

1 **Q. Please state your name, business address and position with PacifiCorp dba**  
2 **Rocky Mountain Power.**

3 A. My name is Darrell T. Gerrard. My business address is 825 N.E. Multnomah,  
4 Suite 1600, Portland, Oregon. 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 (Power Systems  
9 Major) at the University of Utah and Certificate of Completion with Honors in  
10 Electrical Technology from Utah Technical College at Salt Lake. My experience  
11 spans more than 30 years in the electric utility business and electric power  
12 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 planned bulk transmission system and to ensure a  
23 safe and 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 strategy ("Energy Gateway").

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

28 A. The purpose of my testimony is to provide additional details and technical  
29 information on the Company's decision to build the double-circuit 345kv Populus  
30 to Terminal transmission line (Phase I and II), which is part of Segment B of the  
31 Energy Gateway Project (see Exhibit RMP\_\_\_\_(JAC-1)).

32 **Overview of Transmission Project**

33 **Q. Please describe the scale and size of the Populus to Terminal transmission**  
34 **segment.**

35 A. Populus to Terminal will add 135 miles of new transmission line, over 8,600,000  
36 linear feet of conductor and approximately 900 poles will be installed on new  
37 foundations. The Ben Lomond to Terminal section specifically, is approximately  
38 47 miles and includes 3,010,000 linear feet of conductor and over 260 poles. At  
39 the time of this filing, the overall Populus to Terminal segment is on schedule  
40 with a total of 833 transmission structure foundations installed, 871 access roads  
41 constructed, 755 poles set and 6,375,000 linear feet of conductor pulled. For Ben  
42 Lomond to Terminal (Phase 1), 265 foundations are installed, 260 poles set and  
43 2,941,000 linear feet of conductor pulled. The large majority of work remaining  
44 before the June 2010 completion date is substation work at Ben Lomond and  
45 Terminal. Exhibit RMP\_\_\_\_(DTG-1) contains photos of assets in place for Ben  
46 Lomond to Terminal and Populus to Ben Lomond.

47 **Q. Please describe the transmission investment included in this rate case.**

48 A. In this Docket, the Company is seeking cost recovery for the Ben Lomond to  
49 Terminal section (“Phase I”) of the Populus to Terminal transmission segment B  
50 of Energy Gateway, described in more detail in the direct testimony of Mr. John  
51 A. Cupparo. A map showing the entire route of the Populus to Terminal segment  
52 is shown in Exhibit RMP\_\_\_(JAC-2). Phase I is an integral part of the overall  
53 Populus to Terminal transmission segment and is the first section to be  
54 constructed and completed. The Ben Lomond Substation and Terminal Substation  
55 will be expanded to accommodate the new 345 kV transmission lines and  
56 termination points. The Company expects the total investment in the Ben Lomond  
57 to Terminal section (Phase I) to be \$268 million, based on project costs estimates  
58 detailed in Exhibit RMP\_\_\_(DTG-2) and expects the line to be fully in-service by  
59 June 30, 2010, and used and useful to customers at that time.

60 **Q. What is the purpose of the Populus to Terminal transmission segment?**

61 A. In addition to the project benefits described in the testimony of Mr. Cupparo, the  
62 purpose of the Populus to Terminal line project is to:

- 63 • Increase the overall transmission capacity in the existing transmission  
64 corridor between Southeast Idaho and Northern Utah where the existing  
65 system has limited capacity and has demonstrated operational limitations;
- 66 • Meet the immediate need to improve system reliability in the area by  
67 installing transmission capacity to ensure the system can sustain  
68 transmission outages north of Terminal Substation without curtailing  
69 loads, generation or impacting the PacifiCorp East Control Area and

70 neighboring transmission balancing authority areas. Currently between  
71 Terminal Substation and Ben Lomond Substation, there is only one double  
72 345 kV circuit and one single 230 kV circuit. Loss of the existing double  
73 345 kV circuit has potentially serious operational consequences as the  
74 remaining system overloads;

75 • Improve the Company's ability to perform maintenance on transmission  
76 facilities between Populus and Terminal by having alternative  
77 transmission paths that allow facilities to be taken off-line and maintained;

78 • Integrate with future Energy Gateway segments to increase transfer  
79 capability between PacifiCorp's east and west control areas in order to  
80 balance generating resources and loads, enable commercial energy  
81 purchases or sales while allowing integration of new renewable generation  
82 resources;

83 • Provide PacifiCorp with options and greater flexibility when considering  
84 future planned resources to meet customers' growing demands for energy  
85 service requirements while meeting current and future energy  
86 requirements that may be mandated by state and federal regulation;

87 • Facilitate the integration of potential new energy resources in Wyoming,  
88 Utah and Idaho, and help support economic development planned in those  
89 states; and

90 • In the long-term, provide an incremental increase in transmission capacity  
91 and reliability benefits for future Energy Gateway transmission segments  
92 planned between Wyoming, Idaho, Utah, Oregon and Washington, and

93 interconnecting the region in general.

94 **Need for and Benefit of Additional Transmission**

95 **Q. What information has been used in determining the need and justification**  
96 **for this investment?**

97 A. PacifiCorp's Open Access Transmission Tariff ("OATT"), approved by the  
98 Federal Energy Regulatory Commission ("FERC"), provides details regarding  
99 PacifiCorp's requirements and obligations to provide transmission service.  
100 Section 28.2 defines PacifiCorp's responsibilities, which include the requirement  
101 to "plan, construct, operate and maintain the system in accordance with good  
102 utility practice." Section 31.6 defines the requirement for network customers to  
103 supply annual load and resource updates for inclusion in planning studies. The  
104 Company solicits this data annually in order to determine future load and resource  
105 requirements for all transmission network customers including PacifiCorp's  
106 network customers and customers of third parties under our FERC-approved  
107 OATT. The Company's retail loads comprise the bulk of the transmission  
108 network customer needs including those in Utah. Section 28.3 includes the  
109 requirement for PacifiCorp to provide "firm service over the system so that  
110 designated resources can be delivered to designated loads." These future  
111 requirements and needs will be met via Energy Gateway and its segments,  
112 including the Populus to Terminal. Ben Lomond to Terminal is Phase I of that  
113 segment, all of which is an important part of PacifiCorp's overall transmission  
114 plan for Utah and the region.

115 **Q. Are other transmission performance requirements besides growing customer**  
116 **energy demand driving the need for this system investment?**

117 **A.** Yes. In meeting the current and future customer energy needs described above,  
118 the Company must maintain a level of system reliability in order to provide  
119 adequate transmission service. The North American Electric Reliability  
120 Corporation (“NERC”) and the Western Electricity Coordinating Council  
121 (“WECC”) have recently adopted and enacted a significant number of standards  
122 and guidelines that specify in detail the levels of system performance that entities  
123 like PacifiCorp must maintain during the planning, operation and ongoing  
124 maintenance of their bulk electric system. NERC’s reliability standards have been  
125 approved by FERC and are mandatory for all FERC-jurisdictional entities. These  
126 reliability standards are targeted at improving the security and reliability of the  
127 nation’s electric infrastructure and, specifically in our case, in the WECC region.  
128 Investments being made via this transmission project will help PacifiCorp meet  
129 reliability requirements. Further, the investment will provide reliability benefits to  
130 future planned high-voltage transmission additions interconnecting Wyoming,  
131 Utah and Idaho and the region.

132 **Q Are there examples where these new reliability standards and guidelines**  
133 **have resulted in changes to the system and its operation? If so, how is that**  
134 **change driving investments required in transmission?**

135 **A.** Yes. In early 2008, PacifiCorp performed an operational analysis of the  
136 transmission system north of Ben Lomond substation. As a result of this analysis  
137 and reflective of NERC and WECC standards and guidelines, the system firm

138 transmission capacity was reduced from approximately 775MW to 430MW  
139 during heavy load hours and reduced from approximately 900MW to 620MW  
140 during light load hours. This reduction in firm capacity was a result of NERC and  
141 WECC standards and guidelines that require transmission capacity to be reduced  
142 due to potential outage risks associated with multiple transmission lines being  
143 located adjacent to each other in common corridors. The investment in the  
144 Populus to Terminal segment is required to improve the firm capacity in this part  
145 of the transmission system.

146 **Q. How did the Company determine that additional transmission capacity was**  
147 **needed?**

148 A. The Company utilizes the Integrated Resource Plan (“IRP”) to review whether  
149 additional transmission capacity is needed. The IRP uses a public process to  
150 develop a framework for the prudent future actions required to ensure the  
151 Company continues to provide reliable and least-cost electric service to its  
152 customers, while striking an expected balance between cost and risk over the  
153 planning horizon and taking into consideration environmental issues and the  
154 energy policies of our states. As stated in the 2008 IRP, “PacifiCorp’s IRP  
155 mandate is to assure, on a long-term basis, adequate and reliable electricity supply  
156 at a reasonable cost and in a manner consistent with the long-run public interest.”

157 **Q. Did the Company make any commitments to add transmission capacity?**

158 A. Yes. During the MidAmerican Energy Holdings Company (“MEHC”) acquisition  
159 of PacifiCorp in 2006, the Company committed to increase the transmission  
160 capacity by 300 MW from southeast Idaho to northern Utah. The objectives of the

161 transaction commitment were to:

- 162 • Enhance the reliability of the only high use commercial path between  
163 Idaho and Utah;
- 164 • Provide for increased transfer capability between PacifiCorp's east and  
165 west control areas; and
- 166 • Facilitate the delivery of future power from wind projects in Wyoming  
167 and Idaho, and provide PacifiCorp with greater flexibility and the  
168 opportunity to consider additional options regarding future planned  
169 generation capacity additions.

170 **Q. Describe how the Populus to Terminal transmission segment complies with**  
171 **the IRP and MEHC commitment.**

172 A. The Populus to Terminal transmission line segment is designed to meet load  
173 growth, future customer energy service requirements and improve overall system  
174 reliability. Based on the Company's 2008 IRP forecasts, PacifiCorp's network  
175 load obligation is expected to grow during the next 10 to 20 years. In addition,  
176 operational reserve obligations required to balance and maintain system reliability  
177 will increase over time as they are a function of load served. The existing  
178 transmission capacity from southeastern Idaho into Utah is fully subscribed and  
179 no additional capacity can be made available without the addition of new  
180 transmission lines. The Populus to Terminal line will add significant new  
181 incremental transmission capacity (1,400MW planned) to this area of the system  
182 and will help integrate other future planned resources, market purchases and sales  
183 as necessary to help control energy costs. The investment also improves the

184 system reliability as needed, which I discuss later in my testimony. All of the  
185 above support PacifiCorp's IRP and the commitments made by MEHC.

186 **Q. Has the Company performed other studies and analyses that demonstrate the**  
187 **need to improve the reliability of the transmission system in this area?**

188 A. Yes, in addition to the long-term energy resource needs identified in PacifiCorp's  
189 IRP mentioned above, the Company performed specific analysis in late 2007 and  
190 2008 addressing several system disturbance events that severely impacted  
191 generation, customers, and the operation of the transmission system affecting  
192 Wyoming, Utah and Idaho. These events also impacted other utilities  
193 interconnected to PacifiCorp's transmission system. It is evident from these  
194 disturbances and the resulting analysis that the transmission system in this area  
195 does not have the necessary capacity and reliability to meet all of the system  
196 operating conditions expected. NERC electric system reliability standards require  
197 that the system demonstrate adequate performance for all expected operating  
198 conditions expected including multiple contingencies. There have been five  
199 system disturbances since September 2007 for which the Populus to Terminal line  
200 directly mitigates the risk of reoccurrence. Three of these disturbances occurred  
201 on the system north of Ben Lomond substation and two occurred south in the Ben  
202 Lomond to Terminal section. These disturbances resulted in system overloads,  
203 curtailments of schedules, repeated curtailments of interruptible loads and  
204 generation reductions in Wyoming, Utah and other surrounding states. The three  
205 disturbances occurred on September 27, October 15 and October 21, 2007, during  
206 periods of heavy flow northbound from the Terminal Substation towards Ben

207 Lomond and into Idaho. As a result, over 1,450 customers were affected by the  
208 first outage, and Nucor and Monsanto loads were either interrupted and/or  
209 reduced during all three outages. Generation curtailments and adjustments of  
210 more than 1,000 MW had to be requested for all three incidents including reduced  
211 generation from Dave Johnston and Naughton plants in Wyoming. Details and  
212 analysis of the system performance during the events and transmission limitations  
213 are detailed in PacifiCorp System Disturbance Report dated November 11, 2007,  
214 and PacifiCorp's Abbreviated System Disturbance Report to WECC dated  
215 January 28, 2008.

216 On November 27 and November 30, 2007, two disturbances occurred on  
217 the Ben Lomond to Terminal section (refer to Exhibit RMP\_\_JAC-2) of the  
218 system, causing overloads on three WECC designated and monitored transmission  
219 paths. The disturbances impacted more than 400 MW of PacifiCorp generation  
220 along with generation interconnected to three other utilities in surrounding states.

221 Based on the system performance, studies and analysis it is clear that the  
222 existing system requires new capacity to meet expected operating conditions and  
223 reliability requirements on both a short and long-term basis. The investment in the  
224 Ben Lomond to Terminal line is the first step in providing the needed capacity.

225 **Q. What is the transmission capacity and limitations on this system today?**

226 A. The existing transmission capacity in the area between Salt Lake City and  
227 Southeast Idaho is fully subscribed for firm service and has limited transfer  
228 capability between several key transmission substations (Terminal, Ben Lomond,  
229 and proposed Populus) connecting generation facilities in Idaho, Wyoming and

230 Utah. No new capacity will be available until new transmission facilities are  
231 constructed. The limitations and system performance deficiencies are discussed  
232 later in my testimony.

233 **Q. Does the investment in the Ben Lomond to Terminal line provide reliability**  
234 **and capacity benefits to future planned transmission additions in the area?**

235 A. Yes. The existing transmission in the corridor from Terminal to Southeastern  
236 Idaho has limitations. Without investment in the Populus to Terminal line, the full  
237 transfer capability on both of the Gateway West and Gateway South Segments  
238 would not be possible. To obtain the full capacity of the Gateway West and  
239 Gateway South segments, both segments must be electrically interconnected. This  
240 interconnection is achieved by building the Populus to Terminal transmission line  
241 as part of Gateway Central.

242 **Q. What alternatives to the Populus to Terminal project did PacifiCorp**  
243 **consider?**

244 A. The Company considered, but rejected four alternatives. The first alternative was  
245 to not build the line or to upgrade other existing paths or seek additional  
246 transmission corridors into Utah. The Company rejected this alternative because it  
247 did not improve existing system reliability, did not provide any new incremental  
248 transmission capacity required and precluded the ability of new resources to be  
249 delivered into Utah from Wyoming, Idaho, or the Northwest in general. New  
250 incremental transmission capacity is needed for both load service and for  
251 contingencies.

252 The second alternative considered was to rebuild the majority of the

253 existing 138 kV lines interconnecting Utah and Southeast Idaho and continue  
254 operation of these lines at 138 kV. This alternative would have provided only a  
255 small incremental increase of 300 MWs or less in transmission capacity across the  
256 currently constrained path between Southeast Idaho and Utah. It also would not  
257 have provided adequate interconnection capacity between the future Energy  
258 Gateway West and Energy Gateway South segments or offer any additional  
259 capacity for the future. In addition to the marginal increase in transmission  
260 capacity, this alternative had serious constructability issues as it required large  
261 segments of the path to be completely removed from service for extended periods,  
262 a year or more, as these existing 138 kV facilities were rebuilt. This would have  
263 placed significant reliability exposure on the transmission system serving the area  
264 to Rocky Mountain Power customers during construction. This alternative did not  
265 allow the Company to meet its current firm transmission obligations nor did it  
266 meet the long-range resource plans and network load service requirements.

267 The third option considered was to construct a new single circuit 345 kV  
268 transmission line from the future Populus Substation near Downey, Idaho to the  
269 Ben Lomond Substation in Utah, which would have provided some capacity  
270 increase from Idaho to Ben Lomond. The alternative included an upgrade of the  
271 existing 138 kV line between Ben Lomond and Terminal required to realize a  
272 minimum increase in capacity of 300 MW from Ben Lomond to Terminal  
273 substation. However, this alternative would not have provided the necessary  
274 future system capacity between Energy Gateway West and Energy Gateway  
275 South and would have failed to take advantage of maximizing transmission

276 capacity installed in new corridor and our existing Ben Lomond to Terminal  
277 transmission corridor.

278 The fourth option considered was to build a new 500 kV line along the  
279 route. The Company rejected this option because of its high cost, its potential for  
280 significant siting and community impacts, its requirement for a completely new  
281 corridor between Populus and Terminal stations, and its failure to use existing  
282 vacant corridors and property rights that the Company previously obtained.

283 **Q. Please explain any further considerations that the Company made in**  
284 **selecting the Populus to Terminal line.**

285 A. The Company selected this transmission line project based on several factors:

- 286 • It meets short-term and immediate reliability needs while prudently  
287 planning for the future by adding significant long-term incremental  
288 transmission capacity (planned rating 1,400 MWs) across the currently  
289 constrained transmission system. There have been several transmission  
290 outages since 2007 along this corridor that could have been mitigated with  
291 additional transmission facilities. The risk of further unplanned  
292 disturbances is too great if the current facilities are not improved.
- 293 • It allows import of up to 1,400 MWs of forecast resource capacity from  
294 Wyoming and Southern Idaho. This new capacity is required based on  
295 long-term planning results.
- 296 • Construction benefits occur on a significant portion of the transmission  
297 project due to existing corridors that were acquired by Utah Power many  
298 years ago just for this purpose. The project optimizes use of limited and

299 scarce transmission corridor lands by maximizing installed transmission  
300 capacity in new corridors.

301 • Construction could occur with minimum planned outages on existing  
302 facilities remaining in service without increasing reliability exposure to  
303 the current system.

304 • The Company's ability to perform required maintenance will be improved  
305 without significant operational risk associated with taking existing lines  
306 out of service.

307 **Bid Process**

308 **Q. Please describe the Company's typical procurement process used for major**  
309 **transmission projects**

310 A. The Company uses a competitive blind-sealed bid process to contract for the  
311 development of each project unless certain defined conditions apply, such as a  
312 restriction in the supply of technology or design solutions that prevent an open  
313 competitive process. The form of contract tendered is a turnkey, fixed price, date  
314 certain basis for delivery referred to as an engineer, procure and construct  
315 approach. The Company identifies potential bidders that provide the capabilities  
316 required to deliver the work scope within a boundary of project specific technical  
317 specifications and commercial terms. The tender process includes a question and  
318 answer period to clarify any outstanding issues and provides anonymity to the  
319 requesting bidder and responses of a non-confidential nature are provided to all  
320 bidders. Upon receipt of tender documents, the technical proposals are separated  
321 from commercial proposals and a separate technical and commercial evaluation is

322 performed on all qualified bids using pre-established evaluation criteria (see  
323 Exhibit RMP\_\_\_(DTG-3) summary of bidder evaluation). The technical  
324 evaluation is assisted by external consulting firms who have been pre-contracted  
325 for such work based on their industry experience. Upon completion of technical  
326 and commercial evaluations a recommendation is made to enter post-tender  
327 negotiations to reach final terms, conditions and pricing to support contract  
328 execution.

329 **Q. Was this typical procurement process applied to Populus to Terminal?**

330 A. Yes. Specifically for the project, the Company adopted an open competitive  
331 tendering rather than a restrictive competitive tendering process where 75 vendors  
332 were identified and received an invitation to bid. The competitive tendering  
333 process began in October 2007 and provided two separate blind-sealed bidding  
334 opportunities. During the October 2007 to May 2008 bidding period, four  
335 communications were provided to bidders containing additional project-specific  
336 information to assist bidders to refine their submissions specifically to remove  
337 any bid qualifications associated with contingent and non-firm pricing. All bid  
338 responses were due for submittal in May 2008 and again in July 2008 after  
339 additional information was provided to bidders during May 2008 to July 2008  
340 allowing a further refinement of previously submitted design solutions, terms and  
341 conditions, including price. Three qualified bids were received and evaluated  
342 resulting from the May 2008 proposal submissions. Two competing proposals  
343 were received in July 2008. During the separate technical and commercial  
344 evaluations, the Company and its consultants identified non-fixed price aspects of

345 the bidder's proposals affecting cost and schedule. The Company consultant  
346 computed a cost associated with non-fixed price work scope submitted by each  
347 bidder, which was estimated to range from approximately \$103 million to \$429  
348 million. The Company engaged in negotiations to remove or cap the cost of non-  
349 fixed priced work to mitigate post-contract award price escalation and schedule  
350 change. The Company awarded the contract in October 2008 for \$584.6 million  
351 after post-tender negotiation that reduced the contractor's price.

352 **Q. What process, if any, did the Company use to identify and implement cost**  
353 **savings opportunities during the procurement process?**

354 A. During the tender evaluation process, bidders were requested to submit cost  
355 savings opportunities for consideration. Each item was reviewed to assess savings  
356 with respect to potential impact to operability, reliability and maintainability that  
357 were included in the final contract price. In addition, post tender negotiation  
358 included a reduction of \$25 million in consideration of commodity price  
359 reductions, which occurred in the global market during the tender evaluation  
360 period.

### 361 **Construction Process**

362 **Q. Please describe the construction process.**

363 A. The construction process involves several major activities and numerous  
364 subordinate tasks in order to engineer, procure and construct transmission  
365 facilities. The high-level tasks are outlined below:

366 1.) Preconstruction:

367 a. Planning and engineering

- 368                    b. Construction permitting
- 369                    c. Establishment of lay down yards
- 370                    d. Development of safety and construction plans
- 371                    e. Staging of construction crews and materials
- 372                    f. Negotiation of construction stipulation forms with landowners
- 373                    g. Public notification of construction
- 374                    2.) Construct Transmission Line:
- 375                    a. Initial access road construction
- 376                    b. Foundation installation
- 377                    c. Tower installation
- 378                    d. Install conductor and OPGW
- 379                    3.) Construct Substation:
- 380                    a. Access construction and substation grading
- 381                    b. Civil construction
- 382                    c. Steel erection and control building installation
- 383                    d. Equipment installation
- 384                    4.) Testing and commissioning
- 385                    a. Individual line and equipment tests
- 386                    b. Critical punch list resolution
- 387    **Q.    What is the current status of construction for the Ben Lomond – Terminal**
- 388    **phase?**
- 389    A.    Transmission Line: The transmission line is built, with the exception of line
- 390    crossovers, four poles and one foundation outside of Parrish Substation, and one

391 pole outside Terminal Substation. Punch list completion, access road restoration,  
392 right-of-way restoration, and landowner closeout is ongoing.

393 Substation: At the Terminal and Ben Lomond Substations foundations,  
394 civil work and steel erection are primarily completed. Equipment is mostly  
395 installed and is being connected and tested.

396 **Q. Please state why you believe the project will be completed and in service by**  
397 **June 30, 2010.**

398 A. Weekly project management status reports and field verification confirm  
399 construction is on schedule and will be completed by June 30, 2010 barring  
400 unforeseen events at this point.

401 **Conclusion**

402 **Q. Please summarize your testimony.**

403 A. The existing transmission system capacity from southeastern Idaho into Utah is  
404 fully utilized, significant operational limitations exist on the system in this area,  
405 and no additional capacity can be made available without the addition of new  
406 transmission lines. The Ben Lomond to Terminal transmission line investment is  
407 prudent as it meets short-term reliability requirements and meets longer term  
408 customer needs by adding significant incremental transmission capacity between  
409 Southeast Idaho and Northern Utah

410 Further the investment facilitates a stronger interconnection to systems in  
411 Idaho, Utah, and Wyoming and to the Northwest in general. The Ben Lomond to  
412 Terminal transmission line, especially when integrated with the other proposed  
413 Energy Gateway Segments, is fundamental to the development of new renewable

414 and other generation sources in Utah, Idaho and Wyoming. The completion of the  
415 project will be an important step in strengthening the Western Grid's transmission  
416 infrastructure, which is necessary based upon the projected future energy service  
417 requirements of our customers including those in Wyoming.

418 The project was bid out through a competitive bid process followed by  
419 negotiations with the best bidders that resulted in a total contract price of \$584.6  
420 million. The project is on schedule for completion and going into service by June  
421 30, 2010.

422 **Q. Does this conclude your testimony?**

423 A. Yes.