

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Application of Rocky
Mountain Power for Approval of the 2026
Inter-Jurisdictional Cost Allocation Protocol

Docket No. 25-035-47

**REDACTED DIRECT TESTIMONY
AND EXHIBITS
OF
BRADLEY G. MULLINS
SUBMITTED ON BEHALF OF THE
UTAH LARGE CUSTOMER GROUP**

February 5, 2026

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1 **I. INTRODUCTION AND SUMMARY**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A. My name is Bradley G. Mullins. My business address is Vihikari 10, Suite 4023, Kempele,
4 FI-90440 Finland.

5 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

6 A. I am the Principal Consultant for MW Analytics, an independent consulting firm
7 representing utility ratepayers before state public utility commissions in the Western
8 United States.

9 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

10 A. I am testifying on behalf of the Utah Large Customer Group (“UTLCG”), an
11 unincorporated association whose members are large energy users located in Utah that
12 receive electrical services from Rocky Mountain Power (“RMP” or the “Company”).
13 UTLCG members receive electric service through RMP Electric Service Schedule No. 9,
14 General Service – High Voltage, which is supplied at approximately 46 kV or 69 kV or
15 greater.

16 **Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.**

17 A. I have been performing independent energy and utilities consulting services for over 10
18 years. I have sponsored expert witness testimony in over 100 regulatory proceedings on
19 various subject matters, including revenue requirements, regulatory accounting, rate
20 development, and new resource additions. I have a Master of Accounting degree from the
21 University of Utah. A qualification statement and list of recent regulatory appearances can
22 be found in Exhibit BGM-1.

23 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

24 A. I discuss issues associated with the inter-jurisdictional allocation of Net Power Costs
25 (“NPC”) and the impacts of divergent generation portfolios on the cost of ancillary services
26 and resource adequacy.

27 **Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.**

28 A. In this docket, RMP proposes to move away from a systemwide “rolled-in”
29 interjurisdictional cost allocation framework and instead adopt a “Two Portfolio” approach
30 that establishes a distinct resource portfolio for Washington to accommodate Washington’s
31 policies while assigning all remaining resources to Utah, Wyoming, Idaho, Oregon, and
32 California (the “Five States”). Perhaps from a Washington perspective, the 2026 Protocol
33 makes sense because of the need to comply with Washington state laws and policies, and
34 because the proposed 2026 Protocol reduces the total costs allocated to Washington.
35 However, for the remaining Five States, the justification for this change is unpersuasive,
36 as Washington has always relied on a distinct portfolio relative to the other states. This
37 historical reality raises fundamental questions of equity as RMP’s proposal would require
38 the Five States to assume additional costs beyond their rolled-in resource allocations to
39 accommodate Washington’s policy decisions that led RMP to propose a distinct portfolio
40 for Washington in the first place.

41 From an NPC perspective, RMP proposes to evaluate differential state resource
42 portfolios using a method that assigns an energy value to the monthly net position of each
43 state based on the average cost of short-term purchases and sales. This methodology is
44 flawed because it fails to capture hourly differences in the energy value of state portfolios
45 and ignores the systemwide ancillary service benefits that certain portfolios provide

46 relative to others, and the combined effect of RMP’s proposal is a significant cost increase
47 to Utah without marginal benefit. These concerns are exacerbated by the timing of RMP’s
48 planned participation in the California ISO’s Extended Day-Ahead Market (“EDAM”),
49 which is expected to occur before the Commission issues its final order in this matter. RMP
50 has acknowledged that EDAM participation will require changes to the NPC allocation
51 method it now proposes. As a result, the Company essentially asks the Commission to
52 evaluate a proposal now that will require substantial revisions before it can be considered
53 in the context of a general rate case. Therefore, I recommend the Commission:

- 54 • Reject RMP’s 2026 Protocol and proposed NPC allocation framework and order
55 the Company to submit any rate case filed prior to the implementation of a new cost
56 allocation methodology using the 2020 Protocol at least as a starting point.
- 57 • Stay this case, or alternatively, open an investigatory or other docket and order the
58 Company to engage in a collaborative process with the Utah parties, and if possible,
59 stakeholders for the other Five States to provide needed analytics and develop a
60 framework and report to the Commission by a date certain (*e.g.*, August 31, 2026).
61 Such framework must be compatible with the EDAM and must include an approach
62 that values ancillary services and resource adequacy that each state portfolio
63 provides to the system. This approach will allow parties to continue to issue
64 discovery for the purpose of investigating more robust methods and approaches for
65 interjurisdictional allocation until such time as an EDAM-compatible framework is
66 available.
- 67 • Alternatively, the Commission could reject the 2026 Protocol and order a new
68 allocation method in this case (such as the Allocation Framework appended to
69 UTLCG witness Mr. Larsen’s testimony as Exhibit JKL-1), should the Commission
70 find sufficient evidence supporting cost causation of the allocation of the various
71 allocable costs at issue in this proceeding.

72 Notwithstanding, if the Commission decides to approve a temporary NPC
73 allocation method in this proceeding – either RMP’s proposed approach or the Allocation
74 Framework presented by UTLCG Witness Larsen – I recommend that the following be
75 incorporated into the methodology:

- 76 • A Reserves Pool be established to allocate the embedded capacity costs associated
77 with ancillary services between states based on the reserve requirements of each
78 state's loads and resource portfolios.
- 79 • A process to evaluate the extent to which Utah allocated resources may be used to
80 provide not just short-term operating reserves but also long-term planning reserves
81 to the benefit of Washington and, ultimately, Oregon, as those states exit from coal
82 and, potentially, gas resources. If long-term leaning is occurring, additional
83 compensation may be warranted to ensure that Washington and Oregon reimburse
84 the other states for capacity they provide to ensure reliability.

85 II. BACKGROUND

86 A. The Multi-State Process

87 Q. WHAT IS THE MULTI-STATE WORKING GROUP?

88 A. The Multi-State Working Group (“MSWG”) is an informal collection of stakeholders in
89 PacifiCorp’s six-state service territory that has for many years developed and refined
90 interjurisdictional cost allocation methodologies, with the most recent agreement being the
91 2020 Protocol.¹ Since at least the early 2000s, the MSWG has been the principal venue for
92 addressing and resolving issues and disputes surrounding interjurisdictional cost allocation
93 methods between participating jurisdictions. Through the MSWG, participating
94 stakeholders have reached successive agreements to establish common allocation methods
95 and frameworks, including the Revised Protocol,² the 2010 Protocol,³ the 2017 Protocol,⁴
96 and finally, the 2020 Protocol. With the exception of Washington, the MSWG protocols
97 have generally evolved based on a rolled-in method of cost attribution, one in which each

¹ See *In the Matter of the Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 19-035-42, Exhibit RMP ___ (JRS-1) (hereinafter “2020 Protocol”); see also *id.* at Order Approving 2020 Protocol (Apr. 15, 2020).

² See *In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues*, Docket No. 02-035-04, Report and Order (Dec. 14, 2004) (approving Revised Protocol).

³ See *id.* at Report and Order (Feb. 3, 2012) (approving 2010 Protocol).

⁴ See *In the Matter of the Application of Rocky Mountain Power for Approval of the 2017 Protocol*, Docket No. 15-035-86, Order (June 23, 2016) (approving 2017 Protocol); and *In the Matter of the Application of Rocky Mountain Power to Extend the 2017 Protocol through December 31, 2019*, Docket No. 17-035-06, Order (March 23, 2017) (extending 2017 Protocol).

98 jurisdiction receives a percentage of total-system costs using variously defined allocation
99 factors.

100 **Q. HAS WASHINGTON HISTORICALLY PARTICIPATED IN THE MSWG?**

101 A. Prior to the 2020 Protocol, Washington did not participate in the MSWG. While
102 Washington participated in negotiations and became a signatory to the 2020 Protocol, it
103 did so using a distinct resource portfolio and relying on a different allocation method—
104 known as the Washington Interjurisdictional Allocation Methodology (“WIJAM”)—which
105 was not aligned with the allocation methods applied in the other five participating states.

106 **Q. HOW DID THE ROLLED-IN METHOD ALLOCATE PRODUCTION COSTS?**

107 A. Under a rolled-in approach, each state is assigned cost responsibility for a proportional
108 share of the total system generation portfolio, based on its respective load and demand
109 requirements. Under the 2020 Protocol, a state’s share of system generation costs was
110 principally allocated using the System Generation (“SG”) allocation factor, a 75/25 blend
111 of 12 coincident peak (“CP”) demand and energy consumption of each state. Another
112 rolled-in factor used in the allocation of certain NPC accounts was the System Energy
113 (“SE”) factor, which was calculated based solely on each state’s proportional energy
114 consumption. Consistent with this approach, NPC was generally allocated on a system-
115 wide basis, with each state assuming cost responsibility for its portion of system costs as
116 determined by rolled-in allocation factors. To address state-specific policy resources,
117 however, RMP applied lower-of-cost-or-market adjustments to situs resources in NPC,
118 using varied treatment across resources. While these types of resources have historically
119 been limited in scope, these adjustments have expanded in recent years, particularly with
120 the growth of Utah Schedule 32 and 34 programs.

121 **Q. HOW DID A ROLLED-IN APPROACH ALIGN COSTS AND BENEFITS?**

122 A. Under the rolled-in approach NPC costs and benefits were allocated to each state in
123 proportion to its share of the system’s resources resulting in a matching between costs paid
124 and benefits received. In addition, because resources were allocated to each state in
125 proportion to its requirements, the rolled-in method also generally ensured that each state
126 was responsible for funding an equitable share of system-wide resource adequacy. In other
127 words, the “rolled-in” allocation method meant that each state paid for an amount of
128 generation capacity proportionate to its load and demand requirements, so no state paid
129 more or less than its proportionate share.

130 **Q. DID THE 2020 PROTOCOL ACKNOWLEDGE THE POTENTIAL NEED TO**
131 **TRANSITION AWAY FROM A ROLLED-IN METHOD?**

132 A. Yes. Cost allocation challenges arising from divergent state policies have been a major
133 issue in the MSWG forum for many years. In recognition that states would ultimately
134 require differing resource portfolios to meet state policies, the 2020 Protocol was
135 established as a transitional agreement intended to bridge the development of a long-term,
136 permanent framework allowing state portfolios to diverge from the rolled-in system
137 portfolio. To accomplish this, the 2020 Protocol was divided into two general timeframes:
138 an Interim Period and a Post-Interim Period. Principally, parties agreed that during the
139 Interim Period, the rolled-in allocation method established in the 2017 Protocol, subject to
140 several modifications, would continue to be used, and over the duration of the Interim
141 Period, parties would continue negotiations of a permanent allocation framework for the
142 Post-Interim Period. In the context of the Post-Interim Period allocation framework, there
143 were several allocation methods that parties agreed would apply, referred to as the

144 “Resolved Issues.” Post-Interim Period issues that remained unresolved in the 2020
145 Protocol—known as “Framework Issues”—included items, such as the allocation of NPC
146 using a Nodal Pricing Model (“NPM”), as well as realignment of state generation
147 portfolios, with Washington’s Clean Energy Transformation Act (“CETA”) specifically
148 called out.

149 Among these Framework Issues, my testimony focuses primarily on NPC and the
150 NPM, while UTLCG witness Jeffery Larsen discusses, among other things, the allocation
151 of generation resources and overheads.

152 **Q. WHAT WAS THE NODAL PRICING MODEL?**

153 A. The NPM was defined in the 2020 Protocol as “method for pricing electricity [...] that is
154 based on the marginal cost (\$/MWh) of serving the next increment of demand at a given
155 pricing node consistent with existing transmission constraints and the performance
156 characteristics of resources.”⁵ In the agreement, the parties acknowledged that “[a] method
157 to track the costs and benefits of Resource portfolios which may differ for each State will
158 be necessary in the future to maintain the benefits of system dispatch as much as
159 practicable.”⁶ The NPM was intended to achieve this objective by evaluating the value of
160 different state resource portfolios using the marginal cost of production of the resources in
161 each state’s portfolio, along with the marginal cost of load for that state. Accordingly,
162 RMP agreed that it would begin development of a NPM during the Interim Period and
163 implement a model to forecast NPC using the NPM concept.⁷ In this regard, the MSWG
164 parties agreed through the NPM Memorandum of Understanding (“MOU”) in Appendix D

⁵ 2020 Protocol, Appendix A, pp. 5-6, lines 116-19.

⁶ 2020 Protocol, p. 39, lines 826-28.

⁷ *Id.* at pp. 39-40, lines 831-40.

165 of the 2020 Protocol that RMP would retain an outside vendor to develop the NPM system,
166 and that the parties would not oppose recovery of the costs associated with that system.⁸

167 **Q. DID RMP DEVELOP THE NPM?**

168 A. Notwithstanding significant investment, RMP did not succeed in developing a fully formed
169 NPM to use for allocating NPC. While the systems were implemented to develop the NPM,
170 RMP has not proposed using those systems or a NPM in the NPC allocation framework
171 proposed in this case. RMP's anticipated entry into the CAISO EDAM further complicates
172 the NPM issue, because EDAM functions as a NPM and will effectively take the place of
173 the current NPM system created (but not implemented) under the NPM MOU. These
174 complications are addressed in more detail below in connection with RMP's NPC
175 allocation proposal.

176 **Q. FOR HOW LONG WAS THE INTERIM PERIOD SUPPOSED TO LAST?**

177 A. The Interim Period was intended to last until December 31, 2023.⁹ Notwithstanding, the
178 MSWG parties were continuing to negotiate the elements of the Post-Interim Period
179 method and agreed to extend the Interim Period until December 31, 2025.¹⁰

180 **Q. WHY DIDN'T THE MSWG PARTIES REACH AN AGREEMENT REGARDING**
181 **THE POST-INTERIM PERIOD ALLOCATION METHOD?**

182 A. Following the execution of the 2020 Protocol, the MSWG parties, including Utah parties,
183 engaged in extensive discussions to develop the Post-Interim Period allocation method.
184 These discussions were continuing until June 2024, when RMP unilaterally terminated all

⁸ See generally *id.* at Appendix D, Exhibits A and B.

⁹ *Id.* at p. 5, lines 104-07.

¹⁰ In the *Matter of the Application of Rocky Mountain Power for Approval of an Extension to the 2020 Inter-Jurisdictional Cost Allocation Agreement*, Docket No. 23-035-20, Application, p. 4, ¶ 9 (April 12, 2023); see also *id.* at Order Approving Extension of the 2020 Protocol (July 27, 2023).

185 MSP negotiations. RMP informed the MSWG parties that it would no longer be seeking a
186 negotiated allocation agreement between the states through the MSWG. Instead, RMP
187 indicated that it would develop its own allocation proposal and present it for approval on a
188 state-by-state basis. This proceeding followed.

189 **Q. IS THE ALLOCATION PROPOSAL RMP PRESENTED IN THIS CASE A**
190 **“PROTOCOL”?**

191 A. No. In the context of interjurisdictional matters, a “protocol” typically refers to an
192 agreement developed through formal negotiations among jurisdictional entities, and which
193 memorializes the outcomes of those discussions for approval by state regulatory
194 commissions. Since RMP terminated negotiations and there was no agreement reached
195 between the states regarding the Post-Interim Period allocation method, referring to the
196 allocation method proposed in this docket as the “2026 Protocol” is misleading. For
197 purposes of this testimony, I generically refer to RMP’s proposed allocation method as a
198 proposed allocation framework rather than a protocol. This is important because in Exhibit
199 RMP___(RTL-1), PacifiCorp presents a Washington 2026 Protocol document with a
200 number of complex terms. Unlike the 2020 Protocol, the terms of that document were not
201 negotiated nor agreed-to between any of the Five States. Accordingly, the terms of that
202 document cannot be viewed as being “binding” on non-Washington parties or the
203 Commission in the same sense as the 2020 Protocol or its predecessor agreements were.
204 In this regard, approving a new allocation framework outside a general rate case may have
205 limited impact because parties could still advance alternative allocation methods in future
206 cases, and the Commission would retain full authority to evaluate those methods based on
207 the record in those cases. Further complicating consideration outside of a rate case, RMP’s

208 presentation of its proposal does not provide the Commission with a complete picture of
209 how the allocation would affect customer rates, as would typically be evaluated in the
210 context of a comprehensive general rate case filing. Instead, RMP has presented only high-
211 level, “proxy” estimates of impacts.¹¹

212 **Q. DID YOU ASK RMP TO PERFORM RATE IMPACT CALCULATIONS BASED**
213 **ON ACTUAL COMPANY RESULTS?**

214 A. Yes. However, when requested to precisely model the impacts using its actual Results of
215 Operations (“ROO”), RMP declined to perform such an analysis, stating “[t]he Company
216 has not modeled the proposed 2026 Protocol in each of the ROO [Jurisdictional Allocation
217 Models (“JAM”)] and [Regulatory Adjustments Models (“RAM”).”¹² However, as
218 UTLCG witness Larsen explains, there is no consistency in total-Company ROO data
219 among jurisdictions. So, even if RMP assisted the parties in understanding actual impacts
220 from the Company’s proposal, it is difficult to have any confidence in those results.

221 **Q. WHY IS IT IMPORTANT TO GET THE “FULL PICTURE” RATHER THAN**
222 **RELYING ON HIGH-LEVEL ESTIMATES?**

223 A. Absent a full analysis performed on a consistent set of systemwide operating results, it is
224 difficult to form a complete analysis of RMP’s estimates. For instance, RMP uses an NPC
225 forecast for 2026 to estimate NPC impacts,¹³ whereas it relies on its historical results of
226 operations data from 2024 to estimate non-NPC impacts.¹⁴ The NPC forecast, however,
227 includes forecast loads that are markedly different than the loads used to evaluate non-NPC

¹¹ Direct Testimony of Shelley E. McCoy, p.6, lines 104-111.

¹² Response to UTLCG Data Request 5.13, subpart d (provided in Exhibit BGM-2).

¹³ See Direct Testimony of Ramon J. Mitchell, Exhibit RMP___(RJM-1), p.1 (The illustrative NPC allocation examples are monthly over 2026).

¹⁴ Direct Testimony of Shelley E. McCoy, p.6, lines 104-111.

228 revenue requirement impacts. Loads in the 2026 NPC forecast were █% higher than the
229 historical loads used to develop the allocation factors that RMP relied upon in its analysis.
230 This leads to numerous inconsistencies. To estimate the NPC impacts, RMP applied the
231 2024 factors against the 2026 NPC forecast. Due to the higher load, the allocation factors
232 in 2026 are expected to be materially different than the 2024 factors. Compounding this,
233 RMP used forecast 2026 loads when estimating net positions in its NPC allocation
234 framework, leading to a skewed result. Finally, the energy production allocated to a state
235 in its method was based on the 2024 loads, whereas the load used to measure the Five State
236 long or short position was based on 2026 forecast loads, which are markedly different.

237 In addition, by not fully analyzing the impacts in the JAM model, RMP glossed
238 over many aspects of the allocation change. For example, RMP did not quantify the impact
239 of its proposal on the Reasonable Energy Price (“REP”) adjustment.¹⁵ The REP adjustment
240 requires the situs assignment of the cost for new qualifying facility (“QF”) Power Purchase
241 Agreements (“PPA”) that exceeded a “Reasonable Energy Price,” which is a weighting of
242 the forecast market prices at the various hubs where RMP transacts, calculated on a Heavy
243 Load Hour and Light Load Hour basis at the time the contract was executed. To the extent
244 a new QF PPA price exceeds the reasonable energy price calculated at the time the contract
245 was executed, under the terms of the 2020 Protocol, the excess amount is situs assigned to
246 the state that approved the QF PPA. This adjustment is sensitive to changes in allocation
247 factors. Because RMP did not flow the changes through the JAM model, it did not consider
248 these impacts. This highlights why it is important that these types of allocation changes be
249 analyzed in the context of a rate case – or at least with information comparable to what

¹⁵ 2020 Protocol, pp. 30-32, lines 637-57.

250 would be presented in a rate case – where all of the impacts can be reviewed in a consistent
251 and wholistic manner and for the same time period.

252 **B. NPC in the Multi-State Process**

253 **Q. HOW IS NPC DEFINED?**

254 A. NPC refers to the variable energy costs involved in generating electricity for customers.
255 This contrasts with the fixed production costs of RMP’s resource portfolio and the non-
256 energy operations and maintenance expenses tied to those resources. NPC includes the
257 cost of fuel (both coal and gas), the cost of purchased power, and the cost of wheeling (*i.e.*,
258 the cost of transmitting electricity on other utilities’ transmission systems). It also includes
259 the revenues associated with power sales in wholesale markets, including long-term power
260 sales agreements and short-term sales in regional markets. The *net* in NPC, therefore,
261 represents the fact that it includes wholesale sales transactions from system resources that
262 offset the variable energy costs of providing electricity to retail customers. Specific
263 Federal Energy Regulatory Commission (“FERC”) Accounts included in NPC are:

- 264 • Account 447 – Sales for Resale;
- 265 • Account 501 – Fuel (for Steam Power);
- 266 • Account 503 – Steam from Other Sources (Geothermal);
- 267 • Account 547 – Fuel (for Mechanical Power);
- 268 • Account 555 – Purchased Power; and
- 269 • Account 565 – Wheeling.¹⁶

¹⁶ Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of The Federal Power Act, 18 C.F.R. § 101 *et seq.* (2025).

270 **Q. HOW DOES TRANSITIONING FROM A ROLLED-IN ALLOCATION METHOD**
271 **INFLUENCE THE ASSIGNMENT OF NPC?**

272 A. RMP's portfolio is dispatched as a system and that forms the basis for NPC. Individual
273 state portfolios under a non-rolled-in allocation method, however, will produce different
274 impacts on system NPC based on the resource mix of those portfolios. For example, a state
275 portfolio may produce more or less energy in a given hour compared to other state
276 portfolios, leading to different energy values (amounts, costs, and benefits) between the
277 portfolios. Similarly, a state portfolio may contribute more or less dispatchable capacity
278 necessary to meet any applicable resource adequacy requirements and support reserves and
279 load following services for both load and variable energy resources. Thus, transitioning
280 from a rolled-in methodology, where all system resource costs and benefits are allocated
281 proportionally, requires consideration of not only resource production costs within a state
282 portfolio, but also the dispatch-related benefits those state resources provide to the system.
283 Without accounting for both costs and benefits, states with lower-value resource portfolios
284 would effectively benefit from the resource portfolios of other states while avoiding the
285 corresponding costs of those resources. This scenario is colloquially referred to as
286 "leaning."

287 **Q. WHAT FACTORS CAUSE THE SYSTEM VALUE OF DIVERGENT STATE**
288 **RESOURCE PORTFOLIOS TO DIFFER?**

289 A. A rolled-in method aligns each state's share of the system portfolio with the NPC benefits
290 it receives. This is true only if each state shares proportionately in a system that serves
291 load and provides all of the required reserves. However, divergent state requirements have
292 caused state resource portfolios to diverge. Assigning distinct portfolios to individual

293 states results in differing contributions towards the benefit of the system portfolio. In this
294 case, the system-level benefits provided by distinct portfolios vary depending on the mix
295 of resources they contain, and these differences are driven by three primary factors:

- 296 **1. Energy Value** – The value of energy from a portfolio depends on the cost
297 and timing of production. For example, energy generated during periods of
298 high market prices may be more valuable than energy produced when prices
299 are low, and *vice versa*.
- 300 **2. Ancillary Value** – Certain resources, particularly dispatchable resources,
301 provide enhanced system value by supporting reliability. This value
302 includes the provision of contingency and regulation reserves required to
303 meet North American Electric Reliability Corporation (“NERC”)/Western
304 Electricity Coordinating Council (“WECC”) reliability standards, as well as
305 load-following services needed to balance variations in load and variable
306 energy resource output. Other resources, such as variable energy resources,
307 impose additional reserves and following requirements on the system.
- 308 **3. Resource Adequacy Value** – Resource types differ in how they support
309 system capacity necessary to meet peak demands and planning reserve
310 margins. Variable energy resources typically contribute only a fraction of
311 their average output toward peak demand, whereas dispatchable resources
312 often contribute nearly their full nameplate capacity.

313 To ensure that each state’s portfolio costs align with the system benefits it receives, any
314 assessment of methods to allocate NPC and production costs among states with differing
315 resource portfolios must consider the influence of the above categories on system-level
316 costs.

317 **Q. DO THESE FACTORS INFLUENCE COSTS OVER DIFFERENT**
318 **TIMEFRAMES?**

319 **A.** Yes. Leaning can occur in both the short-term and long-term. On the short-term end of
320 the spectrum, the energy value of a portfolio drives cost differences in the short-term,
321 reflecting differences in the system cost of energy necessary to serve loads. Thus, for
322 example, a portfolio that provides less energy value in a given hour than may have been
323 assumed based on the average or forecasted capability of the resources in the state’s

324 portfolio will be leaning on other portfolios during those hours if the state's loads exceed
325 the energy generated by the portfolio. On the long-term end of the spectrum, portfolio
326 capacity costs are incurred to provided needed long-term resource adequacy and those costs
327 become embedded in a state's revenue requirement for its portfolio resources. A portfolio
328 that provides less contribution to long-term resource adequacy relative to its load
329 requirements is therefore leaning on other state portfolios to ensure system reliability,
330 including meeting planning reserve margins to protect against unforeseen contingencies.
331 A state may prefer resources, such as wind and solar, that have a high energy value but
332 contribute little in the way of system capacity. Such a portfolio may create relatively high
333 energy values, yet it may still result in leaning on another state's resources to ensure long-
334 term resource adequacy and that the system is capable of satisfying peak loads and planning
335 reserve margins. In the middle of the spectrum, the ancillary service value of a portfolio
336 has both short- and long-term impacts. While holding reserves necessary to provide
337 ancillary services increases system costs in the short-term, it also requires sufficient
338 flexible capacity resources that must be acquired and paid-for in rates over an extended
339 period of time. A state portfolio that does not possess sufficient flexible capacity to satisfy
340 its share of system ancillary services therefore results in leaning on the fixed capacity costs
341 paid by other states or, alternatively, increasing the cost of production from those resources.

342 **Q. ARE THERE OTHER FACTORS THAT NEED TO BE CONSIDERED WHEN**
343 **DESIGNING AN ALLOCATION METHOD FOR NPC?**

344 A. As a general matter, there is no single correct approach for allocating NPC given the
345 divergence among state resource portfolios. Each approach presents advantages and

346 disadvantages to be weighed when selecting a suitable method. There are certain criteria
347 and guiding principles, however, that I believe should be considered as follows:

- 348 **1. Cost and Benefit Matching** – Each state should pay the full costs and
349 receive the full benefits of the resources included in their portfolio, as
350 discussed above.
- 351 **2. State Portfolio Agnostic** – The method used to allocate NPC should be
352 agnostic to the way that the underlying resources are allocated. In other
353 words, the method needs to be able to allocate costs in a way that allows for
354 the underlying resources to be allocated any way possible, while still fairly
355 apportioning costs and benefits.
- 356 **3. Actual and Forecast NPC Viability** – The method must be suitable for
357 calculating and allocating both actual NPC and forecast NPC, with a focus
358 on actual NPC. Some methods, for example, may be viable in the context
359 of a modeled forecast but not necessarily so for actual NPC and *vice versa*.
360 Notwithstanding, the use of approximation methods for one, or the other,
361 should not be ruled out, considering that a model forecast itself is an
362 approximation method to estimate actual NPC.
- 363 **4. Adaptability** – The allocation methods need to be durable enough to be
364 adapted to changes in the way the system is operated, such as, the transition
365 into a formal day-ahead market like the EDAM. In this context, it may be
366 necessary for the methods to contain enough flexibility to evolve over time,
367 while still relying on the same core allocation concepts and principles.
- 368 **5. Auditability** – The methods developed must be understandable and
369 auditable. Where possible, complexity should be minimized.

370 In the following section, I evaluate RMP's NPC allocation proposal with a focus
371 on these criteria and discuss several challenges with RMP's proposal. Ultimately, I
372 recommend that the Commission require RMP to engage with MSWG parties to develop a
373 viable NPC allocation framework that is compatible with the EDAM. Subsequently, I
374 present several alternative methods and concepts to consider within that process.

375 **III. RMP'S NPC ALLOCATION PROPOSAL**

376 **Q. DOES RMP'S PROPOSED NPC ALLOCATION METHOD MEET THE**
377 **CRITERIA AND GUIDING PRINCIPLES YOU IDENTIFIED?**

378 A. No. Although RMP's proposed method may have the advantage of simplicity, it does not
379 reasonably account for material differences in the value of ancillary services across distinct
380 state portfolios. In addition, the method provides no mechanism for recognizing or
381 addressing differences in resource adequacy across the various state portfolios. More
382 critically, however, the principal method proposed by RMP will effectively be rendered
383 moot by the time the Commission issues its order in this proceeding. The method RMP
384 proposed is only designed to be used until RMP can develop a more comprehensive method
385 that is compatible with EDAM,¹⁷ which RMP is scheduled to join on May 1, 2026. While
386 RMP suggests that its post-EDAM replacement method may overlap in part with the net
387 position NPC allocation proposal, the Company has not provided a clearly defined
388 framework for how the EDAM method would operate. Regardless of the method applied,
389 the EDAM will materially change the way RMP's system is dispatched and the value of
390 state resource portfolios, factors that are not addressed in RMP's principal NPC allocation
391 proposal. Without clearly addressing the implications of EDAM, the Commission has no
392 sound basis to make any concrete findings with respect to the reasonableness of RMP's
393 proposal, as the EDAM will materially impact the outcome of that proposal.

394 **Q. CONSIDERING THESE ISSUES, WHAT DO YOU RECOMMEND?**

395 A. Given its shortcomings, I recommend the Commission reject RMP's NPC allocation
396 proposal. While I present an alternative ancillary service approach below, my primary

¹⁷ Direct Testimony of Ramon J. Mitchell, pp. 12-14, lines 250-82.

397 recommendation is that the Commission direct RMP to order the Company to submit any
398 rate case filed prior to the implementation of a new cost allocation methodology using the
399 2020 Protocol – at least as a starting point. Further, I recommend the Commission stay
400 this case, or alternatively, open an investigatory or other docket and order the Company to
401 engage in a collaborative process with the Utah parties, and if possible, stakeholders from
402 the MSWG and the other Five States to provide needed analytics and develop a framework
403 and report to the Commission by a date certain (*e.g.*, August 31, 2026). For the reasons I
404 discuss, it is imperative that such framework be compatible with the EDAM and include
405 an approach that values ancillary services and resource adequacy that each state portfolio
406 provides to the system. This approach will allow parties to continue to issue discovery for
407 the purpose of investigating more robust methods and approaches for interjurisdictional
408 allocation until such time as an EDAM-compatible framework is available. Alternatively,
409 I recommend the Commission reject the 2026 Protocol and adopt a new allocation method
410 in this case such as the Allocation Framework appended to UTLCG witness Mr. Larsen’s
411 testimony as Exhibit JKL-1, should the Commission find sufficient evidence supporting
412 cost causation of the allocation of the various allocable costs at issue in this proceeding.

413 **A. The Two Portfolio System**

414 **Q. WHAT STATE PORTFOLIOS ARE INCLUDED IN RMP’S PROPOSED**
415 **ALLOCATION FRAMEWORK?**

416 A. RMP’s allocation proposal follows what it refers to as a “two-portfolio structure.”¹⁸ Under
417 this proposal, Washington would be assigned a fixed portfolio of resources, whereas the
418 Five States would be assigned a shared portfolio consisting of all the resources, or portions

¹⁸ *Id.* at p. 2, lines 27-29.

419 thereof, not allocated to Washington. The “Five State Portfolio” resources would be shared
420 between the states based on dynamically calculated allocation factors. Correspondingly,
421 NPC would be allocated using production costs from each state’s allocated resource shares,
422 with a monthly net position balancing adjustment to reconcile differences in energy value
423 between the portfolio production of the Five State Portfolio and its load.

424 **Q. HAS WASHINGTON HISTORICALLY RELIED ON A PORTFOLIO THAT IS**
425 **DISTINCT FROM THE ROLLED-IN SYSTEM?**

426 A. Yes. Washington has always relied on a portfolio that is different from its rolled-in system
427 allocation. Prior to the 2020 Protocol, Washington relied on a cost allocation method
428 known as the Western Control Area (“WCA”) method, in which only resources electrically
429 located in the PacifiCorp Western Balancing Authority Area (“PACW”) were included in
430 Washington rates. This included the Jim Bridger power plants, as well as Colstrip Unit 4.
431 Colstrip Unit 3 has historically been excluded from Washington rates, not due to its
432 electrical location, but because it was disallowed in Washington. In 1984, the Washington
433 Commission disallowed a portion of Colstrip Unit 3 because it was acquired in connection
434 with a power sales agreement with Black Hills Power and Light Company (“Black
435 Hills”),¹⁹ and in 1986, the Company stipulated to remove the entire amount of the facility,
436 along with the energy benefits associated with the power sales agreement with Black
437 Hills.²⁰ Notably, while the Washington WCA portfolio excluded resources located in the
438 PacifiCorp Eastern Balancing Authority Area (“PACE”), it assumed a higher portion of the
439 PACW resources compared to its rolled-in share of the PACW resources. Another aspect

¹⁹ See *In the Matter of Washington Utilities and Transportation Commission v. Pacific Power*, Cause No. U-83-57, Second Supp. Order (June 12, 1984).

²⁰ See *In the Matter of Washington Utilities and Transportation Commission v. Pacific Power*, Docket No. U-86-02, Second Supp. Order (Sept. 19, 1986).

440 of Washington's historic portfolio is that it has historically only included Washington QFs,
441 treating them as situs assigned to Washington.

442 **Q. HOW HAVE THE FIVE STATES HISTORICALLY CONSIDERED**
443 **WASHINGTON'S DISTINCT PORTFOLIO?**

444 A. For allocation purposes, the Five States have historically used a fully rolled-in allocation
445 method, without providing special consideration for Washington's decision to establish
446 rates using a distinct portfolio. As a result of using different methods between Washington
447 and the Five States, however, the PACW resources were effectively over-subscribed,
448 whereas PACE resources were undersubscribed. There has been ongoing debate over
449 whether this treatment resulted in RMP over- or under-recovering its overall system costs,
450 particularly after considering the difference in NPC between these two methods.
451 Washington, for example, has historically paid higher NPC than its share of rolled in
452 system costs, offsetting potential under-recovery of fixed generation costs.

453 **Q. HOW DID WASHINGTON'S PORTFOLIO CHANGE WITH THE 2020**
454 **PROTOCOL?**

455 A. In Appendix F of the 2020 Protocol, Washington agreed to modify its portfolio to be based
456 on a rolled-in system allocation of non-emitting resources, such as hydro wind and solar,
457 excluding QFs. Notwithstanding, as a result of its state policy, Washington decided to
458 retain the WCA allocation for emitting resources, such as gas and coal plants. Accordingly,
459 Washington continued its practice of only including PACE thermal resources in
460 Washington rates, including Hermiston, Chehalis, Jim Bridger, and Colstrip Unit 4. Based
461 on RMP's 2024 ROO, Washington assumed 21.6% of the cost for those PACW thermal

462 resources compared to its rolled-in allocation of 7.5%.²¹ This difference has effectively
463 resulted in RMP recovering approximately 114.1% of the cost of those resources. In
464 connection with this, however, only 92.5% of the thermal resources located in PACE were
465 allocated amongst the Five States.

466 **Q. DID WASHINGTON CHANGE ITS TREATMENT OF QUALIFYING**
467 **FACILITIES IN THE 2020 PROTOCOL?**

468 A. No. Although Washington assumed cost responsibility for non-emitting resources, it
469 retained a situs-assignment approach for QF resources and limited rate recovery to
470 Washington QFs.

471 **Q. HOW HAS WASHINGTON HISTORICALLY PERFORMED JURISDICTIONAL**
472 **ALLOCATION OF NPC?**

473 A. Consistent with its separate portfolio, Washington has historically used a non-rolled-in
474 method to jurisdictionally allocate NPC. That method has evolved from a standalone WCA
475 dispatch simulation into a system-wide simulation that balances Washington's monthly
476 energy requirements against production from its allocated resources, in a manner similar,
477 but not identical, to the approach proposed for the Five States in this docket. In general,
478 the use of that method has resulted in RMP over-recovering its total-system NPC. In 2024,
479 for example, the over-collection of NPC from Washington customers relative to a rolled-
480 in allocation is estimated at approximately \$42.1 million, based on Exhibit BGM-3.²²
481 Accordingly, RMP's claims that its fixed production costs are being under-recovered due
482 to Washington's distinct allocation method does not consider that those under-recoveries

²¹ See e.g., Response to UTLCG Data Request 5.13, Attachment UTLCG 5.13, Workpaper WA JAM December 2024 Results.xlsx, Tab Factors) (provided in Exhibit BGM-2).

²² I note that UTLCG Witness Larsen also addresses this issue and, using a different methodology, reaches the same general conclusion but a slightly different figure.

483 are generally offset by a higher recovery of NPC, resulting in a cost recovery outcome that
484 is more complex than RMP suggests.

485 **Q. HAS WASHINGTON STATE POLICY FURTHER IMPACTED ITS ALLOCATED**
486 **PORTFOLIO?**

487 A. Under the CETA, Washington utilities were required to remove all coal from their allocated
488 resource portfolios by January 1, 2026.²³ For PacifiCorp, this meant the removal of Jim
489 Bridger Units 3 & 4 and Colstrip Unit 4 from rates, all of which were formerly included in
490 Washington's portfolio based on the WCA allocation factor. As part of this transition,
491 however, RMP was required to fully recover from Washington ratepayers the Washington-
492 allocated share of its investment in those resources, and Washington ratepayers also
493 remained responsible for full recovery of decommissioning liability, which continues to be
494 funded through an ongoing rate tracker. Importantly, this treatment means that Washington
495 has fully paid off its approximate 21.6% WCA share of these coal resources, while under
496 the 2020 Protocol, the Five States would continue to bear responsibility for recovery of
497 92.5% of those resources, inclusive of decommissioning costs. Thus, under the 2020
498 Protocol, RMP is already set to recover 114.1% of the costs of those resources.

499 The second policy change affecting cost allocation is the Washington Climate
500 Commitment Act ("CCA"), which imposed carbon allowance obligation costs on the
501 Chehalis power plant, although those costs were partially offset by free allowances
502 associated with the portion of Chehalis included in the Washington portfolio.

²³ WASH. REV. CODE § 19.405.030(1)(a).

503 **Q. HOW HAS PACIFICORP PROPOSED MODIFYING THE WASHINGTON**
504 **PORTFOLIO IN RESPONSE TO THESE CHANGES?**

505 A. The most significant change in its Two Portfolio allocation framework is the allocation of
506 100% of the Chehalis power plant to Washington. Other changes include the assumption
507 of fixed allocations of the Hermiston and Jim Bridger 1 and 2 gas plants and an increased
508 allocation of the Rolling Hills wind facility corresponding to the portion disallowed by
509 Oregon. Washington also retained its historical treatment of QFs using a situs assignment
510 method.

511 **Q. HOW HAS PACIFICORP PROPOSED MODIFYING THE PORTFOLIO OF THE**
512 **OTHER FIVE STATES?**

513 A. Although Washington has always utilized a portfolio that differs from its rolled-in
514 allocation, RMP now proposes that the Five States assume cost responsibility for the
515 portions of all resources not allocated to Washington. Relative to their rolled-in shares,
516 this proposal has three general impacts on the Five States. First, the Five States would lose
517 their historical allocation of the Chehalis power plant. Second, the Five States would
518 assume larger shares of RMP's Jim Bridger 3 & 4 and Colstrip 4, as those resources were
519 removed from Washington rates pursuant to CETA. Third, the portion of gas and coal
520 resources that have never been included in Washington rates would be reallocated to the
521 Five States. Finally, RMP proposes reallocating the cost responsibility for QFs attributable
522 to Washington under the 2020 Protocol to the Five State Portfolio. In addition, while
523 Washington's resource shares would no longer be dynamic, the remaining states would
524 retain dynamic factors for the portion of resources not included in Washington rates.

525 **Q. IS THE TWO PORTFOLIO APPROACH NECESSARY?**

526 A. No. First, Washington has never included a rolled-in share of east-side thermal resources
527 in its portfolio, reflecting its longstanding state policy. The current allocation method
528 under the 2020 Protocol already reflects that reality. Just as it would be unreasonable to
529 now require Washington to assume cost responsibility for resources that don't comply with
530 its state policy, it is equally unreasonable to shift that same cost responsibility to the
531 remaining states simply as a function of Washington's policy. Such a reallocation cannot
532 be justified on the basis of Washington's policy alone, but like any utility plant addition,
533 must be justified based on a finding that the benefits of the new resources outweigh their
534 costs. Such determination necessarily requires a more rigorous and detailed analysis than
535 the high-level cost estimates presented in RMP's filing, including consideration of long-
536 term impacts, risks, and obligations such as decommissioning liability.

537 Second, ratepayers in the Five States have been funding the Chehalis plant for many
538 years. The Commission should consider whether requiring ratepayers in Utah to forego
539 the ongoing benefits of a plant late in its life is an equitable outcome. Like a resource
540 acquisition, plant dispositions typically require the same type of cost benefit analysis in
541 order to justify such an action, and in this case, RMP has not clearly demonstrated any
542 benefits to the Five States in connection with their loss of the Chehalis plant.

543 Finally, Washington has already fully reimbursed its allocated share of the west-
544 side coal plants based on its WCA allocation. As a result, RMP is not harmed by
545 Washington's policy decision to remove those resources from its portfolio. In fact, as
546 discussed above, RMP is in a position to materially over-recover its investment in those
547 plants. If the other states are required to assume Washington's rolled-in share of those

548 plants, RMP would even further over-recover its investment, increasing overall cost
549 recovery for those plants from approximately 114.1% to about 121.6%.

550 **Q. ARE THERE SITUATIONS WHERE PORTFOLIO REALIGNMENT COULD BE**
551 **BENEFICIAL?**

552 A. Potentially, although RMP has not provided any concrete analysis in this proceeding to
553 determine whether the proposed portfolio realignments are reasonable. This issue is
554 discussed in greater detail in UTLCG witness Larsen’s testimony. While some portfolio
555 reallocation may be appropriate, any departure from historical allocations requires a
556 comprehensive cost-benefit justification. Assertions that Washington has declined to
557 include a plant in its portfolio—or that it has elected to include all of a plant in its
558 portfolio—are insufficient to support a finding that it is reasonable to reallocate resources
559 historically included in Utah rates.

560 **Q. WOULD RMP’S PROPOSED REALIGNMENT REPRESENT A SIGNIFICANT**
561 **ENERGY RESOURCE DECISION?**

562 A. Potentially. Although I am not a lawyer, my understanding is that under the Utah Energy
563 Resource Procurement (“ERP”) Act, RMP is required to obtain Commission approval of
564 all “significant energy resource decisions.”²⁴ Approval, specifically requires a finding that
565 the decision is in the public interest, taking into consideration the following:

- 566 (i) the dispatchability of the significant energy resource;
- 567 (ii) the state’s desire to have proven dispatchable generation resources
568 operating within the state to ensure adequate resources to reliably
569 meet the state's energy needs;
- 570 (iii) whether the proposal is consistent with the state energy policy
571 described in Section 79-6-301;

²⁴ UTAH CODE ANN. § 54-17-302(1).

- 572 (iv) whether it will most likely result in the acquisition, production, and
573 delivery of electricity at the lowest reasonable cost to the retail
574 customers of an affected electrical utility located in this state,
575 including any lowered costs resulting from the ability to sell excess
576 energy generated in an interstate energy market;
- 577 (v) long-term and short-term impacts;
- 578 (vi) risk;
- 579 (vii) reliability;
- 580 (viii) financial impacts on the affected electrical utility; and
- 581 (ix) other factors determined by the commission to be relevant.²⁵

582 Utah’s ERP Act applies to “the purchase or lease by an affected electrical utility
583 from an affiliated company of” “electricity and electrical generating capacity.”²⁶ Again, I
584 am not an attorney, and so I am flagging this issue for the Commission but am not offering
585 an opinion on whether this would extend to the circumstances in this case, where the
586 affected electrical utility is acquiring a resource from another jurisdiction.
587 Notwithstanding, regardless of whether an inter-state transfer qualifies as a significant
588 energy resource decision under the statute, the Commission must still evaluate whether
589 such a transfer is in the public interest, and there is no compelling reason why substantially
590 the same public interest considerations would not be applicable in this case. RMP’s filing
591 only provided high level estimates of the rate impacts from the reallocation but did not
592 address any other public interest considerations that the Commission would normally
593 consider with respect to resource decisions, such as risks and long-term impacts.

²⁵ *Id.* § 54-17-302(3)(c).

²⁶ *Id.* § 54-17-102(9)(c)(iv).

594 **Q. SHOULD THE FIVE STATES BE REQUIRED TO PAY MORE COSTS AS A**
595 **RESULT OF WASHINGTON STATE POLICY?**

596 A. No. As a general allocation principle, states should be held harmless from the policy
597 decisions of other states, and allocation of resources to the Five States should not be driven
598 solely by Washington state policy decisions, particularly if that increases the costs for the
599 Five States. Under this principle, the Two Portfolio approach should not require any state
600 to pay more than it would have paid under the rolled-in 2020 Protocol without a
601 demonstrated and supported need and benefit. If it does, that state is effectively being
602 harmed by Washington's policy decisions, which is inconsistent with the principle of
603 equity. Yet, RMP has not shown a demonstrated and supported need and benefit to
604 reallocate to Utah those resources serving (but without payment) Washington. Nor has it
605 shown that the benefits of reallocating Utah's share of Chehalis to Washington outweigh
606 the detrimental impacts from such reallocation. As shown in RMP witness McCoy's
607 testimony, the reallocation is expected to result in harm to the Five States, and for that
608 reason alone, cannot be said to be an equitable outcome.

609 **Q. DOES THE TWO PORTFOLIO SYSTEM SOLVE THE PROBLEM OF**
610 **DIVERGENT STATE POLICIES?**

611 A. No. In fact, it does not even fully address Washington's state policies. Under CETA,
612 Washington is required to ensure that their electricity supply is greenhouse gas neutral by
613 January 1, 2030,²⁷ which by the time the Commission issues an order in this proceeding
614 will be only a little more than three years away. Oregon, on the other hand, has a
615 requirement to eliminate coal from its portfolio by January 1, 2030,²⁸ again a little more

²⁷ WASH. REV. CODE § 19.405.040(1).

²⁸ OR. REV. STAT. § 757.518(2).

616 than three years away. Separately, Oregon has also passed an aggressive greenhouse gas
617 emission reduction program, requiring utilities to reduce carbon emissions to 80% below
618 baseline levels by 2030.²⁹ These imminent policy requirements will surely require further
619 changes to the Two Portfolio system, perhaps leading to a Three Portfolio system, with
620 even further realignment of resources to the detriment of the remaining four states. Yet, if
621 the Commission accepts RMP’s proposal as the template for addressing these policy-driven
622 portfolios, the result is that an increasing amount of costs associated with legacy resources
623 continually get shifted from the states with the policy requirements to the remaining states
624 without them. Approving RMP’s proposal in this case will only make it more challenging
625 to deal with these imminent changes, making it more likely that the other four states—
626 California, Idaho, Utah and Wyoming—are harmed even further as a result of the future
627 changes. Thus, rather than approving a method that will require substantial revisions in
628 the near future, it is more prudent to establish a durable method now that can accommodate
629 those expected portfolio changes going forward.

630 **B. RMP’s Proposed NPC Allocation**

631 **Q. HOW DOES RMP PROPOSE ALLOCATING NPC BETWEEN THE DIFFERENT**
632 **STATE PORTFOLIOS?**

633 A. While allocation factors for the Five State Portfolio would be dynamically calculated
634 among those states using a rolled-in approach, the resources allocated to each state—
635 including any situs-assigned resources—would effectively be treated similar to a discrete
636 state portfolio. NPC would be allocated through a multi-step process in which the monthly
637 energy production of resources assigned to the Five State Portfolio is balanced against that

²⁹ *Id.* § 469A.410(1)(a).

638 monthly load of the Five State Portfolio. The variance between allocated resource
 639 production and load, positive or negative, would then be assigned an energy value based
 640 on the average price of short-term purchases and sales. That value would then be added to
 641 or deducted from the NPC of the resources allocated to the state as a method for addressing
 642 differences in portfolio values between the Five State Portfolio and Washington.

643 **Q. HOW DOES RMP’S PROPOSAL IMPACT NPC?**

644 A. RMP states that “[c]omparisons with the 2020 Protocol show modest changes in NPC, with
 645 reductions for the Five-State Portfolio when considering avoided GHG costs.”³⁰ The
 646 changes that RMP reported were based on a forecast of 2026 NPC developed using the
 647 Aurora model. Those changes are detailed in Table BGM-1, below, based on RMP’s
 648 workpapers provided in response to UTLCG Data Request 5.2.³¹

649 **Table BGM-1**
 650 Impact of RMP NPC Proposal on 2026 Forecast NPC

	State	2020 Protocol	RMP Proposal	Delta	%
1	California	32,774,616	33,161,194	386,578	1.18%
2	Idaho	154,540,454	155,477,663	937,209	0.61%
3	Utah	648,237,736	654,485,380	6,247,644	0.96%
4	Oregon	1,127,643,473	1,135,831,094	8,187,622	0.73%
5	Washington	244,237,475	165,423,207	(78,814,268)	-32.27%
6	Wyoming	369,657,228	370,455,362	798,134	0.22%
7	FERC	375,315	521,703	146,388	39.00%
8	Total	2,577,466,297	2,515,355,603	(62,110,694)	-2.41%

651 The first thing to notice from this figure is on Line 8, the Total-Company NPC
 652 recovery. RMP forecasted total-Company NPC of \$2.515 billion, whereas under the 2020
 653 Protocol allocation method it allocated \$2.577 billion of NPC between the states. Thus,

³⁰ Direct Testimony of Ramon J. Mitchell, p. 2, lines 34-35.

³¹ Response to UTLCG Data Request 5.2 (provided in Exhibit BGM-2).

654 under the 2020 Protocol analysis, RMP materially over-allocated NPC between the six
655 jurisdictions. This variance is driven by Washington’s use of a different NPC allocation
656 method, which is substantially similar to the NPC allocation RMP is now proposing the
657 Five States use. The next thing to notice is on Line 5, the impact of RMP’s NPC allocation
658 proposal on Washington rates. In its direct testimony and workpapers, RMP omitted or
659 hid details of the impact of its NPC allocation proposal on Washington NPC, although that
660 information was provided in discovery.³² The method used to calculate Washington-
661 allocated NPC did not change in the new allocation framework proposal, yet
662 notwithstanding the use of the same method as before, Washington-allocated NPC declined
663 by 32.27%. The principal driver of the reduction is the reallocation of the low-cost, high-
664 value Chehalis plant to Washington. Finally, the most critical aspect of this chart is the
665 material increase in the NPC allocated to all states other than Washington. While RMP
666 refers to these impacts as “modest changes in NPC,”³³ the context of the change and its
667 relationship to the impact to Washington is important. The Five States are being allocated
668 \$32.0 million in additional non-NPC costs through the re-alignment of Washington’s state
669 portfolio.³⁴ Normally, when new resources are added to an energy portfolio, it is expected
670 that it will result in a corresponding reduction to energy costs. If nothing else, a new
671 resource will produce more energy when economical, reducing the cost necessary to serve
672 loads. In this case, however, the exact opposite occurred. Not only are the Five States
673 allocated the cost of more resources, but the allocation of those resources produces an even

³² See e.g., Direct Testimony of Ramon J. Mitchell, pp. 10-12, lines 214-225 (excluding Washington from comparative analysis; and see generally Exhibit RMP___(RJM-1) (omitting Washington data throughout workpaper).

³³ Direct Testimony of Ramon J. Mitchell, p. 2, lines 34-35.

³⁴ Direct Testimony of Shelley E. McCoy, p. 5, line 103, Table 2.

674 higher energy cost. In other words, the Five States are paying for higher-cost resources
675 that increase the cost of energy in the Five State portfolio. This is clear evidence of the
676 inequity of the proposed transfer of resources between the Five States and Washington.
677 Where Washington receives an NPC benefit of approximately \$78.8 million, the other Five
678 States pick-up an additional \$16.5 million in NPC, *in addition* to the \$32.0 million in non-
679 NPC production costs.

680 **Q. HOW DOES THIS NPC ALLOCATION METHOD DIFFER FROM THE**
681 **METHOD USED UNDER THE 2020 PROTOCOL?**

682 A. RMP describes the new method as a five-step process.³⁵ Aside from the use of realigned
683 resource allocation factors, the proposed allocation method is similar to the 2020 Protocol
684 method, with the primary difference being the addition of a monthly net position
685 adjustment.

686 **Q. DOES THE WASHINGTON NPC ALLOCATION METHOD USE THE SAME**
687 **APPROACH?**

688 A. No. While Washington uses substantially the same method to calculate its monthly net
689 position, RMP assigns a different energy value to Washington’s net position than is being
690 proposed in the Five States. The energy value used in the position balancing adjustment
691 for the Five State portfolio is based on the average cost of short-term purchases and sales.
692 Under the Washington approach, which was recently approved by the Washington
693 commission,³⁶ the energy value assigned to Washington’s monthly net position depends on
694 whether Washington is in a surplus or deficit, as described below.

³⁵ Direct Testimony of Ramon J. Mitchell, pp. 4-8, lines 71-135.

³⁶ *Washington Utilities and Transportation Commission v. PacifiCorp dba Pacific Power and Light Co.*, Docket No. UE-250224 (hereinafter “2026 Washington Protocol Docket”), Final Order Rejecting Tariff Sheets; Granting Petition in Part, Subject to Conditions; Authorizing and Requiring Compliance Filing, ¶ 385 (Dec. 22, 2025).

695 *Surplus* rebalancing is done by first eliminating system balancing purchases.
696 If there are not sufficient system balancing purchases to eliminate, an amount
697 of system balancing sales are [sic] imputed that allow the 2026 Protocol to
698 maintain supply-demand balance.³⁷

699 *Shortfall* rebalancing is done by first eliminating system balancing sales. If
700 there are not sufficient system balancing sales to eliminate, an amount of
701 system balancing purchases are [sic] imputed that allows the WIJAM to
702 maintain supply-demand balance. Any system balancing sales that are
703 eliminated or system balancing purchases that are imputed in the rebalancing
704 adjustment are done using the average price of either the system balancing
705 sales or system balancing purchases.³⁸

706 Under Washington's more complex formula, different effective rates are applied
707 depending on whether the monthly net position is a surplus or a deficit. When Washington
708 is in a surplus position, the cost of short-term firm purchases is applied first as the effective
709 rate for valuing the monthly net position. Conversely, when Washington is in a deficit
710 position, the cost of short-term firm sales is applied first as the effective rate for the monthly
711 net position. In general, system balancing purchases involve higher prices than system
712 balancing sales. Accordingly, this differential treatment of surplus and deficit positions
713 results in Washington receiving a more favorable net position adjustment than it would
714 under an approach that applies a single average short-term firm energy value to both
715 surpluses and deficits, as is proposed for the Five State Portfolio. Specifically, Washington
716 receives a higher-than-average benefit when it is in a surplus position and incurs a lower-
717 than-average cost when it is in a deficit position. By valuing surplus positions first against
718 short-term firm purchases, the resulting effective rate for a surplus is higher than it would
719 be if an average of short-term firm purchase and sale rates were applied. Similarly, by

³⁷ *Id.* at Direct Testimony of Ramon J. Mitchell, Exhibit RJM-1CT, pp. 14:23-15:3.

³⁸ *Id.* at Direct Testimony of Ramon J. Mitchell, Exhibit RJM-1CT, p. 15, lines 16-22.

720 valuing deficit positions first against short-term firm sales, the effective rate for a deficit is
721 lower than it would be under an average short-term firm purchase and sale rate.

722 **Q. IS IT FAIR TO PROVIDE WASHINGTON WITH A PREFERENTIAL NPC**
723 **ALLOCATION METHOD?**

724 A. No. Given that the majority of the allocation issues in this case arise from the need to
725 accommodate Washington state policy, it is difficult to justify providing Washington with
726 an NPC allocation method that is inherently more favorable than the method applied to the
727 other states. At a very minimum, if Washington is permitted to use a more favorable
728 method for valuing monthly net positions, that same method should be extended to all states
729 to avoid discriminatory and inconsistent treatment between states.

730 **Q. WHAT IS THE IMPACT OF APPLYING THE WASHINGTON NET POSITION**
731 **BALANCING METHOD TO THE FIVE STATE PORTFOLIO?**

732 A. In Exhibit BGM-4C, I have prepared an analysis demonstrating the difference between the
733 two approaches. That analysis shows that if the Washington net position balancing method
734 were applied consistently to the Five State portfolio that the net position balancing
735 adjustment would decline from \$ [REDACTED] to \$ [REDACTED], an \$ [REDACTED] reduction.
736 Utah's share of this difference is approximately \$ [REDACTED]. As can be seen by comparing
737 Lines 25 and 9 on that report, the average \$/MWh price of sales was lower than the average
738 of both sales and purchases. Correspondingly, the average \$/MWh price for purchases on
739 Line 28 was higher than the average of both purchases and sales. Accordingly, when
740 calculating the additional cost of a short position on Lines 39 – 46, the Washington method
741 resulted in a lower cost than RMP's Five State calculation, and when calculating the benefit

742 of a long position on Lines 29 -37, the Washington method resulted in a higher value than
743 RMP's Five State calculation.

744 **Q. DID RMP CORRECTLY CALCULATE THE FIVE STATE POSITION IN ITS**
745 **CALCULATIONS?**

746 A. It does not appear so. RMP's NPC forecast included energy production associated with
747 Utah Schedule 32 resources in the net position for the Five State portfolio and did not
748 consider the energy benefit of those resources as an offset to the net position allocated to
749 Utah. RMP calculates the net position for the five states in the aggregate and then allocates
750 that net position to each of the Five States in proportion to their respective SG factors.
751 While the costs of those resources are paid for by those Utah Schedule 32 customers, and
752 excluded from NPC, the energy from those resources still needs to be reflected as an offset
753 to Utah's net position. Otherwise, it will result in over-allocating NPC to Utah customers,
754 while allocating the energy benefit of those resources to other states.

755 **Q. ARE SHORT-TERM FIRM PURCHASES AND SALES THE BEST WAY TO**
756 **MEASURE MARGINAL COST?**

757 A. Not necessarily. The *average* cost of short-term firm purchases and sales does not
758 necessarily represent the *marginal* cost of energy production. RMP balances its system
759 with a combination of monthly, daily, and hourly purchases and sales, and the incremental
760 benefit or costs associated with a state's surplus or deficit does not necessarily represent
761 the sum of all those transactions. The costs of these transactions can vary significantly
762 depending on the way in which RMP balances its system. A monthly power product, for
763 example, provides a single fixed price that applies uniformly across all hours of the month.
764 Although that price reflects an average of hourly market prices over the month, it does not

765 vary by hour and is not shaped to reflect the expected hourly price profile. As a result, the
766 price paid for the product during low-priced hours is generally higher than the expected
767 hourly price, while the price paid during high-priced hours is lower than the expected
768 hourly price. Using such a monthly product in the valuation of a state's net position would
769 therefore benefit states that are net long in low-priced hours and net short in high-priced
770 hours. Because system demands are generally correlated with high-priced hours, using
771 monthly pricing creates an incentive that effectively encourages utilities to be short during
772 the periods when power is needed the most, and long when it is not.

773 **Q. DID RMP'S PROPOSAL CONSIDER ANCILLARY SERVICE VALUE?**

774 A. No. Ancillary services, such as operating and regulation reserves, impose material costs
775 on RMP's NPC. These reserves are required to satisfy WECC and NERC reliability
776 standards and require RMP to hold back generation capacity to be able to respond to
777 unplanned forced outages, as well as variations in load and variable energy resource output.
778 The capacity costs of those resources are reflected in the fixed costs included in the
779 Company's revenue requirement (offset by FERC revenue credits). But the energy or NPC
780 "costs" that these reserves impose in NPC do not appear as a line item on the NPC report
781 but rather represent an opportunity cost associated with not being able to fully dispatch
782 reserved capacity to serve customers. Since reserves for ancillary services are
783 predominantly held on thermal resources, the energy value of portfolios with a higher
784 allocation of thermal resources may be reduced because those portfolio resources will be
785 required to hold reserves to provide ancillary services in support of the entire transmission
786 system, including other states' loads and variable energy resources. As a state adds more
787 variable energy resource production to their portfolio, that increases the ancillary service

788 costs borne by the states with a higher allocation of thermal resources. I discuss a potential
789 way to address this below.

790 **C. Actual Net Power Cost**

791 **Q. IS IT NECESSARY TO DEFINE HOW ACTUAL NPC IS HANDLED WHEN**
792 **EVALUATING AN NPC ALLOCATION METHOD?**

793 A. Yes. In general, the primary consideration in evaluating an NPC allocation method should
794 be how that method calculates and allocates actual NPC. Ratemaking is fundamentally
795 concerned with determining a utility's actual costs, or its expected actual costs under
796 normalized conditions. While an NPC forecast is commonly used in a rate case, that is
797 designed to estimate what actual NPC will be in the forecast period. Relying solely on a
798 forecast to justify allocation of actual NPC is problematic because the forecast is meant to
799 *approximate* actual NPC, not define it. While this distinction may appear minor, it is
800 important in evaluating allocation methods because there are certain methods that may be
801 feasible within a modeled simulation that are not feasible—or may produce materially
802 different outcomes—when applied to actual NPC. Thus, the appropriate sequence for
803 evaluating an NPC allocation method is to first establish the methods used to allocate actual
804 NPC and then align the modeled allocation framework to conform with that outcome.

805 **Q. DID RMP DEMONSTRATE HOW IT WOULD USE ITS METHOD TO**
806 **CALCULATE ACTUAL NPC?**

807 A. No. The calculations supporting RMP's proposed allocation method were based on an
808 Aurora model NPC forecast for calendar year 2026 that was prepared in early 2025. In
809 discovery, RMP was asked to provide calculations demonstrating how the proposed
810 allocation method would affect the allocation of actual NPC to each state. RMP objected

811 to this request stating, among other things, that it required “the creation of a new report or
812 analysis” and “information that is not in the Company’s possession, custody or control.”³⁹
813 In its response, RMP instructed UTLCG to “complete their own analysis” of the impacts
814 of RMP’s proposal on Actual NPC allocation.⁴⁰ This answer was problematic because the
815 UTLCG (or any other non-Company party) is not in a position to speculate as to how RMP
816 would implement its own proposal to calculate actual NPC because there are key
817 differences between the modeled Aurora outputs and the accounting data used to calculate
818 actual NPC potentially requiring special consideration. Following conferral, however,
819 RMP eventually agreed to provide a limited analysis of its proposal on actual NPC using
820 2024 data through a supplemental response.⁴¹ But in its supplemental response RMP stated
821 “any work paper provided for this data request is an illustrative example and does not
822 represent how the Company would file its work papers in future dockets / proceedings.”⁴²
823 Thus, it is still not entirely clear how RMP will implement its NPC allocation proposal for
824 actual NPC.

825 **D. Extended Day Ahead Market**

826 **Q. WHAT IS THE EXTENDED DAY AHEAD MARKET?**

827 A. The EDAM is a voluntary regional wholesale electricity market operated by the CAISO.
828 It provides a framework to coordinate and optimize day-ahead energy scheduling across
829 multiple balancing authorities, allowing participating utilities to economically commit
830 generation and schedule power in the day-ahead based on least-cost dispatch for the entire
831 market footprint and subject to transmission constraints. For RMP, participation in this

³⁹ Response to UTLCG Data Request 5.5, subpart b (provided in Exhibit BGM-2).

⁴⁰ *Id.*

⁴¹ 1st and 2nd Supplemental Responses to UTLCG Data Request 5.5 (provided in Exhibit BGM-2).

⁴² 1st Supplemental Response to UTLCG Data Request 5.5 (provided in Exhibit BGM-2).

832 market will represent a major change in the way its system is operated. Rather than
833 independently optimizing its day-ahead portfolio across its own system, RMP will submit
834 its load forecasts, generation offer, and available transmission capability into the market.
835 The CAISO will then optimize dispatch across the entire market footprint, and RMP will
836 be compensated under a locational marginal pricing framework based on the system-wide
837 value of its resource portfolio.

838 **Q. WHEN DOES RMP PLAN TO ENTER THE EDAM?**

839 A. RMP is currently scheduled to begin participating in the EDAM on May 1, 2026, just after
840 the hearing in this case. Thus, by the time that the Commission issues its order in this case,
841 RMP will likely already have begun participating in the market.

842 **Q. HOW WILL THIS CHANGE IMPACT JURISDICTIONAL COST ALLOCATION**
843 **OF NPC?**

844 A. Under a rolled-in cost allocation framework, the impacts of participation in the EDAM are
845 more straightforward to address, because all states would share proportionally in both the
846 costs and the benefits of market participation. Under a portfolio system of cost allocation,
847 however, handling the EDAM is much more complicated as different resources will result
848 in different costs and benefits in the context of the market. For example, a resource
849 included in a state's portfolio may be dispatched in a way that is beneficial to the overall
850 market but detrimental to that state's overall allocation of NPC. Without evaluating market
851 settlements on a resource-by-resource basis, it will be difficult to allocate the costs and
852 benefits of market participation equitably across state portfolios.

853 **Q. WILL THE EDAM ALSO COMPLICATE THE METHODS USED TO FORECAST**
854 **NPC?**

855 A. In the context of the EIM, there has been a disconnect historically between the way that
856 the market benefits are evaluated in forecast base NPC versus the way that they are
857 included in actual NPC. RMP forecasts NPC based on a stand-alone dispatch simulation
858 and includes an approximation of the net benefits associated with EIM market
859 participation. In actual NPC, however, participation in the EDAM impacts the production
860 of individual resources, which is then offset by a variety of settlement payments and
861 revenues received by the market. Given the heightened implications of the EDAM on
862 RMP's system dispatch, continuing to rely on this general approach to forecast the impacts
863 of EDAM participation on NPC may no longer be viable, particularly under a portfolio cost
864 allocation framework. Because this forecasting approach does not reflect dispatch impacts
865 from the market and instead embeds those impacts in a monetary adjustment calculated
866 outside of the simulation, the net positions calculated for individual states in the forecast
867 will not necessarily align with the net positions reflected in actual NPC, which incorporates
868 the outcome of market dispatch.

869 **Q. DOES RMP'S PROPOSED NPC ALLOCATION METHOD CONSIDER THIS**
870 **DISCONNECT?**

871 A. No, but it should. Under any portfolio-based NPC allocation method, the mismatch
872 between actual NPC, which incorporates market dispatch, and the Aurora model forecast
873 dispatch, which does not, needs to be addressed. Thus, as a fundamental part of any
874 portfolio-based cost allocation method, the method for forecasting dispatch in the context

875 of the EDAM also needs to be addressed, otherwise the forecast allocated cost will not
876 necessarily align with the way that actual NPC is ultimately allocated to the states.

877 **Q. HOW DOES RMP PLAN TO ADDRESS THE EDAM IN ITS NPC ALLOCATION**
878 **FRAMEWORK?**

879 A. RMP describes the EDAM as resulting in an “anticipated future change[] to NPC
880 allocation.”⁴³ RMP states that the EDAM is an opportunity to “refine and improve the
881 allocation of NPC,”⁴⁴ although the specific scope of, and process for considering, these
882 refinements was not clear from its testimony.

883 **Q. HOW DOES RMP PLAN TO IMPLEMENT THIS NEW EDAM ALLOCATION**
884 **METHOD?**

885 A. RMP’s testimony only included a few paragraphs about how this new approach would be
886 implemented. It is not clear from the testimony, for example, if this new method would be
887 implemented through a separate docket, or if RMP would simply implement the new
888 method in future rate case filings. Since RMP will likely already be participating in the
889 EDAM by the time this docket concludes and, for reasons noted above, it will be necessary
890 to address the treatment of the EDAM in NPC allocation regardless of the outcome in this
891 proceeding. Even if the Commission were to approve RMP’s NPC allocation proposal, it
892 would still be necessary to address how the settlements and costs associated with the
893 EDAM should be allocated between state portfolios.

894 **Q. HOW DID RMP DESCRIBE THE EDAM ALLOCATION METHOD?**

895 A. RMP states that “actual market settlement data would be used to allocate costs and
896 revenues more precisely to each state” and that such data would replace the proposed

⁴³ Direct Testimony of Ramon J. Mitchell, p. 12, line 250.

⁴⁴ *Id.* at p. 12, lines 254-56.

897 “method of valuing the Net Position based on average short-term firm prices with a more
898 granular approach.”⁴⁵ Thus, in lieu of the net position balancing adjustment, states’
899 allocation of NPC would include an adjustment equal to the net of the (1) EDAM revenues
900 from resources allocated to the state and (2) the costs incurred for that state’s load.⁴⁶ The
901 net cost/revenue for these two items would effectively replace the net position balancing
902 adjustment used in the proposed NPC allocation method.⁴⁷

903 **Q. HOW SIGNIFICANT OF A DEPARTURE IS THIS FROM RMP’S PRINCIPAL**
904 **PROPOSAL?**

905 A. The approach proposed with respect to the EDAM is materially different from RMP’s
906 principal NPC allocation proposal and would represent a wholesale change in the allocation
907 method. Effectively, the EDAM approach would move away from valuing a Five State
908 Portfolio net position, and instead, separately value each state’s loads and resources using
909 market-calculated LMPs. These two approaches are markedly different. First, each state
910 portfolio would be evaluated independently, as opposed to RMP’s proposal which
911 evaluates the position of the Five State Portfolio in aggregate. Further, under the proposed
912 approach, only the net position is subject to an energy valuation adjustment, whereas under
913 the EDAM approach the entirety of a state’s loads and portfolio resources are subject to an
914 energy valuation adjustment.

⁴⁵ *Id.* at p. 13, lines 264-66.

⁴⁶ *Id.* at p. 13, lines 272-78.

⁴⁷ *Id.*

915 **Q. IS IT STRAIGHTFORWARD TO ADOPT THE TYPE OF EDAM ALLOCATION**
916 **METHOD RMP DISCUSSES?**

917 A. No. RMP presents the EDAM method as a straightforward change, just requiring the
918 replacement of a net position adjustment with EDAM settlement data. In practice,
919 however, implementing such a method is complicated and involves significantly greater
920 detail and definition than what RMP discusses in testimony. Participation in the EDAM
921 involves many more aspects than just the locational marginal cost of loads and resources.
922 For example, a major source of market revenue for utilities in such markets results from
923 congestion, effectively amounting to the differences between the locational marginal costs
924 of energy production and loads that arise due to transmission constraints. There are also
925 revenues and charges for ancillary services, reserves, losses, resource sufficiency tests, and
926 a variety of other market elements, which would be necessary to address and evaluate in
927 the context of an EDAM allocation method. And as noted above, RMP's current Aurora
928 model forecasting methods lack the ability to simulate how plants will be dispatched within
929 a broader EDAM footprint. Therefore, apart from determining how NPC will be allocated,
930 it will also be necessary to evaluate how system dispatch will be forecast subsequent to
931 EDAM participation. There are many details that will need to be resolved prior to adopting
932 such a method, although RMP's testimony only presents the EDAM allocation method at
933 a high level.

934 **Q. IS IT PRACTICAL TO APPROVE AN NPC ALLOCATION METHOD THAT**
935 **MUST BE IMMEDIATELY CHANGED?**

936 A. No. In this regard, RMP's principal NPC allocation proposal in this docket is problematic.
937 Under a fully rolled-in cost allocation framework there can be reasonable assurance that

938 the costs and benefits of the EDAM are being equitably distributed to states, as all NPC
939 costs and benefits are shared in proportion to each state's load requirements. Under a
940 portfolio-based allocation method, however, some evaluation of the way the EDAM costs
941 and benefits are allocated will be required to ensure that the market costs and benefits are
942 appropriately flowing to the state portfolios that generate them. Given the timing of RMP's
943 participation in the EDAM, if the Commission were to approve RMP's principal net
944 position balancing NPC allocation proposal, it would be necessary to immediately initiate
945 further process to revise the method to address the cost allocation issues that arise from the
946 EDAM, including further evaluation of the EDAM allocation proposal RMP mentioned in
947 testimony. There is little value in approving an allocation that is known to be transient,
948 and there would be little downside to continuing the use of the existing rolled-in allocation
949 framework to provide time to resolve EDAM cost allocation issues to avoid introducing
950 additional complexity in the interim.

951 **Q. IS IT REASONABLE TO BEGIN EXPLORING AN EDAM METHOD OF COST**
952 **ALLOCATION?**

953 A. Yes. Under the 2020 Protocol, the expectation was that the NPM method for allocating
954 NPC would be the first step toward allocating NPC on a more granular basis to reflect
955 different resource portfolios. The NPM was essentially a shift toward the type of
956 information expected to be provided through an organized day-ahead market like the
957 EDAM. Now that the EDAM is going to be a reality, it is something that needs to be
958 addressed in the context of NPC allocation regardless of what the Commission approves in
959 this case. After the market begins operation, the EDAM dispatch will become the principal
960 source of cost causation with respect to RMP's system dispatch and NPC. It will also

961 become the principal source of market purchases and sales. Accordingly, there is merit in
962 relying on the EDAM as a basis for NPC allocation, although many details would need to
963 be resolved prior to implementing such a method.

964 **E. Recommendation**

965 **Q. GIVEN THE ABOVE, WHAT DO YOU RECOMMEND WITH RESPECT TO**
966 **RMP'S NPC ALLOCATION PROPOSAL?**

967 A. I recommend the Commission reject RMP's NPC allocation proposal in this docket and
968 order that if the Company files a rate case prior to the implementation of a new cost
969 allocation methodology, it must provide its analysis using the 2020 Protocol. Of course
970 the Company or other parties may propose alternative methodologies but without a starting
971 point calculating NPC using the 2020 Protocol methodology it will be difficult in the
972 extreme for parties to present an analysis using that approach, or any approach not
973 presented by the Company, for the Commission's consideration in the timeframes
974 permitted in a rate case. In addition, the Commission should stay this case, or alternatively,
975 open an investigatory or other docket and order the Company to engage in a collaborative
976 process and provide the analytics needed to develop an alternative and more durable
977 framework that addresses these issues, such as compatibility with the EDAM and an
978 approach that values the ancillary services and resource adequacy that each state portfolio
979 provides to the system. This way, parties can continue to issue discovery for the purpose
980 of investigating more robust methods and approaches for interjurisdictional allocation until
981 such time as an EDAM-compatible framework is available. There are several
982 shortcomings in RMP's proposal, such as the use of monthly versus hourly energy values
983 and the non-consideration of ancillary service values. It may be possible to address some

984 of these issues, but working in a collaborative setting with the parties to resolve the larger
985 issue associated with the EDAM is a preferable outcome.

986 **IV. ALTERNATIVE METHODOLOGIES**

987 **Q. HAVE YOU EVALUATED ANY ALTERNATIVE ALLOCATION APPROACHES**
988 **CONSIDERING THE ISSUES YOU IDENTIFY ABOVE?**

989 A. Yes, partially. To address the concerns mentioned above, I provide an alternative approach
990 for accounting for ancillary service obligations. In general, I have presented this as a
991 framework, recognizing that there are many fine details that will need to be resolved if it
992 is to be implemented.

993 Further, with respect to resource adequacy, resolving longer-term reliability issues
994 of divergent state resource portfolios proves elusive. Prior to PacifiCorp’s exit from the
995 Western Resource Adequacy Program (“WRAP”), WRAP provided at least seasonal
996 resource adequacy forward showings. WRAP, or a similar resource adequacy program,
997 could provide data, methodologies, and pricing to account for longer-term leaning
998 concerns. But because PacifiCorp is not a participant in such a program, more work needs
999 to be done to develop a methodology.

1000 **A. Ancillary Service Allocation**

1001 **Q. WHAT IS YOUR RECOMMENDATION ON ANCILLARY SERVICES?**

1002 A. My recommendation is to assign the cost of reserves between states through the
1003 establishment of a “Reserves Pool.” The embedded cost of generation resources associated
1004 with providing ancillary services, including contingency reserves and operating reserves,
1005 is already determined in PacifiCorp’s FERC filings using a method known as a “units most
1006 likely” approach. The UTLCG’s recommended method would follow this same approach

1007 and allocate embedded costs associated with ancillary services to a separate jurisdictional
1008 category, which I refer to in this testimony as a Reserves Pool.⁴⁸ The embedded costs
1009 allocated to the Reserves Pool would then be assigned to each jurisdiction based upon the
1010 reserves required of their respective loads and resources.

1011 **Q. ARE ANCILLARY SERVICES A COST OF CAPACITY OR ENERGY?**

1012 A. Both. The cost of reserves necessary to supply ancillary services can be viewed both from
1013 the perspective of an energy cost or a capacity cost. Ancillary services represent generation
1014 capacity that is withheld and not dispatched for the benefit of native load customers.
1015 Accordingly, the cost associated with ancillary services can be viewed as both the
1016 embedded cost of the withheld generation capacity itself and/or the energy cost impacts of
1017 not dispatching that capacity in serving retail load requirements.

1018 **Q. HOW IS THE COST OF CAPACITY CONSIDERED IN THE CONTEXT OF**
1019 **RMP'S OPEN ACCESS TRANSMISSION TARIFF?**

1020 A. As a balancing authority, RMP is required to provide ancillary services not just for native
1021 customers, but also for the loads and resources of third-party entities that rely on its
1022 transmission system. This includes, for example, the loads and resources of municipal
1023 utilities, independent power producers, and other similar transmission customers. In the
1024 context of RMP's Open Access Transmission Tariff ("OATT"), the rates for ancillary
1025 services, including both regulation reserve services and operating reserve services are
1026 calculated based on the embedded cost of capacity used to supply those reserves. The
1027 method RMP uses to determine this embedded cost is based on a concept known as the
1028 "units most likely" analysis. This approach evaluates the balancing authority area's total

⁴⁸ UTLCG Witness Larsen also discusses this in terms of a PacifiCorp Reserves bucket in his Allocation Framework.

1029 reserve requirements and determines which generation units are most likely to be used to
1030 supply those reserves. Based on this analysis, reserve service rates are calculated by taking
1031 the proportional embedded capacity cost of each resource expected to provide reserves
1032 service and dividing by the total reserves requirement. Those costs are then allocated
1033 between the state and federal jurisdictions using a load ratio share methodology.

1034 **Q. HOW DOES HOLDING RESERVES IMPACT NPC?**

1035 A. Holding reserves typically results in a utility being required to use more expensive sources
1036 of energy to serve retail loads than it otherwise would have if the reserved capacity were
1037 fully dispatchable. From an energy perspective, the cost of reserves is often referred to as
1038 an opportunity cost, since by holding reserves, the utility loses the opportunity to use that
1039 capacity for the benefit of native loads and must instead use higher cost resources to meet
1040 native load requirements.

1041 **Q. CAN THE COST OF ANCILLARY SERVICES BE CONSIDERED**
1042 **SIMULTANEOUSLY AS BOTH A CAPACITY AND ENERGY COST?**

1043 A. No. The cost of ancillary services can either be considered as a cost of capacity or an
1044 opportunity cost of energy, but not both at the same time. The reason for this is that if a
1045 customer is paying the full embedded cost of capacity for a resource, that customer should
1046 otherwise receive the net energy benefits associated with the portion of the capacity they
1047 are paying for. Since the capacity held in reserve is not being dispatched there is effectively
1048 no energy cost or benefit associated with the share of the capacity allocated to the ancillary
1049 service customer when that customer is paying for the underlying capacity.

1050 **Q. HOW ARE THE RESERVES HELD FOR THIRD-PARTY CUSTOMERS**
1051 **CURRENTLY HANDLED FOR RETAIL RATEMAKING?**

1052 A. For retail ratemaking, the reserves held for third party OATT customers are currently
1053 embedded in retail rates by including all of the associated generation embedded costs,
1054 including embedded costs associated with ancillary services, in allocated revenue
1055 requirement. The allocated embedded costs are then offset by a revenue credit equal to the
1056 amounts paid by OATT customers for ancillary services, allocated to each state using their
1057 rolled-in factor. The OATT customers effectively pay for a portion of the capacity costs
1058 from generation resources used to hold reserves through their OATT rates, and the revenue
1059 from those rates is effectively used to offset the embedded costs paid by retail customers.

1060 **Q. WILL THE CURRENT METHOD FOR HANDLING ANCILLARY SERVICES BE**
1061 **VIALE UNDER A NON-ROLLED IN ALLOCATION FRAMEWORK?**

1062 A. No. Under a rolled-in system where each state assumes cost responsibility for a
1063 proportional share of all system resources, allocating reserve costs and benefits—both
1064 capacity costs as well as energy costs—can simply follow with the rolled-in factors. Under
1065 a portfolio approach, however, certain states will be assigned more cost responsibility over
1066 the resources that are being used to provide ancillary services than other states, and absent
1067 a mechanism to address the cost as well as the system benefits associated with the reserves
1068 that each state’s portfolio provides to the system, the result will be some states benefitting
1069 from the portfolio of other states, while reducing the value of the portfolios used to provide
1070 those reserves.

1071 **Q. WHAT METHODS CAN BE USED TO ENSURE THAT THE COST OF**
1072 **RESERVES IS ALLOCATED EQUITABLY AMONG STATE PORTFOLIOS?**

1073 A. Following the above, there are potentially two general methods that can be used to allocate
1074 the costs and benefits of reserves among the states. First, the energy cost impacts
1075 associated with reserves held could be reallocated between the states using an opportunity
1076 cost analysis. This type of analysis is straightforward in the context of a simulated dispatch
1077 model, but it is far more complicated when evaluating actual NPC. Second, the capacity
1078 costs associated with reserves could be reallocated between the states, which is the
1079 principal approach being advocated by the UTLCG. The fact that RMP's OATT third-
1080 party reserve customer rates are based on embedded cost, there is some value in adopting
1081 consistent treatment between the treatment of OATT customers and interjurisdictional
1082 allocation.

1083 **Q. IS IT NECESSARY FOR RMP TO CONTINUE USING A REVENUE CREDIT**
1084 **METHOD FOR ANCILLARY SERVICES PROVIDED TO THIRD PARTY OATT**
1085 **CUSTOMERS?**

1086 A. No. In general, there are two different ways to consider FERC jurisdictional services in a
1087 utility's state jurisdictional revenue requirement: a revenue credit method and a
1088 jurisdictional allocation method. Under the revenue credit method, retail customers pay
1089 100% of the cost associated with the FERC jurisdictional services but then receive a
1090 revenue credit equal to the revenues received from the FERC customers as an offset to the
1091 cost included in rates. The jurisdictional allocation method, however, treats the FERC
1092 jurisdictional customers as a distinct jurisdiction in the interjurisdictional allocation and
1093 thus only considers costs allocated to the states to establish state retail rates. While states

1094 do not have the ability to modify FERC rates, both methods are accepted approaches for
1095 handling interjurisdictional allocations. As an example, RMP provides full requirements
1096 energy supply services to a handful of small public power entities through FERC-regulated
1097 power sales rates. Rather than including the revenue from those customers as a revenue
1098 credit that offsets retail rates, these FERC jurisdictional entities are treated as a separate
1099 jurisdiction in the interjurisdictional allocation, with costs assigned to them using the same
1100 rolled-in method as any other state and without implicating the FERC rates used to
1101 establish those service rates. Many other state jurisdictions use similar jurisdictional
1102 allocation methods to determine the transmission costs applicable to state retail customers
1103 including RMP's sister utilities Nevada Power and Sierra Pacific Power companies.

1104 **Q. HOW DO YOU RECOMMEND HANDLING ANCILLARY SERVICE COST**
1105 **ALLOCATION GOING FORWARD?**

1106 A. Rather than using a revenue credit method for these services, my recommendation is to
1107 transition to the jurisdictional allocation method to properly assign ancillary service costs
1108 to the states. By using the jurisdictional allocation method, this will ensure that there is
1109 alignment between the embedded generation costs included in the jurisdictional allocation
1110 method and the embedded generation costs associated with the ancillary service reserves
1111 provided to third-party OATT customers.

1112 **Q. CAN THIS APPROACH ALSO BE USED TO ALLOCATE ANCILLARY**
1113 **SERVICE COSTS BETWEEN STATES?**

1114 A. Yes. One benefit of using a jurisdictional allocation for reserves services is that a common
1115 method can be applied to allocate ancillary service costs between the states.

1116 **Q. HOW WOULD COST BE ALLOCATED UNDER SUCH AN APPROACH?**

1117 A. Under this approach, the embedded capacity costs associated with ancillary services would
1118 be treated as a separate jurisdictional allocation. Those embedded costs would be allocated
1119 separately to a Reserves Pool category and then each state would assume responsibility
1120 over those costs included in the Reserves Pool in proportion to the ancillary service
1121 requirements that their state-specific loads and resource portfolios impose on the system.
1122 This calculation would be performed on a unit-by-unit basis, using the most recent reserves
1123 study performed by RMP at FERC to satisfy NERC requirements. Any costs allocated to
1124 the reserves pool would be deducted from the costs allocated to a state in connection with
1125 their state portfolio. Correspondingly, the capacity cost of reserves allocated to the
1126 Reserves Pool would then be reallocated back to states in proportion to the reserves that
1127 their portfolio loads and resources impose on the system.

1128 **Q. HAVE YOU PREPARED AN ILLUSTRATION?**

1129 A. Yes. In Exhibit BGM-5, I provide an illustration for how this allocation will function. In
1130 Table BGM-2, below, I provide detail from the Lake Side 2 line item in that exhibit as an
1131 example.

1132
1133

Table BGM-2
Illustration of Reserves Pool Method – Lake Side 2

1	Plant	Lake Side 2		
2	Non-NPC Rev. Rec	\$ 83,354,410	(a)	
3	Nameplate	620.00	(b)	
4	Reserves Held	76.15	(c)	
5	Reserves Pool %	12.28%	(d) = (c) / (b)	
6		Pre-Reserves	Post-Reserves	Allocated Non-NPC
7	State	Alloc. Factor	Prod. Alloc. Factor	Prod. Rev. Req.
8		(e) = SG5B	(f) = (e) * (1-(d))	(f) * (a)
9	CA	1.4%	1.25%	\$ 1,044,520
10	ID	6.5%	5.73%	4,775,791
11	OR	28.3%	24.80%	20,670,554
12	UT	48.8%	42.78%	35,655,853
13	WA	0.0%	0.00%	-
14	WY	15.0%	13.14%	10,953,594
15	FERC*	0.0%	0.02%	16,824
17	Total	100.0%	87.7%	\$ 73,117,137
18		Pre-Reserves	Post-Reserves	Allocated Non-NPC
19		Factor	Production Factor	Reserves Rev. Req.
20	Reserves Pool	0.0%	(g) = (d) 12.28%	(f) * (g) \$ 10,237,273
21	<i>*FERC Full Requirements Power Sales</i>			

1134 As can be seen in Table BGM-2, the approach starts by determining the portion of the
 1135 resource that is attributable to reserves service. In the reserves study supporting RMP’s
 1136 most recent OATT ancillary service rates, RMP calculated that 76.15 MW of the 620 MW
 1137 of the Lake Side 2 power plant was being used for reserves service. Accordingly,
 1138 approximately 12.28% of the embedded cost of the resource would be included in the
 1139 Reserves Pool. To calculate each state’s allocation factors, we would start with the
 1140 allocation factor prior to the application of the reserves pool. In Table BGM-2 above, I
 1141 used the SG5B factor included in RMP’s allocation framework proposal, although this

1142 approach could be used with any set of allocation factors for each resource. Subsequently,
1143 I adjusted the allocation factors for the portion of the plant allocated to the Reserves Pool.
1144 To do this, I multiplied the pre-reserves allocation factor by one minus the reserves
1145 percentage. The percentages then flow through the ordinary cost allocation methods with
1146 a separate category for the amounts allocable to the reserves pool, highlighted in red. This
1147 calculation would be performed for each reserves holding resource, including for contract
1148 resources, such as the Monsanto Reserves product included in NPC. After performing this
1149 calculation for each resource, the amounts allocated to the Reserves Pool would be summed
1150 and the total amount of costs included in the reserves pool would then be re-allocated to
1151 the states based on the amount of reserves required for their respective loads and allocated
1152 resources.

1153 **Q. HOW WOULD THE RESERVES POOL BE REALLOCATED?**

1154 A. The Reserves Pool would be assigned to states by determining the stand-alone reserve
1155 requirements for each jurisdiction, including OATT customers. Since there are diversity
1156 benefits between the different portfolios included in RMP's balancing areas, the sum of the
1157 individual jurisdiction's stand-alone reserves requirement will be greater than the total
1158 reserves required for the system. Accordingly, each state would be allocated the portion
1159 of the reserves pool equal to the percentage of the sum of the stand-alone reserve
1160 requirements, to allow for allocation of reserve diversity benefits.

1161 For example, assume that the actual capacity of operating reserves needed on the
1162 system for all customers was 1200 MW; the load ratio share of that capacity for purposes
1163 of the states' requirements was 1000 MW; Utah's need for operating reserves, if Utah's
1164 loads and resources were considered in isolation, was 500 MW; and the sum of the 6 states

1165 individual need for operating reserves was 1300 MW because losing the diversity of the
1166 system causes total reserve requirements to be higher. In that hypothetical, Utah would be
1167 allocated 38.4% of the actual cost for the 1000 MW of actual reserves required for the
1168 states. That is because $500 \text{ MW} / 1300 \text{ MW} = 38.4\%$. In other words, Utah would be
1169 allocated the fixed costs of 384 MW of the 1000 MW of capacity needed to provide
1170 operating reserves to the states.

1171 This calculation would be done on a plant-by-plant basis. Therefore, applying this
1172 hypothetical to the Lakeside 2 analysis above, Utah would be allocated approximately 29%
1173 of the \$10.2 million cost associated with the portion of Lakeside 2 allocated to the reserve
1174 pool. I reach that figure based on the assumption that the states need 83.3% of the reserve
1175 capacity ($1000 \text{ MW state reserve need} / 1300 \text{ MW total system reserve need}$ in this
1176 hypothetical) and Utah is allocated 38.4% of the state-allocation portion as shown above.
1177 Putting those together, $83.3\% \text{ times } 38.4\% \text{ equals } 29\%$ - Utah's share of the state-allocated
1178 portion of the facility used for reserves.

1179 **Q. HAVE YOU PERFORMED THIS CALCULATION FOR ALL RESERVES**
1180 **HOLDING RESOURCES?**

1181 A. No. This is for two reasons. First, in UTLCG Data Request 6.14, I requested RMP provide
1182 its most recent FERC reserves study. In response, RMP referenced a filing posted on the
1183 FERC website.⁴⁹ That filing, however, did not contain the reserves study that was used to
1184 calculate RMP's OATT ancillary service rates. It only contained a summary of the outputs
1185 from that study as a workpaper to the filing. Accordingly, it was not possible for me to
1186 perform a full illustration of the reallocation for purposes of my Direct Testimony. Again,

⁴⁹ Response to UTLCG Data Request 6.14 (provided in Exhibit BGM-2).

1187 my ability to analyze RMP's proposal and provide more durable alternative
1188 recommendations depends on the Company's provision of necessary data and analytics not
1189 otherwise publicly available. Second, that FERC analysis likely does not evaluate the level
1190 of reserve requirement for each state in isolation considering the state-specific loads and
1191 resources. That analysis would need to be done by the Company for this allocation
1192 approach to be implemented.

1193 **Q. WOULD THIS APPROACH CAUSE WASHINGTON AND OREGON RATES TO**
1194 **INCLUDE THE COSTS OF COAL AND GAS RESOURCES IN VIOLATION OF**
1195 **THE POLICIES IN THOSE STATES?**

1196 A. Perhaps and, as I am not an attorney, I am not opining on whether this approach would
1197 satisfy Washington and Oregon legal requirements. While the costs of all of the resources
1198 that are actually providing reserves for the system would be included in the calculation, the
1199 costs would also include the costs of hydroelectric and battery facilities. Thus, the blended
1200 cost I propose to be reallocated to the states could not be directly attributed to any specific
1201 type of generation resource. However, if this is an issue, the solution cannot be that Oregon
1202 and Washington continue to benefit, in reality, from these resources being dispatched to
1203 provide system reserves but without paying for those resources or, worse yet, causing
1204 customers in other states to pick up the tab. From my perspective, the UTLCG's proposed
1205 ancillary service methodology would represent a fair outcome for Utah ratepayers in terms
1206 of allocating the costs of the capacity necessary to provide operating reserves to Utah. If a
1207 different approach needs to be used in Oregon or Washington, that is between the Company
1208 and the regulators in those states. But what cannot occur is that the full costs of the coal

1209 and gas resources are only allocated to the east side states while those resources are used
1210 to provide operating reserves to both the east and west side customers in actual operations.

1211 **B. Resource Adequacy**

1212 **Q. WHY DOES RESOURCE ADEQUACY, ABOVE AND BEYOND ALLOCATING**
1213 **THE COSTS FOR OPERATING RESERVES NEED TO BE ADDRESSED IN THE**
1214 **NEW INTERJURISDICTIONAL ALLOCATION METHOD?**

1215 A. RMP has to plan its system to provide enough capacity to satisfy peak system loads,
1216 inclusive of a planning reserve margin. The planning reserve margin effectively represents
1217 a buffer against uncertainty in future loads and provides protection against unforeseen
1218 generation outages. Where states' policy decisions are causing those states to exit legacy
1219 thermal resources, and instead pursue portfolios with high penetrations of renewable
1220 resources, the result is that the resource adequacy provided by such states relative to their
1221 load requirements may be insufficient. Variable energy resources commonly only
1222 contribute a fraction of their energy output towards system capacity, with values ranging
1223 from 10-15%, while almost the entire nameplate of a thermal resource can contribute
1224 towards resource adequacy. Absent a method to address this inequity, it will result in
1225 several problems. First, the states with higher penetrations of renewables will be leaning
1226 on the capacity provided by other states, without paying the long-term fixed costs of those
1227 resources. Second, it will necessitate RMP investing in more-expensive types of capacity
1228 resources, such as batteries, or alternatively, require RMP to build more thermal resources,
1229 which it can only allocate to the states that are, from a policy perspective, willing to take
1230 cost responsibility for those resources. Absent a mechanism whereby each state takes
1231 responsibility for its own resource adequacy requirements, costs will be shifted to those

1232 states that have invested in resource adequacy and away from those that have not. And in
1233 fact, without addressing resource adequacy, states will have an incentive to include low-
1234 cost resources in their portfolio that provide little capacity, diminishing the reliability of
1235 the system.

1236 **Q. WHAT METHODS ARE AVAILABLE TO ADDRESS RESOURCE ADEQUACY**
1237 **IN INTERJURISDICTIONAL ALLOCATION?**

1238 A. Resource adequacy plays an important role in allocating costs in the context of organized
1239 markets. Typically, these programs involve each market participant making a resource
1240 adequacy showing that basically involves a comparison between the capacity of the entity's
1241 resources relative to its peak loads, plus a planning reserve margin. Subsequently, trading
1242 mechanisms are established whereby market participants are able to sell, to the extent that
1243 they are long, or purchase, to the extent that they are short, in order to show that they have
1244 enough resources to meet their planning reserve margins. Where a market participant fails
1245 to supply enough resources to meet its requirements, the market will impose penalties
1246 typically based on the cost of building a new capacity resource, the revenue from which is
1247 then allocated back to the other participants in the market.

1248 **Q. DO RESOURCE ADEQUACY MARKETS OR MECHANISMS EXIST IN THE**
1249 **WEST?**

1250 A. Yes. The WRAP is one such market that is scheduled to begin operation in 2027 to provide
1251 a voluntary mechanism to share and assign resource adequacy costs among participating
1252 utilities. Similarly, the CAISO also has a resource adequacy program meant to balance
1253 resource adequacy requirements of the entities participating in that market. RMP has
1254 ultimately decided not to participate in the WRAP, but some similar recognition of resource

1255 adequacy requirements of the individual states is nonetheless important in the context of
1256 interjurisdictional allocation.

1257 **Q. CAN A SIMILAR TYPE OF MARKET MECHANISM EXIST BETWEEN RMP'S**
1258 **STATE JURISDICTIONS?**

1259 A. Yes. One challenge in implementing such a mechanism in the context of interjurisdictional
1260 allocation is that most resource adequacy markets are driven by penalties that apply when
1261 a market participant does not meet its resource adequacy requirements. But in the case of
1262 PacifiCorp, this analysis is, typically, done on a company-wide or perhaps BAA wide-
1263 basis, not a state by state basis. Further, a state does not have the unilateral ability to impose
1264 a penalty on another state within an interjurisdictional allocation framework. Accordingly,
1265 implementing any such method would likely require some sort of agreement between the
1266 states to require that each state be resource adequate in isolation or a mechanism to transfer
1267 allocated costs between states that are long in resource adequacy and those that are short.

1268 **Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS ISSUE?**

1269 A. Resource adequacy is an issue that is challenging to address in state-by-state allocation
1270 proposals, particularly where PacifiCorp's engagement in different regional markets or
1271 capacity mechanisms is currently in a state of flux. Accordingly, I recommend that the
1272 Commission further order the Company to work with parties to propose a methodology to
1273 address the resource adequacy concerns associated with Oregon's and Washington's
1274 respective exits from capacity resources.

1275 **V. SUMMARY**

1276 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

1277 A. Fundamentally, I recommend that for all of the shortcomings in RMP's proposed 2026
1278 Protocol, the Commission reject the proposed NPC allocation framework and require that
1279 any rate case filing made prior to the implementation of a new cost allocation methodology
1280 contain its full analysis using the 2020 Protocol. Further, I recommend the Commission
1281 stay this case, or alternatively, open an investigatory or other docket and order the
1282 Company to engage in a collaborative process with the Utah parties, if not stakeholders
1283 from the Five States to provide needed analytics and develop a more durable framework.
1284 The Commission should establish a date certain (*e.g.*, August 31, 2026) by which a report
1285 on such framework is due. Importantly, for all the reasons I identify, such framework must
1286 be compatible with the EDAM and must include an approach that values ancillary services
1287 and resource adequacy that each state portfolio provides to the system. During this
1288 collaborative process, parties should be enabled to issue discovery for the purpose of
1289 investigating more robust methods and approaches for interjurisdictional allocation until
1290 such time as an EDAM-compatible framework is available.

1291 In the alternative, I recommend the Commission order a new allocation method in
1292 this case such as the Allocation Framework appended to UTLCG witness Mr. Larsen's
1293 testimony as Exhibit JKL-1. I also recommend that the Commission establish a method
1294 for allocating ancillary service costs between states through the establishment of a Reserves
1295 Pool that equitably allocates the embedded cost of capacity used to provide reserves
1296 services to the states that are using those services. Finally, in the longer term, the

1297 Commission should also consider an approach to address resource adequacy from a system
1298 planning perspective and potential long-term capacity leaning.

1299 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

1300 A. Yes.

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