerge during this time period that makes retirement of existing renewable generation or nonemitting resources and replacement with new resources the least-cost, least risk option, just as cheap renewables are currently driving coal out of utility portfolios earlier than is strictly required. If those resources could still be used to meet load, the draft rules could prohibit a utility from retiring them and replacing them with newer, better and cheaper resources – simply because there would be no "current or projected deficit." Utilities have an overarching responsibility to procure least-cost, least-risk portfolios on behalf of their customers, and rules should not be drafted in a way that frustrate this obligation.

Accordingly, PacifiCorp proposes the following changes to Staff's definition of "resource need":

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[2] By the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources and more than 3,500 MW of new wind resources, inclusive of resources that will come online by the end of 2020 that were not in the 2017 IRP. The preferred portfolio also includes nearly 600 MW of battery storage capacity (all collocated with new solar resources), and over 700 MW of incremental energy efficiency and new direct load control resources.
Over the 20-year planning horizon, the preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage (nearly 1,400 MW of which are stand-alone storage resources starting in 2028), and more than 2,700 MW of incremental energy efficiency and new direct load control resources.

> *"Resource need" means a change to system resources, including but ~~any current or projected deficit to meet demand, state or federal requirements, or operational requirements reliably. Such requirements may include, but are~~ not limited to demand response, conservation and efficiency resources, distributed energy resources, nonemitting electric generation, renewable resources, or other generation types, which results in the lowest reasonable cost portfolio.~~,~~ Resource need includes, but is not limited to, capacity and associated energy, capacity needed to meet peak demand in any season, Federal Energy Regulatory Commission jurisdictional operational requirements, or resources required for long-term regulatory compliance, such as fossil-fuel generation retirements, equitable distribution of benefits or reduction of burdens, cost-effective conservation and efficiency resources, demand response, renewable and nonemitting resources.*

PacifiCorp recommends that the first CEIP be due on January 1, 2022, as directed in the legislation

As originally recommended in PacifiCorp's June 2, 2020 CEIP comments, the Commission should retain in rule the legislatively outlined filing date for the first CEIP, which is January 1, 2022. This timeline would allow sufficient review of the utility IRP filings, and would provide opportunities for a robust public process as part of the CEIP. The current due date in the revised rule – October 1, with a draft due on August 1 – would unnecessarily accelerate the timeline for the first CEIP and could shorten the time available for public participation.

Further, an accelerated CEIP would place additional pressure on the IRP timeline and could prevent or severely constrain procurement activities, such as issuance of a request for proposals, from occurring between the date of IRP acknowledgment and the CEIP draft due date of August 1. A draft CEIP containing conservation targets developed in accordance with WAC Chapter 480-109 due on August 1 would materially shorten the current conservation target development schedule. The draft biennial conservation plan and target, which are currently due October 1, would be due two months earlier (August 1). The final conservation plan and target, which are currently due on November 1, would now be due October 1. Conservation target development requires use of the latest information, including conservation potential assessments and the IRP, and it may not be possible to simply start the process earlier to meet this alternate schedule.

The rules should not create compliance obligations before the first compliance period beginning in 2030, and the first Clean Energy Compliance Report should be due in 2034

As originally raised by PacifiCorp in the June 2, 2020 CEIP comments: before 2030, CETA requires utilities to propose interim targets to show progress towards meeting the statutory goals, but does not require compliance with interim targets nor does it impose penalties for non-compliance. The Commission may not create additive compliance obligations that go beyond the scope of the unambiguous direction of the legislature. By adding compliance requirements before 2030 – notwithstanding specific statutory language that "compliance period[s] begin[]

January 1, 2030[3] – Staff's draft rules effectively amend an unambiguous statute. The Commission lacks the authority to adopt such rules because there is no "gap" in CETA's general statutory scheme regarding compliance.[4]

PacifiCorp recommends that the Clean Energy Compliance Report directed in draft WAC 480-100-650(1) be due July 1, 2034, or be retitled as to not create confusion with "compliance" requirements. PacifiCorp's draft redline of WAC 480-100-650(1) has retitled the first report a "status" report and has modified the requirements for that report to be consistent with the statute, but simply changing the date for the first report is a reasonable option as well.

Relatedly, PacifiCorp's redlines have deleted the requirement that the utility meet its interim targets. CETA obligates utilities to meet their four-year targets, but the year-over-year interim targets are not enforceable and the Commission lacks the authority to penalize a utility for failing to meet them.

The social cost of carbon should not be included in the Baseline Portfolio.

PacifiCorp is not convinced that Staff's conclusion that a social cost of carbon should be included in development of the Baseline Portfolio, as proposed by draft WAC 480-100-660(1)(a). The draft rule states that this approach is "in accordance with RCW 19.280.030(3)(a)." However, that statute expressly applies "when developing integrated resource plans and clean energy action plans," as well as in developing and selecting conservation policies, plans and targets, and in selecting intermediate- and long-term resource options. The Baseline Portfolio is not part of developing either a utility's IRP or its CEAP, nor is it a component of conservation policies, plans and targets, nor the selection of resource options.[5] It is intended to compare the costs of CETA compliance to the costs of a portfolio that would have been adopted had CETA not been enacted. Had CETA not been enacted, there would be no social cost of carbon included in a utility's portfolio.[6] Accordingly, there is no authority, nor a reasonable policy justification, for inclusion of the social cost of carbon in the Baseline Portfolio.

A "fully developed" draft IRP is not realistic or necessary

PacifiCorp recommends deletion of the "draft IRP" requirement. If the Commission insists on retaining the draft IRP requirement, PacifiCorp strongly recommends removal of the added language in WAC 480-100-525(2) specifying that a draft IRP must include "fully-developed

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[3] RCW 19.405.040(1)(a).
[4] *See* Green River Cmty. Coll., Dist. No. 10 v. Higher Ed. Pers. Bd., 95 Wash. 2d 108, 112 (1980) ("an agency does not have the power to promulgate rules that amend or change legislative enactments."), Hama Hama Co. v. Shorelines Hearings Bd., 85 Wash. 2d 441, 448 (1975) ("It is likewise valid for an administrative agency to 'fill in the gaps' via statutory construction—as long as the agency does not purport to 'amend' the statute.")
[5] While Staff's draft rules propose that the Baseline Portfolio be developed in the IRP process (see draft WAC 480-100-620(9)(a)) – and the IRP process must consider the social cost of carbon – this link between the Baseline Portfolio and the IRP is one of regulatory convenience, not statutory necessity.
[6] Carbon cost possibilities are included in IRP modeling, but they are not a stand-alone adder as is contemplated by draft WAC 480-100-660(1)(a).

versions" of all elements required. Exactly what would constitute a fully-developed version is unclear, is not realistic, and is unnecessary.

PacifiCorp's IRP process makes use of its entire 2-year cycle. After the publishing of an IRP, the Company is engaged in the regulatory approval / acknowledgment process simultaneously with input development for the subsequent IRP cycle. At the point of the Draft IRP requirement, which comes roughly three months in advance of publishing the IRP, the Company is heavily engaged in running its models and analyzing results in an iterative process wherein model runs are informed by outcomes of prior model runs. The selection of the preferred portfolio occurs shortly before publishing.

Under the current draft rules, the requirement to file a draft IRP would essentially require all of PacifiCorp's multi-state stakeholders to engage in the IRP process three months earlier to reach a nearly complete IRP by the draft IRP due date in Washington. In PacifiCorp's other states, this version would be considered final as the regulatory requirements and feedback from each state would have already been incorporated into the draft. Making substantive changes after this process would be difficult or impossible without disrupting regulatory processes in the other states.

PacifiCorp and Commission Staff have been engaging in informal discussions regarding the requirement to file draft IRP as ordered in docket UE-180259, and working towards a temporary solution for the 2021 IRP cycle. The Company has raised many of its concerns with Staff in those discussions, and provided the Company's expectations of what it may be able to file in a Draft IRP in detail in the "Draft IRP Outline" in July 2020.

If the Commission elects to retain the draft IRP requirement, it is essential that the "fully developed requirement" language be removed, consistent with prior drafts. While some aspects of the IRP document may be suitable for early drafting, much of the analytical description and conclusions cannot be drafted until final selection of the preferred portfolio occurs. The draft preferred portfolio and the draft IRP document must therefore be defined in terms of the limited results and chapter information that exist at that time of the draft IRP filing requirement. This would include information reflected in materials discussed at the Company's public input meetings throughout the IRP development process.

Further, a draft IRP filing and public hearing process, as contemplated in the draft rules, occurs too late in the process to meaningfully impact the final IRP. If the purpose of having a regulatory process for the draft IRP is to allow time for public engagement and stakeholder input, there is simply not enough time to effectuate changes or inform the final IRP in a meaningful way before it becomes due. The earliest the Company could incorporate feedback received after the draft IRP is filed would be in the IRP Update or the next IRP cycle.

Interim Targets may demonstrate progress, but do not have a compliance obligation and are not enforceable

The interim targets that will be proposed by utilities and approved by the Commission in the CEIP process prior to 2030 provide an opportunity to demonstrate progress and to incorporate stakeholder input into the CEIP process. PacifiCorp anticipates meeting the targets proposed in the pre-2030 CEIPs. However, the interim targets are not enforceable, and are distinctly different than the compliance obligations that exist after 2030. The interim targets are demonstrations of progress, and the legislation does not support enforcement action against a utility that does not meet an interim target.

CONCLUSION

PacifiCorp appreciates the opportunity to provide comments in response to the Commission's Notice. Please contact Ariel Son at (503) 813-5410 if you have any questions regarding these comments.

Sincerely,

/s/

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