

1 **Q. Please state your name, business address and present position with**
2 **PacifiCorp dba Rocky Mountain Power (“the Company”).**

3 A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah
4 Street, Suite 600, Portland, Oregon 97232. My present position is Director, Net
5 Power Costs.

6 **Qualifications**

7 **Q. Briefly describe your education and business experience.**

8 A. I received a degree in Mathematics from University of Washington in 1976 and a
9 Masters of Business Administration from University of Portland in 1979. I was
10 first employed by PacifiCorp in 1976 and have held various positions in resource
11 and transmission planning, regulation, resource acquisitions and trading. From
12 1997 through 2000 I lived in Australia where I managed the Energy Trading
13 Department for Powercor, a PacifiCorp subsidiary at that time. After returning to
14 Portland, I was involved in direct access issues in Oregon and was responsible for
15 directing the analytical effort for the Multi-State Process (“MSP”). Currently, I
16 direct the work of the load forecasting group, the net power cost group, and the
17 renewable compliance area.

18 **Purpose of Testimony**

19 **Q. What is the purpose of your testimony in this proceeding?**

20 A. I present the Company’s proposed net power costs (“NPC”) for the 12-month test
21 period ending June 30, 2015. Specifically, my testimony:

- 22 • Explains the calculation of NPC using the Company’s Generation and
23 Regulation Initiative Decision model (“GRID”) model;

- 24 • Describes the primary drivers behind the increase in NPC compared to NPC
25 included in the stipulation approved in the Company’s previous general rate
26 case, Docket No. 11-035-200 (“2012 GRC”);
- 27 • Describes changes the Company has made to the NPC study since the 2012
28 GRC, including updates to the Company’s resource portfolio as well as
29 improvements to the modeling of NPC;
- 30 • Discusses the Company’s proposed treatment of its participation in an energy
31 imbalance market (“EIM”) with the California Independent System Operator
32 (“CAISO”); and
- 33 • Proposes a process to update NPC during the course of this proceeding to
34 improve the accuracy of the Base NPC for energy balancing account (“EBA”)
35 filings while accommodating the needs of other parties to review and validate
36 the NPC updates.

37 **Summary of Net Power Costs**

38 **Q. Please explain the components making up NPC.**

39 A. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses
40 and wheeling expenses, less wholesale sales revenue.

41 **Q. What are the proposed system-wide NPC for the 12-month period ending
42 June 2015?**

43 A. The proposed NPC for the 12 months ending June 30, 2015, are \$1.522 billion on
44 a total Company basis, and \$641.1 million on a Utah-allocated basis. The
45 proposed NPC are approximately \$5.1 million (0.8 percent) higher than the 2012
46 GRC on a Utah-allocated basis.

47 **Determination of NPC and GRID Model Inputs and Outputs**

48 **Q. Please explain how the Company calculates NPC.**

49 A. NPC are calculated for a future test period based on projected data using GRID, a
50 production cost model that simulates the operation of the Company's power
51 system on an hourly basis.

52 **Q. Is the Company's general approach to the calculation of NPC using the**
53 **GRID model the same in this case as in previous cases?**

54 A. Yes. The Company has used the GRID model to determine NPC in its Utah
55 filings for several years.

56 **Q. Is the Company using the same version of the GRID model as used in its 2012**
57 **GRC?**

58 A. Yes.

59 **Q. What inputs were updated for this filing?**

60 A. All inputs have been updated since the 2012 GRC, including system load,
61 wholesale sales and purchase contracts for electricity, natural gas and wheeling,
62 market prices for electricity and natural gas, fuel expenses, and the characteristics
63 and availability of the Company's generation facilities. The transmission areas
64 within the GRID model topology are unchanged since the 2012 GRC, but the
65 transmission capacity between areas has been updated to reflect the Company's
66 transfer rights for the test period.

67 **Q. What reports does the GRID model produce?**

68 A. The major output from the GRID model is the NPC report. This is attached to my
69 testimony as Exhibit RMP___(GND-1). The GRID model also produces more

70 detailed reports in hourly, daily, monthly and annual formats by heavy-load hours
71 (“HLH”) and light-load hours (“LLH”).

72 **Q. Please generally describe the changes in NPC compared to the 2012 GRC.**

73 A. Table 1 below illustrates the change in NPC by category compared to the NPC
74 approved in the 2012 GRC.

Table 1		
Net Power Cost Reconciliation (\$millions)		
	Total Company	Utah Allocated
2012 General Rate Case	\$1,479.2	\$636.0
Increase/(Decrease) to NPC		
Wholesale Sales Revenue	\$106.2	\$47.7
Purchased Power Expense	\$(85.7)	\$(41.0)
Coal Fuel Expense	\$88.3	\$29.8
Natural Gas Fuel Expense	\$(76.7)	\$(36.0)
Wheeling, Hydro and Other Expense	\$10.6	\$4.5
Total Increase/(Decrease) to NPC	\$42.7	\$5.1
2014 General Rate Case	\$1,521.9	\$641.1

75 As shown in Table 1, while total-Company NPC are \$43 million (2.9 percent)
76 higher, on a Utah-allocated basis NPC in this case are only \$5 million (0.8
77 percent) higher than in the 2012 GRC. As described in the testimony of Company
78 witness Ms. Kelcey A. Brown, total system load remained relatively flat
79 compared to the 2012 GRC, but Utah jurisdictional load is lower than in the 2012
80 GRC, resulting in a lower percentage allocation of NPC using the dynamic load-
81 based allocation factors. Unless otherwise noted, references to net power costs or
82 various individual cost items are stated in Utah-allocated amounts.

83 On a Utah-allocated basis, the increase in NPC is the result of a decrease
84 in wholesale sales revenue of \$48 million, an increase in coal fuel expense of \$30
85 million, and an increase in wheeling and other expenses of \$5 million. These
86 increases are partially offset by a decrease in purchased power expense of \$41
87 million, and a decrease in natural gas fuel expense of \$36 million.

88 **Q. Did you calculate the impact to NPC if Naughton Unit 3 is not converted to**
89 **gas during the test period?**

90 A. Yes. As described in the direct testimony of Company witnesses Mr. Steven R.
91 McDougal and Mr. Chad A. Teply, the Company's filing is based on the
92 assumption that the Company will discontinue coal-fired generation at Naughton
93 Unit 3 at the end of 2014 and convert it to a gas-fired resource that will return to
94 operation in June 2015. A second NPC study has been prepared which
95 incorporates the assumption that coal-fired operation at Naughton Unit 3
96 continues through the test period. The revenue requirement impact of continuing
97 coal-fired generation is described in Mr. McDougal's direct testimony. Unless
98 otherwise indicated, the NPC results described in my testimony refer to the
99 scenario that assumes Naughton Unit 3 is converted to gas generation during the
100 test period.

101 **Discussion of Major Cost Drivers in NPC**

102 **Q. Please explain the reduction in wholesale sales revenue.**

103 A. The reduction in wholesale sales revenue is driven by the expiration of four long-
104 term sales contracts and reduced revenue from wholesale market sales. The 2012
105 GRC included approximately \$9.9 million from long-term sales to Nevada and

106 California utilities that expired at the end of 2012. In addition, the long term sale
107 to the Sacramento Municipal Utility District (“SMUD”) expires at the end of 2014
108 and is only included for six months in the current GRC, reducing wholesale sales
109 revenue by approximately \$1.5 million.

110 Revenue from market transactions (represented in GRID as short-term
111 firm and system balancing sales) is approximately \$35.0 million lower than in the
112 2012 GRC. The drop in revenue is due mainly to reduced volume of forward
113 market sales, partially offset by a rise in wholesale market prices. Market sales
114 transactions in the 2012 GRC were included at an average price of \$32.44/MWh,
115 while market sales in the current case are included at an average price of
116 \$33.62/MWh.

117 **Q. Has the Company also seen a decrease in purchased power expense?**

118 A. Yes. Similar to wholesale sales, the reduction in purchased power expense is
119 driven by the expiration of several long-term purchase contracts and reduced
120 expenses related to wholesale market purchases. The 2012 GRC included
121 approximately \$6.1 million for the West Valley tolling agreement, Kennecott
122 generation incentive, Grant County 10 aMW purchase, and Cargill exchange, all
123 of which have now expired. In addition, three large qualifying facilities (“QFs”)
124 that were previously included are not expected to provide generation in the test
125 period, reducing purchased power expense approximately \$5.7 million. The
126 reduction in long-term purchased power expense is partially offset by additional
127 expenses related to a new seasonal purchase contract and purchases from QFs.
128 Further details regarding the changes in contracts are provided later in my

129 testimony.

130 Expenses from market transactions (represented in GRID as short-term
131 firm and system balancing purchases) are approximately \$37.4 million lower than
132 in the 2012 GRC. The drop in expense is due mainly to reduced volume of
133 forward market purchases, partially offset by the impact of higher wholesale
134 market prices. Market purchase transactions in the 2012 GRC were included at an
135 average price of \$27.13/MWh, while market purchases in the current case are
136 included at an average price of \$28.44/MWh.

137 **Q. Please explain the increase in coal expenses in the current proceeding.**

138 A. The increase in coal fuel expense is driven by higher prices for coal during the
139 Test Period. Price increases are reflected in both the costs of third-party coal
140 supply and cost increases at the Company's captive mines. Details on coal price
141 changes are provided in the direct testimony of Company witness Ms. Cindy A.
142 Crane.

143 Generation output from the Company's coal-fired thermal plants is higher
144 than in the 2012 GRC, despite the conversion of Naughton Unit 3 to gas in 2015
145 and the retirement of the Carbon plant in April 2015. Due to the termination of
146 coal-fired operation at Naughton Unit 3 in December 2014, generation at the
147 Naughton plant is lower than the 2012 GRC by approximately 1,225 GWh. The
148 removal of the Carbon units from service in April 2015 causes generation at that
149 plant to be approximately 137 GWh lower than the 2012 GRC. Excluding these
150 reductions, the Company coal generation is approximately 1,600 GWh higher
151 than the 2012 GRC. This increase in generation output reflects the increase in

152 market prices since the prior test period, as there are more periods in which coal
153 generation is more economic than market purchases.

154 **Q. Please discuss the drop in natural gas fuel expense since the 2012 GRC.**

155 A. The reduction in natural gas fuel expense is driven by lower generation volume
156 and a lower average cost of natural gas. The Company's gas generation declined
157 by 688 GWh, primarily due to the removal of the "must run" requirements for the
158 Carrant Creek plant and the Gadsby combustion turbines, partially offset by the
159 addition of the Lake Side 2 plant. The average cost of natural gas generation
160 decreased from \$40.99 per MWh in the 2012 GRC to \$35.38 per MWh in the
161 current case.

162 **Q. Please describe the increase in the wheeling, hydro, and other expense**
163 **category.**

164 A. Expenses in this category are higher due to an increase in wheeling expense
165 resulting from the Bonneville Power Administration ("BPA") 2014 Wholesale
166 Power and Transmission Rate Adjustment Proceeding. Effective October 2013,
167 the Company's wheeling expenses paid to BPA increased by approximately 13
168 percent.

169 **Changes to the Company's Resource Portfolio**

170 **Q. Have changes been made to the modeling of the Company's resources since**
171 **the 2012 GRC?**

172 A. Yes. The Company's modeling incorporates a number of resource changes to
173 account for operational differences between the 2012 GRC and the end of the test
174 period in this case.

- 175 • *Lake Side 2* - The Lake Side 2 plant is expected to begin commercial
176 operation by June 2014, prior to the start of the test period.
- 177 • *Carbon Termination* - The Carbon plant is expected to terminate in April
178 2015.
- 179 • *Naughton 3 Gas Conversion* - Naughton Unit 3 is expected to be removed
180 from service as a coal plant in January 2015 and returned to service as a gas
181 plant in June 2015.
- 182 • *Chehalis Reserves* - Transmission system upgrades necessary to dynamically
183 transfer the Chehalis plant into the Company's PACW balancing authority
184 area were completed in November 2013. As a result, the Chehalis plant is now
185 modeled with reserve-carrying capability throughout the test period, reducing
186 the need for holding reserves on lower cost resources in the Company's west
187 balancing authority area ("PACW"), such as the Jim Bridger plant. In
188 previous cases it was suggested that the Chehalis plant should be modeled
189 with reserve-carrying capability, but at that time, it was not possible for the
190 Company to carry reserves with this plant.
- 191 • *Goodnoe Hills and Leaning Juniper Balancing Area Transfer* - Transmission
192 system upgrades necessary to dynamically transfer the Goodnoe Hills and
193 Leaning Juniper plants into the Company's PACW balancing authority area
194 were completed in April 2013. As a result the Company now provides the
195 regulation and contingency reserves for these plants rather than purchasing
196 them from BPA. The regulation cost was previously included in wheeling

197 expense. The contingency reserve expense was previously included in the
198 purchase power section of NPC under the label “BPA Reserve Purchase”.

199 • *Leaning Juniper Output and Revenue* - The Company will receive a small
200 amount of revenue associated with the Company’s Leaning Juniper facility
201 due to a contract unique to that wind project. As a result of the contract,
202 output at Leaning Juniper is forecast at a slightly reduced level. A confidential
203 copy of the executed contract is provided as part of the filing requirements
204 accompanying the Company’s case and a confidential summary of the
205 contract is provided with the testimony of Ms. Stacey J. Kusters as
206 Confidential Exhibit RMP____(SJK-6).

207 • *St. Anthony Hydro* - The St. Anthony hydro facility in Idaho had been out of
208 service for a number of years and selling the facility was determined to be the
209 most cost-effective path forward. The sale was recently completed, and
210 following the completion of repairs, the new owner will operate the plant as a
211 QF and sell the output to the Company. The project is expected to reach
212 commercial operation prior to the start of the test period.

213 • *Thermal Upgrades/Environmental Controls* - Environmental upgrades at the
214 Hunter and Hayden plants will reduce plant capacity at Hunter 1 in May 2014
215 and at Hayden 1 in May 2015. Further details on these capital projects are
216 provided in the direct testimony of Company witness Chad A. Teply.

217 In addition to the specific changes listed above, the Company has updated the
218 operating characteristics of its generation fleet and incorporated historical
219 operating data through the base period of June 2013.

220 **Q. Have there been changes to the Company's long-term purchase and sale**
221 **contracts since the 2012 GRC?**

222 A. Yes. As described earlier, several long-term purchase and sale contracts that were
223 included in the 2012 GRC have been terminated or will expire by the end of the
224 test period in this case, including:

- 225 • The long-term sales agreement with SMUD expires December 2014.
- 226 • Three sales agreements providing energy and renewable energy credits to
227 Pacific Gas & Electric, Southern California Edison, and Nevada Energy
228 expired December 2012.
- 229 • A 10-average megawatt purchase from Grant County Public Utility District
230 expired August 2012.
- 231 • A tolling agreement for the output of the West Valley generating station
232 expired December 2013.
- 233 • The Pioneer Wind Park II QF contract was terminated due to failure to
234 achieve commercial operation.
- 235 • Existing QF contracts with US Magnesium and SF Phosphates expired
236 December 2012 and December 2013, respectively. Under the previous
237 agreements these customers sold their QF output to the Company as a buy-all,
238 sell-all arrangement, but going forward they are expected to use the generation
239 to first offset retail load.
- 240 • Exchange agreements with Shell and Cargill which provided power deliveries
241 close to the Company's loads during the summer peak terminated in
242 September 2012 and September 2013, respectively.

- 243 • Exchange agreements with BPA and Public Service Company of Colorado
244 (“PSCo”) for integration and delivery of the output of Foote Creek II and III
245 will expire in July 2014 and September 2014, respectively.
- 246 • The Kennecott Generation Incentive agreement terminated in December 2012.
247 The Company has also entered into several new long-term purchase and sale
248 agreements, including:
- 249 • A 13 month sale to Shell with deliveries through August 2014. This contract
250 included an option for the Company to extend deliveries through the end of
251 2014.
- 252 • A seasonal purchase from Constellation for 2013 through 2016, which helps
253 ensure the Company will have sufficient resources to meet peak requirements.
- 254 • A QF contract with Latigo Wind Park for a new wind facility in Utah.
- 255 • A QF contract with OM Power I for a new geothermal facility in Oregon.
- 256 • Various other small QF contracts, including four new solar facilities in Utah
257 receiving Schedule 37 prices.

258 **Q. Did the Company extend any contracts in its NPC study that are scheduled**
259 **to expire during the Test Period?**

260 A. Yes. Several existing QF contracts terminate prior to the end of the Test Period
261 and the Company has assumed that these customers will enter contracts to
262 continue selling to the Company at the most recent avoided cost rates. In addition,
263 the Company assumed the existing contract with US Magnesium for operating
264 reserves would be renewed after it expires in December 2014. The Company
265 anticipates updating NPC in this proceeding as more information becomes

266 available.

267 **Q. Does this case include the natural gas contracts executed as a result of the**
268 **Company's 2012 Natural Gas Request for Proposals?**

269 A. Yes. The Company has entered into two gas swap transactions as a result of the
270 Company's 2012 Natural Gas Request for Proposals ("2012 Gas RFP"). The 2012
271 Gas RFP was filed with the Utah Public Service Commission ("Commission") in
272 Docket No. 12-035-102. On April 19, 2013, the Commission issued an order
273 approving a stipulation recommending pre-approval of the long-term natural gas
274 contract with pricing that yields a market ratio¹ at or below 100 percent and meets
275 explicit price parameters.²

276 **Q. Please outline the material provisions of the stipulation relating to**
277 **transactions from the 2012 Gas RFP.**

278 A. Under the stipulation, the parties agreed that the Company would seek to secure
279 [REDACTED]
280 [REDACTED] whichever is priced more favorably to
281 market. [REDACTED]
282 [REDACTED] The
283 Company agreed to execute only if the transaction: (1) meets the Company's
284 internal credit quality requirements; and (2) has refreshed pricing that yields a
285 market ratio below 100 percent calculated from the Company's forward price

¹A market ratio is a cost-to-value ratio, in which "cost" is the numerator and "value" is the denominator. The "cost" is the bid price. The market "value" of a bid is assessed as a part of the RFP bid evaluation process. Both "cost" and "value" are levelized over the term of the bid in the equation. A lower market ratio reflects a more attractive product. The market ratio provides a comparison between bids with different terms, location of natural gas supply, delivery, settlement, and product type.

²*In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Acquire Natural Gas Resources*, Docket No. 12-035-102, Report and Order (April 19, 2013).

286 curve. The stipulation also dictated a pricing structure with prices for the first two
287 years aligned with current market prices [REDACTED]
288 [REDACTED] In August 2013 the Company executed two [REDACTED] contracts with J.
289 Aron for a total volume of [REDACTED]. Both contracts met the price
290 parameters and market ratio specified in the stipulation. Confidential copies of the
291 executed contracts are provided as part of the filing requirements accompanying
292 the Company's case.

293 **GRID Modeling Improvements**

294 **Q. Has the Company modified its modeling to address any contested issues from**
295 **the 2012 GRC?**

296 A. Yes. In response to issues raised by parties in the Company's 2012 GRC, the
297 Company refined the following inputs to GRID:

- 298 • *Market Capacity* - Sales restrictions on the Mid-Columbia and Palo Verde
299 markets have been removed. The remaining markets continue to be limited by
300 caps on wholesale sales based on the four-year average historical short term
301 firm transactions, broken down by market, month and hour class. The
302 Company's market capacity methodology is discussed in further detail later in
303 my testimony.
- 304 • *"Must Run" Gas Plant Operation* - The 2012 Wind Study did not have
305 resource-specific reserve requirements for Currant Creek and the Gadsby
306 combustion turbines so these plants are now dispatched based on economics,
307 rather than forced online to provide reserves. The 2012 Wind Study and its
308 impact on integration costs in this case are discussed later in my testimony.

309 • *Chehalis Reserves* - As mentioned previously, the transmission system
310 upgrades necessary to dynamically transfer the Chehalis plant into PACW
311 were completed in November 2013. As a result, the Chehalis plant is now
312 modeled with reserve-carrying capability throughout the test period.

313 • *Hydro Forced Outage Rates* - In the current case, the availability of hydro
314 units with storage capability has been normalized to reflect forced outage
315 levels by making a flat percentage reduction in capacity across all hours of the
316 period, a method similar to that used for thermal units. The reductions to plant
317 capacity are based on the outages from the same 48-month historical period
318 used for thermal plants in this case. An additional adjustment to reflect energy
319 lost due to forced outages is made to hydro generation based on historical
320 measurements which began in January 2011. Adjusting for lost energy based
321 on historical measurements captures the flexibility of hydro projects with
322 storage capability to shift generation around outages, while accounting for the
323 operating constraints that may prevent such shifts under certain circumstances.

324 In past cases parties have also challenged the costs related to the DC Intertie
325 transmission contract between the Company and BPA. The Company continues to
326 include the DC Intertie rights in the GRID model, along with the annual wheeling
327 expense. Later in my testimony I provide additional evidence supporting the
328 continued inclusion of this contract in customers' rates.

329 **Q. Has the Company made any changes to improve the accuracy of its NPC**
330 **modeling?**

331 A. Yes. The Company has made various updates to the GRID inputs in order to

332 increase the accuracy of the forecasted NPC, including:

333 • *Wind Generation Shape* - In previous proceedings, wind generation has been
334 based on a P50 forecast, a projection of generation developed through third-
335 party analysis that is expected to have an equal probability of being higher or
336 lower than actual output over time. For modeling purposes in past cases the
337 Company divided the generation into six four-hour blocks per day for each
338 month. All of the hours within a given four-hour block in a month had the
339 same expected energy, creating a flat profile in GRID with very little
340 variation. In this case, the Company has employed a wind shaping
341 methodology that scales actual generation data into an hourly shape that
342 retains the overall energy from the P50 generation estimate. Further details on
343 the wind shaping methodology and how it improves the accuracy of NPC
344 modeling are provided later in my testimony.

345 • *Integration Costs* - The Company's wind integration costs are now based on
346 the 2012 Wind Study released in April 2013 as Appendix H to the Company's
347 2013 Integrated Resource Plan.³ The 2012 Wind Study indicates that the
348 estimated cost of wind integration has declined, primarily because of lower
349 forecast natural gas and power market prices. Further details regarding
350 integration costs in the test period are provided later in my testimony.

351 • *CAISO Fees* - Since January 1, 2013, when California's carbon cap and trade
352 program took effect, electricity imported into California results in a carbon
353 emissions allowance obligation. As a result, the Company has not sold power

³www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacificCorp-2013IRP_Vol2-Appendices_4-30-13.pdf.

354 to the CAISO since that time. Previously, the Company included CAISO sales
355 volumes and wheeling expense based on the 12-month historical period. To
356 align with the recent change in operating practice, the sales volumes and
357 associated wheeling expense have been removed from the test period in this
358 case.

359 **GRID Modeling Improvements - Market Capacity**

360 **Q. Please explain why the Company specifies market capacity limits, a.k.a.**
361 **market caps, in GRID.**

362 A. The GRID model automatically assumes unlimited market depth bound only by
363 the Company's transmission constraints for system balancing sales and purchases;
364 it does not account for load requirements or market illiquidity that would not
365 allow the Company to make sales at a static forecast market price. The
366 Company's transmission access to a market point limits its ability to sell its
367 generation in that market; similarly, counterparties' demand for purchases is
368 limited by their transmission access and their own load and resource balance.
369 Without market caps, the GRID model has no constraints to reflect counterparties'
370 inability to make economic transactions. While market caps have been an input to
371 GRID since its inception, the current method for calculating the caps was put in
372 place in the Company's 2010 general rate case, Docket No. 10-035-124. In the
373 current case, the Company has removed the market caps from the Mid-Columbia
374 and Palo Verde markets.

375 **Q. How are the market caps calculated?**

376 A. For each market, the allowable level of wholesale sales is specified for all hours

377 based on a four-year historical average of both spot and short-term firm wholesale
378 sales transactions, aggregated by month and HLH/LLH periods. In this case the
379 four-year historical average has been updated to the period ending June 2013.

380 **Q. Please further explain the static assumptions of market prices in GRID.**

381 A. The Company's official forward price curve ("OFPC") produces an hourly price
382 that remains static in GRID in each hour, regardless of the changes in load and
383 resource balance. The driving force behind market prices in real-time is based on
384 the dispatch cost of additional generation; therefore, an increase in load or
385 reduction in resources will require that higher cost resources be dispatched, or
386 vice versa. In reality, prices are impacted by changes in the loads and resources of
387 all market participants, including the Company. Without market caps the GRID
388 model will overestimate sales revenues as it continues to make sales at the static
389 hourly market price, even though additional sales would push market prices
390 down.

391 **Q. Why has the Company removed the market caps from the Mid-Columbia
392 and Palo Verde markets?**

393 A. Market caps have been challenged in the past several general rate cases where
394 parties have argued to remove all market caps. The Company proposes to remove
395 market caps at Mid-Columbia and Palo Verde as a compromise position since
396 these two markets are the most liquid market points to which the Company has
397 access. These markets both have many participants and are often used to balance
398 the Company's load and resource position on a forward basis. This is not the case
399 with the other market hub in GRID. As a result, the Company's historical sales at

400 these markets may be more strongly aligned with the Company's resource
401 position, rather than the position of the other counterparties in the market, as
402 would be the case in the less liquid markets.

403 Furthermore, the short-term firm sales volume upon which market caps
404 are based has been declining over time which has lowered the market caps. In past
405 cases, the caps at the Mid-Columbia and Palo Verde markets exceeded the
406 transmission capability and forward transaction position at these markets in all
407 hours and had no impact on the model outcome. With the updated historical
408 volume, the caps at these two markets would be lower than the transmission
409 capability and forward transaction position and would restrict the GRID model's
410 ability to transact at these two most liquid markets, counter to operational reality.

411 With the caps on Mid-Columbia and Palo Verde removed, the GRID
412 model has more flexibility to sell in these markets, better reflecting the
413 Company's actual operating potential.

414 **Q. Did the Company change the calculation of the market caps for the**
415 **remaining four markets modeled in GRID?**

416 A. No. The market caps remain intact for the COB, Four Corners, Mona, and Mead
417 markets. These markets are less liquid and the GRID model must continue to have
418 constraints on the transactions that can occur at these markets. As discussed
419 above, GRID will assume unlimited market depth if market caps are not in place.

420 **GRID Modeling Improvements - Wind Generation Shape**

421 **Q. Please explain how the Company models wind generation in GRID.**

422 A. Total energy from wind generation is included in GRID based on a "P50"

423 forecast. A P50 forecast projects generation at a level that is expected to have an
424 equal probability of being higher or lower than actual output. Typically such a
425 forecast is developed by a third party for an individual wind project by combining
426 wind speed measurements taken prior to the project being constructed with a
427 detailed model of turbine locations and performance characteristics. The projected
428 output in a given hour is then averaged across each month to develop a 12 month
429 by 24 hour matrix of average hourly output. The Company previously input wind
430 generation into GRID using the P50 forecast divided into six four-hour blocks per
431 day. Generation was flat over each four-hour block, and each period was the same
432 for every day during a month. Consequently, the wind generation in GRID
433 exhibited very little variation which is not consistent with operational reality.

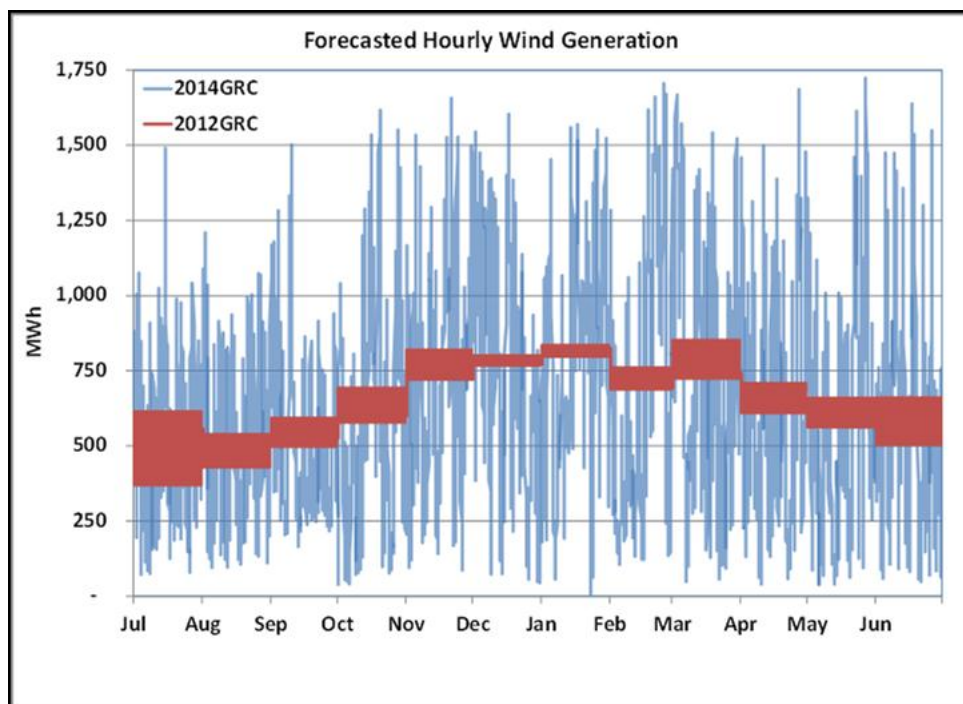
434 In this case, the Company continued to use the P50 forecast to determine
435 total wind generation, but utilized the actual 2012 energy output data from the
436 Company's owned and purchased wind facilities to shape hourly wind generation
437 profiles. The Company scaled actual generation levels up or down so that, when
438 the output within the traditional four-hour blocks is averaged over the course of a
439 month, it is the same as in the P50 forecast. In other words, the total energy output
440 of the wind facilities is the same as the P50 forecast energy output used in
441 previous cases, but the shape of the generation varies on an hourly basis
442 consistent with actual output during 2012.

443 **Q. Why did the Company refine the modeling of its hourly wind profiles to**
444 **reflect historical performance?**

445 A. The Company refined its modeling to improve the accuracy of its NPC forecast,

446 using the most recent reliable data available to develop wind profiles that capture
447 the volatility of wind generation in forecast NPC. Figure 1 below illustrates the
448 difference in the two approaches to developing wind generation profiles. The
449 darker line with smooth step changes represents the previous wind inputs using
450 four-hour blocks. The highly variable line represents the wind inputs that vary
451 hourly based on historical volatility, with the same total wind generation volume
452 as the P50 forecast.

453 **Figure 1**



454 Clearly, an average wind generation forecast shaped over flat four-hour blocks
455 does not capture the actual variability associated with wind generation on the
456 Company's system. Applying the 2012 actual wind generation pattern to the total
457 P50 volumes improves the accuracy of forecasted NPC by capturing more of the
458 cost impacts associated with intermittent wind generation on an hourly basis using
459 the most recent data available.

460 **Q. Why did the Company use a single year, in this case 2012, to derive an hourly**
461 **shape for wind energy?**

462 A. The Company used 2012 data because it represents the most recent calendar year
463 data available at the time of the filing. The use of prior periods would prevent
464 consistent hourly shaping across the Company's wind portfolio, as projects that
465 came online more recently would not have data available from earlier periods.

466 **Q. Is there evidence that the Company's wind shaping methodology based on a**
467 **single year is appropriate?**

468 A. Yes. A technical report published by the National Renewable Energy Laboratory
469 ("NREL")⁴ examined the variability in wind generation over various lengths of
470 time. The report found that "one can expect relatively large inter-annual changes",
471 but "for even shorter-term variations, such as power level from one hour to the
472 next, changes of wind power levels become a stochastic process with a very
473 narrow range of standard deviation values around its respective mean... when
474 those mean and standard deviation values are expressed in terms of the installed
475 capacity of the WPPs⁵, they are almost constant on an annual basis... It can be
476 concluded that short-term wind power fluctuations do not exhibit year-to-year
477 variability."⁶

478 **Q. What does this mean with regard to the Company's wind shaping**
479 **methodology?**

480 A. The Company's methodology ensures that average monthly energy output in each

⁴*Long-Term Wind Power Variability*. Y. H. Wan. Technical Report, NREL/TP-5500-53637. Retrieved online at <http://www.nrel.gov/docs/fy12osti/53637.pdf>.

⁵WPP is an acronym for Wind Power Plant as by NREL.

⁶*Id.*

481 four-hour block remains at the P50 forecast, so it will not result in inter-annual
482 changes in output. Because short-term wind power fluctuations are not expected
483 to vary significantly from year to year, the use of the most recent year will not
484 have significant differences in variability compared to other years.

485 **Q. Has the Company prepared an analysis of the variability of its wind plants**
486 **similar to the analysis presented in the NREL report?**

487 A. Yes. In its study, NREL calculated the coefficient of variation (“COV”), defined
488 as the ratio of standard deviation value to plant nameplate capacity, to gauge the
489 short-term variability of wind generation. The Company applied this same
490 calculation on four of its own wind resources. Table 2 below shows that the COV
491 of the Foote Creek, Wolverine Creek, Goodnoe Hills, and Leaning Juniper wind
492 plants is fairly consistent over time. It also shows that the variability in the
493 Company’s revised modeling is much closer to the historical levels.

Table 2
Yearly COV Value of Yearly Wind Power
(Normalized to Plant Name Plate Capacity)

Year	Leaning Juniper	Goodnoe Hills	Wolverine Creek	Foote Creek 1
2001				0.28
2002				0.26
2003				0.32
2004				0.33
2005				0.33
2006				0.33
2007			0.27	0.30
2008	0.36		0.30	0.30
2009	0.35	0.32	0.29	0.23
2010	0.32	0.29	0.29	0.24
2011	0.31	0.30	0.32	0.31
2012	0.28	0.30	0.31	0.27
Average	0.32	0.30	0.30	0.29
Previous Methodology	0.11	0.11	0.08	0.13
Revised Methodology	0.27	0.29	0.28	0.27

494 **GRID Modeling Improvements - Integration Costs**

495 **Q. Has the Company updated its modeling of wind integration costs?**

496 A. Yes. The Company's wind integration costs are now based on the 2012 Wind
 497 Study released in April 2013 as Appendix H to the Company's 2013 Integrated
 498 Resource Plan. The 2012 Wind Study is the result of an extensive public process
 499 that received guidance from a Technical Review Committee that included
 500 numerous subject-matter experts. The 2012 Wind Study indicates that the
 501 estimated cost of wind integration has declined, primarily because of lower
 502 forecast natural gas and power market prices.

503 **Q. How has the modeling of wind integration changed as a result of the 2012**
 504 **Wind Study?**

505 A. There are three modeling changes compared with the 2012 GRC:

- 506 • The reserve requirements included in the GRID model have been updated
507 reflect the results of the 2012 Wind Study, with adjustments to integrate all
508 additional wind capacity that will be online during the test period, including
509 the Leaning Juniper and Goodnoe Hills plants that will be transferred to
510 PACW.
- 511 • The “must run” settings for Currant Creek and the Gadsby combustion
512 turbines have been removed and these plants are dispatched based on
513 economics.
- 514 • The inter-hour integration costs for load and wind have been updated.

515 **Q. What level of reserves is included in the current case as a result of the 2012**
516 **Wind Study?**

517 A. The 2012 Wind Study concludes that an average of 579 MW of reserves were
518 necessary on the Company’s system in calendar year 2011 to integrate load and
519 2,126 MW of wind capacity. This case includes an average of 616 MW of
520 regulating reserves to integrate load and 2,563 MW of wind capacity.

521 **Q. What are the resulting integration costs included in NPC?**

522 A. The cost of integrating wind generation in the test period is approximately
523 \$2.03/MWh. In the 2012 GRC the cost of integrating wind generation was
524 approximately \$3.44/MWh.

525 **Q. Why have wind integration costs declined since the prior case?**

526 A. Four factors contribute to lower wind integration costs in the test period. First, the
527 inter-hour wind integration expense in the 2012 Wind Study is lower than in the
528 2010 Wind Study. Second, the removal of the “must run” settings for Currant

529 Creek and the Gadsby combustion turbines allows other units to provide
530 generation and/or reserves at lower cost. Third, the addition of the Lake Side 2
531 plant increases the reserve holding capability of the Company's fleet and holds
532 reserves that would otherwise be held on lower cost resources. Finally, the
533 regulating reserve requirement for a given quantity of wind is lower in the 2012
534 Wind Study compared to the 2010 Wind Study. The prior rate case had 9.6 MW
535 of regulating reserves for each 100 MW of wind capacity, while the current case
536 has 8.3 MW of regulating reserves for each 100 MW of wind capacity.

537 **Q. Has the Company included the costs associated with integrating the non-**
538 **owned wind generation in the Company's balancing authority areas?**

539 A. Yes. The Company is required by federal law to provide wind integration services
540 to its wholesale customers on a non-discriminatory basis. Therefore, the Company
541 continues to believe it is appropriate to reflect these costs in rates as prudent and
542 necessary costs associated with operating its system.

543 **Q. Does the Company's case include the revenues associated with integrating**
544 **the non-owned wind generation in the Company's balancing authority areas?**

545 A. Yes. Schedules 3 and 3A of PacifiCorp Transmission's Open Access
546 Transmission Tariff ("OATT") specify the rates for Regulation and Frequency
547 Response Service for network customers and generators that transfer their output
548 off-system, respectively. These OATT revenues are not part of NPC, but are
549 credited against the revenue requirement as wheeling revenue. This revenue is
550 also a component of the EBA costs that are trued-up in the annual EBA filings.

551 **Q. Does this case include costs for integrating solar resources in the Company's**
552 **balancing authority areas?**

553 A. Yes. In Docket No. 12-035-100⁷ the Commission recently determined that the
554 cost of integrating solar resources should be set at a certain portion of wind
555 integration costs until the Company performs a solar integration study. Per the
556 Commission's order, solar integration costs are set at \$2.18/MWh for tracking
557 solar resources, and \$2.83/MWh for fixed solar resources. In this case the
558 Company applied these costs to the generation from five small solar QFs, located
559 in Utah, which will be online during the test period.

560 **GRID Modeling Improvements - DC Intertie**

561 **Q. Please provide background on the DC Intertie contract.**

562 A. In anticipation of the expansion of the Alternating Current ("AC") Intertie to
563 4,800 MW, PacifiCorp and the Bonneville Power Administration ("BPA")
564 reached a settlement of outstanding issues about the right to use the AC and DC
565 Interties and the Midpoint-Medford transmission line. The settlement was
566 documented in a Letter of Understanding ("LOU") which was executed on May
567 28, 1993. A copy of the LOU is provided as Exhibit RMP____(GND-2).⁸ As a
568 result of the LOU, PacifiCorp received 400 MW of bidirectional rights on the AC
569 Intertie, priority rights to an additional 125 MW of southbound transmission, four
570 additional delivery points to the AC Intertie, and 200 MW of northbound rights on
571 the DC Intertie. BPA received rights to up to 400 MW of eastbound transmission

⁷*In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts*, Docket No. 12-035-100, Report and Order (August 16, 2013).

⁸Although the LOU is marked "Confidential," the Company is not asserting that this document is confidential in this docket.

572 on PacifiCorp's Summer Lake-Midpoint line, rights to certain PacifiCorp
573 transmission, and the option to take energy under spring and summer exchanges.
574 The agreement states that the DC Intertie contract term will be equal to the term
575 of the AC Intertie agreement, and that the AC Intertie agreement is extended for
576 the life of the facilities it covers. These rights are functionally equivalent to
577 ownership. Consistent with the LOU, the DC Intertie contract was executed on
578 May 26, 1994.

579 **Q. Why is this background important?**

580 A. It is important because under the LOU, BPA and PacifiCorp agreed that the
581 provisions of the LOU are interdependent and not severable. In other words, an
582 analysis of the DC Intertie cannot be conducted without addressing all of the other
583 rights and obligations PacifiCorp signed up to in the LOU.

584 **Q. What benefits do customers receive from the DC Intertie?**

585 A. The DC Intertie is a valuable transmission asset to the Company and its
586 customers. The contract provides a means to secure capacity and energy from
587 California sources in order to reliably meet retail loads. The transmission rights
588 take advantage of the load diversity between summer-peaking California and the
589 winter-peaking Pacific Northwest and represent an integral piece of the
590 transmission network for maintaining reliability in PACW. The DC Intertie
591 contract is the only PacifiCorp contract that provides firm import rights from the
592 Nevada-Oregon Border ("NOB") market, thereby providing unique market
593 diversity to the Company for the benefit of retail customers.

594 **Q. Is the cost of the DC Intertie out of line with the cost of other transmission?**

595 A. No. For example, point-to-point transmission service under the Company's
596 OATT, including scheduling, costs approximately \$2.20 per KW-month, and the
597 cost of the DC Intertie is approximately \$1.95 per KW-month.

598 **Q. Does the DC Intertie have other value that is not captured by the GRID**
599 **model?**

600 A. Yes. The Company's 2013 IRP relies on market capacity from the DC Intertie
601 and the NOB market to serve peak load. Between 2013 and 2032, the Company's
602 2013 IRP preferred portfolio selected 100 MW of front office transactions from
603 the NOB market annually to reliably meet its retail loads. If the DC Intertie was
604 not available in the IRP, the Company would be required to acquire capacity
605 from another source. An analysis completed using the Company's IRP models
606 with and without the DC Intertie capacity shows higher system costs if the DC
607 Intertie is excluded, with the 20-year present value revenue requirement
608 differential benefit of the DC Intertie exceeding \$85 million.

609 **Q. Is it true that termination of the DC Intertie contract is tied to the AC**
610 **Intertie agreement with BPA?**

611 A. Yes. Consistent with the LOU, the life of the DC Intertie contract is tied to the AC
612 Intertie agreement and the life of the underlying facilities. The ability to terminate
613 the DC Intertie contract is tied to termination of the Company's AC Intertie
614 agreement. If this were to occur, the Company would no longer have the ability to
615 sell wholesale power over the AC Intertie. This outcome would certainly increase
616 NPC.

617 **Q. Does the LOU support that the DC Intertie contract was prudent when**
618 **executed and that it also provides benefits to the Company's customers**
619 **today?**

620 A. Yes. The LOU illustrates that the DC Intertie is an integral piece of the
621 transmission network in PACW for meeting load and providing access to
622 wholesale power over the DC Intertie as well as the AC Intertie.

623 **Energy Imbalance Market**

624 **Q. Please describe the EIM and how it will impact NPC.**

625 A. As proposed, the EIM is a balancing market that optimizes generator dispatch
626 every five minutes within and between the PacifiCorp and CAISO balancing
627 authority areas ("BAAs"). The EIM will allow for more reliable and lower cost
628 operation than is possible with the bilateral hourly market transactions currently
629 available to the Company. An implementation agreement was approved by the
630 Federal Energy Regulatory Commission ("FERC") effective July 1, 2013, and the
631 EIM is targeted to begin (1) operation with PacifiCorp's east BAA ("PACE") and
632 PACW, and (2) participation in the market with the CAISO BAAs, October 1,
633 2014. Participation in the EIM is expected to produce benefits to customers in the
634 form of reduced net power costs, partially offset by costs for initial startup and
635 ongoing operation.

636 **Q. Have the net benefits of EIM participation been identified?**

637 A. Yes; however, because the EIM market design is ongoing, the projected benefits
638 and costs are highly uncertain at this time. The potential benefits of the EIM were
639 analyzed by Energy and Environmental Economics, Inc. ("E3") in a report dated

640 March 13, 2013⁹ E3 identified that the creation of the EIM would produce four
641 principal benefits: interregional dispatch savings, intraregional dispatch savings,
642 reduced flexibility reserves, and reduced renewable energy curtailment
643 (applicable only to CAISO). The projected value of these benefits attributed to the
644 Company is sensitive to modeling assumptions and varies over a wide range.

645 Costs of EIM participation include a one-time charge for the CAISO to
646 expand its network model, plus capital costs and ongoing operation and
647 maintenance (“O&M”) costs. Ongoing O&M expenses fall into two general
648 categories: variable fees paid to CAISO, and O&M related to additional
649 headcount and IT systems and support. Variable fees paid to CAISO consist of a
650 new administrative fee based on actual transactions executed as part of the EIM
651 and additional market charges incurred when doing business with CAISO.

652 **Q. Have you included the EIM costs and benefits in this case?**

653 A. No. Due to the uncertainty surrounding the level of benefits that will be achieved
654 and the costs that will be incurred, particularly in the early stages of EIM
655 operation, the Company has not included the impact of the EIM in this case.

656 **Q. If the EIM achieves commercial operation in October 2014 as planned, how
657 should the net benefits be incorporated into customers’ rates?**

658 A. The actual costs and benefits, including those costs not booked to NPC accounts,
659 should be passed back to customers via the EBA, at least until such time as the
660 costs and benefits are reflected in retail rates. If the Commission does not approve
661 EBA treatment as described in greater detail below, the Company requests that

⁹<http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf>.

662 non-NPC amounts be deferred as a regulatory asset in Account 182 for later
663 inclusion in customer rates.

664 **Q. Will all EIM-related costs and benefits automatically flow through EBA**
665 **accounts?**

666 A. No. While EIM benefits will automatically flow through the EBA in the form of
667 lower NPC, out of all the cost categories, only the market charges will be booked
668 to EBA accounts. Even though the CAISO administrative fees will vary based on
669 the transactions executed over a given time period, FERC and CAISO determined
670 that the fees should be booked to FERC accounts 561 and 575 - non EBA
671 accounts. Notwithstanding this accounting treatment, the Company proposes that
672 these costs be permanently included in the EBA and subject to annual true-up
673 (and sharing band) along with other EBA costs.

674 Other O&M and capital expenditures for EIM will also not be booked to
675 accounts that flow through the EBA. The Company proposes to track these costs
676 for later recovery through the EBA as a specific adder or adjustment, also subject
677 to the EBA sharing band. Once these costs are included in base rates through a
678 future general rate case, an EBA adder for these specific costs will no longer be
679 necessary.

680 **NPC Updates**

681 **Q. Does the Company propose to update NPC during the course of this**
682 **proceeding in order to improve the accuracy of the NPC projections?**

683 A. Yes. Since the implementation of the EBA, Base NPC is set in general rate cases
684 for later comparison to actual NPC during the rate effective period. In order to

685 achieve the most accurate forecast of Base NPC, and thus minimize the deferred
686 NPC, the Company proposes to update the following limited categories of NPC:

- 687 • The OFPC for electricity and natural gas;
- 688 • Coal contracts;
- 689 • Wholesale sales and purchase contracts for electricity and natural gas, for both
690 physical and financial products;
- 691 • Transmission contracts to wheel generation to load centers; and
- 692 • Transportation contracts to deliver natural gas to generation facilities.

693 **Q. Did the Company file updates to NPC in the 2012 GRC?**

694 A. Yes. The Company filed updates to the same limited categories listed above in the
695 2012 GRC several weeks prior to parties filing of direct testimony, per the
696 schedule set in the Scheduling Order in the 2012 GRC. No party objected to the
697 updates and the updated NPC was the basis for the NPC adopted in the settlement
698 stipulation in that case.

699 **Q. Did parties raise any concerns with regard to the Company's update process
700 in the 2012 GRC?**

701 A. Yes. Two parties indicated that the one-month interval between the Company's
702 update filing and the filing of their direct testimony was insufficient for them to
703 fully address the updates. The Division of Public Utilities ("DPU") suggested a
704 six-week interval would be more appropriate, whereas the Office of Consumer
705 Services ("OCS") advocated for an approximate 10-week interval.

706 **Q. How do you respond to the concerns regarding the timing of the updates?**

707 A. The Company acknowledges that the update process must balance the inclusion of

708 the most recently available information against the need for verification by other
709 parties. In the 2012 GRC, nearly all of the Company's 15 updates to NPC were
710 for new contracts, new pricing provided by counterparties according to contract
711 terms, or terminated contracts. These are well-documented interactions with third
712 parties that should be straight-forward to review. Parties were provided
713 supporting documentation and workpapers for seven of the updates nine weeks
714 prior to their filing of direct testimony. Supporting materials for five additional
715 updates were provided six weeks prior to their filing, and the complete support for
716 all of the updates and their cumulative impact was provided four weeks prior to
717 parties filing direct testimony.

718 **Q. What is the Company proposing in this case?**

719 A. The Company is requesting that the Commission establish a fixed schedule of
720 when NPC updates will occur over the course of a rate case proceeding and what
721 particular NPC items will be updated. This will ensure that the update process is
722 applied consistently and that no party will selectively accept or reject updates only
723 on the basis that they increase or decrease NPC.

724 **Q. When does the Company propose to make these updates during this and
725 future general rate case proceedings?**

726 A. The Company proposes to update NPC for the limited categories prior to parties'
727 filing their direct testimony. In this proceeding, the Company proposes to file the
728 update one month prior to the date that other parties will file direct testimony. In
729 addition, prior to the update filing, the Company will periodically provide new
730 information in those categories that will be reflected in the update filing, either on

731 a monthly basis or when a significant amount of information has been
732 accumulated. The Company believes that this will allow adequate time for parties
733 to review the information prior to filing their direct testimony.

734 **Q. Does the Company have a specific recommendation with regard to the**
735 **update of its OFPC?**

736 A. The Company recommends that its update filing utilize the March 31, 2014,
737 OFPC. The Company will make the workpapers underlying this update available
738 for parties to review during early April 2014, which should be well before their
739 direct testimony is filed. This will provide a reasonable balance between the
740 benefits of up-to-date information against the time needed for review.

741 **Q. What other updates does the Company anticipate?**

742 A. In addition to the list of update categories cited earlier, FERC recently approved
743 BAL-002-WECC-2, which modifies the contingency reserve requirements,
744 effective January 28, 2014. Implementation is “the first day of the 3rd quarter
745 following regulatory approval,” which will be October 2014. The current
746 contingency reserve requirement is for the sum of five percent of load
747 responsibility served by hydro generation and seven percent of the load
748 responsibility served by thermal generation. Wind and solar is treated the same as
749 hydro. The newly approved contingency reserve requirement is for the sum of
750 three percent of hourly integrated load plus three percent of hourly integrated
751 generation. The timing of the ruling did not allow enough time for the Company
752 to create a precise methodology in GRID that would accurately capture the impact
753 of the modified reserve requirement in its direct testimony.

754 **Q. Why is it reasonable to update NPC during the course of a general rate case**
755 **proceeding?**

756 A. The Company's load and resource balance for the test period changes with market
757 prices and contracts. As a result, the operation of the Company's system continues
758 to change during the course of the general rate case proceeding. The Company's
759 proposal to update NPC will ensure that the NPC forecast for the rate effective
760 period is as accurate as possible.

761 **Q. Will such updates unreasonably impact other parties' abilities to review the**
762 **Company's NPC?**

763 A. No. The Company believes the review time is reasonable given the limited scope
764 of the update and the provision of new information in a timely fashion. These
765 updates are transparent, apply equally whether they increase or decrease NPC, can
766 be easily verified and are straightforward to model in GRID. In addition, the
767 Company will provide work papers to support these updates.

768 **Q. Do other commissions allow the Company to update its NPC inputs,**
769 **including the forward price curve after the initial filing?**

770 A. Yes. This has become regular practice in Oregon and Washington with the goal of
771 improving the accuracy of the NPC in rates. For example, the Oregon Public
772 Utility Commission authorizes the Company to update its forward price curve and
773 new information on contracts for electricity and natural gas after it has entered its
774 final order, but prior to the time rates go into effect.

775 **Q. Does this conclude your direct testimony?**

776 A. Yes.