BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZING CONSTRUCTION OF THE MONA-OQUIRRH 500/345 KV TRANSMISSION LINE	))))))	DOCKET NO. 09-035-54 DPU EXHIBIT 1.0

DIRECT TESTIMONY

JONI S. ZENGER, PHD

ON BEHALF OF THE

UTAH DIVISION OF PUBLIC UTILITIES

MARCH 30, 2010

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Introduction

Q. Please state your name and occupation.

A. My name is Dr. Joni S. Zenger. I am employed by the Division of Public Utilities (Division) of the Utah Department of Commerce as a Technical Consultant.

Q. What is your business address?

A. Heber M. Wells Office Building, 160 East 300 South, Salt Lake City, Utah, 84111.

Q. On whose behalf are you testifying?

A. The Division.

Q. Do you have any attachments that you are filing that accompany your testimony?

A. Yes. Exhibit 1.1 lists the previous dockets and dates in which I have testified in Utah. Exhibit 1.2 is a schematic diagram of the proposed project. The table that identifies the federal, state, and local permits or licenses that are potentially required for the construction of this project is replicated as Exhibit 1.3.[1] Exhibit 1.4 represents the Company's Energy Gateway Transmission Expansion Project, and it illustrates the relationship of the Mona to Oquirrh transmission segment to the project as a whole.[2]

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[1] Draft Environmental Impact Statement for the Mona to Oquirrh Transmission Corridor Project and Draft Pony Express Resource Management Plan Amendment, April 2009, Table 1-3.
[2] http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/507-8_EnergyGateway_FactSheet_Web.pdf.

PacifiCorp's transmission network is illustrated by the topology map provided as Exhibit 1.5. [3]

Q. Please describe your education and work experience.

A. I began working for the Division in the fall of 2000 and completed my Doctorate degree in Economics at the University of Utah in early 2001. At the Division, I work on various energy-related projects such as general rate cases, renewable energy, integrated resource planning, and electric transmission. I have testified before the Utah Public Service Commission (Commission) on numerous occasions for the Division. (See Exhibit 1.1).

Purpose and Summary of Testimony

Q. What is the purpose of the testimony that you are now filing?

A. My testimony addresses Rocky Mountain Power's (the Company) Application for a Certificate of Public Convenience and Necessity (CPCN) for its proposed Mona to Oquirrh transmission line (Line or Project). The purpose of my testimony is three-fold. First, I provide the procedural background and description of the Project. Second, I review the statutory guidelines that govern this application as well as the scope of the Division's investigation in this case. Third, I present the Division's analysis and findings supporting the need and associated benefits for the proposed CPCN.

Q. Please summarize the Division's recommendations regarding this Application.

[3] PacifiCorp's 2008 Integrated Resource Plan, May 29, 2009, p. 138.

A. Based on the Company's requirement to meet future electrical load growth in Utah and to provide current and future service in a reliable and economic manner to its customers and based on the Company's existing transmission capacity, the Division finds there is a legitimate need for this Line to be built. The construction of this transmission and its associated facilities meets the statutory Public Convenience and Necessity requirement, is in the public interest, and will benefit Utah ratepayers. The Division recommends that the Commission grant the application contingent upon the Company obtaining all of the necessary permits required to construct and complete the proposed Mona to Oquirrh Line. The Division also recommends that the Commission require the Company to submit information regarding its plans for use of this and future transmission lines with regard to serving its native load and other customers at the time cost recovery is sought and in future CPCN applications.

Background

Q. Will you briefly explain the procedural history of this case?

A. On June 30, 2009, the Company filed a document titled "Rocky Mountain Power's Notice of Intent to File Application for Certificate of Public Convenience and Necessity." In this filing, the Company describes that it was unable to file its formal application for the CPCN because the Company was currently in the process of obtaining federal approval for the Project pursuant to the National Environmental Protection Act (NEPA). During the federal review process, the Company asked the Commission to open a docket, issue a protective order, and allow discovery in the case, as the Company's plans were to have a CPCN issued no later than December 15, 2009. The Company's June 30, 2009 filing stated that the Company would be filing Preliminary Testimony within one week of the filing of the Notice of Intent.

Approximately four months later, on November 23, 2009, the Company filed its formal Application for the CPCN along with accompanying testimony of Mr. Darrell T. Gerrard and Mr. Bruce N. Williams. The Commission issued its Scheduling Order on January 12, 2010.

Q. What was the significance of the Commission's Scheduling Order?

A. Besides establishing the dates governing the scheduling of this docket, the Commission's Order clarified that the purpose of this proceeding is limited to the issue of whether the present or future public convenience and necessity does or will require the construction of the Line.

Q. What topics are not part of this proceeding?

A. The Commission clearly stated that it does not have jurisdiction over the location or siting of the Line; therefore, no siting issues are to be addressed. Other issues that the Commission identified that are not to be addressed in this proceeding include concerns related to cost issues or pertaining to Utah local government entities' requirements for siting that should be addressed by the Electric Facilities Review Board.[4]

The Division has conducted its analysis in this docket under the standards for issuance of a CPCN and has not conducted an analysis of the prudence of the Project's

[4] Scheduling Order, Docket No. 09-035-54, January 12, 2010, pp. 1-2.

costs. Therefore, the Division's support for the issuance of a certificate in this docket should not be taken as a finding that the costs incurred for the Project were prudent. The Division will address prudence issues at the appropriate time during a rate case or in another appropriate filing.

Description of Project

Q. Will you please describe the Company's Mona to Oquirrh transmission Line that is the subject of the proposed CPCN Application?

A. The exact placement of the Line has yet to be finalized, as the Company is working on obtaining the required permits for the project. The currently proposed Mona to Oquirrh Project consists of 345 kV and 500 kV segments of an approximately 140 mile overhead transmission line passing through the following four Utah counties: Juab, Salt Lake, Tooele, and Utah. The Project is located entirely within the state boundaries and does not require construction that would cross state lines.

The proposed Project also includes two future substations—the Mona Annex Substation near the community of Mona, in Juab County and the Limber Station to be located in Tooele County. The Project includes a three-mile long single circuit 345 kV transmission line that would connect the existing Mona Substation to the future Mona Annex Substation and then a 500 kV line would extend north approximately 62 miles to the future Limber Substation. Two double circuit 345 kV lines will run from the proposed Limber substation, one line extending to the existing Oquirrh Substation located in West Jordan and the second line running to the existing Terminal substation located near the Salt Lake City International Airport. The U.S. Bureau of Land Management (BLM) prepared a schematic diagram of the proposed Line and associated substations. This diagram is reproduced and attached to my testimony as Exhibit 1.2.[5]

If completed, the Project will add incremental transmission capacity at a planned rating of up to 1,500 MW to the electrical system. Company witness Mr. Darrell T. Gerrard describes the Project in further detail in his Direct Testimony, including the mileage of each segment and the necessary upgrades of existing transmission plant.[6]

Q. You previously mentioned that the Project is under federal review. Please explain and provide a status update on the Project's NEPA review?

A. The NEPA requires federal agencies to consider environmental effects in their decision-making processes by evaluating the environmental impacts of their proposed actions and by considering reasonable alternatives to those actions. In accordance with the NEPA review, the BLM and coordinating agencies prepared a Draft Environmental Impact Statement (DEIS) that was published in the Federal Register for public comment on May 15, 2009. The BLM has been holding public meetings and evaluating proposed alternative routes. However, to date a final Environmental Impact Statement (EIS) has not been issued. After the final EIS is issued there will be a subsequent protest period and a concurrent review by the Utah Governor's Public Lands Policy Coordination Office. After that period, a Record of Decision will be issued by the BLM. The Record

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[5] Draft Environmental Impact Statement for the Mona to Oquirrh Transmission Corridor Project and Draft Pony Express Resource Management Plan Amendment, April 2009, Table 1-3.
[6] Direct Testimony of Darrell T. Gerrard, Docket No. 09-035-54, November 2009, lines 59-80.

of Decision that identifies the selected siting of the Line must be issued before any construction of the Project can begin. The Company needs federal approval to ensure that the Project complies with all applicable environmental laws and regulations. In addition, the Project requires approval from local governments, municipalities, and cities as part of the local permitting process. The Division notes that the Company has yet to obtain an amendment to a Tooele County ordinance and has not, at the time of this writing, obtained a conditional use permit from Tooele County.[7]

Q. What is the significance of the NEPA review in this docket?

A. Approximately 24 percent, or about 34 miles, of the Mona to Oquirrh Project would be located on lands administered by the BLM.[8] Other portions are located on state and private land or within easements already owned by the Company. The proposed Project has been going through an extensive environmental and permitting review by the BLM and other stakeholders. The NEPA process identifies significant environmental impacts, provides mitigation measures to avoid or minimize adverse impacts, and informs local governments and the public of reasonable alternatives to the plan filed by the Company. The BLM as well as Rocky Mountain Power have been involved in this federal review process since 2007.

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[7] http://www.transcriptbulletin.com/view/full_story/6572427/article-Planning-commission-says-no-to-RMP-route?instance=home_news_left.
[8] http://www.blm.gov/pgdata/etc/medialib/blm/ut/salt_lake_fo/planning/monatransmission.Par.71455.File.dat/Dear%20Reader%20Letter%205-5.pdf.

The Company has complied with the statutory requirements of Utah Code Ann. § 54-18-102 by holding formal and informal public meetings along the proposed corridor and by providing information in the form of newsletters, mailings, and publications in weekly newspapers, and by maintaining a website devoted to the Mona to Oquirrh Project that is updated regularly. Many direct, indirect, residual, and cumulative impacts from the proposed Line or alternatives to the Line will have been fully vetted and considered once federal authorities issue an approval. I will discuss this further in the section on alternatives.

<u>Public Convenience and Necessity</u>

Q. Why does the Company need to obtain a CPCN from the Commission?

A. In addition to obtaining local permitting and federal requirements, Utah statutes require that the Company must also obtain Commission approval for a CPCN prior to construction of certain utility plant, route, or system. Utah Code Ann. § 54-4-25 addresses the need for the certificate and is restated in part below:

> (1) Except as provided in Section 11-13-304, a gas corporation, electric corporation, telephone corporation, telegraph corporation, heat corporation, water corporation, or sewerage corporation may not establish, or begin construction or operation of a line, route, plant, or system or of any extension of a line, route, plant, or system, without having first obtained from the commission a certificate that present or future public convenience and necessity does or will require the construction.[9]

[9] Utah Code Ann. § 54-4-25.

Title 54 of the Utah Code also requires that the construction of such facilities does not adversely conflict with or extend into the territory of another existing certificated public utility territory. The Company states in its Application that this Line is not an extension into service territory of another public electric utility, and that no other public utility has intervened in this docket.[10] The Western Electricity Coordinating Council (WECC) three-step path rating process requires the Company to follow certain steps and guidelines to work with neighboring utilities. In addition, the Division, through its discovery, can confirm that the Company is currently in the process of acquiring the requisite permits and rights of way, but to date has not yet obtained all of the necessary approvals required to go forward with building this Line. The list of major permits that the BLM identified as potentially requiring approval in order to construct, operate, and maintain the Project is attached as Exhibit 1.3.

Q. How does the Division determine "the present or future public convenience and necessity" referenced above?

A. The Division's analysis in this investigation is based on guidance from the *Mulcahy v. Public Service Commission of Utah* case where the Utah Supreme Court discussed at length the question as to what constitutes the "public convenience and necessity" contemplated by Utah Code Ann. § 54-4-25. The Division finds the following excerpts from *Mulcahy* instructive (bold added):

[10] Rocky Mountain Power's Application for Certificate of Public Convenience and Necessity, Docket No. 09-035-54, November 21, 2009, p. 9, ¶ 23.

> The “convenience” and “necessity” required to support an application for a certificate of convenience and necessity are those of the UCA § 54-4-25, **not those of individuals**. “Necessity” and “convenience” are not to be construed as synonymous. Convenience is much broader and more inclusive than necessity, but effect must be given to both.[11]
>
> And in determining whether or not the convenience and necessity of the public is best subserved by the proposed service, **the needs and welfare of the people of the territory or community affected are considered as a whole**.[12]
>
> Necessity means **reasonably necessary** and not absolutely imperative. It does not mean “necessary” in the ordinary sense of the term. The convenience of the public must not be circumscribed by holding the term “necessity” to mean an essential requisite. **It means a public need without which the public, people generally of the community, would be inconvenienced or handicapped in the pursuit of business** or wholesome pleasure, or both.[13]

The statute implies that many factors need to be considered. However, the paramount consideration is the benefit and welfare of the public as a whole. The applicant must show that the existing service is not adequate and convenient and that the new service would eliminate this inadequacy and inconvenience. In other words, the Company must show that the public interest would be best served if the certificate were granted.

Q. What reasonable need did the Division find that justifies Commission action to grant this Application for a CPCN?

A. The overarching and primary need for the proposed Project is based on the Company’s obligation as a regulated utility to provide safe, reliable, and cost-effective electric

[11] *Mulcahy v. Public Serv. Comm’n*, 101 Utah 245, 117 P.2d 298 (1941), p. 8.
[12] 9.
[13] Id.

transmission service to its customers. Due to population growth and customer usage in Utah, the present and long-term demands for electricity require the Company to find a means to supply that service both now and in the future. I will provide evidence of this later in my testimony, including demographic data, current and projected electric demand, and the characteristics of the existing transmission infrastructure that require this Line to be built.

At the same time, the Company's transmission system must be designed to meet strict WECC reliability criteria, individual utility criteria, and mandatory North American Electric Reliability Corporation (NERC) standards that contain penalty provisions if not met.

Q. Please report the Division's findings with respect to demographic data that substantiate the need for this Line?

A. The Division updated the data filed by the Company with respect to Utah's population growth. The Company, in Mr. Gerrard's testimony, referenced the 2009 Economic Report to the Governor for population data. The Division updated the data filed by the Company with more recent forecasts from the Governor's Office of Planning and Budget. According to the updated information, the state's population increased to 2,800,089 as of July 1, 2009, an increase of 1.5 percent over the previous year.[14] The prior two year's state growth rates were 2.2 percent in 2008 and a record 3.2% in 2007. The current long-term forecast predicts that Utah's population is expected to more than triple from 2.2

[14] http://governor.utah.gov/DEA/ERG/2010ERG.pdf.

million in 2000 to 6.8 million in 2060, for an average annual growth of approximately 1.9 percent. Most importantly, approximately 60 percent of the state's projected population growth of new residents is forecasted to be in northern Utah in Salt Lake, Davis, Utah, and Weber counties.[15] The proposed Line would facilitate the delivery of generation resources to the Wasatch Front, where growth is forecasted to be the strongest and where, due to reliability concerns, a separate corridor other than the existing Mona to Camp Williams corridor is needed.

Q. Will you please explain the need for this Line in terms of the expected load growth and forecasted electric demand in Utah?

A. Not only does the state's population continue to increase, but also electrical usage and peak demand continues to increase over time. During the past few years, the Division, the Company, and numerous stakeholders have been involved in discussions at state and federal levels regarding the critical need to expand transmission systems in the region. This process includes very long-range planning to ensure the transmission system integrates well with other utility systems in the WECC.

To illustrate the need for this Line, average annual load growth, which is primarily affected by population growth, is projected to increase by 2.5 percent for the next ten years according to the Company's 2008 Integrated Resource Plan (IRP) projections.[16] The IRP is the long-term planning tool the Company uses to determine the

[15] Id.
[16] PacifiCorp's 2008 Integrated Resource Plan - Errata, July 24, 2009, p. 267.

least-cost, least-risk portfolio of resources that will be needed to meet future load growth. Due to the recession, a slowdown in net migration, and a decrease in the growth in usage per customer, the rate of growth of retail sales have slowed, but growth is still expected to increase over the long run.[17]

The Company's 2008 IRP uses the December 2008 forecast and shows the load for PacifiCorp's service territories increasing at an average rate of 2.1 percent annually from 2009 to 2018.[18] The 2008 IRP estimates that there will be system-wide coincidental peak load growth of 2.2 percent from 2009 to 2018 and a Utah average annual rate of about 2.6 percent.[19] Based on Utah demographic data discussed above and in IRP modeling results, the Line is needed in order to meet projected near-term and future long-term load.

Q. According to the current 2008 IRP, when will PacifiCorp's electric system experience a capacity deficit?[20]

A. The Company's system capacity load and resource balance, according to the IRP, indicate that PacifiCorp's system will become capacity deficient on a summer hour basis in the year 2011 using a 12 percent reserve margin.[21] In addition, the Company also prepares a capacity and energy balance on an east and west control area basis.[22] The

[17] Direct Testimony of Darrell T. Gerrard, Docket No. 09-035-54, November 2009, p. 11, lines 256-261.
[18] Id.
[19] Id. at p. 268.
[20] To date, the Commission has not issued an order acknowledging the 2008 IRP.
[21] PacifiCorp's 2008 Integrated Resource Plan, May 29, 2009, p. 91.
[22] PacifiCorp's 2008 Integrated Resource Plan was modeled using the November 2008 load forecast. The Company prepared a February 2009 load forecast, but it was not modeled in the 2008 IRP.

2008 IRP shows a deficit in PacifiCorp-East (PACE) area, consisting of Idaho, Wyoming, and Utah, also beginning in 2011. The projected electrical shortfall is based on factors I previously mentioned, such as population growth, customer usage, as well as existing and projected resources.

According to the Company's Confidential Response to DPU data request #4.6-2, I estimate that the Wasatch Front coincidental load will grow substantially between 2009 and 2018.[23] The Company states that 100 percent of the new Line is being built to meet northern Utah (areas north of Mona) load needs.[24] These statistics show that there is a significant need to bring resources from southern Utah to meet the energy needs along the Wasatch Front. The recommended 1,500 MW transmission expansion plan remained part of the preferred portfolio option throughout the IRP modeling process.

Q. Is the transmission capacity of the existing transmission infrastructure sufficient to meet future resource needs?

A. Not for the long term. The existing generation resources that serve northern Utah come primarily from the Carbon, Hunter, Huntingon, Currant Creek, and Lake Side plants. The transmission system that provides the electric services from these generation load centers to the Wasatch Front currently consist of two 345 kV lines running from Huntington and Castle Dale to Spanish Fork and Camp Williams. There are also four 345 kV lines running from Mona to Camp Williams, the fourth of which was constructed to carry load

[23] Company Confidential Response to DPU data request #4.6-2 Attachment, March 5, 2010.
[24] Company Response to DPU data request #2.20 (e), January 14, 2010.

from the existing Currant Creek plant. In addition, several smaller lines carry power throughout the region, such as the line from the Helper area to Spanish Fork.

The Division conducted further discovery regarding the existing transmission infrastructure. In the Company's Response to DPU data request #2.10 (b), the Company states the following:

> Currently the system has limited capacity to deliver energy north of Mona Utah and into the northern part of the state.
>
> Limitations exist today for delivery of energy north both during both heavy load hours and light load hours of the year. The Mona to Oquirrh transmission line is needed to provide an additional and separate transmission path across this existing limitation. The line has been physically located away from existing lines in the area to provide the reliability necessary.[25]

The Company's 2008 IRP includes the Energy Gateway Transmission Expansion plan as part of the modeled transmission topology.[26] This was included based on results from the Company's 2007 IRP which determined the Energy Gateway Plan was cost effective from a system benefits perspective.[27]

The Company's 2008 IRP preferred portfolio determined the need for an additional 831 MW of gas fired generating resources to be acquired in the 2014 to 2016 time period.[28] While a specific generating resource has not yet been proposed, expansions to the Currant Creek and Lake Side plants are two possibilities.

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[25] Company's Response to DPU data request #2.10 (b), January 14, 2010.
[26] PacifiCorp's 2008 Integrated Resource Plan, May 28, 2009.
[27] PacifiCorp 2007 Integrated Resource Plan, May 30, 2007, p. 3, http://www.pacificorp.com/File/File74765.pdf
[28] PacifiCorp's 2008 Integrated Resource Plan, May 29, 2009, p. 254.

The additional 1,500 MW of transmission capacity from the Mona to Oquirrh Project will facilitate bringing future generating resources to network customers. In addition, the planned capacity of the proposed Line will provide greater flexibility and opportunities for the Company to consider additional options regarding planned generation capacity additions.

Q. Please explain the Energy Gateway Transmission Project as it pertains to this pending Application for a CPCN.

A. The Energy Gateway Project is a major transmission expansion strategy that was announced by PacifiCorp in 2007. The Company plans to build approximately 2,000 miles of new transmission lines across the west, designed as a hub and spoke configuration that will move energy to retail loads. Energy Gateway will connect PacifiCorp's east and west control areas, providing flexibility to access new and existing resources and deliver electricity to the Company's customers throughout its service territory. The Mona to Oquirrh Line is the second segment of the overall Gateway Central project and plays an important role in the overall Energy Gateway strategy. The first portion of the project, the Populus to Terminal line, for which the Commission previously granted a CPCN, was recently completed and is now in operation.

The Company is currently in the project siting and planning stages of the two subsequent segments--Gateway South and Gateway West. Gateway West is expected to be in service sometime in the 2014 to 2018 timeframe, followed by Gateway South in the range of 2017 to 2019.[29] Exhibit #1.4 illustrates the various Gateway segments and the approximate locations of the planned future segments.[30]

As illustrated in the attached map, Gateway South, as presently planned, will interconnect Gateway Central through the proposed Mona Annex Substation. Mona will be a major collection point where energy will be delivered from various resource areas and delivered in the state and throughout the region. Terminal will also be a point of receipt and delivery, where energy will connect to the Populus substation in Downey, Idaho.

Q. What is the present and future need of the new Mona Annex substation?

A. The current Mona substation was historically engineered and constructed for 345 kV operations. The existing substation has been an important interconnection link with Deseret Generation and Transmission's (DG&T) Bonanza Plant and the Intermountain Power Plant. As part of the Energy Gateway Project review, the Company determined that it was not feasible to upgrade the existing substation site to meet the large scale expansion plans required for the long-term needs of the Energy Gateway Project.[31] Therefore, the Mona Annex substation, approximately three miles from the current substation, will be built to withstand the congestion of multiple existing and new terminating lines at various voltages. The Mona Annex Substation will also be a major interconnection point for power sales, transfers, and purchases. Exhibit 1.5 illustrates the

[29] Company's Response to DPU data request #2.10 (c), January 14, 2010.
[30] http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/507-8_EnergyGateway_FactSheet_Web.pdf.
[31] Company's Response to DPU data request #2.28, January 14, 2010.

PacifiCorp transmission system topology and shows the designated load and generation centers, as well as the geographical transmission paths linking to and from the Mona Substation.[32]

The completion of upgrades and new build outs at the Terminal and Limber substations will complete the Gateway Central project. The Terminal line extends to Downey, Idaho, connecting the southeast Idaho transmission network to the Wasatch Front. This interconnection of transmission lines and substations is required to meet current and long-term electrical demand as part of the Company's long-term business plan. The completion of this remaining segment of the Gateway Central project will mean that more energy can be transported to and from the southern portion of the state to the Wasatch Front and to and from southern Idaho during the respective on and off peak seasons. There are several needs that the proposed Line will meet, including improving reliability, enhancing operational flexibility, facilitating economic market sales and purchases, and providing transmission capacity for projected generation resources.

Q. Please identify the constraints on the current transmission system that would be alleviated if this Line is built.

A. PacifiCorp's transmission system consists of an interconnection of transmission lines. Every generator, line, and customer is connected together such that anything that happens to the grid can constrain or affect to some degree everything else in the network. The existing infrastructure in the Mona to Camp Williams corridor, along with the projected

[32] PacifiCorp's 2008 Integrated Resource Plan, May 29, 2009, p. 138.

load demands will, in the near future, put added stress on the existing transmission network as additional power is added to the system. Portions of the transmission system are becoming loaded to their maximum reliability limits as the uses of the transmission systems change relative to the limits that they were designed for.

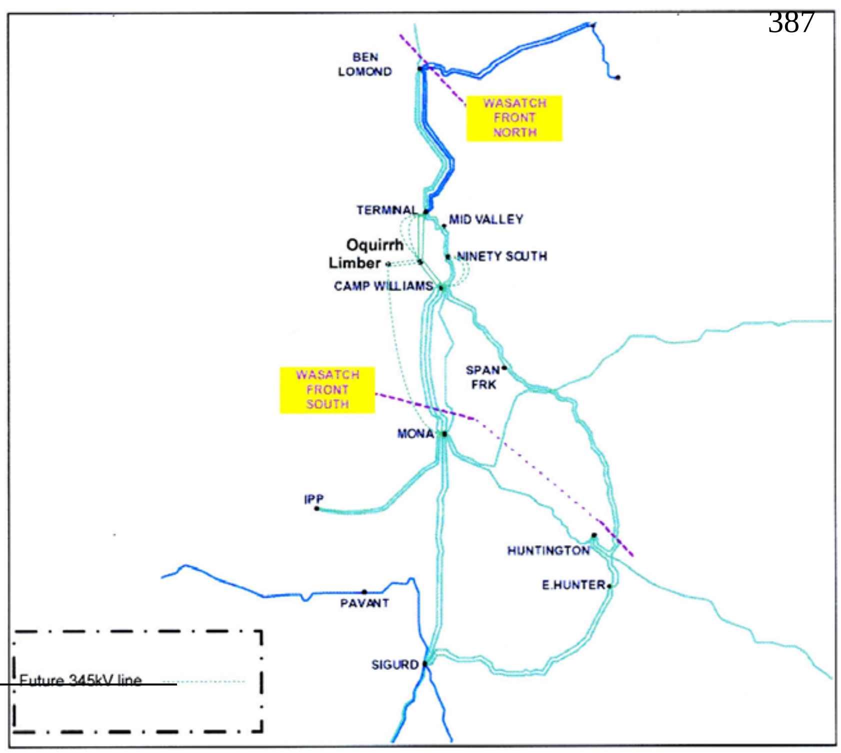
According to the Company's Response to DPU data request #2.26, with one element out of service in the corridor north of Camp Williams, the normal system capacity of 2,762 MW to 3,350 MW will decrease by anywhere from 827 MW to 1,130 MW. According to NERC standards, a N-2 incident means that two or more transmission facilities, triggered by a single common mode, are out of service at the same time. With a N-2 loss of 345 kV lines, the loss of load and generation increases to almost the system capacity (2,000 MW to 4,000 MW) with potential voltage collapses in the Wasatch Front area. The new Line would reduce the possibility of thermal overloading on the one remaining 345 kV line running from Camp Williams to the Wasatch Front in the same right-of-way.

The proposed Line must adhere to all minimum regional planning criteria and strictly enforced NERC reliability standards to ensure operational reliability. The NERC has worked diligently over the past few years to strengthen its reliability standards and has not been shy in imposing penalty payments for those utilities that do not conform to the stricter standards. Therefore, it is important for the Company to work to improve and strengthen its transmission system to avoid making penalty payments and to keep the operating system safe, secure, and reliable not only now, but also in the future. The

Company states that this Project is not being built due to a regulatory commitment such as a merger commitment, but because it is truly needed as a system improvement to the existing transmission network in order to serve the needs of current and future customers.[33]

Q. How will the proposed Line improve the operational limitations of PacifiCorp's transmission system?

A. The Company described in its Response to DPU data request #2.10 (b) that the existing electrical grid has limited capacity to import energy from Wasatch Front South to the northern part of the state. The map below illustrates the designated Wasatch Front North and South areas.[34]



[33] Rocky Mountain Power's Pending Application, June 30, 2009, p. 5 and Rocky Mountain Power's Application for a CPCN, November 21, 2009, p. 4.
[34] Company's Response to DPU data request #2.10 (b), January 14, 2010.

The proposed Line will alleviate the existing limitation by adding available transfer capability. This will facilitate delivering energy north of Mona, where demand accounts for 80% of the state's load.[35]

Also illustrated in the map are the four existing lines running from Mona to Camp Williams. The proposed Line is needed to provide a separate and additional path through the state. Adding an alternative transmission path such as the proposed Line will increase operational flexibility for the Company to perform maintenance work on the system or should there be an outage on the system due to weather or other emergencies. The Company's projections show that if the currently proposed Line is placed into service by 2014, the import limitations that currently exist will be relieved and extended beyond the year 2019. [36]

<u>Public Interest Concerns</u>

Q. Mr. Gerrard discusses the benefits of the proposed Line to the Company's wholesale transmission customers.[37] Will you please clarify if the transmission capacity from

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[35] Direct Testimony of Darrell T. Gerrard, Docket No. 09-035-54, November 2009, p. 18, lines 404-406.
[36] Company's Response to DPU data request #2.10 (c), January 14, 2010.
[37] Direct Testimony of Darrell T. Gerrard, Docket No. 09-035-54, November 2009, pp. 20-21, lines 466-490.

the proposed Line will benefit Utah retail customers or wholesale customers (which may be located outside of the state)?

A. In general, upgrades to the existing transmission system will necessarily improve reliability to all users of the system, including wholesale and retail customers. The Company claims, however, that "100 percent of the capacity from the proposed Line will be reserved to serve the needs of PacifiCorp's network customers" and in the same data request that "100% of the new line is to meet northern Utah load service needs."[38] While it is true that without increased northbound transmission capacity, the Company, Utah Associated Municipal Power Systems (UAMPS), and other entities such as Utah Municipal Power Association (UMPA) and DG&T, may be required to find alternative resource energy supply to serve load growth, potentially increasing their power costs. What is not true is that UAMPS, UMPA, and DG&T are network customers in the technical sense of the definition. The definition of "network customers" includes Utah retail ratepayers as well as transmission providers that request service through PacifiCorp's Open Access Same-Time Information System (OASIS) as determined by the Federal Energy Regulatory Commission (FERC) Pro Forma Open Access Transmission Tariff (OATT). The Company clarifies in its Response to DPU data request # 2.20 (a), that because UAMPS, UMPA, and DG&T have contracts that have been in place pre-OATT, the Company classifies these contracts as "legacy contracts"

[38] Company Response to DPU data request #2.20(d) and (e), January 14, 2010.

with terms and conditions like network service. In the Company's Response to DPU data request #4.8, the Company states the following:

> Unlike PacifiCorp Commercial & Trading, UAMPS, UMPA, and Deseret are not network customers under PacifiCorp's Open Access Transmission Tariff. These three customers have network "like" service which means that network transmission is used for serving their loads.

As far as the portion of Utah retail ratepayers that will benefit from the incremental capacity addition of the Line, Attachment R of PacifiCorp's OATT, breaks down the tariff network load (retail) load and non-tariff network load (wholesale). The transmission system load ratio share as of August 1, 2009 is as follows:

	MW
Total Tariff Network Load	8,639
Total Non-Tariff Network Load	1,238
Total Network Load	9,877

According to the load ratio table above, the non-tariff network load served is 12.5 percent of the total network load. In addition, PacifiCorp's retail Utah load is 1,966 MW or 22.76 percent of the PacifiCorp's system wide retail peak according to the Company's Response to DPU data request #3.1. The total non-tariff (wholesale) network load is 1,238 MW. The Company claims that over 300 MW of this load is geographically located around St. George, Utah and that the non-tariff network load in the Wasatch Front is estimated to be 938 MW.[39] The Division estimates that the total Utah network load served by the Mona to Oquirrh transmission system is around 2,904 MW (1,966 MW plus 938 MW). Although the Company claims that 90.5 percent of the proposed Project will be used to serve PacifiCorp's retail customers system wide,[40] the Division finds that approximately 67 percent of the Project will serve Utah retail customers (1,966 MW divided by 2,904 MW).

Q. Please describe how costs for this Line will be allocated among PacifiCorp tariff (retail) customers and non-tariff network customers?

A. PacifiCorp's network customers include retail (tariff) and wholesale (non-tariff) customers. Retail rates are recovered through a general rate case proceeding or other regulatory filing before each respective state commission. PacifiCorp's wholesale and transmission business is regulated by the FERC. PacifiCorp's non-tariff customers pay rates as determined by the FERC Pro Forma OATT, which is updated annually.[41] According to the current Electric Tariff, 7th Revised Volume No. 11, the load ratio share calculations can change due to the following four conditions: (1) new network load is added by a network customer, (2) existing network load is removed by a network customer, (3) existing network load changes from one network customer to another, or (4) a transmission rate case is filed with FERC.

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[39] Company Response to DPU data request #3.1, March 5, 2010.
[40] Id.
[41] http://www.oasis.pacificorp.com/oasis/ppw/PACRESTATEDOATTASOF1-10-10.PDF.

The Company is required by FERC to update its load ratio share annually on August 1 of each year, but may file for tariff rate changes at the Company's discretion. The previous OATT was filed in 2008 when the Company requested incentive rate treatment for the Energy Gateway Project.[42] The Division does not know when the Company will file its next FERC rate case. Therefore, the cost impacts of the proposed $450 million project on Utah retail, wholesale, and customers purchasing power from UAMPS, UMPA, or DG&T will be an issue to contend with in a future prudence review, which is outside the scope of this proceeding.[43] These issues are not reasons for us to find the Project not reasonably necessary.

The current practice for the Company's transmission assets is to recover all costs through rates charged to retail customers and to credit back to them any revenues obtained from transmission service. Where the large majority of a line's load is intended for retail service, this practice is reasonable. In essence, transmission revenues serve as a "bonus" to customers. However, if a significant portion of a new line is expected to serve the load of another utility or to provide network sales, retail customers may be placed at risk if all costs are initially charged to them. For example, a decline in anticipated load in another state could depress sales, or wholesale prices could depress sales revenue, thus leaving retail customers to pay a disproportionate net share of the cost of a line relative to their use. In some cases, it might be more appropriate for ratepayers to pay directly only

[42] http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Services/EL08_75.pdf.
[43] PacifiCorp has a transmission service and operating agreement in place with UAMPS (FERC Rate Schedule No. 297) with UMPA (FERC Rate Schedule 637), and DG&T (FERC Rate Schedule No. 280).

for an allocated share of a new line, leaving to wholesale customers payment of the remaining share and allowing the Company to assume the risk, and to retain revenues from such customers. While the Division makes no conclusion as to which is more appropriate on the Mona to Oquirrh Project, it feels that examination of such issues would be appropriate at the point that cost recovery is sought for the Project. The Division therefore recommends that the Commission require the Company, at the time it seeks cost recovery on this line, to file detailed information relating to the expected shares of native load, service to other Utah utilities, and network sales that the line is anticipated to support, both in the near and long terms. Because several additional transmission segments are anticipated in the coming years, the Division also recommends that the Commission require in its order that such information be provided in both CPCN and cost recovery filings for future transmission projects.

Financial Viability

Q. Is the Company capable of financing the construction of this Project?

A. Yes. In spite of hard times for the rest of the nation, the Company has not only committed to build this Project, but also has access to capital markets at favorable rates to do so. According to the most recent filing in the 2009 General Rate Case, PacifiCorp has an A- rating by Standard & Poor's and a A3 rating by Moody's Investors Service--both investment grade ratings.[44] These data support the filing made by Mr. Bruce N. Williams in the current docket. Mr. William's also notes that the Company obtained $1,000

[44] Docket No. 09-035-23, Company Response to MDRB 2.18.

million of first mortgage bonds, as well as cash equity contributions from its parent company last year. The Company's parent company, MidAmerican Energy Holding Company (MEHC) has shown itself to be a long-term investor in capital intensive energy businesses. MEHC is associated with Berkshire Hathaway (rated AAA), facilitating PacifiCorp's access to capital and reducing long-term debt financing costs. Finally, the Company has authority to issue securities for this Project.[45] Based on its review, the Division concludes that the Company should have access to capital markets in order to build, operate, and maintain the Project.

Q. How much money will the proposed Line cost Utah ratepayers?

A. The estimated Project cost at the current time is $450 million.[46] The estimated annualized first year revenue requirement is $71,694,000 on a total company basis, with Utah's share (assuming all costs are recovered initially from ratepayers) being approximately 42% of this amount or about $30.1 million. Transmission function items are allocated to the individual jurisdictions that PacifiCorp serves on a system generation (SG) allocation code. Rate recovery for the tariff customer charges will be determined through the appropriate general rate case or other type of filing.[47] Costs will be allocated to non-tariff network customers as described above according to the tariff process for determining load share allocation (Attachment R filing with FERC). Transmission assets are included in FERC rate base, and revenues received from third-party customers are

[45] Direct Testimony of Bruce Williams, Docket No. 09-035-54, November 2009, p. 2.
[46] Company Response to DPU data request #2.5, January 14, 2010.
[47] Company's Response to DPU data request #2.4 and #2.6, January 14, 2010.

credited back to retail rates as wheeling revenues through net power costs, thus benefiting Utah retail ratepayers.

<u>Alternatives Considered</u>

Q. Were there any alternatives that the Division looked at in lieu of constructing the transmission Line?

A. A plausible alternative that the Division considered is demand side management and energy efficiency measures. Efficient use of energy and demand-side measures would reduce usage and are important measures to reduce energy consumption. However, even with efficiency measures, the existing transmission system is severely constrained and fully subscribed, as I described above. The transmission line would still need to be built to meet growing energy and system capacity needs. None of the above alternatives would achieve the long-range, system-wide needs, such as meeting load growth, system reliability, operational flexibility, market transfers, and the delivery of power from renewable resources.

Q. Will you please discuss other alternatives that were considered in this case?

A. Yes. One alternative that the Division looked at would be not to build the Line. To serve the expected continued growth in electricity consumption and peak demand, especially along the Wasatch Front, additional electricity would need to be generated or imported into Utah by existing transmission facilities. The load would have to be met by curtailing or interrupting other customers. In the event that the Commission decides to not grant this application, the Company would not be able to meet its previously planned resource additions or its network load obligation without curtailing energy or purchasing front office transactions that may not be economical at the time of need. Transmission projects can take up to five years to plan, permit, design, and construct. Since many potential and confirmed resources are located far from population centers where the power must be delivered, the Company would not have time to find alternatives to the current plan, design, and construction layout. Additional transmission capacity must be built to deliver energy to customers.

The Division finds this alternative to be unacceptable. It would not meet future load growth needs, would not address the Integrated Resource Plan and Business Plan of the Company, and would not add the incremental capacity and reliability needed on the network.

The Division also reviewed alternatives in the Company's financial analysis results, which found the proposed project the least expensive alternative to deliver the required 1,500 MW system.[48]

The Division studied the BLM's review of alternatives, which was wide-ranging and comprehensive. The BLM looked at the Project in terms of the best overall combination of criteria that include system reliability, constructability, economics, environmental, and community concerns. The BLM determined that the Project was in

[48] Company's Confidential Response to DPU data request #4.6-2, March 5, 2010.

fact needed and the no action alternative was unacceptable. The Division concurs with the BLM's determination of need for this Project.

The BLM's analysis also considered alternative transmission technologies, developing new generation facilities in northern Utah, and the use of existing transmission lines. The BLM looked at 22 alternate substation sites as well as numerous possible transmission line routes, all of which were studied, assessed, and compared by teams of professionals in their fields. The Division commends the BLM for including federal, state, and local agencies in the scoping, consultation, and coordination of the project study. A broad range of stakeholders provided input to the BLM on this Project, including the Utah Governor's Public Lands Policy Coordination Office.

At this time the BLM has not issued its Final EIS Report. However, the Draft EIS report supports the proposed Line and associated substations (as currently filed in this docket) as superior to all other choices and concludes that it is not only environmentally benign, but serves the needs of the public as a whole.[49] As previously described, the Division agrees that the present and future public convenience and necessity must serve the needs of the public as a whole. Due to the scope of this proceeding, the Division makes no finding on the timing of the construction of the Project or the route selection.

Conclusion and Recommendations

Q. **Will you please summarize the Division's analysis and findings?**

[49] http://www.blm.gov/pgdata/etc/medialib/blm/ut/salt_lake_fo/planning/monatransmission.Par.94024.File.dat/Volume%20II%20-%20Appendices,%20Maps,%20and%20Simulations.pdf.

A. The Division studied and reviewed the statutory requirements applicable to this case, and then applied them to the variety of factors demonstrating the public interest requirement and the "convenience and necessity" requirement both for the future and the current time period. The Division makes the following findings in this case:

- The Company will be able to finance the transmission Line either from its own funds or through external capital sources. The estimated Project costs are in the range of $450 million. The first year revenue requirement is approximately $30.1 million on a Utah basis.
- The Company has secured franchise agreements permitting construction within public thoroughfares and has applied, or is in the process of applying, to local governmental entities for conditional-use permits and similar land use authorizations. To date, the Division is aware of an outstanding conditional use permit in Tooele County.
- The transmission Line will not conflict with or adversely affect the operations of any existing certificated fixed public utility providing retail electric service to the public. The transmission Line does not constitute an extension into the certificated service territory of any existing public electric utilities. To date no other party has requested intervention in this case.

The Division finds this Line is needed and complies with the "convenience and necessity" requirement based on the following reasons:

- The public welfare as a whole will be inconvenienced if no action is taken.

- The Company must meet its load growth obligation, and forecasts show that both load and peak demand will continue to grow, especially along the Wasatch front; this Line is needed to provide operational and system flexibility on the Company's transmission network. In other words, the existing service is not adequate and convenient, and the construction of the proposed Line will eliminate this inadequacy and inconvenience.
- Ratepayers will benefit by having reliable service due to the increased transfer capability and operational flexibility provided by the Line. The Division finds that the other considered alternatives were inferior to this Line being constructed.
- The Company is willing to invest in this Line, and this Line provides the necessary link in order for the Gateway Energy Transmission Expansion Project to realize the full benefits of the Project.

Q. What is the Division's recommendation in this case?

A. The Division recommends issuance of the certificate contingent upon the Company acquiring all necessary permits. If the Commission grants the certificate, the Division further recommends that the Company file within ten days of the Commission's order a report detailing all necessary permits indicating which ones are yet to be obtained and a time line of the expected acquisition for each outstanding permit. If after a reasonable time all necessary permits have not been acquired, the Division recommends that the Company be ordered to appear before the Commission explaining in detail any delays in obtaining the permits. Based on the Company's explanations of any delays, intervening parties may request additional information from the Company and the opportunity to file additional evidence in this case. The Division suggests 90 days after the Commission's order is a reasonable amount of time.

Q. Does the Division have any additional recommendations or proposals that pertain to this case?

A. The Division wants to be clear that the Tooele County conditional use permit or land ordinance amendment issue must be resolved before the Company is awarded a construction CPCN. Therefore, our recommendation for the Commission to grant a conditional CPCN hinges on the Company obtaining all permits, including Tooele County, before it grants blanket approval of the CPCN. The Division also recommends that the Commission require that the Company, at the time that it seeks cost recovery for this Project, submit detailed information relating to the expected shares of native load, service to other Utah public utilities, and network sales that the Line is anticipated to support, both in the near and long terms. The Division also recommends that the Commission require such information to be provided in both CPCN and cost recovery filings for all future transmission projects.

Q. Does this conclude your testimony?

A. Yes.