

Rocky Mountain Power
Docket No. 10-035-124
Witness: Darrell T. Gerrard

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Darrell T. Gerrard

Main Grid Transmission

January 2011

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 Darrell T. Gerrard. My business address is 825 NE Multnomah, Suite
4 1600, Portland, Oregon 97232. I am Vice President of Transmission System
5 Planning for PacifiCorp.

6 **Qualifications**

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

8 A. I have a Bachelor of Science degree in Electrical Engineering (Electric Power
9 Systems Major) from the University of Utah and Certificate of Completion with
10 Honors in Electrical Technology from Utah Technical College at Salt Lake. My
11 experience spans more than 30 years in the electric utility business and electric
12 power industry in general. I have working experience and have had management
13 responsibility for a number of functional organizations at PacifiCorp including:
14 Area Engineering, Area Planning, Region Engineering, T&D Facilities
15 Management, Transmission, Substation and Distribution Engineering, System
16 Protection and Control, T&D Project Management and Delivery, Asset
17 Management, Electronic Communications, Hydro System Engineering,
18 Transmission Grid Operations, and most recently Transmission System Planning.

19 **Q. What are your responsibilities as Vice President of Transmission System**
20 **Planning?**

21 A. I am responsible for transmission planning activities required to support
22 PacifiCorp’s existing and future bulk transmission system and to ensure a safe and
23 reliable transmission system provides adequate service to our customers

24 economically. I am also responsible for the conceptual and detailed system
25 planning and architecture associated with the Company's long-term Energy
26 Gateway Transmission Expansion Plan ("Energy Gateway").

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

28 A. The purpose of my testimony is to explain and support a portion of the
29 transmission capital expenditures included in the Company's application for a
30 general rate increase. Specifically, my testimony identifies the major capital
31 investments in the Company's main transmission grid that will be placed into
32 service between June 30, 2010 (the end of the base year in this case) and June 30,
33 2012 (the end of the test period in this case), explains the primary driver(s)
34 creating the need for these projects and resulting investment, and describes the
35 benefits to customers and the electrical system overall.

36 **Q. Customer load growth information is an important factor in determining the**
37 **need and the timing of transmission projects. What load information was**
38 **used to determine project need and to determine the investments are needed**
39 **now?**

40 A. PacifiCorp's Open Access Transmission Tariff ("OATT"),¹ approved by the
41 Federal Energy Regulatory Commission ("FERC") details the Company's
42 requirements and obligations to provide transmission service. Section 28.2 defines
43 PacifiCorp's responsibilities, which include the requirement to "plan, construct,
44 operate and maintain the system in accordance with good utility practice." Section
45 31.6 defines the requirement for network customers to supply annual load and

¹ http://www.oasis.pacificorp.com/oasis/ppw/OATTVol11Baseline_20100908.pdf

46 resource updates for inclusion in planning studies. The Company solicits this data
47 annually in order to determine future load and resource requirements for all
48 transmission network customers. The Company's retail loads comprise the bulk of
49 the transmission network customer needs, including those in Utah. Section 28.3
50 includes the requirement for PacifiCorp to provide "firm service over the system
51 so that designated resources can be delivered to designated loads." The project
52 investments included in this proceeding are necessary to meet these requirements
53 and customer demand.

54 The customer load demands from 2010 network customer loads and resource
55 submittals indicates demand in the Wasatch Front of Utah alone is anticipated to
56 grow from a peak of 4800 MW in 2011 to 6,211 MW in 2019. The Wasatch Front
57 area of Utah comprises more than 80 percent of the electrical demand in the state
58 of Utah.

59 **Q. Do you believe that such customer load demand forecasts reflect the**
60 **economic conditions in Utah and impacts on customer demand?**

61 A. Yes. While I'm not an expert on the economy, I can attest to the fact that
62 reductions in customer energy demand forecasts have coincided with the
63 economic downturn. As stated above, the company requests and reviews all of its
64 forecasted energy demand and resource submittals annually. The 2010 customer
65 demand forecasts for the Wasatch Front, for example, showed a reduction in
66 forecasted customer demand for the year 2018 of nearly 375 MW compared to the
67 2018 forecasts received in 2009. Despite this reduction, the overall demand
68 forecast for the Wasatch Front is still expected to grow to 6,211 MW by 2019.

69 **Q. Can you provide examples of instances where the Company revised its**
70 **investment timing as a result of reductions in forecasted demand?**

71 A. Yes. The Company uses its customer demand forecasts and best available
72 information to determine project need and investment timing. Examples of
73 projects in this filing which have been rescheduled and influenced by actual and
74 forecast reductions in customer demand include:

- 75 • The \$16 million Pinto 345 kV Series Capacitor project was delayed one
76 year from 2009 to 2010 based on reduced risk due to lower customer
77 demand as well as construction schedules;
- 78 • The Red Butte Static VAR Compensator project was delayed early in its
79 project life cycle from 2009 to 2011, again based on reduced risk due to
80 lower customer demand. The Company delayed the full investment, to the
81 benefit of customers, by installing only an initial \$4 million portion of the
82 device in 2010, delaying more than \$44 million of remaining investment
83 by two years; and
- 84 • The Mona to Oquirrh project, the second segment of Gateway Central,
85 was delayed two years from 2011 to 2013 due to changing business
86 requirements along with some reduced risk resulting from slower
87 customer growth and reduced demand.

88 **Q. Which customers provided load data for PacifiCorp's 2010 annual load and**
89 **resource forecast?**

90 A. All PacifiCorp network load customers provided their annual load and resource
91 forecast in 2010. These customers include: PacifiCorp Commercial and Trading,

92 Utah Associated Municipal Power Systems, Utah Municipal Power Agency,
93 Deseret Power Electric Cooperative, Bonneville Power Administration, Basin
94 Electric Power Cooperative, and Moon Lake Electric Association.

95 **Q. Are there other transmission performance requirements, besides growing**
96 **customer energy demand, driving the need for these system investments?**

97 A. Yes. In meeting the current and future customer energy needs described above,
98 the Company must maintain a minimum level of system reliability to provide
99 adequate transmission service. The North American Electric Reliability
100 Corporation (“NERC”) and the Western Electricity Coordinating Council
101 (“WECC”) have recently enacted a significant number of standards and guidelines
102 that specify in detail the levels of system performance that utilities must maintain
103 during the planning, operation and ongoing maintenance of their bulk electric
104 systems. NERC’s reliability standards were approved by FERC and are
105 mandatory for all FERC-jurisdictional entities. These reliability standards are
106 targeted at improving the security and reliability of the nation’s bulk electric
107 system, including the system in Utah. The projects and related investments
108 discussed herein are required for the Company to comply with these mandatory
109 reliability standards and to provide safe, reliable and efficient transmission service
110 to customers.

111 **Q. What specific reliability performance standards and criteria require the**
112 **project investments in this case and drive their timing to completion?**

113 A. PacifiCorp plans, designs and operates its transmission system to meet or exceed
114 NERC Standards for Bulk Electric Systems and WECC Regional standards and

115 criteria. The NERC standards are federal law stated in 18 CFR Part 40
116 (Mandatory Reliability Standards for Bulk-Power Systems). The WECC
117 standards and criteria are deemed necessary for the WECC Region to meet or
118 exceed NERC standards. There are currently more than 100 approved NERC
119 standards to which the Company must comply. The project investments and their
120 respective in-service date timing are required to maintain compliance with the
121 following:

- 122 • NERC TPL-001 System Performance Under Normal Conditions²
- 123 • NERC TPL-002 System Performance Following Loss of a Single
124 BES Element³
- 125 • NERC TPL-003 System Performance Following Loss of Two or
126 More BES Elements⁴
- 127 • NERC TPL-004 System Performance Following Extreme BES
128 Events⁵
- 129 • TPL 001-WECC-1-CR System Performance Criteria Normal Conditions⁶
- 130 • TPL 002-WECC-1-CR System Performance Criteria Following Loss of a
131 Single BES Element
- 132 • TPL 003-WECC-1-CR System Performance Criteria Following Loss of
133 Two or More BES

² NERC TPL-001 can be found at: <http://www.nerc.com/files/TPL-001-0.pdf>

³ NERC TPL-002 can be found at: <http://www.nerc.com/files/TPL-002-0.pdf>

⁴ NERC TPL-003 can be found at: <http://www.nerc.com/files/TPL-003-0.pdf>

⁵ NERC TPL-004 can be found at: <http://www.nerc.com/files/TPL-004-0.pdf>

⁶ TPL 001-WECC-1-CR – TPL 004-WECC -1-CR can be found at:
<http://www.wecc.biz/Standards/WECC%20Criteria/TPL-001%20thru%20004-WECC-1-CR%20-%20System%20Performance%20Criteria.pdf>

- 134 • TPL 003-WECC-1-CR System Performance Criteria Following Extreme
- 135 BES Events
- 136 • NERC TOP-002 Normal Operations Planning⁷
- 137 • NERC TOP-004 Transmission Operations⁸
- 138 • NERC TOP-007 Reporting SOL and IROL Violations⁹

139 The above-referenced standards dictate the minimum levels of transmission
140 system reliability, redundancy and performance required for transmission
141 facilities in this case.

142 **Q. Please discuss further how these standards and criteria influence the timing**
143 **of the transmission project investments you discuss in this filing.**

144 A. These mandatory standards require the Company to have a forward-looking
145 transmission plan of action to reliably serve current and anticipated customer
146 demands under all expected operating conditions, including normal system
147 operations (all system elements in service) and during system contingencies
148 (where elements of the transmission system are out of service), both planned or
149 otherwise. NERC Transmission Planning Standard TPL 002 states:

150 **A. Introduction**
151 **Purpose:** System simulations and associated assessments are needed
152 periodically to ensure that reliable systems are developed that *meet*
153 *specified performance requirements with sufficient lead time*, and continue
154 to be modified or upgraded as *necessary to meet present and future system*
155 *needs.*

⁷ NERC TOP-002 can be found at: <http://www.nerc.com/files/TOP-002-2.pdf>

⁸ NERC TOP-004 can be found at: <http://www.nerc.com/files/TOP-004-2.pdf>

⁹ NERC TOP-007 can be found at: <http://www.nerc.com/files/TOP-007-0.pdf>

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B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

- R1.1.** Be made annually.
- R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

- R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
 - R2.1.1.** Including a schedule for implementation.
 - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
 - R2.1.3.** Consider lead times necessary to implement plans.

(Emphasis added)

In conclusion, the Company is required to have both short-term and long-term transmission plans to reliably meet all expected current and forecasted customer electrical demands. The requirement to have such a plan and prudently act on all projects in that plan is not optional for the Company. The Company conducts annual load and resource forecasting analyses and revises its investment timing as a result of identified reductions in forecasted demand where appropriate. Most of the projects in this filing require multi-year planning, permitting and construction processes, and the Company must consider the lead times and schedules for implementation.

192 **Q. Please describe the major transmission investments that the Company is**
193 **adding to rate base in this filing.**

194 A. As reflected by Mr. Steven McDougal's Exhibit RMP____(SRM-3), between June
195 30, 2010, and June 30, 2012, the Company will place into service over \$1.1 billion
196 of transmission investment. My testimony discusses major capital projects making
197 up \$929.9 million of total investment as follows: 1) completion of the first segment
198 of Energy Gateway (Populus to Terminal); 2) transmission projects greater than
199 \$10 million; and 3) transmission projects less than \$10 million and larger than \$1
200 million. Exhibit RMP____(DTG-1) contains a list of these projects, including a
201 short project description for each transmission investment and investment totals.
202 Company witness Mr. Douglas N. Bennion addresses, separately, approximately
203 \$236.4 million of local transmission investments in his testimony.

204 **Populus to Terminal**

205 **Q. Please describe the projects related to completion of the first segment of**
206 **Energy Gateway (Populus to Terminal).**

207 A. The Populus to Terminal project was fully energized and placed into service
208 November 19, 2010. Exhibit RMP____(DTG-1) contains a list of transmission
209 projects related to the Populus to Terminal segment of Energy Gateway that have
210 been, or will be, placed into service after June 30, 2010, totaling approximately
211 \$575.5 million on a total company basis. The Ben Lomond to Terminal portion of
212 the project was placed into service early in 2010 and the related costs are included
213 in the unadjusted rate base balances in this case. Because the Populus to Ben
214 Lomond portion of the project was completed in November 2010, the related costs

215 are added to rate base as part of the capital addition adjustment in Mr. McDougal's
216 revenue requirement calculations.

217 **Q. Has the Commission already approved recovery of some of the Populus to**
218 **Terminal transmission investments? If so, please explain why these**
219 **investments are included in this case.**

220 A. Yes. The Company included two segments of the Populus to Terminal project in
221 its two major plant addition ("MPA") filings in Docket Nos. 10-035-13 and 10-
222 035-89. In those dockets, the Company fully explained and justified the benefits
223 of the Populus to Terminal project for Utah ratepayers. Effective January 1, 2011,
224 the related revenue requirement is being collected from Utah customers through a
225 surcharge in Schedule 40. In addition to the project costs included in the two MPA
226 filings, this general rate case includes in rate base residual closing costs and the
227 Borah Reconductor portion of the project, which amount to approximately three
228 percent of the total project cost. As a result of this case all of the Populus to
229 Terminal project investments will be included in base rates and Schedule 40 will
230 be eliminated.

231 **Transmission Projects Greater than \$10 Million**

232 **Q. Please describe the other transmission investments that the Company is**
233 **adding to rate base in this filing which are greater than \$10 million.**

234 A. Between June 30, 2010, and June 30, 2012, the Company will place into service
235 approximately \$294 million of transmission investment for projects over \$10
236 million each. Exhibit RMP____(DTG-1) individually lists and breaks out these
237 projects, as follows:

238 **1. Red Butte Static VAR Compensator and 345 kV Capacitor: \$49 million.**

239 Installation of a 300 MVAR Static VAR Compensator and 345 kV capacitor is
240 required along with facility expansion at the Red Butte substation in southwest
241 Utah. Studies of the southwestern Utah area have shown the need for additional
242 reactive power support during normal steady-state operations and during system
243 outage conditions. This project is required to ensure continued reliable service to
244 existing and growing loads in this area. This includes the customers of Rocky
245 Mountain Power, UAMPS and Deseret. It is also needed to maintain the
246 Company's existing firm point-to-point firm transmission service contract
247 obligations on the WECC rated transmission Path TOT 2C, which connects the
248 Company's transmission system to Nevada at Nevada Energy's Harry Allen
249 substation. The project is also required to maintain compliance with mandatory
250 NERC/WECC Transmission Planning Standards TPL-01 through 04 and
251 Transmission Operating Procedures TOP 02, 04, and 07.¹⁰

252 **2. 90th South - Camp Williams 345 kV Double Circuit Line: \$43 million**

253 This project requires building a new double circuit 345 kV line 10.7 miles long in
254 an existing corridor located between the Camp Williams and 90th South
255 substations and modification of those facilities. Transmission operational transfer
256 capability and reliability studies conducted northbound into the Wasatch Front
257 area in Utah have demonstrated the need for the new double circuit 345 kV
258 transmission line (10.7 miles). During periods of heavy customer demand along
259 the Wasatch Front energy imports from the Company's generation facilities in the

¹⁰ http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf

260 southern part of the state must be limited for reliability reasons. The transmission
261 path serving the Wasatch Front from Camp Williams cannot withstand a double
262 line loss (loss of an existing corridor) and operate within mandatory
263 WECC/NERC reliability criteria; such an event would overload the remaining
264 transmission circuits in the area north of Camp Williams. This project and its
265 resulting investment are necessary for ongoing reliable load service to existing
266 customers and for future long term load growth forecasted in the area. The project
267 is also required to maintain compliance with mandatory WECC transmission
268 planning TPL-01 through 04 and transmission operating standards TOP-02, 04
269 and 07.

270 **3. Terminal Substation - Replace two 345/138 kV Transformers: \$41 million**

271 This project requires removal of the two existing 345-138 kV 450 MVA
272 transformers at the Terminal substation and necessarily replaces and modifies the
273 existing facilities. Areas of the Salt Lake valley are currently served from six
274 interconnected 345-138 kV transformers operating as a network. Two
275 transformers are located at each of the 90th South, Mid Valley, and Terminal
276 substations. Studies performed for the summer loading season including calendar
277 years 2010 to 2013 showed that if one of these transformers were out of service
278 (planned or unplanned) the remaining transformers would become overloaded
279 beyond their operating limitations. The most severe overload would occur due to
280 loss of one of the 450 MVA transformers at the Terminal substation. This project
281 and its resulting investment is required to provide ongoing reliable service to
282 existing customers and for future long term load growth forecasted for the area.

283 The project is also required to maintain compliance with mandatory WECC
284 Transmission Planning Standards TPL-01 through 04.

285 **4. Wallula - McNary 230 kV Single Circuit Line: \$36 million**

286 This project requires building a new 30 mile long 230 kV transmission line in a
287 new right-of-way from the existing PacifiCorp Wallula substation in Washington
288 to the existing Bonneville Power Administration McNary substation near
289 Umatilla, Oregon. To date, the line route has been determined, initial line design
290 has been completed and the majority of required permits have been acquired. The
291 Wallula substation will be expanded within existing property bounds to
292 accommodate the new line connection. PacifiCorp's transmission system in the
293 Walla Walla area, including the existing lines between Walla Walla, Wallula and
294 McNary, is currently fully subscribed. PacifiCorp has a signed contract, for firm
295 point-to-point transmission service from Wallula to McNary, and is required
296 under it's OATT to construct this project in order to meet the terms of these
297 transmission service contracts. The project and it's investment is required to
298 facilitate integration of new renewable energy sources being constructed in the
299 Wallula area.

300 **5. Dave Johnston - Casper 230 kV Rebuild - Casper Sub: \$31 million**

301 This project involves relocation of portions and rebuilding of all of the existing
302 Dave Johnston – Casper 230 kV #1 line. Additionally the project requires
303 installation of a new conductor on the existing Dave Johnston – Casper 230 kV #2
304 line. The project scope also includes modification of facilities at the Casper and
305 Dave Johnston Substations. Without this project the WECC rated Path TOT4A

306 operating capacity must be reduced by 100 megawatts resulting in curtailment of
307 firm energy transfers from the Dave Johnston and Wyodak plants and reductions in
308 firm and non-firm power sales across the path. This project is required to maintain
309 existing transmission capacity to serve existing customer demand and to meet
310 forecast future load growth in areas of Wyoming and to maintain existing WECC
311 Path ratings. The project and resulting investment are also necessary to maintain
312 compliance with NERC/WECC Transmission Planning Standards TPL-01 through
313 04 and Transmission Operating Standards TOP-02, 04, and 07.

314 **6. Install Shunt Capacitors in Wyoming - Platte Sub SVC: \$18 million**

315 This project requires installation of a Static VAR Controller for reactive power
316 support and 230 kV voltage control in south/central Wyoming. The project
317 includes 230 kV equipment and control installations at several existing substations:
318 Atlantic City, Midwest, Riverton and Platte. The industrial load growth in
319 Wyoming is currently being added in large megawatt increments, which the
320 current 230 kV system cannot support. This project is required to maintain existing
321 transmission transfer capacity to continue to reliably serve existing customers and
322 to meet forecast future load growth in areas of Wyoming while maintain existing
323 WECC rating on Path TOT4A. This path is a critical interconnection to the wider
324 transmission system connecting Utah, Idaho and Wyoming. The project and
325 resulting investments are also necessary to maintain compliance with
326 NERC/WECC Transmission Planning Standards TPL-01 through 04 and
327 Transmission Operating Standards TOP-02, 04, 07.

328 **7. Malin Substation 500 kV Series Capacitor Replacement: \$17 million**

329 This project required the replacement of the Company's existing 500 kV series
330 capacitor located in Bonneville Power Administration's Malin substation near
331 Klamath Falls, Oregon. There are currently three separate series capacitors
332 installed on the California-Oregon AC Intertie 500 kV system, one of which is
333 owned by the Company. The Company's series capacitor located at Malin is the
334 smallest of the existing three capacitors and thereby is the limiting electrical
335 element in obtaining a higher operating transfer capacity on the Pacific AC
336 Intertie, of which the Company is also part owner. Replacement of the series
337 capacitor was agreed to as a necessary transmission system upgrade under FERC
338 Docket Number ER07-822-000 Article VII.

339 **8. Pinto 345 kV Series Capacitor: \$17 million**

340 This project requires the installation of a new 345 kV series capacitor bank at the
341 existing Pinto substation. The new equipment has been installed on existing
342 Company-owned property to the east of the Pinto substation and required
343 modification of the Pinto facility. The series capacitor is required to provide
344 normal steady-state service to existing customers in the area and is required for
345 long term future load growth. The project is also required to meet the Company's
346 existing firm point-to-point transmission service contracts on the WECC rated Path
347 2A "Pinto to Four Corners." This path is a critical interconnection to the wider
348 transmission system connecting Utah into the Four Corner states. The project and
349 resulting investments are necessary to maintain compliance with NERC/WECC

350 Transmission Planning Standards TPL-01 through 04 and Transmission Operating
351 Standards TOP-02, 04, 07.

352 **9. Harry Allen Sub Install Transformer: \$15 million**

353 This project requires installation of a second 300 MVA 230/345 kV transformer at
354 Nevada Energy's Harry Allen substation. This is a 230/345 kV transformer which
355 electrically connects the Company's single Red Butte 345 kV line to Nevada. The
356 existing transformer at Harry Allen is not capable of serving the existing or future
357 forecasted customer loads in southwest Utah. Under certain expected operating
358 conditions at Red Butte the existing transformer will become overloaded above its
359 operating limits. The project and resulting investment are necessary to maintain
360 compliance with NERC/WECC Transmission Planning Standards TPL-01 through
361 04 and Transmission Operating Standards TOP-02, 04, 07.

362 **10. Union Gap - Add 230 - 115kV Capacity: \$15 million**

363 This project requires installation of a third 150 MVA 230/115 kV transformer and
364 expansion of both the 230 kV and 115 kV facilities at the existing Union Gap
365 substation in Yakima, Washington, which is one of two main 230/115 kV source
366 substations serving the Upper Yakima Valley of Washington. Failure of one of the
367 existing transformers would result in unacceptable overload of the remaining
368 transformer. This project and resulting investment is required to reliably meet
369 existing customer load service and to meet the load growth demands forecasted for
370 the future. This project and resulting investments are also necessary to maintain
371 compliance with NERC/WECC Transmission Planning Standards TPL-01 through
372 04 and Transmission Operating Standards TOP-02, 04, 07.

373 **11. Mona - Limber - Oquirrh 500/345 kV line Phases 0, I, II: \$13.7 million**

374 The Mona to Oquirrh project is the second segment of Energy Gateway Central.

375 This plant addition is the total of three investments required for development and

376 construction of the initial portion of the Mona to Oquirrh segment. The first project

377 \$8.4M requires “looping in” the Company’s existing Camp Williams to Terminal

378 345kV line into and out of the Company’s existing Oquirrh 345kV substation

379 located in South Jordan Utah. This project is required for increased reliability

380 necessary to maintain reliable service to existing and future customers in the

381 Wasatch Front of Utah during transmission line outages north of Camp Williams.

382 The project and resulting investment are necessary to maintain compliance with

383 NERC/WECC Transmission Planning Standards TPL-01 through 04 and

384 Transmission Operating Standards TOP-02, 04, 07.

385 The second and third investments as part of this plant addition are necessary plant

386 held for future use which the Company has included to allow for recovery of these

387 costs. The Company has contracted to purchase the real property for the future

388 Clover substation, near Mona Utah for \$3.3 million, and for the future Limber

389 substation in Tooele County for \$2.0 million. These future substations are required

390 in order to provide 345/138kv transmission service to customers in the Mona and

391 Cedar City area and to customers in Tooele County respectively. In addition the

392 property needed for both of these substations are part of the Company’s Gateway

393 Central plans. Securing substation property for both stations is required in 2011 in

394 order for the Company to effectively complete substation physical layouts, perform

395 geotechnical studies, engineering and designs, and to establish necessary

396 transmission line entrances and exits and to avoid line crossings and conflicts and
397 prepare complete bid packages .

398 The Mona to Oquirrh project is necessary to remove existing transmission system
399 limitations, reliably serve existing customers and serve forecasted long term load
400 growth in the state. It is also required to meet the Company's integrated resource
401 plans and is necessary to deliver identified energy resources to load centers. The
402 Mona to Oquirrh project has been issued a Certificate of Public Convenience and
403 Necessity by the Utah Public Service Commission under Docket No. 9-035-54,
404 dated June 16, 2010, and has been approved by the Utah Utility Facility Review
405 Board under Docket No. 10-035-39, dated June 10, 2010.

406 **Transmission Projects under \$10 Million**

407 **Q. Please describe the major transmission investments that the Company is**
408 **adding to rate base in this filing which are under \$10 million and greater than**
409 **\$1 million.**

410 A. Exhibit RMP___(DTG-1) individually lists projects that are less than \$10 million
411 and greater than \$1 million each. These projects total \$60.5 million dollars and are
412 required to meet requirements and obligations under the Company's retail tariffs
413 and FERC-approved Open Access Transmission Tariff ("OATT") and to maintain
414 compliance with mandatory reliability and operational standards. These projects
415 include: upgrading transmission facilities necessary to provide adequate and
416 reliable service benefiting our existing customers and meeting their energy
417 demands forecasted in the future, meeting transmission service requests and
418 generator interconnection requests and third party customer transmission service

419 contracts required by FERC under the Company's OATT, and maintaining the
420 system in compliance with NERC/WECC reliability standards.

421 **Q. Please summarize your testimony.**

422 A. The major transmission capital expenditures included in my testimony are all
423 essential to meet customers' needs, both current and future, while providing safe,
424 adequate, reliable and efficient electric transmission service. The major portion of
425 the transmission investment associated with plant additions in this case are a
426 result of the Populus to Terminal project, which has already been scrutinized by
427 parties through the regulatory process where the Company demonstrated
428 prudence, purpose and need and that the project is used and useful. As a result of
429 this filing, Populous to Terminal will be rolled into base rates and the current
430 surcharge will be eliminated. The other transmission plant additions in this case
431 will provide transmission service benefits to all of the Company's customers,
432 including those in Utah, by providing access to low cost resources, increasing
433 system reliability required for transport of energy to load centers while helping to
434 control delivered energy costs.

435 **Q. Are the Transmission capital investments included in this case in the public**
436 **interest and do you recommend that the Commission include them in the**
437 **Company's rate base?**

438 A. Yes. The transmission capital investments included in this case are in the public
439 interest for the reasons I discuss throughout my testimony, including serving the
440 public with safe, adequate and reliable service. For these reasons, I recommend

441 that the Commission approve these investments for inclusion in the Company's
442 rate base.

443 **Q. Does this complete your testimony?**

444 **A. Yes.**