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BEFORE THE UTILITY FACILITY REVIEW BOARD

ROCKY MOUNTAIN POWER, Petitioner, vs. TOOELE COUNTY, Respondent.	**DIRECT TESTIMONY OF DARRELL T. GERRARD**

BACKGROUND OF WITNESS

Q. Please state your name, business address, and present position.

A. My name is Darrell T. Gerrard. My business address is 825 NE Multnomah Boulevard, Portland, Oregon 97242. I am currently employed as Vice President—Transmission System Planning for PacifiCorp. I have held my present position since May 2007.

Q. What are the primary duties of your present position?

A. The primary duties of my present position include management and oversight of all Main Grid Transmission System Planning requirements for both Rocky Mountain Power and Pacific Power, which are operating units of PacifiCorp. (PacifiCorp and Rocky Mountain Power are referred to herein as the "Company.") My responsibilities include ensuring that proper planning activities are performed as necessary for the Company's large transmission system. I am also responsible for the conceptual design and ongoing electrical transmission system planning required to support the Company's Energy Gateway Program.

Q. Please describe your education and business experience.

A. I have a Bachelor of Science degree in Electrical Engineering from the University of Utah. My experience spans more than 30 years in the electric utility business and electric industry in general. I have experience in and have been responsible for a number of functional organizations at the Company, including Area Engineering, Area Planning, Region Engineering, Transmission & Distribution Facilities Management, Transmission, Substation and Distribution Engineering, System Protection and Control, Transmission & Distribution Project Management and Delivery, Asset Management, Electronic Communications, Hydro System Engineering, Transmission Grid Operations, and most recently Transmission System Planning.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony will demonstrate the need in the immediate future for the construction of a new transmission line from the existing Mona substation west of Mona to the existing Oquirrh substation located in West Jordan, with an additional proposed substation (Limber) in the southwest portion of the Tooele Valley and an additional transmission line extending from the future Limber substation to the existing Terminal substation near the Salt Lake International Airport (the "Transmission Project" or the "Project") to ensure safe, reliable, adequate, and efficient delivery of electricity to the Company's Customers.[1]

The overall Project was developed to minimize transmission line length and maximize reliability. Mr. Brandon Smith's testimony, filed concurrently herewith, will demonstrate how these criteria have been applied to minimize the Project costs and impacts on communities.

Q. Please summarize your testimony.

A. In summary, the Transmission Project is needed to support both short- and long-term energy demands and will strengthen the overall reliability of the Company's existing transmission system. Currently, the existing transmission system, of which the Project will be a part, has limited capability to deliver energy into the largest load center in Utah, which is identified in this testimony as the "Critical Load Area," and which includes all or portions of Salt Lake, Tooele, Utah, Davis, Weber, Cache, and Box Elder Counties. *See* Exhibit DTG-1 (Critical Load Area).

Electricity used within the Critical Load Area is generated primarily from power plants located in central and southeastern Utah and transmitted to the Critical Load Area via

[1] "Customers" as used in this Testimony shall be defined to include all retail and network customers of the Company.

high voltage transmission lines. Due to current and expected growth within the Critical Load Area, the existing transmission capacity north of the Mona substation (located in Juab County) is fully subscribed and is expected to be operating near or at its design capacities in the near future. By 2013, the Company will be unable to serve its existing Customers in Tooele County in the Critical Load Area, including Tooele County, meet load service obligations under its FERC tariff and will not be able to maintain compliance with North American Electric Reliability Corporation ("NERC") Reliability Standards. Additional transmission capacity is required to meet the Company's load service and contract obligations to its Customers, as well as third party point-to-point customers, for the long term.

By constructing the Transmission Project, overall reliability of the transmission system will be improved by adding incremental new transmission capacity northbound and southbound between the Company's power plants in Utah and other sources of energy in the Four Corners Region and the Desert Southwest. Because the Project increases the existing transmission capability from the Mona area to the Critical Load Area, the system will have improved capability to integrate new generation resources from central and southern Utah, and will provide improved connection to markets in the Desert Southwest and Four Corners Region, and other markets available through interconnections at Mona. *See* Exhibit DTG-2 (Major Transmission Paths Serving Utah).

Utah is currently one of the fastest growing states, and projections indicate that it will continue to grow rapidly for decades. Staying ahead of future electric demand is therefore critical in meeting the electric demand of the Company's Customers. In addition to meeting the Company's Customers' future energy requirements, the Transmission Project is key to maintaining the Company's compliance with mandated NERC and Western Electricity Coordinating Council ("WECC") Bulk Electric System reliability and performance standards.

Due to the long lead times associated with planning, siting, permitting, design and construction associated with major electric system infrastructure projects like this one, as an essential service provider, the Company must permit and construct the Project now.

OVERALL TRANSMISSION SYSTEM PLAN

Q. Please provide an overview of PacifiCorp's current transmission system and future transmission expansion plans.

A. PacifiCorp owns and operates approximately 15,800 miles of transmission lines ranging from 46 kV to 500 kV across the western states. As of December 31, 2008, PacifiCorp's current total Company net transmission assets have a book value of approximately $1.8 billion. PacifiCorp is interconnected with more than 80 generation plants and 15 adjacent control areas at approximately 124 points of interconnection. To provide electric service to its retail and wholesale customers, PacifiCorp owns or has interest in generation resources directly interconnected to its transmission system with a system peak capacity of approximately 12,131 megawatts ("MW"). This generation capacity includes a diverse mix of resources including coal, hydro, wind power, natural gas simple cycle and combined cycle combustion turbines, and geothermal. The Company's transmission system's performance and operation is an integral part of the WECC electric system and has a significant influence throughout the West. That is, if the Company's system fails, it will have a broad reaching effect not only on Utah Customers but also on the electrical system across the West.

Energy Gateway is the Company's comprehensive transmission plan. Energy Gateway will improve reliability, reduce transmission system constraints and improve the flow of electricity to Rocky Mountain Power's Customers. The Energy Gateway plan is comprised of eight interrelated and interdependent transmission segments with an estimated investment of $6 billion, as outlined in Exhibit DTG-3 (Energy Gateway Transmission Expansion Plan). The eight line segments within Energy Gateway have been grouped and labeled as Gateway Central, Gateway West, Gateway South and the Westside. Energy Gateway, when fully implemented, will traverse six states, numerous communities and counties, and significant areas of federally-administered lands. Energy Gateway will add approximately 2,000 miles of new transmission lines to PacifiCorp's transmission system over the next ten to twelve years. For Energy Gateway, the eight identified transmission segments provide specific capabilities to the Company's system, while providing the benefits of Energy Gateway to other regional transmission lines. The primary objectives required of Energy Gateway are to:

- Add significant levels of new incremental transmission capacity necessary to adequately provide energy services to Customer's long term and comply with the Company's Federal Energy Regulatory Commission ("FERC") approved Open Access Transmission Tariff ("OATT")[2] and other regulatory requirements.

- Improve system reliability and ensure ongoing compliance with FERC/NERC mandatory Bulk Electric System Reliability Standards and WECC Regional Criteria.

- Provide necessary transmission system capacity to deliver current 2008 Integrated Resource Plan ("IRP")[3] requirements and to provide necessary

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[2] PacifiCorp's most recent OATT dated July 13, 2007 (PacifiCorp OV11 Tariff) is available online at: http://www.oasis.pacificorp.com/oasis/ppw/PACRestatedOATT20100219.pdf

[3] PacifiCorp's 2008 IRP dated May 28, 2009, along with the subsequent update dated March 31, 2010, are available online at:

2008 IRP, Volume I:
http://www.pacificorp.com/content/dam/pacificorp/doc/Environment/Environmental_Concerns/Integrated_Resource_Planning_3.pdf

2008 IRP, Volume II:
http://www.pacificorp.com/content/dam/pacificorp/doc/Environment/Environmental_Concerns/Integrated_Resource_Planning_6.pdf

2008 IRP Update:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2008IRPUpdate/PacifiCorp-2008IRPUpdate_3-31-10.pdf

IRP Web Page:
http://www.pacificorp.com/es/irp.html

options to future IRPs enabling continued access to low cost energy sources, including renewables.

- Improve interconnections with existing market hubs and resource hubs, and improve the capability and reliability of the transmission system generally in the western states region.

Gateway Central is being completed first as it provides urgent and necessary capacity and reliability improvements for Utah. Gateway Central is comprised of three transmission segments: (1) Populus to Terminal, (2) Mona to Oquirrh, including the Limber to Oquirrh 345 kV transmission line, the future Limber Substation, and the future Limber to Terminal 345 kV transmission line; and (3) future Oquirrh to Terminal 345 kV transmission line. These transmission segments will improve reliability and transfer capability to the existing system within Utah, and also establish the necessary electrical interconnection between Gateway West and Gateway South. The Gateway West, Gateway Central and Gateway South line segments, when complete, will be the first 500 kV alternating current ("AC") lines to be installed in Wyoming, southeast Idaho and Utah. Gateway Central will provide an essential reliability backbone allowing Gateway West and Gateway South to operate at a higher reliability and at an overall higher capacity than would otherwise be possible without the Gateway Central interconnection. When viewed in the context of the Energy Gateway plan, this Project will not only add incremental transmission capacity to the Critical Load Area, but will also strengthen PacifiCorp's overall system while supporting future generation resource development to benefit all of the Company's Customers.

As described earlier in my testimony, the Mona to Oquirrh transmission segment is comprised of three sections, which in total extend 141 miles from the Mona substation to the proposed Limber substation, and two separate and geographically diverse 345 kV double-circuit segments from the future Limber substation, one connected to the existing Oquirrh substation and the other connected to the existing

Terminal substation. *See* Exhibit DTG-4 (Mona to Oquirrh 500/345 kV Transmission Project).

Q. What is the current status of the implementation of Energy Gateway?

A. As noted, the Energy Gateway transmission expansion plan consists of eight individual segment additions to the Company's transmission system. The Mona to Oquirrh transmission segment, designated as "Segment C" within Gateway Central in the Exhibit DTG-3 (Energy Gateway Transmission Expansion Plan), is an essential component of the overall Energy Gateway plan. The size and complexity of Energy Gateway requires the transmission expansion to be completed in a phased approach spanning approximately 10 to 12 years for obtaining all federal, state, and local permitting, and construction of the transmission segments. A general description of each segment is set out below. The Company is fully engaged in Energy Gateway, which is scheduled to be completed by 2019.

Segment A (Walla Walla to McNary) is 56 miles of 230 kV transmission line that completed permitting in 2009, and the first 30 mile segment, Walla Walla to McNary, began right-of-way acquisition in 2010, with construction to commence in 2011.

Segment B (Populus to Terminal) is 136 miles of 345 kV double-circuit transmission line that completed permitting and right-of-way acquisition in 2009, started construction in early 2009 and is scheduled to be completed in late 2010.

Segment C (Mona to Oquirrh and Oquirrh to Terminal) consists of Mona to Oquirrh and Limber to Terminal transmission lines, making up 67 miles of 500 kV transmission line and 74 miles of 345 kV double-circuit transmission line. The National Environmental Policy Act ("NEPA") process for this Project was initiated in 2007 and the Environmental Impact Statement ("EIS") and record of decision from the Bureau of Land Management ("BLM") is scheduled to be completed in the fourth quarter of 2010. The Oquirrh to Terminal Project is scheduled for construction to begin in early 2011 and is expected to be completed by mid 2013. The Oquirrh to

Terminal project is a 15 mile double-circuit 345 kV transmission line that is also part of Segment C. The Project is in the final stages of permitting and right-of-way acquisition is scheduled for completion in 2011 and construction scheduled from 2011 to 2013.

Segments D and E (Windstar to Populus and Populus to Hemingway) make up the Gateway West project and consist of 1,100 miles of 500 kV transmission line and 150 miles of 230 kV transmission line. PacifiCorp initiated the NEPA process in 2008, and is scheduled to have a final EIS and record of decision in 2012, with construction scheduled for completion in phases from 2014 through 2018.

Segments F and G (Aeolus to Mona and Mona to Crystal) form the 800 miles of 500 kV transmission line that comprises the Gateway South project. The NEPA process was initiated in late 2008 and is scheduled for a final EIS and record of decision in 2015, with the Project scheduled for completion between 2017 and 2019. The Sigurd to Red Butte project is a 161 mile 345 kV line that is part of Segment G. It is undergoing its own NEPA process which is scheduled to receive a final EIS and record of decision in the first quarter 2011. Construction is scheduled to begin in 2012 and the project is scheduled for completion in 2014.

Segment H (Hemingway to Captain Jack) is 375 miles of 500 kV transmission line that is in the early regional planning stages.

Q. What analysis did the Company perform to develop its master transmission plan?

A. The Company's analysis has been extensive and has been conducted and completed over a number of years. PacifiCorp's FERC-approved Open Access Transmission Tariff provides details regarding PacifiCorp's planning requirements and contractual obligations to provide safe, reliable, adequate and efficient transmission service. Section 28.2 defines PacifiCorp's responsibilities, which include the requirement to "plan, construct, operate and maintain the system in accordance with good utility practice." Section 31.6 defines the requirement for network customers to supply annual load and resource updates for inclusion in planning studies. Through its OATT, the Company solicits this data annually in order to determine future load and resource requirements for all network customers, including PacifiCorp's network customers and customers of third parties under the Company's FERC-approved OATT and other FERC-approved agreements. The Company's retail loads comprise the bulk of the transmission network customer needs, including those in Utah. Section 28.3 includes the requirement for PacifiCorp to provide "firm service over the system so that designated resources can be delivered to designated loads." These future requirements and needs will be met via Energy Gateway and its segments, including the Mona to Oquirrh segment, which is an essential part of PacifiCorp's overall transmission plan for Utah and the region. In addition to the OATT requirements stated above, the analysis incorporated compliance requirements associated with mandatory national and regional reliability standards and criteria which I discuss in detail later in my testimony.

Q. What customers provided load and resource data in PacifiCorp's 2009 annual load and resource forecast?

A. PacifiCorp's network customers provided their annual 10-year load and resource forecast for the years 2009-2018. These customers from all states include: Utah Associated Municipal Systems ("UAMPS"), Utah Municipal Power Agency ("UMPA"), Deseret Generation & Transmission Co-operative ("DG&T"), Bonneville Power Administration ("BPA"), Basin Electric Power Cooperative ("Basin Electric"), Moon Lake Electric Association, and PacifiCorp Commercial and Trading ("PacifiCorp C&T"). PacifiCorp C&T addresses the entire Critical Load Area, including Tooele County.

Q. How does the Company's future energy resource planning benefit from Energy Gateway, and in particular the current and future Integrated Resource Plans?

A. The Company utilizes an integrated resource plan to establish future resources necessary to serve its Customers. This is the resource plan and associated risk analysis framework used to specify prudent future actions required to ensure that the Company continues to provide reliable and efficient electric service to its Customers, while striking an expected balance between cost and risk over the planning horizon and taking into consideration environmental issues, along with the energy policies of the states served by the Company, including Utah. As stated in Chapter 2 of the 2008 IRP, its purpose is to fulfill "the Company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. It was developed through a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties." (2008 IRP, at page 17.) Resource portfolio modeling conducted for the Company's recent IRPs has shown that additional transmission capacity is necessary and cost-effective for supporting future generation resource needs. The 2008 IRP includes the Mona-Oquirrh segment C as part of the modeled transmission topology for the purpose of selecting the Company's current preferred portfolio of future supply-side and demand-side resources as shown on the 2008 IRP Uopdate March 31, 2010. Exhibit DTG-5 (2008 IRP Resource Table).

Q. Please describe the regional transmission studies and analysis that have been conducted related to Energy Gateway and specifically the Gateway Central segments and what have these studies found.

A. Over the past decade, numerous studies have been issued that document the need for new transmission in the western United States. As early as 2002, the Department of Energy National Transmission Grid Study identified the Wyoming-Idaho interface as a major constrained interface, and found that under optimal conditions the Wyoming-Northern Utah interface is congested during 50 percent or more of the hours during the year.[4] In 2004, the Rocky Mountain Area Transmission Study reached similar conclusions, the result of which was a recommended expansion of the 345 kV transmission lines connecting the Bridger substation to points south and west as critically needed improvements.[5] In addition, the Department of Energy's 2006 National Electric Transmission Congestion Study ("DOE Congestion Study") identified several constrained transmission paths in the West, including lines used to deliver electricity

[4] National Transmission Grid Study at pp 15, 18. A full copy of this report is available at http://www.pi.energy.gov/documents/TransmissionGrid.pdf.
[5] RMATS at Chapter 3-2, which shows the Bridger expansion as a critical expansion area from Wyoming to Northern Utah and Wyoming to Idaho. The full report is available at http://psc.state.wy.us/htdocs/subregional/Reports.htm

from generation plants in Wyoming to loads in Utah and Oregon.[6] Specifically, the DOE Congestion Study illustrated that the expansion of the Bridger West facility serving Idaho and Northern Utah is critical to relieve congestion from Wyoming to Northern Utah, and Wyoming to Idaho.[7] Similarly, the Western Interconnection 2006 Congestion Assessment Study, which was issued by the DOE Western Congestion Analysis Task Force, identified areas of congestion in the Rocky Mountain states, and projected that based on 2005 load and resource forecasts and a production model, many of the paths associated with the various segments of Energy Gateway were forecasted to be heavily congested.[8]

Reports initiated by the Western Governor's Association ("WGA") also show certain paths in PacifiCorp's service territory (such as the Populus to Terminal segment) to be constrained.[9] Lastly, the Department of Energy sponsored a study through Idaho National Laboratories to assess the economic impact of not building transmission. While the report focused on assessing economic impact on the Pacific Northwest, it also provides discussion and support for the "hub and spoke" design which is similar to the Energy Gateway model for connecting resource areas to load. The report also describes the interconnected nature of transmission as being *geographically dispersed*, yet interdependent.[10]

Existing Northern Tier Transmission Group ("NTTG") sub-regional transmission planning studies, currently in draft and conducted in accordance with FERC Order 890-A, show overall benefits to the region as a result of PacifiCorp's proposed Energy

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[6] The National Electric Transmission Congestion Study (August 2006) at pp 31-35). The transmission constraints identified in this study were identified by reviewing recent transmission studies such as those conducted by WECC and SSG-WI. The full report is available at http://nietc.anl.gov/documents/docs/Congestion_Study_2006-9MB.pdf.

[7] Such expansion is addressed by the Segment E portion of the Project.

[8] A full copy of this study is available at http://www.oe.energy.gov/DocumentsandMedia/ DOE_Congestion_Study_2006_Western_Analysis.pdf.

[9] The full report is available at http://www.westgov.org/wga/initiatives/cdeac/TransmissionReportfinal.pdf.

[10] The Cost of Not Building Transmission: Economic Impact of Proposed Transmission Line Projects for the Pacific Northwest Economic Region. Full report is available at http://www.pnwer.org/Portals/0/Presentations/2008%20summit/Cost%20of%20not%20building%20transmission.pdf (emphasis added).

Gateway. Additionally, the Company filed for incentive rates with FERC on July 3, 2008. The incentive rate process at FERC is analogous to a need determination. The Company was granted incentive rate treatment, but equally important FERC issued a 4-0 decision in which it stated:

> *"…we find that PacifiCorp has adequately demonstrated that the Project (with the exception of segment A* [Walla Walla to McNary]*) will ensure reliability and reduce transmission congestion… We find that segments B through H of the Project would establish for the first time a backbone of 500 kV transmission lines in PacifiCorp's Wyoming, Idaho and Utah regions. This would provide a platform for integrating and coordinating future regional and sub-regional electric transmission projects being considered in the Pacific Northwest and the Intermountain West, connecting existing and potential generation to loads in an efficient manner, thus reducing the cost of delivered power. Also, the Petition cites the 2006 DOE National Electric Transmission Congestion Study and the 2004 Rocky Mountain Area Transmission Study in stating that that proposed Project will reduce congestion or maintain reliability in the Western Interconnection. Additionally, the project would establish a direct link between PacifiCorp's east and west control areas, providing numerous benefits including increasing transfer capability, reducing the need for curtailments, and reducing transmission congestion." [¶39]*

Commissioner Suedeen G. Kelly echoes the petition stating that:

> *"…while Segments B* [Populus to Terminal] *and C* [Mona to Oquirrh] *provide a variety of benefits when considered in isolation, they also enable PacifiCorp to achieve the planned transfer capability rating of subsequent segments."*

Commissioner Kelly's statement emphasizes the crucial nature of the Mona to Oquirrh transmission expansion, not only to the state of Utah, but to Energy Gateway overall.[11]

[11] http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Services/EL08_75.pdf

Q. Did Mid-American Energy Holding Co. make any transmission facilities commitments when it acquired PacifiCorp?

A. Yes. At the time of the acquisition of the Company by Mid-American Energy Holdings Company ("MEHC"), many regulatory and intervening parties in the regulatory docket referenced as *In the Matter of the Application of MidAmerican Energy Holdings Company And PacifiCorp dba Utah Power & Light Company for an Order Authorizing Proposed Transaction, Docket No. 05-035-54*, wanted the Company to make critical transmission infrastructure investments to support the future demands and growth of its Customers and their communities. As a result, the Company made specific commitments and developed plans for a significant transmission expansion program across the system.[12] One of the first components of the plan related to the transmission system that will be completed in 2010 which is a new double circuit 345 kV transmission line from the Populus substation near Downey, Idaho to the Terminal substation. The second component of the plan is the Mona to Oquirrh transmission Project, which completes Utah commitments regarding transmission lines.

Q. What are the specific reliability requirements addressed in the Company's transmission plans?

A. PacifiCorp plans, designs and operates its transmission system to meet or exceed NERC Standards for Bulk Electric Systems and WECC Regional standards and criteria. The NERC standards are federal law stated in 18 CFR Part 40 (Mandatory Reliability Standards for Bulk-Power System). The WECC standards and criteria are deemed necessary for the WECC Region to meet or exceed NERC standards. There are currently more than 100 approved NERC standards to which the Company must comply. For all Energy Gateway segments, including the Mona to Oquirrh Project, the following are directly applicable to the planning, siting, permitting, design, construction and subsequent operation:

[12] The MEHC transaction merger commitments can be found online at: http://www.psc.utah.gov/utilities/electric/06orders/Mar/0503554RptOrd.pdf

- NERC TPL-001 System Performance Under Normal Conditions[13]
- NERC TPL-002 System Performance Following Loss of a Single BES Element[14]
- NERC TPL-003 System Performance Following Loss of Two or More BES Elements[15]
- NERC TPL-004 System Performance Following Extreme BES Events[16]
- TPL 001-WECC-1-CR System Performance Criteria Normal Conditions[17]
- TPL 002-WECC-1-CR System Performance Criteria Following Loss of a Single BES Element[18]
- TPL 003-WECC-1-CR System Performance Criteria Following Loss of Two or More BES[19]
- TPL 003-WECC-1-CR System Performance Criteria Following Extreme BES Events[20]
- NERC TOP-002 Normal Operations Planning[21]
- NERC TOP-004 Transmission Operations[22]
- NERC TOP-007 Reporting SOL and IROL Violations[23]

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[13] NERC TPL-001 can be found at: http://www.nerc.com/files/TPL-001-0.pdf

[14] NERC TPL-002 can be found at: http://www.nerc.com/files/TPL-002-0.pdf

[15] NERC TPL-003 can be found at: http://www.nerc.com/files/TPL-003-0.pdf

[16] NERC TPL-004 can be found at: http://www.nerc.com/files/TPL-004-0.pdf

[17] http://www.wecc.biz/Standards/WECC%20Criteria/TPL%20–%20(001%20thru%20004)%20–%20WECC%20–%201%20–%20CR%20-%20System%20Performance%20Criteria.pdf

[18] http://www.wecc.biz/Standards/WECC%20Criteria/TPL%20–%20(001%20thru%20004)%20–%20WECC%20–%201%20–%20CR%20-%20System%20Performance%20Criteria.pdf

[19] http://www.wecc.biz/Standards/WECC%20Criteria/TPL%20–%20(001%20thru%20004)%20–%20WECC%20–%201%20–%20CR%20-%20System%20Performance%20Criteria.pdf

[20] http://www.wecc.biz/Standards/WECC%20Criteria/TPL%20–%20(001%20thru%20004)%20–%20WECC%20–%201%20–%20CR%20-%20System%20Performance%20Criteria.pdf

[21] NERC TOP-002 can be found at: http://www.nerc.com/files/TOP-002-2.pdf

[22] NERC TOP-004 can be found at: http://www.nerc.com/files/TOP-004-2.pdf

[23] NERC TOP-007 can be found at: http://www.nerc.com/files/TOP-007-0.pdf

The above-referenced standards dictate the minimum levels of transmission system reliability, redundancy and performance required for Energy Gateway to interconnect to the larger western grid. These are performance based standards and criteria that among other things, require utilities to consider the proximity of new and existing transmission lines for reliability purposes during planning, determination of system capacity ratings and establishing limits, both normal and emergency as necessary for daily operations. The responsibility to comply with these mandatory reliability standards, along with the method of implementation, is clearly imposed on the Company.

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

> **A. Introduction**
> **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that *meet specified performance requirements with sufficient lead time*, and continue to be modified or upgraded as <u>*necessary to meet present and future system needs.*</u>
>
> **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 current and forecasted customer needs. This requirement to have a plan and act on that plan is not optional.

Q. What requirements are specified by the WECC and NERC documents that PacifiCorp must consider in locating multiple transmission lines?

A. The NERC TPL 003 requires the Company to plan for outages of two or more system components, including transmission lines. Table 1 section C.5 of the NERC TPL 003 requires that "*for an event that results in loss of two or more elements specifically addressing an outage of any two circuits of a multi circuit tower line (i.e. loss of a double circuit structure or other common mode of failure that results in the simultaneous loss of two circuits),*" there be no "*cascading*" of generation or uncontrolled outages to Customers. In addition, the Company must comply with the WECC criteria. WECC System Performance Criteria TPL 003-WECC-1-CR Requirement WRS1.1 states "*NERC Category C.5 initiating event of a non-three phase fault with normal fault clearing time shall also apply to the common mode contingency of two adjacent circuits on separate towers unless the frequency is determined to be less than one in 30 years.*"

This means when two transmission lines are installed on common structures <u>or</u> transmission lines are located adjacent to each other (less than a span length), the Company, at a minimum, must plan for loss of both circuits simultaneously and must build redundancy in the system to withstand this multiple line outage in order to meet all applicable performance standards.

Q. What are the consequences or impacts if PacifiCorp's transmission system fails to meet these performance standards because lines are too close together?

A. Should the Company fail to meet NERC performance standards and criteria resulting in widespread uncontrolled loss of generation or customer demand, WECC System Performance Criteria TPL-004WECC-1-CR, Requirement WRS5 states:

"*For any event that has actually resulted in cascading, the Planning Authority or Transmission Planner shall have documentation that it has taken action so that future occurrences of the event will not result in cascading, or it must have documentation that it has WECC PCC approval that the Mean Time Between Failure (MTBF) is greater than 300yrs (frequency less than .0033 outages/year).*"

In the event both Energy Gateway paths and other existing lines are constructed such that a system outage occurs as a result of multiple line outages, PacifiCorp would be required to provide mitigation steps stated above to prevent future occurrences. These mitigation measures would likely result in lower overall Energy Gateway capacity (i.e., lower ratings and operating limits) and reduced utilization of assets. To account for the reduced utilization, the Company would be required to construct additional transmission lines.

The burden of proof of reliable performance and compliance with the National and Regional Reliability Standards lies heavily on the shoulders of utilities like PacifiCorp that own and operate transmission systems. In the event PacifiCorp's new transmission line fails to perform in accordance with the above planning requirements and standards due to common mode outages of adjacent lines, the Company will be required by WECC and NERC to limit the capacity and/or operation of the lines to levels that will not cause major disturbances or disruptions to the grid. This reduction in system capacity limits the Company's ability to serve existing and new Customers. Additional transmission lines and transmission line corridors would then be required to restore lost capacity and to add back the additional level of system redundancy that the new transmission project was ultimately expected to deliver. In addition, the Company could be subject to significant fines and sanctions for lack of compliance with NERC standards if it was determined the

Company failed to plan and to construct properly. This determination, of course, is often made “after the fact” in a significant outage and at that time mitigation measures required from placing lines too close together are limited at best.

Q. Has the Company experienced outages and/or system disturbances caused by multiple lines located in close proximity?

A. Yes, several significant outages have occurred on the Company’s extra high voltage (“EHV”) [24] lines. Occurrences have been experienced due to a wide number of causes including; fire, smoke, high winds, flooding, ice and severe storms, landslides, aircraft as well as other human interference or action. The following are just some examples:

- 1981 – Due to a human-caused fire, two 345 kV lines north of Camp Williams were forced out of service and a third 345 kV line cascaded, resulting in a state wide blackout.
- 1982-83 - Landslides on the two Emery-Sigurd 345 kV lines destroyed transmission towers.
- 1983 - Severe wind storms caused two 345 kV, two 230 kV and three 138 kV lines between Salt Lake City and Ogden to go down.
- 1990 – An Air Force jet contacted transmission causing outages of double circuit 345 kV and 230 kV lines between Terminal and Ben Lomond.
- 2000 - Fires in the corridor of Emery-Camp Williams and Huntington-Spanish Fork 345 kV lines forced lines out of service.
- 2002-2003 - Multiple fires in the corridor between Mona and Camp Williams forced lines out of service due to smoke and to protect fire fighters in the area.
- 2007 - A fire caused both the Mona to Huntington and the Mona to Bonanza 345 kV lines in Central Utah to be de-energized for fire crew safety.
- 2007 - Three 345 kV lines connecting Jim Bridger Wyoming to southeast Idaho experienced a fire that forced multiple lines out of service.

[24] “EHV” means transmission lines of 345 kV or greater.

Q. Have other utilities experienced outages and or system disturbances caused by multiple EHV lines located in close proximity?

A. Yes. The 1992 BLM Western Regional Corridor Study notes that on at least one occasion, high winds caused the loss of two adjacent 500 kV line towers on the Pacific Intertie and the resulting power outage left an estimated 5.2 million customers in several states without power. This simultaneous loss of two major EHV lines serving Southern Oregon and California resulted in a system reliability and capacity review. The result of the review was the requirement in 1993 to build a new (third) 500 kV transmission line across the Pacific Intertie to restore capacity and improve reliability. During the planning of the subsequent third line of the Oregon/California AC Intertie, considerable efforts were made to maintain a separation of at least five miles with one mile minimum if absolutely no other alternative routes existed.

On August 6-8, 11-12, 1990, fires caused six simultaneous outages (along with 17 single lines outages) of the two Round Mountain-Table Mountain 500 kV lines in northern California. Fires burned randomly back and forth across the corridor for more than 12 miles. Customer load interruptions ranged from 90 MW to 1000 MW at times.

Q. How has the Company's transmission plans addressed the reliability requirements?

A. The conceptual planning and design of Energy Gateway has been engineered to meet all reliability performance standards and criteria during normal and emergency operations. The concept is based on regional interconnection of large resource hubs with load centers through large scale, high capacity EHV transmission lines. Fundamental to meeting those standards is the necessity of adequate redundancy provided through multiple transmission lines and having those multiple lines located in wide, geographically diverse corridors to significantly reduce the risk of common mode outages.

The Company has designed Energy Gateway in such a manner as to create a "Triangle of Reliability." *See* Exhibit DTG-6 (Energy Gateway Separation and Design). Gateway Central, Gateway West and Gateway South, each create a leg of this triangle. With the loss of any one leg of the triangle, the other path (along with the existing underlying transmission system in the area) would provide an acceptable level of backup that would limit disruptions to the wider interconnected electric grid, continue to allow customers to be served and keep generation connected to the system. However, with the simultaneous loss of any two legs of the triangle, the transmission system could experience uncontrolled system collapse resulting in the loss of generation and loss of significant customer load for both the Company and other interconnected utilities in the region.

The Company must account for the real possibility that multiple lines (new and existing) in the area could be forced out of service due to human caused physical interference, sabotage, smoke and fire, microbursts, severe winds, blizzards, ice storms, salt or dust storms, etc.

As a result, the Company continues to pursue to locate the Gateway South and Gateway West lines in new corridors separated from one another by a wide distance are prudent in order to maintain the Triangle of Reliability.

Q. What is the minimum standard that specifically addresses the location of transmission lines?

A. The National Electrical Safety Code ("NESC") (ANSI C2-2007) is the code that specifies the minimum electrical clearances of electric supply lines from other obstacles such as adjacent transmission lines, roads, highways, railroads, buildings and other structures, etc. The NESC sets forth the minimum standards and requires the utility to apply industry-accepted practices in the design and construction of its transmission systems. PacifiCorp designs, constructs and operates its electric systems in such a manner to meet or exceed these minimum NESC requirements.

CURRENT TRANSMISSION SITUATION IN UTAH

Q. Describe the current transmission situation for bringing power into the Critical Load Area from the south and how the Transmission Project fits into that situation.

A. There are limited options for gaining new transmission capacity into the Critical Load Area. *See* Exhibit No. DTG-2 (Major Transmission Paths Serving Utah). Further, new resources identified to serve the Critical Load Area for the next four to five years will be located in the southern part of Utah as shown in the Company's 2008 IRP. Currently, a majority of the electricity serving the Critical Load Area and further north is generated at the Company's facilities in Carbon, Juab, and Emery Counties, or is imported over multiple lines connected to the Desert Southwest. This energy must be transported and delivered from the south on existing transmission lines to the Critical Load Area. These central and southern Utah generating facilities include the Carbon, Hunter, Huntington, and Currant Creek power plants. The Company's transmission system that provides electrical service to the Critical Load Area from central and southern Utah presently consists of eight lines: two 345 kV lines from the Huntington and Castle Dale (Emery substation) areas to the Spanish Fork and Camp Williams Substations, four 345 kV lines from the Mona area to the Camp Williams Substation, and two smaller 138 kV lines from the Helper area (Carbon substation) to the Spanish Fork substation. These transmission lines along with other interconnected lines are also used to import power into Utah from Nevada, the Four Corners Region, and other energy providers connected to the existing Mona substation. It is necessary to then move this energy north to the Company's Customers in the Critical Load Area, including Tooele County. Similarly, the Company's municipal and other customers rely on generation located south of or connected to Mona to serve their loads and expect to rely on increased capacity of existing facilities to serve their load growth needs north of Mona. As stated earlier, without Energy Gateway, including the Mona to Oquirrh Project, the increase in Customer demand could not be reliably served. The new transmission capacity provided by the Mona to Oquirrh project is required.

As northern Utah's electrical usage continues to grow, particularly in the Critical Load Area, existing transmission lines have diminished capacity to serve projected customer energy demand and still continue to ensure a safe, reliable, adequate and efficient supply of electricity. Transmission studies and analysis show that the existing capacity of the transmission system from Mona north into the Critical Load Area will have to subsequently be reduced, in proportion to any future increase in customer demand, in order to maintain system reliability and maintain compliance with the performance standards discussed above. The system is currently fully subscribed for firm transmission service and is operating at or near its full capability. These studies show future electrical demand of the Critical Load Area will exceed the capacity of existing transmission lines near term. The Company must prudently plan in advance of this event. Due to the long lead times associated with planning, siting, permitting, design and construction associated with major electric system infrastructure projects like this one, as an essential service provider, the Company must permit and construct the Project now.

Q. Is the Mona to Oquirrh segment a requirement in the Company's latest IRP?

A. Yes. The 2008 IRP includes the Mona to Oquirrh segment. Energy Gateway is designed to use a "hub and spoke" concept in which the Mona to Oquirrh Project is an integral "spoke."

Q. Are there other justifications driving the need to execute and complete the transmission project other than stated above?

A. Yes. Nearly 70% of the electrical load in the state of Utah is located within the Critical Load Area. *See* Exhibit DTG-1 (Critical Load Area). Currently the system has limited capacity to deliver energy north of Mona, Utah and into the Critical Load Area. Demand increases in the Critical Load Area reduce the capability of the transmission import path and reduce the ability to use existing generation resources in southern Utah, connections at Mona and other connections in the southern part of the state to serve the Critical Load Area. The Mona to Oquirrh transmission line is needed to provide an additional and separate transmission path around this existing limitation. The Project, when completed, significantly improves the Critical Load Area import capability limit.

Q. Please explain how the Energy Gateway "Triangle of Reliability" criteria have been applied locally to the Mona to Oquirrh Project.

A. The same "Triangle of Reliability" strategy applied to the overall Energy Gateway project has been applied twice in designing the Mona to Oquirrh Project, as set forth below. *See* Exhibit DTG-4 (Mona to Oquirrh 500/345/138kV Transmission Project).

Mona/Oquirrh/Limber Triangle - The first leg of the triangle is the existing Mona to Camp Williams to Oquirrh lines, the second leg is the proposed Oquirrh to Limber line located in Tooele County, and the third leg is the proposed Limber to Mona line. As described in Mr. Smith's testimony, in order to ensure the reliability of this triangle, the BLM, Juab County and Utah County have worked with the Company to site the proposed Mona to Limber transmission line route in such a manner as to maintain adequate separation from existing EHV transmission lines.

Limber/Oquirrh/Terminal Triangle - The first leg of the triangle is the proposed Limber to Oquirrh line, the second leg is the future Oquirrh to Terminal line, and the third leg is the future Limber to Terminal line. In order to ensure the reliability, separation of each leg of this triangle is required.

Q. In the past, the Company has located more than one transmission line in a common corridor. Why is this no longer an acceptable practice?

A. Industry standards applicable to the reliability of electric supply have become stronger and more stringent as the United States' dependence on electricity has increased. FERC's approval of more than 100 national reliability standards have also been established to increase reliability margins and reduce significant impacts resulting from large scale outages and blackouts of the electric system. In addition, many of PacifiCorp's existing transmission lines were built over 15 years ago and their capacity has been used up. These transmission lines can no longer provide adequate margins of redundancy. In particular, the increased utilization of the existing lines between Mona and the Critical Load Area has eliminated the ability to use those lines to back up any new EHV lines within the same transmission corridor.

There are conditions that would allow more than one transmission line to be located in a common corridor, however, current performance standards dictate that system reliability and redundancy requirements must be met in that event. There are two primary reasons why this practice would be considered acceptable:

First, instances where there are physically no practicable or viable options available to locate new lines away from existing lines, for example physical pinch points created by large bodies of water, geography or terrain. In this event, line route alternatives become impractical due to extremely long routes that become electrically limited (project no longer meets needs of customers) or the cost of the alternative is exorbitant and would not be seen as prudent. However, the NERC reliability standards still apply, and the Company would have to meet those standards with additional generation sources or more transmission lines.

Second, where there is deemed to be sufficient redundancy and other backup transmission lines in the interconnected system to maintain reliable service to customers, transmission lines may be located in proximity because outages of multiple lines do not cause undue disruption to the local area or to the grid as a whole.

The capacity of the new line, its functional impact to the local transmission system, and interconnection to the wider transmission grid (inside and outside of PacifiCorp's system) must be evaluated. In short, not all transmission lines are alike in their voltages, capacity requirements, electrical function and redundancy levels. EHV lines like those proposed for Energy Gateway have significant impacts to local and wider interconnected transmission grids, and require special consideration.

ADDITIONAL BENEFITS RESULTING FROM THE PROJECT

Q. Will the Mona to Oquirrh transmission project provide other benefits to the Company's existing and future transmission system?

A. Yes. While the Project specifically provides additional transmission capacity in Utah, it is also a critical segment of the Company's overall Energy Gateway transmission plan. The Project positions the Company to be strongly interconnected to the current and future electric grid in the region and provides necessary options for access to additional resources necessary to control future energy costs. It also supports and is in concert with the development of other transmission projects being planned throughout the western region.

Q. Will the Transmission Project provide increased reliability for the Company's wholesale transmission customers?

A. Yes. Utah Associated Municipal Power Systems, Utah Municipal Power Association, and Deseret Generation & Transmission rely on Utah-based generation or imports into Utah to serve their loads. Increased capacity in the northbound direction from the Mona substation provides required reliability for long-term load service in northern Utah. Without increased northbound transmission capacity from the Company, these entities would be required to find alternative resource energy supplies to serve load growth which would potentially increas their power costs. Increasing capacity across this path will significantly improve a point of constraint on the system that currently affects several transmission customers.

Q. How is this Project critical to Tooele County, and how will its citizens benefit?

A. The Project is critical to short-term and long-term electric service to Tooele County. Currently, energy supplies for Tooele County are provided by three existing 138 kV transmission lines extending from the Oquirrh and Terminal substations. One of these 138 kV transmission lines brings energy from the existing Oquirrh substation to Tooele County. Two additional 138 kV transmission lines bring energy from Terminal substation to Tooele County. Tooele County has historically benefited and prospered, through a 44% increase in electrical energy consumption since 2002, based on electric supply from these existing substations located in the Salt Lake Valley and from the electric transmission system interconnected therein.

The capacity on the existing 138 kV transmission lines has been exhausted by load growth in Tooele County. By 2013, it is anticipated that the Company will be unable to serve its existing Customers in Tooele County reliably with the existing 138 kV transmission system served from Terminal and Oquirrh substations and will not be able to maintain compliance with NERC Reliability Standards. Equally important is the fact that the Company is presently unable to provide new service to any new large economic development customers requesting service for new facilities or the expansion of their existing facilities attempting to locate or expand within Tooele County. As a result, the Company will be unable to serve the future load required for any further economic development in the Tooele Valley prior to the completion of the Project and future Limber substation. Based on 2009 network Customer loads and resource submittals, the Critical Load Area, including Tooele County, is anticipated to grow from a peak of 4709 MW in 2009 to 6,586 MW in 2018, nearly an 1800 MW increase by 2018. Significant load growth is expected to continue in Tooele County which is consistent with the views expressed by the Tooele County economic development staff during the conditional use permitting process for the Project. In the future, the Limber substation and the 500 kV line from the Mona substation will provide new long term load service capacity and increased reliability to Tooele County. Without Energy Gateway, including the 2013 Mona to Oquirrh Project, this load increase could not be served with the existing and future planned energy resources.

CONCLUSIONS AND RECOMMENDATIONS

Q. Please explain why the Company is approaching the Utility Facility Review Board now for a project that is not scheduled for completion until 2013.

A. Time is of the essence. Large transmission projects such as the Mona to Oquirrh Project are complex, and require long lead times to complete the siting and permitting processes, which includes the NEPA permitting process in addition to other federal, state and local regulation and permitting compliance. With this in mind, the Company has been proceeding with the Project siting and permitting processes since 2005. However, in addition to the years required to site and permit the Project, several additional years are necessary to complete the specific Project design work, order and acquire materials, and construct the Project. At this point, the Company has only three years to complete these tasks. Any further delay in obtaining a conditional use permit from Tooele County will jeopardize the Company's ability to provide safe, reliable, adequate and efficient electric service to its Customers within the Critical Load Area, including the Tooele Valley.

The Company is an essential service provider of electric services and as such must implement long-range planning strategies in order to meet the anticipated energy needs of its Customers. Failure to proactively and prudently plan for future growth would put the Company in a reactive posture, requiring it to operate its systems at or above design parameters, increasing the likelihood of system damage and diminishing backup capacity, and in the end, leading to increased system down time and Customer power outages. Increasing the risk of potential breach of national reliability standards of which the Company may be sanctioned if it failed to plan and act. Long-term scheduling, planning and implementation of transmission projects such as the Mona to Oquirrh Project increase the adequacy and reliability of the Company's electric service to its Customers, and significantly reduce overall project costs, thereby saving the Company's Customers money.

Q. What do you recommend?

A. The Company requests the Board:

(1) Find that the Project and the Company's proposed route as identified in the conditional use permit application, which was denied by Tooele County on March 30, 2010, is necessary in order for the Company to provide safe, reliable, adequate and efficient service to its Customers;

(2) Require Tooele County to approve a conditional use permit for the Mona to Oquirrh transmission line to be located within the Company's proposed transmission corridor as specified in Mr. Smith's testimony. *See* Exhibit BDS-9.1 (Company's Approved Transmission Line Corridor – Limber South) and Exhibit BDS-9.2 (Company's

Approved Transmission Line Corridor – Limber East); and require the County, in defining the transmission centerline within the corridor, minimize the number of angles or corners by using straight lines wherever possible in order to reduce the number of large corner structures and foundations, mitigate construction and environmental impacts, and assure a cost efficient solution for the Company's Customers; and

(3) Require the County approve a conditional use permit consistent with the Board's findings within 60 days following the decision of the Board.

Q: Does this conclude your direct testimony?

A: Yes.

EXHIBITS TO DIRECT TESTIMONY OF DARRELL T. GERRARD

EXHIBIT DTG-1: Critical Load Area

EXHIBIT DTG-2: Major Transmission Paths Serving Utah

EXHIBIT DTG-3: Energy Gateway Transmission Expansion Plan

EXHIBIT DTG-4: Mona to Oquirrh 500/345 kV Transmission Project

EXHIBIT DTG-5: 2008 IRP Resource Table

EXHIBIT DTG-6.1: Energy Gateway Separation and Design - Introduction to Project Scale

EXHIBIT DTG-6.2: Energy Gateway Separation and Design – Scenario (1)

EXHIBIT DTG-6.3: Energy Gateway Separation and Design – Scenario (2)

EXHIBIT DTG-6.4: Energy Gateway Separation and Design – Scenario (3)