

Phase II – Market Reliance

1 I. INTRODUCTION

2 Q. PLEASE STATE YOUR NAME, POSITION AND YOUR BUSINESS
3 ADDRESS.

4 A. My name is Daniel E. Gimble. I am a special projects manager with the
5 Office of Consumer Services (Office). My business address is 160 E. 300
6 S., Salt Lake City, Utah.

7

8 Q. PLEASE DISCUSS YOUR EDUCATION AND QUALIFICATIONS.

9 A. I have a B.A. degree with honors in economics and history from Western
10 Michigan University. I also have an M.A degree in economics from the
11 same university. I completed course work towards a Ph.D. in economics
12 at the University of Utah. In 1987, I joined the Utah Public Service
13 Commission (Commission) Staff and in 1990 was hired by the Office. In
14 my time with the Office, I have worked in various capacities and have
15 been a manager since 2003.

16

17 Q. HAVE YOU APPEARED AS A WITNESS BEFORE THIS COMMISSION
18 IN PRIOR CASES INVOLVING ROCKY MOUNTAIN POWER OR OTHER
19 UTILITIES?

20 A. Yes. Since 1991 I have testified numerous times in major cases involving
21 Rocky Mountain Power (Company) and other utilities providing service in
22 Utah. These cases include general rate cases, merger and acquisition
23 dockets, excess net power costs, avoided cost rates, gas pass-through
24 proceedings, and the sale of Qwest's Dex (Yellow Pages) asset. I most
25 recently appeared before the Commission in Docket 09-035-23, testifying
26 in support of the Office's positions on cost-of-service, rate spread and rate
27 design.

28

29 Q. DID YOU PREVIOUSLY FILE TESTIMONY IN PHASE I OF THIS
30 DOCKET?

31 A. No, this is my first time filing testimony in this proceeding.

32

33 Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN PHASE II
34 OF THIS PROCEEDING?

35 A. My testimony addresses the issue of market reliance¹ as it relates to the
36 design and implementation of an Energy Balancing Account Mechanism
37 (ECAM) for Utah. In connection with the issue of market reliance, my
38 testimony discusses:

- 39 • An overview of the market reliance issue;
- 40 • The Company's current market reliance strategy, particularly in the
41 2012-2014 bridging period;²
- 42 • The supporting evidence and independent verification of the
43 assumptions underlying the Company's market reliance strategy;
- 44 • Guidance and concerns expressed by the Commission regarding
45 market reliance; and
- 46 • Recommendations of the Office with respect to the Company's market
47 reliance strategy separately and in relationship to its ECAM proposal.

48

49 Q. IS THE OFFICE SUBMITTING DIRECT TESTIMONY OF OTHER
50 WITNESSES IN PHASE II OF THIS PROCEEDING?

51 A. Yes. Mr. Paul Wielgus and Dr. Lori Schell are filing testimony on behalf of
52 the Office addressing hedging concepts and the Company's revised gas
53 hedging framework. In my testimony I present the recommendations
54 contained in the testimony of all Office witnesses relating to the areas of
55 hedging practices and market reliance.

56

¹ Market Reliance refers to the Company's use of short-term market products ranging between one to three years, such as wholesale market purchases or power exchanges, to meet load requirements, especially in the third quarter peak period. The Company interchangeably refers to these types of market products as short-term resources or front office transactions in its 2008 IRP Update. I will use this term, market reliance, as a convenient reference for this concept throughout this testimony.

² Action Item 2 in the 2008 IRP Update refers to a "bridging strategy" to support the deferral of intermediate and baseload resources until summer 2015 in the eastern control area. Throughout my testimony I refer to bridging strategy or "bridging period" in reference to this deferral of intermediate and baseload resources to 2015.

Phase II – Market Reliance

57 Q. PLEASE SUMMARIZE THE OFFICE'S RECOMMENDATIONS.

58 A. In deciding whether some form of ECAM is in the public interest, the
59 Commission should do the following,

60 • Act upon the recommendations relating to the Company's hedging
61 practices proposed by the Office's experts, Mr. Wielgus and Dr.
62 Schell, that the Company should:

63
64 (1) Perform a thorough analysis of all costs associated with its
65 hedging practices (Wielgus);

66 (2) Evaluate the use of options to reduce price volatility (Wielgus);

67 (3) Evaluate the cost and benefit of the partial leveling of rates that
68 results from hedging natural gas compared to acquiring more non-
69 gas resources instead of gas resources. (Wielgus);

70 (4) Compare the value of its hedging practices with other ways to
71 address price volatility, such as the Enterprise Risk Management
72 (ERM) approach (Wielgus);

73 (5) Provide ample opportunity for affected parties to have input into
74 the process of evaluating the Company's hedging practices
75 (Wielgus);

76 (6) Reduce its volume-based hedge targets to reflect historical
77 system balancing levels (Schell);

78 (7) Re-examine the acceptable range of TEVaR levels (Schell).

79

80 Neither natural gas hedging costs nor natural gas fuel costs should
81 be allowed in an ECAM design until this evaluation has been
82 completed. If customers are going to be required to bear the risks
83 of natural gas cost fluctuation, they should have input into
84 establishing appropriate hedging strategies and associated costs.

85

86 • Require the Company to perform a comprehensive analysis
87 justifying the adequacy and depth of the western market to support

Phase II – Market Reliance

88 the projected volumes and prices associated with FOTs, as
89 indicated in its current resource plan. This justification should
90 include independent validation of the Company's market
91 assessment. This analysis should be required before the costs
92 associated with market purchases are allowed in any ECAM design
93 and also required on an ongoing basis in all future IRPs.

- 94 • Consider developing and applying limits on the volume of FOTs for
95 purposes of inclusion in an ECAM.

96

97 **II. OVERVIEW OF THE MARKET RELIANCE ISSUE**

98 Q. PLEASE DESCRIBE THE BACKGROUND OF THE MARKET RELIANCE
99 ISSUE.

100 A. Michele Beck, on behalf of the Office in Phase I of this case, raised the
101 issue of how the implementation of an ECAM would shift the risks
102 associated with a planning strategy that relied too heavily on market
103 purchases from the Company to consumers. In its Report and Order in
104 Phase I issued February 9, 2010, the Commission specifically directed
105 parties to address this issue in Phase II by stating "we would like to see
106 the two issues raised by the Office of Consumer Services addressed:
107 namely, is the company's use of natural gas hedging and the level of and
108 reliance on market energy affected by the use of an ECAM?"

109

110 Q. HAS THE OFFICE PREVIOUSLY RAISED THESE TYPES OF ISSUES
111 IN OTHER FORUMS?

112 A. Yes. The Office (and other parties) has raised concerns about the level of
113 the Company's reliance on market purchases in the Company's IRP filings
114 for many years.

115

116 Q. HOW DOES THE OFFICE PROPOSE ADDRESSING THE ISSUE IN
117 THIS PHASE OF THE CASE?

Phase II – Market Reliance

- 118 A. The Office recommends, and puts forth in this testimony, an approach as
119 follows:
- 120 • First, examine the Company's current market reliance strategy.
 - 121 • Second, evaluate whether the strategy has been well supported with
122 evidence and whether the underlying assumptions can be
123 independently verified.
 - 124 • Third, examine whether the strategy is consistent with Commission
125 guidance.
 - 126 • Fourth, determine how much of these costs are appropriate to be
127 passed through to customers in establishing a potential ECAM design.
- 128

129 **III. COMPANY'S CURRENT LEVEL OF MARKET RELIANCE**

130 Q. WHAT SOURCE DID THE OFFICE USE IN EVALUATING THE
131 COMPANY'S CURRENT LEVEL OF MARKET RELIANCE?

132 A. The Office reviewed the Company's 2008 IRP Update, which was filed
133 with the Commission on March 31, 2010. This is the most current source
134 of resource planning assumptions and information.

135

136 Q. PLEASE SUMMARIZE THE SALIENT CHANGES IN THE IRP UPDATE
137 AS COMPARED TO THE EARLIER 2008 IRP.

138 A. Five significant changes are identified in 2008 IRP Update – changes that
139 result in a revised action plan.³ These changes are as follows:

- 140 • Peak and energy load forecasts have been adjusted downward for
141 Oregon and Utah in the near-term and over the entire 10-year
142 planning horizon for Wyoming. This results in PacifiCorp's system
143 remaining slightly resource surplus through 2011, and reduces the

³ 2008 IRP Update, Table 6.1. Table 6.1 compares the updated action plan to the 2008 IRP action plan filed about one year ago.

Phase II – Market Reliance

- 144 2012 system resource deficit from approximately 1,900 MWs to
145 1,264 MWs.⁴
- 146 • The need for a large, eastside combined cycle plant is deferred
147 from 2014 to 2015 and the gas peaker anticipated to be needed in
148 2016 is supplanted by a large, eastside combined cycle plant to be
149 in-service in 2018.
 - 150 • New wind resources are eliminated for the 2012-2016 period. In
151 addition, the total amount of new wind resources over the 2009-
152 2019 period is reduced by 161 MWs in the IRP Update.⁵
 - 153 • The 200 MW expansion of the Utah Cool Keeper Demand-Side
154 Program is reduced to a modest increase of 30 MW over the ten-
155 year planning period.
 - 156 • New wholesale sales contracts appear in the Company's load and
157 resource balance table in the years 2012 and 2013. These appear
158 to be separate one-year sales contracts at 250 MW (2012) and 300
159 MW (2013).

160

161 Q. WHAT ARE THE IMPLICATIONS OF THE REVISED ACTION PLAN IN
162 THE 2008 IRP UPDATE FOR THE ACQUISITION OF SHORT-TERM
163 VERSUS LONG-TERM RESOURCES?

164 A. According to Table ES.1, which is labeled as the Company's "2010
165 Business Plan Portfolio" in the IRP Update, the Company is planning to
166 heavily rely on annual short-term market purchases to meet load growth
167 throughout the ten-year planning period. Only two major resources –
168 combined cycle "proxy" plants at the Lakeside and Currant Creek sites –
169 are added over the planning period.⁶ Based on the resource numbers

⁴ Table 3.9 – Capacity Load and Resource Balance (12% PRM). According to Table 3.9, the System Position is "Resource Deficit" by 1,264 in 2012. This resource deficit is projected to rapidly increase to 2,189 MWs by 2014.

⁵ 447 MWs of eastside wind resources are acquired or built in the 2011-2012 period and the next wind resource (eastside at 160 MWs) is delayed to 2017. A comparison of Table 9.1 of the 2008 IRP with Table ES.1 in the 2008 IRP update shows a total reduction in wind resources from 1,048 MWs to 887 MWs over the 2009- 2019 period.

⁶ Lakeside 2 and Currant Creek 2 proxies are scheduled for 2015 and 2018, respectively.

Phase II – Market Reliance

170 indicated in Table ES.1 of the IRP Update, my Table 1 (below) compares
 171 annual long-term resource additions with short-term resource additions.
 172 Table 1 shows that in the 2012-2019 period, the Company plans to rely on
 173 annual short-term resources to meet between 47% and 91% of its annual
 174 resource needs and that this reliance on the short-term market is most
 175 pronounced in the 2012-2014 period.

Table 1

Year	2012	2013	2014	2015	2016	2017	2018	2019
LTR ⁷	344	149	125	708	136	251	721	292
STR ⁸	604	932	1,223	794	923	958	636	794
Total	948	1,081	1,348	1,503	1,059	1,208	1,357	1,087

178

179 Q. THE LAST YEAR OF THE BRIDGING PERIOD IS 2014. WHAT IS THE
 180 COMPANY'S SYSTEM LOAD AND RESOURCE POSITION IN 2014?

181 A. In Table 3.9 of the 2008 IRP Update (pg. 33), the Company reports a
 182 system resource deficit position of 2,198 MW in 2014. This represents an
 183 increase in the system deficit position from 1,264 MW in 2012 to 2,198
 184 MW in 2014. However, I believe it is very important for the Commission to
 185 understand that the eastside of the system is more severely resource
 186 deficit than the westside throughout the 2012-2014 bridging period. In
 187 2014, the eastside resource deficit position has increased to 1,680 MW
 188 out of the 2,198 MW system deficit.⁹

189

⁷ Long-Term Resources.

⁸ Short-Term Resources. Short-term resources represent front office transactions that the Company typically enters into for a period of 1-3 years.

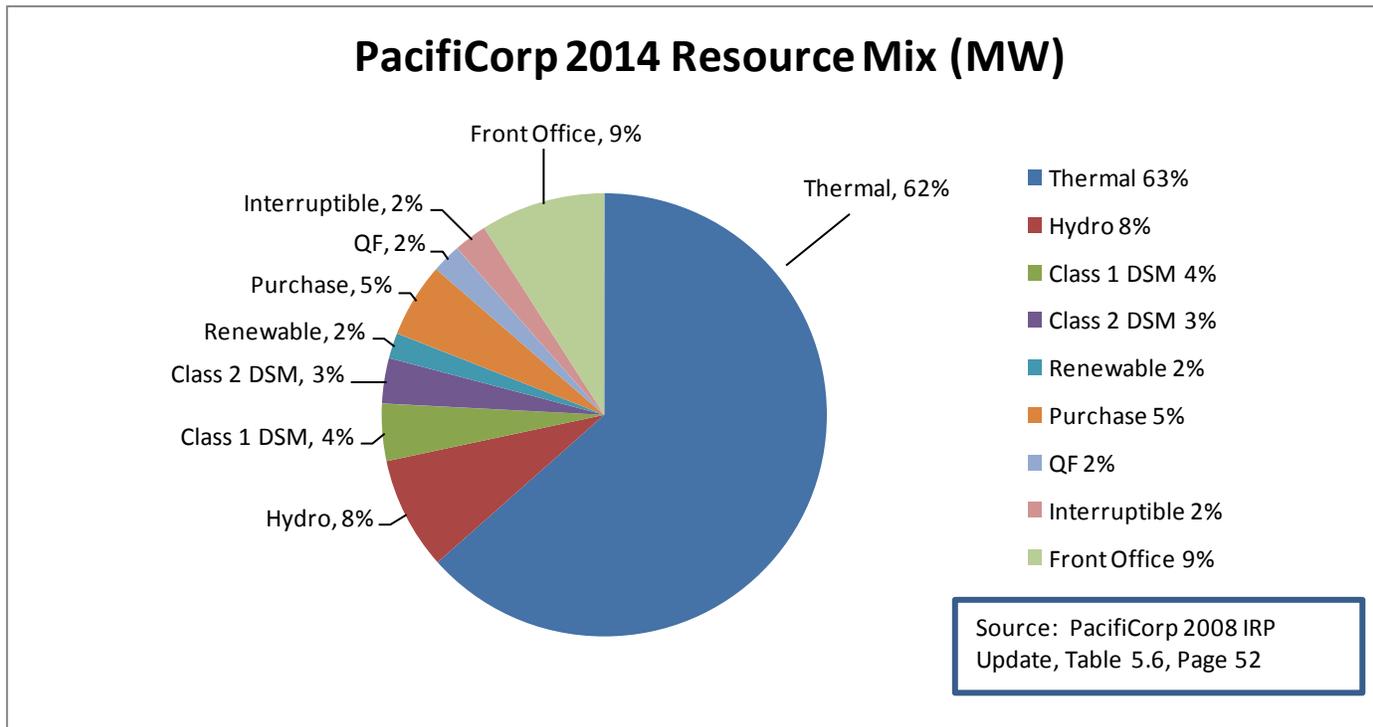
⁹ Table 5.6 of the IRP Update shows that approximately half of the eastside resource shortfall is resolved via the transfer of 830 MW of power from the westside to the eastside of the system. This is presumably the transfer of power from Bridger and other resources made available through existing and possibly incremental transmission capacity (See 2008 IRP Update, Action Item 2, last bullet addressing incremental transmission). A substantial portion of the remaining eastside resource deficit position is met with 519 MW of front office transactions.

Phase II – Market Reliance

190 Q. IN 2014, WHAT PERCENTAGE OF THE TOTAL RESOURCE MIX DO
 191 SHORT-TERM RESOURCES REPRESENT IN COMPARING THE 2008
 192 IRP UPDATE TO THE 2008 IRP?

193 A. From a capacity standpoint, short-term resources in the 2008 IRP Update
 194 are approximately 9.0% of the Company’s overall resource mix in 2014.¹⁰
 195 The 9.0% level represents an increase over the 6.8% reported in the 2008
 196 IRP.¹¹ While short-term resources are not a significant component of the
 197 Company’s total resource mix relative to coal or gas combined-cycle
 198 resources, they are proportionately higher in 2014 because of the deferral
 199 of the Lakeside 2 proxy from 2014 to 2015 and changes in assumptions
 200 relating to wind and demand-side management resources. PacifiCorp’s
 201 updated resource mix for 2014 is illustrated in Table 2 below.
 202

203 Table 2



¹⁰Table 5.6 of the 2008 IRP Update indicates 1,223 MW of front office transactions are needed in 2014 and that total resources are 13,500 MW in 2014. 1,233 MW/13,500 MW = 9.05%.

¹¹ 2008 IRP, pg. 249.

218

219 Q. IF THE 2008 IRP UPDATE ACTION PLAN STILL TARGETED A 2014 IN-
220 SERVICE DATE FOR THE LAKESIDE 2 PROXY RESOURCE, HOW
221 WOULD THAT IMPACT THE AMOUNT OF SHORT-TERM RESOURCES
222 NEEDED IN 2014?

223 A. Maintaining a 2014 in-service date for the 607 MW Lakeside 2 proxy
224 would effectively cut the reported 1,233 MW need for short-term resources
225 in half. Thus, the percentage of short-term resources would fall from
226 approximately 9.0% to 4.5% in 2014.

227

228 Q. WHAT IS THE IMPETUS DRIVING THE SIGNIFICANT CHANGES IN
229 THE 2008 IRP UPDATE THAT YOU DESCRIBE ABOVE?

230 A. The 2008 IRP Update is closely linked with management's 2010 business
231 planning process wherein management re-evaluated resource needs
232 given lower near-term load forecasts and recessionary economic
233 conditions. On Page 15 of the 2008 IRP Update the Company states,

234

235 "A main finding of the 2010 business planning process was that
236 given the current load forecast and the economic turndown, the
237 operating and capital budgets supporting the 2009 business plan
238 would not maintain a capital structure that is optimal for both
239 customers and the Company, and would increase rate pressure on
240 customers. For example, assessment of the initial projected capital
241 budget with resource acquisitions and resultant cash flows
242 indicated difficulty in maintaining current debt ratings. As a
243 consequence, PacifiCorp reexamined the need and timing for
244 capital investments and, where appropriate and feasible, the
245 business plan eliminates or defers investments. The revised capital
246 budget included expenditure reductions on the order of \$3.5 billion
247 in the early years of the plan, relative to the budget established for
248 the 2009 business plan."

249

250 Q. WHAT CONCERNS DOES THE OFFICE HAVE WITH THE 2010
251 BUSINESS PLAN PORTFOLIO AS IT RELATES TO THE COMPANY'S
252 REQUEST FOR IMPLEMENTATION OF AN ECAM IN UTAH?

253 A. The Office is concerned that if an ECAM is approved and implemented,
254 then resource deferrals included in the 2010 Business Plan Portfolio
255 expose Utah customers to the risk associated with market price volatility,
256 poor hydro conditions, and a quicker recovery of loads from the economic
257 recession than forecasted by the Company. A confluence of rising market
258 prices, prolonged drought conditions and demand recovery above
259 forecasted levels would likely create significant upward pressure on net
260 power costs, especially in the 2012-2014 bridging period when
261 PacifiCorp's 2010 Business Plan calls for a heavy reliance on short-term
262 market purchases to meet load requirements. Thus, the Company's
263 proposal to design (2010) and implement (2011) an ECAM arrives just in
264 advance of the time PacifiCorp's system is expected to be resource deficit
265 and could result in shifting more market reliance risk from Company
266 management to Utah customers. Thus, it is critically important that the
267 Company supports and verifies the assumptions underlying its market
268 reliance strategy.

269

270 **IV. SUPPORTING EVIDENCE AND INDEPENDENT VERIFICATION**

271 Q. DID THE COMPANY PRESENT INFORMATION IN ITS 2008 IRP
272 UPDATE THAT SUPPORTS THE ASSUMPTIONS UNDERLYING ITS
273 MARKET RELIANCE STRATEGY?

274 A. In the IRP Update the Company presents updated gas and power market
275 price forecasts based on its September 2009 natural gas price curve and
276 its September 30, 2009 official forward price curves. The September 2009
277 natural gas price forecast is similar to the October 2008 forecast used in
278 preparing the 2008 IRP, for the 2012-2014 period.¹² After 2014 the

¹² 2008 IRP Update, Figure 4.1, pg. 37

Phase II – Market Reliance

279 September 2009 forecast is much lower than the October 2008 forecast
280 through the year 2030. Similarly, the Company's September 2009 power
281 market price forecasts for Palo Verde (Annual Flat and Annual Heavy
282 Load Hour Prices) and Mid-Columbia (Annual Flat Prices) are close to the
283 prices forecasted in October 2008 for the 2012-2014 period. After 2014
284 the September 2009 market price forecasts are much lower than the
285 October 2008 forecasts for the Palo Verde and Mid-Columbia markets.
286 Thus, the projected gas and market prices in the near-term are similar in
287 both forecasts.

288

289 Q. DID THE OFFICE REQUEST THAT THE COMPANY PROVIDE ITS
290 MOST RECENT GAS AND MARKET PRICE FORECASTS?

291 A. Yes. In response to OCS DRs 8.1 – 8.3, the Company provided its March
292 2010 gas and market price forecasts. These March 2010 forecasts show
293 that the Company anticipates both gas and market prices to be
294 significantly lower in the 2012-2016 period compared to the September
295 2009 forecasts. After 2016, the March 2010 gas and market price
296 forecasts more closely track the September 2009 forecasts through the
297 year 2021. Therefore, the March 2010 price forecasts represent the
298 Company's most current forward view; an outlook which suggests softer
299 prices in the near-term gas and electric markets.

300

301 Q. WHAT IS THE COMPANY'S CURRENT VIEW OF PRICES AT THE
302 PALO VERDE AND MID-COLUMBIA MARKET HUBS?

303 A. According to the Company's response to OCS 8.1, the Company's price
304 projections for Palo Verde and Mid-Columbia market hubs are lower in the
305 March 2010 forecast compared to the September 2009 forecast. Table 3
306 below provides a comparison between the March 2010 and September
307 2009 price forecasts for these two market hubs. In Table 3, I show the
308 annual high load hour (HLH) price forecast at Palo Verde and the annual
309 flat price forecast at Mid-Columbia.

310

311

Table 3

312

Palo Verde

Mid-Columbia

313

Average Annual HLH Prices

Average Annual Flat Prices

314

Sep-09Mar-10Sep-09Mar-10

315

2010 \$54.60 \$42.40 \$46.91 \$38.50

316

2011 \$59.97 \$47.75 \$50.81 \$40.43

317

2012 \$60.94 \$52.00 \$51.46 \$44.33

318

2013 \$62.48 \$54.50 \$51.89 \$46.53

319

2014 \$63.95 \$57.25 \$52.79 \$48.97

320

2015 \$65.50 \$60.25 \$53.99 \$51.43

321

2016 \$67.87 \$65.84 \$58.99 \$57.02

322

2017 \$69.62 \$71.74 \$63.53 \$63.11

323

2018 \$69.85 \$75.00 \$63.73 \$65.61

324

2019 \$74.08 \$74.91 \$67.27 \$66.15

325

326

Since the Company's reliance on short-term resources is particularly acute

327

in the 2012-2014 bridging period, prices in those three years are

328

highlighted in Table 2 for comparison purposes. Focusing on the Palo

329

Verde market, the Company's March 2010 price forecast is approximately

330

15% lower for 2012, 13% lower for 2013 and 11% lower for 2014. The

331

same general forecast pattern holds for the Mid-Columbia market. Thus,

332

the Company's March 2010 near-term market price forecasts appear to

333

better substantiate the Company's deferral of gas and wind resources in

334

its revised 2008 IRP action plan than its prior market price forecasts.

335

However, there remains the issue of validating the reasonableness of the

336

Company's March 2010 electric market price forecasts.

337

338

Q. DID YOU ATTEMPT TO ACCESS OTHER FORECASTS RECENTLY

339

PUBLISHED TO CONFIRM THE REASONABLENESS OF THE

340

COMPANY'S MARCH 2010 ELECTRIC PRICE FORECASTS?

Phase II – Market Reliance

341 A. Yes. In February 2010, the Northwest Power Planning Council (NWPPC)
 342 published its 6th Power Plan (Plan). Appendix D of the Plan includes the
 343 NWPPC’s current forecasts for the Mid-Columbia market hub. Table 4
 344 below compares PacifiCorp’s March 2010 with the NWPPC’s February
 345 2010 forecast for the Mid-Columbia market hub.¹³

Table 4

Mid-Columbia

Average Annual Flat Prices

	<u>PC - Mar-10</u>	<u>NWPPC Feb-10</u>
351 2010	\$38.50	\$32.64
352 2011	\$40.43	\$37.43
353 2012	\$44.33	\$44.54
354 2013	\$46.53	\$50.94
355 2014	\$48.97	\$57.77
356 2015	\$51.43	\$63.12
357 2016	\$57.02	\$67.95
358 2017	\$63.11	\$72.08
359 2018	\$65.61	\$74.92
360 2019	\$66.15	\$78.23

361

362 Q. WHAT DOES THIS PRICE COMPARISON ON TABLE 4 INDICATE?

363 A. Starting in 2014 the NWPPC’s price outlook for the Mid-Columbia market
 364 hub is significantly higher. For instance, in 2014 the NWPPC forecasts a
 365 price that is approximately 15% higher than PacifiCorp’s price projection.

¹³ In forecasting market electricity prices PacifiCorp and the NWPPC use different forecasting tools - PacifiCorp relies on the Midas model and the NWPPC uses the Aurora model. Additionally, the Company forecasted numbers are in nominal terms and the NWPPC numbers are reported in (2006) constant dollar terms. To facilitate an accurate comparison of forecasted market prices the Office requested that NWPPC provide its nominal price forecasts by market zone. This information was provided via e-mail on June 15, 2010 and the “PNW Eastside – All Hours” price forecast is used in Table 4 for comparison purposes. The Office can provide NWPPC’s market zone price forecasts to interested parties upon request.

Phase II – Market Reliance

366 Thus, PacifiCorp's market price forecast for Mid-Columbia appears to be
367 optimistic compared to the NWPPC's price outlook.

368

369 Q. WHAT IS THE OFFICE'S REACTION TO THE FACT THE TWO PRICE
370 FORECASTS FOR MID-COLUMBIA SHARPLY DIFFER BEGINNING IN
371 2014?

372 A. Given that Mid-Columbia is a primary market hub in the Pacific Northwest,
373 the Office expected to find better agreement between the two price
374 outlooks. There is a concern that PacifiCorp market view is more
375 optimistic at a point in time (2014) when the Company's system resource
376 deficit position grows to 2,198 MW. The Office plans to request
377 PacifiCorp's June 2010 forward price curves to see if any upward
378 adjustments are made to the Company's market price outlook.¹⁴

379

380 Q. WHAT ADDITIONAL INFORMATION DID THE COMPANY PRESENT IN
381 THE 2008 IRP UPDATE TO SUPPORT ITS MARKET RELIANCE
382 STRATEGY?

383 A. On pages 41-42 of the 2008 IRP Update, the Company discusses
384 changes to annual Front Office Transaction (FOT) acquisition limits. The
385 two most significant changes presented in Table 4.2 of the IRP Update
386 are:

387

388 • Elimination of the Nevada-Utah Border (NUB) market hub, which
389 was prompted by the acquisition of firm Nevada Power
390 transmission service from Mead to Utah beginning in 2012. This
391 transmission service allows PacifiCorp to acquire up to 300 MW of
392 3rd Quarter 6 x 16 FOT Product from Mead in the 2012-2014
393 period.¹⁵

¹⁴ PacifiCorp's June 2010 forward price curves will be the most current forecasts available prior to the scheduled August 17, 2010 hearing.

¹⁵ The 300 MW increase in transmission service from Mead to Utah is temporary; it subsequently declines to only 100 MW for the 2015-2016 period.

Phase II – Market Reliance

- 394 • Increasing the maximum availability of the 3rd Quarter 6 x 16 FOT
395 Product at Mona from 200 MW to 300 MW beginning in 2013 and
396 continuing thereafter. This is an incremental increase of 100 MW
397 compared to the assumption for Mona in the 2008 IRP.

398

399 These two changes increase the FOT acquisition limits by 300 MW in
400 2012 and by 400 MW for the years 2013 and 2014. Therefore, the
401 Company asserts it can move 400 MW of additional FOTs into its eastern
402 control area by 2013 to serve loads.

403

404 Q. CAN YOU DETERMINE FROM THE IRP UPDATE WHETHER THIS 400
405 MW TOTAL INCREASE IN ACQUISITION LIMITS WILL BE USED TO
406 SERVE GROWING RETAIL LOADS OR ARE THERE NEW
407 WHOLESALE SALES CONTRACTS IN THE BRIDGING PERIOD?

408 A. According to “East Changes - Market Sales” presented on pg. 35 of the
409 IRP Update, the Company recently entered into new wholesale sales
410 contracts for 2012 and 2013. These wholesale transactions involve a 250
411 MW sales contract in 2012 and a 300 MW sales contract in 2013.¹⁶
412 Consequently, it appears that a substantial portion of the increase in FOT
413 purchases made available by the 400 MW increase in acquisition limits will
414 be used to meet new wholesale sales obligations in the Company’s
415 eastern control area and will not be used to serve retail load.

416

417 Q. IN THE 2008 IRP UPDATE DID THE COMPANY SPECIFICALLY DEFINE
418 AND DESCRIBE THE DIFFERENT TYPES OF STANDARD MARKET
419 PRODUCTS THAT IT REFERS TO AS FOT?

420 A. No. Whereas the Company furnishes a more detailed description of FOT
421 in its 2008 IRP (see pgs. 130-133), it simply states in the IRP Update that,

¹⁶ Table 3.10 on page 34 of the IRP Update illustrates the differences by category between the 2010 Business Plan Portfolio that serves as the basis for the revised action plan for the 2008 IRP Update and the action plan associated with the 2008 IRP. On the eastside, two new wholesale sales of 250 and 300 MW are indicated in 2012 and 2013, respectively.

422

423

“Front office transactions represent contracts for standard market products acquired on a forwards basis typically for a one-to-three year term.” (IRP Update, pg. 27-28)

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Q. WOULD IT BE USEFUL FOR THE COMMISSION AND OTHER PARTIES TO UNDERSTAND THE VARIOUS TYPES OF STANDARD MARKET PRODUCTS THAT ARE PRESENTLY AVAILABLE TO THE COMPANY AND HOW THEY MIGHT DIFFER BY MARKET HUB?

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A. Yes. Since the Company’s 2010 Business Plan Portfolio depends heavily on front office transactions to meet load requirements, a complete description of standard market products that are currently available, and possible variations on those products, by market hub would be useful.

432

433

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436

Q. IN THE 2008 IRP UPDATE DID THE COMPANY IDENTIFY AND DESCRIBE FRONT OFFICE TRANSACTIONS THAT HAVE ALREADY BEEN ACQUIRED FOR THE BRIDGING PERIOD?

437

438

439

A. Yes. In Table 3.6 of the 2008 IRP Update (pg. 25), the Company identifies six FOTs for the 2010 -2013 period that are considered as existing resources in calculating the Company’s system load and resource position.¹⁷ These FOTs are categorically separated into (a) two firm market purchase contracts and (b) four exchange contracts. The firm purchases total 150 MW, the market hub is Mona and the contract terms range between 2010 - 2012. The exchanges total 300 MW, the market hubs are Mona and Four Corners and the contract terms range between 2012 - 2013. Copies of these contracts were provided to the Office as Confidential Attachment 8.5 in response to OCS DR 8.5.

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¹⁷ The Company’s response to OCS DR 8.6 confirmed that these FOT transactions are treated as existing resources and do not serve to reduce the amount of incremental short-term resources indicated in Table ES-1 of the 2008 IRP Update.

Phase II – Market Reliance

- 450 Q. DO THESE SIX SPECIFIC FOT TRANSACTIONS PROVIDE SOME
451 ASSURANCE TO THE COMMISSION THAT THE COMPANY WILL BE
452 ABLE TO RELIABLY AND ECONOMICALLY CONTRACT FOR THE
453 LEVELS OF FOT TRANSACTIONS INDICATED IN ITS 2008 IRP
454 ACTION PLAN?
- 455 A. This will depend on the liquidity and depth in the western market to
456 support PacifiCorp's FOT volumes that total 1,223 MWs by 2014. The
457 Commission should require the Company to provide its current analysis of
458 market liquidity and depth.
459
- 460 Q. IS THERE A REASONABLE STARTING POINT TO GAIN AN
461 UNDERSTANDING OF CURRENT PROJECTIONS OF RESOURCE
462 ADEQUACY IN WESTERN POWER MARKETS?
- 463 A. Yes. WECC regularly publishes a Power Supply Assessment (PSA) for
464 the western power market. These PSAs include sub-regional load and
465 resource balance forecasts under various assumptions and conditions.
466
- 467 Q. WHAT IS THE MOST RECENT VINTAGE OF WECC'S POWER SUPPLY
468 ASSESSMENT (PSA) FOR THE WESTERN MARKET?
- 469 A. The latest PSA was published October 2009 and is based on data
470 provided by WECC member utilities in Spring 2009. The October 2009
471 PSA includes a 2.0% increases in existing and Class 1 resources for 2010
472 and a 2.8% increase for these resources for 2017. Over the same time
473 period, demand destruction due to the economic recession has reduced
474 load forecasts by an average of 3.6%. According to WECC, certain sub-
475 regions that were projected to be deficit in the 2008 PSA are now
476 forecasted to be surplus in the 2009 PSA.¹⁸
477 .
- 478 Q. HOW ARE THE ANALYSES AND RESULTS IN THE 2009 PSA
479 ORGANIZED AND PRESENTED?

¹⁸ 2009 PSA, Executive Summary, pg. 1.

Phase II – Market Reliance

480 A. WECC uses a supply adequacy model (SAM) to model 26 zones in the
481 western interconnect, which are aggregated into seven subregions to
482 perform load and resource analysis and report results. These seven
483 zones include Canada, Northwest, Basin, Rockies, Desert Southwest, No.
484 Cal, So. Cal/MX. PacifiCorp's service territories are primarily in the
485 Northwest, Basin and Rockies sub-regions. Since PacifiCorp is a major
486 seller and buyer of power in the western market, it is also important to
487 understand projections of resource adequacy in other sub-regions as well,
488 especially the Desert Southwest market.¹⁹ Lastly, the SAM model allows
489 economy transfers of power to occur primarily between sub-regions that
490 are in close proximity. However, the model has limitations in that it is not
491 an economic dispatch model. According to WECC this limitation is one
492 factor contributing to an unrealistic level of surplus in the Northwest sub-
493 region in the 2009 PSA.²⁰

494

495 Q. BASED ON WECC'S CURRENT PROJECTIONS, WHEN DO
496 RESOURCE DEFICITS FIRST APPEAR FOR THE BASIN, ROCKIES
497 AND NORTHWEST SUB-REGIONS?

498 A. WECC presents these surplus-deficit projections according to two distinct
499 scenarios -- a stand-alone scenario that assumes no economic power
500 transfers among sub-regions and a more realistic scenario that assumes
501 economic power transfers occur. Under the latter scenario, resource
502 deficits initially appear for these sub-regions as follows:²¹

503

- 504 • Basin: Summer 2013;
- 505 • Rockies: Summer 2018;

¹⁹ Market hubs such as Palo Verde, Mead, Mona and Four Corners provide important market resource opportunities for PacifiCorp, as noted by the Company in various sections of its 2008 IRP Update.

²⁰To address this problem, WECC will be using PROMOD (an energy dispatch model) in future IRPs to more accurately reflect power transfers within the western interconnect.

²¹ Initial year projected for resource deficit, by sub-region, is provided in the 2009 PSA in Table 3, pg. 9. Reserve margin assumptions differ across sub-regions and are provided in Table 4, pg. 9.

- 506 • Northwest: Surplus for entire period (2010-2018)

507

508 However, there are a few caveats that need to be briefly mentioned
509 related to these resource deficit projections. First, the Basin, on a stand-
510 alone basis, is severely resource deficit over the entire planning cycle.
511 Thus, utilities operating in the Basin rely heavily on power purchases and
512 exchanges to meet load requirements. Second, the Rockies is essentially
513 in load and resource balance beginning in 2014 and continuing through
514 2018. If planned resources are not added or loads significantly increase,
515 then the Rockies could quickly become resource deficit as well. Third, the
516 surplus in the Northwest is overstated because of modeling limitations and
517 hydro availability could deteriorate under pro-longed drought conditions.²²
518 Fourth, the reserve margins differ by sub-region and by season (summer-
519 winter) within a sub-region. For example, the summer reserve margins for
520 the Basin, Rockies and Northwest are 12.0%, 12.3%, and 18.6%,
521 respectively. The summer and winter reserve margins for the Rockies are
522 12.3% and 13.5%, respectively. Consequently, increasing the reserve
523 margin to a uniform level of 15.0% would more quickly deplete surpluses
524 in the Basin and Rockies and push these sub-regions into a resource
525 deficit position much earlier.

526

527 Q. YOU EARLIER STATED THAT RESOURCE ADEQUACY IN OTHER
528 SUB-REGIONS, SUCH AS THE DESERT SOUTHWEST, IS IMPORTANT
529 BECAUSE PACIFICORP IS AN ACTIVE TRADER IN THE WESTERN
530 MARKET. WHEN DOES A RESOURCE DEFICIT FIRST APPEAR FOR
531 THE DESERT SOUTHWEST MARKET?

532 A. The Desert Southwest is projected to become resource deficit in summer
533 2016. However, the possibility of the resource surplus ending sooner or
534 later than 2016 largely depends on whether resources are added in

²² WECC also notes that the surplus in the Northwest does not consider the limitations on the hydro system's ability to sustain capacity output levels beyond one hour and that this surplus is not available to support heavy load hour contracts in summer months.

Phase II – Market Reliance

535 California as presently scheduled.²³ Long delays or postponement of
536 these resources will impact the length of the resource surplus for the
537 Desert Southwest. Therefore, future resource developments in the Desert
538 Southwest may substantially impact PacifiCorp because of its reliance on
539 power from Desert Southwest market hubs to meet load requirements.

540

541 Q. DOES THE OFFICE HAVE CONCERNS REGARDING THE LEVEL OF
542 EVIDENCE PROVIDED BY THE COMPANY TO SUPPORT ITS MARKET
543 RELIANCE STRATEGY AND THE NEED FOR INDEPENDENT
544 VERIFICATION OF THE LIQUIDITY AND DEPTH OF THE WESTERN
545 MARKET?

546 A. Yes. While the Company identifies two different market products –
547 purchases and exchanges – that it intends to rely on in the years 2010 –
548 2013, it provides the Commission and parties minimal analysis of the
549 liquidity and depth of the western market in the critical 2012-2014 bridging
550 period. The primary information shared with regulators and interested
551 parties are its quarterly forward market price curves -- and the most recent
552 one produced for Mid-Columbia is lower than NWPPC's Mid-Columbia
553 price forecast over the same time period. Given the heavy reliance placed
554 on short-term market products by the Company in the earlier years of the
555 planning period, the Office believes that independent verification of
556 PacifiCorp's market assessment is a required next step, especially given
557 that the Company has asked for a Commission decision on its ECAM
558 proposal later this year.

559

560 **V. COMMISSION GUIDANCE AND CONCERNS REGARDING MARKET**
561 **RELIANCE STRATEGIES**

562 Q. HAS THE COMMISSION RECENTLY RAISED SIMILAR CONCERNS
563 ABOUT THE NEXUS BETWEEN THE COMPANY'S APPLICATION TO

²³ 2009 PSA, pg. 49.

Phase II – Market Reliance

564 IMPLEMENT AN ECAM AND THE RISKS STEMMING FROM ITS
565 RELIANCE ON SHORT-TERM MARKET RESOURCES?

566 A. Yes. On pages 29-30 of its 2008 IRP Order issued April 1, 2010, the
567 Commission states:

568

569 “We are concerned with the Company’s stated confidence in
570 managing the risk associated with reliance on the market for a
571 significant portion of its customers’ power requirements, especially
572 combined with its comfort with planning to a 12 percent planning
573 reserve. These decisions appear to leave little room for forecast
574 error related to prices and loads. Meanwhile, the Company is
575 asking for an energy cost adjustment mechanism in a separate
576 docket. In part, the Company there argues it cannot effectively
577 manage the risks, even one year out, of the costs associated with
578 unexpected fuel prices, wholesale electric prices, and loads.”

579

580 Thus, the Commission, like the Office and possibly other parties, is
581 rightfully apprehensive about whether the Company has developed a
582 credible strategy to manage market risk in order to protect Utah customers
583 from large fluctuations in net power costs, given its ECAM proposal.
584 Given these concerns, the Commission in its 2008 IRP Order provided
585 guidance to the Company in four specific areas, including how the risk of
586 relying on short-term market resources should be allocated between
587 shareholders and ratepayers.

588

589 Q. PLEASE LIST AND SUMMARIZE THE FOUR AREAS WHERE THE
590 COMMISSION PROVIDED GUIDANCE TO THE COMPANY.

591 A. On Page, 30 of its 2008 IRP Order, the Commission directs the Company
592 to address the following areas in preparing its next IRP:

Phase II – Market Reliance

- 593 • Hedging: Include hedging costs in IRP analysis and perform
594 sensitivity analysis to determine hedging strategies that minimize
595 costs and risks for customers.
- 596 • Western Market: Include an analysis of the adequacy of the
597 western market to support the volumes of purchases in the
598 Company's action plan. The Commission also agreed with the
599 Office that WECC is a reasonable source for this evaluation.
- 600 • Allocation of Risk: Identify whether customers or shareholders will
601 be expected to bear the risk of reliance on the wholesale market.
- 602 • Additional Stochastic Analysis: Discuss methods to augment the
603 Company's stochastic analysis of risks attendant to reliance on
604 market purchases in an IRP public meeting.

605

606 Q. DOES THE PROCESS OF DEVELOPING SOUND PUBLIC POLICY ON
607 ECAM ISSUES REQUIRE THE COMPANY TO FULLY ADDRESS THE
608 FOUR AREAS DELINEATED ABOVE AS PART OF THE ECAM
609 DOCKET?

610 A. I would think so. Given the close and immediate relationship between the
611 Company's 2008 IRP and ECAM proposal noted by the Commission on
612 pages 29-30 of its recent IRP Order, the sensible course of action is for
613 the Company to perform the required analysis and provide evidence to the
614 Commission so that it can make an informed decision on the
615 appropriateness of the level, allocation and management of risk
616 associated with the Company's market reliance strategy.

617

618 Q. HAS THE COMMISSION PREVIOUSLY RULED OR PROVIDED
619 GUIDANCE ON WHO BEARS THE RISK OF PLANNING DECISIONS?

620 A. Yes. In its 2007 IRP Order, the Commission stated the following: "The
621 Company bears the risk for any unreasonable cost to ratepayers
622 associated with its decision to change the quantity and type of resources it

Phase II – Market Reliance

623 procures based on asserted but unexamined risks.” (2007 IRP Order, pg
624 34)

625

626 Q. WHY IS THIS GUIDANCE IMPORTANT?

627 A. Because FOT are a form of resource procurement. Fewer FOT are
628 needed when more generation resources are constructed or procured and
629 more FOT are needed when other procurement is postponed. If an ECAM
630 is allowed, then the Company could pass through the costs of this
631 procurement choice (FOT) directly to the customer. Under this
632 circumstance, the risks of this procurement decision would not end up
633 being borne by the Company as anticipated by the Commission in its
634 previous IRP Order.

635

636 **VI. CONCLUSIONS AND RECOMMENDATIONS**

637 Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF INFORMATION
638 PROVIDED BY THE COMPANY IN ITS IRP UPDATE, RESPONSES TO
639 OFFICE DATA REQUESTS AND OUTSIDE SOURCES SUCH AS
640 WECC’S 2009 PSA?

641 A. The Company has committed to new wholesale sales during a period
642 when gas and wind resources are deferred, reliance on short-term market
643 resources is sharply increased to meet load requirements and the Basin
644 sub-region is expected to be resource deficit. Concurrent with these
645 developments is the Company’s ECAM proposal, which is being debated
646 before the Commission – a proposal that directly stems from the
647 Company’s claim that it has uncontrollable risks associated with fuel
648 prices, wholesale electric prices and loads.

649 A significant portion of the risk the Company alleges as
650 uncontrollable may actually be manageable by timely acquiring rather than
651 continuing to defer planned physical resources and developing a credible
652 risk management program. By minimizing planning risk, the Company can
653 focus on a number of important risk management issues raised in the

Phase II – Market Reliance

654 testimony of the Office's experts, including appropriately managing
655 enterprise and operational risks. The question remains whether Utah
656 ratepayers can be adequately protected against potentially higher rates
657 resulting from PacifiCorp's market reliance strategy through the
658 combination of a credible risk management program, possible volume
659 limits on short-term resources, and proper design of an ECAM.

660

661 Q. HOW DO YOUR CONCLUSIONS RELATE TO THE POTENTIAL
662 DESIGN OF AN ECAM?

663 A. The Office evaluated these issues in the context of potential ECAM design
664 using the four steps outlined at the beginning of my testimony. First, we
665 assessed the overall level of market reliance. Based on this assesment,
666 the Office believes that not all short-term purchases or FOT transactions
667 carry the same risk. Therefore, examining the level of market reliance
668 alone is not sufficient. Second, we evaluated the evidence and
669 independent verification of the Company's market assessment. This
670 evaluation raised some serious concerns for the Office as there is little or
671 no independent verification and it appears that the Company may be using
672 an optimistic price forecast in critical years. Third, we reviewed the
673 Commission guidance on these issues and whether the Company's plans
674 are consistent with this guidance. Although some of the specific guidance
675 I've cited was not directed to be completed until the next IRP, the Office
676 has deep concerns about the extent to which this analysis has not been
677 presented.

678 The Office believes it is only appropriate to consider market
679 purchases in ECAM design after these previous three steps have been
680 complete. The Office's fundamental conclusion remains the same as it
681 was in Phase I: allowing the costs associated with market purchases in
682 the ECAM would inappropriately shift risks of market price spikes to the
683 customer, contrary to previous Commission orders that these risks would

Phase II – Market Reliance

684 be borne by the Company. Therefore, the Office asserts that the
685 Commission has two alternatives:

- 686 ▪ Do not allow these costs into an ECAM until sufficient analysis justifies
687 their inclusion, or
- 688 ▪ Establish limits for the total amount of market purchases that could be
689 allowed to flow through the ECAM.

690

691 Q. WHAT KIND OF LIMITS WOULD THE OFFICE RECOMMEND?

692 A. The Commission would have to take into account many factors in
693 establishing limits for the inclusion of market purchases in an ECAM.
694 First, all economy energy purchases should be allowed. It is always in the
695 interest of customers for the Company to purchase energy when the costs
696 are lower than the variable production costs. Before any limits are
697 established, the Commission would need additional explanation of the
698 types of short term products available and being utilized. Some types of
699 FOT and short-term purchases are firm products that don't carry a lot of
700 risk and for which restrictions may not be appropriate. Also, since it is
701 presumed that energy not served (ENS) and differences between
702 forecasted demand and actual will also be served from the market, an
703 examination of these factors must also be included when considering
704 potential limits in an ECAM design. Therefore, the Office's conclusion is
705 that establishing limits would require a focused proceeding to determine
706 what limits are reasonable and to avoid imposing arbitrary restrictions.

707

708 Q. WOULDN'T THIS TYPE OF ANALYSIS BE DIFFICULT TO
709 ACCOMPLISH?

710 A. The Office acknowledges that this kind of analysis would be somewhat
711 complex. However, it would provide the additional benefits of better
712 understanding both of markets and the Company's planning process.
713 Further, absent this kind of analysis, the inclusion of market purchases

Phase II – Market Reliance

714 into an ECAM cannot be accomplished without an inappropriate shift of
715 risk to consumers.

716

717 Q. PLEASE SUMMARIZE THE OFFICE'S RECOMMENDATIONS.

718 A. In deciding whether some form of ECAM is in the public interest, the
719 Commission should do the following,

720 • Act upon the recommendations relating to the Company's hedging
721 practices proposed by the Office's experts, Mr. Wielgus and Dr.
722 Schell, that the Company should:

723

724 (1) Perform a thorough analysis of all costs associated with its
725 hedging practices (Wielgus);

726 (2) Evaluate the use of options to reduce price volatility (Wielgus);

727 (3) Evaluate the cost and benefit of the partial leveling of rates that
728 results from hedging natural gas compared to acquiring more non-
729 gas resources instead of gas resources. (Wielgus);

730 (4) Compare the value of its hedging practices with other ways to
731 address price volatility, such as the Enterprise Risk Management
732 (ERM) approach (Wielgus);

733 (5) Provide ample opportunity for affected parties to have input into
734 the process of evaluating the Company's hedging practices
735 (Wielgus);

736 (6) Reduce its volume-based hedge targets to reflect historical
737 system balancing levels (Schell);

738 (7) Re-examine the acceptable range of TEVaR levels (Schell).

739 Neither natural gas hedging costs nor natural gas fuel costs should
740 be allowed in an ECAM design until this evaluation has been
741 complete. If customers are going to be required to bear the risks of
742 natural gas cost fluctuation, they should have input into the
743 appropriate hedging strategies and associated costs.

744

Phase II – Market Reliance

- 745 • Require the Company to perform a comprehensive analysis
746 justifying the adequacy and depth of the western market to support
747 the projected volumes and prices associated with FOTs, as
748 indicated in its current resource plan. This justification should
749 include independent validation of the Company's market
750 assessment. This analysis should be done before the costs
751 associated with market purchases are allowed in any ECAM design
752 and also required on an ongoing basis in all future IRPs.
- 753 • Consider developing and applying limits on the volume of FOTs for
754 purposes of inclusion in an ECAM.

755

756 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY ON MARKET
757 RELIANCE ISSUES IN THE ECAM CASE?

758 A. Yes it does.

759

760