



UTAH

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To: Public Service Commission of Utah

From: Office of Consumer Services
Michele Beck, Director
Cameron Irmas, Utility Analyst

Date: September 4, 2026

Subject: **Docket No. 25-R318-01**, Proposed Rulemaking
Concerning Utah Code §§ 54-26-101 to -901, Large-
Scale Electric Service Requirements

INTRODUCTION

S.B. 132, Electric Utility Amendments, became effective on May 7, 2025, and contains provisions requiring the Public Service Commission of Utah (PSC) to make rules to help effectuate the statute. Following rulemaking proceedings, the PSC established the New Rule, which became effective on January 1, 2026.

On April 28, 2026, the PSC issued a Notice of Comment Period soliciting stakeholders' proposed amendments to the New Rule by June 16, 2026. The Notice also states that PSC Staff are investigating and surveying large load tariffs to provide guidance regarding a Large Load Flexible Tariff (LLFT). On July 22, 2026, the PSC issued a Notice of Additional Comment Period, requesting input on issues raised both in the initial rulemaking and in recent filings, including utility declaration requirements, amendments to Rocky Mountain Power's (RMP) Open Access Transmission Tariff (OATT), and transmission costs. On August 20, 2026, parties filed Responsive Comments addressing these topics. The OCS offers reply comments addressing these filings and provides additional recommendations for future rulemaking.



UTILITY DECLARATION

In Responsive Comments, RMP proposed changes to the declaration process as well as an updated set of requirements to confirm that a closed private generation system is electrically separated from the transmission and distribution system, including a comprehensive set of requirements.¹ RMP also recommended that the closed private generation system pay a fee of \$15,000, and that, upon receiving necessary documentation, RMP will provide a declaration within seven business days.

The OCS agrees with RMP's seven-day declaration timeline. In Responsive Comments, the OCS cautioned against any timelines that may inhibit the utility's ability to verify system isolation; however, the OCS appreciates RMP's effort to establish well-defined requirements that will enable it to produce the declaration in a reasonable timeline. The OCS also agrees with the proposed fee, which is consistent with the direct assignment of costs to large load customers established in S.B. 132. Explicit recovery of the engineering review costs incurred by the company in verifying system isolation protects other ratepayers from cross-subsidization.

While RMP's proposal identifies specific engineering requirements for the declaration, the OCS does not possess sufficient in-house expertise to fully verify these engineering details or the underlying timelines determining when a closed private generation system has reached a state of readiness for a declaration. Some parties have suggested that a group stakeholder process and/or technical conference is warranted to better converge upon a solution; however, the OCS notes that a previous technical conference on this topic, held on September 17, 2025, did not result in alignment between stakeholders. The OCS believes that a more focused approach is necessary and recommends the PSC consider an approach similar to what was used in the initial rulemaking, i.e., to retain an expert engineering consultant to provide guidance on the technical requirements and practical engineering timelines for meeting the declaration. This expert review would facilitate a more focused examination of this topic in subsequent technical conferences or other stakeholder discussions. While the OCS agrees with RMP's assessment that the Company is the appropriate party to make a declaration based on its obligation to provide safe and reliable service to other ratepayers, the OCS believes that additional PSC guidance on the requirements may enable the Rule to better facilitate applicants obtaining that declaration.

EXISTING TRANSMISSION COSTS

The OCS maintains its previous concurrence with DPU that the Rule be amended to expressly require an applicant to account for costs associated with the existing transmission system.

¹ Rocky Mountain Power Responsive Comments, Exhibit A.

The OCS offers additional comments to further the ongoing stakeholder discussion on specific methods as requested by the PSC in its Notice. The OCS believes, however, that an overly prescriptive application of accounting methods in the Rule itself is not appropriate: one of the strengths of the existing Statute and Rule is that it acknowledges the inherent variability in large load customers and the resulting service contracts made with the utility.

In Responsive Comments, RMP recommended that costs associated with a large load customer's use of the existing transmission system should be addressed in large load contracts. RMP further offers a potential solution in the form of a Peak Demand Charge, determined by a customer's monthly peak demand (non-coincident peak) as well as Schedule 1, Schedule 3, and Network Integration Transmission Service (NITS) rates. The revenues from this charge would in turn be allocated among PacifiCorp's six-state service territory. RMP additionally clarifies that this charge is distinct from any mechanisms for recovery of incremental costs, such as those represented in the Reservation Charge,² and furthermore that issues of double recovery are avoided due to the exclusion of incremental costs from rate base.

The OCS appreciates RMP's continued collaboration in these proceedings and presentation of a solution to the PSC's request for transmission cost allocation methods. The OCS believes that a demand-based charge is a necessary, but not quite sufficient, approach to ensuring that large load customers pay for their use of existing transmission. In an ideal case, a monthly demand charge would be sufficient, as the new large load would behave as expected, with high demand and high load factor, and the customer would pay accordingly. However, tying transmission costs directly to usage alone introduces underutilization risk: if that load does not materialize and is thus lower than expected, the customer will underpay. The OCS proposes an additional mechanism to mitigate this risk, in the form of a minimum billing demand. This establishes a floor on the demand used for billing purposes, based on a percentage of the contract demand. This approach is well supported by most existing large load tariffs,³ including Dominion Energy's Schedule GS-5, which explicitly defines a minimum transmission charge of 85% of contract demand.⁴

The OCS agrees with RMP's method of separating accounting requirements, namely that a Peak Demand Charge must be distinct from any incremental cost recovery methods, and that incremental costs must be kept out of rate base and system allocation factors. While this

² 26-035-05 Direct Testimony of Craig M. Eller for Rocky Mountain Power, at 4. "The Reservation Charge compensates the capital costs of the Customer load facilities allowance (i.e., metering costs), bridging market capacity purchases, incremental generation resources, and the Company's return on its investment at a rate that will prevent any subsidization from existing customers."

³ Natalie Mims Frick et al., *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities (2026 Update)*, Lawrence Berkeley National Lab. & The Brattle Group, Tech. Brief at 5 (Aug. 2026).

⁴ *In re Va. Elec. & Power Co. d/b/a Dominion Energy Va.*, Va. State Corp. Comm'n Case No. PUR-2025-00058, Sched. GS-5 (Approved 2025)

approach is consistent with S.B. 132 and the Rule, the multi-jurisdictional allocation of resulting revenues from the Peak Demand Charge deserves additional consideration. In Responsive Comments, RMP specified that the customer's load should be removed from system allocation factors. This reiterates a critical point from the accounting treatment in the previously approved large load contract:

The dynamic allocation factors used in the Company's cost allocation process will be adjusted to account for the new Customer load. Specifically, the Customer's loads and peaks will be excluded from the derivation of Utah's allocation factors, ensuring that the Customer's load does not distort the allocation of costs to other customers.⁵

The OCS understands this to mean that, by isolating the large load customer's load at the system allocation level, RMP has ensured that ratepayers in other states will not absorb this potential cost shift. Therefore, in a case where ratepayers in other jurisdictions do not bear these costs, a more consistent application would retain them within Utah, the jurisdiction bearing the physical load, and in turn credit 100% of these Peak Demand Charge revenues against Utah's Transmission Revenue Requirement. The OCS looks forward to further discussion of transmission cost allocation methods ahead of future large load service contract filings.

RECOMMENDATIONS

The OCS recommends that the PSC:

- Retain an expert engineering consultant to provide guidance on technical requirements and timelines to inform potential modifications to the existing declaration rules.
- Adopt DPU's proposed addition requiring applications to account for costs associated with the existing transmission system. The OCS, along with other parties, will further address multi-jurisdictional allocation of associated revenues in appropriate subsequent dockets and forums.

⁵ 26-035-05 Rocky Mountain Power's Live Summary of Direct Testimony of Ramon J. Mitchell for the March 17, 2026 Hearing at 3.