

Rocky Mountain Power
Docket No. 26-035-20
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Supplemental Testimony of Ramon J. Mitchell

October 2026

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1 **I. INTRODUCTION**

2 **Q. Are you the same Ramon J. Mitchell who previously submitted direct testimony**
3 **in this proceeding on behalf of PacifiCorp d/b/a Rocky Mountain Power**
4 **(“PacifiCorp” or the “Company”)?**

5 A. Yes. My direct testimony explained how the Washington Service Area Transfer¹
6 affects the cost of power for the customers who remain on PacifiCorp’s system, and it
7 demonstrated that the transaction decreases the average unit cost of power for the five
8 states that PacifiCorp will continue to serve after the sale closes. This supplemental
9 testimony builds on that analysis and addresses a related question: what it would cost
10 the customers of the five remaining states if the share of the remaining system that is
11 not allocated to them today were left unassigned rather than reassigned to them.

12 **II. PURPOSE AND SUMMARY OF SUPPLEMENTAL TESTIMONY**

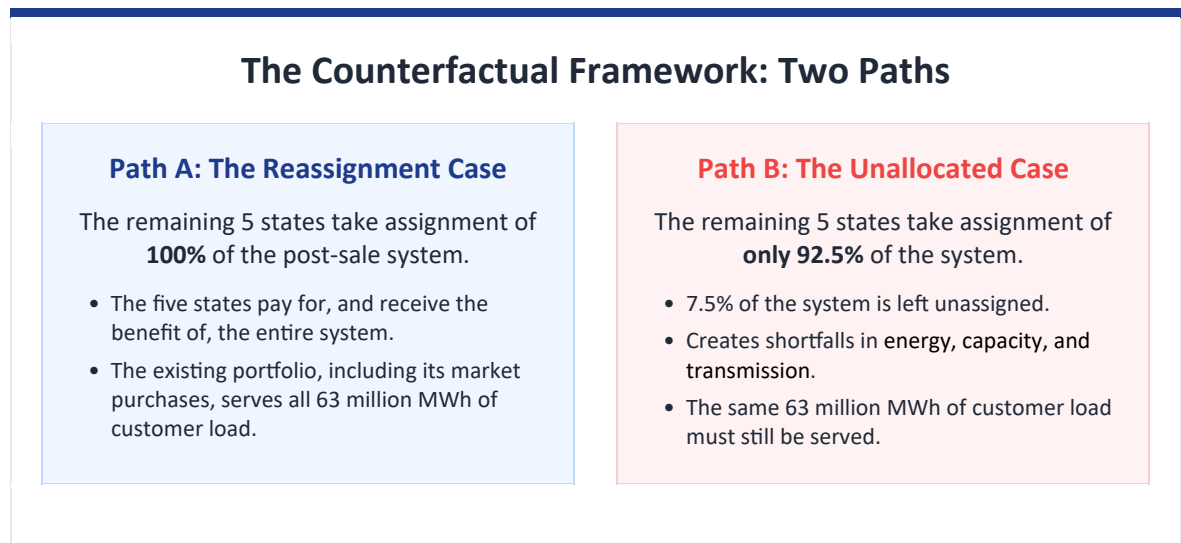
13 **Q. What is the purpose of your supplemental testimony?**

14 A. My supplemental testimony compares two ways of treating the approximately 7.5
15 percent share of PacifiCorp’s remaining system that the allocation factors of the 2020
16 PacifiCorp Inter-Jurisdictional Allocation Protocol (“2020 Protocol”) do not allocate
17 to the five remaining states today (the “Unassigned Share”). In the first, that share is
18 reassigned to the five states that PacifiCorp will continue to serve: California, Idaho,
19 Oregon, Utah, and Wyoming. In the second, it is left unassigned. Figure 1 summarizes
20 the two paths. I quantify the costs and benefits of each treatment for the customers of
21 the remaining five states. My analysis shows that when the entire post-sale system is

¹ The Washington Service Area Transfer is the Company’s proposed sale of its Washington service area and certain Washington-based generation (the Chehalis natural gas plant and the Marengo and Goodnoe Hills wind facilities), transmission, and distribution assets to Gem Sub LLC, a Washington affiliate of Portland General Electric Company, as described in the Company’s application in this docket, which refers to it as the “Service Area Transfer.”

22 allocated among the remaining five states, those states benefit from lower costs.
23 Measured for calendar year 2027,² the five states together avoid \$262 million of costs
24 within the power costs categories I quantify by accepting reassignment of the
25 Unassigned Share rather than leaving it unassigned.³ My supplemental testimony
26 addresses only net power costs, production tax credits, incremental wheeling costs, and
27 renewable energy credits. Other components of revenue requirement associated with
28 the Unassigned Share are addressed by Company witness Shelley E. McCoy, and
29 Company witness Joelle R. Steward's supplemental testimony brings those
30 components together with my results.

Figure 1



31 **Q. You have used the term “counterfactual.” What do you mean by that term?**

32 A. A counterfactual analysis asks what would happen under one decision and what would
33 happen under an alternative, holding everything else the same. The counterfactual

² All analyses in this supplemental testimony use a 2027 forecast period and, for calendar year normalization purposes, assume the Washington Service Area Transfer is effectuated on January 1, 2027.

³ Power Costs Allocation Post Sale 2027 100P CONF.xlsx (confidential workpaper), tab “Summary”; Power Costs Allocation Post Sale 2027 92.5P CONF.xlsx (confidential workpaper), tab “Summary.”

analysis compares two scenarios that are identical in every respect except one—the treatment of the 7.5 percent Unassigned Share of existing resources and transmission. In the first scenario, which I call the “Reassignment Case,” the five states take assignment of 100 percent of the post-sale system. In the second scenario, which I call the “Unallocated Case,” the five states take assignment of only approximately 92.5 percent of the post-sale system, and the remaining approximately 7.5 percent is left unassigned. The underlying model used in my direct testimony, the loads to be served, the power plants on the system (which assumes the sale of the Chehalis natural gas plant and the Marengo and Goodnoe Hills wind plants in the Washington Service Area Transfer), the transmission lines, the weather, the fuel prices, the calendar year,⁴ and all other assumptions are the same in both scenarios. Because everything else is held constant, any difference in cost between the two scenarios is attributable solely to the reassignment decision itself. For consistency with the supplemental testimony of Company witness McCoy, the Reassignment Case corresponds to what she terms the Reallocation Analysis, and the Unallocated Case corresponds to her Counterfactual Analysis.

Q. Please summarize your principal conclusions.

A. In the Unallocated Case, the five states would pay for only approximately 92.5 percent of the post-sale system, but customers in those states would still need the same energy, capacity, and delivery capability as in the Reassignment Case, because their loads do not change. Declining to pay for approximately 7.5 percent of the system does not reduce customers’ electricity use; it creates three shortfalls that must be filled from

⁴ See note 2.

56 somewhere else at prevailing prices and tariffs. First, the remaining five states would
57 be short 3.9 million megawatt-hours of energy in 2027, which would cost \$211 million
58 to replace at forward market prices (prices agreed upon today for electricity delivered
59 in future months).⁵ Second, the remaining five states would lose approximately [REDACTED]
60 [REDACTED] of accredited capacity, the dependable capability that is counted on to meet
61 peak demand with a reserve margin and that helps the Company pass the resource
62 sufficiency tests of the organized markets in which it participates. Replacing it with
63 equivalent utility-scale battery capacity would cost approximately \$104 million per
64 year, after crediting the revenue the batteries would earn in the market and the share of
65 the transitional power purchase agreement's delivery obligation that departs with the
66 Unassigned Share.⁶ Third, the five states would be short the transmission needed to
67 import the replacement energy, and the incremental wheeling costs of delivering it—
68 the reservation and scheduling charges of the PacifiCorp and Bonneville Power
69 Administration tariffs—would total \$30 million.⁷ In addition, the five states would
70 forgo \$20.5 million of federal production tax credits that flow to customers as a
71 reduction to costs.⁸ Against these costs, the remaining five states would avoid \$122
72 million of fuel and purchased-power expense by not paying for the Unassigned Share.
73 They would also lose approximately \$14 million of the savings PacifiCorp earns
74 through the Extended Day-Ahead Market and the Western Energy Imbalance Market,
75 and approximately \$4.8 million of wholesale sales revenues. Netting all of these items,

⁵ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Market."

⁶ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tabs "Capacity" and "Summary."

⁷ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Wheeling."

⁸ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tabs "2027 PTCs" and "2027 PTCs 92.5."

the cost of the Unallocated Case at the total-system level is approximately \$263 million for 2027. When those effects are assigned to individual states under the 2020 Protocol's allocation factors, the five states' combined cost is approximately \$262 million.⁹ The two figures differ by about \$0.5 million, mainly because a few resources are assigned directly to particular states and a small share of costs is allocated to the Federal Energy Regulatory Commission's wholesale jurisdiction, as Section VIII explains. Expressed on a unit basis, in the Reassignment Case, each of the remaining five states saves between \$4.13 and \$4.22—approximately \$4.17 on average—for each megawatt-hour its customers consume, equal to approximately 14 percent of power costs in the Reassignment Case. There is no state for which the Unallocated Case is the cheaper outcome. Table 6 lists each component of these results. They do not include the embedded costs, meaning the costs of existing plant already on the Company's books, that the five states would avoid in the Unallocated Case; witness McCoy addresses those costs, and witness Steward's supplemental testimony brings the witnesses' results together. Separately, the five states would also lose renewable energy credits worth approximately \$4.0 million in 2027 (approximately \$2.0 million for Utah), which I present in Section IX and do not include in these figures.

Q. How is the remainder of your supplemental testimony organized, and how does it relate to the testimony of the Company's other witnesses?

A. Section III establishes the framework of the counterfactual analysis, including its starting point and its valuation principles. Sections IV, V, and VI quantify the three shortfalls in turn: energy, capacity, and transmission. Section VII quantifies the forgone

⁹ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Summary"; Power Costs Allocation Post Sale 2027 100P CONF.xlsx (confidential workpaper), tab "Summary."

98 production tax credits. Section VIII translates the total-system results into results for
99 each individual state. Section IX quantifies the renewable energy credits the five states
100 would lose in the Unallocated Case. Section X discusses the robustness of the results,
101 and Section XI summarizes my conclusions. My testimony complements the testimony
102 of the Company's other witnesses. Witness McCoy, whose supplemental testimony
103 accompanies mine, addresses the revenue requirement impacts other than net power
104 costs. Witness Steward's supplemental testimony brings the witnesses' results together.
105 Company witness Michael G. Wilding explains, from an operational perspective, why
106 PacifiCorp cannot practically manage an unassigned share of the remaining system as
107 a separate portfolio. My supplemental testimony is confined to net power costs,
108 production tax credits, incremental wheeling costs, and renewable energy credits.

109 **Q. What exactly is the "Unassigned Share" that sits at the center of your analysis?**

110 A. When the sale closes, Washington's retail loads leave PacifiCorp's system, and the
111 Chehalis, Goodnoe Hills, and Marengo plants, certain transmission rights, and the
112 Washington qualifying-facility contracts leave with them. What remains is the post-
113 sale system: every other plant, contract, and transmission right the Company owns or
114 controls, all of which would physically operate to serve the customers of the five
115 remaining states. The 2020 Protocol's dynamic allocation factors (percentages,
116 recalculated annually from each state's share of system loads, that divide shared costs
117 among the states), applied to that remaining system as they stand today, would allocate
118 approximately 92.5 percent of it to the five states. The rest is either allocated to
119 Washington today or, for resources that the Washington Inter-Jurisdictional Allocation
120 Methodology (WIJAM) in the 2020 Protocol does not allocate to Washington, not

121 allocated to any state. That remaining share works out to approximately 7.5 percent,
122 which is why my workpapers model the Unallocated Case by scaling the five states'
123 share of system resources¹⁰ by a factor of approximately 0.925 (more precisely 0.9253,
124 or $1 - 0.0747$), the five states' combined share.¹¹ Once Washington's loads are gone,
125 however, no customer is left to pay for any part of that share unless it is reassigned.
126 The Commission therefore faces a choice. Its answer could fall anywhere between
127 reassigning all of the Unassigned Share and reassigning none of it, and my analysis
128 compares those two ends of the range. At one end, the Commission would reassign the
129 Unassigned Share to the five states' customers, who then pay for it and receive the
130 associated output, capacity, transmission, and tax benefits. At the other end, it would
131 leave the share unassigned, in which case customers pay for, and receive, only 92.5
132 percent of the post-sale system. The Company has proposed in this proceeding that the
133 remaining system be allocated among the remaining five states using the 2020
134 Protocol's dynamic allocation factors. My testimony quantifies the estimated costs of
135 those two options, not the many combinations in between.

136 **Q. Is the Company proposing a long-term allocation of the remaining system to the**
137 **other states in this proceeding?**

138 **A.** No. As discussed in the supplemental testimony of Company witness Joelle R. Steward,
139 the Company and the other parties that signed the stipulation that led to this

¹⁰ Situs resources, qualifying-facility purchases, short-term market transactions, and wheeling expense are not scaled by the 0.925 factor.

¹¹ The five states' combined share of the shared post-sale system is 92.53 percent, equivalent to a Washington system generation allocation factor of 7.47 percent, which I round to 7.5 percent. Witness McCoy derives the factor in her accompanying testimony; *see also* Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Summary" (applying the factor to the post-sale system); Power Costs Allocation Post Sale 2027 92.5P CONF.xlsx (confidential workpaper), tabs "Factors" and "Resource Allocation."

supplemental filing (together, the “Stipulating Parties”) agreed to extend certain elements of the 2020 Protocol on a temporary basis. Under that stipulation, any reallocation of the remaining system decided in this proceeding will be used for ratemaking only through December 31, 2028, and the Stipulating Parties will work toward a successor allocation methodology to take effect January 1, 2029.

III. THE COUNTERFACTUAL FRAMEWORK

Q. What is the starting point of your counterfactual analysis?

A. The starting point is the complete post-sale system proposed in the Company’s initial filing, operated for the benefit of the remaining five states.¹² In the Reassignment Case, the five states retain all of the generating resources, purchase contracts, accredited capacity, and transmission of the post-sale system, together with the market purchases the Company uses to serve load, which total 63 million megawatt-hours at the system level for 2027. The Unallocated Case begins from the identical physical system and the identical loads. The system load is the same 63 million megawatt-hours in both cases, because customers’ consumption does not depend on how regulators divide up cost responsibility among states.¹³ Holding the loads and the physical system constant ensures a like-for-like comparison: the only thing that differs between the two cases is the share of the system for which the five states pay and from which they benefit.

Q. How does the Reassignment Case relate to the analysis in your direct testimony?

A. The Reassignment Case is the same 2027 post-sale case presented in my direct testimony. Its total-system power costs of \$1,848.6 million match the 2027 post-sale

¹² My analysis is measured against the Company’s initial filing so that the two can be compared directly. It does not reflect any updates the Company may present later in this proceeding.

¹³ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab “Summary” (showing identical net system load of 62,843,723 megawatt-hours in both cases).

figure in Exhibit RMP____(RJM-3), and my direct testimony showed that this post-sale case has a lower unit cost of power than the pre-sale system.¹⁴ The question in this supplemental testimony is therefore not whether the sale benefits customers, which my direct testimony addresses, but whether customers are better off with the post-sale system allocated entirely among the remaining five states or with a 7.5 percent share of it left unassigned.

Q. If the Unassigned Share is left unallocated, what specifically changes for the five states?

A. Three things change, and each one creates a shortfall that must be filled at prevailing prices and tariffs. First, the five states lose approximately 7.5 percent of the energy output of the shared system resources: 7.5 percent of the coal fleet's output, of the gas fleet's output, of the hydroelectric, wind, and solar output, and of the energy delivered under the Company's long-term purchase contracts. Summed across the year, that lost energy is 3.9 million megawatt-hours.¹⁵ Second, the five states lose approximately 7.5 percent of the system's accredited capacity, meaning the dependable capability that resource-adequacy planning counts on to meet peak demand plus a reserve margin and that helps the Company pass the resource sufficiency tests of the organized markets in which it participates, which I explain and value in Section V. Third, the five states lose the benefit of approximately 7.5 percent of the Company's transmission capability, because in the Unallocated Case they are not paying for it, and the replacement energy

¹⁴ Power Costs Allocation Post Sale 2027 100P CONF.xlsx (confidential workpaper), tab "Post-Sale 100P TC NPC," total power costs of \$1,848,608,103; Direct Testimony of Ramon J. Mitchell, Exhibit RMP____(RJM-3), "Delta Model Forecast," 2027 Power Costs Post-Sale.

¹⁵ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Market" (monthly short positions by balancing authority area).

181 they import must be delivered over transmission that must be purchased. Because the
182 five states' loads are unchanged, none of these losses reduces what their customers
183 need; each loss must be replaced in full, and the replacement has a price. The five states
184 would also forgo approximately 7.5 percent of the federal production tax credits that
185 reduce their revenue requirement. Sections IV through VII quantify those prices and
186 credit the costs the five states avoid by not being allocated the Unassigned Share.

187 **Q. Why can't the Company simply keep the 7.5 percent share, operate it, and sell its**
188 **output back to the remaining five states' customers, so that no one has to replace**
189 **anything?**

190 A. Because giving customers that output at its embedded cost would be, in substance,
191 reassigning the share to them: if customers pay the embedded cost of the share and
192 receive its energy, its capacity, and its tax credits, that is reassignment under a different
193 label. The only other alternative is for the Company to hold the share as a merchant,
194 meaning outside of regulated rates, and sell its output at market for its own account.
195 Company witness Wilding explains that this is not a practical operational outcome. As
196 witness Wilding describes, separating the share would require un-designating portions
197 of the Company's network resources, obtaining new point-to-point transmission that
198 may not be available without study or upgrades, and creating separate market
199 registrations and models for fractional shares of generating units that can be committed
200 and dispatched only as whole facilities. My analysis assumes those problems could be
201 overcome and does not include the cost of overcoming them, so in that respect it
202 understates the cost of leaving the share unassigned.

203 **Q. Are the costs you quantify modeled constructs, or would customers actually pay**
204 **them?**

205 A. The energy and transmission shortfalls would be paid for in cash, the capacity shortfall
206 is valued at the price of the product that would replace it, and the production tax credits
207 would simply be lost. In the Unallocated Case, the replacement energy would be
208 purchased from counterparties at trading hubs such as Mid-Columbia and Four Corners
209 and paid for in cash. The transmission to deliver that energy would be reserved from
210 the transmission functions of PacifiCorp and the Bonneville Power Administration and
211 paid for in cash at posted tariff rates. The accredited capacity would have to be replaced
212 to maintain the planning reserve margin; I value it at the annual cost of the replacement
213 resource, a utility-scale battery, net of the revenue that resource would earn, which is
214 the measure Company witness Wilding uses in his direct testimony. The forgone
215 production tax credits are federal dollars that, in the Reassignment Case, reduce the
216 revenue requirement. Each element of my analysis therefore corresponds to money that
217 would flow, or fail to flow, through the remaining five states' rates. Figure 2
218 summarizes these four losses.

Figure 2

What is the 7.5% “Unassigned Share”?

If the 5 states do not pay for the 7.5% of the system that is not allocated to them today, their customers’ energy needs do not shrink. They lose access to 7.5% of the system’s benefits:

Lost Energy — 7.5% of output from the coal, gas, hydro, wind, and solar fleets.

Lost Capacity — 7.5% of the fleet’s accredited resource-adequacy capability.

Lost Transmission — 7.5% of delivery capability to move power to customer loads.

Lost Tax Credits — 7.5% of federal production tax credits (PTCs) that lower rates.

IV. THE ENERGY SHORTFALL AND NET POWER COSTS

Q. What are “net power costs”?

A. Net power costs, or NPC, are the costs the Company incurs to obtain the energy its customers consume, net of the revenues it earns when it sells surplus energy to others. The category includes fuel burned in the Company’s own plants, payments for power purchased from other parties, and payments for wheeling, which is the charge for moving power across a utility’s transmission lines, less the Company’s revenues from wholesale sales. Net power costs are a significant component of the cost of serving customers. In the Reassignment Case, the five states’ total-system net power costs for 2027 are \$2.122 billion, which is \$33.77 for each of the 63 million megawatt-hours of load served.¹⁶ The question for this section is how much larger that figure becomes in the Unallocated Case, when approximately 7.5 percent of the shared system’s energy must be replaced with market purchases.

¹⁶ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab “Summary.”

232 **Q. How large is the energy shortfall in the Unallocated Case, and how is it distributed**
233 **across the year?**

234 A. The shortfall is 3.9 million megawatt-hours for calendar year 2027. That quantity is
235 approximately 6.3 percent of the five states' load rather than a full 7.5 percent, because
236 situs resources (those tied to a specific state), qualifying-facility purchases (purchases
237 from small independent generators that federal law requires the Company to buy),
238 short-term market transactions, and wheeling expense are unchanged between the two
239 cases. The shortfall exists in every month of the year, ranging from a low of 290,805
240 megawatt-hours in April to a high of 374,065 megawatt-hours in January, with a second
241 peak of 365,670 megawatt-hours in August.¹⁷ The seasonal pattern matters because the
242 price of replacement energy is highest in the months when the shortfall is large: the
243 winter heating months and the summer cooling months, when demand across the
244 western United States is at its peak.

245 **Q. How did you price the replacement energy?**

246 A. I priced each month's shortfall at forward market prices for two organized wholesale
247 trading hubs that correspond to the two halves of PacifiCorp's system. Energy short in
248 the PacifiCorp West balancing authority area (a balancing authority area is the territory
249 within which a utility must keep electricity supply and demand in continuous balance)
250 is priced at the Mid-Columbia hub, a principal trading point of the Pacific Northwest,
251 and energy short in the PacifiCorp East balancing authority area is priced at the Four
252 Corners hub, a principal trading point of the desert Southwest. Wholesale power at
253 these hubs trades in two daily blocks with different prices: heavy-load hours, which are

¹⁷ Spreadsheet 92.5 Percent CONF.xlsx (confidential worksheet), tab "Market."

254 the daytime and evening hours of Monday through Saturday when demand and prices
255 are higher, and light-load hours, which are the nights, Sundays, and holidays when
256 demand and prices are lower.¹⁸ For each month I weighted the heavy-load-hour and
257 light-load-hour forward prices by the number of hours in each block and by the location
258 of the shortfall, producing a blended price per megawatt-hour for that month's
259 replacement purchases.¹⁹ The blended prices range from \$28.58 per megawatt-hour in
260 March, when spring runoff and mild weather depress prices, to \$82.64 per megawatt-
261 hour in August, when summer demand is at its peak. Table 1 presents the monthly
262 shortfall, the blended market price, and the resulting cost.

¹⁸ The heavy-load-hour and light-load-hour convention is standard in western wholesale power markets and is defined, for example, in the Bonneville Power Administration's 2026 transmission rate schedules. Bonneville Power Administration, 2026 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions, BP-26-A-01-AP02, Section III (Definitions) (July 2025), available at <https://www.bpa.gov/-/media/Aep/rates-tariff/bp-26/Final-Proposal/Appendix-EFinal-Proposal-Transmission-Rate-Schedules-and-GRSPsBP26A01AP02.pdf>.

¹⁹ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Market" (including the monthly heavy-load-hour and light-load-hour counts). Forward prices are the Company's official forward price curve as of December 31, 2025.

263 **Table 1 — Monthly Energy Shortfall and Replacement Cost at Market Prices, 2027**

Month	Shortfall (MWh)	Blended Price (\$/MWh)	Replacement Cost (\$)
January	374,065	62.29	23,301,992
February	317,859	52.59	16,716,505
March	315,897	28.58	9,028,989
April	290,805	31.17	9,064,834
May	294,197	29.63	8,717,009
June	317,997	41.71	13,264,435
July	360,937	75.93	27,406,363
August	365,670	82.64	30,219,336
September	304,634	63.87	19,456,987
October	309,570	42.53	13,165,379
November	325,728	44.14	14,376,263
December	372,059	70.03	26,054,596
Total	3,949,418	53.37 (weighted avg.)	210,772,689

Source: Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab “Market.” Blended prices weight Mid-Columbia and Four Corners heavy-load-hour and light-load-hour forward prices by hours and by the location of each month’s shortfall. Monthly figures are rounded, and costs are computed at full precision, so a cost shown may differ slightly from the product of the rounded figures in its row; totals are per the workpaper.

264 **Q. The \$211 million in Table 1 is the gross cost of replacement energy. Do the five**
265 **states avoid any costs in the Unallocated Case that should be credited against that**
266 **figure?**

267 A. Yes. My analysis credits them in full. In the Unallocated Case the five states do not pay
268 the operating costs of the approximately 7.5 percent share they decline. They avoid \$47
269 million of coal fuel expense and \$36 million of natural gas fuel expense, because 7.5
270 percent of the thermal fleet’s output is no longer generated on their behalf. They avoid
271 \$22 million of payments under long-term firm purchase contracts, \$6.2 million of Mid-
272 Columbia hydroelectric purchase expense, \$11 million of storage and exchange
273 contract expense, and \$432,000 of other generation expense.²⁰ Together those avoided
274 costs total \$122 million, which is credited to the Unallocated Case in my analysis. Two

²⁰ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab “Summary.”

275 items within net power costs work in the opposite direction. PacifiCorp participates in
276 organized wholesale markets—the Extended Day-Ahead Market and the Western
277 Energy Imbalance Market, regional platforms through which participating western
278 utilities trade with one another at the lowest available cost—and the value of that
279 participation grows with the size of the system being optimized; with only 92.5 percent
280 of the system, the five states forgo approximately \$14 million of those organized-
281 market benefits. Wholesale sales revenues also decline by \$4.8 million, principally
282 because the transitional power purchase agreement is supplied from the system as a
283 whole, so the five states retain only 92.5 percent of its revenues in the Unallocated
284 Case. Separately from net power costs, the five states must also account for the
285 accredited capacity embedded in the Unassigned Share, which I quantify in Section V
286 at \$104 million per year. Table 2 summarizes the net differences in the net power costs
287 components from the Reassignment Case to the Unallocated Case.

288 **Table 2 — Net Power Costs Differences Between the Reassignment Case and the**
289 **Unallocated Case**

Component	Amount (\$)
Replacement energy purchased at market prices (Table 1)	210,772,689
Avoided coal fuel expense	(47,022,924)
Avoided natural gas fuel expense	(35,691,278)
Avoided contract purchase and other expense	(39,473,093)
Forgone organized-market benefits (EDAM and WEIM)	14,053,143
Reduced wholesale sales revenues	4,848,795
Net increase in net power costs	107,487,331

Source: Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab “Summary.” Amounts in parentheses are costs avoided in the Unallocated Case and are credited against the replacement costs. The contract and other expense line combines long-term firm, Mid-Columbia, storage and exchange, and other generation expense. The forgone organized-market benefits are savings from PacifiCorp’s participation in the Extended Day-Ahead Market and the Western Energy Imbalance Market. They shrink when the five states pay for only 92.5 percent of the system. Components are rounded and may not add to the total.

290 **Q. What do these figures mean for total net power costs and for the unit cost of**
291 **power?**

292 A. Total-system net power costs rise from \$2.122 billion in the Reassignment Case to
293 \$2.230 billion in the Unallocated Case, a net increase of \$107 million, or 5.1 percent.
294 Because the load is identical in both cases, the increase flows directly into the unit cost
295 of power: net power costs rise from \$33.77 to \$35.48 per megawatt-hour of load, an
296 increase of \$1.71 for every megawatt-hour the remaining five states' customers
297 consume. When the forgone production tax credits that I quantify in Section VII are
298 included, the combined measure of net power costs less production tax credits rises
299 from \$29.42 to \$31.45 per megawatt-hour, an increase of \$2.04, or 6.9 percent of the
300 Reassignment Case level.²¹ That increase is before counting the unallocated capacity
301 value of Section V or the incremental wheeling costs of Section VI.

302 **V. THE UNALLOCATED CAPACITY VALUE**

303 **Q. What is the unallocated capacity value, and why must the five states account for**
304 **it in the Unallocated Case?**

305 A. Every generating resource on the shared system carries qualifying capacity (also called
306 accredited capacity)—the amount of dependable output the resource is credited with at
307 the moments the system is most stressed—and the sum of that accredited capacity is
308 what PacifiCorp counts on to meet its customers' peak demand plus a planning reserve
309 margin, meaning a safety margin above expected peak demand. Dependable capacity
310 also supports the Company's participation in the organized markets. Before each
311 trading day, the Extended Day-Ahead Market tests whether each participating area has

²¹ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Summary."

312 offered enough supply of its own to meet its expected load, and a participant that falls
313 short faces a surcharge; the Western Energy Imbalance Market runs a similar test before
314 each hour and limits the market transfers into an area that fails it. The Unassigned Share
315 is a share of that accredited capacity. If the five states decline to take assignment of the
316 share, they lose approximately 7.5 percent of the capacity the remaining system is
317 counted on to hold at its summer peak, and they must stand ready to replace it, because
318 their customers' need for dependable capacity does not shrink when the share goes
319 unassigned. Company witness Wilding's resource-adequacy workpapers show that the
320 post-sale system is not long on capacity at the July 2027 peak, so accredited capacity
321 that leaves with the Unassigned Share would have to be replaced rather than absorbed
322 by surplus.²² Even in a year when the system had capacity to spare, accredited capacity
323 would still have value, because other utilities buy it to meet their own resource-
324 adequacy requirements. Capacity that leaves with the Unassigned Share is therefore
325 either a need the five states must fill again or a value they give up. In his direct
326 testimony, Company witness Wilding values unallocated capacity by the cost of the
327 utility-scale battery capacity that would replace it, net of the market value that such a
328 battery would earn on its own. I adopt that method here and apply it to the Unassigned
329 Share.²³

²² Wilding Workpaper_RA_Visuals HIGHLY CONF.xlsx (highly confidential workpaper supporting the direct testimony of Company witness Wilding), tab "System RA_SAT" (July 2027 accredited capacity of the post-sale system compared with peak load plus planning reserve margin).

²³ Direct Testimony of Company witness Wilding (avoided battery cost methodology); Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Capacity."

330 **Q. How much capacity does the Unassigned Share carry?**

331 A. I measure the Unassigned Share against the shared resources whose allocation changes
 332 between the two cases. At the July system peak, the month witness Wilding uses in his
 333 direct testimony to value capacity for the full year, those shared resources carry [REDACTED]
 334 [REDACTED] of qualifying capacity. The transitional power purchase agreement with the
 335 buyer commits [REDACTED] of July capacity away from the system, and because the
 336 five states would shed 7.47 percent of that obligation along with 7.47 percent of the
 337 fleet, the commitment is credited against the fleet before the share is measured. The
 338 Unassigned Share is therefore 7.47 percent of [REDACTED], or approximately [REDACTED]
 339 [REDACTED] of accredited capacity at the system peak. Expressed as the utility-scale
 340 battery capacity that would provide the same accredited contribution—batteries are
 341 credited at an average summer contribution of [REDACTED]—the share is equivalent to
 342 approximately [REDACTED] of battery capacity.²⁴

343 **Q. How did you place a dollar value on that capacity?**

344 A. I use the avoided-cost method from witness Wilding's direct testimony. The value of
 345 capacity is what it would cost to replace it with the marginal resource-adequacy
 346 resource—a utility-scale battery—at the price of [REDACTED] that witness
 347 Wilding uses.²⁵ Applied to the [REDACTED] of battery-equivalent capacity, the gross
 348 avoided cost is approximately \$153.1 million per year. That figure asks only what the
 349 remaining five states would pay a battery developer for the same accredited capability
 350 the Unassigned Share already provides.

²⁴ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Capacity."

²⁵ Wilding - Avoided Battery Cost CONF.xlsx (confidential workpaper supporting the direct testimony of Company witness Wilding), tab "Avoided Battery Cost," cells O6 (utility-scale battery price of [REDACTED]) and K10 (average summer storage qualifying-capacity contribution of [REDACTED]).

Q. Does the valuation credit the offsetting value that replacement batteries would earn?

A. Yes. A battery does not stand idle between reliability events; it buys energy when prices are low and sells when prices are high, and that arbitrage revenue offsets part of its cost. Witness Wilding’s direct testimony workpapers quantify the realized arbitrage value at [REDACTED] for a four-hour battery, and I credit that value in full—approximately \$48.7 million per year across the [REDACTED].²⁶ The construction is symmetric between the cases in the same way as the rest of my analysis: the capacity that departs with the Unassigned Share is charged at replacement cost, the market value the replacement would earn is credited in full, and the capacity the share commits away under the transitional power purchase agreement is netted out before anything is valued. Table 3 presents the derivation step by step.

Table 3 — Derivation of the Unallocated Capacity Value

Step	Source	Basis	Amount
Shared-fleet qualifying capacity, July	Wilding direct RA workpapers	July system peak	[REDACTED]
Less: transitional PPA commitment	Wilding direct RA workpapers	July commitment	[REDACTED]
Unassigned Share of net capacity	1 – 0.9253	7.47%	[REDACTED]
Battery-equivalent capacity	Avg. summer battery contribution	[REDACTED]	[REDACTED]
Avoided battery cost, gross	Wilding direct testimony	[REDACTED]	153,109,076
Less: energy arbitrage value	Wilding workpapers	[REDACTED]	(48,731,084)
Unallocated Capacity Value (\$/yr)	—	—	104,377,993

Source: Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab “Capacity”; Direct Testimony of Company witness Wilding and supporting workpapers (battery price, average summer storage qualifying-capacity contribution, and realized arbitrage value). Figures rounded; the “Capacity” tab lists every shared resource and its July qualifying capacity.

²⁶ Wilding - Avoided Battery Cost CONF.xlsx (confidential workpaper supporting the direct testimony of Company witness Wilding), tab “BS Profile CONF,” cell L3 (realized energy-arbitrage value of [REDACTED] for a four-hour utility-scale battery, computed from hourly Mid-Columbia prices for 2030; as in his direct testimony, I apply that value to 2027 without adjustment).

364 **Q. Applying that method, what is the unallocated capacity value?**

365 A. The unallocated capacity value is \$104,377,993 per year—approximately \$104.4
366 million. Because capacity is a distinct product from energy, this value enters my
367 comparison as its own line alongside net power costs, production tax credits, and
368 wheeling.²⁷

369 **VI. INCREMENTAL WHEELING COSTS**

370 **Q. Why does the Unallocated Case create a transmission cost at all?**

371 A. Because energy cannot serve customers until it is delivered, and delivery requires
372 transmission. In the Reassignment Case, the five states pay for and receive the benefit
373 of the Company's entire post-sale transmission system, which is sufficient to move the
374 output of the system's resources to the five states' loads. In the Unallocated Case, the
375 five states do not pay for approximately 7.5 percent of that transmission capability, on
376 the same logic by which they do not pay for 7.5 percent of the generation. The
377 transmission share retained in that case is fully committed to delivering the output of
378 the resources they retain; it does not create spare firm capability from the market hubs
379 to their loads. Witness Wilding's supplemental testimony explains the same point
380 operationally: network transmission provides access to serve retail load from
381 designated resources, and a reduced network allocation neither frees up nor guarantees
382 the availability of point-to-point delivery capability from market hubs. In plain terms,
383 network service moves the Company's own designated resources to its retail customers,
384 while point-to-point service is a reservation between two specified points, which is
385 what a purchase at a hub requires. Newly purchased energy at a hub requires its own

²⁷ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tabs "Capacity" and "Summary."

386 firm delivery path, which is what this section prices. The Unallocated Case obliges the
387 import of 3.9 million megawatt-hours of replacement energy purchased at wholesale
388 trading hubs, and imported energy must be delivered over transmission on a firm basis,
389 meaning with a reserved, non-interruptible right of delivery, because it is serving retail
390 load that cannot be curtailed when lines are busy. The five states therefore must
391 purchase firm transmission service sufficient to deliver the replacement energy. I refer
392 to these delivery charges as incremental wheeling costs. They are incremental because
393 they are new cash outlays that exist only in the Unallocated Case. They consist of the
394 reservation charge for the firm path itself, together with the scheduling charge and, on
395 PacifiCorp's system, the voltage-support charge that accompany a reservation. My
396 analysis prices these at the posted tariff rates of the two major transmission providers
397 whose systems the deliveries would primarily use: the PacifiCorp transmission function
398 in the East and the Bonneville Power Administration in the West.²⁸

399 **Q. How did you determine how much firm transmission the five states would need to**
400 **reserve?**

401 **A.** Firm transmission is purchased as a reservation: a fixed number of megawatts, reserved
402 for a whole month, that the customer may use in any hour of that month. A reservation
403 must therefore be sized for the periods within the month when the shortfall runs above
404 its average, not for the average alone. For each month I sized the reservation by asking
405 what constant delivery rate, used at a reasonable fraction of its capability, would move
406 that month's shortfall, and I set that fraction, called the load factor, at 88 percent, which

²⁸ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Wheeling."

407 is the ratio of the average month's shortfall to the largest month's shortfall.²⁹ Dividing
408 each month's megawatt-hours by the hours in the month and by that 88 percent, and
409 rounding up to the next whole megawatt, produces reservations averaging
410 approximately 465 megawatts in the East and 48 megawatts in the West across the year.

411 **Q. Please walk through the eastern calculation.**

412 A. The eastern shortfall is the portion of the replacement energy for delivery to loads in
413 the PacifiCorp East balancing authority area, totaling 3.6 million megawatt-hours
414 across 2027. Delivering it requires firm point-to-point service on the PacifiCorp
415 transmission system at the rates of PacifiCorp's Open Access Transmission Tariff.
416 Those rates are set by a transmission formula rate on file with the Federal Energy
417 Regulatory Commission and updated annually; the 2026 annual update was filed on
418 May 14, 2026, in Docket No. ER26-2546-000, and the resulting rates are posted
419 publicly on the Company's Open Access Same-Time Information System.³⁰ Three
420 tariff charges apply. The long-term firm point-to-point reservation itself is billed at
421 \$4,989.7784 per megawatt of reserved capacity per month. Alongside it, every point-
422 to-point customer pays two small operating charges: Schedule 1, for scheduling, system
423 control, and dispatch, at \$64.5303 per megawatt-month, and Schedule 2, for reactive
424 supply and voltage control, at \$133.583 per megawatt-month.³¹ The shortfall quantities

²⁹ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tabs "Market" and "Wheeling." The hours-weighted average monthly shortfall is 329,422 megawatt-hours against a maximum month of 374,065 megawatt-hours, a ratio of 88 percent, which is applied as the load factor of each month's reservation.

³⁰ PacifiCorp, Transmission Services (describing the 2026 Transmission Formula Rate Annual Update, Federal Energy Regulatory Commission Docket No. ER26-2546-000, and the posting of rates on OASIS), available at <https://www.pacificorp.com/transmission/transmission-services.html>; Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Wheeling" (citing PacifiCorp OASIS, Rate Table (June 1, 2026), available at https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Rate_Table_20260601.pdf).

³¹ PacifiCorp Transmission and Ancillary Services Rates, rates as of June 1, 2026, Schedule 7 (long-term firm point-to-point, monthly), Schedule 1 (SC), and Schedule 2 (RV) columns; Federal Energy Regulatory Commission Docket Nos. ER26-2546-000 (Schedules 1 and 7, effective June 1, 2026) and ER21-1015

425 are measured against the system's net load, which already includes transmission losses,
426 so the analysis adds no separate charge for energy lost in delivery. Applying these
427 charges to the monthly reservations—5,583 megawatt-months across 2027—produces
428 an eastern incremental wheeling cost of \$29.0 million for 2027: \$27.9 million of
429 reservation charges and \$1.1 million of scheduling and voltage-support charges.³²

430 **Q. Please walk through the western calculation.**

431 A. The western shortfall is the portion of the replacement energy for delivery to loads in
432 the PacifiCorp West balancing authority area, totaling approximately 363,000
433 megawatt-hours across 2027. The PacifiCorp West balancing authority area is
434 integrated with the Bonneville Power Administration's Federal Columbia River
435 Transmission System, the backbone grid of the Pacific Northwest, so delivery to
436 PacifiCorp's western loads requires firm point-to-point service from the Bonneville
437 Power Administration. Bonneville is a federal power marketing administration, not an
438 investor-owned utility. Its rates are set in formal statutory rate proceedings and then
439 submitted to the Federal Energy Regulatory Commission, which confirms and
440 approves them under the Northwest Power Act. Under the BP-26 rate proceeding,
441 concluded by the Administrator's Final Record of Decision on July 24, 2025, and
442 effective for fiscal years 2026 through 2028, Bonneville's long-term firm point-to-
443 point rate under rate schedule PTP-26 is \$2.043 per kilowatt-month.³³ Bonneville's

(Schedule 2, effective January 1, 2021), available at
https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Rate_Table_20260601.pdf.

³²Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Wheeling."

³³ Bonneville Power Administration, 2026 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions, BP-26-A-01-AP02, PTP-26 § II.A (\$2.043 per kilowatt per month for Long-Term Firm PTP Transmission Service) (July 2025), available at <https://www.bpa.gov/-/media/Aep/rates-tariff/bp-26/Final-Proposal/Appendix-EFinal-Proposal-Transmission-Rate-Schedules-and-GRSPsBP26A01AP02.pdf>; Bonneville Power Administration, Transmission Rates, available at <https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/transmission-rates>.

reservations carry a companion charge as well: its Scheduling, System Control, and Dispatch rate of \$0.391 per kilowatt-month applicable to long-term firm point-to-point service.³⁴ Applying these charges to the monthly reservations—570 megawatt-months across 2027—produces a western incremental wheeling cost of \$1.4 million for 2027.³⁵ Table 4 presents both sides of the system by month.

Table 4 — Monthly Incremental Wheeling Costs, 2027

Month	East (MWh)	East (\$)	West (MWh)	West (\$)	Total (\$)
January	337,561	2,676,952	36,504	136,304	2,813,256
February	285,517	2,505,752	32,342	133,870	2,639,622
March	289,417	2,293,048	26,481	99,794	2,392,842
April	264,356	2,163,351	26,449	102,228	2,265,579
May	266,890	2,116,660	27,307	102,228	2,218,888
June	284,009	2,324,175	33,988	131,436	2,455,611
July	332,243	2,635,449	28,693	107,096	2,742,545
August	338,975	2,687,328	26,695	99,794	2,787,122
September	279,445	2,287,860	25,189	97,360	2,385,220
October	282,268	2,235,981	27,302	102,228	2,338,209
November	290,134	2,376,054	35,593	138,738	2,514,792
December	336,011	2,661,388	36,048	136,304	2,797,692
Total	3,586,825	28,963,999	362,592	1,387,380	30,351,379

Source: Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab “Wheeling.” Costs reflect whole-megawatt monthly reservations sized at an 88 percent load factor and billed at the PacifiCorp and Bonneville Power Administration long-term firm point-to-point rates, together with the scheduling charges of both providers and PacifiCorp’s voltage-support charge; the shortfall quantities are stated inclusive of transmission losses, so no separate loss charge applies. Monthly figures are rounded, and costs are computed at full precision, so a cost shown may differ slightly from the sum of the rounded components in its row; totals are per the workpaper.

Q. Are the assumptions behind these incremental wheeling costs reasonable?

A. Yes. The reservations are sized in whole megawatts, month by month, with headroom for the periods when the shortfall runs above its monthly average. The 88 percent load

³⁴ Bonneville Power Administration, 2026 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions, BP-26-A-01-AP02, ACS-26 § II.A (Scheduling, System Control, and Dispatch rate for Long-Term Firm Point-to-Point Transmission Service, not to exceed \$0.391 per kilowatt per month, charged per segment) (July 2025), available at <https://www.bpa.gov/-/media/Acp/rates-tariff/bp-26/Final-Proposal/Appendix-EFinal-Proposal-Transmission-Rate-Schedules-and-GRSPsBP26A01AP02.pdf>.

³⁵ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab “Wheeling.”

453 factor is the hours-weighted average monthly shortfall divided by the largest monthly
454 shortfall.³⁶ A 100 percent load factor, meaning a reservation used fully in every hour
455 of the month, would produce the smallest possible reservations and a cost of
456 approximately \$27 million; a reservation shaped to deliver only in heavy-load hours
457 would require larger reservations and a cost of approximately \$46 million to \$49
458 million. The 88 percent figure lies between those bounds. The rates are the posted tariff
459 rates that any transmission customer, affiliated or not, would pay for the same service,
460 including the scheduling charges and, on PacifiCorp's system, the voltage-support
461 charge. The analysis omits the costs that appear when market conditions are tighter
462 than the tariff rates assume: transmission congestion, the cost of network upgrades if
463 long-term firm capacity is not available in the exact quantities needed, and the premium
464 prices of short-term purchases when it is not. Witness Wilding's supplemental
465 testimony describes the same possibilities from an operational perspective: new point-
466 to-point service requests may require study, may not be readily available, and may
467 require transmission upgrades. Each of those omissions understates, rather than
468 overstates, the cost of the Unallocated Case.

³⁶ The derivation of the 88 percent load factor is in note 29. For context on the average utilization of transmission systems, see Ryan Hledik, Long Lam & Kate Peters, The Brattle Grp., *The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability* 5 (Mar. 2026) (commissioned by the Utilize Coalition and GridLab), <https://www.brattle.com/wp-content/uploads/2026/03/The-Untapped-Grid-Mar-2026.pdf> (finding that because the U.S. power system “is built to serve infrequent spikes in demand, less than half of its capacity is used throughout the year”); Mark Golden, *The Hidden Transmission Capacity of the American West*, Stan. Energy (Dec. 11, 2025), <https://energy.stanford.edu/news/hidden-transmission-capacity-american-west> (reporting a Stanford study finding transmission lines “throughout the West operating well below capacity”).

469 **VII. PRODUCTION TAX CREDITS**

470 **Q. What are production tax credits, and why do they belong in this analysis?**

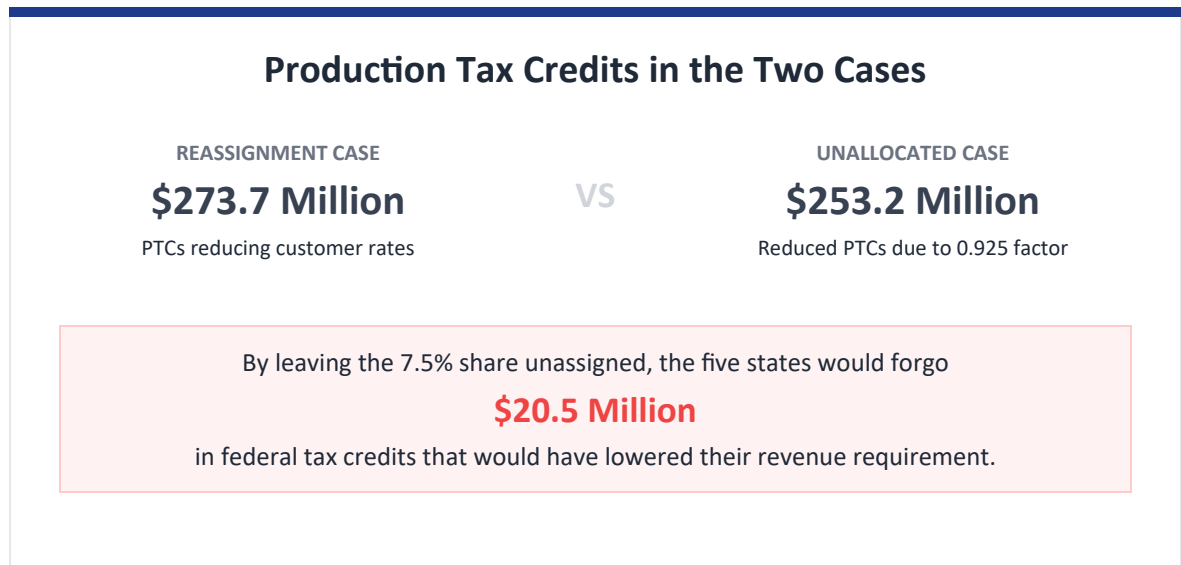
471 A. The federal production tax credit is a per-kilowatt-hour incentive, delivered through
472 the federal tax system, earned for electricity generated from qualifying energy
473 resources, principally wind on PacifiCorp's system. These credits matter to this
474 analysis because every dollar of production tax credit the Company earns offsets the
475 revenue requirement that customers pay for the resources. When the five states decline
476 a megawatt-hour of qualifying wind energy, they therefore lose both the zero-fuel-cost
477 energy and the federal credit that comes with it.

478 **Q. How much production tax credit value do the five states forgo in the Unallocated**
479 **Case?**

480 A. In the Reassignment Case, the post-sale system earns \$273.7 million of production tax
481 credits in 2027 for the benefit of the remaining five states. In the Unallocated Case,
482 with shared wind facilities' qualifying output scaled by the 0.925 factor, the credits fall
483 to \$253.2 million. The difference, \$20.5 million, is federal credit value the remaining
484 five states would forgo, as depicted in Figure 3.³⁷ The ten-year credit windows of the
485 facilities repowered or placed in service in 2019 through 2021 expire between 2029
486 and 2031, while the credits for the more recently placed-in-service wind facilities
487 extend beyond that horizon, so the forgone-credit component persists at approximately
488 this level through the end of this decade and declines thereafter. Credits associated with
489 an unassigned share would stay with the Company.

³⁷ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tabs "2027 PTCs" and "2027 PTCs 92.5."

Figure 3



VIII. RESULTS FOR EACH OF THE FIVE STATES

Q. You have presented total-system results. How do the results translate to each individual state?

A. Rates are set state by state, so the results most relevant to this Commission are the state-level results. The two state-level workpapers apply the 2020 Protocol’s allocation methodology—the resource allocations and dynamic factors carried on their “Resource Allocation” and “Factors” tabs—separately to the Reassignment Case and the Unallocated Case, producing for each state its allocated net power costs less production tax credits, plus incremental wheeling costs, plus the unallocated capacity value, in each case.³⁸ Table 5 presents the results, and Table 6 lists each component of the total-system result together with each state’s total. Every state’s cost is lower in the

³⁸ Power Costs Allocation Post Sale 2027 100P CONF.xlsx and Power Costs Allocation Post Sale 2027 92.5P CONF.xlsx (confidential workpapers), tabs “Summary,” “Load,” “Resource Allocation,” and “Factors.”

501 Reassignment Case, by amounts ranging from \$3.5 million for California to \$129.8
502 million for Utah, and the five states together save \$262 million.

503 **Table 5 — State-Level Power Costs Results, Reassignment Case Versus Unallocated**
504 **Case**

State	Reassignment Case (\$)	Unallocated Case (\$)	Savings (\$)	Savings (\$/MWh)	Savings (%)
California	24,752,482	28,219,588	3,467,106	4.22	14.0
Idaho	117,278,837	133,782,746	16,503,909	4.17	14.1
Oregon	528,232,979	601,714,669	73,481,690	4.17	13.9
Utah	914,470,666	1,044,226,664	129,755,997	4.19	14.2
Wyoming	269,144,243	308,127,649	38,983,407	4.13	14.5
Total	1,853,879,207	2,116,071,316	262,192,109	4.17	14.1

Source: Power Costs Allocation Post Sale 2027 100P CONF.xlsx and Power Costs Allocation Post Sale 2027 92.5P CONF.xlsx (confidential workpapers), tab “Summary” of each. Amounts reflect allocated net power costs less production tax credits, plus incremental wheeling costs and the unallocated capacity value; the dollar, dollar-per-megawatt-hour, and percentage columns all include the wheeling and capacity components. Percentage savings are expressed relative to each state’s Reassignment Case cost. Figures are rounded to the nearest dollar; totals are per the workpaper.

505 **Q. The state-level savings total \$262.2 million, while the total-system result presented**
506 **in Sections IV through VII is \$262.7 million. Please explain the difference.**

507 A. The two figures measure the same thing on two different bases, and the difference,
508 approximately \$0.5 million, arises from the items the two bases treat differently. The
509 total-system calculation in Sections IV through VII measures the change in system-
510 wide costs. The state-level calculation assigns each element to the jurisdiction that
511 bears it, and two features of that assignment cause the sums to diverge slightly. First, a
512 small share of system costs is allocated to the Federal Energy Regulatory
513 Commission’s wholesale jurisdiction rather than to the five states, so the five-state total
514 excludes that slice (approximately \$56,000 of the difference). Second, the situs and
515 specially treated resources, such as the Black Cap Solar and Rolling Hills wind
516 facilities, together with the Oregon-specific treatment of production tax credits from
517 Rolling Hills, are repriced at the jurisdictional level rather than at a uniform system

518 share (approximately \$423,000 of the difference).³⁹ With those jurisdictional
519 treatments applied, the summed state-level savings are modestly smaller than the
520 system-level figure. Both figures point in the same direction and support the same
521 conclusion. I present the state-level figure, approximately \$262 million, as the headline
522 result because rates are set by jurisdiction, and the state-level figures are the ones that
523 correspond to what each state's customers would actually experience. The same
524 jurisdictional treatments explain why the Reassignment Case total in Table 5 (\$1,853.9
525 million) differs by approximately \$5.3 million from the total-system figure of \$1,848.6
526 million in Exhibit RMP___(RJM-3) to my direct testimony; both describe the same
527 2027 post-sale case.

³⁹ Spreadsheet 92.5 Percent CONF.xlsx (confidential workpaper), tab "Side by Side"; Power Costs Allocation Post Sale 2027 100P CONF.xlsx and Power Costs Allocation Post Sale 2027 92.5P CONF.xlsx (confidential workpapers), tabs "Summary," "Post-Sale 100P FERC NPC," "Post-Sale 92.5P FERC NPC," "Post-Sale 100P TC NPC OR," and "Post-Sale 92.5P TC NPC OR."

Table 6 — Components of the Cost of the Unallocated Case, 2027 (\$ millions)

Component	Total System	California	Idaho	Oregon	Utah	Wyoming
Replacement energy purchased at market prices (Table 1)	210.8	—	—	—	—	—
Avoided coal fuel expense	(47.0)	—	—	—	—	—
Avoided natural gas fuel expense	(35.7)	—	—	—	—	—
Avoided contract purchase and other expense	(39.5)	—	—	—	—	—
Forgone organized-market benefits (EDAM and WEIM)	14.1	—	—	—	—	—
Reduced wholesale sales revenues	4.8	—	—	—	—	—
Net increase in net power costs (Table 2)	107.5	—	—	—	—	—
Forgone production tax credits (Section VII)	20.5	—	—	—	—	—
Incremental wheeling costs (Section VI)	30.4	—	—	—	—	—
Unallocated capacity value (Section V)	104.4	—	—	—	—	—
Power costs categories, net (state figures from Table 5)	262.7	3.5	16.5	73.5	129.8	39.0

Source: Sections IV through VII and Table 5 of this testimony. State power costs figures are the state-level results of Table 5; the total-system figure is the system-level result of Sections IV through VII; the two differ by the approximately \$0.5 million reconciling amount described in Section VIII. Components are rounded separately and may not add to the totals shown. The table does not include the renewable energy credits discussed in Section IX. Parentheses denote avoided costs.

529

IX. RENEWABLE ENERGY CREDITS

530

Q. What are renewable energy credits, and how does the Unallocated Case affect them?

531

532

A. A renewable energy credit, or REC, is a certificate showing that one megawatt-hour of electricity was generated by a renewable resource, such as a wind or solar plant. RECs have value because they can be used to meet state renewable energy requirements or sold to others. In the Reassignment Case, the five states receive all of the RECs available from the remaining system. In the Unallocated Case, they would not receive the RECs that belong to the Unassigned Share, so they would receive only

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538 approximately 92.5 percent of those RECs. The exception is RECs from qualifying
 539 facilities and certain situs arrangements.⁴⁰

540 **Q. What is the value of the RECs the five states would lose?**

541 A. In 2027, the five states would receive approximately [REDACTED] fewer RECs in the
 542 Unallocated Case. At [REDACTED] per REC, the average of the Company's annual REC sale
 543 prices from 2022 through 2025, those RECs are worth approximately [REDACTED], of
 544 which approximately [REDACTED] is Utah's share.⁴¹ This amount is not included in
 545 Table 6 or in the other totals in my testimony; it is an additional cost of the Unallocated
 546 Case.

547 **X. ROBUSTNESS OF THE RESULTS**

548 **Q. Are the results highly sensitive to the forward market prices used in the analysis?**

549 A. No, for two reasons. If market prices turn out lower than the forward prices used in this
 550 analysis, the largest cost in the Unallocated Case—buying replacement energy—falls.
 551 But part of the savings credited to that case in Table 2 falls with it: cheaper markets
 552 also mean lower fuel costs on the system, so there is less expense to avoid. A falling
 553 market therefore shrinks the Unallocated Case's bill and its credit together, so the gap
 554 between the two cases narrows by less than the price drop alone would suggest. In
 555 addition, the unallocated capacity value, the wheeling costs, and the forgone production
 556 tax credits—together roughly \$155 million—are set by battery costs, tariff rates, and
 557 federal credit levels rather than by market energy prices, so they change little as prices
 558 move. If market prices rise, the Unallocated Case becomes more expensive. The choice

⁴⁰ See note 10.

⁴¹ REC Report 92.5 Percent CONF.xlsx (confidential workpaper), tabs "REC Benefit Summary," "Historical REC Value," and "State Summary."

559 is between an owned resource base whose costs are largely fixed and an annual market
560 purchase of nearly four million megawatt-hours whose cost moves with market prices.

561 **Q. Did you test the results against a different forward price curve?**

562 A. Yes. The forward curve underlying Table 1 is the Company's official forward price
563 curve as of December 31, 2025, consistent with the data series supporting the
564 Company's direct filing, applied identically wherever prices enter the analysis. To test
565 the result against lower prices—the direction adverse to my conclusion—I recomputed
566 the entire analysis using the Company's June 30, 2026 official forward price curve,
567 under which replacement power prices average approximately 10 percent lower on the
568 blended basis used in Table 1, natural gas prices are correspondingly lower, and coal
569 prices remain at their long-term contract levels. The Company's production-cost model
570 was re-run under the new curve for the Reassignment Case, so dispatch, market
571 purchases, and sales all update; the Unallocated Case was then derived from that re-run
572 in the same way as in my primary analysis. The direction of the result does not change:
573 the cost of the Unallocated Case is approximately \$248 million within my quantified
574 categories under the lower curve, with every state still better off under reassignment.⁴²
575 A structural feature reinforces this result. Roughly \$155 million of the primary result—
576 the capacity, wheeling, and production-tax-credit categories—is set by battery costs,
577 tariff rates, and federal credit levels rather than by market energy prices; those
578 categories are essentially unchanged under the lower curve.

⁴² Spreadsheet 92.5 Percent 20260630_OFPC CONF.xlsx (confidential workpaper), tabs "Summary" and "Market." Under the June 30, 2026 curve, the blended monthly replacement prices of Table 1 average approximately 10 percent lower than under the December 31, 2025 curve; individual hub forward prices average approximately 13 percent lower.

579 **Q. Does your conclusion depend on the allocation factors used to divide the results**
580 **among the states?**

581 A. No. Allocation factors determine how a total cost is divided among the states, not
582 whether a total cost exists. Because the Unallocated Case imposes a net cost at the total-
583 system level, any set of positive allocation factors divides that cost among the states,
584 so each state's share is a cost rather than a benefit; the situs and jurisdiction-specific
585 items described in Section VIII are small relative to the state-level results. Table 5
586 confirms the point state by state: under the 2020 Protocol's dynamic factors, every
587 state's cost is lower with reassignment, within the narrow band of \$4.13 to \$4.22 per
588 megawatt-hour of savings.

589 **Q. What does the Reassignment Case ask the remaining five states to take on?**

590 A. What the remaining five states take in the Reassignment Case is approximately 7.5
591 percent of the post-sale system—its energy, its capacity, its transmission, and its federal
592 tax credits—at its embedded cost. The alternative is buying the same services at market
593 and tariff prices for approximately \$263 million more within the power costs categories
594 I quantify. Each state's unit cost of power is between \$4.13 and \$4.22 per megawatt-
595 hour lower with reassignment, and no state's position worsens. Declining reassignment
596 would result in customers paying more for the same electric service.

597 **Q. Why does the analysis price energy, capacity, and transmission as separate items?**

598 A. The three items are distinct products, purchased separately and priced separately in
599 wholesale markets and tariffs. Energy is the commodity itself. Capacity is the
600 dependable ability to produce when demand peaks, which a utility must hold whether
601 or not it is called on. Transmission is the delivery path. A utility short of all three must

buy all three, and no one of the purchases substitutes for another. My accounting counts each dollar once: the capacity value appears as its own line (Table 3) and not within the net power costs of Table 2; the market prices of Table 1 contain no delivery component, which is priced only in Section VI; and the production tax credits are a separate federal cash flow that overlaps with none of the three. Purchases at hubs such as Mid-Columbia and Four Corners are delivered at the hub itself; moving that energy from the hub to PacifiCorp's customers requires the separate firm transmission service priced in Section VI.

Q. Why is calendar year 2027 an appropriate test year?

A. Calendar year 2027 is the first year after the assumed closing of the Washington Service Area Transfer,⁴³ which makes it the clearest single year for measuring the decision now before the Commission, but nothing about the result is a one-year artifact. Its drivers are structural. The battery price and the transmission tariff rates are multi-year figures; the Bonneville rates are fixed through fiscal year 2028. The production tax credit losses persist for as long as the wind facilities remain within their credit windows. The energy shortfall recurs every year the loads exist, and its cost moves with the market for both cases symmetrically. I have not repeated this analysis for a later year, but its drivers, the market and tariff prices of the replacement services relative to the costs the five states would avoid, are not specific to 2027. The Unallocated Case is not costly because 2027 is unusual; it is costly because the market and tariff prices of the replacement services exceed the costs the five states would avoid by declining the share, and those drivers persist beyond 2027.

⁴³ See note 2.

In addition, the stipulation that led to this supplemental filing is short-term: any reallocation decided here will be used for ratemaking only through December 31, 2028, and the stipulation contemplates a successor allocation methodology to take effect January 1, 2029. That successor process, not this testimony, is the place for a long-term analysis.

XI. CONCLUSION

Q. Please summarize your conclusion and your recommendation to the Commission.

A. The Washington Service Area Transfer leaves behind a system that serves the customers of Utah, Wyoming, Idaho, Oregon, and California. My supplemental testimony supports the Company's proposal that the remaining system be allocated entirely among the remaining five states, rather than leaving any part of it unassigned. Leaving the Unassigned Share unallocated would require the five states to replace 3.9 million megawatt-hours of energy at a market cost of \$211 million, replace the approximately [REDACTED] of accredited capacity embedded in the share with equivalent utility-scale battery capacity, valued at approximately \$104 million per year net of the market value the replacement would earn, pay \$30 million of incremental wheeling costs to deliver the purchased energy, and forgo \$20.5 million of federal production tax credits, \$14 million of organized-market benefits, and \$4.8 million of wholesale sales revenues. Against those costs, the remaining five states would avoid approximately \$122 million of fuel and purchased-power costs. The net cost of the Unallocated Case is therefore approximately \$263 million in 2027 at the total-system level within the power costs categories I quantify, with each state's customers paying between \$4.13 and \$4.22 more per megawatt-hour (approximately \$4.17 on average) within those categories. Witness McCoy addresses the embedded costs the five states

648 would avoid, and witness Steward's supplemental testimony brings the witnesses'
649 results together. Separately, the remaining five states would also lose renewable energy
650 credits worth approximately \$4.0 million in 2027 (approximately \$2.0 million for
651 Utah), which are not included in these figures. Reassignment of the Unassigned Share
652 through the 2020 Protocol's dynamic allocation factors produces the lower-cost
653 outcome for each state individually and for the five states collectively. I recommend
654 that the Commission adopt the Company's proposal to reassign the Unassigned Share
655 using the 2020 Protocol's dynamic allocation factors.

656 **Q. Does this conclude your supplemental testimony?**

657 **A.** Yes.