# Appendix A – Proponent's Purpose and Need

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# APPENDIX A – PROPONENT'S PURPOSE AND NEED

## A.1 Introduction

In the recent past, the Intermountain area experienced more than a decade of economic prosperity and growth. This, coupled with an increase in per-customer electric usage, has resulted in a significant increase in the overall demand for electricity. As a result of this growth, system studies indicate the southwest Utah transmission system will be fully utilized by 2014. Consequently, Rocky Mountain Power (a business unit of PacifiCorp) needs to increase its existing transmission capacity by 2014. In addition, the southwest Utah area's electric load is fed from the existing 345-kilovolt (kV) Sigurd to Three Peaks to Red Butte transmission line, and a second 345 kV transmission line between the Sigurd and Red Butte substations in a different corridor is needed to add reliability in case of a potential transmission outage in the area that could interrupt electric supply to customers. These needs are further substantiated by regional transmission studies that recommend the construction of an additional extra-high-voltage (EHV) transmission line from the existing Sigurd Substation to the existing Red Butte Substation to increase system capacity in the transmission grid, improve system reliability, and meet Rocky Mountain Power's (the Company) responsibilities as an essential service provider and regulated utility (Southwest Utah Technical Studies Group [SUTSG] 2009). Therefore, the Company's purpose of the Sigurd to Red Butte 345 kV – No. 2 Transmission Project (Project) is to increase system capacity, improve reliability, and meet the Company's responsibilities as an essential service provider and regulated utility by constructing a new 345 kV transmission line between the Sigurd and Red Butte substations in a different corridor (to the maximum extent practicable) than the existing Sigurd to Three Peaks to Red Butte transmission line.

## A.2 Need as a Regulated Utility

One purpose of the Project is to directly support PacifiCorp's obligations as a regulated utility, including its need to:

- Meet U.S. Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariff (OATT) contract obligations for load service, transmission service, and transmission access
- Comply with mandatory North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) Bulk Electric System Reliability Standards
- Address reliability and system constraints within its existing transmission system that necessitate the development of additional transmission capacity
- Provide increased capacity as required to serve existing and growing loads
- Provide safe, reliable, adequate, and efficient electricity to its customers

The Company's regulatory obligations are further explained in detail below.

### A.2.1 Regulatory Context

PacifiCorp is an electric utility that transmits electricity via a grid of transmission lines located throughout a six-state region and a distribution system that serves approximately 1.7 million retail customers. Rocky

Mountain Power delivers electricity to customers in Utah, Wyoming, and Idaho. As an essential service provider, Rocky Mountain Power is required to operate under the oversight and regulatory controls of the Public Service Commission of Utah, the Wyoming Public Service Commission, and the Idaho Public Utility Commission. Pacific Power, another business unit of PacifiCorp, provides service to customers in Oregon, Washington, and California and is subject to the regulatory oversight of the Oregon Public Utility Commission, the Washington Utilities and Transportation Commission, and the California Public Utilities Commission. Although the objectives of these multiple commissions vary somewhat, they do share a common goal of ensuring utilities such as Rocky Mountain Power provide safe, reliable, adequate, and efficient delivery of electricity.

The Company is also a federally regulated utility that operates under the jurisdiction of the FERC. As provided in PacifiCorp's OATT under Sections 15.4, 28.2, and 28.3, PacifiCorp is obligated to expand its transmission system to provide requested Firm Transmission Service (transmission service that may not be interrupted for any reason except during an emergency when continued delivery of power is not possible). It is also obligated to provide sufficient capacity to reliably deliver resources to Network and Native Load Customers. PacifiCorp's Attachment K of the OATT also requires planning for the expansion of the system to ensure its transmission system meets industry, regulatory, and reliability standards. The Sigurd to Red Butte 345 kV – No. 2 Transmission Line Project is needed to ensure these long term requirements are met.

The Company must also comply with the National Electric Safety Code (NESC) C2-2007, which establishes minimum electrical safety rules and design for transmission lines. The NESC Section 1, page 1, General Rules paragraph 012 C. (Institute of Electrical and Electronics Engineers 2007) states:

> For all particulars not specified in these rules, construction and maintenance should be done in accordance with accepted good practice for the given local conditions known at the time by those responsible for the construction or maintenance of communication or supply lines and equipment.

This mandates the Company follow other industry standards, requirements, and guidelines, in addition to applying its firsthand practical experience when planning, siting, designing, and constructing its electric transmission system.

The NERC is another regulatory body under which the Company must operate. In 2007, FERC certified NERC as an Electric Reliability Organization. In so doing, NERC acquired the legal authority to enforce reliability standards with all users, owners, and operators of the bulk power system in the United States, and made compliance with those standards mandatory and enforceable. Transmission systems in the United States, like the proposed Sigurd to Red Butte 345 kV – No. 2 Project, must be planned, operated, and maintained under NERC reliability standards. Furthermore, a primary driver behind this Project is the NERC requirement that the Company have a forward-looking and long-range transmission plan to meet current and forecasted customer needs.

The WECC has been designated as a Regional Reliability Organization, certified and supervised by NERC and FERC. It is responsible for coordinating expansion and ensuring bulk electric system reliability in the Western Interconnection (one of the two major alternating current power grids in North America, the other being the Eastern Interconnection). In addition, WECC provides an environment for coordinating the planning, capacity rating, and operational limits for the interconnected system via the activities of its members as set forth in the WECC Bylaws. As such, WECC is required to enforce standards set by NERC and can develop and enforce additional FERC-approved regional reliability standards necessary in the West. In compliance with these standards, transmission systems must be built with sufficient levels of redundancy to enable the transmission system to reliably operate in the event of loss or outage of the system elements (i.e., transmission line segments or substation elements).

The Energy Policy Act of 2005 provided a framework for enforceable reliability standards. The FERC and NERC can impose civil penalties of up to $1 million per day per violation. The penalty amount is based on guidance that takes into account a number of factors, including the severity of the violation, the risk to the reliability of the bulk power system caused by the violation, and the responsible entity's compliance efforts. At the federal level, FERC may also impose penalties for noncompliance with reliability standards. On a regional scale, NERC regional councils, in this case WECC, their members (including PacifiCorp), and all other electric industry participants, are required to comply with all applicable NERC standards, including, but not limited to, NERC TPL (Planning) and TOP (Operating) standards that provide minimum requirements for how the system must be planned and operated.

## A.2.2 NERC and WECC Reliability Standards and Performance Criteria

NERC and WECC are focused on reliability through two overarching methods: (1) enforcement of mandatory NERC reliability standards and WECC criteria and (2) application of WECC policies and procedures. NERC and WECC require Transmission Providers like the Company to meet certain performance requirements during normal operation and system outage events. They also require detailed risk assessments of system impacts that would result from a multitude of outage scenarios. Compliance with these standards and regional criteria falls on the responsibility of Rocky Mountain Power as a Transmission Owner and Transmission Planner under NERC registration.

Consequently, the following NERC and WECC standards and criteria apply to Rocky Mountain Power's transmission system and its design of the proposed Project, including, but not limited to:

- TPL 001: Category A – System Performance Under Normal (No Contingency) Conditions
- TPL 002: Category B – System Performance Following Loss of a Single Bulk Electric System (BES) Element
- TPL 003: Category C – System Performance Following Loss of Two or More BES Elements
- TPL 004: Category D – System Performance Following Extreme Events Resulting in the Loss of Two or More BES Elements

WECC criteria under which Rocky Mountain Power is governed include:

- TPL 001 – WECC-1-CR System Performance Criteria Normal Conditions
- TPL 002 – WECC-1-CR System Performance Criteria Following Loss of a Single BES Element
- TPL 003 – WECC-1-CR System Performance Criteria Following Loss of Two or More BES Elements
- TPL 004 – WECC-1-CR System Performance Criteria Following Extreme BES Events (WECC 2008)

Some WECC criteria are additional (more restrictive) to NERC TPL Standards, including WECC's voltage and frequency performance requirements. For example, NERC standard TPL 003 C.5 requires Rocky Mountain Power to plan "for an event that results in the 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)" [italics added] (NERC 2008). Whereas the WECC regional planning TPL-002-WECC-1-CR goes further and stipulates that the NERC TPL 003 C.5 initiating event shall *also* apply to the common mode contingency (one event causes multiple facilities to trip) of two adjacent circuits *on separate towers* unless the frequency is determined to be less than 1 in 30 years [italics added]. In this case, the WECC requirement extends beyond the NERC standard because it is applies to cases where two transmission circuits are installed on common structures *or* are located adjacent to each other, which is a frequent condition for many of the alternatives proposed in the Sigurd to Red Butte 345 kV – No. 2 Project. This means the utility, at a minimum, must plan for loss of multiple circuits simultaneously such that the system has adequate redundancy to withstand such an outage without affecting any of the grid's electrical consumers.

The NERC and WECC standards and criteria are performance-based. Therefore, they do not dictate the site-specific locations of proposed transmission lines. The physical arrangement of new and existing lines and corridors is left up to the Transmission Provider because it is most knowledgeable about the best method to meet system performance requirements and manage reliability risks and costs. Should a Transmission Provider fail to meet NERC standards and WECC criteria, resulting in widespread uncontrolled loss of generation or customer demand, WECC System Performance Criteria TPL-004 WECC-1-CR, Requirement WRS5 states that "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 Planning Coordination Committee PCC) approval that the Mean Time Between Failure is greater than 300 years (frequency less than .0033 outages/year)" (WECC 2008). Severe measures would be required to meet this elevated level of required system performance.

NERC Transmission Planning Standard TPL 002 states that "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 necessary to meet present and future system needs." This means that the Company must 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 unplanned.

Collectively these standards intend to protect the West's interconnected electrical grid by dictating minimum performance levels of transmission system reliability for projects like the proposed Sigurd to Red Butte 345 kV – No. 2 Project. In the event a transmission line fails to perform in accordance with these standards, the Company would be required to remedy the problem to the satisfaction of WECC, which historically has resulted in restricting the operating capacity of the lines to levels that will not cause disruptions to the grid and/or the construction of additional transmission line(s).

### A.2.3 WECC Transmission Corridors

WECC's definition for a common corridor is a "contiguous right-of-way or two parallel rights-of-way with structure centerline separation less than the longest span length of the two transmission circuits at the point of separation or 500 feet, whichever is greater, between the transmission circuits. This definition does not apply to the last five spans of the transmission circuits entering into a substation" (WECC 2008).

The "longest span" fluctuates based on the voltage of the line and the terrain. Planning requires a technical risk analysis of the consequences of a major disturbance involving two or more EHV lines. The WECC studies are intended to account for "unanticipated" outages or, in other words, events and circumstances that are not predictable but certainly deemed credible due to the utility's system operating experience and history. Within the proposed Project Area, there are two other existing EHV lines (the IPP 500 kV and Sigurd to Three Peaks to Red Butte 345 kV transmission lines) that Rocky Mountain Power must consider when siting the proposed Project. If the proposed Project and the existing EHV lines are all co-located in the same corridor, then Rocky Mountain Power must be able to demonstrate it has an acceptable back-up plan in place should they be simultaneously out of service for any reason. For Rocky Mountain Power to reliably serve immediate future loads within the southwest Utah area, a new transmission line needs to be designed such that it meets NERC and WECC planning and reliability criteria by being built in an alignment that is not considered as an adjacent circuit to the existing Sigurd to Red Butte 345 kV – No. 1 transmission line.

## A.2.4 Use of Federally Designated Corridors

As part of its original feasibility analysis, the Company considered routes in federally designated corridors located within the Project Area, but suggested the removal of some from further consideration based upon many factors, including its fundamental need to comply with NERC and WECC requirements. The Westwide Energy Corridor Programmatic Environmental Impact Statement (WWEC PEIS) confirms that compliance with NERC and WECC standards is essential to reliability by stating in Chapter 2.6.3:

> One area where the [NERC and WECC] reliability standards or criteria critically dictate corridor specifications is with respect to the distance separations between multiple bulk electricity transmission lines located in common or adjacent corridors. Reliability criteria recently proposed by WECC address the potential for simultaneous or successive failures of multiple transmission lines within a common corridor or within parallel adjacent corridors. These proposed WECC reliability criteria establish regional differences from NERC reliability standards TPL-001 through TPL-004 and require transmission system planners and designers to address the likelihood and consequences of the simultaneous or successive outages of multiple lines (cascading) due to what WECC system operators have determined to be credible events, including the simultaneous loss of two adjacent lines occurring at a frequency greater than once every 300 years (Argonne National Laboratories 2008).

The WWEC PEIS continues to add that:

> Compliance with NERC and regional reliability standards is essential to guaranteeing the reliability of the nation's bulk electricity transmission network and nothing in this PEIS, including the establishment of energy corridors that may subsequently result, contravenes, replaces, or relaxes the applicability or enforceability of NERC or WECC reliability standards or the supporting directives to member organizations contained in WECC reliability criteria. In those instances where the postulated specifications of hypothetical energy corridors are inconsistent with the reliability standards or criteria, those specifications shall be deemed moot, replaced with specifications that are consistent with the applicable standards or criteria (Argonne National Laboratories 2008).

## A.2.5 Company and Industry Experience

The Company has significant experience that shows multiple transmission lines located in the same general proximity have experienced significant simultaneous outages due to a variety of causes, including, but not limited to, fire and smoke, high winds, dust storms, ice storms, blizzards, lightning, landslides, earthquakes, vandalism, tower or conductor failure, equipment failure, airplane collisions, and other experience. Examples include:

- 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 Utah state-wide blackout.
- 1982–1983: Landslides on the two Emery to Sigurd 345 kV lines destroyed transmission towers.
- 1983: Severe wind storms destroyed sections of two 345 kV, two 230 kV, and three 138 kV lines between Salt Lake City and Ogden.
- 1990: An Air Force jet practicing touch-and-go landings at the Salt Lake International Airport clipped an overhead shield wire with its fuel tank which wrapped around the double-circuit 345 kV and 230 kV lines between Terminal and Ben Lomond substations causing outages between Terminal and Ben Lomond.
- 2000: Fires in the corridor of Emery to Camp Williams and Huntington to 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. It should be noted that this area would not reasonably be considered as densely forested.

In addition to the Company's experience, other significant system outages have been experienced by other utilities in the WECC:

- 1990: Fires caused six simultaneous outages (along with 17 single line outages) of two Round Mountain to 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 megawatts (MW) to 1000 MW at times.
- 1993: 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.

# A.3 Need to Improve Capacity

## A.3.1 Current and Projected Electrical Demand

Rocky Mountain Power and Pacific Power serve retail electric customers in the states of California, Idaho, Oregon, Utah, Washington, and Wyoming (native load).

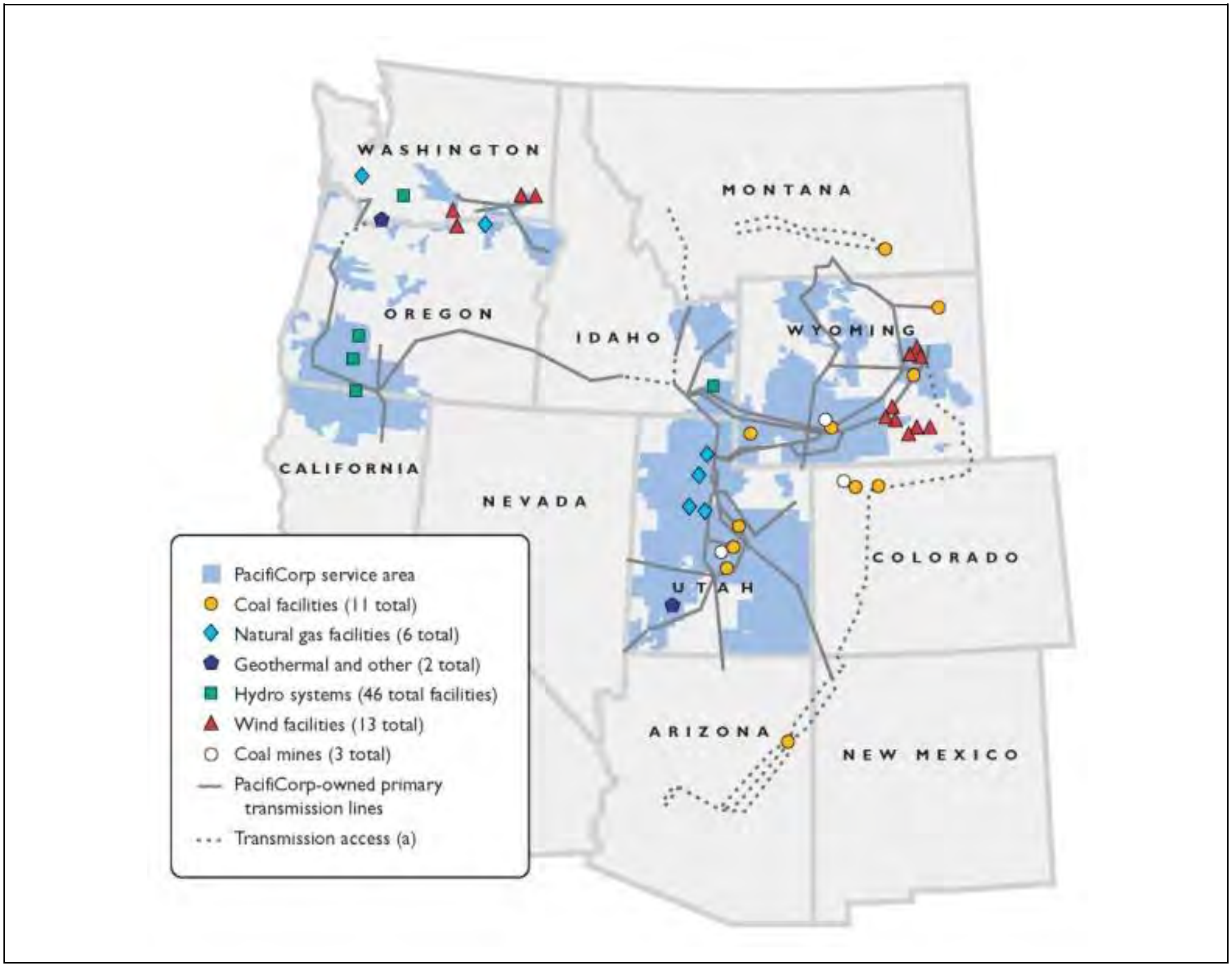



**Figure A-1 PacifiCorp Service Territory**

Between 1997 and 2009, the population in the counties served by Rocky Mountain Power has grown substantially[1]. Along with this growth there has been an even greater growth in the demand for electricity[2]. As a regulated utility serving these counties, Rocky Mountain Power has an obligation to provide safe reliable service to existing and future customers on a nondiscriminatory basis. Rocky Mountain Power currently forecasts an increase in overall peak demand at 2.2 percent each year over the next 5 years and by 2.4 percent each year over the next 10 years[3].

[1] SOURCE: Global Insight state and county estimates, February 2009
[2] SOURCE: Rocky Mountain Power billing system
[3] SOURCE: Rocky Mountain Power Integrated Resource Plan, October 5, 2010

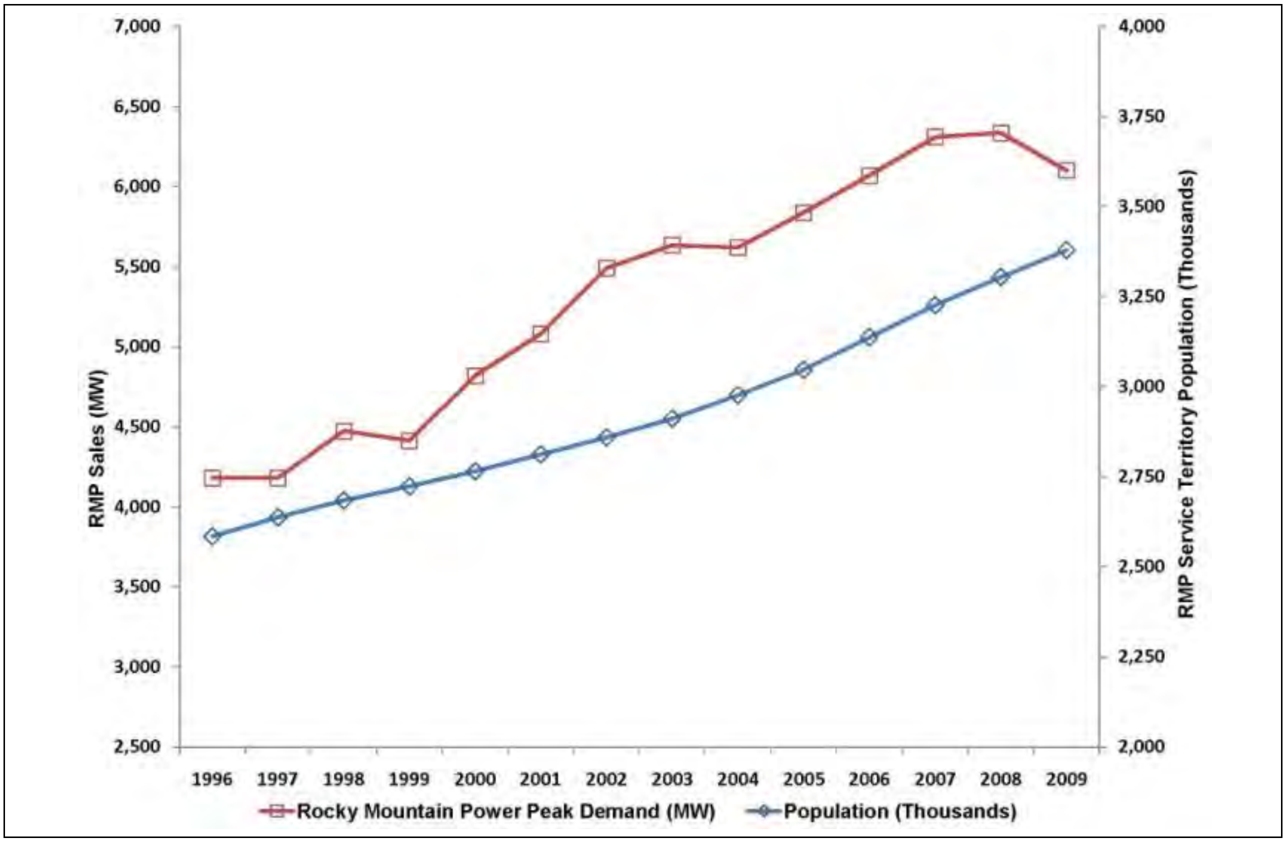
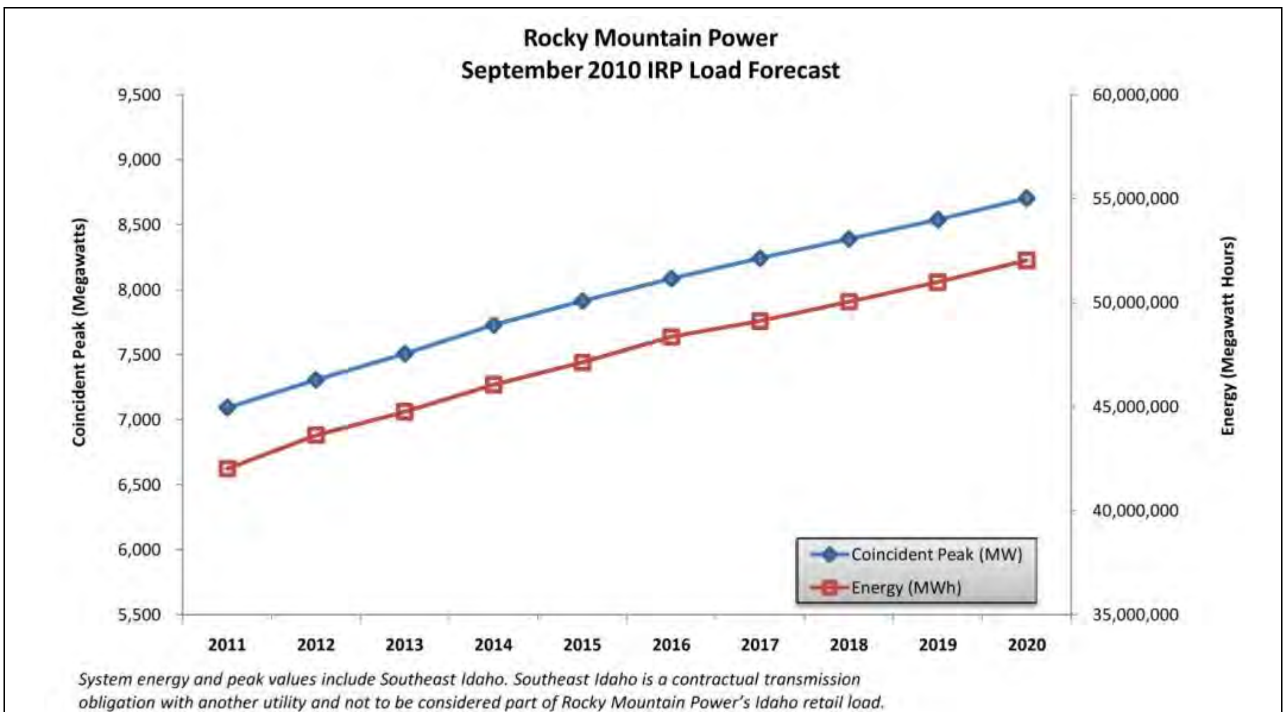



**Figure A-2 Energy Demand Since 1996**




SOURCE: Data is provided b PacifiCorp Integrated Resource Plan (October 5, 2010 Public Input Meeting Presentation)

**Figure A-3 Projected Peak Demand and Energy Usage**

PacifiCorp forecasts its load growth for retail customers in Utah alone will increase by over 1,000 MW in 10 years. These forecasts are based on the integrated resource plans (IRP) prepared by PacifiCorp as required to fulfill the regulatory requirements and guidelines established by the public utility commissions of the states PacifiCorp serves. The IRP also addresses the obligations of PacifiCorp pursuant to its Open Access Transmission Tariff to plan for, and expand, its transmission system in a non-discriminatory manner based on the needs of its native load customers, network customers, and all eligible customers that agree to expand their transmission systems. This includes entities that generate, or plan to generate, electricity, including coal-fired, natural-gas-fired, and renewable energy sources (wind and geothermal). Therefore, in addition to ensuring both existing and future transmission capacity is available to meet the needs of its retail and native load customers, PacifiCorp has an obligation to meet the growing needs of other network customers. PacifiCorp provides network service to 11 utilities, which in turn provide electric service to retail customers.

Load projections provided by each of the participating transmission utilities in southwest Utah are summarized in Figure A-4. Each participant is required to provide PacifiCorp with forecasted load information consistent with the most recent Loads and Resources 10-Year Forecast submitted annually to PacifiCorp transmission services. These network customers (including Deseret Generation and Transmission [DG&T] and the Utah Associated Municipal Power Systems [UAMPS]) estimate their demand for electricity will grow by an average of 4 percent over the next ten years.[4]

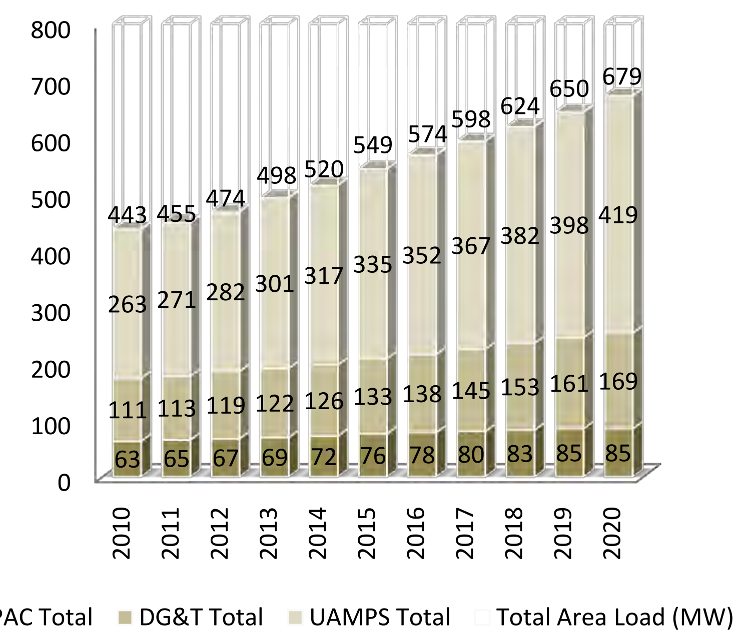



**Figure A-4 Southwest Utah Load Projections**

These projections suggest a substantial growth rate throughout the forecast period, demonstrating that between 2010 and 2020 the southwest Utah transmission load is expected to increase by approximately 236 MW, from 443 MW to 679 MW.

[4] Data taken from customer submitted Load and Resources information from 2008.

In addition to these forecasts, PacifiCorp periodically performs studies in cooperation with other southwest Utah transmission providers and load-serving entities to assess the transmission system needs in the area, such as the most recent Southwest Utah Planning Study Report done in 2009. This study concluded that prior to 2014 there is a need to install other substation facilities to support southwest Utah load growth while simultaneously maintaining the maximum system transfer capability for imports and exports. However, the study also found that while these additional substation facilities will enable the system to serve both load and transfer requirements through the summer of 2013, a new Sigurd – Red Butte 345 kV transmission line will still be needed for the summer of 2014 and beyond (SUTSG 2009).

## A.3.2 Existing Capacity

Capacity refers to the amount of power a transmission line (or set of lines in a transmission path as described below) can reliably deliver. Capacity is measured in MW and is limited by the current (in amperes) the line, or groups of lines for a path, can carry, or the minimum voltage levels at the substations. Multiple transmission lines generally located in similar alignments and operating electrically in parallel are referred to as electrical transmission paths. Each transmission line in a given path has an assigned capacity rating, which determines the limits of its operable range. The rating is determined by a regional transmission organization, such as WECC. The members collectively agree upon a rating based upon the results of detailed technical studies performed by the owner/operator of each proposed system facility addition. These studies evaluate the new facility's effects upon the overall transmission path's reliability under all conditions, such as thermal overload, instability, congestion, and other considerations. All ratings are done in conformance with accepted industry practice, NERC Standards, and WECC criteria and policies.

Existing capacity in the southwest Utah area is limited due to the capability of the existing transmission lines serving the area, particularly out of the Red Butte Substation. The southwest Utah area is principally served from the Red Butte 345 kV substation via a single 345 kV line and a single 230 kV line, both originating from the Sigurd substation. The existing Sigurd to Three Peaks to Red Butte 345 kV line, which extends to the Harry Allen Substation in southern Nevada, serves a dual purpose of importing/exporting power into southern Utah and serving the native southwest Utah area load.

## A.3.3 Need to Allow Power Sales, Transfers, and Purchases

PacifiCorp's wholesale transmission services are regulated by FERC under cost-based regulation subject to PacifiCorp's OATT, which requires it to provide transmission service to eligible wholesale customers. PacifiCorp's transmission business operates independently and markets its transmission services using an Open Access Sametime Information System. Power transfers into and through southern Utah are made via the existing Sigurd to Three Peaks to Red Butte 345 kV line. South of Red Butte, the Red Butte to Harry Allen 345 kV regional transmission tie line is used to transfer power from southwest Utah to southern Nevada and vice versa

The current system supports up to 300 MW of transfers (bi-directional) between southwestern Utah and Nevada. As a result of this Project and other Company projects underway in the area, the capacity of the existing system is planned to increase by 300MW for a total system planned capacity of 600MW (bi-directional). This additional transmission capacity can be used by the Company to make off-system sales during periods of surplus energy, and under its OATT the Company can provide firm transmission services to third parties in Region, both of which provide benefits to the Company's customers by reducing their overall energy costs.

## A.3.4 Service Load

The proposed Sigurd to Red Butte 345 kV – No. 2 Project will not only support future electrical load growth in southwestern Utah, but also will improve the ability of PacifiCorp's transmission system to transport energy into central Utah and to growth areas along the Wasatch Front. Due to the interconnected nature of its transmission system, this Project will benefit PacifiCorp's system and the Western Interconnection in a regional context.

## A.3.5 Access to Potential Renewable/Generation Sources

The additional transmission line proposed will provide improved access to markets, existing and new generation sources, and thereby provide options to integrate new energy resources, including renewable energy. In this regard, this project supports PacifiCorp's current and future Integrated Resource Plans. While there are several renewable projects under development in Beaver County, the proposed Project is independent of, and would be built regardless of, those new generation projects.

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