Avista 10 Year Transmission Plan

2011 LOCAL PLANNING REPORT
(AS REVISED WITH 2012 UPDATE)

TRANSMISSION PLANNING

Prepared by Avista Transmission Planning

www.avistautilities.com

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2011 LOCAL PLANNING REPORT
(AS REVISED WITH 2012 UPDATE)

Date Completed: November 14, 2012

Prepared By: John Gross

Nov 14, 2012

Scott Waples Director, System Planning — Date

Version History

Version	Version Date	Action	Change Tracking	Reviewed By
A	08 Nov 2011	Draft Study Results	Revised 2010 LPR	T. Rolstad
1	14 Nov 2012	Local Transmission Plan Update	Incorporated assessments	J. Gross

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1 INTRODUCTION

During normal application of Avista's Attachment K process, the completion of the 2012 "Year 2" would result in an update of the 2011 Local Planning Report and an update on the facilities and projects identified in that Report. In the next "Year 1" of the Attachment K process (2013), Avista anticipates a shift that will result in the Local Planning Report being built on a number of area Planning Assessments performed on an ongoing basis by Avista. To assist with that transition, Avista has chosen to redraft the 2011 Local Planning Report in the format that will be used going forward, resulting in a Year 2 product that looks similar to a Year 1 Local Planning Report.

As stated above, Avista's 2012 Local Planning Report update is the culmination of the 2011-2012 Local Transmission Planning Process (Process) as outlined in Attachment K to Avista Corporation's ("Avista") Open Access Transmission Tariff ("OATT")FERC Electric Volume No. 8. The purpose of the Process is to identify any Single System Projects needed to mitigate future reliability and load-service requirements for the Avista Transmission System. The collection of Single System Projects in the Local Planning Report provides a ten year transmission expansion plan. The plan, and associated Local Planning Report, includes all transmission system facility improvements identified as necessary to meet the applicable local and regional reliability performance criteria as well as projects developed outside of the Process defined herein. Such reliability impacts were identified by performing technical studies, which can include powerflow, transient voltage stability, short circuit and voltage collapse studies. Development of the Local Planning Report also supports compliance with applicable local and regional reliability standards.

The Process calls for a biennial process corresponding with the Regional Planning Process[1] Avista participates in, ColumbiaGrid. The results from both years of the biennial planning process will be provided to ColumbiaGrid for incorporation into their planning process.

Avista's OATT is located on its Open Access Same-time Information System (OASIS) at http://www.oatioasis.com/avat. Additional information regarding Avista's Transmission Planning is located in the Transmission Planning folder on Avista's OASIS.

1.1 LOCAL PLANNING

The Local Planning Report has been prepared within the two-year process as defined in Avista's OATT Attachment K. The Local Planning Report identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, including both grandfathered, non-OATT agreements and rollover rights, over a ten (10) year planning horizon. Additionally, the Local Planning Report typically incorporates the results of any

[1] As described in FERC Order 890 and its subsequent Orders, and Order 1000

stakeholder-requested economic congestion studies results that were performed. For the 2011-2012 planning cycle, no economic congestion studies were requested or incorporated.

1.2 REGIONAL PLANNING

Avista coordinates its planning processes with other transmission providers through membership in the ColumbiaGrid, Northern Tier Transmission Group (NTTG) and the Western Electricity Coordinating Council (WECC). Avista uses the ColumbiaGrid process for its regional planning and coordination with adjacent regional groups and other planning entities. Avista uses the WECC for its interconnection wide planning and development of wide-area planning proposals.

2 TRANSMISSION SYSTEM DESCRIPTION

2.1 OVERVIEW

Avista is a publicly held energy company involved in the production, transmission and distribution of energy (natural gas and electricity) as well as other energy-related businesses. Avista (formerly known as the Washington Water Power Company) was founded on March 13, 1889, in Spokane, Washington, by ten enterprising men who saw the potential of one of the Northwest's most abundant natural resources — moving water.

Avista's primary market area covers more than 30,000 square miles, with energy generation, transmission, and distribution facilities in four Western states. The company serves more than 335,000 electric customers in eastern Washington and northern Idaho. Avista's electric power generation and transmission assets range in age from modern 21st century equipment to equipment that was patented and placed in service over 100 years ago.

The service territory served by the Avista electrical system is generally centered on the Spokane, Washington and Coeur d'Alene, Idaho load centers. Avista also serves a smaller southern load center located near Lewiston, Idaho and Clarkston, Washington. Figure 2-1 geographically displays the Avista service territory.

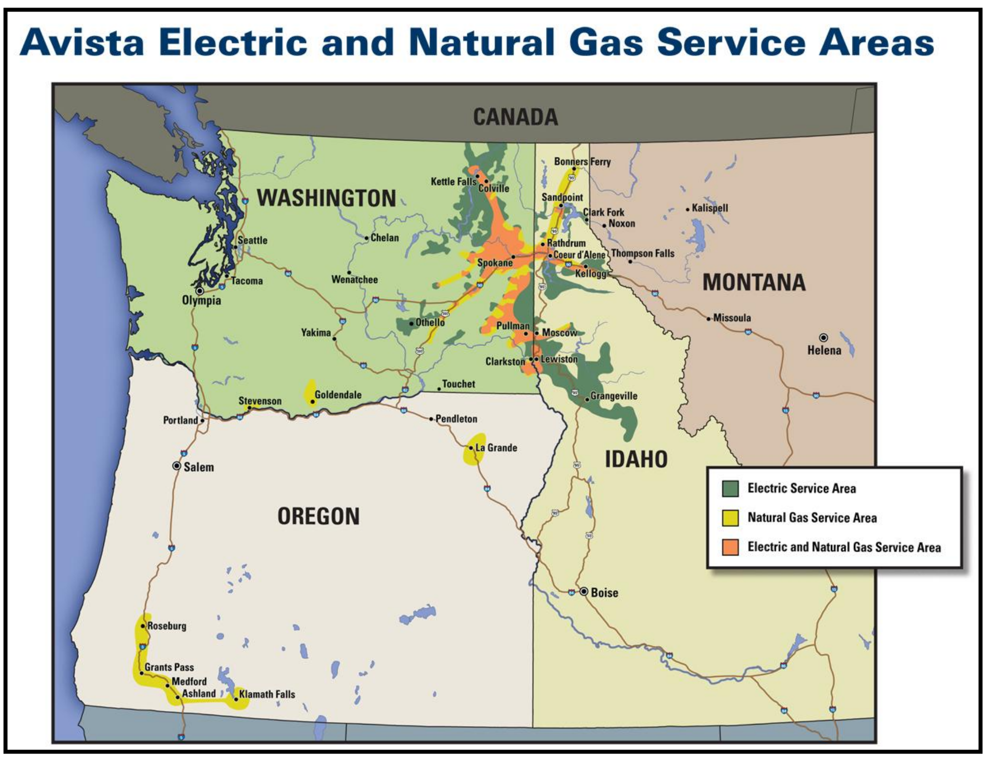

FIGURE 2-1: AVISTA SERVICE TERRITORY.

2.2 TRANSMISSION SYSTEM

2.2.1 Voltages and Paths

The Avista transmission system is comprised of 230 kV and 115 kV transmission lines. The 115 kV system serves a dual purpose with much of the 115 kV providing sub-transmission service. Avista owns transmission assets in the following WECC rated paths:

- Path 6: West of Hatwai
- Path 8: Montana to the Northwest
- Path 14: Idaho to the Northwest

Avista is not the Path Operator for either Path 8 (operated by North Western Energy) or Path 14 (operated by Idaho Power Company). Path 6 is jointly operated by Avista and BPA—the West of Hatwai path is "operated" by the two parties by ensuring that neither party schedules beyond its allocation.

Avista's transmission system has been historically designed to serve Avista's native load and accommodate those energy transfers bringing energy in from "off-system" to serve the Avista load.

2.2.2 Points of Interconnection

Avista's Balancing Authority Area is directly interconnected to the Balancing Authority Areas operated by Bonneville Power Administration, Public Utility District No. 2 of Grant County (GCPD), Public Utility District No. 1 of Chelan County, Idaho Power Company, PacifiCorp, NorthWestern Energy, Seattle City Light, and Tacoma Power.

As a practical matter (with regards to Transmission Planning studies), the most important points of interconnection are associated with the BPA 500/230 kV transformers located at the following BPA stations: G.H. Bell (Spokane, WA), Hatwai (Lewiston, ID), and Hot Springs (Hot Springs, MT).

Within Avista's Balancing Authority Area, Avista's Transmission System is interconnected with Pend Oreille PUD's Transmission System and several Load Serving Entities including: Big Bend Electric Cooperative, City of Cheney, City of Chewelah, Clearwater Power Company, City of Coulee Dam, Fairchild Air Force Base, Idaho County Light & Power Cooperative, Inland Power & Light Company, Kootenai Electric Cooperative, Modern Electric Water Company, Northern Lights, City of Plummer, and Vera Irrigation District.

2.2.3 Transmission System Regions

It has proven convenient for Avista Transmission Planners to separate its electrical service territory into geographical regions. These regional areas are shown with their approximate boundaries in Figure 2-2.

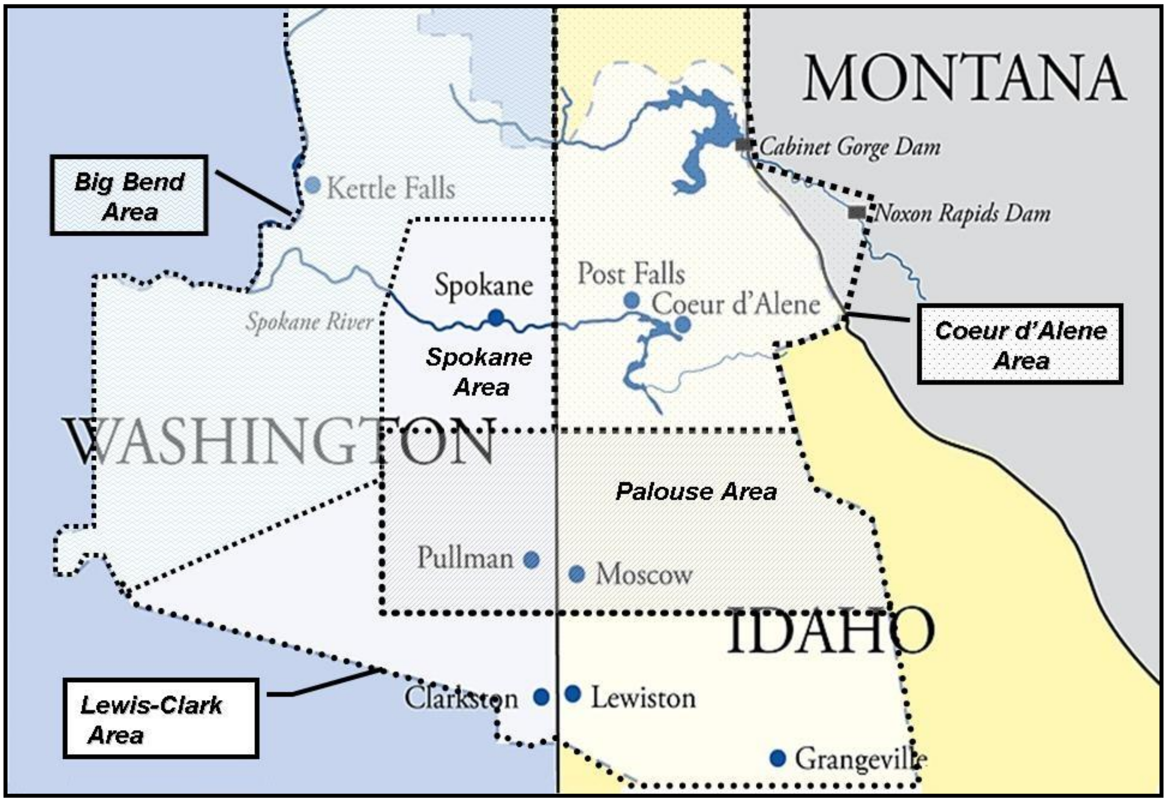

FIGURE 2-2: AVISTA TRANSMISSION SYSTEM REGIONS.

Figure 2-3 shows a substation level drawing of Avista's 230 kV transmission system including interconnections to foreign utilities. The Avista 230 kV transmission system consists of two "rings" centered near the Spokane/Coeur D'Alene area (i.e. the northern ring) and the Lewiston/Clarkston area (i.e. the southern ring). The two rings are interconnected (north to south) at the Benewah Substation. Additionally, the two rings are interconnected to the BPA 500 kV transmission system providing a low impedance path from Bell and Hot Springs Substations to the Hatwai Substation.

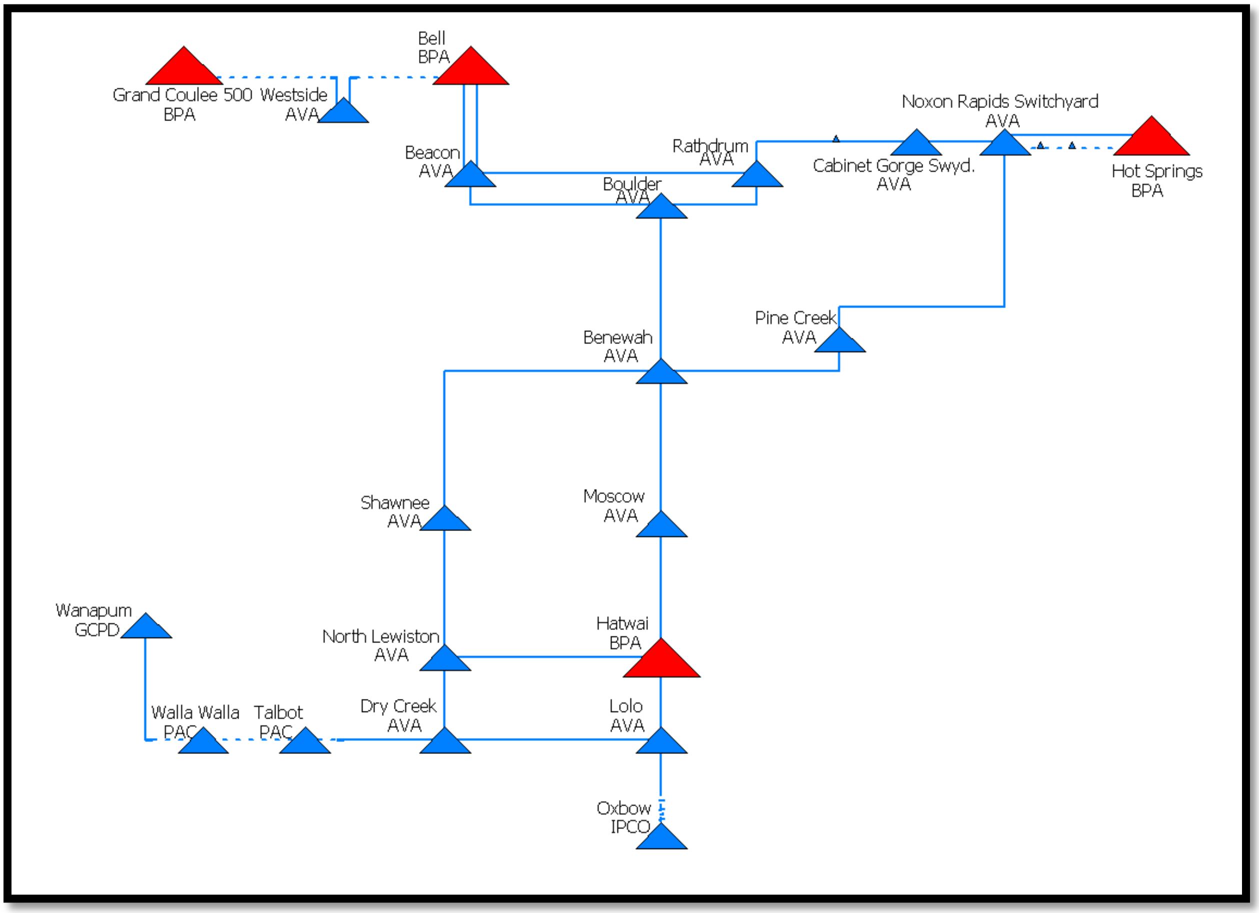

FIGURE 2-3: AVISTA 230 KV TRANSMISSION SYSTEM.

2.3 GENERATION RESOURCES

Avista has a diverse mix of generation with a majority of its generation being hydro power based on various projects located on the Spokane River (Washington and Idaho) and the Clark Fork River (Idaho and Montana). Avista owns eight hydro-electric generating plants as well as coal (partial ownership), natural gas, and wood-waste combustion plants in five eastern Washington, northern Idaho, eastern Oregon, and eastern Montana locations. Avista also has long energy contracts for delivery of energy generated by various Mid-C projects. Table 2-1 and Table 2-2 list the various generating projects owned by Avista.

Project Name	Fuel	Location	Project Start Date	Maximum Capability (MW)[2]	Expected Energy (aMW)
Monroe Street	Spokane River	Spokane, WA	1890	15.0	**11.6**
Post Falls	Spokane River	Post Falls, ID	1906	18.0	**9.8**
Nine Mile	Spokane River	Nine Mile Falls, WA	1925	24.0	**13.3**
Little Falls	Spokane River	Ford, WA	1910	36.0	**23.7**
Long Lake	Spokane River	Ford, WA	1915	88.0	**58.4**
Upper Falls	Spokane River	Spokane, WA	1922	10.0	**8.6**
Cabinet Gorge	Clark Fork	Clark Fork, ID	1952	271.0	**123.8**
Noxon Rapids	Clark Fork	Noxon, MT	1959	580.0	**197.1**
Total	All Hydro			1042.0	446.3

TABLE 2-1: AVISTA HYDROELECTRIC GENERATION RESOURCES.

Project Name	Fuel	Location	Project Start Date	Maximum Capability (MW)[3]
Colstrip 3&4 (15%)	Coal	Colstrip, MT	1984	**240.0**
Rathdrum (CT)	Gas	Rathdrum, ID	1995	**191.0**
Northeast (CT)	Gas/Oil	Spokane, WA	1978	**72.0**
Boulder Park (IC)	Gas	Spokane, WA	2002	**25.0**
Coyote Springs 2 (CC)	Gas	Boardman, OR	2003	**306.0**
Kettle Falls	Wood	Kettle Falls, WA	1983	**55.5**
Kettle Falls (CT)	Gas	Kettle Falls, WA	2002	**8.0**
Total	All Thermal			897.5

TABLE 2-2: AVISTA THERMAL GENERATION RESOURCES.

[2] The maximum capability is the higher of the name plate capacity or the maximum capability—these numbers may vary from the 2009 Electric IRP numbers.

[3] The maximum capability figures associated with thermal power plants is the highest of either the summer, winter, or nameplate capacities. These numbers may conflict with the project description numbers.

2.3.1 Hydroelectric Generation: Clark Fork and Spokane River

Avista operates its hydro-electric facilities on the Clark Fork and Spokane rivers in a coordinated fashion. In other words, Avista operates these facilities in such a way that natural stream flows are maintained as much as possible. In general, the generation patterns simulated in the various models evaluated by Avista System Planning are consistent in that downstream generation is dispatched in a coordinated fashion with upstream generation.

2.3.1.1 Spokane River Hydroelectric Projects

Avista owns and operates six hydroelectric projects on the Spokane River. The following section includes a short description of the Spokane River projects with the maximum capacity and nameplate ratings for each plant. The maximum capacity of a generating unit is the total amount of electricity a plant can safely generate. This is often higher than the nameplate rating. The nameplate, or installed capacity is the plant's capacity as rated by the manufacturer. Note that the projects are discussed in hydraulic order, i.e. in an upstream to downstream order.

The maximum total electrical capacity of Avista's Spokane River projects is approximately 191 MW.

2.3.1.1.1 Post Falls

The upper most hydro facility on the Spokane River is Post Falls, located at its Idaho namesake near the Washington/Idaho border. The project began operation in 1906 and maintains lake elevation during the summer for Lake Coeur d'Alene. The project has six units, with the last added in 1980. The project is capable of producing 18.0 MW and has a 14.75 MW nameplate rating. Avista's energy supply function is studying the potential to replace the powerhouse with two larger units to increase energy production at the plant, and another option to increase generation by upgrading Unit 6.

2.3.1.1.2 Upper Falls

The Upper Falls project began generating in 1922 in downtown Spokane and is within the city's Riverfront Park. This project is comprised of a single 10.0 MW unit with a 10.26 MW maximum capacity rating. Rewinding the generator and replacing the runner is under consideration by Avista's energy supply function; the upgrade would increase generation by approximately 2.0 MW.

2.3.1.1.3 Monroe Street

The Monroe Street facility was the Company's first generating unit. It started service in 1890 near what is now Riverfront Park. Rebuilt in 1992, the single generating unit has a 15.0 MW maximum capacity and a 14.8 MW nameplate rating. The 2009 Avista Electric IRP indicates that a second powerhouse at Monroe Street is under evaluation.

2.3.1.1.4 Nine Mile

The Nine Mile project was built by a private developer in 1908 near Nine Mile Falls, Washington, nine miles northwest of Spokane. The Company purchased it in 1925 from the Spokane & Eastern Railway. Its four units have a 17.6 MW maximum capacity and a 26.4 MW nameplate rating. Currently (CY 2010) Unit 1 provides no generation and Unit 2 is limited to half load. These units will be replaced and are expected to be online by 2012 and 2013. A rubber dam will be added to the facility, replacing flashboards, to take advantage of high flows. The total incremental capacity is 8.8 MW and an additional 4.4 aMW of renewable energy from its former operational capability.

2.3.1.1.5 Long Lake

The Long Lake project is located northwest of Spokane and maintains Lake Spokane, also known as Long Lake. The facility was the highest spillway dam with the largest turbines in the world when it was completed in 1915. The plant was upgraded with new runners in the 1990s, adding 2.2 aMW of renewable energy. The project's four units provide 88.0 MW of combined capacity and have an 81.6 MW nameplate rating. The 2009 IRP evaluates two additional upgrades at the project, either an additional 24 MW unit in the existing powerhouse or the development of a second powerhouse with a 60 MW generator.

2.3.1.1.6 Little Falls

The Little Falls project was completed in 1910 near Ford, Washington, and is Avista's furthest downstream hydro facility on the Spokane River. The facility was recently upgraded to generate an additional 0.6 aMW of renewable energy with a runner replacement on Unit 4. The facility's four units generate 35.2 MW of maximum capacity and have a 32.0 MW nameplate rating. Generator rewinds at each of these units were examined as resource options in the 2009 Electric IRP for a total potential of 4.0 MW of additional capacity and 1.3 aMW of energy.

2.3.1.2 Clark Fork River Hydroelectric Project

The Clark Fork River Project includes hydroelectric projects near Clark Fork, Idaho, and Noxon, Montana, 70 miles south of the Canadian border. The plants are operated under a FERC license through 2046. The maximum electrical capacity of Avista's Clark Fork River projects is 851 MW.

2.3.1.2.1 Noxon Rapids

The Noxon Rapids project includes four generators installed between 1959 and 1960, and a fifth unit added in 1977. The current plant configuration has a maximum capacity of 541.0 MW and a generator nameplate rating of 480.6 MW. Upgrades to units 1, 2, 3 and 4 were completed in 2012. The upgrades added 30 MW of capacity and 6 aMW of qualified renewable energy to the Company's resource portfolio.

2.3.1.2.2 Cabinet Gorge

The Cabinet Gorge plant started generating power in 1952 with two units. The plant was expanded with two additional generators in the following year. The current maximum capacity of the plant is 270.5 MW; it has a nameplate rating of 265.2 MW. Upgrades at this project began with the replacement of Unit 1 in 1994. Unit 3 was upgraded in 2001 and Unit 2 was upgraded in 2004. Unit 4, received a $6 million turbine upgrade in 2007, increasing its generating capacity from 55 MW to 64 MW, and adding 2.1 aMW of renewable energy. The Company is evaluating the addition of a fifth unit at the project. This addition would add 50 to 60 MW of capacity and up to 10.2 aMW of renewable energy. Cabinet

Gorge operates as a re-regulation facility to Noxon Rapids (i.e. Cabinet Gorge is downstream of the Noxon Rapids project).

2.3.2 Thermal Resources

Avista owns seven thermal assets located across the Northwest. The Company's thermal resources provide dependable low-cost energy to serve base loads and provide peak load serving capabilities.

The total Avista thermal electric capacity is approximately 897.5 MW.

2.3.2.1 Colstrip

The Colstrip plant, located in Eastern Montana, consists of four coal-fired steam plants owned by a group of utilities (Avista, NorthWestern Energy, PacifiCorp, PPL Montana, Portland General Electric, and Puget Sound Energy). PPL Montana operates the facilities and is responsible for submitting evidence for the purposes of complying with NERC Reliability Standards (i.e. for the Generator Operator/Owner functions). Avista owns 15 percent of Units 3 and 4. Unit 3 was completed in 1984 and Unit 4 was finished in 1986. The Company's share of each Colstrip unit has a maximum net capacity of 120.0 MW and a nameplate rating of 123.5 MW. Capital improvements to both units were completed in 2006 and 2007 to improve efficiency, reliability and generation capacity. The upgrades included new high-pressure steam turbine rotors and a conversion from analog to digital control systems. These capital improvements increased the Company's share of generation by 4.2 MW at each unit without any additional fuel consumption. Note that the units at Colstrip are subjected to generation tripping, due to the Acceleration Trend Relay (i.e. the "ATR"), for transmission outages well west of the Colstrip project.

2.3.2.2 Rathdrum

Rathdrum is a two-unit simple-cycle combustion turbine. The gas-fired plant is located near Rathdrum, Idaho. It entered service in 1995 and has a maximum capacity of 180.0 MW in the winter and 126.0 MW in the summer. The nameplate rating is 166.5 MW.

2.3.2.3 Northeast

The Northeast plant, located in northeast Spokane, is a two-unit aero-derivative simple cycle plant completed in 1978. The plant is capable of burning natural gas or fuel oil, but current air permits prevent the use of fuel oil. The combined maximum capacity of the units is 68.0 MW in the winter and 42.0 MW in the summer, with a nameplate rating of 61.2 MW. Northeast is primarily used for reserve capacity to protect against reliability concerns and market aberrations and is seldom operated under "normal" conditions.

2.3.2.4 Boulder Park

The Boulder Park project was completed in Spokane Valley in 2002. The site uses six natural gas-fired internal combustion engines to produce a combined maximum capacity and nameplate rating of 24.6 MW.

2.3.2.5 Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined cycle combustion turbine located near Boardman, Oregon. The plant began service in 2003. The maximum capacity is 280.6 MW in the winter and 226.5 MW in the summer and the duct burner provides the unit with an additional capability of up to 20.4 MW. The nameplate rating for this plant is 287.3 MW.

2.3.2.6 Kettle Falls and Kettle Falls CT

The Kettle Falls biomass facility was completed in 1983 near Kettle Falls, Washington and is one of the largest biomass plants in North America. The open-loop biomass steam plant is fueled by waste wood products from area mills and forest slash, but can also run on natural gas. A gas-fired CT was added to the facility in 2002. The CT burns natural gas and sends exhaust heat to the wood facilities boiler to increase wood fuel efficiency. The wood portion of the plant has a maximum capacity of 50.0 MW and a nameplate rating is 50.7 MW; typically the plant operates between 45 and 47 MW due to fuel quality issues. The plant's capacity increases to 56.0 MW when operated in combined-cycle mode with the CT. The CT produces 5.2 MW of peaking capability in the summer and 7.8 MW in the winter. The CT resource has limited operations in winter if the gas pipeline is constrained.

2.4 BALANCING AUTHORITY AREA LOADING

As of 2012 the Avista Balancing Authority Area (BAA) serves a peak electrical load of around 2200 MW; peak load typically occurs during the winter heavy load hours usually mid-day in January. The extremely cold December 2008 still sets the Avista winter peak (post aluminum smelter shutdown). Figure 2-4 graphically depicts the winter peaking nature of the Avista's BAA load.

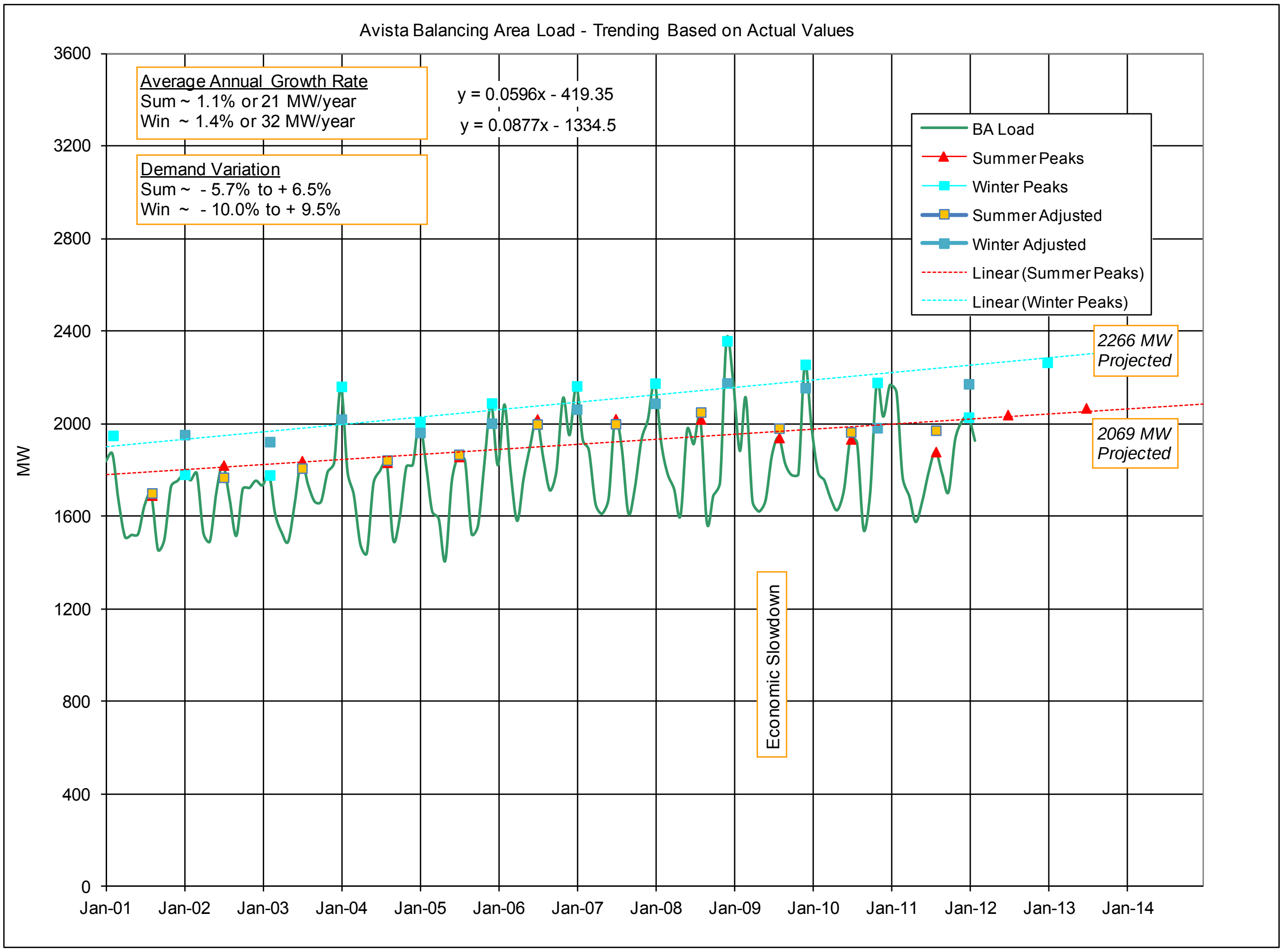

FIGURE 2-4: AVISTA BALANCING AUTHORITY AREA LOAD TREND.

Avista has been a winter peaking utility with a steady increase in air conditioning load creating a situation of relatively high summer loads associated with high temperatures. These high temperatures reduce the thermal capacity of our equipment, and (when associated with relatively high loads) produce what has evolved into the limiting season for serving load and accommodating transfers of energy. Figure 2-5 shows the effects of air conditioning loads on Avista's summer load (based on exceptional temperature changes in 2008 that illustrate the Avista air conditioning load).

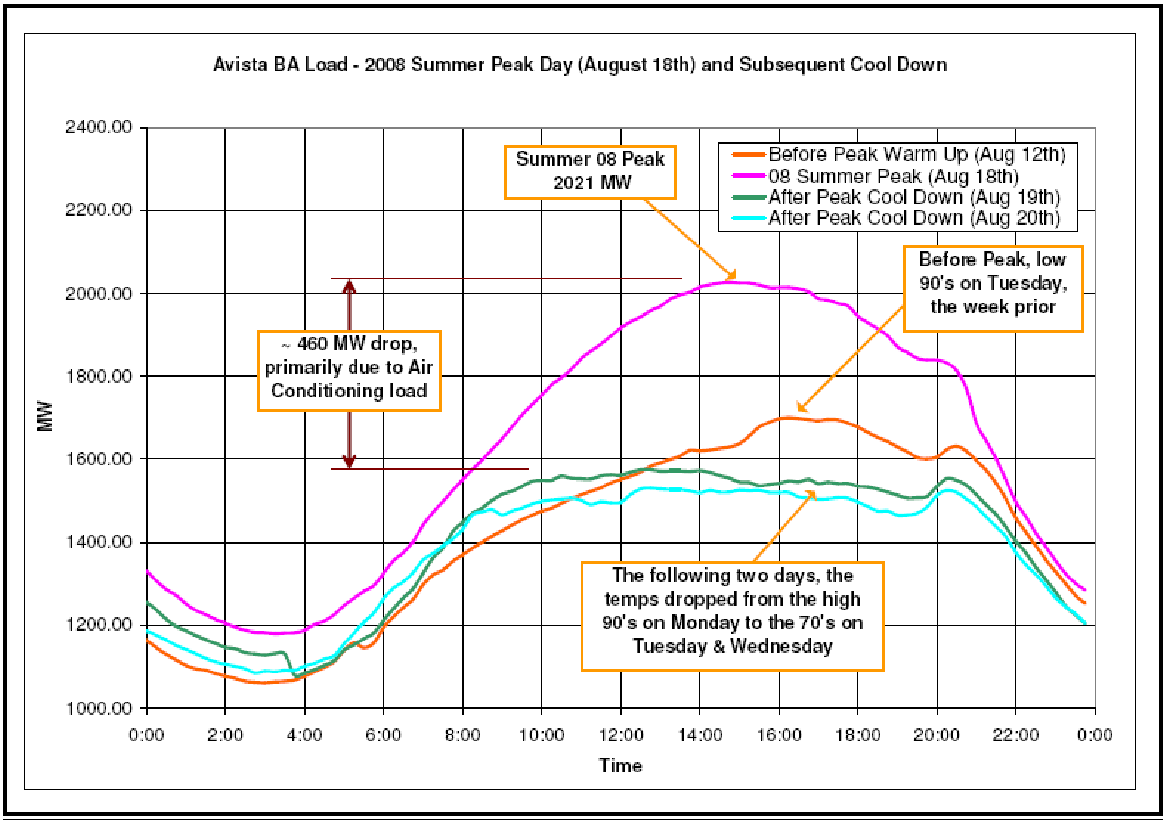

FIGURE 2-5: AIR CONDITIONING LOAD EFFECTS ON BALACNING AUTHORITY AREA LOAD.

3 DEVELOPMENT OF PLANNING ASSESSMENT

3.1 LOCAL PLANNING PROCESS

The development of the Local Planning Report and the associated Planning Assessments follows the Local Transmission Planning Process (Process) provided in Attachment K, Part III – The Avista Local Transmission Planning Process of Avista's OATT. The Process is open to all Interested Stakeholders, including, but not limited to, all Transmission Customers, interconnection customers, and state authorities. Avista held a Study Development Meeting during the second quarter of 2011 providing participants an opportunity to provide comments for data gathering, initial assumptions and input into the study development. All comments received at the Study Development Meeting, or during the 30 days following, were incorporated into the Planning Assessments.

Avista then held a Draft Study Report meeting in the fall of 2011 to discuss the Draft Local Planning Report. After the comment period following that meeting, Avista confirmed and finalized the 2011 Local Planning Report.

The purpose of the Process is to identify any Single System Projects that are needed to mitigate future reliability and load-service requirements for Avista's Transmission System. The Planning Assessments identify reliability impacts observed on Avista's Transmission System, and provide a list of the Single System Projects proposed to mitigate those issues. Such reliability impacts were identified by performing technical studies, which included powerflow, transient stability, short circuit, and voltage collapse studies.

3.2 TRANSMISSION PLANNING CRITERIA

The transmission planning reliability criteria used in evaluating the performance of the transmission system is the present North American Electric Reliability Corporation (NERC) Reliability Standards and WECC regional reliability criteria including the following:

- TPL-001-WECC-CRT-2 – System Performance Criterion
- TPL-001 – System Performance Under Normal Conditions
- TPL-002 – System Performance Following Loss of Single BES Element
- TPL-003 – System Performance Following Loss of Two or More BES Elements
- TPL-004 – System Performance Following Extreme BES Events

3.3 TRANSMISSION PLANNING ASSUMPTIONS

The following assumptions have been used in the Process for performing technical studies. The assumptions are made upon the experience of Avista's System Planning Group and to comply with NERC Reliability Standards.

3.3.1 Planning Case Development

Avista's System Planning Group develops a set of base cases (Planning Cases) biannually to model its Transmission Planner and Planning Coordinator areas as well as the regional Transmission System. The Planning Case development process outlined in the internal document *TP-SPP-04 – Data Preparation for Steady State and Dynamic Studies* is used which includes using WECC approved base cases and applying steady state and dynamic data modifications as required to represent desired scenarios. The resulting Planning Cases represent a normal System condition (N-0). Planning Cases include the following:

- All existing facilities. No planned transmission expansion project facilities. During previous studies, inclusion of non-committed planned transmission facilities has incorrectly hidden potential reliability and load-service requirements. Subsequently, a Corrective Action Plan was not developed as required.
- Known outages of generation or Transmission Facilities with a duration of at least six months. Presently, Avista does not have planned outages outside the operations planning horizon. Long duration outages outside of Avista's Transmission Planner or Planning Coordinator areas are typically modeled in WECC approved base cases.
- Real and reactive load forecasts and resources required for load. Load forecasts for Network Customers and Point-to-Point Customers are requested at a Study Development Meeting as part of Avista's Transmission Planning Process. Typically, the BPA submits its forecast load information as a Network Customer to Avista for inclusion in the technical studies. Avista's Transmission Planning Group incorporates the forecasted load data for its Load Serving Entity ("Avista LSE") into the technical studies.
- Known commitments for Firm Transmission Service and Interchange. Modeling WECC Rated Paths at their limits represents all existing known commitments. Future commitments exceeding the limits of WECC Rated Paths are not presently studied.

The following scenarios are developed to represent various seasonal conditions:

- Heavy Summer: typical summer peak scenario where the Avista Balancing Authority Area load is near peak and the local hydro generation is at a typical mid-summer output. This scenario represents Avista's heavy summer loading with moderate transfers into Avista's Balancing Authority Area. This scenario is limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the System is near capacity.
  - Year two (next year, i.e. 2013 case if case is created and used in 2012).
  - Year five
  - Year ten
- Heavy Summer with Low Local Hydro Generation (Heavy Summer, Low Hydro Case): typical summer peak scenario where the Avista Balancing Authority Area load is near peak and the local

hydro generation has a low output. This scenario plays a dual role, in that it represents both Avista's heavy summer loading scenario along with the sensitivity of significant transfers into Avista Balancing Authority Area to supplement the low hydro generation dispatch. This scenario is limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the System is near capacity.

- Year two (next year, i.e. 2013 case if case is created and used in 2012).
- Year five
- Year ten

- Heavy Winter: typical winter peak scenario where the Avista Balancing Authority Area load is heavy but the lower ambient temperature increases the operating limits of the various elements of the Transmission System. Local hydro generation is at a moderate level and there are significant transfers into Avista's Balancing Authority Area from regional thermal resources.
  - Year two (next year, i.e. 2013 case if case is created and used in 2012).
  - Year five
  - Year ten
- Light Summer with High West of Hatwai Flows (High Transfer Case): during light summer (night time loading) with high Western Montana Hydro and high Montana thermal generation, the WECC rated path "West of Hatwai" (WECC Path #6) reaches its heaviest loading. During this scenario, portions of the Transmission System are nearing their stability limits. These limits define some of the operating constraints for the region and also establish some of the arming levels for Remedial Action Schemes (RAS). This scenario is also limited by the summer thermal limits on various elements of the transmission system, which helps to define where the system is near capacity.
  - Year two (next year, i.e. 2013 case if case is created and used in 2012).
  - Year five

A detailed summary of specific flows and loading levels for the Planning Cases used in the 2011 Planning Assessments can be provided upon request.

3.3.2 Load Forecast

Load forecasts for Network Customers and Point-to-Point Customers were requested at the Study Development Meeting. The BPA submitted its forecast load information as a Network Customer to Avista for inclusion in the technical studies. Avista's System Planning Group incorporated forecast load data for the Avista LSE into the technical studies.

3.3.3 Planned Transmission Facilities

No planned transmission expansion project facilities are included in the bases cases used in technical studies performed for the Planning Assessments. During previous Planning Assessments inclusion of non-committed planned transmission facilities has incorrectly hidden potential reliability and load-service requirements. Subsequently, a Corrective Action Plan was not developed as required by the Process.

3.3.4 Planned Generation Facilities

Only potential generation projects in the Avista Interconnection Request queue that have executed Interconnection Agreements are modeled (with corresponding upgrades) in the base cases for technical studies.

The 2011 Planning Assessments did not include any potential generation in the technical studies.

3.3.5 Contingencies

The contingencies evaluated for powerflow and transient stability technical studies are a standard contingency set used by Avista's System Planning Group, reviewed and updated annually. Documentation on the contingency set is provided by Transmission Planning Standards, Policies and Procedures TP-SPP-06 Contingency Analysis. The standard contingency set includes outages in Avista's Transmission System as well as outages in adjacent Planning Coordinator and Transmission Planner Areas.

3.4 ACCESS TO PLANNING DATA

The base cases used in the Process can be provided within 10 calendar days, via email or other media, to any WECC member that makes a request. Non-WECC members will be required to sign a confidentiality agreement with the WECC before any base cases can be shared. Once the WECC confirms a confidentiality agreement has been signed, the requested base case(s) shall be provided within 10 calendar days. Any additional information needed to replicate the technical study results of the Process can be provided, upon written request.

3.5 IDENTIFICATION OF ANALYTICAL TOOLS

The following Analytical Tools were used to perform technical studies:

- PowerWorld Simulator Software, Version 15
  - PowerWorld Simulator is an interactive power systems simulation package designed to simulate high voltage power systems operation on a time frame ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses using mathematical calculations based on system impedances, load levels and generation output. PowerWorld provides the user with a variety of sophisticated study tools such as an automated

contingency processor, an Available Transfer Capability (ATC) tool, an Optimal Power Flow tools, various voltage stability tools (i.e. PV and QV tools), and a Transient Stability Analysis tool.

- GE Positive Sequence Load Flow, Version 17.05
  - The GE Positive Sequence Load Flow (PSLF) software suite is a package of programs for studying power system transmission networks and equipment performance in both the steady-state and dynamic environments.
- ASPEN OneLiner Software Build 2007.11.7 Group-1
  - ASPEN OneLiner is a PC-based short circuit and relay coordination program for relay engineers. OneLiner is an interactive productivity tool allowing the engineer to accurately model the transmission system, perform fault analysis by simulating all classical fault types, graphically plot fault solution and relay coordination curves and validate relay settings through relay models and automatic checking module.

4 SINGLE SYSTEM PROJECTS AND CORRECTIVE ACTION PLANS

All of the projects described in this summary of plans are subject to change at any time by Avista. These projects describe a possible fix to a future problem—Avista constantly reassess's the need for any project and will (if deemed appropriate) re-assign the budgeted dollars of a project to a technically superior project. Dollars are budgeted to future projects based on preliminary study work; the detailed Study Plans and Study Reports are documented prior to construction of any project identified in the five or ten plan. Note that typically the detailed design work is initiated after the need is identified from the preliminary study work (i.e. the on-going system assessments performed by System Planners).

4.1 BIG BEND AREA

4.1.1 Lind Capacitor Bank Project

Description: Install both a 6.71 MVAr and a 13.42 MVAr capacitor bank at Lind Substation.

Schedule: Scheduled for completion in 2012.

Status: Under Construction.

Need: Currently, there is an issue with low voltage in the area served out of the Lind Substation. During heavy loading (spring/summer irrigation), the Lind area 115 kV transmission voltages have dipped to levels below both normal and contingency minimums.

4.1.2 Odessa Capacitor Bank Project

Description: Install two steps of 13.42 MVAr capacitor bank at Odessa Substation.

Schedule: Scheduled for completion in 2013.

Status: Design.

Need: During a line end open scenario on the Devils Gap – Stratford 115 kV Transmission Line, open at Stratford Substation, low voltage is observed at the following substations: Wilson Creek (GCPD), Irby and Odessa Substations.

4.1.3 Stratford Substation Strain Bus Project

Description: Rebuild portions of the existing strain bus and replace the CT's on circuit breaker A50 at Stratford Substation.

Schedule: Scheduled for completion in 2015.

Status: Proposed.

Need: Thermal overloads are observed on the GCPD Stratford – Larson 115 kV Transmission Line for the outage of the GCPD Columbia – Quincy 230 kV Transmission Line. The bottleneck on this line is at the Avista Stratford Substation terminal and is limited by both the circuit breaker CT's and the existing strain bus. Heavy thermal loading on the Stratford – Larson 115 kV Transmission Line also results from Avista moving the "star point" on the Devils Gap – Stratford 115 kV Transmission Line. Currently, the "star point" is moved to the Devils Gap end, during spring and summer seasons, to add additional load to Stratford Substation which helps to sink the local generation. The preferred "star point" would be at Odessa, to minimize exposure to transmission line outages.

4.1.4 Benton – Othello SS Rebuild Project

Description: Rebuild the Benton – Othello SS 115 kV Transmission Line.

Schedule: Scheduled for completion in 2016.

Status: Proposed.

Need: Thermal overloads are observed on the Avista owned segments of the Benton – Othello Switching Station 115 kV Transmission Line for the outage of the Columbia – Quincy 230 kV Transmission Line or the Wheeler Tap – Basset 115 kV Transmission Line.

4.1.5 Addy – Devils Gap Rebuild Project

Description: Reconductor a 1.84 mile section of the Addy – Devils Gap 115 kV Transmission Line.

Schedule: Scheduled for completion in 2017.

Status: Proposed.

Need: Thermal overloads are observed on the Addy – Devils Gap 115 kV Transmission Line for the outage of the Addy – Bell 230 kV Transmission Line.

4.1.6 Lind – Warden Rebuild Project

Description: Reconductor the Lind – Warden 115, beginning with the Warden – Roxboro 115 section due to conductor loading and losses.

Schedule: Scheduled for completion in 2018.

Status: Proposed.

Need: During heavy summer loading, thermal overloads are observed on the Lind – Warden 115 kV Transmission Line when either the Devils Gap – Lind or the Lind – Shawnee 115 kV Transmission Lines is sourced out of Lind.

4.1.7 Planned System Modifications

Modifications not driven by studies conducted as part of the Process include the following:

- Convert the distribution voltage at Harrington Substation from 4 kV to 13 kV, scheduled for completion in 2014.
- Add a new 115/13 kV distribution transformer and feeder at Gifford Substation, scheduled for completion in 2015.
- Build a new 49° North Substation with a 115/21 kV distribution transformer and feeder and a new nine mile 115 kV transmission radial tap line, scheduled for completion in 2017.
- Rebuild portions of the Devils Gap – Lind 115 kV Transmission Line around Gaffney Substation, based on condition of poles; planned in the ten year planning horizon.

- General distribution feeder upgrades
- Add a second 115/13 kV transformer at Lee & Reynolds Substation to provide capacity for contingency (Othello or Lee & Reynolds transformer loss) and maintenance.

4.2 COEUR D'ALENE

4.2.1 Lancaster Interconnection Project

Description: Loop the Avista Boulder – Rathdrum 230 kV Transmission Line into the BPA Lancaster Substation.

Schedule: Scheduled for completion in 2013.

Status: Design and budgeted.

Need: Several benefits are gained by the interconnection including significant System performance improvement.

4.2.2 Coeur d'Alene Relay Upgrade Project

Description: Upgrade 115 kV transmission line protection systems in the Coeur d'Alene Area to communication aided schemes.

Schedule: Scheduled for completion in 2014.

Status: Design and budgeted.

Need: System studies have revealed sensitivity to Western Montana Hydro (WMH) Complex generation output and slow clearing 115 kV transmission faults in the Spokane and Coeur d'Alene Areas.

4.2.3 Cabinet – Bronx – Sand Creek Rebuild Project

Description: Reconductor the existing Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines with conductor capable of providing a minimum of 150 MVA thermal capacity at 40°C ambient temperature

Schedule: Scheduled for completion in 2016.

Status: Design and budgeted.

Need: The Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines exhibit thermal overloads for various single contingency issues in the Sandpoint sub-area. Outages causing thermal overloads include Libby 230/115 kV Transformer, Cabinet – Rathdrum 230 kV Transmission Line, and the Albeni Falls – Sand Creek 115 kV Transmission Line open at Albeni Falls Substation.

4.2.4 Coeur d'Alene – Pine Creek Rebuild Project

Description: Reconductor the existing Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line with conductor capable of providing a minimum of 150 MVA thermal capacity at 40°C ambient temperature and operating the transmission line normally closed.

Schedule: Scheduled for completion in 2016.

Status: Proposed.

Need: Thermal overloads are observed on the Hayden – Rathdrum and Dalton – Hayden segments of the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line for the outage of the Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line. The Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line also exhibits thermal overloads for the outage of the Hayden – Rathdrum segment of the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line. During these single contingency configurations, the load at Hayden, Dalton, Coeur d'Alene 15th St., and Blue Creek Substations is being supplied by a single 115 kV transmission line.

4.2.5 Spirit Lake Capacitor Bank Project

Description: Install two steps of 13.4 MVAr capacitor bank (26.8 MVAr total) at Spirit Lake Substation.

Schedule: Scheduled for completion in 2017.

Status: Proposed.

Need: Low voltages are observed at distribution substations along the Pine Street – Rathdrum 115 kV Transmission Line for a line end open condition on the transmission line at Rathdrum Substation. Serving Old Town, Blanchard, Hoodoo, Spirit Lake, Athol and Scarcello Substations out of Pine Street Substation yields voltages of 0.937 pu (107.8 kV) at Athol Substation during a heavy winter scenario in the ten year planning horizon.

4.2.6 O'gara Capacitor Bank Project

Description: Install 13.4 MVAr capacitor bank at O'Gara Substation.

Schedule: Scheduled for completion in 2020.

Status: Proposed.

Need: Low voltages are observed at St. Maries Substation for single contingency outages of either the Bell 500/230 kV #1 or Hot Springs 500/230 kV Transformers. The 230 kV transmission system voltages are reduced as a result of these transformer outages and using the post-transient contingency methodology does not consider system operator intervention to switch capacitor banks or modify 230/115 kV transformer taps. The ability to serve Plummer, O'Gara, and St. Maries Substations from Pine Creek Substation with the Benewah – Plummer segment of the Benewah – Pine Creek 115 kV Transmission Line open illustrates voltage support issues at St. Maries Substation.

4.2.7 Planned System Modifications

Modifications not driven by studies conducted as part of the Process include the following:

- Replace Pine Creek 230/115 kV #1 Autotransformer; procurement of transformer in 2012,
- Rebuild the Blue Creek Substation; budgeted to be completed in 2012,
- Increase transformation capacity at the Lucky Friday Substation; budgeted to be completed in 2012,
- Reconstruct the existing Noxon Rapids 230 kV Switchyard; budgeted to be completed in 2016,
- Rebuild portions of the Burke – Thompson A &B and Burke – Pine Creek #3 & #4 Transmission Lines; budgeted to be completed in 2016,
- Install distribution facilities at the existing Bronx Switching Station; planned in the ten year planning horizon,
- Construct a new Carlin Bay Substation and associated transmission and distribution facilities; planned in the ten year planning horizon.

4.3 LEWISTON/CLARKSTON AREA

4.4 PALOUSE

4.4.1 Palouse Wind Interconnection

Description: Construct Thornton Switching Station on the Benewah – Shawnee 230 kV Transmission Line for the Palouse Wind Interconnection.

Schedule: Scheduled for completion in 2012.

Status: Under construction.

Need: Avista signed a Power Purchase Agreement for First Wind's Palouse Wind Project in June 2011. The Palouse Wind Project (Project #17) will interconnect with Avista's Transmission System on the Benewah – Shawnee 230 kV Transmission Line and provide Avista with approximately 40 average megawatts of renewable energy, or as much as 105 megawatts of nameplate capacity, under a 30-year power purchase agreement with deliveries beginning in 2012.

4.4.2 Moscow Transformer Replacement Project

Description: Rebuild the Moscow 230 Substation and replace existing 125 MVA 230/115 kV transformer and regulator with a 250 MVA autotransformer.

Schedule: Scheduled for completion in 2014.

Status: Under construction.

Need: The N-1 contingency loss of the Shawnee 230/115 kV Transformer can cause the Moscow 230/115 kV Transformer to overload to 99% of its nameplate rating in the five year planning horizon and to 120% in the ten year planning horizon.

4.4.3 Garfield Capacitor Bank Project

Description: Install one step of 13.4 MVAr capacitor bank at Garfield Substation.

Schedule: Scheduled for completion in 2015.

Status: Proposed.

Need: During a line end open scenario on the Latah Jct. – Moscow 230 115 kV Transmission Line open at Moscow 230 Substation, low voltage were observed at the following substations: Potlatch, Palouse, Garfield and Brinken's Corner Substations.

4.4.4 Planned System Modifications

Modifications not driven by studies conducted as part of the Process include the following:

- Smart Grid Demonstration Project; scheduled for completion in 2012,

- Rebuild the Pullman Substation (now called Turner Substation); scheduled for completion in 2012,
- Construct a new substation near Bovill for large industrial customer; scheduled for completion in 2013,
- Rebuild the Moscow City – North Lewiston 115 kV Transmission Line, scheduled for completion in 2015,
- Add an additional 20 MVA distribution transformer to the North Moscow Substation; required in the 5 year planning horizon,
- Construct the new Tamarack Substation approximately 1.5 miles East of North Moscow Substation; required in the 5 year planning horizon.

4.5 SPOKANE

4.5.1 Westside Transformer Replacement Project

Description: Replace the existing 125 MVA Westside #1 & #2 230/115 kV Transformers with 250 MVA transformers and reconstruct Westside Substation with the 230 kV bus arrangement as a double bus double breaker configuration and the 115 kV bus configuration to eliminate tie breaker failure and bus outage as credible contingencies.

Schedule: Scheduled for completion in 2016.

Status: Proposed.

Need: The existing Westside #1 & #2 230/115 kV Transformers show thermal overloads during an all lines in service condition within the ten year planning horizon. Both transformers have a nameplate rating of 125 MVA. The continuous ratings determined by the rating methodology provided in IEEE C57.91 are 108 MVA and 124 MVA respectively for Transformer #1 and #2. During a heavy summer, low hydro scenario Transformer #1 loads to 108.5% (CY 2015) and 141.56% (CY 2020) in the five and ten year planning horizon respectively.

4.5.2 Garden Springs Substation Integration Project

Description: Construct a new Garden Springs Substation with a 250 MVA 230/115 kV transformer, a radial 230 kV transmission line to Westside Substation, and 115 kV reconductor/integration work.

Schedule: Scheduled for completion in 2017.

Status: Proposed.

Need: Under a single contingency configuration, the Beacon #1 & #2 230/115 kV Transformers show thermal overloads of 103.28% and 113.77% in the five and ten year planning horizon respectively for a Heavy Summer, Low Hydro scenario.

4.5.3 Spokane Valley Transmission Reinforcement Project

Description: New 115 kV Irvin Substation, 115 kV reconductor work, rebuild of Millwood Substation, and addition of circuit breakers to Opportunity Substation.

Schedule: Scheduled for completion in 2016.

Status: Design and budgeted.

Need: Several single contingency outages cause thermal overloads and low voltages in the Spokane Valley Area. The more severe outages tend to be line-end-open scenarios on the Beacon – Boulder #1 & #2 and Ninth & Central – Otis Orchards 115 kV Transmission Lines. Increased load growth and increased demand requirements of Inland Empire Paper have pushed the existing transmission system to its limits.

4.5.4 Hallett & White Capacitor Bank Project

Description: Install capacitor bank at Hallett & White Substation.

Schedule: Scheduled for completion in 2013.

Status: Proposed.

Need: Low voltage issues exist for local contingency scenarios.

4.5.5 Ninth & Central – Sunset Rebuild Project

Description: Reconductor the Ninth & Central – Sunset 115 kV Transmission Line.

Schedule: Scheduled for completion in 2016.

Status: Proposed.

Need: Segments of the Ninth & Central – Sunset 115 kV Transmission Line exhibit thermal overloads for various contingencies in the area. The primary cause of these overloads is the loss of a line which supplies the South Spokane and West Plains Areas. The existing Ninth & Central – Sunset 115 kV Transmission Line is primarily constructed of 795 kcmil conductor but is limited by some segments of 250 CU conductor. The segment from Ninth & Central to the Glenrose Tap experiences the worst thermal overloads of 101.83% and 115.4% in the five and ten year planning horizon for line end open condition at Westside on the Sunset – Westside 115 kV Transmission Line.

4.5.6 Beacon Substation Rebuild Project

Description: Reconstruct the Beacon Substation 230 kV bus to a double bus double breaker configuration and the 115 kV bus configuration to eliminate tie breaker failure and bus outage as credible contingencies.

Schedule: Scheduled for completion in 2019.

Status: Proposed.

Need: Single bus outages of either the 115 kV or 230 kV buses at Beacon Substation cause thermal overloads to the remaining 115 kV transmission lines. Both voltage levels have bus tie breakers and their failure to open during a fault condition causes more severe thermal overloads then a single bus outage. A 115 kV bus tie failure causes the Otis Orchards – Ninth & Central 115 kV Transmission Line to overload at 149.95% and 171.45% in the five and ten year planning horizon neglecting the more substantial overload of the Westside 230/115 kV Transformers. A 230 kV bus tie failure exhibits the worst thermal overload on the Bell – Northeast 115 kV Transmission Line with 199.75% and 232.35% in the five and ten year planning horizon.

4.5.7 Westside Re-Integration Project

Description: Construct a new 230 kV transmission line from the Bell – Coulee Corridor to the Westside Substation to separate existing double circuit.

Schedule: Scheduled for completion in 2016.

Status: Proposed.

Need: The common mode double circuit outage of the Bell – Westside and Coulee – Westside 230 kV Transmission Lines causes similar issues to a 230 kV bus outage at Westside Substation. This double circuit transmission line is the primary source to Westside Substation. If the Garden Springs project is executed and includes a new 230 kV transmission line to supply Garden Springs from Westside Substation, it is unacceptable to have two 230/115 kV substations rely on a single mode failure. With the existing transmission system configuration this outage will cause the Third & Hatch – Post Street 115 kV Transmission Line to overload to 138.19% and 166.87% in the five and ten year planning horizon.

4.5.8 Spokane Relay Upgrade Project

Description: Upgrade 115 kV transmission line protection systems in the Spokane Area to communication aided schemes.

Schedule: Scheduled for completion in 2014.

Status: Design and budgeted.

Need: System studies have revealed sensitivity to Western Montana Hydro (WMH) Complex generation output and slow clearing 115 kV transmission faults in the Spokane and Coeur d'Alene Areas.

4.5.9 Spokane Area Generator OOS Project

Description: Install redundant out of step protection at Nine Mile HED, and Boulder Park Generation Facilities.

Schedule: Scheduled for completion in 2014.

Status: Proposed.

Need: The Nine Mile Generator Units 3 and 4 were observed going out of step for a three phase fault on the Nine Mile – Westside 115 kV Transmission Line with time delayed clearing by the Nine Mile terminal. Boulder Park Generators Units 1 through 6 will go out of step for Zone 2 time delayed three phase faults on either of the Boulder – Otis #1 and #2 115 kV Transmission Lines with time delayed clearing by either terminal.

4.5.10 Planned System Modifications

Modifications not driven by studies conducted as part of the Process include the following:

- Smart Circuits Project
- Millwood Substation Rebuild
- Ninth & Central Substation Configuration
- Sunset Substation Rebuild
- Construct new North/South Freeway, Downtown West, Hawthorne, Otis Orchards, and Greenacres Distribution Substations required for load service.

5 POINT OF CONTACT

A Point of Contact for questions regarding the Planning Assessment and the projects described within it has been designated. Please contact the party named below for any questions:

John Gross
Transmission Planning Engineer, System Planning
PO Box 3727, MSC-16
Spokane, WA 99220
john.gross@avistacorp.com
(509) 495-4591

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Appendix A - 2011 Big Bend Planning Assessment

Big Bend Area

2011 PLANNING ASSESSMENT

Long Lake HED

TRANSMISSION PLANNING

Prepared by Dean Spratt

www.avistautilities.com

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Big Bend Area

2011 PLANNING ASSESSMENT

Date Completed: December 20, 2011

Prepared By: Dean Spratt

The signature below indicates approval by the Director of System Planning. This Planning Assessment has been conducted with due diligence and has been reviewed and accepted by the Interested Stakeholders. This approval certifies this Planning Assessment as an adequate transmission planning approach for the area of interest.

Dec 20, 2011

Scott Waples Director System Planning

Date

Version History

Version	Version Date	Action	Change Tracking	Reviewed By
A	16 Sept 2011	Preliminary Draft for Review	New Document	Dean Spratt
B	19 Oct 2011	2nd draft for general comments	Updated per review	Dean Spratt
0	09 Sep 2011	Final Report	Eng & Ops input	Dean Spratt

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Big Bend Area

2011 PLANNING ASSESSMENT

1 EXECUTIVE SUMMARY

The Avista Big Bend Area is located primarily in the Ferry, Stevens, Pend Oreille, Lincoln and Adams Counties in the state of Washington. In addition, Avista has a shared 230 kV transmission line in Grant, Franklin, Garfield and Asotin Counties in Washington. The geographic features, and therefore the characterization of the Transmission System, throughout the Big Bend Area vary greatly. The majority of the load served in the area can be categorized as rural, low density load with areas that are highly influenced by irrigation load. The Transmission System consists of a 230 kV backbone system and the underlying 115 kV transmission lines which serve the local loads. All of the load serving 230 kV transmission is owned by neighboring utilities and provide sources for the local areas.

Load growth in the Big Bend Area is projected to be 1.0% for summer and 1.1% for winter based on historic load growth data. Total anticipated load not including Transmission System losses for peak summer 2012 is 222 MW and 207 MW for peak winter 2012. Total installed distribution (i.e.115/4, 115/13.8, 115/24 or 115/34 kV) Avista owned transformation capacity in the Big Bend Area is 349.3 MVA based on transformer nameplate ratings.

Pend Oreille County PUD is considered part of this study area, but their load service and transmission infrastructure is planned and managed by their internal personnel. Pend Oreille County PUD load, transmission and generation is not included in the bulk of this report, given that they are isolated from the Big Bend Area by a phase shifting transformer at their Box Canyon Hydro Project.

This Planning Assessment identifies any reliability impacts identified on Avista's Transmission System, and provides a list of the Single System Projects proposed to mitigate those issues. Such reliability impacts were identified by performing technical studies, which included powerflow, transient stability, short circuit, and voltage collapse analysis. **For Single System Projects not identified in previously completed Planning Assessments, a separate Corrective Action Plan (detailed project study) will be conducted as necessary to determine the technically superior project(s) to be carried forward into the Avista capital budgeting process.**

A summary of the Single System Projects are provided in the following list. Some projects have required in service dates earlier than those identified in this Planning Assessment but due to budget, construction and/or operational schedule it is understood that some issues cannot be mitigated in the desired timeframe. This Planning Assessment suggests obtainable project schedules to represent a realistic planning approach with the appropriate budgetary support. **All projects listed here (or superior alternatives) must be completed within the ten year planning horizon.**

- Install both a 6.71 MVAr and a 13.42 MVAr capacitor bank at Lind Substation, scheduled for completion in 2012.
- Install two steps of 13.42 MVAr capacitor bank at Odessa Substation, scheduled for completion in 2013.
- Rebuild portions of the existing strain bus and replace the CT's on circuit breaker A50 at Stratford Substation, scheduled for completion in 2015.
- Rebuild the Benton – Othello SS 115 kV Transmission Line, scheduled for completion in 2016.
- Reconductor a 1.84 mile section of the Addy – Devils Gap 115 kV Transmission Line, scheduled for completion in 2017.
- Reconductor the Lind – Warden 115, beginning with the Warden – Roxboro 115 section due to conductor loading and losses. This is a productivity project, scheduled for completion in 2018.

The total cost of the proposed Single System Projects based on Avista's System Planning Group's analysis of the Big Bend Area Transmission System is expected to be approximately $11.50 million.

Following is a list of planned system modifications developed by Avista's Engineering Department. Planned system modifications in the Big Bend Area driven by Avista's Engineering Department are expected to be an additional $12.50 million.

- Convert the distribution voltage at Harrington Substation from 4 kV to 13 kV, scheduled for completion in 2014.
- Add a new 115/13 kV distribution transformer and feeder at Gifford Substation, scheduled for completion in 2015.
- Build a new 49° North Substation with a 115/21 kV distribution transformer and feeder and a new nine mile 115 kV transmission radial tap line, scheduled for completion in 2017.
- Rebuild portions of the Devils Gap – Lind 115 kV Transmission Line around Gaffney Substation, based on condition of poles; planned in the ten year planning horizon.
- General distribution feeder upgrades
- Add a second 115/13 kV transformer at Lee & Reynolds Substation to provide capacity for contingency (Othello or Lee & Reynolds transformer loss) and maintenance.

The total cost of infrastructure improvements planned for the Big Bend Area is expected to be approximately $24.00 million.

For reference, the following is a list of planned system modifications that affect the Big Bend Area introduced by neighboring utilities.

- Grant County PUD is constructing a new Columbia – Rocky Ford 230 kV Transmission line. This new line will bypass Rocky Ford Substation and establish a direct tie between Columbia and Larson Substations. Completion is planned for fall of 2013.
- Grant County PUD plans to rebuild the Wheeler Tap – Ruff 115 kV line to 795 ACSS to support new load at their Warden Substation. The work has been coordinated for 2012 and 2013.
- The BPA is rebuilding 54 miles of the Coulee – Bell 115 kV Transmission Line between Creston and Bell Substations. The new conductor will be 795 ACSR/TW Toutle and the construction is to be complete by December of 2012.
- The BPA is currently rebuilding the 47 mile Tucannon – Walla Walla 115 kV Transmission Line to 795 ASCR/TW Toutle. The planned completion is fall of 2011
- The BPA is planning on rebuilding the Benton – Midway 115 kV Transmission Line, due to condition. This should be a minimal impact to the Big Bend Area. As part of this rebuild, they plan to also rebuild their portion of the Benton – Othello Switching Station 115 kV line to 795 ACSR/TW. This latter project is based on the condition of poles and not capacity and is still in the planning stage.

2 GENERAL SYSTEM DESCRIPTION

The Avista Big Bend Area is located primarily in the Ferry, Stevens, Pend Oreille, Lincoln and Adams Counties in Washington. In addition, Avista has a shared 230 kV transmission line in Grant, Franklin, Garfield and Asotin Counties in the state of Washington. The geographic features, and therefore the characterization of the Transmission System, throughout the Big Bend Area vary greatly. The majority of the load served in the area can be categorized as rural, low density load with areas that are highly influenced by irrigation load. The Transmission System consists of a 230 kV backbone system and underlying 115 kV transmission lines that serve the local loads. All of the 230 kV transmission is owned by neighboring utilities and provide sources for the local areas.

The Western Electricity Coordinating Council (WECC) rated path West of Hatwai (Path 6) borders the eastern edge of the Big Bend Area. Avista owns three transmission lines and three substation terminals that define the path. The BPA owns the remaining transmission facilities which comprise the West of Hatwai path.

The main transmission lines in the northern portion of the Big Bend Area are: the Boundary – Addy – Bell 230 kV Transmission Line, the Boundary – Cusick – Usk – Bell 230 kV Transmission Line and the Boundary – Sacheen – Bell 230 kV Transmission Line (all owned by BPA). In the western portion there are: the Columbia – Larson, the Larson – Wheeler – Sand Dunes and the Sand Dunes –Frenchman Hills – Midway 230 kV Transmission Lines (GCPD). In the Southern portion there are: the Wanapum – Walla Walla 230 kV (AVA/PACW), the Talbot – Walla Walla (PACW) and the Talbot – Dry Creek 230 kV Transmission Lines (AVA/PACW). These last three lines do not serve any Big Bend Area load; they merely cross the geographic area. This study area is surrounded by large generation and transmission corridors, which can significantly affect the underlying 115 kV transmission system.

The main transmission sources that feed load in the Big Bend Area are: the 230/115 kV, 167 MVA transformer at Boundary (POPD), the 230/115 kV, 150 MVA transformer at Addy (BPA), the 230/115 kV, 250 MVA transformer at Larson (GCPD), the 230/115 kV, 250 MVA transformer at Sand Dunes (GCPD) and the 230/115 kV, 280 MVA transformer at Benton (BPA).

Local generation facilities within the Big Bend Area include the following:

Kettle Falls ST	Unit 1 @ 50 MW	Avista
Kettle Falls CT	Unit 1 @ 7 MW	Avista
Little Falls HED	Unit 1 & 3 @ 8.2 MW each	Avista
	Unit 2 @ 8.8 MW	Avista
	Unit 4 @ 8.6 MW	Avista
Long Lake HED	Unit 1, 2 & 4 @ 22.2 MW each	Avista
	Unit 3 @ 21.9 MW	Avista

- Main Canal HED Unit 1 @ 22 MW GCPHA[1]
- Summer Falls HED Unit 1 & 2 @ 46.2 MW GCPHA

There are also numerous small hydro generators in the area; Meyers Falls, Sheep Creek, and Phillips Ranch are the larger plants, which amount to less than 3 MW total.

The Big Bend Area has two projects that are in the interconnection study process. They are still in the proposal phase, as no final agreements have been arranged. These projects were not included in the study work conducted for this Planning Assessment. The projects include the following:

- Project #08 73.5 MW Benton – Othello SS 115 kV Transmission Line
- Project #33 400 MW Lind – Shawnee 115 kV Transmission Line

The west portion of the 115 kV Transmission System in the Big Bend area is operated with normally open points referred to as "star points". A star point is used to minimize power flow and to mitigate overloads on the 115 kV system in the event of an outage on the overlying 230 kV or 500 kV Transmission System. These overloads also occur with no outages on the 230 kV and 500 kV systems throughout the summer, therefore these lines cannot be operated normally closed. Operating in a "star" configuration reduces exposure to loads served by long transmission lines and also reduces overall system losses in the area. In the Big Bend Area, "star point" switches may be operated open or closed based on outages, specific flow conditions, or due to operational constraints. The areas around Colville and Othello are operated as a network, with the 115 kV lines closed through. The central area around Lind is primarily operated in a "star point" configuration with the 115 kV lines open.

Avista's communication system in the Big Bend Area is limited to analog and digital microwave, radio, and power line carrier. Local protection schemes, such as the permissive overreaching transfer trip (POTT) schemes, are only in place on the Colville – Republic – Kettle Falls 115 kV Transmission Line (BPA). The Walla Walla – Wanapum 230 kV Transmission Line uses analog microwave. The Dry Creek – Talbot and the Talbot – Walla Walla 230 kV Transmission Lines use power line carrier for their permissive overreaching transfer trip (POTT) protection schemes. Presently there is no redundant means of communication on these 230 kV transmission lines.

The Big Bend Area is divided into sub-areas based on their geographical nature and transmission configuration. These sub-areas include the following:

Pend Oreille: This sub-area is owned and operated by Pend Oreille County PUD (POPD). The area is sourced primarily by the Usk (BPA) and Albeni Falls (BPA) Substations, in addition to generation at the Box Canyon Hydroelectric Project. Lastly, there is a 115 kV tie to the Colville sub-area, but the flow of

[1] Owned by the Grand Coulee Project Hydro Authority, operated by and telemetered into Seattle City Light

power is maintained near zero, by a phase shifting transformer owned and operated by Pend Oreille County PUD. Pend Oreille County PUD substations providing load service to the sub-area include Box Canyon, Cusick, Diamond Lake, Metaline Falls, Pine Street and Usk Substations. Pend Oreille County PUD is the NERC registered Transmission Operator of the POPD system.

Colville: This sub-area is sourced primarily by the Colville (BPA) and Addy (BPA) Substations in addition to thermal generation near Kettle Falls. Avista provides transmission service to the City of Chewelah at the Chewelah Substation. Avista's substations providing load service to the sub-area include Spirit, Kettle Falls, Colville, Greenwood, Orin, Arden, Addy, Gifford, Chewelah, Valley, Ford and Long Lake Substations. Avista owns three 115 kV transmission lines providing local load service to the sub-area: the Kettle Falls – Addy, the Addy – Gifford and the Addy – Devils Gap 115 kV Transmission Lines. the BPA owns the remaining 115kV transmission lines that support the sub-area: the Boundary – Box Canyon – Colville, the Colville – Kettle Falls – Republic and the Addy – Colville 115 kV Transmission Lines. Lastly, Spirit Substation (AVA) is a tap off of the Boundary – Colville 115 kV Transmission Line (BPA).

Big Bend: This sub-area is sourced primarily by Devils Gap, Chelan (CHPD), Stratford, Warden, Benton (BPA) and Shawnee Substations. Generation from the Main Canal and Summer Falls Hydro Facilities operate in conjunction with the irrigation season, so they are also an important source for local transmission in the area. Note that Seattle City Light purchases transmission service for the Main Canal and Summer Falls generation. Avista provides transmission service for: Big Bend Electric Cooperative at Delight, Lee & Reynolds, Marengo, Ralston, Ritzville and Roxboro; Grant County PUD at Coulee City and Wilson Creek and Inland Power & Light at Gaffney, Irby, Odessa and Wagner Lake. Avista's substations providing load service to the sub-area include: Davenport, Harrington, Lee & Reynolds, Lind, Little Falls, Odessa, Othello, Reardan, Ritzville, Roxboro, South Othello, Sprague, Washtucna and Wilbur Substations. Avista owns eight 115 kV transmission lines providing local load service to the sub-area: the Chelan – Stratford, the Devils Gap – Stratford, the Devils Gap – Lind, the Lind – Shawnee, the Lind – Warden, the Benton – Othello SS and the Othello SS – Warden #1 & #2 115 kV Transmission Lines. Refer to Appendix B - System One Line Drawing for the "star points" on these lines.

Avista Mid-C Tie: This consists of three 230 kV transmission lines, two of which are jointly owned by Avista and PacifiCorp to connect (or tie) both owners to the Mid Columbia trading hub (Mid-C) at the Wanapum Substation (GCPD). Avista owns 44.45 miles of the Walla Walla – Wanapum 230 kV Transmission Line between Wanapum Substation and the Franklin County east border. PacifiCorp owns the Talbot – Walla Walla 230 kV Transmission Line. Avista owns 28.27 miles of the Dry Creek – Talbot 230 kV Transmission Line between Dry Creek Substation and the Garfield County west border. A Memorandum of Understanding (AV-TR03-0168) spells out the specifics of the joint agreement. Generally the capacity is evenly split up to the capacity of the line, at which time each party has priority rights up to 240 MW depending on direction of contractual flow. These lines do not directly serve any Avista customer load in the Big Bend.

Load growth in the Big Bend Area is projected to be 1.0% for summer and 1.1% for winter based on historic load growth data. Total anticipated load not including Transmission System losses for peak summer 2012 is 222 MW and 207 MW for peak winter 2012. Total installed distribution (i.e.115/4, 115/13.8, 115/24 or 115/34 kV) Avista owned transformation capacity in the Big Bend Area is 349.3 MVA based on transformer nameplate ratings.

Pend Oreille County PUD is considered part of this study area, but their load service and transmission infrastructure is planned and managed by their internal personnel. Pend Oreille County PUD load, transmission and generation is not included in the bulk of this report, given that they are isolated from the Big Bend Area by a phase shifting transformer at their Box Canyon Hydro Project. POPD, as a Transmission Operator, is responsible for the operation of their system.

3 DEVELOPMENT OF PLANNING ASSESSMENT

3.1 LOCAL PLANNING PROCESS

The development of this Planning Assessments follows the local transmission planning process (Process) provided in *Attachment K, Part III – The Avista Local Transmission Planning Process* of Avista Corporation's Fourth Revised Volume No. 8 of the Open Access Transmission Tariff ("OATT"). The Process is open to all Interested Stakeholders, including, but not limited to, all Transmission Customers and interconnection customers, and state authorities. Avista held a Study Development Meeting during the second quarter of 2011 providing participants an opportunity to provide comment for data gathering, initial assumptions and input into the study development. All comments received at the Study Development Meeting, or during the 30 days following, were incorporated into the Planning Assessment.

The purpose of the Process is to identify any Single System Projects that are needed to mitigate future reliability and load-service requirements for Avista's Transmission System. This Planning Assessment identifies any reliability impacts identified on Avista's Transmission System, and provides a list of the Single System Projects proposed to mitigate those issues. Such reliability impacts were identified by performing technical studies, which included powerflow, transient stability, short circuit, and voltage collapse studies. **For Single System Projects not identified in previously completed Planning Assessment, a separate Corrective Action Plan (detailed project study) will be conducted as necessary to determine the technically superior project(s) to be carried forward into the Avista capital budgeting process.**

3.2 TRANSMISSION PLANNING CRITERIA

The transmission planning reliability criteria used in evaluating the performance of the transmission system is the present North American Electric Reliability Corporation (NERC) Reliability Standards and WECC regional reliability criteria including the following:

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

TRANSMISSION PLANNING ASSUMPTIONS

The following assumptions have been used in the Process for performing technical studies. The assumptions are made upon the experience of Avista's System Planning Group and to comply with NERC Reliability Standards.

3.2.1 Base Case Development

Avista's System Planning Group develops a set of base cases annually using WECC approved base cases, applying steady state and dynamic data modifications as required to represent desired scenarios. Four seasonal scenarios are developed which represent bookends that have been historically established through previous technical studies. The scenarios developed include the following:

1. Heavy Summer with High Local Hydro Generation (Heavy Summer, High Hydro Case)

   This is the typical summer peak scenario where the Avista Balancing Authority Area load is near peak and the local hydro generation is at a typical mid-summer output. This scenario represents Avista's heavy summer loading with moderate transfers into Avista's Balancing Authority Area. This scenario is limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the System is near capacity.

2. Heavy Summer with Low Local Hydro Generation (Heavy Summer, Low Hydro Case)

   This is the typical summer peak scenario where the Avista Balancing Authority Area load is near peak and the local hydro generation has a low output. This scenario plays a dual role, in that it represents both Avista's heavy summer loading scenario along with the sensitivity of significant transfers into Avista Balancing Authority Area to supplement the low hydro generation. This scenario is limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the System is near capacity.

3. Heavy Winter Case

   This is the typical winter peak scenario where the Avista Balancing Authority Area load is heavy but the lower ambient temperature increases the operating limits of the various elements of the Transmission System. Local hydro generation is at a moderate level and there are significant transfers into Avista's Balancing Authority Area from regional thermal resources.

4. Light Summer with High West of Hatwai Flows (High Transfer Case)

   During light summer (night time loading) with high Western Montana Hydro and high Montana thermal generation, the WECC rated path "West of Hatwai" (WECC Path #6) reaches its heaviest loading. During this scenario, portions of the Transmission System are nearing their stability limits. These limits define some of the operating constraints for the region and also establish some of the arming levels for Remedial Action Schemes (RAS). This scenario is also limited by the summer thermal limits on various elements of the transmission system, which helps to define where the system is near capacity.

These base cases are developed to represent both the five and ten year planning horizon. A detailed summary of specific flows and loading levels for the base cases used in the 2011 Planning Assessments can be viewed in the interoffice memorandum SP-2011-03 – 2011 Planning Cases Summary Data.

3.2.2 Load Forecast

Load forecasts for Network Customers and Point-to-Point Customers were requested at the Study Development Meeting. The BPA submitted its forecast load information as a Network Customer to Avista for inclusion in the technical studies. Avista’s System Planning Group incorporated forecast load data for its Load Serving Entity (“Avista LSE”) into the technical studies.

3.2.3 Planned Transmission Facilities

No planned transmission expansion project facilities are included in the bases cases used in technical studies performed for the Planning Assessments. During previous Planning Assessments inclusion of non-committed planned transmission facilities has incorrectly hidden potential reliability and load-service requirements. Subsequently, a Corrective Action Plan was not developed as required by the Process.

3.2.4 Planned Generation Facilities

Only potential generation projects in the Avista Interconnection Request queue that have executed Interconnection Agreements are modeled (with corresponding upgrades) in the base cases for technical studies.

The 2011 Planning Assessments did not include any potential generation in the technical studies.

3.2.5 Contingencies

The contingencies evaluated for powerflow and transient stability technical studies are a standard contingency set used by Avista’s System Planning Group, reviewed and updated annually. Documentation on the contingency set is provided by System Planning Policy and Procedure SP-PP-06 Contingency Analysis.

3.3 ACCESS TO PLANNING DATA

The base cases used in the Process can be provided within 10 calendar days, via email or other media, to any WECC member that makes a request. Non-WECC members will be required to sign a confidentiality agreement with the WECC before any base cases can be shared. Once the WECC confirms a confidentiality agreement has been signed, the requested base case(s) shall be provided within 10 calendar days. Any additional information needed to replicate the technical study results of the Process can be provided, upon written request.

3.4 IDENTIFICATION OF ANALYTICAL TOOLS

The following Analytical Tools were used to perform technical studies:

- PowerWorld Simulator Software, Version 15
    - PowerWorld Simulator is an interactive power systems simulation package designed to simulate high voltage power systems operation on a time frame ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 busses using mathematical calculations based on system impedances, load levels and generation output. PowerWorld provides the user with a variety of sophisticated study tools such as an automated contingency processor, an Available Transfer Capability (ATC) tool, an Optimal Power Flow tools, various voltage stability tools (i.e. PV and QV tools), and a Transient Stability Analysis tool.
- GE Positive Sequence Load Flow, Version 17.05
    - The GE Positive Sequence Load Flow (PSLF) software suite is a package of programs for studying power system transmission networks and equipment performance in both the steady-state and dynamic environments.
- ASPEN OneLiner Software Build 2007.11.7 Group-1
    - ASPEN OneLiner is a PC-based short circuit and relay coordination. OneLiner is an interactive productivity tool allowing the engineer to accurately model the transmission system, perform fault analysis by simulating all classical fault types, graphically plot fault solution and relay coordination curves and validate relay settings through relay models and automatic checking module.

4 SINGLE SYSTEM PROJECTS AND CORRECTIVE ACTION PLANS

4.1 PLANNED SYSTEM MODIFICATIONS

The following sections *d*escribe projects to either enhance the existing Big Bend Area Transmission System or mitigate deficiencies discovered during the course of the Process. These items should be addressed as construction schedules and annual budgets permit:

4.1.1 Spirit Substation – Minor Rebuild

Partial rebuild of Spirit Substation to replace obsolete under-rated 115 kV fuses, station feeder breakers, a 3-phase regulator with standard single-phase regulators, and update the metering and add SCADA. In addition, approximately 6 miles of the 12F1 feeder, heading north to Northport, is being rebuilt to correct voltage issues. This substation work is under construction and will be completed spring of 2012.

4.1.2 Gifford Substation – Add New Capacity

There is currently a 115/34.5 kV, 12 MVA transformer serving load in the area. There is an additional (3) single phase 34.5/13.2 kV, 1500 kVA pole mounted, bucking transformation outside of the substation. This project will add a new 115-13.2 kV, 3.75 MVA transformer, feeder position and regulator at the Gifford Substation and create a new GIF12F1 feeder to serve the north branch load. The project is scheduled for construction in 2015.

4.1.3 Orin Substation – Rebuild and Add New Capacity

Orin Substation is on the list for a rebuild based on condition. It is wood pole construction and the 115/13 kV, 7.5 MVA transformer is currently loaded to 80%. This project is currently in latter years of the 5 to 10 year planning horizon and mentioned here for completeness.

4.1.4 Ford Substation – Relocation

Currently, Ford Substation sits on land that the Dawn Mining Company needs to reclaim. They are required to fence and secure the non operational uranium mine property due to ongoing reclamation activities at the uranium mill site. This would require Avista to move the substation less than half a mile. This will be an opportunity to remove the (3) single phase 115/13 kV transformer bank and the 115/2.4 kV transformer. This project is also in the 5 to 10 year planning horizon and mentioned here for completeness.

4.1.5 Forty Nine Degrees North Substation – Add New Capacity

The 49 Degrees North Ski Resort is adding a new double chair lift and a mid mountain lodge, construction is to be completed the fall of 2012. This is phase one of their five phase master plan. The existing distribution is being reinforced to accommodate the planned expansion, but there is limited additional capacity. A dedicated feeder at a higher voltage level and a new transformation at Chewelah Substation or a new distribution substation and a 115 kV radial transmission tap line will be required if the resort continues to expand.

4.1.6 Bruce Siding Substation – Add New Capacity

Currently there is a large agricultural processing center about 6 miles east of Othello in addition to typical irrigation load. This area is served out of Lee & Reynolds Substation by two, 5 mile long distribution feeders and the existing load is approximately 2.2 MW. A customer had proposed a new local industrial load in 2007, which would require a new distribution substation local to the area. This proposed load has been subsequently delayed. A new Bruce Siding Substation remains a 5 to 10 year project, mentioned here for reference. The OthelloSS – Warden #2115 kV Transmission Line passes directly through the area and the substation property has not been purchased.

4.1.7 Distribution Upgrades

Several distribution feeders have been identified as needed to be upgraded or replaced due to their existing condition and recent historical performance. Included also are feeder ties, which will aid in the operational flexibility of the distribution system. The scheduling, budgeting, design and construction required for this work is done by the Distribution Engineering Group and therefore are only mentioned here for completeness.

4.2 NORMAL SYSTEM CONDITIONS (N-0): NERC CATEGORY A

4.2.1 Low Voltage in the Lind Area

Currently, there is an issue with low voltage in the area served out of the Lind Substation. During heavy loading (spring/summer irrigation), the Lind area 115 kV transmission voltages have dipped to levels below both normal and contingency minimums. Warden Substation is the normal source, with the Lind – Warden 115 kV Transmission Line feeding the Lind Substation. Modeling indicates N-0 transmission voltages as low 0.92pu at the Ritzville Substation for heavy summer in the 5 year case. Figure 4-1 shows that with the loss of the Sand Dunes – Warden 115 kV Transmission Line, this voltage sinks to 0.87pu. Unacceptable voltages, as low as 0.87pu also occur at the Roxboro Substation if the tie to the source at Warden is not available and Roxboro has to be sourced from Devils Gap and Shawnee Substations. Note that Roxboro accounts for 50% of the load in the Lind area.

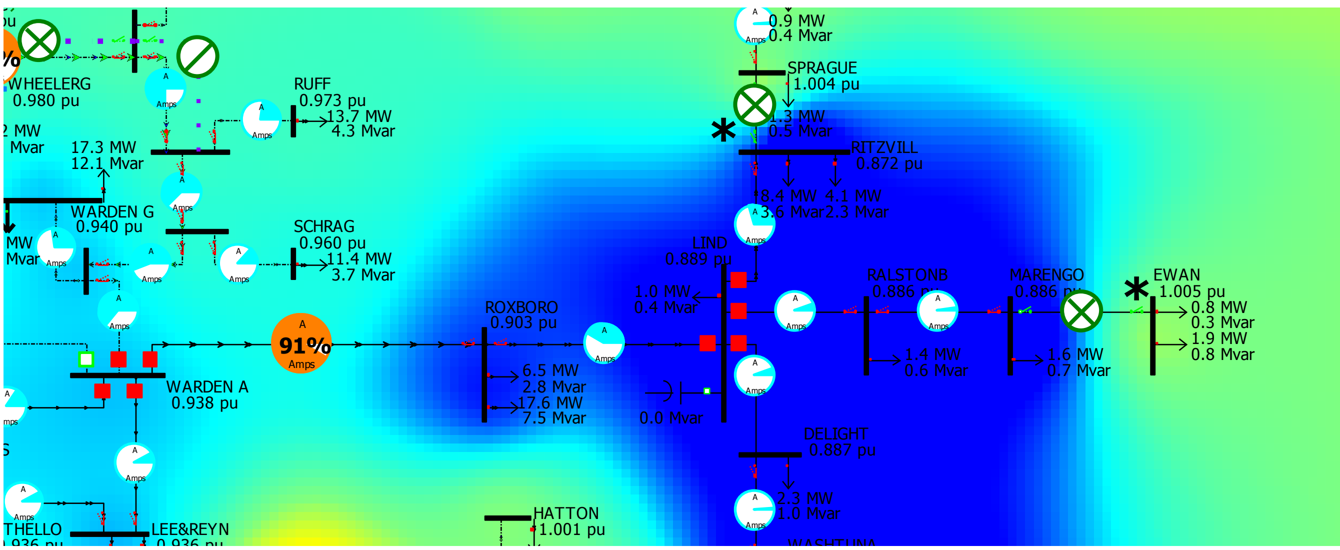


FIGURE 4-1: LOW VOLTAGE, SAND DUNES - WARDEN OUTAGE

Reactive support at Lind corrects this N-0 issue along with eliminating or reducing numerous other contingency issues. The alternative chosen was to install a capacitor bank, consisting of one step of 6.71 MVAr and one step of 13.42 MVAr, at the Lind Substation. Details of the issues, further analysis and the recommended solution are provided in the System Planning Memo SP-2011-02.

Substation Engineering has completed the design and the substation equipment has been ordered; the project is planned to be constructed during the spring of 2012 and in service prior to summer peak loading. Estimated cost for this project is $1.00 million

4.3 SINGLE CONTINGENCY ISSUES (N-1): NERC CATEGORY B

4.3.1 Devils Gap – Stratford 115 kV Transmission Line, Voltage Support

During a line end open scenario on the Devils Gap – Stratford 115 kV Transmission Line, open at Stratford Substation, low voltage is observed at the following substations: Wilson Creek (GPUD), Irby and Odessa Substations (see Figure 4-2). These low voltages only occur during heavy spring and summer loading conditions and become worse as load growth continues. Voltage as low as 0.86 pu occurs at Wilson Creek Substation in the five year planning horizon. The primary cause of this issue is the 86 miles of small conductor (mostly 7#8 CU) and heavy load at the west end of the transmission line.

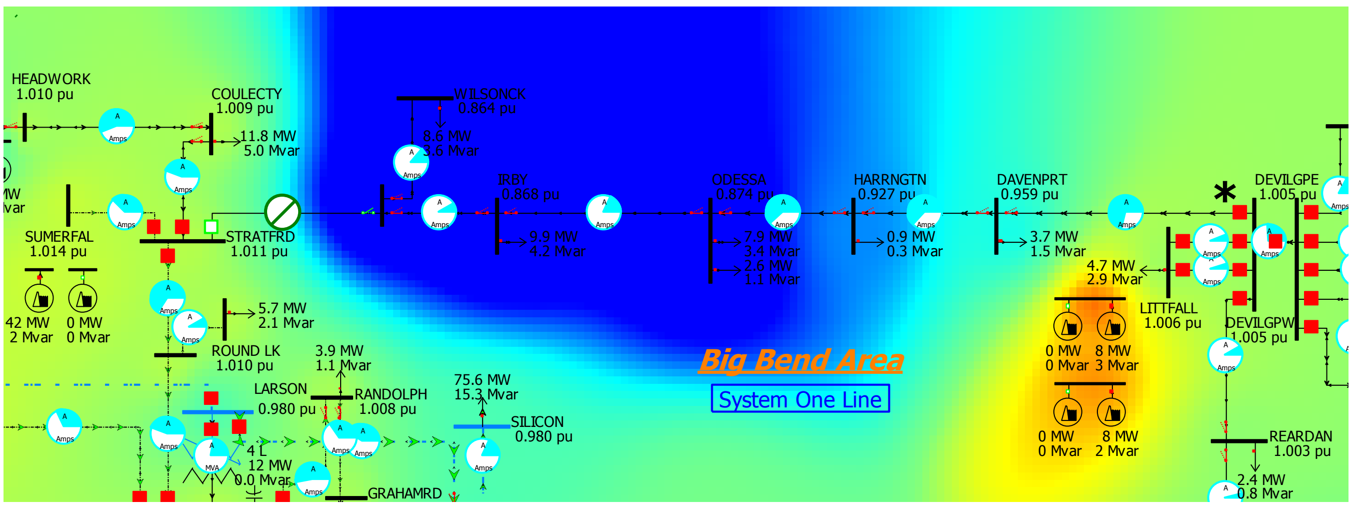


FIGURE 4-2: LOW VOLTAGE, DEVILS GAP – STRATFORD, OPEN AT STRATFORD

The following are possible alternatives to mitigate the potential low voltage issue:

1. Do nothing – Unacceptable low voltage issues will worsen with time. The window for equipment maintenance is also limited to fall, winter and early spring.
2. Reconductor approximately 56.4 miles of the Devils Gap – Stratford 115 kV Transmission Line with 556 conductor, specifically the Devils Gap – Davenport – Harrington – Odessa sections. The bus voltage at Wilson Creek Substation under the line end open scenario will increase to 0.93 pu in the 10 year horizon. Estimated cost for this option is $9.35 million.
3. Move the Wilson Creek load onto Grant County's Larson –Stratford 115 kV line. This requires building a new 8.5 mile long tap, which would parallel the existing Larson –Stratford 115 kV Transmission Line, from Round Lake (GCPD) constructed with 556 conductor. A maintenance tie would remain to transfer Wilson Creek to the Larson –Stratford 115 kV Transmission Line (though there would be issues with moving load between Balancing Areas). Estimated cost for this option is $3.60 million.

4. Install two steps of 13.42 MVAr each, capacitor banks at Odessa Substation. This results in a 1.2% step in normal configuration and a 5.5% voltage step during the worst case contingency scenario. Voltage at Wilson Creek Substation under the line end open scenario will increase to 0.96 pu in the 10 year planning horizon. Estimated cost for this option is $0.75 million.

Alternative 4 is recommended to be carried forward, pending a detailed Corrective Action Plan, to mitigate the observed low voltages during single contingency issues. The low voltage issues observed are presently operating issues as documented in the Avista 2011 Summer Operating Studies Report and should be mitigated as soon as feasibly possible. The proposed capacitor bank installation is planned to be completed spring 2013.

4.3.2 Benton – Othello SS 115 kV Transmission Line, Thermal Loading

Thermal overloads are observed on the Avista owned segments of the Benton – Othello Switching Station 115 kV Transmission Line for the outage of the Columbia – Quincy 230 kV Transmission Line or the Wheeler Tap – Basset 115 kV Transmission Line. Note also that the capacity of Avista's tie to Benton (BPA) cannot serve the 96 MW of summer load in the Lind and Othello areas.

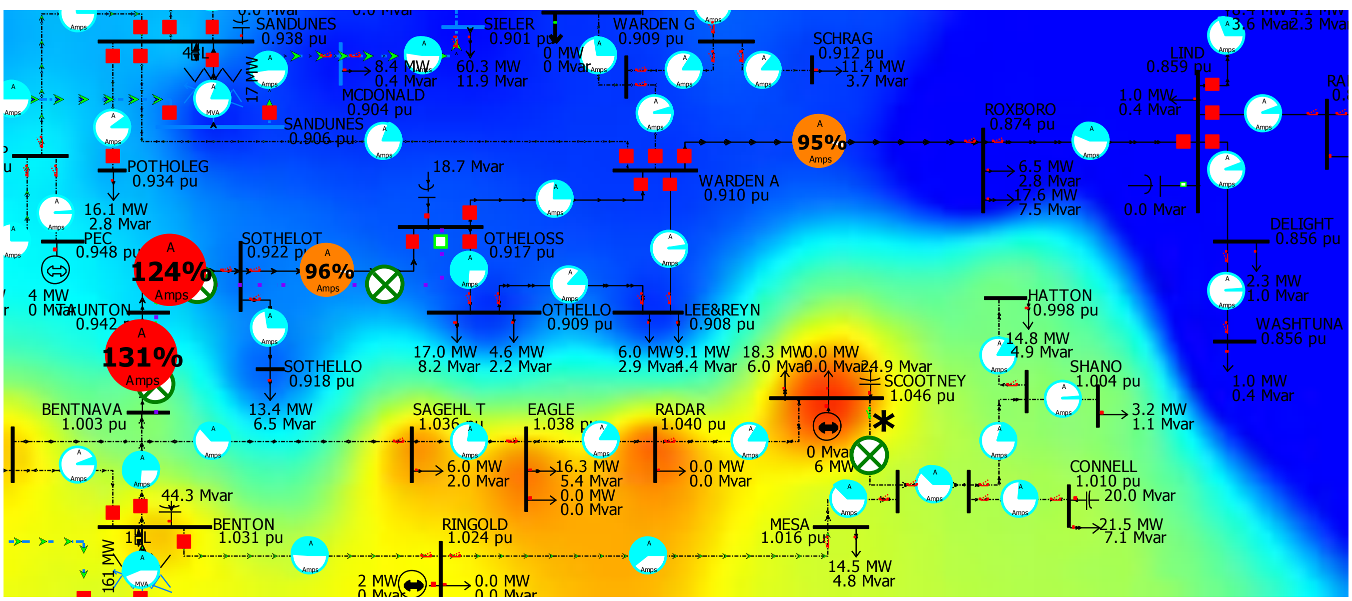


FIGURE 4-3: THERMAL ISSUE, COLUMBIA-QUINCY 230KV OUTAGE

The following are possible alternatives to mitigate the potential thermal overload issue:

1. Do nothing – thermal overload of the Benton – Othello Switching Station 115 kV Transmission Line will become worse with time. Currently, we can open the Benton – Othello Switching Station 115 kV Transmission Line at Othello Switching Station to mitigate this overload. Grant County PUD has no plans for further 230 kV system reinforcements in their area.

2. Reconductor Avista's 26 mile section of the Benton – Othello Switching Station 115 kV Transmission Line with 556 conductor (this includes a crossing of the Columbia River). This reduces this N-1 thermal overload to 56% in the 10 year case. Estimated cost for this option is $7.00 million.

3. Provide a new 230/115 kV source to the Big Bend sub-area at the existing Othello Switching Station. This requires the construction of two new 9.3 mile 230 kV transmission lines on separate right of ways and tapping into the existing Walla Walla – Wanapum 230 kV Transmission Line. The existing Othello Switching Station would need to be reconstructed to allow for the 230 kV transmission line terminal positions, a 250 MVA 230/115 kV auto-transformer and an updated 115 kV bus arrangement. Estimated cost for this option is $20.75 million.

Alternative 2 is recommended to be carried forward, pending a detailed project analysis, to mitigate the observed thermal overloads during single contingency issues. Mitigation of multiple contingency issues further supports the recommendation of Alternative 2 for the ten year planning horizon. Reconductoring of the Benton – Othello Switching Station 115 kV Transmission Line is proposed to be completed by 2016.

4.3.3 Stratford – Larson 115 kV Transmission Line, Thermal Loading

Thermal overloads are observed on the Stratford – Larson 115 kV Transmission Line for the outage of the Columbia – Quincy 230 kV Transmission Line. Figure 4-4 shows the overload in the 5 year heavy summer case. The bottleneck on this line is at the Stratford Substation terminal and is limited by both the circuit breaker CT's and the existing strain bus.

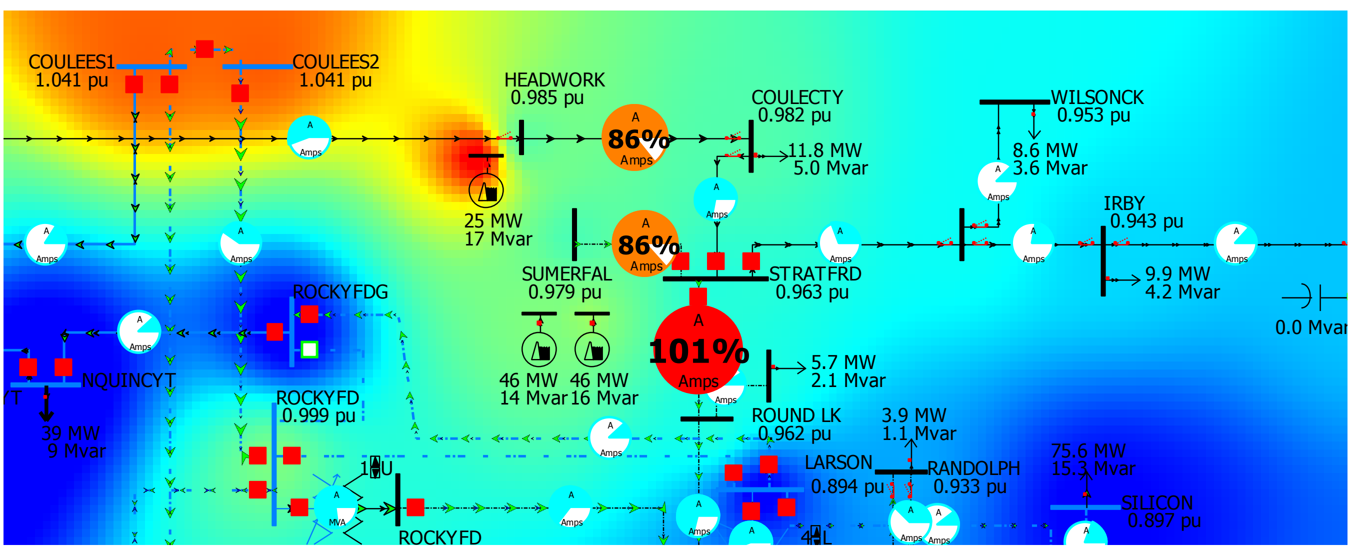


FIGURE 4-4: THERMAL ISSUE, COLUMBIA - QUINCY 230KV OUTAGE

Heavy thermal loading on the Stratford – Larson 115 kV Transmission Line also results from Avista moving the “star point” on the Devils Gap – Stratford 115 kV Transmission Line. Currently, the “star point” is moved to the Devils Gap end, during spring and summer seasons, to add additional load to Stratford Substation which helps to sink the local generation. The preferred “star point” would be at Odessa, to minimize exposure to transmission line outages. Figure 4-5 shows the heaving thermal loading on Stratford – Larson 115 kV Transmission Line when the Devils Gap – Stratford 115 kV Transmission Line is open at Stratford.

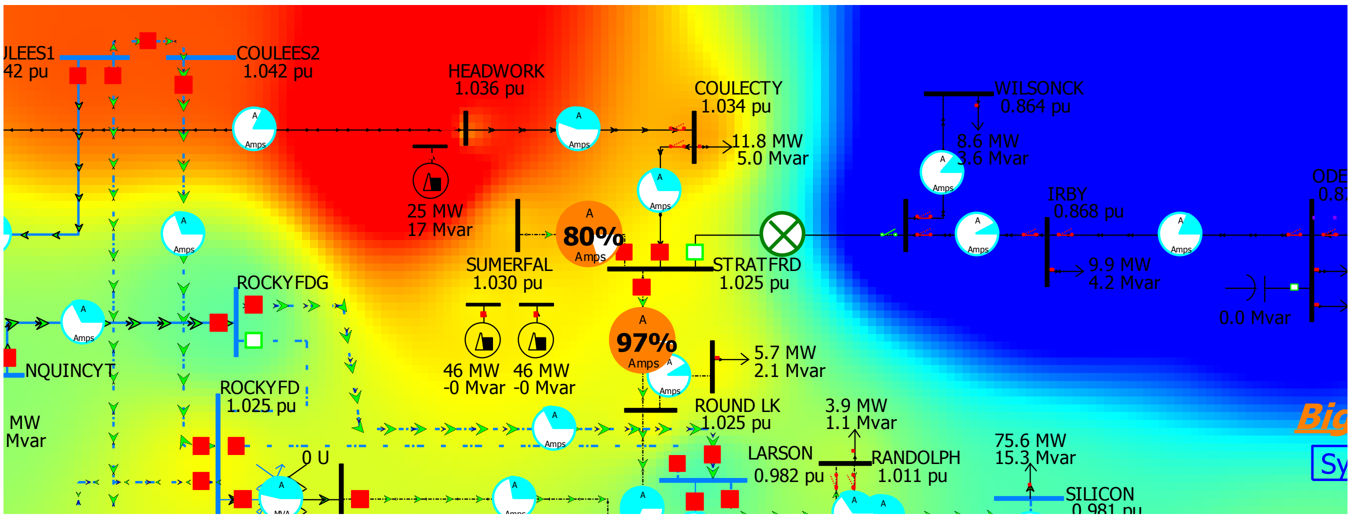


FIGURE 4-5: THERMAL ISSUE, STRATFORD – DEVILS GAP 115KV OUTAGE

The following are possible alternatives to mitigate the potential thermal overload issue:

1. Do nothing – thermal overload of the Stratford – Larson 115 kV Transmission Line will become worse with time. Currently, generation output can be lowered at either the Summer Falls or Main Canal Hydro facilities to mitigate this potential thermal overload.

2. Rebuild portions of the existing strain bus at Stratford and replace the CT’s. Estimated cost for this option is $0.25 million. The window for this construction is short and limited to early spring or fall, when both irrigation loading and local generation ramps down.

Alternative 2 is recommended to be carried forward, pending a detailed project analysis. Though this is a marginal thermal overload in the 10 year planning horizon, this rebuild will make it so the “star point” can be moved back to Odessa Substation. This will increase the operating flexibility and improve reliability. The substation work is proposed to be completed by 2015.

4.3.4 Lind - Warden 115 kV Transmission Line, Thermal Loading

During heavy summer loading, thermal overloads are observed on the Lind – Warden 115 kV Transmission Line when either the Devils Gap – Lind or the Lind – Shawnee 115 kV Transmission Lines is sourced out of Lind. Figure 4-6 shows that in the 10 year case, with the new reactive support in service at Lind, the thermal loading is at 97% when the load is transferred from Shawnee to the Lind source.

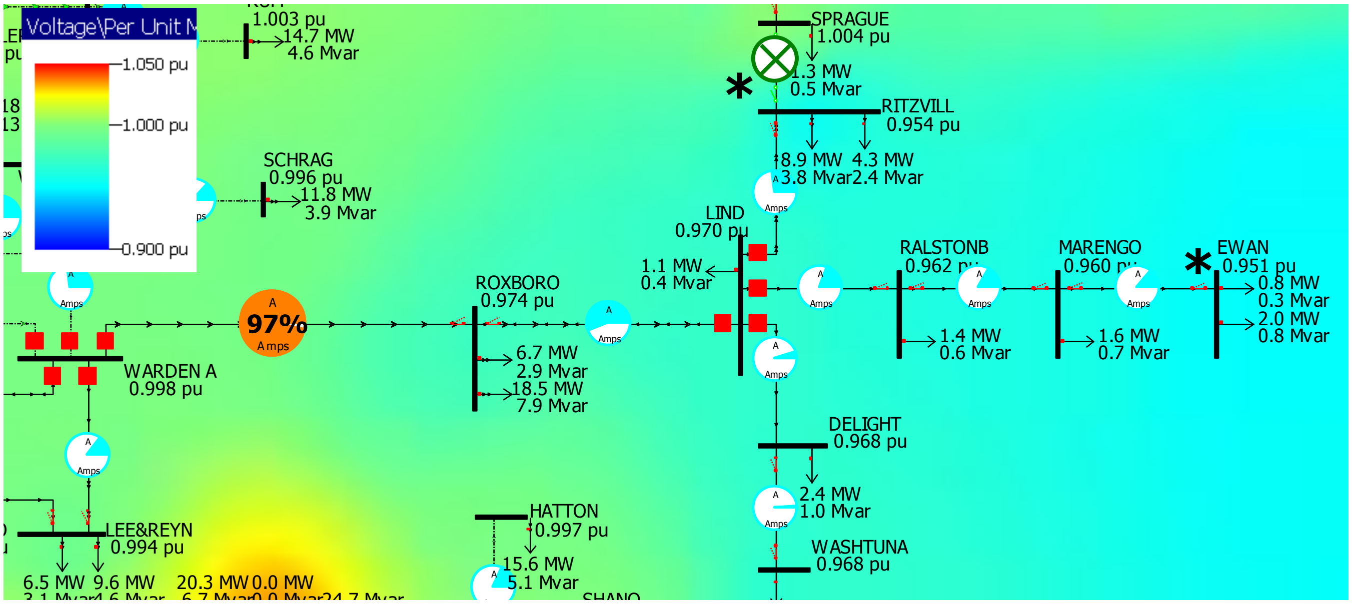


FIGURE 4-6: THERMAL ISSUE, LIND – SHAWNEE 115KV, OPEN AT SHAWNEE

The following are possible alternatives to mitigate the potential thermal overload issue:

1. Do nothing – thermal overload of the Lind – Warden 115 kV Transmission Line will become worse with time.

2. Reconductor approximately 10.77 miles of the Lind – Warden 115 kV Transmission Line with 795 conductor, specifically the Roxboro – Warden section. Thermal loading drops to 40% with this reconductor in the 10 year horizon. Estimated cost for this option is $1.75 million.

Alternative 2 is recommended to be carried forward, pending a detailed project analysis. The Lind – Warden 115 kV Transmission Line is a candidate for rebuilding based on loading and losses. This is a productivity project and the transmission work is proposed to be completed by 2018.

4.3.5 Addy – Devils Gap 115 kV Transmission Line, Thermal Loading

Thermal overloads are observed on the Addy – Devils Gap 115 kV Transmission Line for the outage of the Addy – Bell 230 kV Transmission Line. Figure 4-7 shows the thermal overload in the 5 year high transfers case. For reference, there is a Remedial Action Scheme (RAS) associated with this Addy – Bell 230 kV outage, but it is not triggered in this case.

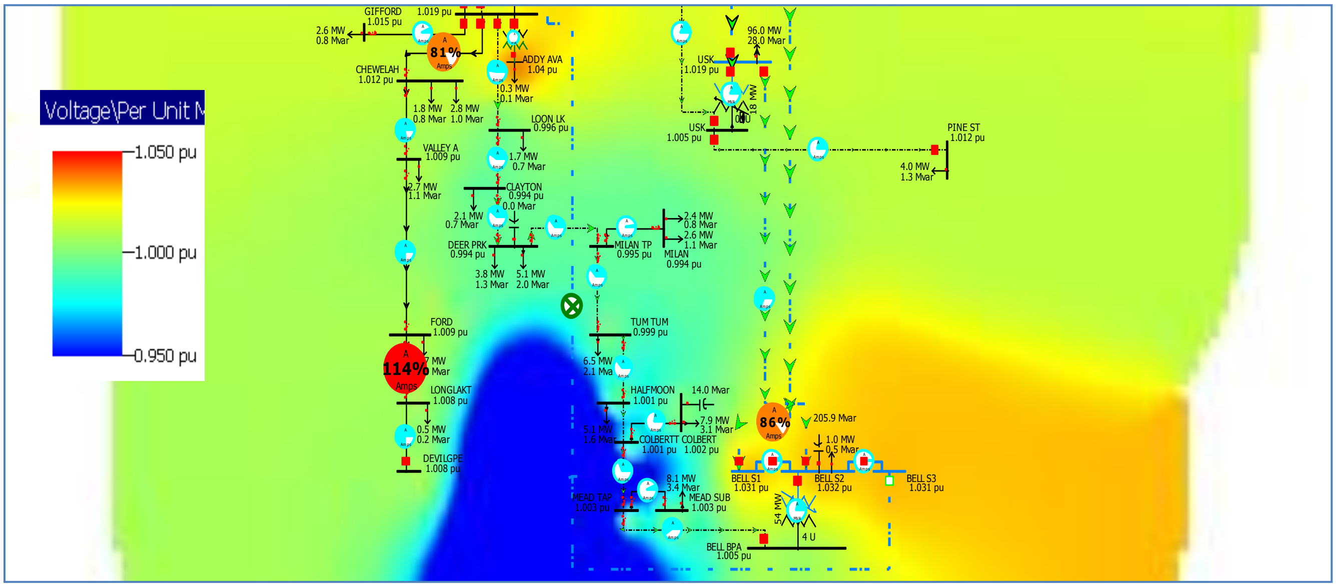


FIGURE 4-7: THERMAL ISSUE, ADDY-BELL 230KV OUTAGE

1. Do nothing – thermal overload of the Addy – Devils Gap 115 kV Transmission Line will become worse with time. Currently, we can open the Addy – Devils Gap 115 kV Transmission Line at either end to mitigate this overload.

2. Reconductor a 1.84 mile section, south of Ford Substation, of the Addy – Devils Gap 115 kV Transmission Line with 556 conductor. Thermal loading drops to 77% with this reconductor in the 10 year horizon. Estimated cost for this option is $0.75 million.

Alternative 2 is the recommended solution. The majority of the Addy – Devils Gap 115 kV Transmission Line has been rebuilt to 556 AAC, with the exception of two line sections. Rebuilding this section reduces transmission line loading and also provides greater operational flexibility, by not having to sectionalize this transmission line for contingencies. The reconductoring of this section of the Addy – Devils Gap 115 kV Transmission Line is proposed to be completed by 2017.

4.4 MULTIPLE CONTINGENCY ISSUES: NERC CATEGORY C AND D

4.4.1 Benton – Othello SS 115 kV Transmission Line, Thermal Loading

Several multiple contingency issues cause thermal overloading on Avista owned segments of the Benton – OthelloSS 115 kV Transmission Line. The contingencies causing potential violations include a Warden 115 kV bus (see Figure 4-8) or a Sand Dunes 115 kV bus (see Figure 4-9) outage. These outages also result in numerous low voltage issues. The aforementioned reactive support project at Lind Substation greatly reduces the number and impact of the voltage issues, but do not correct the thermal issues.

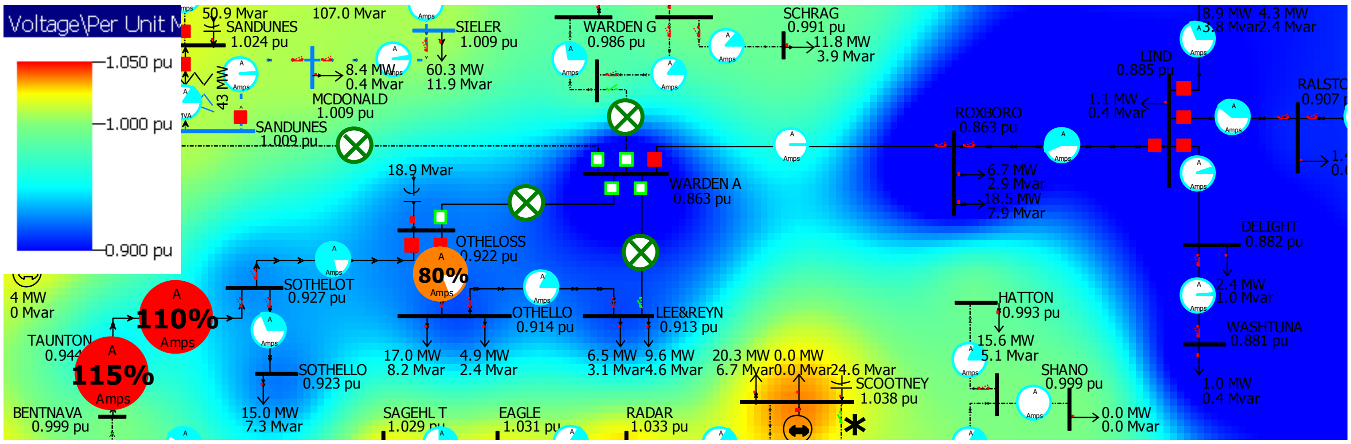


FIGURE 4-8: WARDEN 115 BUS OUTAGE.

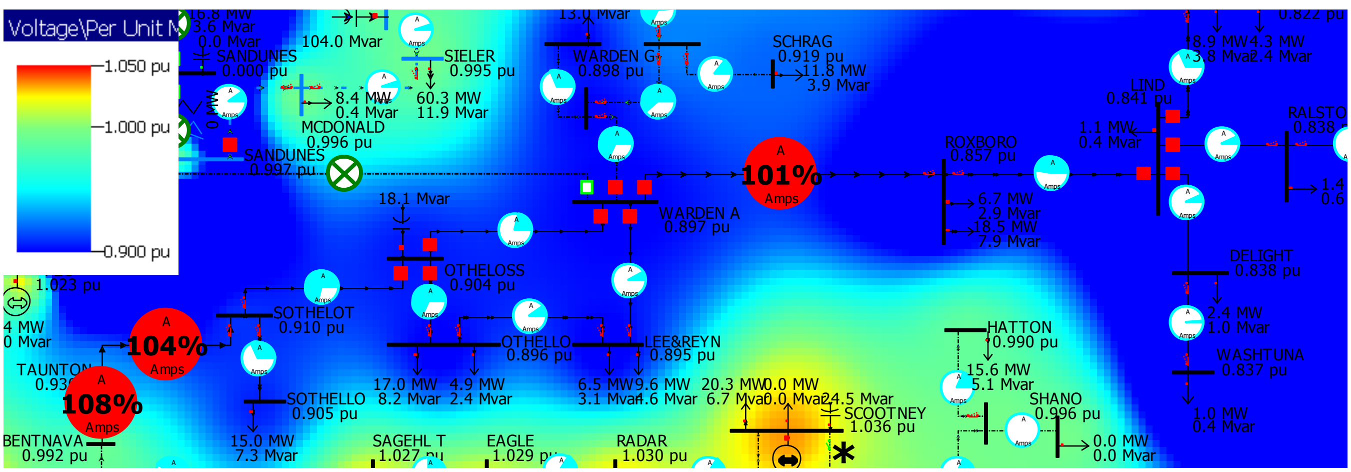


FIGURE 4-9: SAND DUNES 230 BUS OUTAGE.

Refer to section 4.3.2 for a discussion of the N-1 contingencies that impact this transmission line and the recommended system improvements. Line reconductoring, in addition to new reactive support at Lind Substation, will reduce the impacts to the Big Bend Area for these contingencies issues.

4.4.2 Devils Gap – Stratford 115 kV Transmission Line, Voltage Support

A Stratford Substation bus outage results in low voltage at the following substations: Wilson Creek (GPUD), Irby and Odessa Substations (see Figure 4-10). These low voltages only occur during heavy spring and summer loading conditions and become worse as load growth continues. The lowest voltage occurs at Wilson Creek Substation; in the five year horizon the voltage is 0.86 pu and 0.85 in the ten year horizon. The primary cause of this issue is 86 miles of small conductor, mostly 7#8 CU and heavy load at the end of the transmission line. Note that the Summer Falls HED generation will also be off line for this outage.

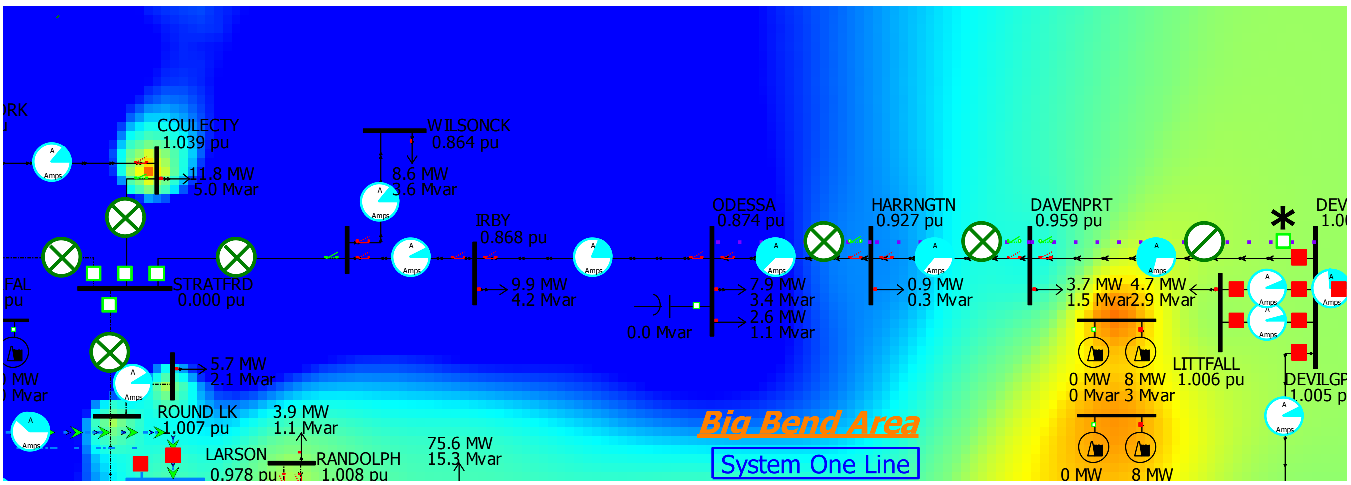


FIGURE 4-10: STRATFORD 115 BUS OUTAGE.

Refer to section 4.3.1 for a discussion of N-1 contingencies that impact this transmission line and the recommended system improvements. Reactive support at the Odessa Substation will correct the voltage issues in the 5 and 10 year planning horizon.

4.5 RESULTING ISSUES

This Planning Assessment assumes that all of the Single System Projects identified are completed within the ten year planning horizon to mitigate the discussed issues. For reference, there are 2021 emergent issues that will be addressed in future Big Bend Area Planning Assessments. These issues include the following:

1. The distribution feeding Northport out of Spirit Substation is nearing the limits for serving load. Either a new 115 kV line extension to Northport along with a new substation or introducing a higher distribution voltage out of Spirit Substation may be required to meet load growth in the area. Any 115 kV plan will need to be coordinated with BPA.

5 VOLTAGE STABILITY ANALYSIS (PV & QV)

Steady state analysis techniques were used to evaluate the voltage stability performance in the Big Bend Area. Further investigation of voltage stability using dynamic (time-domain) simulation is presented in Section 7. PV and QV analysis were used to assess the Area's conformity with the relevant planning criteria. PV analysis of a particular area or of a particular transfer path reveals the static stability margin of the area or of the path under study while QV analysis yields the reactive power margin at a particular bus in the transmission system under consideration. A more detailed explanation and further information can be referenced in "*TPL – (001 thru 004) – WECC – 1 – CR – System Performance Criteria*".

A key element of voltage stability studies is the determination of a critical bus or a cluster of critical busses. According to the WECC publication "Voltage Stability Criteria, Undervoltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology" (1998), the critical bus exhibits one or more of the following characteristics under the worst single or multiple contingency:

- Has the highest voltage collapse point on the QV curve.
- Has the lowest reactive power margin.
- Has the greatest reactive power deficiency.
- Has the highest percentage change in voltage.

The following sections provide methodology and results for the PV and QV analysis conducted.

5.1 PV ANALYSIS

5.1.1 Methodology

A PV curve is obtained in power-flow simulation by monitoring a voltage at a bus of interest and varying (increasing) the power (load or transfer) in small increments until power-flow divergence is encountered. Each equilibrium point represents a steady-state operating condition. Path 6 - West of Hatwai divides the Big Bend Area, therefore a Transfer Path PV Curve analysis was performed as well as a Load Ramp PV Curve analysis for load in the Big Bend Area.

The Transfer Path PV Curve analysis was conducted on the 2012 Heavy Transfer Case. All busses in the Northwest were monitored while generation was increased in the Western Montana Hydro Complex, Boundary Hydro project, and in the Montana Area while generation was decreased in the Lower Columbia River Hydro system. Transfers across Path 6 were increased until voltage collapse occurred (i.e. the case became numerically unstable).

The Load Ramp PV Curve analysis was conducted on the 2016 Heavy Summer, Low Hydro case and all busses in the Big Bend Area were monitored. All loads within the Big Bend Area were increased until voltage collapse occurred (i.e. the case became numerically unstable). It was assumed that all additional generation necessary to supply the increase in load came from a distribution of all generation in WECC.

A set of contingencies depicting one or more transmission outages was used to produce a series of PV curves for the Load Ramp PV Curve analysis. The operating limit can be established as the lowest of the following as obtained from the PV analysis results:

1. 5% below the area load magnitude at the 'nose-point' for Category A performance.
2. 5% below the area load magnitude corresponding to the 'nose-point' on the PV curve representing the worst Category B contingency.
3. 2.5% below the area load magnitude corresponding to the 'nose-point' on the PV curve representing the worst Category C contingency (controlled load shedding is allowed to achieve this operating limit).

5.1.2 Results

Transfer Path Impacts: As generation in the Western Montana Hydro Complex, Boundary Hydro project, and in the Montana Area is increased, the transfers across Path 6 and Path 8 also increased until a theoretical maximum transfer limit was reached. A nose point was not reached therefore identifying Path 6 and Path 8 as flow limited (opposed to reliability limited). A balance of generation levels and load on the east side of the paths directly impacts the amount of power transferred across the paths. The load in the Montana and Western Montana Areas could be reduced therefore increasing the transfer amounts but further load reduction may fall outside a realistic simulation approach.

The PV Analysis results for Path 6 showed a theoretical flow limit of 4460 MW for all line in service condition. This exceeds the existing East to West Path 6 Transfer Limit of 4277 MW as posted in the 2011 Path Rating Catalog. The simultaneous line right-of-way outage of both the Hot Springs – Noxon #1 & #2 230 kV Transmission Lines as well as a breaker failure at Taft Switching Station appear to be the most limiting contingencies (see Figure 5-1). The Avista 2011 Summer Operating Studies Report identifies the nose of the PV curve at 4785 MW.

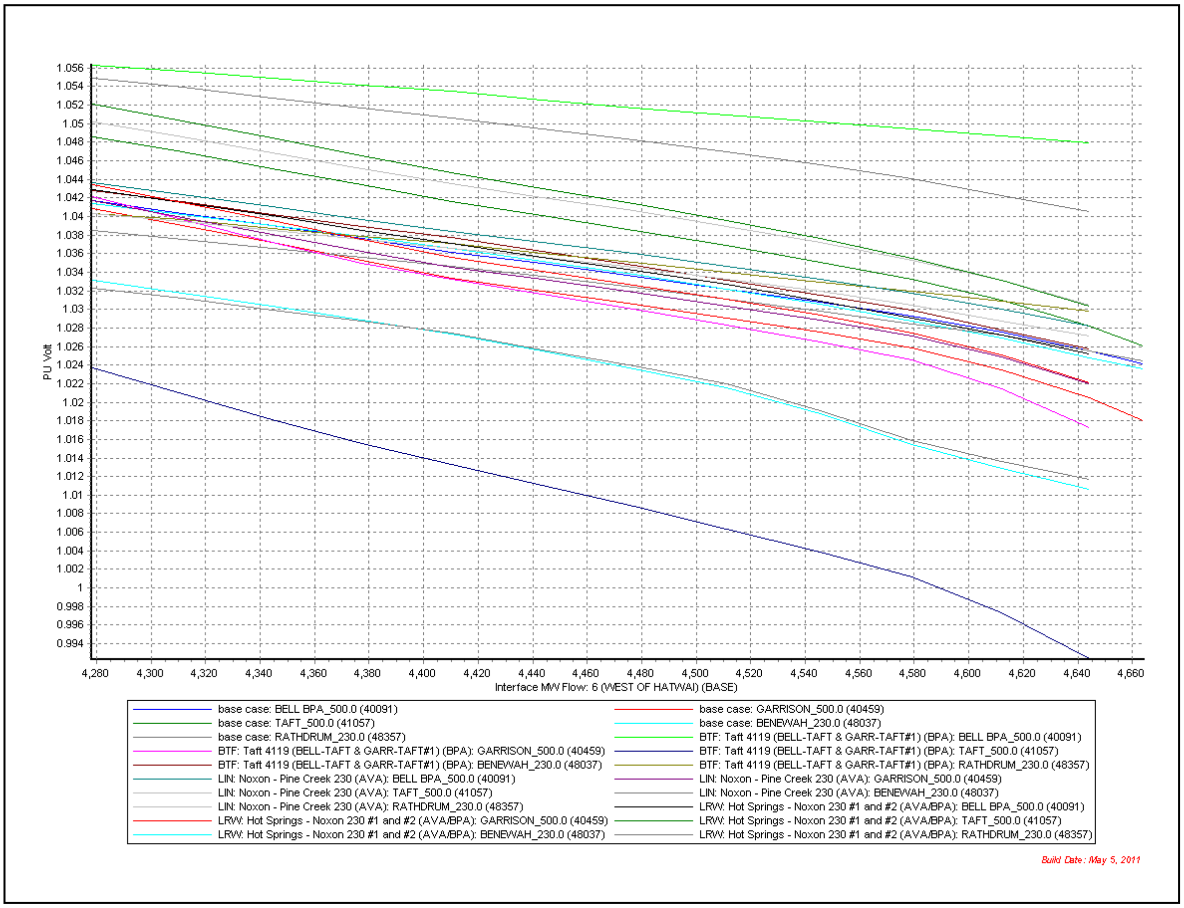


FIGURE 5-1: PATH 6 TRANSFER PATH PV CURVE RESULTS FOR CRITICAL BUSSES.

Load Ramp Impacts: As load increases in the Big Bend Area, the worst Category B contingency is the line end open scenario on the Lind - Warden 115 kV Transmission Line open at Warden Substation. The nose point occurs near 380 MW therefore the theoretical operating limit could be a total Big Bend Area load of 361 MW, about one and a half times the present peak summer load of the Big Bend Area. The worst Category C contingency becomes the Sand Dunes 115 kV bus outage. The critical bus for this outage is the Ritzville 115 kV bus. Controlled load shedding is allowed therefore the criticality of this contingency is not easily determined. Figure 5-2 shows the PV curves for two critical busses and the worst performing contingencies. From observation, the post transient voltage deviation at Ritzville Substation exceeds 15% for the Sand Dunes 115 kV bus outage.

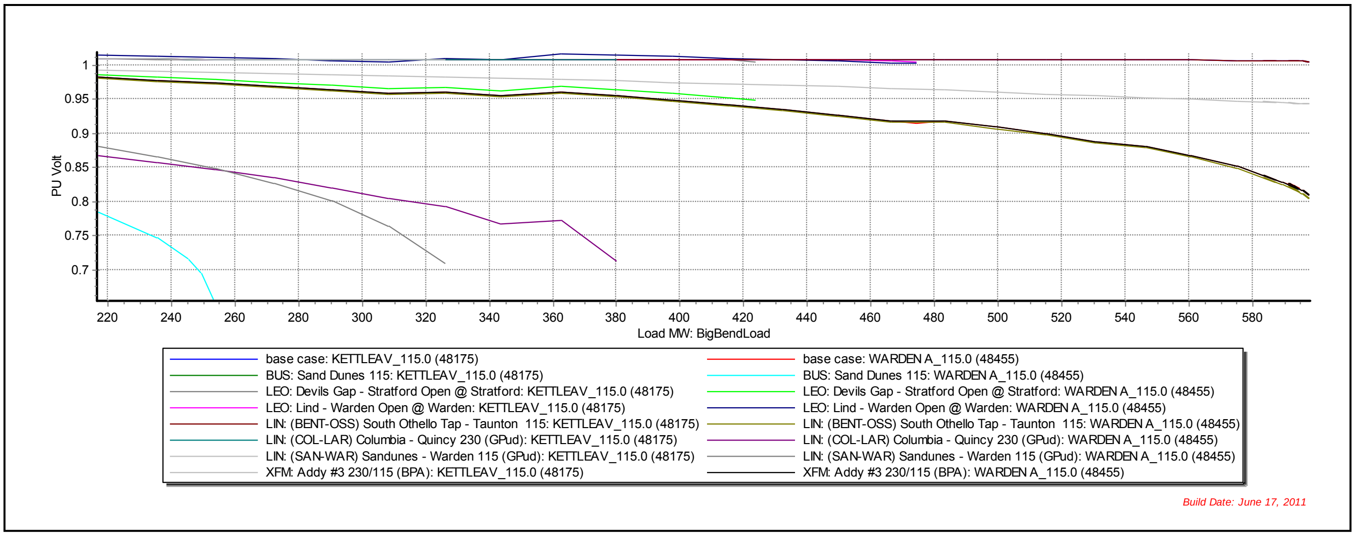


FIGURE 5-2: LOAD RAMP PV CURVE RESULTS FOR CRITICAL BUSSES.

5.2 QV ANALYSIS

5.2.1 Methodology

Using the results from the PV analysis, a set of critical busses can be determined. All critical busses and 115 kV busses of 230/115 kV transformers are studied in the QV analysis. All bus voltages in the Big Bend Area are monitored as the reactive demand at the bus under study is varied. This process is repeated for a set of contingencies depicting one or more transmission outages and for the remaining busses to be studied. LTC and switched shunts were disabled to provide a post-transient response prior to operator intervention. The reactive power margin (RPM) can be accessed from the results of the QV analysis. RPM is defined as the negative of the value of the reactive demand at the minimum point of the QV curve.

5.2.2 Results

The QV analysis showed there is adequate reactive power margin for the 115 kV source busses and critical busses in the Big Bend Area. Table 5-1 lists the reactive margin with the system in normal operating configuration. Table 5-2 and Table 5-3 show the results of the worst performing contingency for each bus analyzed.

The smallest reactive margin at the critical busses analyzed occurred at the Lind 115 kV bus with a value of 53 MVAr for the line end open scenario on the Lind Warden 115 kV Transmission Line open at Warden Substation.

Bus Name	Nom kV	Contingency Scenario	V at Q0	Q0	Qinj_0	V at Qmin	Qmin
KETTLEAV	115	BASECASE	1.01	0	0.0	0.62	-218.8
LIND	115	BASECASE	0.94	0	0.0	0.52	-89.5
OTHELOSS	115	BASECASE	0.98	0	21.5	0.56	-242.1
STRATFRD	115	BASECASE	1.00	0	0.0	0.58	-232.9
WARDEN A	115	BASECASE	0.98	0	0.0	0.56	-281.0

TABLE 5-1: CATEGORY A QV ANALYSIS RESULTS FOR 5 YEAR HORIZON.

Bus Name	Nom kV	Contingency Scenario	V at Q0	Q0	Qinj_0	V at Qmin	Qmin
KETTLEAV	115	LEO: COLVILLE BPA - KETTLE FALLS OPEN @ COLVILLE BPA (BPA)	1.01	0	0.0	0.59	-103.2
LIND	115	LEO: LIND - WARDEN OPEN @ WARDEN	0.89	0	0.0	0.53	-53.4
OTHELOSS	115	LIN: (SAN-WAR) SANDUNES - WARDEN 115 (GPUD)	0.94	0	19.8	0.55	-134.9
STRATFRD	115	LIN: (COL-QUI) COLUMBIA-QUINCY 230 (GPUD)	0.93	0	0.0	0.57	-148.4
WARDEN A	115	LIN: (SAN-WAR) SANDUNES - WARDEN 115 (GPUD)	0.94	0	0.0	0.58	-135.4

TABLE 5-2: CATEGORY B QV ANALYSIS RESULTS FOR 5 YEAR HORIZON.

Bus Name	Nom kV	Contingency Scenario	V at Q0	Q0	Qinj_0	V at Qmin	Qmin
KETTLEAV	115	BUS: ADDY 115	0.98	0	0.0	0.62	-45.0
LIND	115	BUS: SAND DUNES 115	0.86	0	0.0	0.50	-50.0
OTHELOSS	115	BUS: SAND DUNES 115	0.92	0	18.8	0.56	-111.5
STRATFRD	115	BUS: SAND DUNES 115	0.98	0	0.0	0.56	-199.5
WARDEN A	115	BUS: SAND DUNES 115	0.91	0	0.0	0.58	-108.5

TABLE 5-3: CATEGORY C QV ANALYSIS RESULTS FOR 5 YEAR HORIZON.

6 SHORT CIRCUIT ANALYSIS

7 DYNAMIC STABILITY ANALYSIS

7.1 STUDY METHODOLOGY

Transient stability analysis is commonly employed in the study of power system stability to reveal the total "system trajectory" following a disturbance.

Standard WECC, NERC and Avista requirements for disturbance performance were used to evaluate the results of dynamic stability analysis simulations. These requirements are as follows for Category B contingencies:

- Maximum allowable transient voltage dip of 25 percent at load busses or 30 percent at non-load busses.
- Maximum allowable transient voltage dip not to exceed 20 percent for more than 20 cycles at load busses.
- Minimum allowable frequency of 59.6 Hz for 6 cycles or more at load busses.
- Maximum allowable post-transient voltage deviation of 5 percent from pre-disturbance voltage.

The WECC/NERC voltage performance criteria are illustrated in Figure 7-1. A more detailed explanation and further information can be referenced in "*TPL – (001 thru 004) – WECC – 1 – CR – System Performance Criteria*".

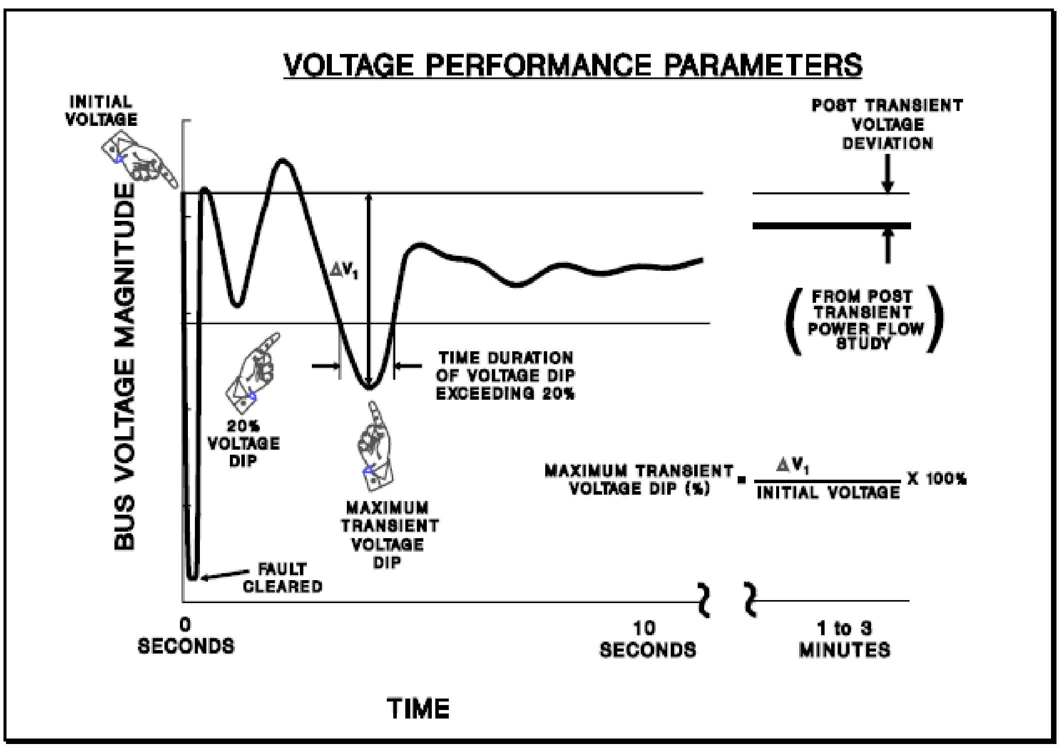


FIGURE 7-1: WECC/NERC VOLTAGE PERFORMANCE CRITERIA AND PARAMETERS.

Avista's System Planning Group uses GE PSDS software to perform transient stability simulations. The dynamic stability simulation module DYTOOLS is utilized to batch process multiple contingency scenarios in an efficient manner. Analysis of the results is conducted using a user written program to screen for criteria violations. A summary of violations is produced as well as individual plot files for each simulation performed.

Past studies have shown that transient stability on Avista's system is influenced by Western Montana Hydro, West of Hatwai flows, Northwest to Idaho flows, and Montana to the Northwest flows. As these three transfer paths can be heavily loaded during light load hours, the light load case is the most stressed. Avista's System Planning Group presently analyzes the four seasonal cases described in Subsection 0. The following are issues observed which should be addressed.

7.2 SINGLE CONTINGENCY ISSUES (N-1): NERC CATEGORY B

7.2.1 Kettle Falls Out-Of-Step

The Kettle Falls thermal generation was observed going out of step for a three phase fault, close in to Addy, on the Kettle Falls –Addy 115 kV Transmission Line with time delayed clearing. Out of Step relay protection is in place to clear the generation for this outage. Figure 7-2 shows the impacts to the area without the Out of Step relay protection at the Kettle Falls generator.

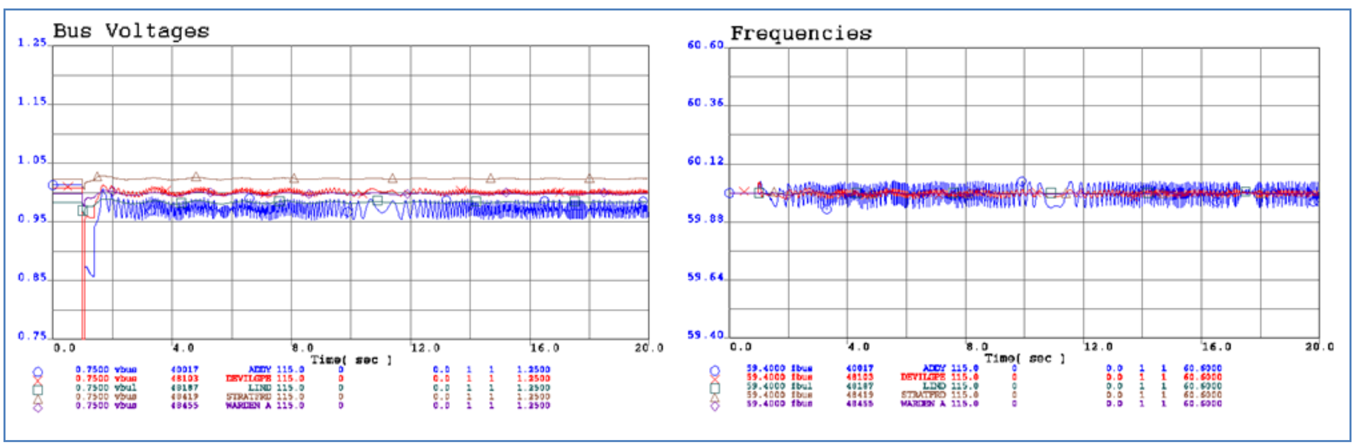


FIGURE 7-2: AREA IMPACT FROM KETTLE FALLS GOING OUT OF STEP

There are no further N-1 future reliability and load-service requirements discovered during the Process in the Big Bend Area.

7.3 MULTIPLE CONTINGENCY ISSUES: NERC CATEGORY C

There are no multiple contingency future reliability and load-service requirements discovered during the Process in the Big Bend Area.

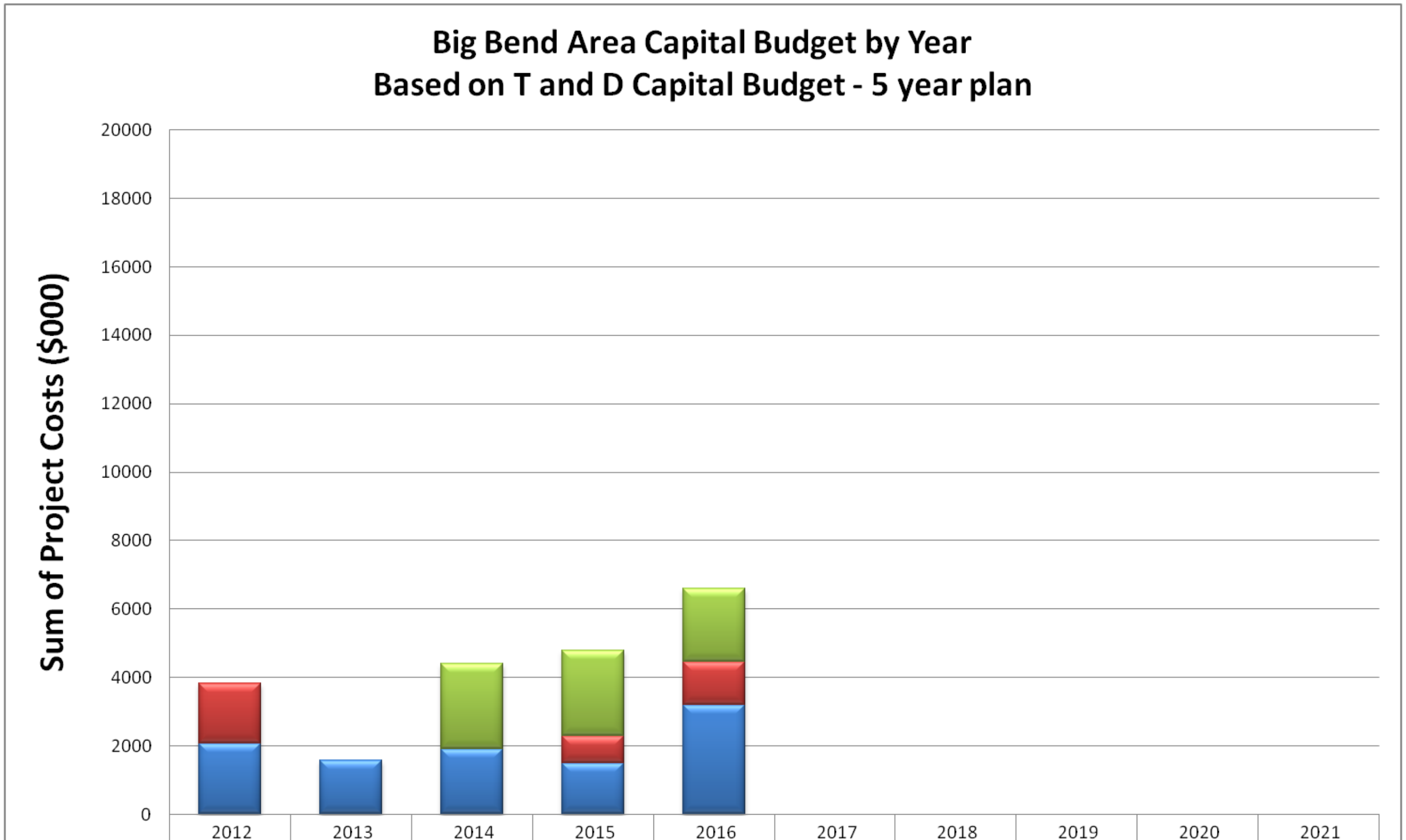
8 RECOMMENDED PROJECT PRIORITIZATION AND SCHEDULE

Most of the projects identified in Section 4 are scheduled and budgeted in Table 8-1 below. Some projects have required in service dates earlier than those identified in this Planning Assessment but due to budget, construction and/or operational schedule it is understood that some issues cannot be mitigated in the desired timeframe. This report suggests obtainable project schedules to represent a realistic planning approach.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
System Planning Projects	**$ 1,750,000**		**$ 2,500,000**	**$ 2,500,000**	**$ 2,000,000**						**$ 8,750,000**
TPL-001, N-0	**$ 1,000,000**										**$ 1,000,000**
Lind Capacitor Project	**$ 1,000,000**										**$ 1,000,000**
ER: 2481 - System - Replace/Install Capacitor Banks	$ 1,000,000										$ 1,000,000
TPL-002, N-1	**$ 750,000**		**$ 2,500,000**	**$ 2,500,000**	**$ 2,000,000**						**$ 7,750,000**
Benton - Othello SS 115 Rebuild Project			**$ 2,500,000**	**$ 2,500,000**	**$ 2,000,000**						**$ 7,000,000**
ER: 2457 - Benton - Othello Switching Station 115 kV Reconductor			$ 2,500,000	$ 2,500,000	$ 2,000,000						$ 7,000,000
Odessa Capacitor Project	**$ 750,000**										**$ 750,000**
ER: 2481 - System - Replace/Install Capacitor Banks	$ 750,000										$ 750,000
Other Projects	**$ 2,069,672**	**$ 1,569,672**	**$ 1,915,000**	**$ 2,300,000**	**$ 4,600,000**						**$ 12,454,344**
(blank)	**$ 2,069,672**	**$ 1,569,672**	**$ 1,915,000**	**$ 2,300,000**	**$ 4,600,000**						**$ 12,454,344**
Driven by Distribution Eng.	**$ 2,069,672**	**$ 1,569,672**	**$ 1,315,000**	**$ 2,300,000**	**$ 4,600,000**						**$ 11,854,344**
ER: 1006 - Power Transformers-Distribution (incl sales tax)					$ 350,000						$ 350,000
ER: 2301 - Tribal Settlement & Permits	$ 119,672	$ 119,672									$ 239,344
ER: 2325 - Bruce Siding 115 Sub-Construct 10 MVA Sub				$ 50,000							$ 50,000
ER: 2365 - Spirit 115 Sub- Incr Xfmr Capacity	$ 250,000	$ 250,000									$ 500,000
ER: 2414 - System - Dist Reliability - Improve Worst Feeders	$ 550,000	$ 500,000	$ 750,000	$ 825,000	$ 900,000						$ 3,525,000
ER: 2459 - 49° North - 115-21 kV Feeder					$ 2,550,000						$ 2,550,000
ER: 2514 - Distribution - Spokane NorthWest	$ 1,150,000	$ 700,000	$ 565,000	$ 625,000	$ 800,000						$ 3,840,000
ER: NEW122 - Gifford - Add 115-13 kV XFMR/FDR				$ 800,000							$ 800,000
Driven by Operations											
ER: 2293 - System-SCADA II											
Driven by Substation Eng.			**$ 600,000**								**$ 600,000**
ER: 2289 - Harrington 115 Sub - Convert to 13 kV			$ 600,000								$ 600,000
ER: 2336 - System - Replace Dist Power Xfmrs											
ER: 2449 - System - Replace Substation Air Switches											
ER: 2493 - System - Replace/Install Voltage Regulators											
Grand Total	**$ 3,819,672**	**$ 1,569,672**	**$ 4,415,000**	**$ 4,800,000**	**$ 6,600,000**						**$ 21,204,344**

TABLE 8-1: RECOMMENDED PROJECT PRIORITIZATION AND SCHEDULE.

Figure 8-1 provides a graphical view of the capital budget for the Big Bend Area as presented in Table 8-1. The budgeted amounts are categorized in columns by the group or entity responsible for executing the projects.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Grand Total	3820	1570	4415	4800	6600	0	0	0	0	0
Transmission	0	0	2500	2500	2150	0	0	0	0	0
Substation	1750	0	0	800	1250	0	0	0	0	0
Distribution	2070	1570	1915	1500	3200	0	0	0	0	0

FIGURE 8-1: BIG BEND AREA CAPITAL BUDGET BY YEAR.

9 POINT OF CONTACT

A Point of Contact for questions regarding the Planning Assessment and the projects described within it has been designated. Please contact the party named below for any questions:

Kenneth Dillon
Contracts Engineer, Transmission Services
PO Box 3727
Spokane, WA 99220
kenny.dillon@avistacorp.com
(509) 495-4436

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Appendix A - Transmission Map

Redacted per CEII requirements

Appendix B - System One Line Drawing

Redacted per CEII requirements

Appendix C - System Power Flow Plots

2016 Heavy Winter

2016 Heavy Summer, Low Hydro

2021 Heavy Winter

2021 Heavy Summer, Low Hydro

Redacted per CEII requirements

Appendix D - Power Flow Violation Summary

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Redacted per CEII requirements

Appendix E - Transient Stability Results

The following tables provide the results from a user written program which analyzes the transient stability simulations performed. Due to the number of simulation performed, plots of the results or detailed analysis results are not included in this Planning Assessment but can be provided upon request.

Redacted per CEII requirements

Appendix B - 2011 Coeur d’Alene Planning Assessment

Coeur d'Alene Area

2011 PLANNING ASSESSMENT

TRANSMISSION PLANNING

Prepared by John Gross

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Coeur d'Alene Area

2011 PLANNING ASSESSMENT

Date Completed: September 30, 2011

Prepared By: John Gross

The signature below indicates approval by the Director of System Planning. This Planning Assessment has been conducted with due diligence and has been reviewed and accepted by the Interested Stakeholders. This approval certifies this Planning Assessment as an adequate transmission planning approach for the area of interest.

Sept 30, 2011

Scott Waples Director, System Planning — Date

Version History

Version	Version Date	Action	Change Tracking	Reviewed By
A	29 June 2011	Preliminary Draft	New Document	J. Gross
B	25 July 2011	Draft for Comment	Planning Group Review	J. Gross
C	26 Aug 2011	Final Draft for Consideration	Comments and reorganized	J. Gross
0	30 Sept 2011	Final Report	Eng & Ops Input	J. Gross

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TABLE OF CONTENTS

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Coeur d’Alene Area

2011 PLANNING ASSESSMENT

1 EXECUTIVE SUMMARY

The Avista Coeur d’Alene Area is located primarily in Kootenai, Benewah, Bonner, and Shoshone Counties in the state of Idaho and Sanders County in the state of Montana. The geographic features, and therefore the characterization of the Transmission System, throughout the Coeur d’Alene Area vary greatly. The cities of Coeur d’Alene, Post Falls, and Sandpoint contain the majority of the Area’s load and the remaining load can be categorized as rural and low density. The Transmission System consists of several major elements: a 500 kV source at the Bonneville Power Administration’s (BPA) Hot Springs Substation, a 230 kV backbone system which provides energy transfer capacity from local hydro generation resources as well as sources to the Area, and the underlying 115 kV transmission lines which serve the local loads.

Load growth in the Coeur d’Alene Area is projected to be 2.1% for summer and 2.2% for winter based on ten years of historic load growth data. Total anticipated load not including Transmission System losses for peak summer 2012 is 357 MW and 440 MW for peak winter 2012. Total installed distribution (i.e. 115/13.8 or 115/21 kV) transformation capacity in the Coeur d’Alene Area is 764 MVA based on transformer nameplate ratings.

This Planning Assessment identifies any reliability impacts identified on Avista’s Transmission System, and provides a list of the Single System Projects proposed to mitigate those issues. Such reliability impacts were identified by performing technical studies, which included powerflow, transient stability, short circuit, and voltage collapse analysis. **For Single System Projects not identified in previously completed Planning Assessments, a separate Corrective Action Plan (detailed project study) will be conducted as necessary to determine the technically superior project(s) to be carried forward into the Avista capital budgeting process.**

A summary of the Single System Projects are provided in the following list. Some projects have required in service dates earlier than those identified in this Planning Assessment but due to budget, construction and/or operational schedule it is understood that some issues cannot be mitigated in the desired timeframe. This Planning Assessment suggests obtainable project schedules to represent a realistic planning approach with the appropriate budgetary support. **All projects listed here (or superior alternatives) must be completed within the ten year planning horizon.**

- Loop the Avista Boulder – Rathdrum 230 kV Transmission Line into the BPA Lancaster Substation; scheduled for completion in 2013,

- Upgrade 115 kV transmission line protection systems in the Coeur d'Alene Area to communication aided schemes; scheduled for completed in 2014,
- Reconductor the existing Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines with conductor capable of providing a minimum of 150 MVA thermal capacity at 40°C ambient temperature; budgeted to be completed in 2016,
- Reconductor the existing Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line with conductor capable of providing a minimum of 150 MVA thermal capacity at 40°C ambient temperature; budgeted to be completed in 2016 (reconstructing the transmission line with 230 kV capability will be analyzed),
- Install two steps of 13.4 MVAr capacitor bank (26.8 MVAr total) at Spirit Lake Substation; budgeted to be completed in 2017,
- Install 13.4 MVAr capacitor bank at O'gara Substation; budgeted to be completed in 2020.

The total cost of the proposed Single System Projects based on Avista's System Planning Group's analysis of the Coeur d'Alene Area Transmission System is expected to be approximately $36 million. Following is a list of planned system modifications developed by Avista's Engineering Department. Planned system modifications in the Coeur d'Alene Area driven by Avista's Engineering Department is expected to be approximately $28 million.

- Replace Pine Creek 230/115 kV #1 Autotransformer; procurement of transformer in 2012,
- Rebuild the Blue Creek Substation; budgeted to be completed in 2012,
- Increase transformation capacity at the Lucky Friday Substation; budgeted to be completed in 2012,
- Reconstruct the existing Noxon Rapids 230 kV Switchyard; budgeted to be completed in 2016,
- Rebuild portions of the Burke – Thompson A &B and Burke – Pine Creek #3 & #4 Transmission Lines; budgeted to be completed in 2016,
- Install distribution facilities at the existing Bronx Switching Station; planned in the ten year planning horizon,
- Construct a new Carlin Bay Substation and associated transmission and distribution facilities; planned in the ten year planning horizon.

Further analysis will be conducted to determine when additional 230/115 kV transformation is required in the Coeur d'Alene sub-area. Though a new 230 kV substation is not presently required within the ten year planning horizon, strategic acquisition of right-of-way and substation property ahead of further urban development should be considered. A long range transmission plan is necessary to begin preliminary property acquisition investigation.

The proposed reconductor and reconstruction of the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line may present an opportunity to construct the transmission line with the ability to upgrade to or add a 230 kV transmission line to the right-of-way in the future. With limited routing options for a future 230 kV transmission line into the Coeur d'Alene sub-area from the east, utilizing the existing 115 kV right-of-way may be a feasible alternative. Constructing a 230 kV transmission line from Pine Creek Substation to Rathdrum Substation would provide potential negotiation alternatives when the existing fifty year agreement with the Coeur d'Alene Tribe for the Benewah – Pine Creek 230 kV Transmission Line right-of-way across Tribe owned land expires in 2058. Further justification for a 230 kV transmission line may include increased transfer capability and potential load service benefits. Detailed analysis of additional cost and timing of adding 230 kV transmission line facilities will be evaluated in the production of the Corrective Action Plan developed to justify reconductoring of the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line. Preliminary estimated additional cost for reconstructing the 115 kV transmission line with 230 kV structures is $7 to 9 million.

2 GENERAL SYSTEM DESCRIPTION

The Avista Coeur d'Alene Area is located primarily in Kootenai, Benewah, Bonner, and Shoshone Counties in the state of Idaho and Sanders County in the state of Montana. The geographic features, and therefore the characterization of the Transmission System, throughout the Coeur d'Alene Area vary greatly. The cities of Coeur d'Alene, Post Falls, and Sandpoint contain the majority of the Area's load and the remaining load can be categorized as rural and low density. The Transmission System consists of several major elements: a 500 kV source at the Bonneville Power Administration's (BPA) Hot Springs Substation, a 230 kV backbone system which provides energy transfer capacity from local hydro generation resources as well as sources to the Area, and the underlying 115 kV transmission lines which serve the local loads.

The major sources to the Coeur d'Alene Area include hydro generation resources located within the Area or near the eastern edge in Western Montana, natural gas fired combustion turbines and combined cycle combustion turbines in Northern Idaho, the 500/230 kV transformer at Hot Springs Substation in Western Montana, and local hydro generation resources on the Spokane River. Avista owns two 230 kV transmission lines, the Noxon – Pine Creek and Cabinet Gorge – Rathdrum 230 kV Transmission Lines, which connect the Clark Fork Hydro Complex located in Northern Idaho and Western Montana to 230 kV stations in the Coeur d'Alene Area. In general, the remaining sources are connected to the Coeur d'Alene Area through the BPA Transmission System.

The Western Electricity Coordinating Council (WECC) rated path Montana to Northwest (Path 8) borders the eastern edge of the Coeur d'Alene Area. Avista owns approximately the first four miles of the Burke – Thompson Falls A & B 115 kV Transmission Lines from the Burke Substation. These two transmission lines are included in the Montana to Northwest path definition. The BPA and Northwestern Energy own the remaining transmission facilities which comprise the Montana to Northwest path.

Local generation facilities within the Coeur d'Alene Area include the following:

Albeni Falls HED	Unit 1 – 3 @ 16 MW each	Army Corps of Engineers
Cabinet Gorge HED	Unit 1 & 4 @ 65 MW each Unit 2 & 3 @ 78 MW each	Avista
Noxon Rapids HED	Unit 1 -4 @ 115 MW each Unit 5 @ 123 MW	Avista
Lancaster CCCT	Units 1 & 2 @ 290 MW total, Winter 249 MW total, Summer	Cogentrix Energy
Plummer	Unit 1 @ 5 MW	Stimson Lumber

Post Falls HED	Unit 1-5 @ 2.8 MW each Unit 6 @ 4 MW	Avista
Rathdrum CT	Unit 1 & 2@ 89 MW each, Winter 70 MW each, Summer	Avista

There is presently one generation interconnection request within the Coeur d'Alene Area. Large Generator Interconnection Request #26 is for an additional 42 MW to the existing Noxon Rapids HED. The requested interconnection is for 14 MW each year from 2010 to 2012. This project was not included in the study work conducted for this Planning Assessment.

The 115 kV Transmission System in the Coeur d'Alene Area is primarily operated in a networked configuration. Other areas of Avista's Transmission System operate with normally open points referred to as "star points". A star point is used to minimize power flow to mitigate overloads on the 115 kV system in the event of an outage on the overlying 230 kV Transmission System, as well as reducing overall system losses in the area. Operating in a "star" configuration also reduces exposure to loads served by long transmission lines. In the Coeur d'Alene Area, star points switches can be operated open or closed based on outages, specific flow conditions, or due to operational constraints.

Avista's communication system in the Coeur d'Alene Area includes a wide variety of technologies including: fiber optic cable, analog and digital microwave, radio, and power line carrier. Local protection schemes, such as the permissive overreaching transfer trip (POTT) schemes used on 115 kV transmission lines, utilize the local area fiber network established by the former Avista Corporation affiliate Avista Communications. Microwave and direct (station to station) fiber are used for the 230 kV transmission line protection schemes.

The Coeur d'Alene Area is divided into sub-areas based on their geographical nature and transmission configuration. These sub-areas include the following:

Coeur d'Alene: This sub-area is sourced primarily by Rathdrum Substation. Non-Avista load serving entity, Kootenai Electric Cooperative, provides retail service in this sub-area. Avista provides transmission service to Kootenai Electric Cooperative at nine separate substations: Appleway, Hayden, Coeur d'Alene 15th St., Rathdrum, Prairie, Pleasant View, Dower Road, Scarcello, and Athol Substations. Avista's substations providing load service to the sub-area include Pleasant View, Idaho Road, Rathdrum, Huetter, Hern, Prairie, Post Falls, Appleway, Avondale, Dalton, Coeur d'Alene 15th St. and Blue Creek Substations. There are three 115 kV transmission lines providing local load service to the sub-area: Ramsey – Rathdrum #1 & #2 and Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Lines. The Otis Orchards – Post Falls and Boulder – Rathdrum 115 kV Transmission Lines provide load service to the western edges of the sub-area and the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line provides an additional source to the sub-area if the normally open point is closed. The Rathdrum CT and Lancaster CCCT Generation Projects are located in the Coeur d'Alene sub-area and are interconnected to the Rathdrum and Lancaster Substations respectively.

Sandpoint: This sub-area is sourced primarily by the Albeni Falls, Sand Creek, and Cabinet Gorge Substations. The Sandpoint sub-area is closely surrounded by BPA's Transmission System and BPA customers including Northern Lights Electric Company. This Planning Assessment only analyzes Avista's portion of the Transmission System, therefore BPA's facilities in the sub-area are purposely excluded. For this analysis, Avista is considered to be the only load serving entity providing retail service in the Sandpoint sub-area. Avista's substations providing load service to the sub-area include Cabinet Gorge, Cabinet, Clark Fork, Oden, Sandpoint, Priest River, and Sagle Substations. The Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines provide local load service to the sub-area. Avista's Sagle Substation is connected to Northern Lights Electric Co-operative's Sandpoint – Dufort 115 kV Transmission Line Tap off BPA's Albeni Falls – Sand Creek 115 kV Transmission Line at BPA's Sandpoint Substation. Avista's Priest River Substation is connected to BPA's Albeni Falls – Sand Creek 115 kV Transmission Line.

Silver Valley: This sub-area is sourced primarily by the Burke and Pine Creek Substations. Avista is the only load serving entity providing retail service in the Silver Valley sub-area. Avista's substations providing load service to the sub-area include Mission, Pine Creek, Bunker Hill, Big Creek, Osburn, Wallace, and Lucky Friday Substations. The Burke – Pine Creek #3 & #4 115 kV Transmission Lines provide local load service to the sub-area.

Western Montana Hydro Complex: The Clark Fork hydro complex consisting of the Cabinet Gorge and Noxon Rapids HED are located within the Coeur d'Alene Area and are included in the definition of the Western Montana Hydro (WMH) Complex. The Libby and Hungry Horse HED connected to the BPA Transmission System make up the remaining portion of WMH Complex. The present operational limit of the WMH Complex is 1750 MW; Avista's contractual capacity is 850 MW. Avista has installed a line loss detection remedial action scheme (RAS) on the 230 kV transmission lines in the Area which reduces Avista generation at Noxon Rapids and/or Cabinet Gorge depending on the generation output levels and outages which might occur. The Clark Fork RAS, in combination with BPA's Western Montana RAS, significantly increases the level of coincident generation possible in the WMH Complex as well as for the Colstrip Coal Plant in Montana.

Load growth in the Coeur d'Alene Area is projected to be 2.1% for summer and 2.2% for winter based on ten years of historic load growth data. Total anticipated load not including Transmission System losses for peak summer 2012 is 357 MW and 440 MW for peak winter 2012. Total installed distribution (i.e. 115/13.8 or 115/21 kV) transformation capacity in the Coeur d'Alene Area is 764 MVA based on transformer nameplate ratings.

3 DEVELOPMENT OF PLANNING ASSESSMENT

3.1 LOCAL PLANNING PROCESS

The development of this Planning Assessments follows the local transmission planning process (Process) provided in *Attachment K, Part III – The Avista Local Transmission Planning Process* of Avista Corporation's Fourth Revised Volume No. 8 of the Open Access Transmission Tariff ("OATT"). The Process is open to all Interested Stakeholders, including but not limited to, all Transmission Customers, interconnection customers, and state authorities. Avista held a Study Development Meeting during the second quarter of 2011 providing participants an opportunity to provide comments for data gathering, initial assumptions and input into the study development. All comments received at the Study Development Meeting, or during the 30 days following, were incorporated into the Planning Assessment.

The purpose of the Process is to identify any Single System Projects that are needed to mitigate future reliability and load-service requirements for Avista's Transmission System. This Planning Assessment identifies any reliability impacts identified on Avista's Transmission System, and provides a list of the Single System Projects proposed to mitigate those issues. Such reliability impacts were identified by performing technical studies, which included powerflow, transient stability, short circuit, and voltage collapse studies. **For Single System Projects not identified in previously completed Planning Assessment, a separate Corrective Action Plan (detailed project study) will be conducted as necessary to determine the technically superior project(s) to be carried forward into the Avista capital budgeting process.**

3.2 TRANSMISSION PLANNING CRITERIA

The transmission planning reliability criteria used in evaluating the performance of the transmission system is the present North American Electric Reliability Corporation (NERC) Reliability Standards and WECC regional reliability criteria including the following:

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

3.3 TRANSMISSION PLANNING ASSUMPTIONS

The following assumptions have been used in the Process for performing technical studies. The assumptions are made upon the experience of Avista's System Planning Group and to comply with NERC Reliability Standards.

3.3.1 Base Case Development

Avista's System Planning Group develops a set of base cases annually using WECC approved base cases, applying steady state and dynamic data modifications as required to represent desired scenarios. Four seasonal scenarios are developed which represent bookends that have been historically established through previous technical studies. The scenarios developed include the following:

1. Heavy Summer with High Local Hydro Generation (Heavy Summer, High Hydro Case)

   This is the typical summer peak scenario where the Avista Balancing Authority Area load is near peak and the local hydro generation is at a typical mid-summer output. This scenario represents Avista's heavy summer loading with moderate transfers into Avista's Balancing Authority Area. This scenario is limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the System is near capacity.

2. Heavy Summer with Low Local Hydro Generation (Heavy Summer, Low Hydro Case)

   This is the typical summer peak scenario where the Avista Balancing Authority Area load is near peak and the local hydro generation has a low output (a typical late summer output). This scenario plays a dual role, in that it represents both Avista's heavy summer loading scenario along with the sensitivity of significant transfers into Avista Balancing Authority Area to supplement the low hydro generation. This scenario is limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the System is near capacity.

3. Heavy Winter Case

   This is the typical winter peak scenario where the Avista Balancing Authority Area load is heavy but the lower ambient temperature increases the operating limits of the various elements of the Transmission System. Local hydro generation is at a moderate level and there are significant transfers into Avista's Balancing Authority Area from regional thermal resources.

4. Light Summer with High West of Hatwai Flows (High Transfer Case)

   During light summer (night time loading) with high Western Montana Hydro and high Montana thermal generation, the WECC rated path "West of Hatwai" (WECC Path #6) reaches its heaviest loading. During this scenario, portions of the Transmission System are nearing their stability limits. These limits define some of the operating constraints for the region and also establish some of the arming levels for Remedial Action Schemes (RAS). This scenario is also limited by the summer thermal limits on various elements of the transmission system, which helps to define where the system is near capacity.

These base cases are developed to represent both the five and ten year planning horizon. A detailed summary of specific flows and loading levels for the base cases used in the 2011 Planning Assessments can be viewed in the interoffice memorandum SP-2011-03 – 2011 Planning Cases Summary Data.

3.3.2 Load Forecast

Load forecasts for Network Customers and Point-to-Point Customers were requested at the Study Development Meeting. The BPA submitted its forecast load information as a Network Customer to Avista for inclusion in the technical studies. Avista's System Planning Group incorporated forecast load data for its Load Serving Entity ("Avista LSE") into the technical studies.

3.3.3 Planned Transmission Facilities

No planned transmission expansion project facilities are included in the bases cases used in technical studies performed for the Planning Assessments. During previous Planning Assessments inclusion of non-committed planned transmission facilities has incorrectly hidden potential reliability and load-service requirements. Subsequently, a Corrective Action Plan was not developed as required by the Process.

3.3.4 Planned Generation Facilities

Only potential generation projects in the Avista Interconnection Request queue that have executed Interconnection Agreements are modeled (with corresponding upgrades) in the base cases for technical studies.

The 2011 Planning Assessments did not include any potential generation in the technical studies.

3.3.5 Contingencies

The contingencies evaluated for powerflow and transient stability technical studies are a standard contingency set used by Avista's System Planning Group, reviewed and updated annually. Documentation on the contingency set is provided by System Planning Policy and Procedure SP-PP-06 Contingency Analysis. The standard contingency set includes outages in Avista's Transmission System as well as outages in adjacent Planning Coordinator and Transmission Planner Areas.

3.4 ACCESS TO PLANNING DATA

The base cases used in the Process can be provided within 10 calendar days, via email or other media, to any WECC member that makes a request. Non-WECC members will be required to sign a confidentiality agreement with the WECC before any base cases can be shared. Once the WECC confirms a confidentiality agreement has been signed, the requested base case(s) shall be provided within 10 calendar days. Any additional information needed to replicate the technical study results of the Process can be provided, upon written request.

3.5 IDENTIFICATION OF ANALYTICAL TOOLS

The following Analytical Tools were used to perform technical studies:

- PowerWorld Simulator Software, Version 15
    - PowerWorld Simulator is an interactive power systems simulation package designed to simulate high voltage power systems operation on a time frame ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses using mathematical calculations based on system impedances, load levels and generation output. PowerWorld provides the user with a variety of sophisticated study tools such as an automated contingency processor, an Available Transfer Capability (ATC) tool, an Optimal Power Flow tools, various voltage stability tools (i.e. PV and QV tools), and a Transient Stability Analysis tool.
- GE Positive Sequence Load Flow, Version 17.05
    - The GE Positive Sequence Load Flow (PSLF) software suite is a package of programs for studying power system transmission networks and equipment performance in both the steady-state and dynamic environments.
- ASPEN OneLiner Software Build 2007.11.7 Group-1
    - ASPEN OneLiner is a PC-based short circuit and relay coordination program for relay engineers. OneLiner is an interactive productivity tool allowing the engineer to accurately model the transmission system, perform fault analysis by simulating all classical fault types, graphically plot fault solution and relay coordination curves and validate relay settings through relay models and automatic checking module.

4 SINGLE SYSTEM PROJECTS AND CORRECTIVE ACTION PLANS

4.1 PLANNED SYSTEM MODIFICATIONS

The following sections describe projects to either enhance the existing Coeur d'Alene Area system or mitigate deficiencies discovered during the course of the Process. These items should be addressed as construction schedules and annual budgets permit:

4.1.1 Noxon Rapids 230 kV Switchyard Rebuild

The existing Noxon Rapids 230 kV Switchyard has been identified to be in need of a rebuild due to the present age and condition of the equipment included in the station. The existing bus work is constructed as strain bus and configured as a single bus with a tie breaker separating the East and West buses. Presently the station is the interconnection point of the Noxon Rapids Hydro Electric Dam and a significant asset in the reliable operation of the Western Montana Hydro Complex. An unplanned outage caused by equipment failure or other means causes curtailment of the local generation facilities. Due to the significance of the station, a complete rebuild will require detailed coordination with Avista's resource department and neighboring utilities, primarily the BPA. Construction of the station as a double breaker double bus configuration is proposed to begin in 2013.

4.1.2 Blue Creek Rebuild

The Blue Creek Substation is scheduled to be rebuilt in 2012. Rebuild of the station is necessary to accommodate the replacement of the 20 MVA distribution transformer. The station will be built as a green field substation adjacent to the existing station.

4.1.3 Big Creek Rebuild

The Big Creek Substation is a wood substation and has been identified by the Substation Engineering group to be rebuilt under the wood substation rebuild program. Construction should be planned in the five to ten year planning horizon. Coordination with other substation projects may allow the Big Creek Substation rebuild to be pushed forward into the five year planning horizon.

4.1.4 Appleway Rebuild

The existing Appleway Substation is presently undergoing a rebuild due to increased distribution capacity requirements and facility condition. The station consisted of 20 MVA and 30 MVA distribution transformers serving four Avista distribution feeders and one feeder for Kootenai Electric Cooperation. The station was comprised of wood structures some of which were damaged due to past fires. New construction consists adding two new Avista distribution feeders therefore requiring a total of two 30 MVA transformers. Kootenai Electric Cooperation has requested to no longer be served through the Appleway Substation. The rebuild also includes the addition of 115 kV circuit breakers and utilization of standard steel structures and other Substation Engineering standard design practices. The project is scheduled to be completed in 2011. The 115 kV circuit breaker functionality will not be operational until the remote terminals at Ramsey Switching Station and Rathdrum Substation are upgraded in 2012.

4.1.5 Pine Creek Transformer Replacement

The existing Pine Creek 230/115 kV #1 Autotransformer consists of a nominal 125 MVA, 230/115 kV transformer and a 115/115 kV voltage regulating transformer. The Substation Engineering Group has identified the need to replace these devices with a single 125 MVA autotransformer. The new transformer will be specified to match the Avista's present standard configuration. Procurement of the transformer is budgeted for 2012.

4.1.6 Burke – Pine Creek #3 & #4 Rebuild and Burke – Thompson Falls A& B 115 kV Transmission Line Rebuild

Reconstruction of the existing Burke – Pine Creek #3 & #4 and Burke – Thompson Falls A & B 115 kV Transmission Lines has been proposed. The work has been broken in the following phases:

Phase 1: Reconstruct approximately (4) miles (8 miles total) of Avista 115kV transmission facilities on the Burke – Thompson Falls A & B 115 kV Transmission Lines between Burke Substation and the Montana border (end of Avista ownership). Present conductor is a 556 ACSR "Dove" design. Based on ratings requirements, this may be replaced with a 795 ACSR "Drake" conductor (or other). Present construction consists of 45' H-frame structures on 300'-400' spans. Preliminary design calls for a single pole braced post with enough pole height to accommodate snow accumulations up to 20 feet. The existing facilities present a risk management liability, as well as a potential NERC "Alert" Line Ratings problem. Fiber optic communication requirements will need to be determined.

Phase 2: Reconstruct approximately (4) miles (8 miles total) of Avista 115kV transmission facilities on the Burke – Pine Creek #3 & #4 115 kV Transmission Lines between Big Creek Substation and a point immediately east of the retired Bunker Hill Mine smelter. Years of smelter atmospheric discharge has caused considerable corrosion and weathering to these down-wind structures. Present conductors are 397 ACSR "Ibis" and 250 19-strand copper designs. Based on ratings requirements, these will likely be replaced with another conductor design. Present construction consists of H-frame structures on 500'-1000' spans. Preliminary design calls for an "in-kind" H-frame replacement. A potential offset of costs exists if area developer follows through on relocation request. Relocation may result in switching to a single pole design based on topography issues. Fiber optic communication requirements will need to be determined.

Phase 3: Reconstruct approximately (5-6) miles of Avista 115kV transmission facilities on the Burke – Pine Creek #4 115 kV Transmission Line between Wallace Substation and Burke Substation. Onerous access makes the existing route very difficult to maintain the line originally constructed in 1941. Present conductor is 250 19-strand copper design. Based on ratings requirements, these may be replaced with another conductor design. Present construction consists of H-frame structures on 500'-800' spans. Preliminary design calls for a single pole braced-post toughened-glass I-string hybrid design compatible with difficult access/tree threat area. Fiber optic communication requirements will need to be determined.

4.1.7 Noxon – Hot Springs #2 230 kV Permitting

The existing settlement with the Confederated and Salish Kootenai Tribes on the ability to own and operate Avista's Noxon – Hot Springs #2 230 kV Transmission Line within the Flathead Reservation will expire in 2015. Efforts to renew Avista's existing permit will be pursued during 2012 to 2015. Presently, no feasible alternative has been established for a possible relocation of the transmission line.

4.1.8 Julia Street

The BPA entered into a Network Integration Transmission Service System Impact Study Agreement with Avista Corporation ("Avista") for a proposed Julia Street Substation 0.4 miles south east of Avista's Ramsey substation. The BPA has given a projected initial operating date of December, 2011. A study conducted by Avista's System Planning Group analyzed two Point of Delivery (POD) options as designated in the System Impact Study Agreement, agreed upon in correspondence received April 15. The study results show the favored POD for the proposed Julia Street Substation is a tap of the Ramsey – Rathdrum #2 115 kV Transmission Line. The Network Integration Transmission Service System Impact Study for Julia Street Substation conducted by Reuben Arts and Randy Spacek dated June 6, 2011 provides further detail on the proposed interconnection of Julia Street Substation.

4.1.9 Carlin Bay Substation

Forecasted load growth along the East side of Coeur d'Alene Lake is expected to cause the total load to exceed the capability of the existing 13.2 kV distribution system in the area. A new substation named Carlin Bay Substation has been proposed and property was purchased in 2010. Preliminary proposals include connecting the new substation to Avista's Transmission System by a 13 mile radial 115 kV transmission line to the existing O'gara Substation. Rebuilding the existing O'gara Substation to be a switching station is recommended to mitigate the reliability impact to the area by reducing the transmission line exposure distances. The project is presently budgeted in the ten year planning horizon but right-of-way acquisition should be pursued in the near term.

4.1.10 Bronx Substation

It has been proposed to add distribution facilities to the existing Bronx Switching Station to support load growth in the surrounding area. Distribution capacity at Bronx Switching Station will relieve loading on Sandpoint and Oden Substation distribution facilities allowing extra capacity to support load growth in Dover. The expansion of Bronx Switching Station may be coordinated with the rebuild of the Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines.

4.1.11 Lucky Friday Substation

The existing Lucky Friday Substation presently feeds the Lucky Friday Mine. Future growth at the mine including a new mining shaft will require increasing the existing 115 kV to 13.2 kV transformation capacity at Lucky Friday Substation. Presently the mine is supplied by a single 12 MVA transformer. Depending on the projected load growth, the existing transformer will be replaced with a 20 MVA or 30 MVA transformer. Further consideration to reliability and redundancy to the mine and also transferring load from Wallace Substation feeders to be normally supplied from Lucky Friday Substation may require an improved substation design.

4.1.12 Coeur d'Alene 115 kV Transmission Line Relay Upgrades

System studies have revealed sensitivity to Western Montana Hydro (WMH) Complex generation output and slow clearing 115 kV transmission faults in the Spokane and Coeur d'Alene Areas. WMH generation consists of Avista's Noxon Rapids and Cabinet Gorge hydroelectric dams, the U.S. Army Corps of Engineers' Libby hydroelectric dam, and the U.S. Bureau of Reclamation's Hungry Horse hydroelectric dam. The WMH output typically peaks in late spring and early summer due to water runoff conditions. Installation of protection systems which support high speed fault clearing on the Spokane / Coeur d'Alene 115 kV Transmission System significantly reduces the WMH sensitivity to 115 kV faults. This allows operation of the 115 kV Transmission System in a manner which supports high reliability to customers and offers flexibility during outage conditions.

The required communication infrastructure upgrades to implement communication aided tripping has been completed. The replacement of protection relays is still required at a number of substations before the communication aided tripping schemes can be utilized.

4.2 NORMAL SYSTEM CONDITIONS (N-0): NERC CATEGORY A

4.2.1 Lancaster Interconnection

Avista's Power Supply Group obtained ownership of the Power Purchase Agreement (PPA) for the output of the Lancaster Combined Cycle Combustion Turbine. The Lancaster Loop-in Project study authored by Tracy Rolstad in 2009 identifies the interconnection of the BPA's Lancaster Switching Station with Avista's Transmission System by looping the Boulder – Rathdrum 230 kV Transmission Line. Several benefits are gained by the interconnection including significant System performance improvement and contractually related matters associated with the PPA.

The 2010 Spokane Area Regional Assessment also identifies the execution of the Lancaster Interconnection as one of the required projects to mitigate the forecasted overloading of the Westside 230/115 kV Autotransformers. A Line and Load Interconnection Request has been submitted to the BPA. Presently the necessary studies are being conducted by the BPA to finalize the Line and Load Interconnection Request Facilities Study.

4.3 SINGLE CONTINGENCY ISSUES (N-1): NERC CATEGORY B

4.3.1 Bronx – Cabinet and Bronx – Sand Creek

The Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines exhibit thermal overloads for various single contingency issues in the Sandpoint sub-area. Outages causing thermal overloads include Libby 230/115 kV Transformer (see Figure 4-1), Cabinet – Rathdrum 230 kV Transmission Line (see Figure 4-2), and the Albeni Falls – Sand Creek 115 kV Transmission Line open at Albeni Falls Substation (see Figure 4-3). Low voltages are also observed for a line end open condition on the Bronx – Sand Creek 115 kV Transmission Line open at Sand Creek Substation (see Figure 4-4). Voltages of 0.903 pu (103.8 kV) at Sandpoint Substation during a heavy winter scenario in the ten year planning horizon limits the ability to restore service to Sandpoint Substation for a Bronx – Sand Creek 115 kV Transmission Line outage.

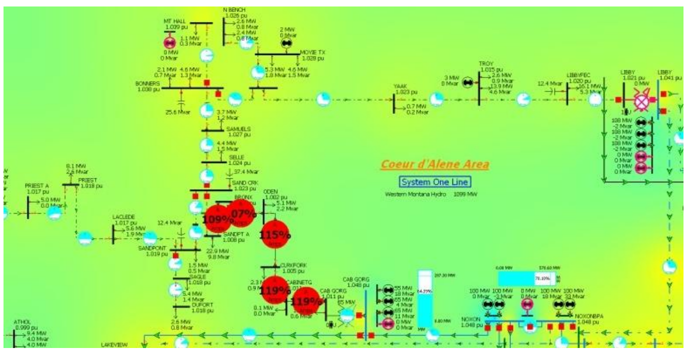


FIGURE 4-1: LIB XFM OUTAGE.

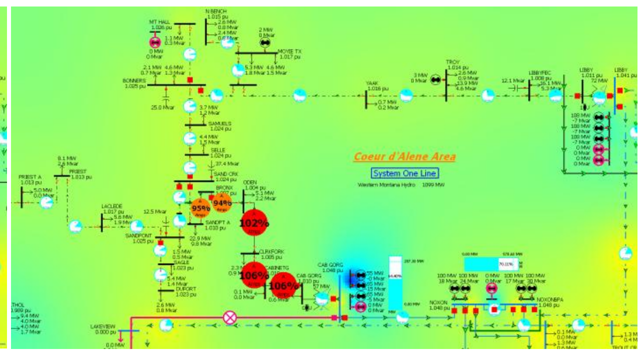


FIGURE 4-2: CAB-RAT 230 OUTAGE.

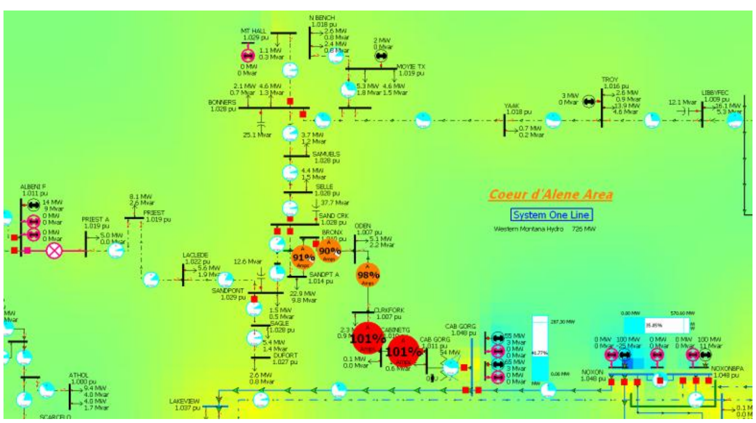


FIGURE 4-3: ALFL-SDCK LEO.

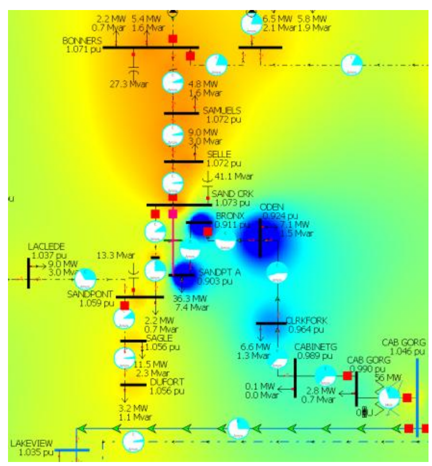


FIGURE 4-4: BRX-SPT OUTAGE.

Details of the issues and description of potential mitigation approaches are provided in System Planning memo SP-2010-10 date December 27, 2010 authored by Tracy Rolstad. The preferred mitigation alternative is to reconductor/rebuild the Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines with conductor capable of providing 150 MVA thermal capacity at

40°C ambient temperature. The issues observed on the Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines are presently operating issues as documented in the Avista 2011 Summer Operating Studies Report and therefore are TPL-002, R1 violations. Presently the mitigation project is budgeted to be started in 2011 and completed by 2016.

4.3.2 Coeur d'Alene – Rathdrum and Coeur d'Alene – Ramsey

Thermal overloads are observed on the Hayden – Rathdrum and Dalton – Hayden segments of the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line for the outage of the Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line (see Figure 4-5). The Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line also exhibits thermal overloads for the outage of the Hayden – Rathdrum segment of the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line (see Figure 4-6). During these single contingency configurations, the load at Hayden, Dalton, Coeur d'Alene 15th St., and Blue Creek Substations is being supplied by a single 115 kV transmission line. Present load forecasts yield loading levels of 106% and 120% of the existing facility ratings for the five and ten year planning horizons respectively during a heavy summer loading scenario with a single contingency condition.

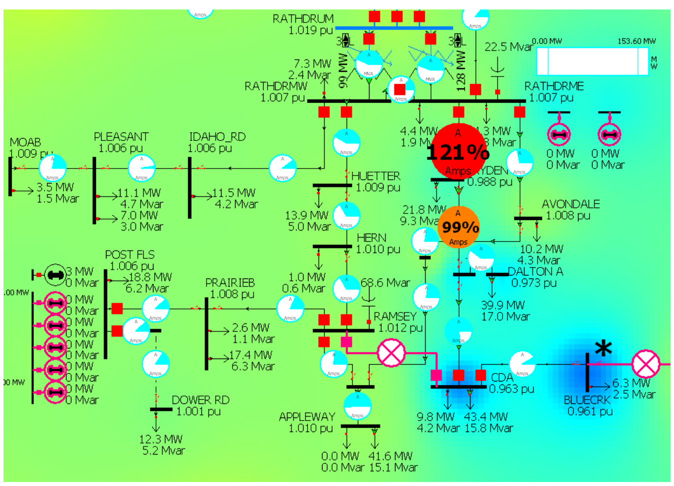


FIGURE 4-5: HAY-RAT 115 OUTAGE.

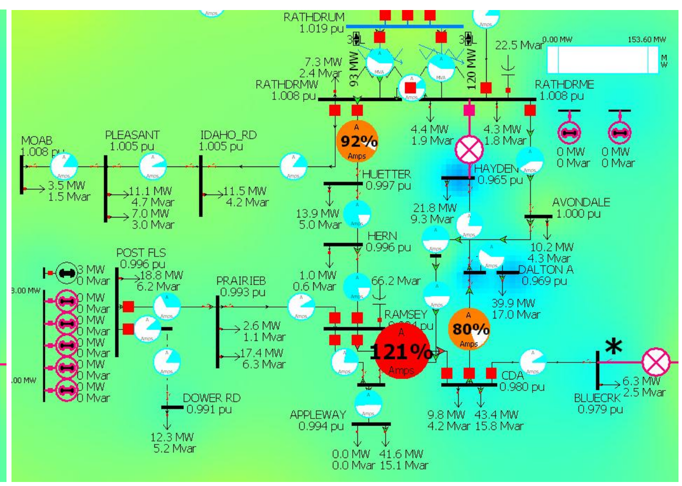


FIGURE 4-6: HAY-RAT 115 OUTAGE.

The following are possible alternatives to mitigate the potential thermal overload issue:

1. Do nothing – thermal overload of the Coeur d'Alene 15th St. – Ramsey and Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Lines will become worse with time. Violation of TPL-002, R2 will be observed without a Corrective Action Plan. Closing the normally open point on the Coeur d'Alene 15th St – Pine Creek 115 kV Transmission Line relieves the thermal overload. Establishing an emergency rating for these transmission lines allowing system operator intervention would meet the requirements of TPL-002.

2. Construct a 115 kV switching station at the existing Dalton Substation with four 115 kV transmission line terminal positions. The Dalton Substation is presently connected to the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line and the Ramsey – Rathdrum #2 115 kV

Transmission Line passes very close to the substation. The proposed switching station would include bringing the Ramsey – Rathdrum #2 115 kV Transmission Line into the substation providing an additional transmission line to supply the load at Hayden, Dalton, Coeur d'Alene 15th St., and Blue Creek Substations during a single outage condition. Estimated cost for alternative 2 is $4 million.

3. Relocate the interconnection point of Dalton Substation from the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line to the Ramsey – Rathdrum #2 115 kV Transmission Line. Relocation of the Dalton Substation reduces the amount of load connected to the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line. The specific thermal issues are mitigated in the short term but a new thermal issue is created with outage of the Rathdrum – Avondale segment of the Ramsey – Rathdrum #2 115 kV Transmission Line which heavily loads Ramsey – Rathdrum #1 115 kV Transmission Line. Estimated cost for alternative 3 is $200,000.

4. Reconductor the existing Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line with conductor capable of providing 150 MVA thermal capacity at 40°C ambient temperature. Reconductoring the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line will allow it to be operated normally closed therefore providing an additional source to the Coeur d'Alene sub-region. Estimated cost for alternative 4 is $10.5 million.

5. Provide an additional 230 kV source to the Coeur d'Alene sub-area at the existing Coeur d'Alene 15th St. Substation. Alternative 5 would require constructing a new 13 mile 230 kV transmission line from Rathdrum Substation to Coeur d'Alene 15th St. Substation. It would be proposed to double circuit the existing Coeur d'Alene 15th St. – Rathdrum, and/or the Ramsey – Rathdrum #1 or #2 115 kV Transmission Lines but consideration to double circuit line outages needs to be evaluated. Coeur d'Alene 15th St. Substation would need to be reconstructed to allow for a 230 kV transmission line terminal position, a 250 MVA 230/115 kV auto-transformer, and the necessary 115 kV interconnection facilities. Estimated cost for alternative 5 is $25 million. It should be noted a radial 230 kV transmission line from Pine Creek Substation to Coeur d'Alene 15th St. Substation instead of from Rathdrum Substation would provide similar system performance and may have a comparable cost.

6. Provide an additional 230 kV source to the Coeur d'Alene sub-area at the existing Dalton Substation. Alternative 6 would require constructing a new 8 mile 230 kV transmission line from Rathdrum Substation to Dalton Substation. It would be proposed to double circuit the existing Coeur d'Alene 15th St. – Rathdrum, and/or the Ramsey – Rathdrum #1 or #2 115 kV Transmission Lines but consideration to double circuit line outages needs to be evaluated. Dalton Substation would need to be reconstructed to allow for a 230 kV transmission line terminal position, a 250 MVA 230/115 kV auto-transformer, and the necessary 115 kV interconnection facilities. Estimated cost for alternative 6 is $20 million. It should be noted a radial 230 kV transmission line from Pine Creek Substation to Dalton Substation instead of from

Rathdrum Substation would provide similar system performance and may have a comparable cost.

7. Reconductor the Hayden – Rathdrum and Dalton – Hayden segments of the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line and the Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line with conductor to provide 150 MVA thermal rating. Increasing the capacity of the transmission lines alleviates the thermal overloads which were observed in the ten year planning horizon. Estimated cost for alternative 7 is $4 million.

Alternative 4 is recommended to be carried forward, pending a detailed Corrective Action Plan, to mitigate the observed thermal overloads during single contingency issues. Mitigation to multiple contingency issues further supports the recommendation of alternative 4 for the ten year planning horizon. Reconductoring of Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line is proposed to be started in 2013 and completed by 2016. The potential thermal loading for the issues described above is near 95% for 2012.

4.3.3 Saint Maries Voltage support

Low voltages are observed at St. Maries Substation for single contingency outages of either the Bell 500/230 kV #1 or Hot Springs 500/230 kV Transformers. The 230 kV transmission system voltages are reduced as a result of these transformer outages and using the post-transient contingency methodology does not consider system operator intervention to switch capacitor banks or modify 230/115 kV transformer taps. The ability to serve Plummer, O'gara, and St. Maries Substations from Pine Creek Substation with the Benewah – Plummer segment of the Benewah – Pine Creek 115 kV Transmission Line open illustrates voltage support issues at St. Maries Substation. Sourcing the load only from Pine Creek Substation yields voltages of 0.948 pu (109 kV) during heavy winter scenario in the ten year planning horizon (see Figure 4-7).

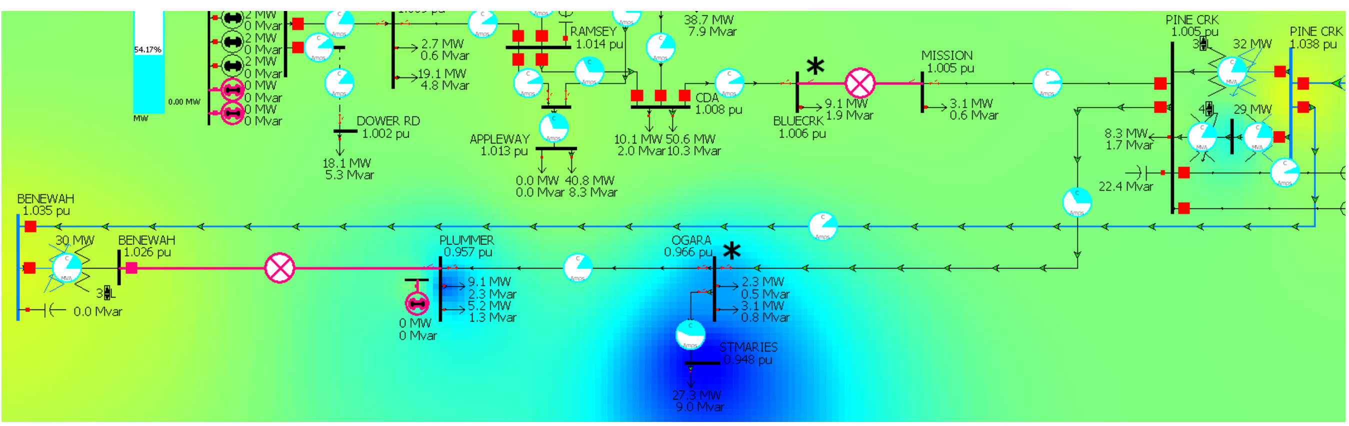


FIGURE 4-7: BEN-PIN LINE END OPEN CONDITION.

The following are possible alternatives to mitigate the potential low voltage issue:

1. Do nothing – Voltage support at St. Maries Substation will worsen with time. Violation of TPL-002, R2 will be observed without a Corrective Action Plan. Presently telemetry for O'gara and St. Maries Substations is not available therefore system operators will not be automatically notified by low voltage alarms of potential low voltages issues which require corrective action.
2. Install 13.4 MVAr capacitor bank at O'gara Substation. Voltage at St. Maries Substation is increased to 0.975 pu (112.13 kV) during the line end open scenario of the Benewah – Pine Creek 115 kV Transmission Line open at Benewah for a heavy winter scenario in the ten year planning horizon.

Alternative 2 is recommended to be carried forward, pending a detailed Corrective Action Plan, to mitigate the observed low voltages during single contingency issues. The proposed capacitor bank installation should be completed by 2020.

4.3.4 Pine Street – Rathdrum 115 Line Voltage Support

Low voltages are observed at distribution substations along the Pine Street – Rathdrum 115 kV Transmission Line for a line end open condition on the transmission line at Rathdrum Substation. Serving Old Town, Blanchard, Hoodoo, Spirit Lake, Athol and Scarello Substations out of Pine Street Substation yields voltages of 0.937 pu (107.8 kV) at Athol Substation during a heavy winter scenario in the ten year planning horizon (see Figure 4-8). The load at Athol and Scarcello Substations makes up 67% of the load on the Pine Street – Rathdrum 115 kV Transmission Line. Athol and Scarcello Substations are also electrically closer to Rathdrum Substation on the 33.24 mile transmission line.

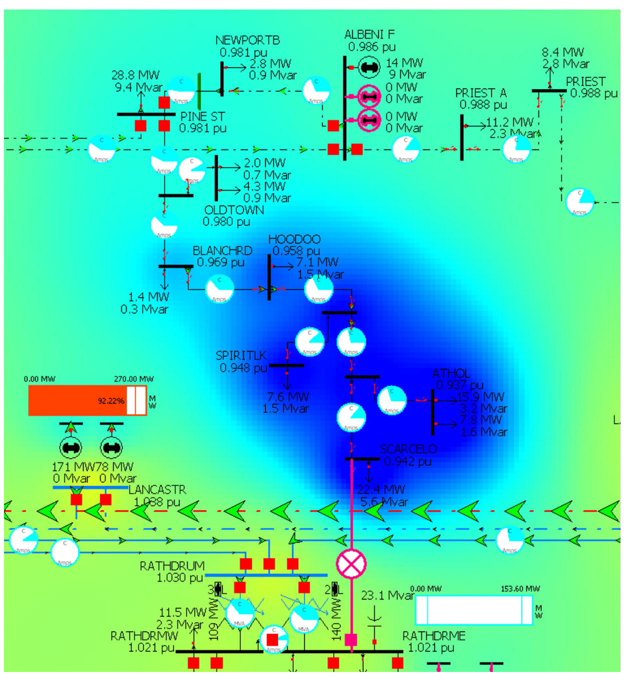


FIGURE 4-8: PNE-RAT LINE END OPEN CONDITION.

The following are possible alternatives to mitigate the potential low voltage issue:

1. Do nothing – Voltage support at substations along the Pine Street – Rathdrum 115 kV Transmission Line will worsen with time. Violation of TPL-002, R2 will be observed without a Corrective Action Plan. Load restoration to Athol and Scarcello Substations may be constrained during heavy winter scenarios.
2. Install two steps of 13.4 MVAr capacitor bank (26.8 MVAr total) at Spirit Lake Substation. Voltage at Athol Substation is increased to 0.989 pu (113.7 kV) during the line end open scenario of the Pine Street – Rathdrum 115 kV Transmission Line open at Rathdrum for a heavy winter scenario in the ten year planning horizon.
3. Construct a new breakered station near the Spirit Lake Substation Tap. The new station would accommodate the installation of two steps of 13.4 MVAr capacitor bank (26.8 MVAr total) as well as provide a reduction in transmission line exposure for the six substations served by the Pine Street – Rathdrum 115 kV Transmission Line.
4. Request Kootenai Electric Cooperative to install two steps of 13.4 MVAr capacitor bank (26.8 MVAr total) at either their Athol or Scarcello Substations. Voltage at Athol Substation is increased to above unity pu (115 kV) during the line end open scenario of the Pine Street – Rathdrum 115 kV Transmission Line open at Rathdrum for a heavy winter scenario in the ten year planning horizon.
5. Construct a new radial 115 kV transmission line from Rathdrum Substation to Athol Substation and serve the load at Athol Substation from the new radial transmission line. A potential full build out would be new transmission line from Rathdrum Substation to Sand Creek Substation utilizing the Northern Lights tap off the Albeni Falls – Sand Creek 115 Transmission Line.

Alternative 2 is recommended to be carried forward, pending a detailed Corrective Action Plan, to mitigate the observed low voltages during single contingency issues. The proposed capacitor bank installation is proposed to be completed by 2017.

4.4 MULTIPLE CONTINGENCY ISSUES: NERC CATEGORY C AND D

4.4.1 Rathdrum 115 kV Bus Tie Failure and Bus Outages

Single bus outages of the 115 kV buses at Rathdrum Substation cause thermal overloads of 115 kV transmission lines in the area. An East 115kV Bus outage causes up to 139% thermal overloading of the Ramsey – Rathdrum #1 115 kV Transmission Line for a heavy summer scenario in the ten year planning horizon (see Figure 4-9). A West 115 kV Bus outage is less severe as only a single transmission line feeding the Coeur d'Alene sub-area is taken out of service (see Figure 4-10). The Rathdrum Substation 115 kV bus configuration includes a bus tie breaker between the East and West 115 kV Buses. Failure of the bus tie breaker causes severe thermal overloads on the Otis Orchards – Post Falls and Post Falls – Ramsey 115 kV Transmission Lines far exceeding 200%. Consequently, the tripping of the Post Falls – Ramsey 115 kV Transmission Line by thermal relay during a heavy summer scenario in the ten year planning horizon (see Figure 4-11) would cause the entire Coeur d'Alene sub-area to be out of service. A scenario with heavy summer loading and Western Montana Hydro exceeding 1550 MW, where the Boulder – Rathdrum and Otis Orchards – Post Falls 115 kV Transmission Lines are operated open according to SOP-02 – 115kV "Star Network" Operation, and a Rathdrum Substation 115 kV bus tie breaker failure would also cause the entire Coeur d'Alene sub-area to be out of service.

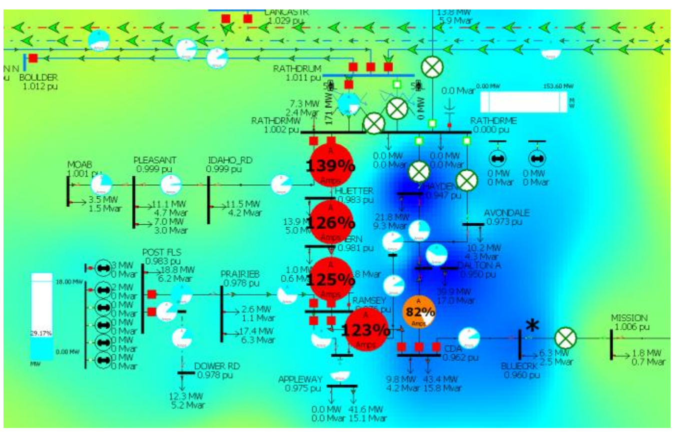


FIGURE 4-9: RAT 115 EAST BUS OUTAGE.

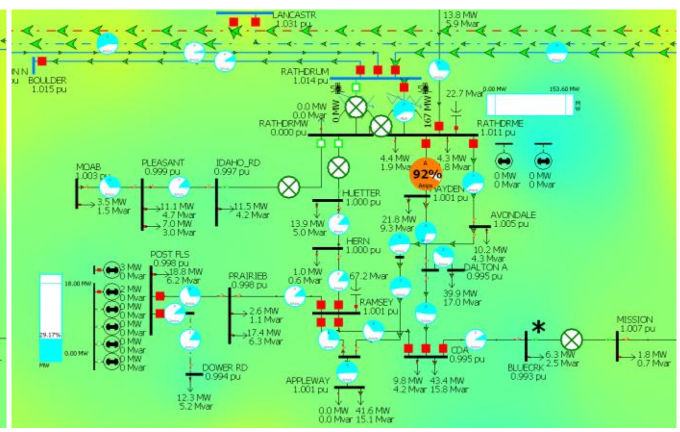


FIGURE 4-10: RAT 115 WEST BUS OUTAGE.

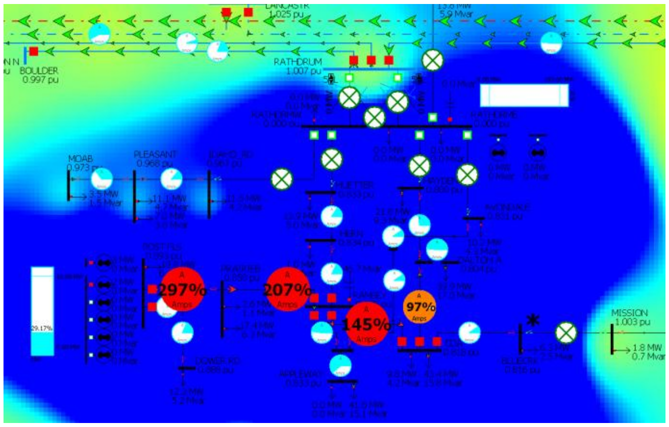


FIGURE 4-11: RAT 115 TIE BREAKER FAILURE.

The following are possible alternatives to mitigate the bus outage and tie breaker failure issues:

1. Do nothing – the implementation of SOP-23 – Manual Load Shedding for Localized Events allowing for the controlled shedding of load will mitigate the thermal overloads. A tie breaker failure will require nearly all of the Coeur d'Alene sub-region to be tripped until service to the Rathdrum Substation 115 kV Buses is restored.

2. Add series tie breaker to the 115 kV buses to eliminate a bus tie failure as a credible outage. Single bus outages will still be credible and will continue to cause thermal overload issues.

3. Construct bus configurations on the 115 kV buses allowing for bus outages to no longer be credible outages. Acceptable bus configurations could be double bus double breaker or breaker and a half. Estimated cost for alternative 3 is $5 million.

4. Provide an additional 230 kV source to the Coeur d'Alene sub-area at the existing Coeur d'Alene 15th St. Substation. Alternative 4 would require constructing a new 13 mile 230 kV transmission line from Rathdrum Substation to Coeur d'Alene 15th St. Substation. It would be proposed to double circuit the existing Coeur d'Alene 15th St. – Rathdrum, and/or the Ramsey – Rathdrum #1 or #2 115 kV Transmission Lines but consideration to double circuit line outages needs to be evaluated. Coeur d'Alene 15th St. Substation would need to be reconstructed to allow for a 230 kV transmission line terminal position, a 250 MVA 230/115 kV auto-transformer, and the necessary 115 kV interconnection facilities. Estimated cost for alternative 4 is $25 million. It should be noted a radial 230 kV transmission line from Pine Creek Substation to Coeur d'Alene 15th St. Substation instead of from Rathdrum Substation would provide similar system performance and may have a comparable cost.

5. Provide an additional 230 kV source to the Coeur d'Alene sub-area at the existing Dalton Substation. Alternative 5 would require constructing a new 8 mile 230 kV transmission line from Rathdrum Substation to Dalton Substation. It would be proposed to double circuit the existing Coeur d'Alene 15th St. – Rathdrum, and/or the Ramsey – Rathdrum #1 or #2 115 kV

Transmission Lines but consideration to double circuit line outages needs to be evaluated. Dalton Substation would need to be reconstructed to allow for a 230 kV transmission line terminal position, a 250 MVA 230/115 kV auto-transformer, and the necessary 115 kV interconnection facilities. Estimated cost for alternative 5 is $20 million. It should be noted a radial 230 kV transmission line from Pine Creek Substation to Dalton Substation instead of from Rathdrum Substation would provide similar system performance and may have a comparable cost.

6. Reconductor the existing Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line with conductor capable of providing 150 MVA thermal capacity at 40°C ambient temperature. Reconductoring the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line will allow it to be operated normally closed therefore providing an additional source to the Coeur d'Alene sub-region. Estimated cost for alternative 6 is $10.5 million.

Alternative 6 is recommended to be carried forward, pending a detailed Corrective Action Plan, to mitigate the observed thermal overloads during multiple contingency issues. Mitigation to single contingency issues further supports the recommendation of alternative 6. The issues observed due to bus outage at Rathdrum Substation are presently operating issues as documented in the Avista *2011 Summer Operating Studies Report* and should be mitigated as soon as feasibly possible. Reconductoring of d'Alene 15th St. – Pine Creek 115 kV Transmission Line is proposed to be started in 2013 and completed by 2016.

4.4.2 Ramsey Bus Outage

Single bus outage at Ramsey Substation causes thermal overloads on the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line (see Figure 4-12). The bus outage contingency causes near identical issue as the outage of the Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line. During these outage conditions, the load at Hayden, Dalton, Coeur d'Alene 15th St., and Blue Creek Substations is being supplied by a single 115 kV transmission line. Present load forecasts yield loading levels of 106% and 120% of the existing facility ratings for the five and ten year planning horizons respectively during a heavy summer loading scenario.

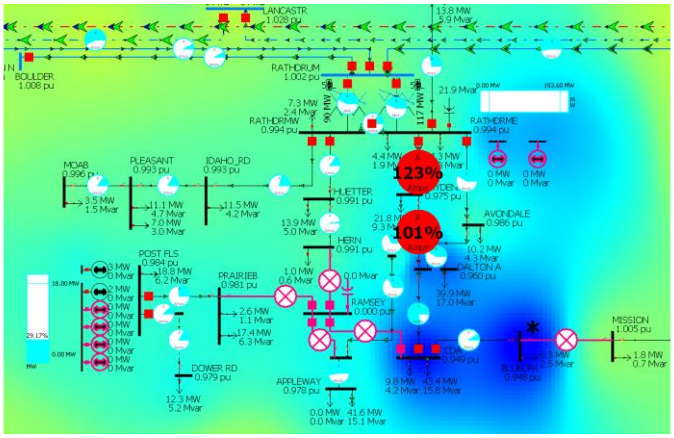


FIGURE 4-12: RAM BUS OUTAGE.

The following are possible alternatives to mitigate the bus outage issue:

1. Do nothing – Closing the normally open point on the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line after a Ramsey bus outage has occurred will mitigate the thermal overloads. The implementation of SOP-23 – Manual Load Shedding for Localized Events allowing for the controlled shedding of load will also mitigate the thermal overloads.

2. Reconductor the existing Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line with conductor capable of providing 150 MVA thermal capacity at 40°C ambient temperature. Reconductoring the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line will allow it to be operated normally closed therefore providing an additional source to the Coeur d'Alene sub-region. Estimated cost for alternative 2 is $10.5 million.

Alternative 2 is recommended to be carried forward, pending a detailed Corrective Action Plan, to mitigate the observed thermal overloads during multiple contingency issues. Mitigation to single contingency issues further supports the recommendation of alternative 2. Reconductoring of Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line is proposed to be started in 2013 and completed by 2016. The potential thermal loading for the issues described above is near 97% for 2012.

4.4.3 CDA-RAM and RAM-RAT #2 Double Circuit Outage

Double circuit outage of the Coeur d'Alene 15th St. – Ramsey and Ramsey – Rathdrum #2 115 kV Transmission Lines causes thermal overloads on the Coeur d'Alene 15th St. – Rathdrum 115 kV Transmission Line (see Figure 4-13). The double circuit contingency causes near identical issue as the outage of the Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line. During these outage conditions, the load at Hayden, Dalton, Coeur d'Alene 15th St., and Blue Creek Substations is being supplied by a single 115 kV transmission line. Present load forecasts yield loading levels of 106% and 120% of the existing facility ratings for the five and ten year planning horizons respectively during a heavy summer loading scenario.

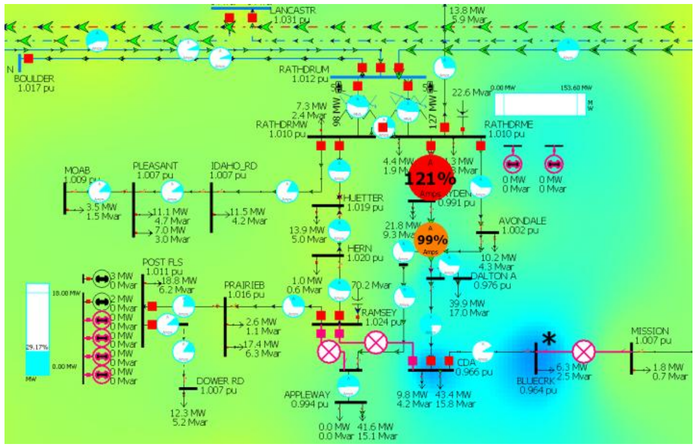


FIGURE 4-13: CDA-RAM & APW-RAM OUTAGE.

The following are possible alternatives to mitigate the double line outage issue:

1. Do nothing – Closing the normally open point on the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line after the double line outage has occurred will mitigate the thermal overloads. The implementation of SOP-23 – Manual Load Shedding for Localized Events allowing for the controlled shedding of load will also mitigate the thermal overloads.

2. Reconductor the existing Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line with conductor capable of providing 150 MVA thermal capacity at 40°C ambient temperature. Reconductoring the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line will allow it to be operated normally closed therefore providing an additional source to the Coeur d'Alene sub-region. Estimated cost for alternative 2 is $10.5 million.

Alternative 2 is recommended to be carried forward, pending a detail Corrective Action Plan, to mitigate the observed thermal overloads during multiple contingency issues. Mitigation to single contingency issues further supports the recommendation of alternative 2. Reconductoring of Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line is proposed to be started in 2013 and completed by 2016. The potential thermal loading for the issues described above is near 96% for 2012.

4.4.4 Cabinet – Bronx and Bronx – Sand Creek

The Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines exhibit thermal overloads for the simultaneous outage of both the Cabinet Gorge 230 kV Switchyard – Rathdrum and the Lancaster – Noxon Rapids 230 kV Transmission Lines in the same right of way corridor (see Figure 4-14). Also, the simultaneous outage of the Cabinet Gorge 230 kV Switchyard – Rathdrum and Cabinet Gorge 230 kV Switchyard – Noxon Rapids 230 kV Transmission Lines isolates the entire Cabinet Gorge HED on the remaining Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines consequently thermally overloading them (see Figure 4-15). The simultaneous outage of the Cabinet Gorge 230 kV Switchyard – Rathdrum and Cabinet Gorge 230 kV Switchyard – Noxon Rapids 230 kV Transmission Lines has occurred in the past (04 April 2011 for 3:14 hours) and the Cabinet Gorge 230 kV Switchyard 230/115 kV Transformer protection scheme tripped for loss of synchronism therefore no thermal overloading occurred.

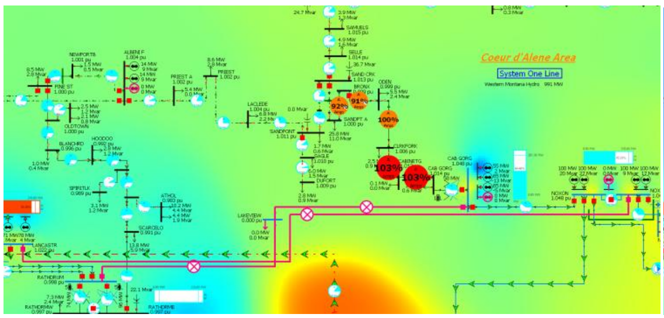


FIGURE 4-14: CAB-RAT & LAN-NOX OUTAGE.

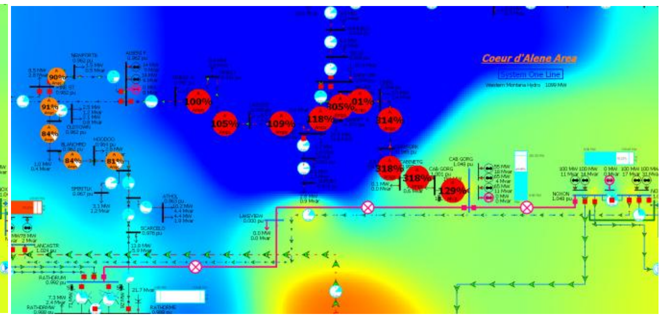


FIGURE 4-15: CAB-RAT & CAB-NOX OUTAGE.

Details of the issues and description of potential mitigation approaches are provided in System Planning memo SP-2010-10 date December 27, 2010 authored by Tracy Rolstad. The preferred mitigation alternative is to reconductor/rebuild the Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines with conductor capable of providing 150 MVA thermal capacity at 40°C ambient temperature. The issues observed on the Bronx – Cabinet Gorge 230 kV Switchyard and Bronx – Sand Creek 115 kV Transmission Lines are presently operating issues as documented in the Avista 2011 Summer Operating Studies Report and should be mitigated as soon as feasibly possible. Presently the mitigation project is budgeted to be started in 2011 and completed by 2016.

4.5 RESULTING ISSUES

This Planning Assessment assumes that all of the Single System Projects identified in Section 4 are completed within the ten year planning horizon to mitigate the discussed issues. For reference, there are 2021 emergent issues that will be addressed in future Coeur d'Alene Area Planning Assessments. These issues include the following:

1. Tie breaker failure on the Rathdrum Substation 115 kV bus will still cause overloading of the Otis Orchards – Post Falls and Post Falls – Ramsey 115 kV Transmission Lines.
2. Loss of the Rathdrum Substation 115 kV East Bus loads the Rathdrum – Ramsey #1 115 kV Transmission Line to 91%.
3. Operating the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line normally closed provides a third source to Coeur d'Alene 15th St. Substation keeping it in service if the two existing transmission lines trip but low voltages (0.95 pu) are observed when serving Coeur d'Alene 15th St. Substation solely from Pine Creek Substation.
4. Avista's Sandpoint Substation exhibits high voltages (1.05 pu) for loss of the Albeni Falls – Sand Creek 115 kV Transmission Line.

Further analysis will be conducted to determine when additional 230/115 kV transformation is required in the Coeur d'Alene sub-area. Though a new 230 kV Substation is not presently required within the ten year planning horizon, strategic acquisition of right of way and substation property ahead of further urban development should be considered. A long range transmission plan is necessary to begin preliminary property acquisition investigation.

The proposed reconductor and reconstruction of the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line may present an opportunity to construct the transmission line with the ability to upgrade to or add a 230 kV transmission line to the right-of-way in the future. With limited routing options for a future 230 kV transmission line into the Coeur d'Alene sub-area from the east, utilizing the existing 115 kV right-of-way may be a feasible alternative. Constructing a 230 kV transmission line from Pine Creek Substation to Rathdrum Substation would provide potential negotiation alternatives when the existing fifty year agreement with the Coeur d'Alene Tribe for the Benewah – Pine Creek 230 kV Transmission Line right-of-way across Tribe owned land expires in 2058. Further justification for a 230 kV transmission line may include increased transfer capability and potential load service benefits. Detailed analysis of additional cost and timing of adding 230 kV transmission line facilities will be evaluated in the production of the Corrective Action Plan developed to justify reconductoring of the Coeur d'Alene 15th St. – Pine Creek 115 kV Transmission Line. Preliminary estimated additional cost for reconstructing the 115 kV transmission line with 230 kV structures is \$7 to 9 million.

5 VOLTAGE STABILITY ANALYSIS (PV & QV)

Steady state analysis techniques were used to evaluate the voltage stability performance in the Coeur d'Alene Area. Further investigation of voltage stability using dynamic (time-domain) simulation is presented in Section 7. PV and QV analysis were used to assess the Area's conformity with the relevant planning criteria. PV analysis of a particular area or of a particular transfer path reveals the static stability margin of the area or of the path under study while QV analysis yields the reactive power margin at a particular bus in the transmission system under consideration.

A key element of voltage stability studies is the determination of a critical bus or a cluster of critical buses. According to the WECC publication "Voltage Stability Criteria, Undervoltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology" (1998), the critical bus exhibits one or more of the following characteristics under the worst single or multiple contingency:

- Has the highest voltage collapse point on the QV curve,
- Has the lowest reactive power margin,
- Has the greatest reactive power deficiency,
- Has the highest percentage change in voltage.

The following sections provide methodology and results for the PV and QV analysis conducted.

5.1 PV ANALYSIS

5.1.1 Methodology

A PV curve is obtained in power-flow simulation by monitoring a voltage at a bus of interest and varying (increasing) the power (load or transfer) in small increments until power-flow divergence is encountered. Each equilibrium point represents a steady-state operating condition. Path 8 – Montana to Northwest borders the eastern edge of the Coeur d'Alene Area and is therefore a Transfer Path PV Curve analysis was performed as well as a Load Ramp PV Curve analysis for load in the Coeur d'Alene Area.

The Transfer Path PV Curve analysis was conducted on the 2012 Heavy Transfer Case. All buses in the Montana and Northwest were monitored while generation was increased in the Western Montana Hydro Complex, Boundary Hydro project, and in the Montana Area and generation was decreased in the Lower Columbia River Hydro system. Transfers across Path 8 were increased until voltage collapse occurred (i.e. the case became numerically unstable). Path 6 – West of Hatwai is in series with Path 8 therefore the assumed generation increments and decrements increased transfers across Path 6 as well as Path 8.

The Load Ramp PV Curve analysis was conducted on the 2016 Heavy Summer, Low Hydro case and all busses in the Coeur d'Alene Area were monitored. All loads within the Coeur d'Alene Area were increased until voltage collapse occurred (i.e. the case became numerically unstable). It was assumed that all additional generation necessary to supply the increase in load came from a distribution of all generation in WECC.

A set of contingencies depicting one or more transmission outages was used to produce a series of PV curves for both the Load Ramp and Transfer Path PV Curve analysis. The operating limit can be established as the lowest of the following as obtained from the PV analysis results:

1. 5% below the area load magnitude at the 'nose-point' for Category A performance,
2. 5% below the area load magnitude corresponding to the 'nose-point' on the PV curve representing the worst Category B contingency,
3. 2.5% below the area load magnitude corresponding to the 'nose-point' on the PV curve representing the worst Category C contingency (controlled load shedding is allowed to achieve this operating limit).

5.1.2 Results

As generation in the Western Montana Hydro Complex, Boundary Hydro project, and in the Montana Area is increased, the transfers across Path 6 and Path 8 increased until a theoretical maximum transfer limit was reached. A nose point was not reached therefore identifying Path 6 and Path 8 as flow limited (opposed to reliability limited). A balance of generation levels and load on the east side of the paths directly impacts the amount of power transferred across the paths. The load in the Montana and Western Montana Areas could be reduced therefore increasing the transfer amounts but further load reduction may fall outside a realistic simulation approach.

The PV Analysis results for Path 8 showed a theoretical flow limit of 2290 MW for all line in service condition. This slightly exceeds the existing East to West Path 8 Transfer Limit of 2200 MW as posted in the 2011 Path Rating Catalog. The simultaneous line right-of-way outage of both the Hot Springs – Noxon #1 & #2 230 kV Transmission Lines as well as a breaker failure at Taft Switching Station appear to be the most limiting contingencies (see Figure 5-1) though the contingency list studied does not contain an exhaustive list of outages in NorthWestern's Transmission System. The Avista 2011 Summer Operating Studies Report identifies the nose of the PV curve at 2435 MW.

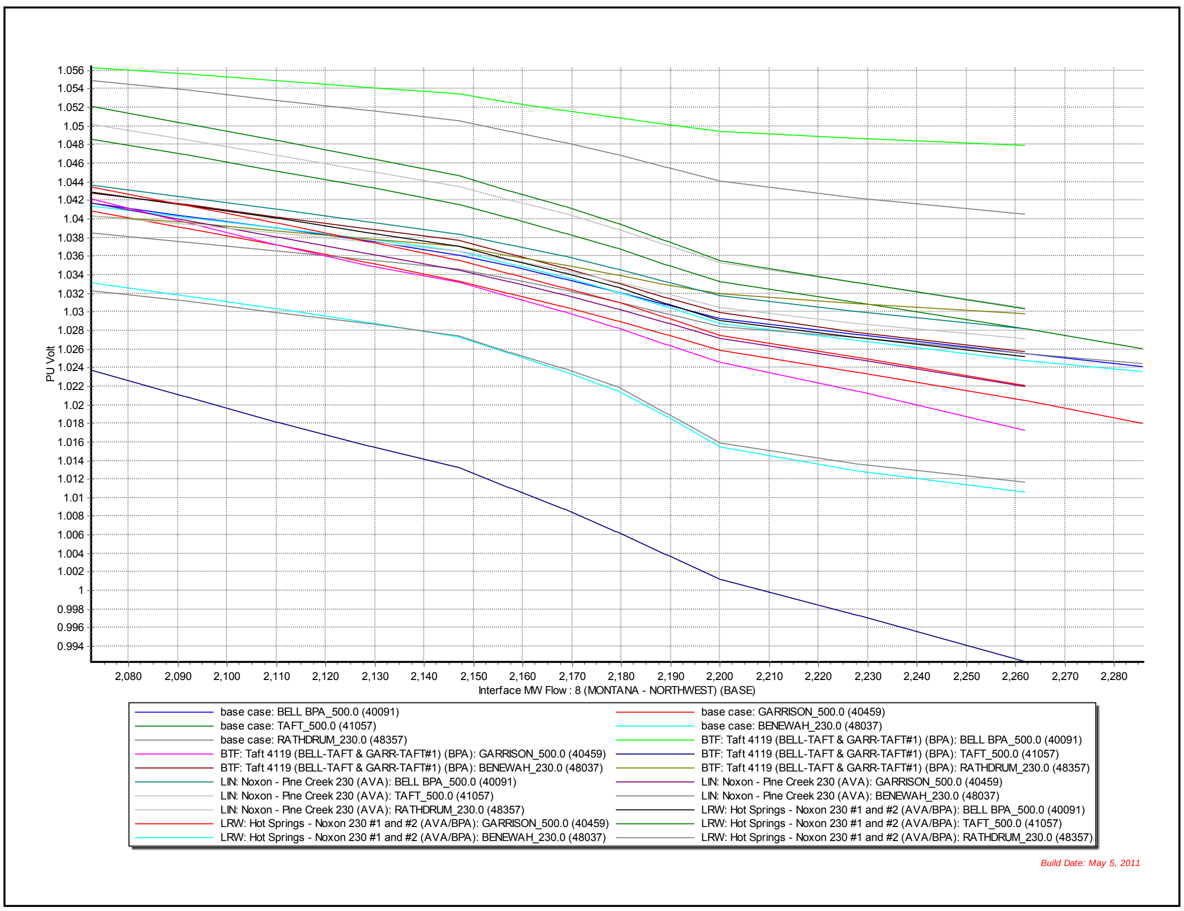


FIGURE 5-1: PATH 8 TRANSFER PATH PV CURVE RESULTS FOR CRITICAL BUSSES.

The PV Analysis results for Path 6 showed a theoretical flow limit of 4460 MW for all line in service condition. This exceeds the existing East to West Path 6 Transfer Limit of 4277 MW as posted in the 2011 Path Rating Catalog. The simultaneous line right-of-way outage of both the Hot Springs – Noxon #1 & #2 230 kV Transmission Lines as well as a breaker failure at Taft Switching Station appear to be the most limiting contingencies (see Figure 5-2). The Avista 2011 Summer Operating Studies Report identifies the nose of the PV curve at 4785 MW.

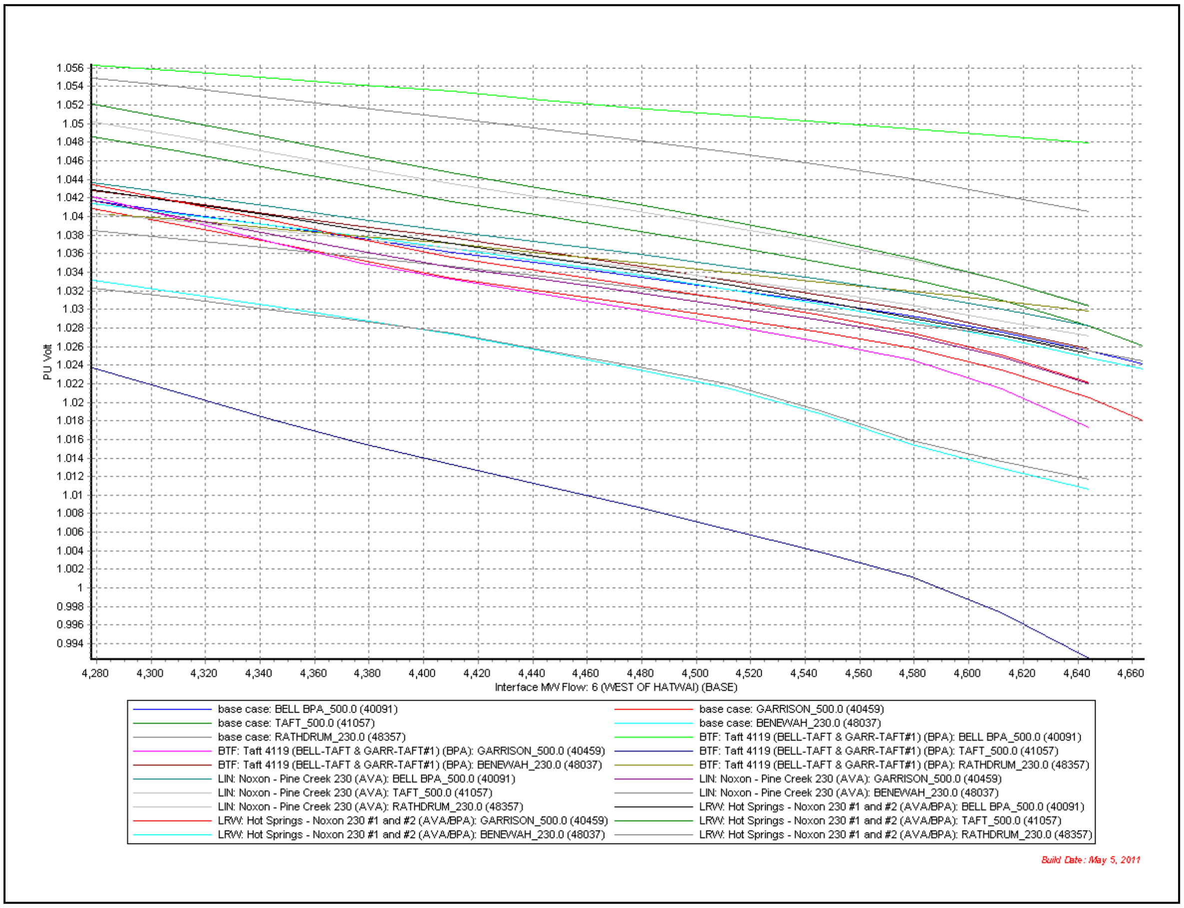


FIGURE 5-2: PATH 6 TRANSFER PATH PV CURVE RESULTS FOR CRITICAL BUSES.

As load increases in the Coeur d'Alene Area, the Category B contingencies studied yielded critical buses for buses only on the end of a line for a line-end-open scenario. The worst Category B contingency was the line-end-open scenario on the Bronx – Sand Creek 115 kV Transmission Line open at Sand Creek Switching Station. The nose point occurs near 1100 MW therefore the theoretical operating limit could be a total Coeur d'Alene Area load of 1045 MW, nearly three times the present peak summer load of the Coeur d'Alene Area. The worst Category C contingency becomes the 115 kV bus tie failure at Rathdrum Substation. The critical bus for this outage is the Coeur d'Alene 15th Street 115 kV bus. Controlled load shedding is allowed therefore the criticality of this contingency is not easily determined. Figure 5-3 shows the PV curves for two critical buses and the worst performing contingencies. From observation, the post transient voltage deviation at Coeur d'Alene 15th Street Substation exceeds 10% for the Rathdrum East and West 115 kV bus outage. This issue is also address in Subsection 4.4.

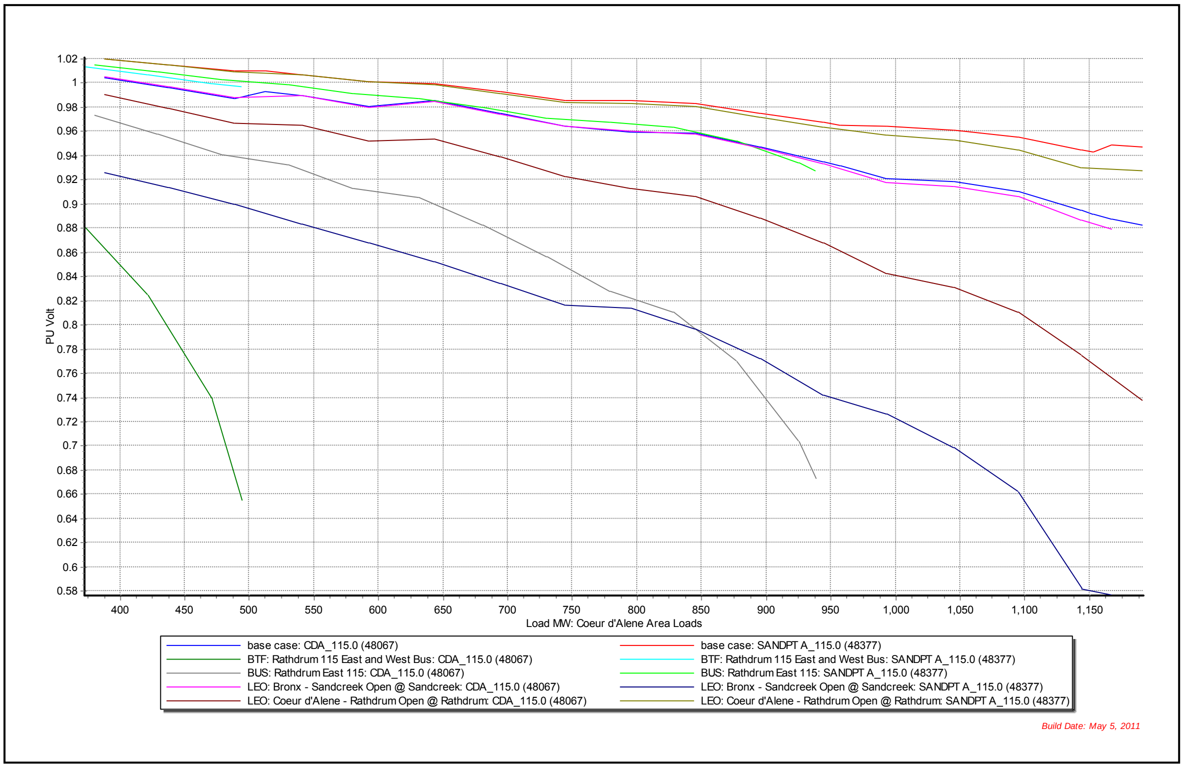


FIGURE 5-3: LOAD RAMP PV CURVE RESULTS FOR CRITICAL BUSSES.

5.2 QV ANALYSIS

5.2.1 Methodology

Using results of the PV analysis, a set of critical busses can be determined. All critical busses and 115 kV busses of 230/115 kV transformers are studied in the QV analysis. All bus voltages in the Coeur d'Alene Area are monitored as the reactive demand at the bus under study is varied. This process is repeated for a set of contingencies depicting one or more transmission outages and for the remaining buses to be studied. LTC and switched shunts were disabled to provide a post-transient response prior to operator intervention. The reactive power margin (RPM) can be assessed from the results of the QV analysis. RPM is defined as the negative of the value of the reactive demand at the minimum point of the QV curve.

5.2.2 Results

The QV analysis showed there is adequate reactive power margin for the 115 kV source busses and critical busses in the Coeur d'Alene Area. Table 5-1 and Table 5-2 show the results of the worst performing contingency for each bus analyzed.

The Cabinet Gorge 115 kV bus had the least reactive margin for the 115 kV busses of 230/115 kV transformers at 54 MVAr during the outage of the Cabinet Gorge 230/115 kV Transformer and 53 MVAr for the 230 kV bus outage at Cabinet Gorge Substation. These outage scenarios are also addressed in Subsections 4.3 and 4.4.

The smallest reactive margin at the critical busses analyzed occurred at the Sandpoint 115 kV bus with a value of 61 MVAr for the Sand Creek – Sandpoint segment outage on the Bronx – Sand Creek 115 kV Transmission Line. This issue is also addressed in Subsection 4.3.

Bus Name	Nom kV	Contingency Scenario	V at Q0	Q0	Qinj_0	V at Qmin	Qmin
CAB GORG	115	XFM: CABINET GORGE 230/115	1.03	0	0	0.542	-54.22
SANDPT A	115	LEO: BRONX - SANDCREEK OPEN @ SANDCREEK	0.93	0	0	0.506	-61.08
CDA	115	LIN: (CDA-RAM) COEUR D'ALENE - RAMSEY 115	0.97	0	0	0.524	-219.7
BURKE	115	LIN: NOXON - PINE CREEK 230 (AVA)	1	0	0	0.552	-242.18
PINE CRK	115	XFM: HATWAI 500/230 XFMR (BPA)	1	0	22.32	0.533	-413.84
RATHDRMW	115	XFM: BELL 500/230 XFMR (BPA)	1	0	0	0.625	-534.09
RATHDRME	115	XFM: BELL 500/230 XFMR (BPA)	1	0	22.44	0.625	-534.13
NOXON	230	LIN: LANCASTER - NOXON 230 (BPA)	1.05	0	0	0.638	-799.25

TABLE 5-1: CATEGORY B QV ANALYSIS RESULTS FOR 5 YEAR HORIZON.

Bus Name	Nom kV	Contingency Scenario	V at Q0	Q0	Qinj_0	V at Qmin	Qmin
CAB GORG	115	BUS: CABINET 230KV (AVA)	1.03	0	0	0.542	-53.73
SANDPT A	115	BUS: SAND CREEK 115 (BPA)	0.93	0	0	0.506	-60.97
CDA	115	BTF: RATHDRUM 115 EAST AND WEST BUS	0.88	0	0	0.58	-72.33
PINE CRK	115	BUS: PINE CREEK 230KV (AVA)	1.01	0	22.51	0.637	-87.25
BURKE	115	BUS: PINE CREEK 230KV (AVA)	1	0	0	0.64	-106.89
RATHDRMW	115	BUS: RATHDRUM EAST 115	1	0	0	0.554	-531.07
RATHDRME	115	BUS: RATHRUM WEST 115	1.01	0	22.77	0.543	-587.8
NOXON	230	LRW: CABINET - RATHDRUM 230 AND LANCASTER - NOXON 230 (AVA/BPA)	1.05	0	0	0.6778	-666.57

TABLE 5-2: CATEGORY C QV ANALYSIS RESULTS FOR 5 YEAR HORIZON.

6 SHORT CIRCUIT ANALYSIS

7 DYNAMIC STABILITY ANALYSIS

7.1 STUDY METHODOLOGY

Transient stability analysis is commonly employed in the study of power system stability to reveal the total "system trajectory" following a disturbance.

Standard WECC, NERC and Avista requirements for disturbance performance were used to evaluate the results of dynamic stability analysis simulations. These requirements are as follows for Category B contingencies:

- Maximum allowable transient voltage dip of 25 percent at load buses or 30 percent at non-load buses.
- Maximum allowable transient voltage dip not to exceed 20 percent for more than 20 cycles at load buses.
- Minimum allowable frequency of 59.6 Hz for 6 cycles or more at load buses.
- Maximum allowable post-transient voltage deviation of 5 percent from pre-disturbance voltage.

The WECC/NERC voltage performance criteria are illustrated in Figure 7-1. A more detailed explanation and further information can be referenced in "*TPL – (001 thru 004) – WECC – 1 – CR – System Performance Criteria*".

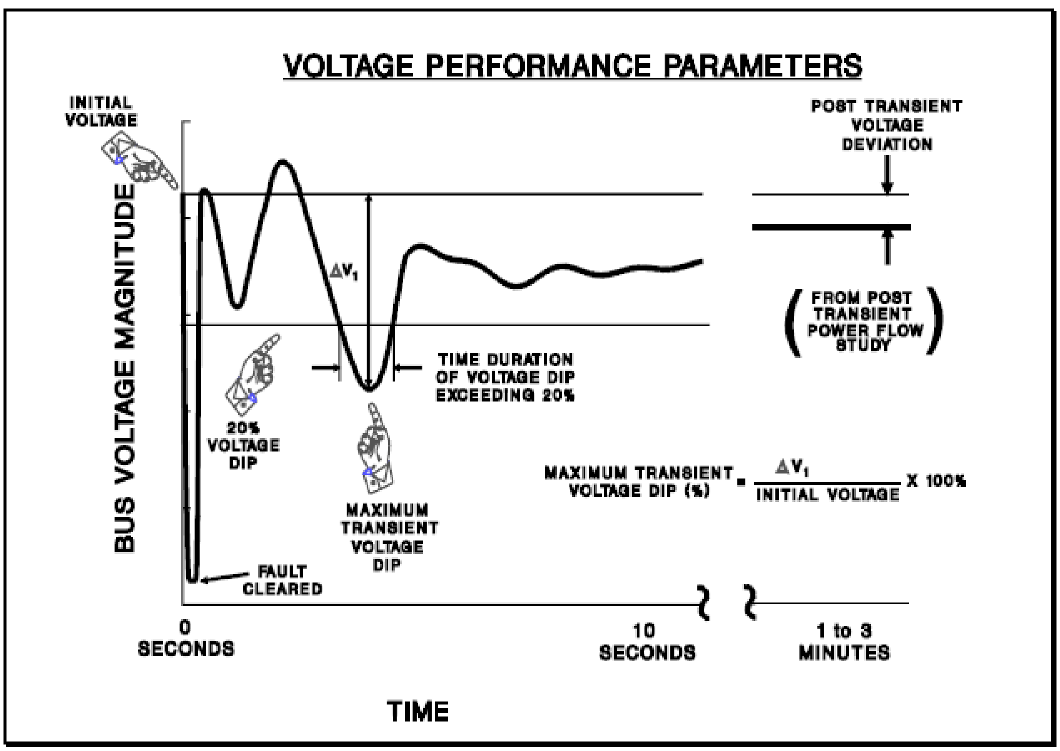


FIGURE 7-1: WECC/NERC VOLTAGE PERFORMANCE CRITERIA AND PARAMETERS.

Avista's System Planning Group uses GE PSDS software to perform transient stability simulations. The dynamic stability simulation module DYTOOLS is utilized to batch process multiple contingency scenarios in an efficient manner. Analysis of the results is conducted using a user written program to screen for criteria violations. A summary of violations is produced as well as individual plot files for each simulation performed.

Past studies have shown that transient stability on Avista's system is influenced by Western Montana Hydro, West of Hatwai flows, Northwest to Idaho flows, and Montana to the Northwest flows. As these three transfer paths can be heavily loaded during light load hours, the light load case is the most stressed. Avista's System Planning Group presently analyzes the four seasonal cases described in Subsection 3.3. The following are issues observed which should be addressed.

7.2 SINGLE CONTINGENCY ISSUES (N-1): NERC CATEGORY B

7.2.1 Post Falls Out-Of-Step

The Post Falls Generators Units 1 through 5 were observed going out of step for a three phase fault on the Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line with time delayed clearing by the Ramsey terminal during the High Transfer scenario. According to SOP-02 – 115kV "Star Network" Operation when Western Montana Hydro reaches 1550 MW the Otis Orchards – Post Falls and Boulder – Rathdrum 115 kV Transmission Lines are operated open. Opening the Otis Orchards – Post Falls 115 kV Transmission Line leaves the Post Falls Hydro Facility connected to the system through only the Post Falls – Ramsey 115 kV Transmission Line. Sourcing fault current through Ramsey Substation consequently causes the rotor angles of Units 1 through 5 to pass the critical angle where loss of synchronism will occur (see Figure 7-2).

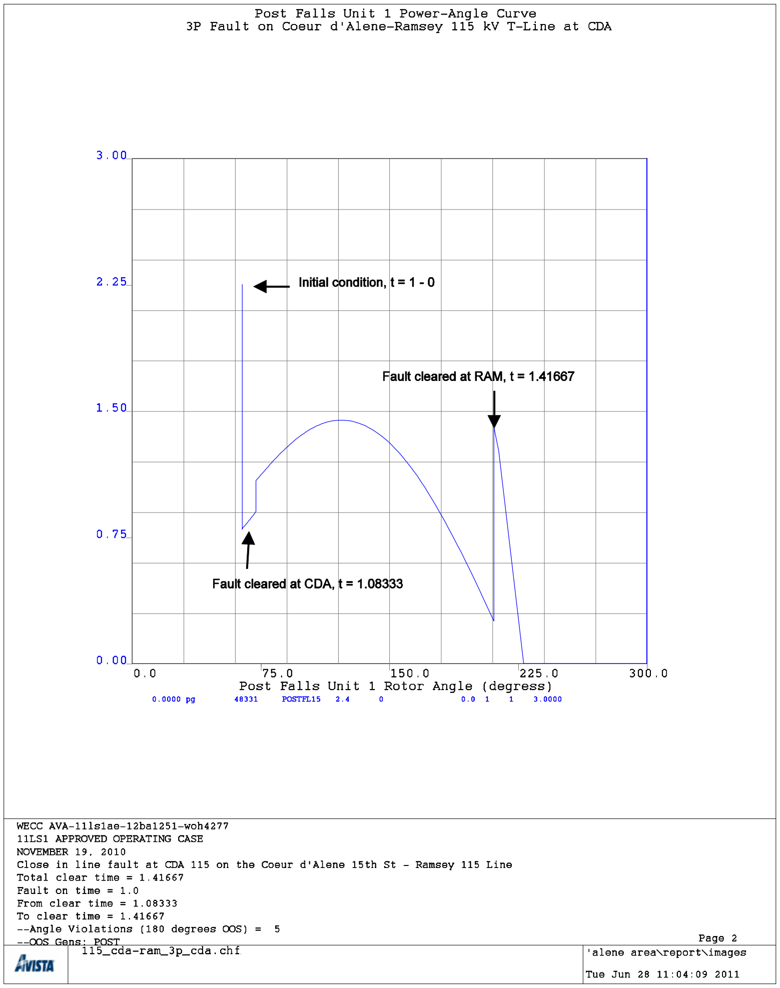


FIGURE 7-2: POST FALLS POWER-ANGLE OUT OF STEP PLOT.

The Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line was identified to be within Tier 2 of Dennis Howey's Memo *"Upgrading 115 kV Relay Schemes" for Spokane – Coeur d'Alene area transmission lines*, dated December 15, 2005. Under the Upgrade 115 kV Relay Scheme program, the clearing times are reduced to approximately seven cycles for zone two time delayed fault clearing by implementing communication aided tripping protection schemes. The improved clearing time will mitigate the potential out of step condition observed at Post Falls. Presently the work required to upgrade the Coeur d'Alene 15th St. – Ramsey 115 kV Transmission Line protection scheme is scheduled for 2012. Protection scheme upgrades are also being implemented on the Boulder – Otis Orchards #1 and #2 115 kV Transmission Lines in 2011 which may allow for modification of SOP-02 – 115kV "Star Network" Operation to have the Otis Orchards – Post Falls and Boulder – Rathdrum 115 kV Transmission Lines operated closed during high Western Montana Hydro conditions. Operating with the transmission lines closed will also mitigate the potential out of step condition at Post Falls.

7.2.2 Libby – Noxon Three Phase Fault

During high generation levels in the Western Montana Hydro Complex, outage of the Libby – Noxon Rapids 230 kV Transmission Line causes various voltage and frequency violations at load busses in the Western Montana Area. Libby Generator Dropping RAS is triggered for loss of the Libby – Noxon Rapids 230 kV Transmission Line. Both power houses at Libby will be dropped if the total output of Libby and Hungry Horse is greater than 850 MW or if Northwest Montana Net Load is less than -360 MW then only power house two at Libby will be dropped. The conditions studied in the High Transfer case warrant the dropping of both power houses during a three phase fault on the Libby – Noxon Rapids 230 kV Transmission Line.

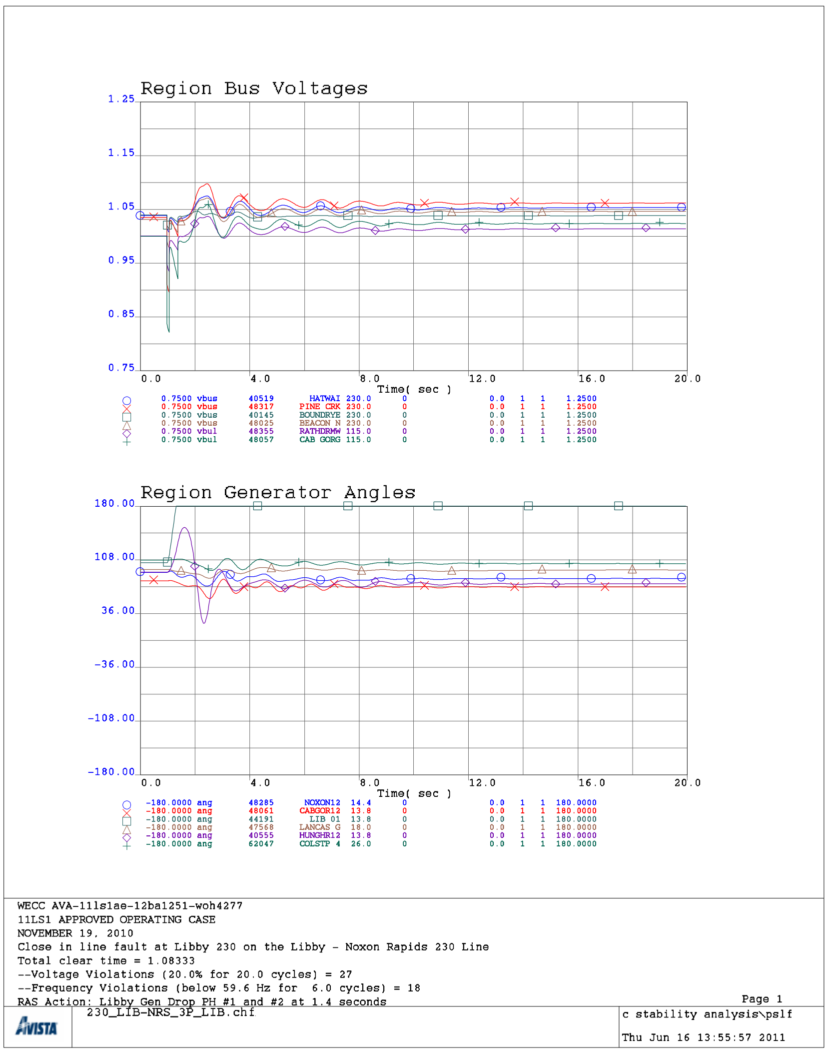


FIGURE 7-3: LIBBY - NOXON THREE PHASE FAULT TRANSIENT STABILITY RESULTS.

The voltage and frequency violation observed occur only on BPA's system and the Libby – Noxon 230 kV Transmission Line is within BPA's system therefore an actual violation of the WECC criteria does not occur and no mitigation is required. BPA is aware of the potential issue and Avista continues to monitor future performance in the area to ensure voltage and frequency violations are not observed at Avista facilities.

7.3 MULTIPLE CONTINGENCY ISSUES: NERC CATEGORY C

7.3.1 Noxon West Bus Outage

A fault on the West 230 kV Bus at Noxon Rapids Switching Station causes several potential voltage and frequency violations in the Western Montana Area. Clearing the West 230 kV Bus will cause an outage of the Libby – Noxon Rapids 230 kV Transmission Line. The potential issues observed are directly related to the issues discussed in Section 7.2. Reconstruction of the existing Noxon 230 kV bus to a Double Breaker Double Bus configuration will eliminate bus outages.

8 RECOMMENDED PROJECT PRIORITIZATION AND SCHEDULE

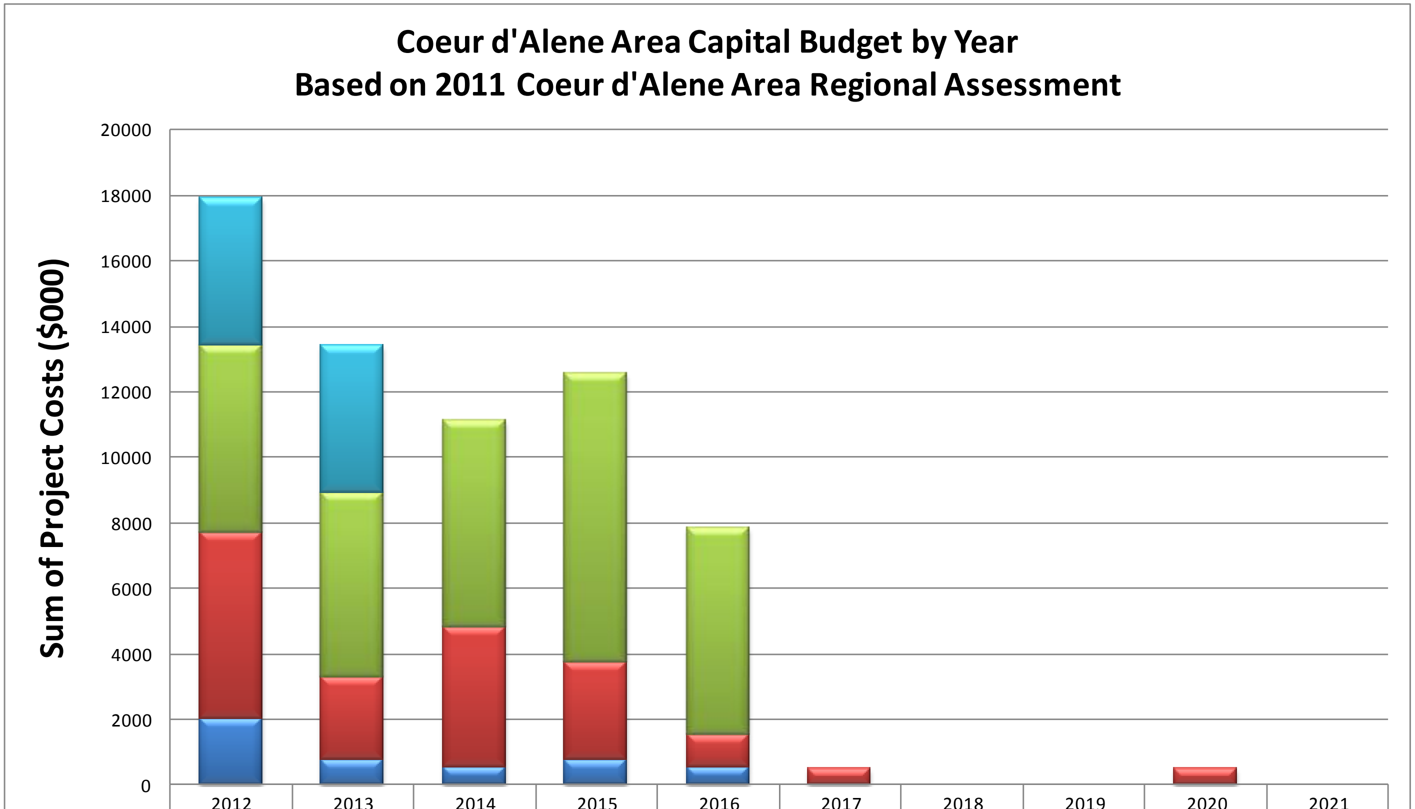
The projects identified in Section 4 are scheduled and budgeted in Table 8-1 below. Some projects have required in service dates earlier than those identified in this Planning Assessment but due to budget, construction and/or operational schedule it is understood that some issues cannot be mitigated in the desired timeframe. This report suggests obtainable project schedules to represent a realistic planning approach.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
System Planning Projects	**$7,000,000**	**$8,800,000**	**$7,250,000**	**$6,000,000**	**$6,000,000**	**$500,000**			**$500,000**		**$36,050,000**
TPL-001, N-0	**$4,500,000**	**$5,000,000**									**$9,500,000**
Lancaster Integration Project	**$4,500,000**	**$5,000,000**									**$9,500,000**
ER: NEW120 - Lancaster - Integrate Power Plant	$4,500,000	$4,500,000									$9,000,000
ER: 2551 - Lancaster - Integrate Power Plant		$500,000									$500,000
TPL-002, N-1	**$2,500,000**	**$3,800,000**	**$7,250,000**	**$6,000,000**	**$6,000,000**	**$500,000**			**$500,000**		**$26,550,000**
Benewah-Pine Creek Voltage Support Project									**$500,000**		**$500,000**
ER: 2481 - System - Replace/Install Capacitor Banks									$500,000		$500,000
Bronx-Cabinet and Bronx-Sand Creek	**$2,500,000**	**$2,500,000**	**$2,500,000**	**$2,500,000**	**$2,500,000**						**$12,500,000**
ER: 2423 - System- Rebuild Transmission - Condition	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000						$12,500,000
Coeur d'Alene - Pine Creek Rebuild Project		**$50,000**	**$3,500,000**	**$3,500,000**	**$3,500,000**						**$10,550,000**
ER: NEWXXX - CDA-PIN 115kV Rebuild/Reconductor		$50,000	$3,500,000	$3,500,000	$3,500,000						$10,550,000
Pine Street-Rathdrum Voltage Support Project						**$500,000**					**$500,000**
ER: 2481 - System - Replace/Install Capacitor Banks						$500,000					$500,000
Spokane/Coeur d'Alene Relay Upgrade Project		**$1,250,000**	**$1,250,000**								**$2,500,000**
ER: 2217 - Spokane - CDA 115kV Line Relaying Upgrades		$1,250,000	$1,250,000								$2,500,000
Other Projects	**$10,904,190**	**$4,629,190**	**$3,850,000**	**$6,550,000**	**$1,850,000**						**$27,783,380**
(blank)	**$10,904,190**	**$4,629,190**	**$3,850,000**	**$6,550,000**	**$1,850,000**						**$27,783,380**
Driven by Distribution Eng.	**$2,120,076**	**$1,020,076**	**$550,000**	**$750,000**	**$550,000**						**$4,990,152**
ER: 1006 - Power Transformers-Distribution (incl sales tax)											
ER: 2301 - Tribal Settlement & Permits	$20,076	$20,076									$40,152
ER: 2399 - Blue Creek Sub-Rebuild											
ER: 2414 - System - Dist Reliability - Improve Worst Feeders	$675,000	$550,000	$550,000	$550,000	$550,000						$2,875,000
ER: 2465 - Bronx 115-21 kV Sub - Construct	$100,000			$200,000							$300,000
ER: 2480 - Carlin Bay 115-13 Substation											
ER: 2515 - Distribution - CdA East & North	$1,325,000										$1,325,000
ER: 2521 - St. Maries 634 - New FDR		$450,000									$450,000
Driven by Substation Eng.	**$3,700,000**										**$3,700,000**
ER: 2280 - System-Replace Obsolete Circuit Switchers											
ER: 2306 - Appleway 115-Sub - Rebuild											
ER: 2342 - Pine Ck 230 Sub - Rebuild Dist / Replace Cap Bank											
ER: 7050 - Productivity											
ER: 2546 - Blue Creek Sub-Rebuild	$1,900,000										$1,900,000
ER: 2547 - Lucky Friday Sub-Rebuild	$1,800,000										$1,800,000
Driven by Transmission Eng.	**$3,084,114**	**$2,584,114**		**$2,500,000**							**$8,168,228**

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
ER: 2301 - Tribal Settlement & Permits	$84,114	$84,114									$168,228
ER: 2550 - Burke-Thompson A&B 115kV Transmission Line Rebuild	$2,500,000	$2,500,000		$2,500,000							$7,500,000
ER: 25xx - Noxon-Hot Springs #2 Beaver Creek Relocation	$500,000										$500,000
Noxon Switchyard Rebuild Project		**$1,025,000**	**$3,300,000**	**$3,300,000**	**$1,300,000**						**$8,925,000**
ER: 2532 - Noxon 230 kV Substation - Rebuild		$1,025,000	$3,300,000	$3,300,000	$1,300,000						$8,925,000
Pine Creek Transformer Replacement Project	**$2,000,000**										**$2,000,000**
ER: 2000 - Power Transformers-Transmission & GSU (incl sales tax)	$2,000,000										$2,000,000
Grand Total	**$17,904,190**	**$13,429,190**	**$11,100,000**	**$12,550,000**	**$7,850,000**	**$500,000**			**$500,000**		**$63,833,380**

TABLE 8-1: RECOMMENDED PROJECT PRIORITIZATION AND SCHEDULE.

Figure 8-1 provides a graphical view of the capital budget for the Coeur d’Alene Area as presented in Table 8-1. The budgeted amounts are categorized in columns by the group or entity responsible for executing the projects.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Grand Total	17904	13429	11100	12550	7850	500	0	0	500	0
BPA	4500	4500	0	0	0	0	0	0	0	0
Transmission	5684	5659	6300	8800	6300	0	0	0	0	0
Substation	5700	2500	4250	3000	1000	500	0	0	500	0
Distribution	2020	770	550	750	550	0	0	0	0	0

FIGURE 8-1: COEUR D’ALENE AREA CAPITAL BUDGET BY YEAR.

9 POINT OF CONTACT

A Point of Contact for questions regarding the Planning Assessment and the projects described within it has been designated. Please contact the party named below for any questions:

Kenneth Dillon
Contracts Engineer, Transmission Services
PO Box 3727
Spokane, WA 99220
kenny.dillon@avistacorp.com
(509) 495-4436

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Appendix A - Transmission Map

Appendix B - System One Line Drawing

Appendix C - System Power Flow Plots

2016 Heavy Winter

2016 Heavy Summer, High Hydro

2021 Heavy Winter

2021 Heavy Summer, High Hydro

Appendix D - Power Flow Violation Summary

Appendix E - Transient Stability Results

The following tables provide the results from a user written program which analyzes the transient stability simulations performed. Due to the number of simulation performed, plots of the results or detailed analysis results are not included in this Planning Assessment but can be provided upon request.

Appendix C - Lewiston/Clarkston Planning Assessment

Appendix D - 2011 Palouse Planning Assessment

Palouse Area

2011 PLANNING ASSESSMENT

TRANSMISSION PLANNING

Prepared by John Gross

www.avistautilities.com

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Palouse Area

2011 PLANNING ASSESSMENT

Date Completed: December 16, 2011

Prepared By: John Gross

The signature below indicates approval by the Director of System Planning. This Planning Assessment has been conducted with due diligence and has been reviewed and accepted by the Interested Stakeholders. This approval certifies this Planning Assessment as an adequate transmission planning approach for the area of interest.

Dec 16, 2011

Scott Waples Director System Planning Engineer — Date

Version History

Version	Version Date	Action	Change Tracking	Reviewed By
A	1 Sept 2011	Preliminary Draft	New Document	J. Gross
B	15 Sept 2011	Draft for Comment	Planning Draft Review	J. Gross
0	16 Dec 2011	Final Report	Eng & Ops Input	J. Gross

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TABLE OF CONTENTS

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Palouse Area

2011 PLANNING ASSESSMENT

1 EXECUTIVE SUMMARY

The Avista Palouse Area is located primarily in the Spokane and Whitman Counties in Washington and Latah County in Idaho. The majority of the load served in the area can be categorized as rural, low density load with exception of the cities of Pullman, WA and Moscow, ID. The Transmission System consists of a 230 kV backbone system and underlying 115 kV transmission lines that serve the local loads. The 230 kV transmission lines provide sources for the local area and North and South transfers across Avista's system.

Load growth in the Palouse Area is projected to be 1.6% for summer and 1.6% for winter based on historic load growth data. Total anticipated load not including Transmission System losses for peak summer 2012 is 152 MW and 209 MW for peak winter 2012. Total installed distribution (i.e. 115/13.8 or 115/21 kV) transformation capacity in the Palouse Area is 320.8 MVA based on transformer nameplate ratings.

This Planning Assessment identifies any reliability impacts identified on Avista's Transmission System, and provides a list of the Single System Projects proposed to mitigate those issues. Such reliability impacts were identified by performing technical studies, which included powerflow, transient stability, short circuit, and voltage collapse analysis. **For Single System Projects not identified in previously completed Planning Assessments, a separate Corrective Action Plan (detailed project study) will be conducted as necessary to determine the technically superior project(s) to be carried forward into the Avista capital budgeting process.**

A summary of the Single System Projects are provided in the following list. Some projects have required in service dates earlier than those identified in this Planning Assessment but due to budget, construction and/or operational schedule it is understood that some issues cannot be mitigated in the desired timeframe. This Planning Assessment suggests obtainable project schedules to represent a realistic planning approach with the appropriate budgetary support. **All projects listed here (or superior alternatives) must be completed within the ten year planning horizon.**

- Construct Thornton Switching Station for the Palouse Wind Interconnection; scheduled for completion in 2012,
- Rebuild the Moscow 230 Substation and replace existing 125 MVA 230/115 kV transformer and regulator with a 250 MVA autotransformer, scheduled for completion in 2014,
- Install 15 MVAr capacitor bank at Garfield Substation, scheduled for completion in 2015.

The total cost of the proposed Single System Projects based on Avista's System Planning Group's analysis of the Palouse Area Transmission System is expected to be approximately $13.5 million. Following is a list of planned system modifications developed by Avista's Engineering Department. Planned system modifications in the Palouse Area driven by Avista's Engineering Department is expected to be approximately $22 million.

- Smart Grid Demonstration Project; scheduled for completion in 2012,
- Rebuild the Pullman Substation (now called Turner Substation); scheduled for completion in 2012,
- Construct a new substation near Bovill for large industrial customer; scheduled for completion in 2013,
- Rebuild the Moscow City – North Lewiston 115 kV Transmission Line, scheduled for completion in 2015,
- Add an additional 20 MVA distribution transformer to the North Moscow Substation; required in the 5 year planning horizon,
- Construct the new Tamarack Substation approximately 1.5 miles East of North Moscow Substation; required in the 5 year planning horizon.

2 GENERAL SYSTEM DESCRIPTION

The Avista Palouse Area is located primarily in the Spokane and Whitman Counties in Washington and Latah County in Idaho. The majority of the load served in the area can be categorized as rural, low density load with the exception of the cities of Pullman, WA and Moscow, ID. The Transmission System consists of a 230 kV backbone system and underlying 115 kV transmission lines that serve the local loads. The 230 kV transmission lines provide sources for the local area and North and South transfers across Avista's system.

The main transmission lines in the area are: Benewah – Shawnee, Benewah – Moscow 230, Benewah – Pine Creek, Benewah – Boulder, Hatwai – Moscow 230 and North Lewiston – Shawnee 230 kV Transmission Lines.

The main sources that feed load in the Palouse Area include three 230/115 kV transformers located at Benewah, Shawnee and Moscow 230 Substations. The transformer located at Shawnee Substation is rated 250 MVA and the other two transformers are rated 125 MVA. Transformation sources in Avista's system are designed to have in service spares. This type of configuration provides back up sources to loads for loss of a 230/115 kV transformer.

There is presently no generation of significant capacity located within the Palouse Area. Three projects are in the interconnection study process but are still in the proposal phase as no final agreements have been arranged. The projects include the following:

- Project #14 210 MW North Lewiston – Shawnee 230 kV Transmission Line
- Project #31 150 MW Lind – Shawnee 115 kV Transmission Line
- Project #32 100 MW Benewah – Shawnee 230 kV Transmission Line

Avista signed a Power Purchase Agreement for First Wind's Palouse Wind Project in June 2011. The Palouse Wind Project (Project #17) will interconnect with Avista's Transmission System on the Benewah – Shawnee 230 kV Transmission Line and provide Avista with approximately 40 average megawatts of renewable energy, or as much as 100 megawatts of nameplate wind capacity, under a 30-year power purchase agreement with deliveries beginning in 2012. The energy qualifies under Washington State's Energy Independence Act (RCW 19.285) to meet Avista's Washington State-mandated renewable portfolio standard (RPS) requirements.

The 115 kV Transmission System in the Palouse Area is primarily operated with normally open points referred to as "star points". A star point is used to minimize power flow to mitigate overloads on the 115 kV system in the event of an outage on the overlying 230 kV Transmission System, as well as reducing overall system losses in the area. Operating in a "star" configuration also reduces exposure to loads served by long transmission lines. In the Palouse Area, star points switches can be operated open or closed based on outages, specific flow conditions, or due to operational constraints.

Avista's communication system in the Palouse Area includes a wide variety of technologies including: fiber optic cable, power line carrier (PLC) and analog/digital microwave. The Benewah – Shawnee 230 kV Transmission Line uses fiber optic cable for its permissive overreaching transfer trip (POTT) protection scheme. The other 230 kV transmission lines in the area also have POTT schemes but they rely on either PLC or microwave communication. Presently there is no redundant means of communication between the Northern and Southern portions of Avista' system. As the Palouse Area lies between the Northern and Southern portions, it would be ideal to provide a second path of communication utilizing the infrastructure in the area if redundancy is required. There is also no redundant means of communication for some transmission lines within the Southern portion of Avista's system therefore yielding potential loss of the POTT protection schemes.

The Palouse Area is not divided into sub-areas due to the geographical nature and transmission configuration it contains. The area is defined by the following 115 kV transmission lines:

The Shawnee – Sunset 115 kV Transmission Line feeds Chambers, East Colfax, Rosalia, Spangle and Hangman Substations. The normal star point on the Shawnee – Sunset 115 kV Transmission Line is North of East Colfax Substation at switch A147. The total Avista owned distribution transformation capacity is 36.875 MVA. Chambers and Hangman Substations are owned and operated by Inland Power & Light (IP&L) and provide an additional 25.4 MVA of transformation capacity to the area. There is an auto sectionalizing scheme present on the Shawnee – Sunset 115 kV Transmission Line to aid in a quick restoration of power to the customers fed from the transmission line.

The Lind – Shawnee 115 kV Transmission Line feeds Diamond, Ewan, Marengo and Ralston Substations. The normal star point on the Lind – Shawnee 115 kV Transmission Line is West of Ewan Substation at switch A156. The total Avista owned distribution transformation capacity is 13.124 MVA. Ralston Substation is owned and operated by Big Bend Electric Co-Op (BBEC) and provides an additional 25 MVA of transformation capacity to the area. The distribution system out of Diamond and Marengo Substations is operated at 24 kV. The St. John Substation consists of a 3 MVA 24/13 kV transformer and is located between Ewan and Diamond Substation distribution feeders.

The Eighth & Fancher – Latah Junction 115 kV Transmission Line feeds Rockford, Setters, Mica and Hopkins Substations. The normal star point on the Eighth & Fancher – Latah Junction 115 kV Transmission Line is South of Eighth & Fancher at switch A164. The total Avista owned distribution transformation capacity is 7.5 MVA. Setters Substation is owned and operated by Kootenai Electric Cooperative (KEC). Mica and Hopkins Substations are owned and operated by Inland Power & Light (IP&L). These stations provide an additional 33 MVA of transformation capacity.

The Latah Junction – Moscow 230 115 kV Transmission Line feeds Latah Junction, Tekoa, Garfield, Palouse, Potlatch and Brincken's Corner Substations. The normal star point on the Latah Junction – Moscow 230 115 kV Transmission Line is North of Garfield Substation at Switch A114. The total Avista owned distribution transformation capacity is 47.812 MVA. Brincken's Corner Substation, owned by the BPA, contains a 25 MVA, 115/69 kV transformer which supplies Brinken's Corner, Tensed and Fernwood Substations which are owned by Clearwater Power Company. Potlatch and Brincken's Corner Substations are classified to be within a radial service area. There is an auto sectionalizing scheme present on the Latah Junction – Moscow 230 115 kV Transmission Line to aid in a quick restoration of power to the customers fed from the transmission line.

The cities of Pullman, WA and Moscow, ID are fed by the Shawnee – Terre View, Moscow 230 – Terre View, Shawnee – South Pullman and Moscow 230 – North Lewiston – South Pullman 115 kV Transmission Lines. The Moscow 230 – North Lewiston – South Pullman 115 kV Transmission Line has a normal star point South of Moscow City at switch A186. The other transmission lines are operated normally closed. These transmission lines feed Pullman, Terre View, North Moscow, Moscow 230, Moscow City, Leon Junction, South Pullman and Armstrong Substations. The total Avista owned distribution transformation capacity is 189.5 MVA. The distribution system out of Moscow 230 Substation is operated at 24 kV. Armstrong Substation is owned and operated by IP&L and provides an additional 7.5 MVA of transformation capacity to the area. There are auto sectionalizing schemes present on the Shawnee – Terre View, Moscow 230 – Terre View and Moscow 230 – North Lewiston – South Pullman 115 kV Transmission Lines to aid in a quick restoration of power to the customers fed from these transmission lines.

The Moscow 230 – Orofino 115 kV Transmission Line feeds Juliaetta and Deary Substations. The Moscow 230 – Orofino 115 kV Transmission Line is operated normally closed. The total Avista owned distribution transformation capacity is 26 MVA. Deary Substation is classified to be within a radial service area. The distribution system out of Deary Substation is operated at 24 kV and has back up service provided by Moscow 230 Substation.

Load growth in the Palouse Area is projected to be 1.6% for summer and 1.6% for winter based on historic load growth data. Total anticipated load not including Transmission System losses for peak summer 2012 is 152 MW and 209 MW for peak winter 2012. Total installed distribution (i.e. 115/13.8 or 115/21 kV) transformation capacity in the Palouse Area is 320.8 MVA based on transformer nameplate ratings.

3 DEVELOPMENT OF PLANNING ASSESSMENT

3.1 LOCAL PLANNING PROCESS

The development of this Planning Assessments follows the local transmission planning process (Process) provided in *Attachment K, Part III – The Avista Local Transmission Planning Process* of Avista Corporation's Fourth Revised Volume No. 8 of the Open Access Transmission Tariff ("OATT"). The Process is open to all Interested Stakeholders, including, but not limited to, all Transmission Customers and interconnection customers, and state authorities. Avista held a Study Development Meeting during the second quarter of 2011 providing participants an opportunity to provide comment for data gathering, initial assumptions and input into the study development. All comments received at the Study Development Meeting, or during the 30 days following, were incorporated into the Planning Assessment.

The purpose of the Process is to identify any Single System Projects that are needed to mitigate future reliability and load-service requirements for Avista's Transmission System. This Planning Assessment identifies any reliability impacts identified on Avista's Transmission System, and provides a list of the Single System Projects proposed to mitigate those issues. Such reliability impacts were identified by performing technical studies, which included powerflow, transient stability, short circuit, and voltage collapse studies. **For Single System Projects not identified in previously completed Planning Assessment, a separate Corrective Action Plan (detailed project study) will be conducted as necessary to determine the technically superior project(s) to be carried forward into the Avista capital budgeting process.**

3.2 TRANSMISSION PLANNING CRITERIA

The transmission planning reliability criteria used in evaluating the performance of the transmission system is the present North American Electric Reliability Corporation (NERC) Reliability Standards and WECC regional reliability criteria including the following:

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

3.3 TRANSMISSION PLANNING ASSUMPTIONS

The following assumptions have been used in the Process for performing technical studies. The assumptions are made upon the experience of Avista's System Planning Group and to comply with NERC Reliability Standards.

3.3.1 Base Case Development

Avista's System Planning Group develops a set of base cases annually using WECC approved base cases, applying steady state and dynamic data modifications as required to represent desired scenarios. Four seasonal scenarios are developed which represent bookends that have been historically established through previous technical studies. The scenarios developed include the following:

1. Heavy Summer with High Local Hydro Generation (Heavy Summer, High Hydro Case)

   This is the typical summer peak scenario where the Avista Balancing Authority Area load is near peak and the local hydro generation is at a typical mid-summer output. This scenario represents Avista's heavy summer loading with moderate transfers into Avista's Balancing Authority Area. This scenario is limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the System is near capacity.

2. Heavy Summer with Low Local Hydro Generation (Heavy Summer, Low Hydro Case)

   This is the typical summer peak scenario where the Avista Balancing Authority Area load is near peak and the local hydro generation has a low output. This scenario plays a dual role, in that it represents both Avista's heavy summer loading scenario along with the sensitivity of significant transfers into Avista Balancing Authority Area to supplement the low hydro generation. This scenario is limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the System is near capacity.

3. Heavy Winter Case

   This is the typical winter peak scenario where the Avista Balancing Authority Area load is heavy but the lower ambient temperature increases the operating limits of the various elements of the Transmission System. Local hydro generation is at a moderate level and there are significant transfers into Avista's Balancing Authority Area from regional thermal resources.

4. Light Summer with High West of Hatwai Flows (High Transfer Case)

   During light summer (night time loading) with high Western Montana Hydro and high Montana thermal generation, the WECC rated path "West of Hatwai" (WECC Path #6) reaches its heaviest loading. During this scenario, portions of the Transmission System are nearing their stability limits. These limits define some of the operating constraints for the region and also establish some of the arming levels for Remedial Action Schemes (RAS). This scenario is also limited by the summer thermal limits on various elements of the transmission system, which helps to define where the system is near capacity.

These base cases are developed to represent both the five and ten year planning horizon. A detailed summary of specific flows and loading levels for the base cases used in the 2011 Planning Assessments can be viewed in the interoffice memorandum SP-2011-03 – 2011 Planning Cases Summary Data.

3.3.2 Load Forecast

Load forecasts for Network Customers and Point-to-Point Customers were requested at the Study Development Meeting. The BPA submitted its forecast load information as a Network Customer to Avista for inclusion in the technical studies. Avista's System Planning Group incorporated forecast load data for its Load Serving Entity ("Avista LSE") into the technical studies.

3.3.3 Planned Transmission Facilities

No planned transmission expansion project facilities are included in the bases cases used in technical studies performed for the Planning Assessments. During previous Planning Assessments inclusion of non-committed planned transmission facilities has incorrectly hidden potential reliability and load-service requirements. Subsequently, a Corrective Action Plan was not developed as required by the Process.

3.3.4 Planned Generation Facilities

Only potential generation projects in the Avista Interconnection Request queue that have executed Interconnection Agreements are modeled (with corresponding upgrades) in the base cases for technical studies.

The 2011 Planning Assessments did not include any potential generation in the technical studies.

3.3.5 Contingencies

The contingencies evaluated for powerflow and transient stability technical studies are a standard contingency set used by Avista's System Planning Group, reviewed and updated annually. Documentation on the contingency set is provided by System Planning Policy and Procedure SP-PP-06 Contingency Analysis.

3.4 ACCESS TO PLANNING DATA

The base cases used in the Process can be provided within 10 calendar days, via email or other media, to any WECC member that makes a request. Non-WECC members will be required to sign a confidentiality agreement with the WECC before any base cases can be shared. Once the WECC confirms a confidentiality agreement has been signed, the requested base case(s) shall be provided within 10 calendar days. Any additional information needed to replicate the technical study results of the Process can be provided, upon written request.

3.5 IDENTIFICATION OF ANALYTICAL TOOLS

The following Analytical Tools were used to perform technical studies:

- PowerWorld Simulator Software, Version 15
  - PowerWorld Simulator is an interactive power systems simulation package designed to simulate high voltage power systems operation on a time frame ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses using mathematical calculations based on system impedances, load levels and generation output. PowerWorld provides the user with a variety of sophisticated study tools such as an automated contingency processor, an Available Transfer Capability (ATC) tool, an Optimal Power Flow tools, various voltage stability tools (i.e. PV and QV tools), and a Transient Stability Analysis tool.
- GE Positive Sequence Load Flow, Version 17.05
  - The GE Positive Sequence Load Flow (PSLF) software suite is a package of programs for studying power system transmission networks and equipment performance in both the steady-state and dynamic environments.
- ASPEN OneLiner Software Build 2007.11.7 Group-1
  - ASPEN OneLiner is a PC-based short circuit and relay coordination program for relay engineers. OneLiner is an interactive productivity tool allowing the engineer to accurately model the transmission system, perform fault analysis by simulating all classical fault types, graphically plot fault solution and relay coordination curves and validate relay settings through relay models and automatic checking module.

4 SINGLE SYSTEM PROJECTS AND CORRECTIVE ACTION PLANS

4.1 PLANNED SYSTEM MODIFICATIONS

The following sections describe projects to either enhance the existing Palouse Area Transmission System or mitigate deficiencies discovered during the course of the Process. These items should be addressed as construction schedules and annual budgets permit:

4.1.1 Palouse Wind Interconnection

Avista signed a Power Purchase Agreement for First Wind's Palouse Wind Project in June 2011. The Palouse Wind Project (Project #17) will interconnect with Avista's Transmission System on the Benewah – Shawnee 230 kV Transmission Line and provide Avista with approximately 40 average megawatts of renewable energy, or as much as 100 megawatts of nameplate wind capacity, under a 30-year power purchase agreement with deliveries beginning in 2012. The energy qualifies under Washington State's Energy Independence Act (RCW 19.285) to meet Avista's Washington State-mandated renewable portfolio standard (RPS) requirements. The Palouse Wind Project will consist of a mix of Vestas V100, 1.8 MW and V112, 3 MW "Grid Standard" Wind Turbine Generators (WTG).

The location of the Palouse Wind Project is 4 miles south of Rosalia, WA and 4 miles east from Avista's Benewah - Shawnee 230 kV Transmission Line. The Point of Interconnection (POI) was selected to be a new 230 kV switching station located approximately 32.3 electrical miles south of the Benewah Substation on the Benewah – Shawnee 230 kV Transmission Line. The new POI switching station has been named Thornton Switching Station. The final Facilities Study for Project #17 provides details to the equipment, engineering, procurement and construction required to implement the interconnection of the Palouse Wind Project. Figure 4-1 illustrates the project diagram provided in the Facilities Study. Following the completion of the Facilities Study, a decision was made by Avista's Engineering, Operations, and Planning Directors that the bus configuration be changed to a ring bus design with a designated transmission line position for the Palouse Wind Project. The decision was based on geographical constraints, cost, construction schedule, and customer needs. The Thornton Switching Station will be Avista's first 230 kV ring bus design.

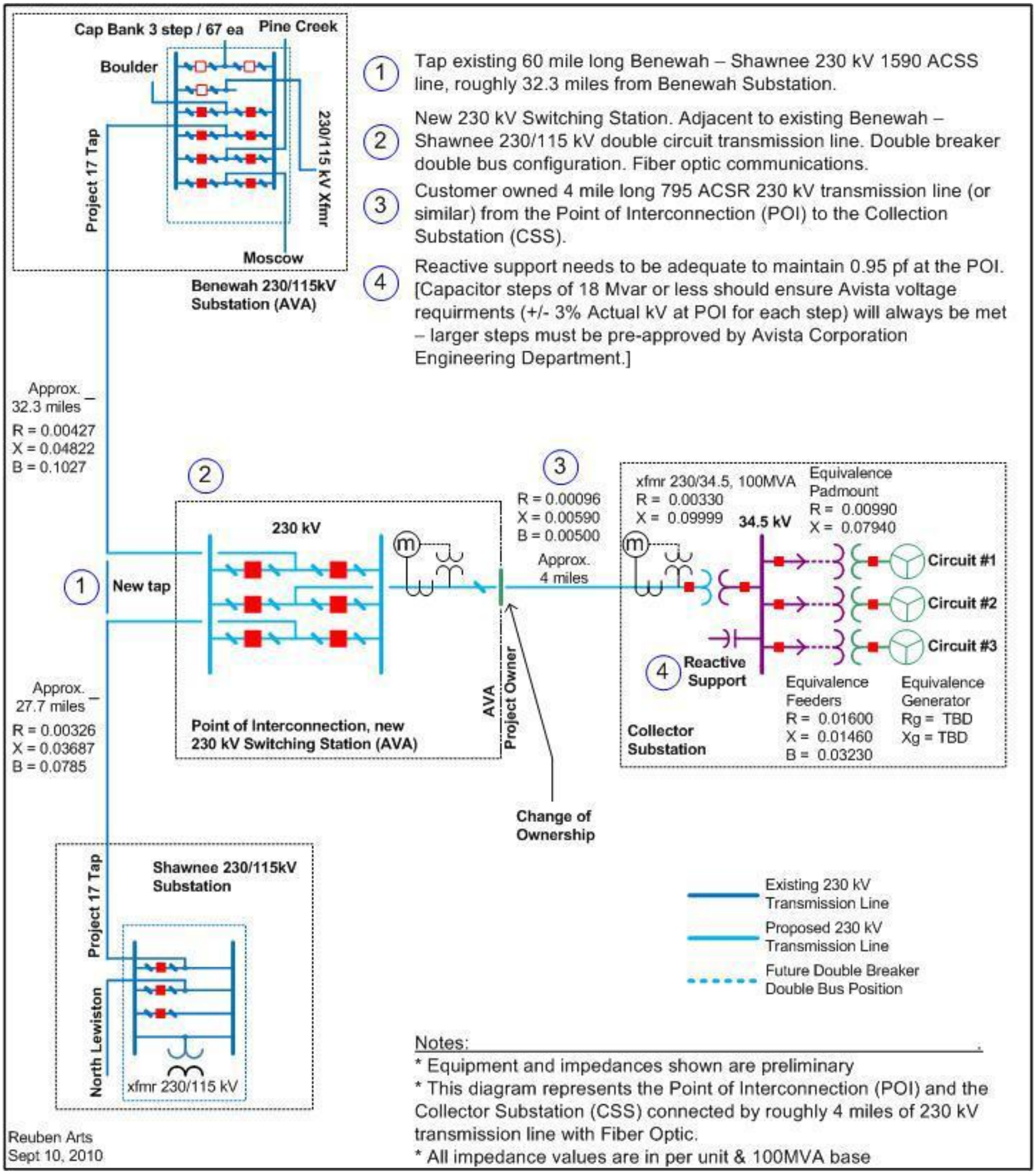


FIGURE 4-1: PALOUSE WIND INTERCONNECTION PROJECT DIAGRAM.

4.1.2 Pullman Substation Rebuild (Turner Substation)

The existing Pullman Substation is being reconstructed due to equipment condition and capacity requirements. Completion of the rebuild is scheduled for 2012 and the new substation will be named Turner Substation. The new substation will be constructed to the latest Substation Engineering practices and will have the ability to perform as desired for the Smart Grid Demonstration Project being executed in the area.

4.1.3 Industrial Load Near Bovill

An industrial customer has approach Avista with a request for electrical service to be provided near Bovill, ID. Initial projections of desired capacity range from 6 to 10 MW. The existing distribution feeders in the area will be inadequate to supply the additional load. Preliminary concepts to serve the new customer include constructing a new 8 mile 115 kV transmission line from the existing Deary Substation and constructing a new distribution substation near the industrial customer's facilities. Preliminary estimates for the proposed projects required to serve the customer is $6.3 million. Detailed design and construction will not be initiated until the customer provides sufficient documentation of its proposed facility and an "official" request for service.

4.1.4 Smart Grid Demonstration Project

The Smart Grid Demonstration Project grants are focused on the demonstration of smart grid technologies that can be applied at a local level but be leveraged to provide benefits to an entire region as well as the nation. Avista is one of eleven utility participants, Bonneville Power Administration, and a diverse team of vendor partners led and managed by Battelle in a project now known as the Northwest Smart Grid Project. Each utility submitted a "subproject" that satisfied the goals and objectives of the regional project and that of each specific utility. These subprojects were then rolled into the larger cooperative project.

The primary objectives of the regional project are to:

- Develop a transactive control system using incentive signals to coordinate customer and utility assets, including demand response, distributed generation and storage, and distribution automation. The system would operate in an automated fashion while maintaining local control of grid assets.
- Measure and validate smart grid costs and benefits for customers, utilities, regulators and the nation. Data and analysis from this project would become a foundation for future smart grid investments.
- Apply smart grid capabilities to support the integration of the rapidly expanding portfolio of renewable resources in the region.
- Contribute to the knowledge of interoperability standards.

4.1.5 North Moscow Transformation

It has been proposed to add an additional 20 MVA distribution transformer to the North Moscow Substation. The additional transformer at North Moscow Substation is needed within 5 years. The project was initially proposed based on a new large growth area off Highway 270 near the Idaho and Washington state line.

4.1.6 Tamarack Substation

A new distribution substation located in the northeastern outlying area of Moscow has been proposed. The new substation has been named Tamarack Substation and is proposed to be connected to the Moscow 230 – Terre View 115 kV Transmission Line approximately 1.5 miles East of North Moscow Substation. Tamarack Substation is needed within 5 years depending on specific load growth in the area.

4.1.7 Moscow City – North Lewiston 115 kV Rebuild

The Moscow City – North Lewiston 115 kV Transmission Line has been identified for reconstruction by the Transmission Engineering Group due to existing physical condition. The existing conductor consists primarily of 7#8 CU and short distances of 556 kcmil. The System Planning Group has assessed the potential loading of the transmission line and with the present operating configuration, 556 kcmil conductor will provide adequate capacity within the ten year planning horizon. Further details of the proposed project can be referenced in the System Planning Memo SP-2011-05 – Moscow City – North Lewiston 115 kV Transmission Line Rebuild.

4.1.8 Potlatch Transformer Replacement

Potlatch #1 115/13.8 kV Transformer has been identified to be replaced as part of Avista's effort to eliminate equipment with high PCB levels. Replacement of the transformer is planned for 2013 or 2014 as funding for the project becomes available. Potlatch #1 115/13.8 kV Transformer is the first project identified to be completed under the proposed Substation PCB Replacement Program. Additional substation work may be required as the substation is nearing the end of its life cycle.

4.1.9 Transformer Tap Positions

Due to recent transmission system reconfigurations including the new Benewah – Shawnee 230 kV Transmission Line, there is a need to evaluate the present tap positions on all of the distribution transformers and determine if they are set at their desired setting. Historically Avista has set tap positions to accommodate for the worst case contingency in the area. In several locations this may result in overuse of the feeder regulators meaning a continual bucking or boosting of the voltage during normal operating conditions. An analysis will be conducted to comprehensively review the Palouse Area and perform any corrective actions that are deemed necessary as a result.

4.1.10 Distribution Upgrades

Several distribution feeders have been identified as needed to be upgraded or replaced due to their existing condition and recent historical performance. The scheduling, budgeting, design and construction required for this work is done by the Distribution Engineering Group and therefore are only mentioned here for completion.

Additional distribution upgrades include the addition of feeder ties which will aid in the operational flexibility of the distribution system. The regional operation engineers largely drive these types of projects and are therefore only mentioned here for completion.

4.2 NORMAL SYSTEM CONDITIONS (N-0): NERC CATEGORY A

There are no N-0 future reliability and load-service requirements discovered during the Process in the Palouse Area.

4.3 SINGLE CONTINGENCY ISSUES (N-1): NERC CATEGORY B

4.3.1 Moscow 230/115 kV Transformer

The existing Moscow 230/115 kV Transformer consists of a nominal 125 MVA, 230/115 kV transformer and a 115/115 kV voltage regulating transformer. The N-1 contingency loss of the Shawnee 230/115 kV Transformer can cause the Moscow 230/115 kV Transformer to overload to 99% of its nameplate rating in the five year planning horizon and to 120% in the ten year planning horizon (see Figure 4-2). Overloading of the Moscow 230/115 kV Transformer is also identified in the Avista 2011 Summer Operating Studies Report and therefore is a TPL-002, R1 violation.

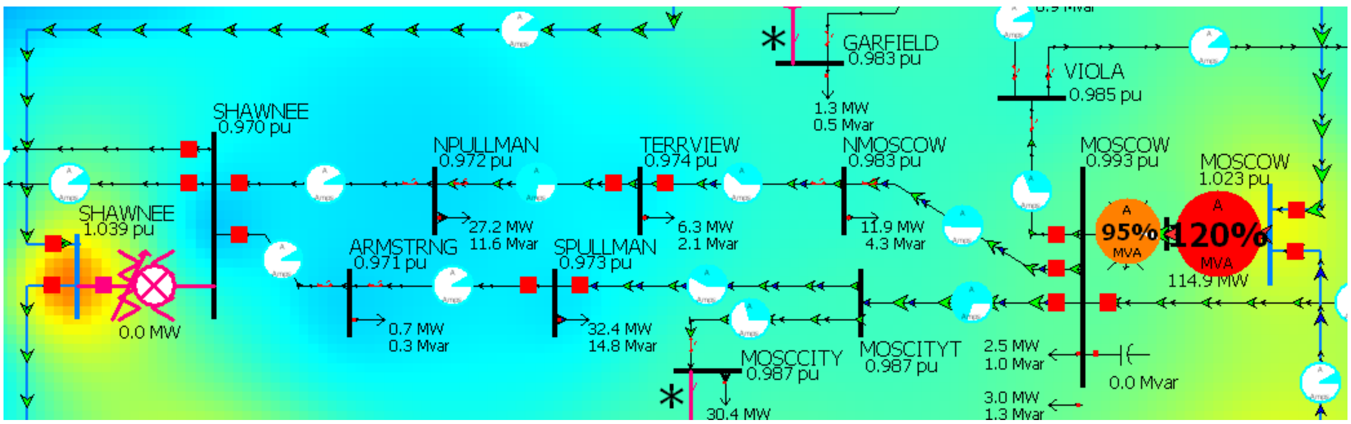
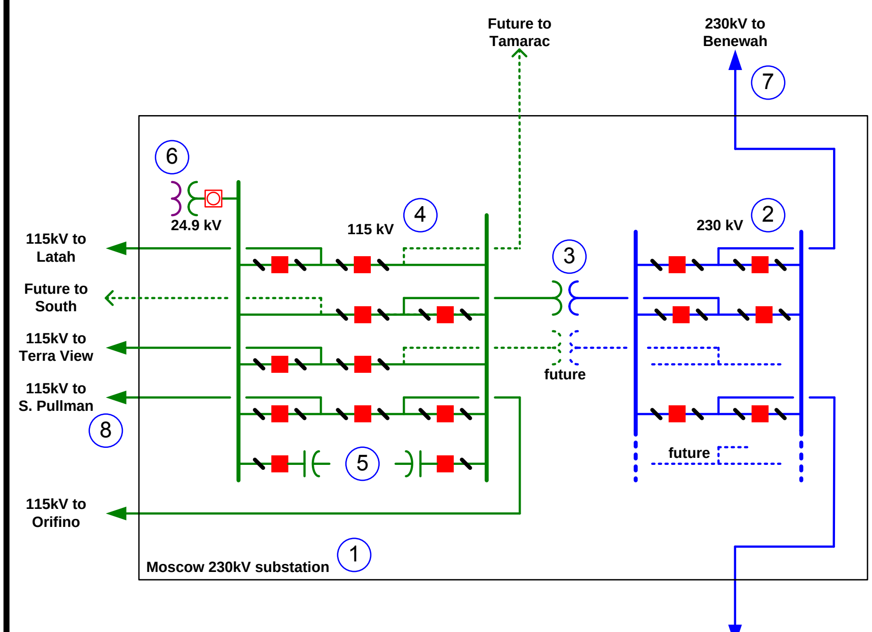


FIGURE 4-2: SHN 230/115 OUTAGE.

A Correction Action Plan has been developed and is documented in System Planning Memo SP-2010-07 – Moscow 230 kV Sub – 230/115 kV Autotransformer Capacity Increase. The selected Single System Project to mitigate overloading of the Moscow 230/115 kV Transformer is to replace it with a 250 MVA transformer. Substation Engineering has identified several issues which warrant a rebuild of the Moscow 230 Substation therefore a complete rebuild of the station has been coordinated with the replacement of the transformer. Figure 4-3 show the new station configuration. Construction began in 2010 and is scheduled to be completed in 2014. The new 250 MVA transformer is scheduled to be delivered to the station in October 2011.



1. New property, earthwork, grading, gravel, fence, gate and landscaping
2. Construct new three terminal 230kV double breaker, double bus arrangement w/ space for (2) future bays
3. Install new 230/115kV, 250MVA, AutoTransformer w/ LTC +/- 5%
4. Construct new five terminal, 115kV breaker and half arrangement w/ space for (2) future bays or equivalent arrangement
5. Install (2) new 115kV cap bank - (1) Step of 33.5 MVAr each
6. New 115/25kV, 20MVA transformer with (2) feeder positions
7. Build (2) new 230kV, 1590 ACSR line extensions – substation equipment to match line ampacity
8. Build (4) new 115kV, 795 ACSR line extensions – substation equipment to match line ampacity

Notes:
1) The line north to Tamarac is 5 to 10 years out & 2nd 230/115 XFMR is ~20 years out. The future 230kV & 115kV line positions are not required within the 10 Year Planning timeframe and therefore have no in service date estimates.
2)

	PROJECT SCOPE UPDATE REVISION NOTES		
2	Full DB-DB buildout & 2nd cap bank	DWS	09-15-2010
1	Issue for design & build	DWS	07-27-2010
0	Initial design and arrangement	DWS	07-14-2009
NO.	REVISION	BY	DATE

Moscow23 Substation Rebuild

Project Diagram: SP-0224

AVISTA Corp.

SPOKANE, WASHINGTON

ORIGINAL DATE	APPROVAL
July 27, 2010 DESIGN: SYSTEM PLANNING	

FIGURE 4-3: SP-0224 MOSCOW23 SUBSTATION REBUILD PROJECT DIAGRAM.

4.3.2 Latah Jct. – Moscow 230 115 kV Transmission Line

During a line end open scenario on the Latah Jct. – Moscow 230 115 kV Transmission Line open at Moscow 230 Substation, low voltage were observed at the following substations: Potlatch, Palouse, Garfield and Brinken's Corner Substations (see Figure 4-4). An outage of the Moscow 230 230/115 kV Transformer will also cause similar low voltage issues but are not as severe (see Figure 4-5). These low voltages only occur during heavy winter loading conditions and become worse as load growth continues. The lowest voltage occurs at Potlatch Substation; in the five year horizon the voltage is 0.93 pu and 0.93 in the ten year horizon. The primary cause of this issue is 40 plus miles of small conductor including 1/0 CW and 7#7 CU and heavy load at the end of the transmission line.

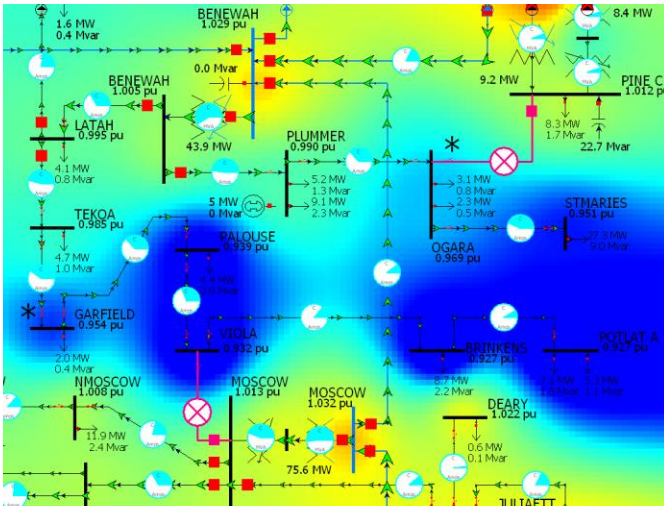


FIGURE 4-4: M23-VIO OUTAGE.

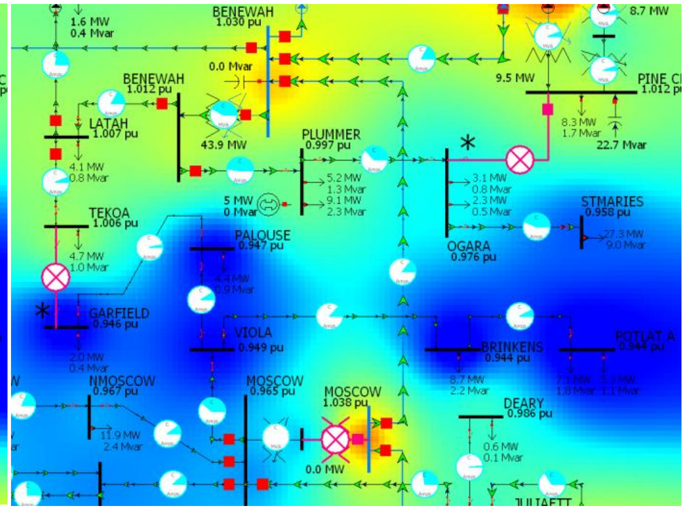


FIGURE 4-5: M23 XFM OUTAGE.

The following are possible alternatives to mitigate the potential low voltage issue:

1. Status Quo – Low voltage issues will worsen with time. Increasing the operating voltage at Benewah Substation by tapping the autotransformer and shifting load from Latah Junction Substation to the Third & Hatch – Ninth & Central 115 kV Transmission Line by closing air switch A164 will provide some relief in the then ten year planning horizon.

2. Reconductor approximately 36.5 miles of the Latah Jct. – Moscow 230 115 kV Transmission Line with 556 conductor from 5.5 miles south of Latah Junction Substation to Viola Switching Station. Voltage at Potlatch Substation under the line end open scenario will increase to 0.97 pu in the 10 year horizon.

3. Install 15 MVAr capacitor bank at Garfield Substation. Voltage at Potlatch Substation under the line end open scenario will increase to 0.97 pu in the 10 year planning horizon.

Alternative 3 is recommended to be carried forward, pending a detailed Corrective Action Plan, to mitigate the observed low voltages during single contingency issues. The proposed capacitor bank installation should be completed by 2015.

4.3.3 Lind – Shawnee 115 kV Transmission Line

During the Heavy Summer scenario, low voltages are observed at Diamond, Ewan, and several other substations located in the Big Bend Area during the line end open scenario of the Lind – Shawnee 115 kV Transmission Line open at Shawnee Substation (see Figure 4-6). The Lind – Shawnee 115 kV Transmission Line has a normally open point at air switch A156 on the west side of Ewan Substation therefore the line end open scenario occurs while restoring service to Diamond and Ewan Substations from Lind Substation.

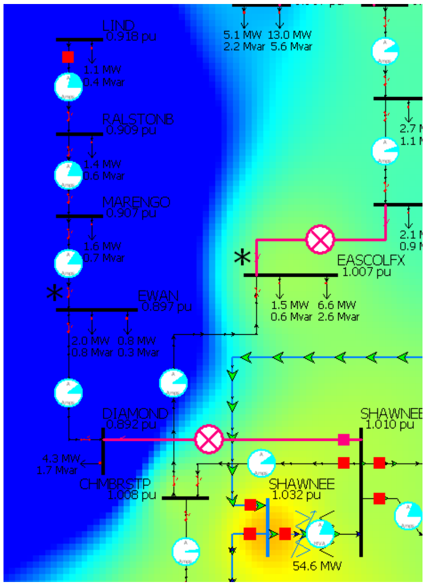


FIGURE 4-6: DIA-SHN OUTAGE.

Possible alternatives to mitigate the potential low voltage issue will be address in the Big Bend Area Planning Assessment. The installation of a capacitor is proposed at Lind Substation which will improve the low voltage issue but it does not provide for complete mitigation of the documented issue.

4.4 MULTIPLE CONTINGENCY ISSUES: NERC CATEGORY C AND D

4.4.1 Moscow 230/115 kV Transformer

Several multiple contingency issues cause thermal overloading of the Moscow 230 230/115 kV Transformer. The contingencies causing potential violations include bus outages Shawnee 115 kV bus (see Figure 4-7), Shawnee 230 kV bus (see Figure 4-8), and Hatwai 230 kV bus (see Figure 4-9), a 500 kV breaker failure at Hatwai Substation (see Figure 4-10), and common right-of-way outage of the Shawnee – South Pullman and Shawnee – Terre View 115 kV Transmission Lines (see Figure 4-11).

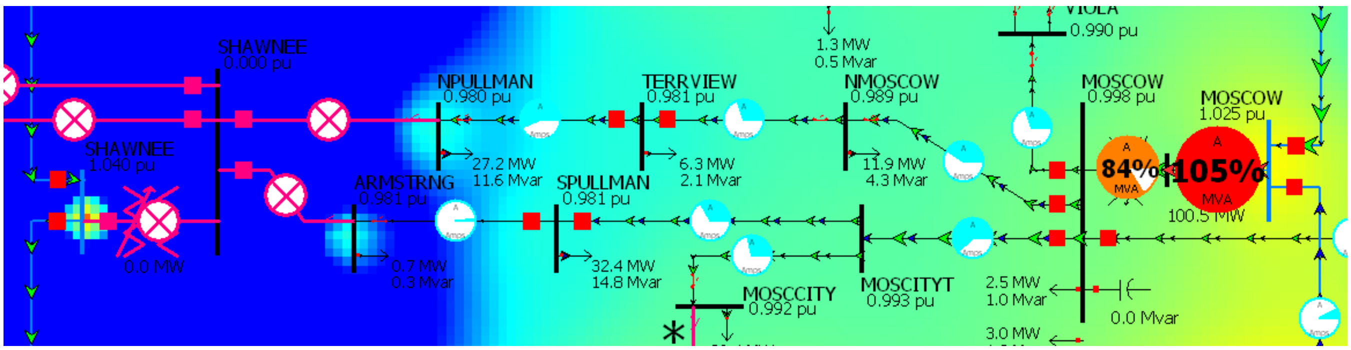


FIGURE 4-7: SHN 115 BUS OUTAGE.

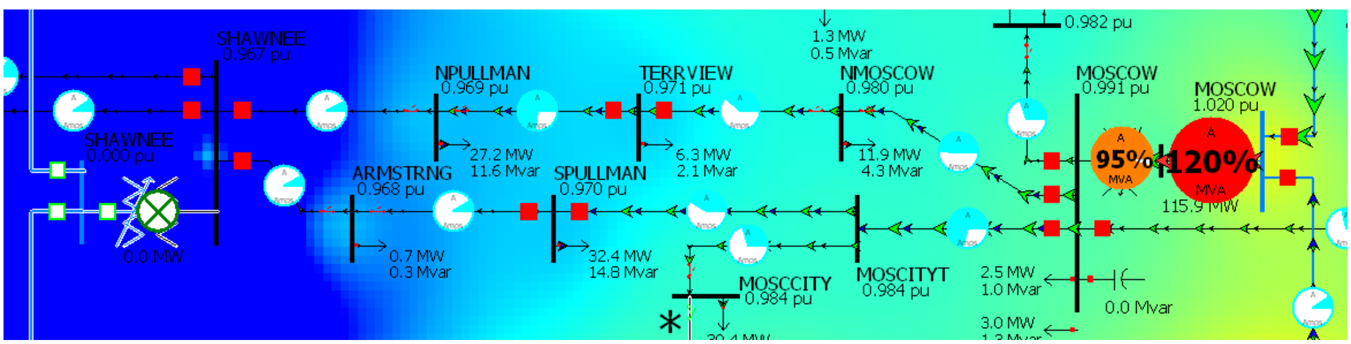


FIGURE 4-8: SHN 230 BUS OUTAGE.

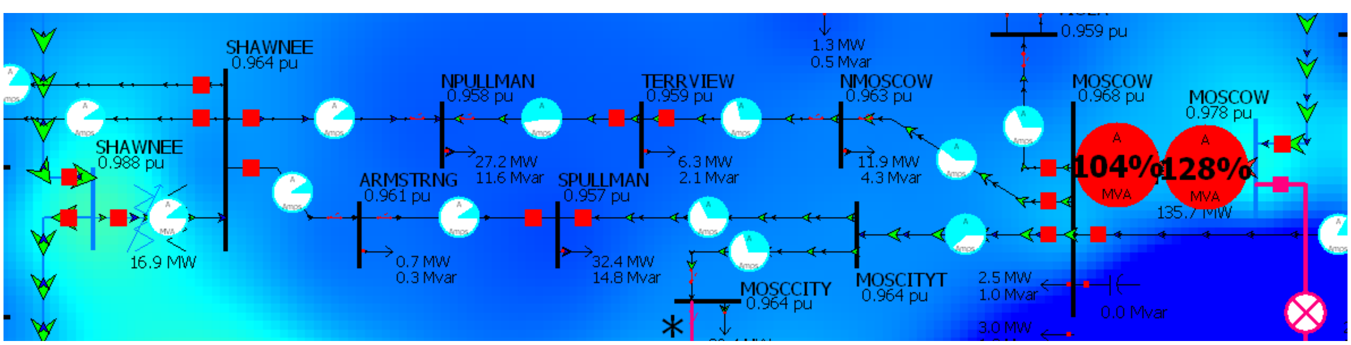


FIGURE 4-9: HAT 230 BUS OUTAGE.

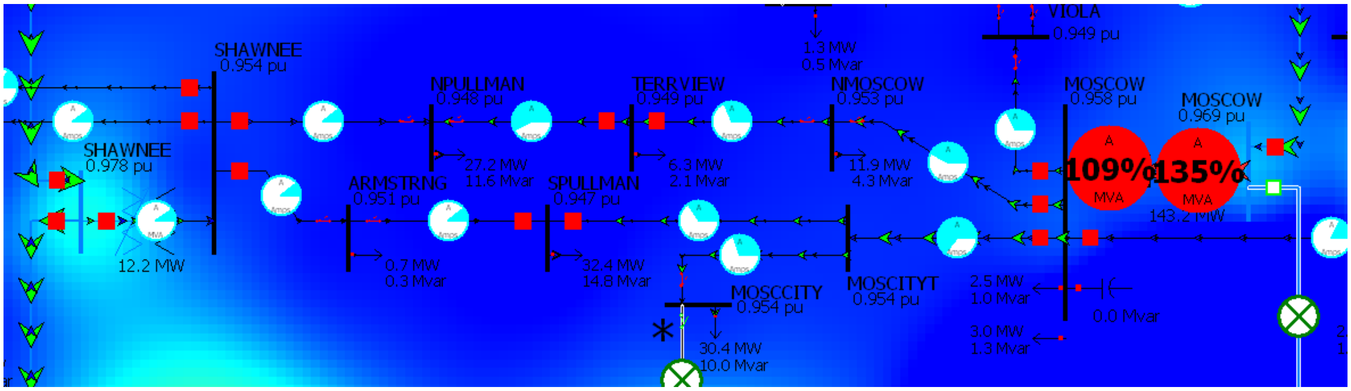


FIGURE 4-10: HAT 500 BREAKER FAILURE.

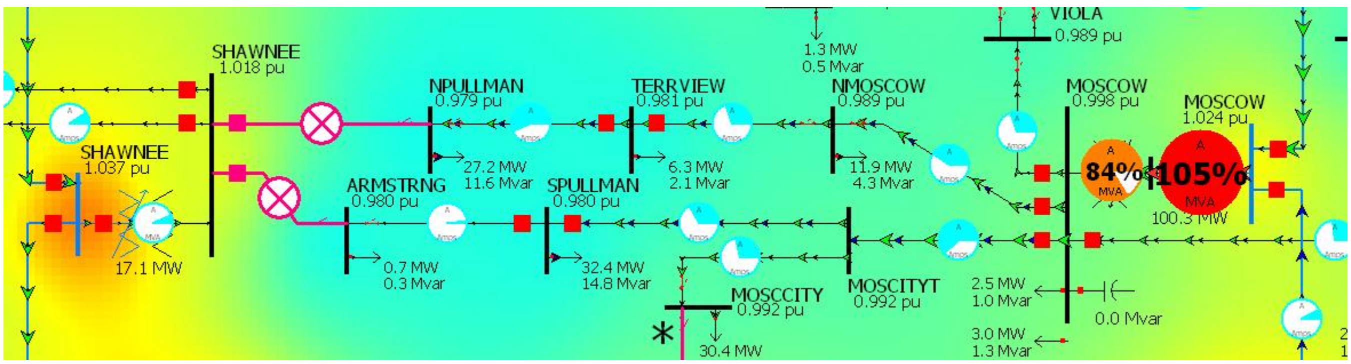


FIGURE 4-11: SHN-SPU & SHN-TVW OUTAGE.

Overloading of the Moscow 230 230/115 Transformer will be mitigated by replacing it with a 250 MVA transformer as discussed in Section 4.3.1 for single contingency issues.

4.4.2 Moscow 115 kV Bus Outage

A 115 kV bus outage at Moscow 230 Substation causes low voltage violations at Moscow City Substation. This condition occurs in heavy loaded cases, summer and winter, and becomes worse with continued load growth. The following are possible alternatives to mitigate the potential low voltage issue:

1. Do nothing – The Moscow 115 kV bus configuration will be constructed in a breaker and a half configuration during the rebuild of the Moscow 230 Substation therefore mitigating the low voltage issues. Prior to completion of the rebuild, the low voltage issue can be mitigated by adjusting the tap position on the Shawnee 230/115 kV Transformer within the 10 year planning horizon. Additional voltage support can be achieved by transferring Moscow City Substation to North Lewiston by closing switch A143. Completion of the Tamarack Substation will also reduce the load at Moscow City Substation therefore reducing the voltage drop from Shawnee Substation.

2. Install 30 MVAr capacitor bank at Shawnee Substation. The capacitor bank will supply additional reactive power support for loss of the source at Moscow 230 Substation.

Alternative 1 is recommended to be carried forward to mitigate the observed low voltages during multiple contingency issues.

4.4.3 Rosalia and Spangle Low Voltage

Rosalia and Spangle Substations experience low voltage violations for loss of a major source in the Spokane Area. The number of contingencies that cause this violation and the severity is increased with load growth. The following are options to mitigate this issue:

1. Do nothing – this issue can be mitigated by transferring Rosalia and Spangle Substations to Shawnee Substation.

2. Reinforce the Spokane Area to reduce the voltage violation severity for loss of major source.

Alternative 1 is recommended to be carried forward, pending a detailed Corrective Action Plan, to mitigate the observed low voltages during multiple contingency issues. This issue can only be solved by addressing more severe issues in the Spokane Area and is therefore deferred to the Spokane Area Planning Assessment.

4.4.4 Shawnee and Moscow Transformer Outages

The unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer) should be assessed. During a simultaneous outage of both the Shawnee and Moscow 230/115 kV Transformers, the Transmission System around Pullman and Moscow area is unable to adequately support customer demand without reconfiguring the local 115 kV transmission lines. Figure 4-12 illustrates the double transformer outage scenario with operator intervention between loss of the first transformer but without changing the configuration of the 115 kV Transmission System.

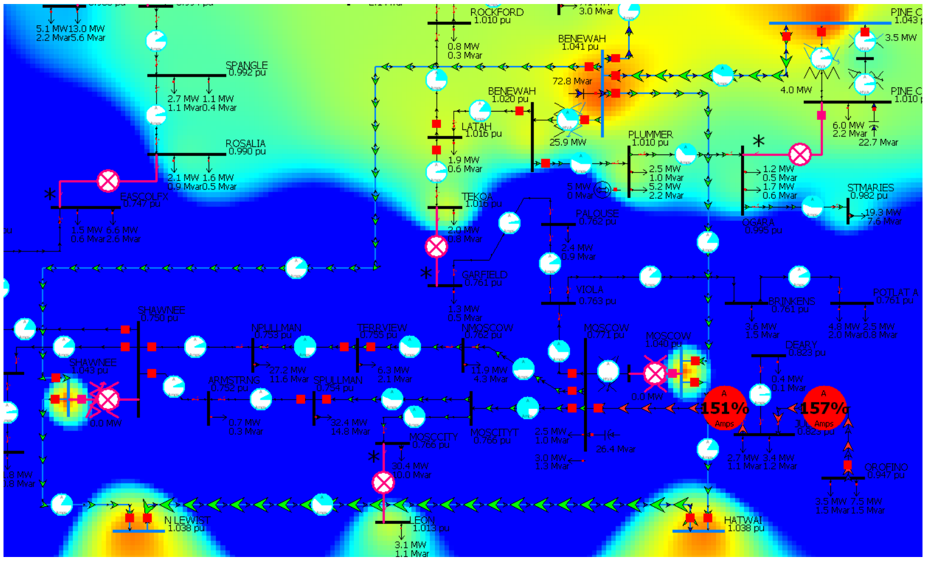


FIGURE 4-12: SHN & M23 XFMR OUTAGE.

After the loss of the first transformer, closing in the normally open points at Garfield and East Colfax Substations and moving the Moscow City Substation to the Moscow City – North Lewiston 115 kV Transmission Line better prepares the local Transmission System for an outage of the second transformer. Figure 4-13 illustrates the double transformer outage with reconfiguration of the 115 kV Transmission System in the Heavy Summer, Low Hydro scenario for the 10 year planning horizon. If a subsequent contingency occurs (N-1-1-1), the local Transmission System will be unable to supply peak customer demand.

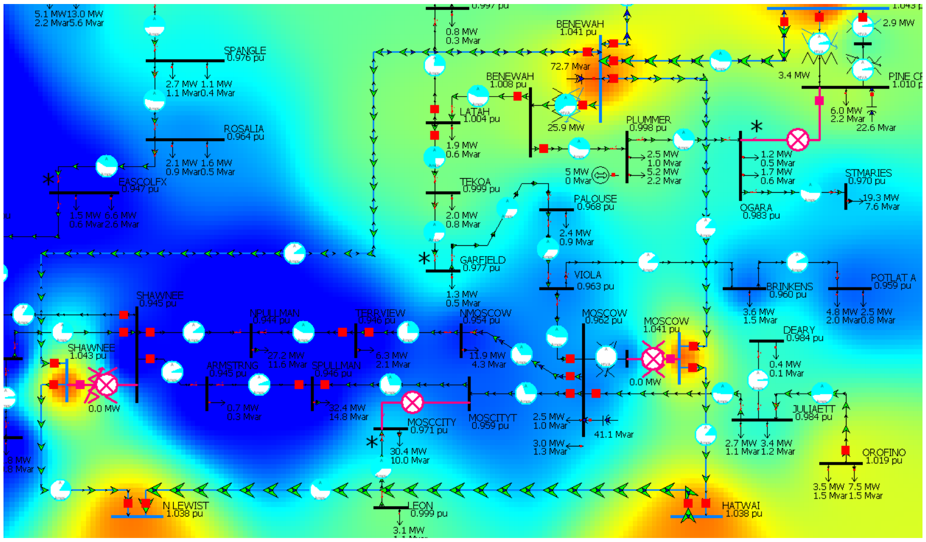


FIGURE 4-13: SHN & M23 XFMR OUTAGE WITH RESTORATION.

4.5 RESULTING ISSUES

This Planning Assessment assumes that all of the Single System Projects identified in Section 4 are completed within the ten year planning horizon to mitigate the discussed issues. There are no emergent issues forecasted beyond the ten year planning horizon. Future Palouse Area Planning Assessments will continue to monitor for emerging issues.

5 VOLTAGE STABILITY ANALYSIS (PV & QV)

Steady state analysis techniques were used to evaluate the voltage stability performance in the Palouse Area. Further investigation of voltage stability using dynamic (time-domain) simulation is presented in Section 7. PV and QV analysis were used to assess the Area's conformity with the relevant planning criteria. PV analysis of a particular area or of a particular transfer path reveals the static stability margin of the area or of the path under study while QV analysis yields the reactive power margin at a particular bus in the transmission system under consideration.

A key element of voltage stability studies is the determination of a critical bus or a cluster of critical buses. According to the WECC publication "Voltage Stability Criteria, Undervoltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology" (1998), the critical bus exhibits one or more of the following characteristics under the worst single or multiple contingency:

- Has the highest voltage collapse point on the QV curve,
- Has the lowest reactive power margin,
- Has the greatest reactive power deficiency,
- Has the highest percentage change in voltage.

The following sections provide methodology and results for the PV and QV analysis conducted.

5.1 PV ANALYSIS

5.1.1 Methodology

A PV curve is obtained in power-flow simulation by monitoring a voltage at a bus of interest and varying (increasing) the power (load or transfer) in small increments until power-flow divergence is encountered. Each equilibrium point represents a steady-state operating condition. No defined WECC paths are located in the Palouse Area therefore only a Load Ramp PV Curve analysis was performed.

The Load Ramp PV Curve analysis was conducted on the 2016 Heavy Winter case and all busses in the Palouse Area were monitored. All loads within the Palouse Area were increased until voltage collapse occurred (i.e. the case became numerically unstable). It was assumed that all additional generation necessary to supply the increase in load came from a distribution of all generation in WECC.

A set of contingencies depicting one or more transmission outages was used to produce a series of PV curves for the Load Ramp PV Curve analysis. The operating limit can be established as the lowest of the following as obtained from the PV analysis results:

1. 5% below the area load magnitude at the 'nose-point' for Category A performance,

2. 5% below the area load magnitude corresponding to the ‘nose-point’ on the PV curve representing the worst Category B contingency,
3. 2.5% below the area load magnitude corresponding to the ‘nose-point’ on the PV curve representing the worst Category C contingency (controlled load shedding is allowed to achieve this operating limit).

5.1.2 Results

As load increases in the Palouse Area, the worst Category B contingency is the line end open scenario on the Latah Junction – Moscow 230 115 kV Transmission Line open at Moscow 230 Substation. The nose point occurs near 540 MW therefore the theoretical operating limit could be a total Palouse Area load of 513 MW, nearly two and a half times the present peak winter load of the Palouse Area. The worst Category C contingency becomes the Shawnee 230 kV bus outage. The critical bus for this outage is the Ewan 115 kV bus. Controlled load shedding is allowed therefore the criticality of this contingency is not easily determined. Figure 5-1 shows the PV curves for two critical buses and the worst performing contingencies. From observation, the post transient voltage deviation at Potlatch Substation exceeds 5% for the line end open scenario on the Latah Junction – Moscow 230 115 kV Transmission Line. This issue is also address in Section 4.3.2.

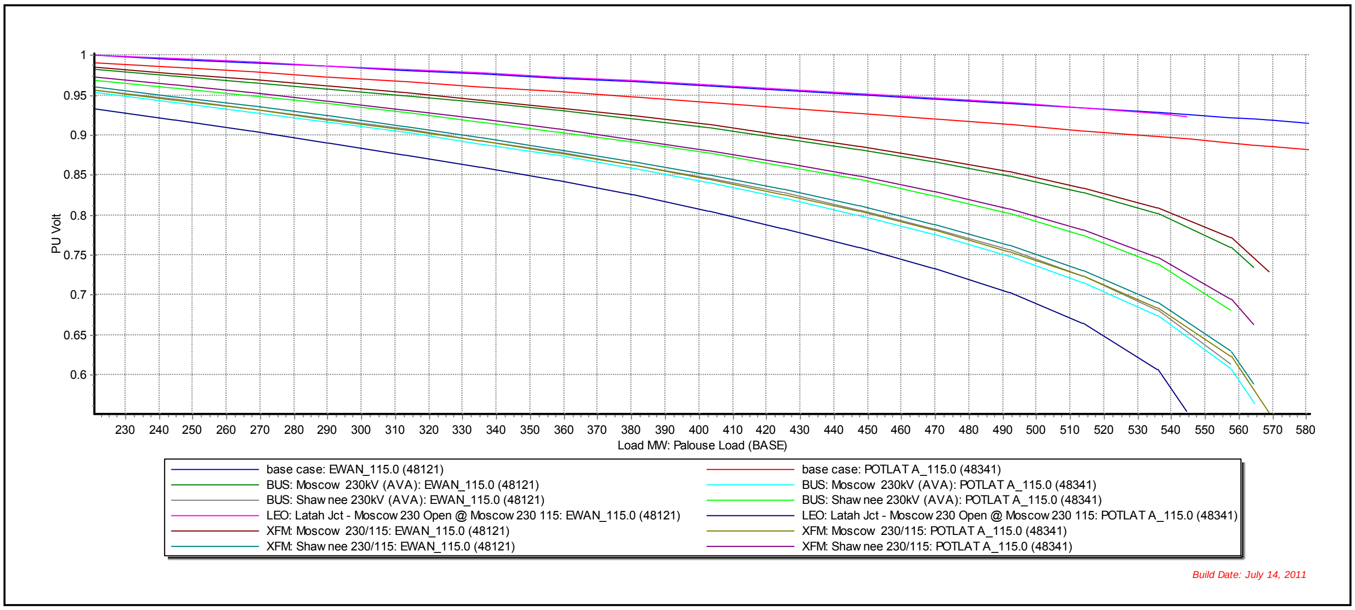


FIGURE 5-1: LOAD RAMP PV CURVE RESULTS FOR CRITICAL BUSSES.

5.2 QV ANALYSIS

5.2.1 Methodology

Using results of the PV analysis, a set of critical busses can be determined. All critical busses and 115 kV busses of 230/115 kV transformers are studied in the QV analysis. All bus voltages in the Palouse Area are monitored as the reactive demand at the bus under study is varied. This process is repeated for a set of contingencies depicting one or more transmission outages and for the remaining buses to be studied. LTC and switched shunts were disabled to provide a post-transient response prior to operator intervention. The reactive power margin (RPM) can be assessed from the results of the QV analysis. RPM is defined as the negative of the value of the reactive demand at the minimum point of the QV curve.

5.2.2 Results

The QV analysis showed there is adequate reactive power margin for the 115 kV source busses and critical busses in the Palouse Area. Table 5-1 and Table 5-2 show the results of the worst performing contingency for each bus analyzed.

The Shawnee 115 kV bus had the least reactive margin for the 115 kV busses of 230/115 kV transformers at 161 MVAr during the outage of the Shawnee 230/115 kV Transformer and 160 MVAr for the 230 kV bus outage at Shawnee Substation.

The smallest reactive margin at the critical busses analyzed occurred at the Potlatch 115 kV bus with a value of 42 MVAr for the line end open scenario on the Latah Junction – Moscow 230 115 kV Transmission Line open at Moscow 230 Substation. This issue is also addressed in Section 4.3.2.

Bus Name	Nom kV	Contingency Scenario	V at Q0	Q0	Qinj_0	V at Qmin	Qmin
POTLAT A	115	LEO: LATAH JCT - MOSCOW230 OPEN @ MOSCOW230 115	0.93	0	0	0.502	-42.1
EWAN	115	XFM: SHAWNEE 230/115	0.96	0	0	0.5	-63.08
SHAWNEE	115	XFM: SHAWNEE 230/115	0.97	0	0	0.521	-161.37
MOSCCITY	115	XFM: MOSCOW 230/115	0.97	0	0	0.524	-199.49
MOSCOW	115	XFM: MOSCOW 230/115	0.98	0	0	0.526	-208.1
BENEWAH	115	LEO: LATAH JCT - MOSCOW230 OPEN @ MOSCOW230 115	1.01	0	0	0.606	-267.38

TABLE 5-1: CATEGORY B QV ANALYSIS RESULTS FOR 5 YEAR HORIZON.

Bus Name	Nom kV	Contingency Scenario	V at Q0	Q0	Qinj_0	V at Qmin	Qmin
EWAN	115	BUS: SHAWNEE 230KV (AVA)	0.96	0	0	0.497	-62.65
POTLAT A	115	BUS: MOSCOW 230KV (AVA)	0.95	0	0	0.503	-95.39
MOSCCITY	115	BUS: MOSCOW 115	0.96	0	0	0.5	-108.22
SHAWNEE	115	BUS: SHAWNEE 230KV (AVA)	0.97	0	0	0.518	-160.11
MOSCOW	115	BUS: MOSCOW 230KV (AVA)	0.97	0	0	0.533	-206.55
BENEWAH	115	BUS: MOSCOW 230KV (AVA)	1.01	0	0	0.557	-270.91

TABLE 5-2: CATEGORY C QV ANALYSIS RESULTS FOR 5 YEAR HORIZON.

6 SHORT CIRCUIT ANALYSIS

7 DYNAMIC STABILITY ANALYSIS

7.1 STUDY METHODOLOGY

Transient stability analysis is commonly employed in the study of power system stability to reveal the total "system trajectory" following a disturbance.

Standard WECC, NERC and Avista requirements for disturbance performance were used to evaluate the results of dynamic stability analysis simulations. These requirements are as follows for Category B contingencies:

- Maximum allowable transient voltage dip of 25 percent at load buses or 30 percent at non-load buses.
- Maximum allowable transient voltage dip not to exceed 20 percent for more than 20 cycles at load buses.
- Minimum allowable frequency of 59.6 Hz for 6 cycles or more at load buses.
- Maximum allowable post-transient voltage deviation of 5 percent from pre-disturbance voltage.

The WECC/NERC voltage performance criteria are illustrated in Figure 7-1. A more detailed explanation and further information can be referenced in "*TPL – (001 thru 004) – WECC – 1 – CR – System Performance Criteria*".

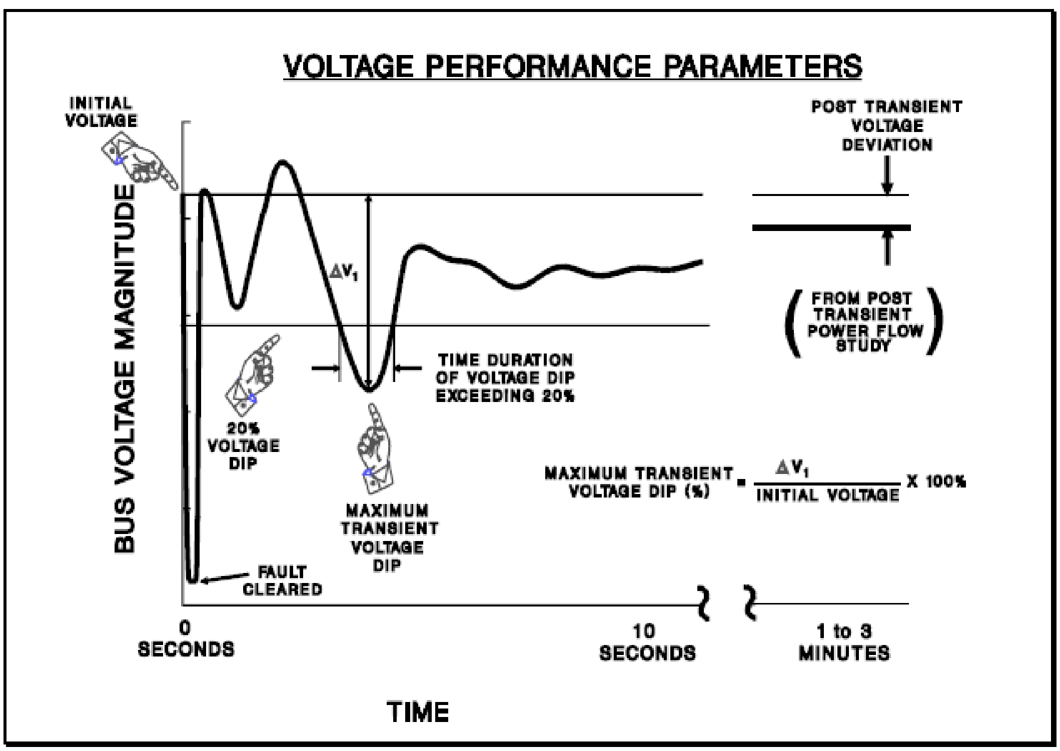


FIGURE 7-1: WECC/NERC VOLTAGE PERFORMANCE CRITERIA AND PARAMETERS.

Avista's System Planning Group uses GE PSDS software to perform transient stability simulations. The dynamic stability simulation module DYTOOLS is utilized to batch process multiple contingency scenarios in an efficient manner. Analysis of the results is conducted using a user written program to screen for criteria violations. A summary of violations is produced as well as individual plot files for each simulation performed.

Past studies have shown that transient stability on Avista's system is influenced by Western Montana Hydro, West of Hatwai flows, Northwest to Idaho flows, and Montana to the Northwest flows. As these three transfer paths can be heavily loaded during light load hours, the light load case is the most stressed. Avista's System Planning Group presently analyzes the four seasonal cases described in Subsection 3.3. The following are issues observed which should be addressed.

7.2 SINGLE CONTINGENCY ISSUES (N-1): NERC CATEGORY B

There are no N-1 future reliability and load-service requirements discovered during the Process in the Palouse Area.

7.3 MULTIPLE CONTINGENCY ISSUES: NERC CATEGORY C

There are no multiple contingency future reliability and load-service requirements discovered during the Process in the Palouse Area.

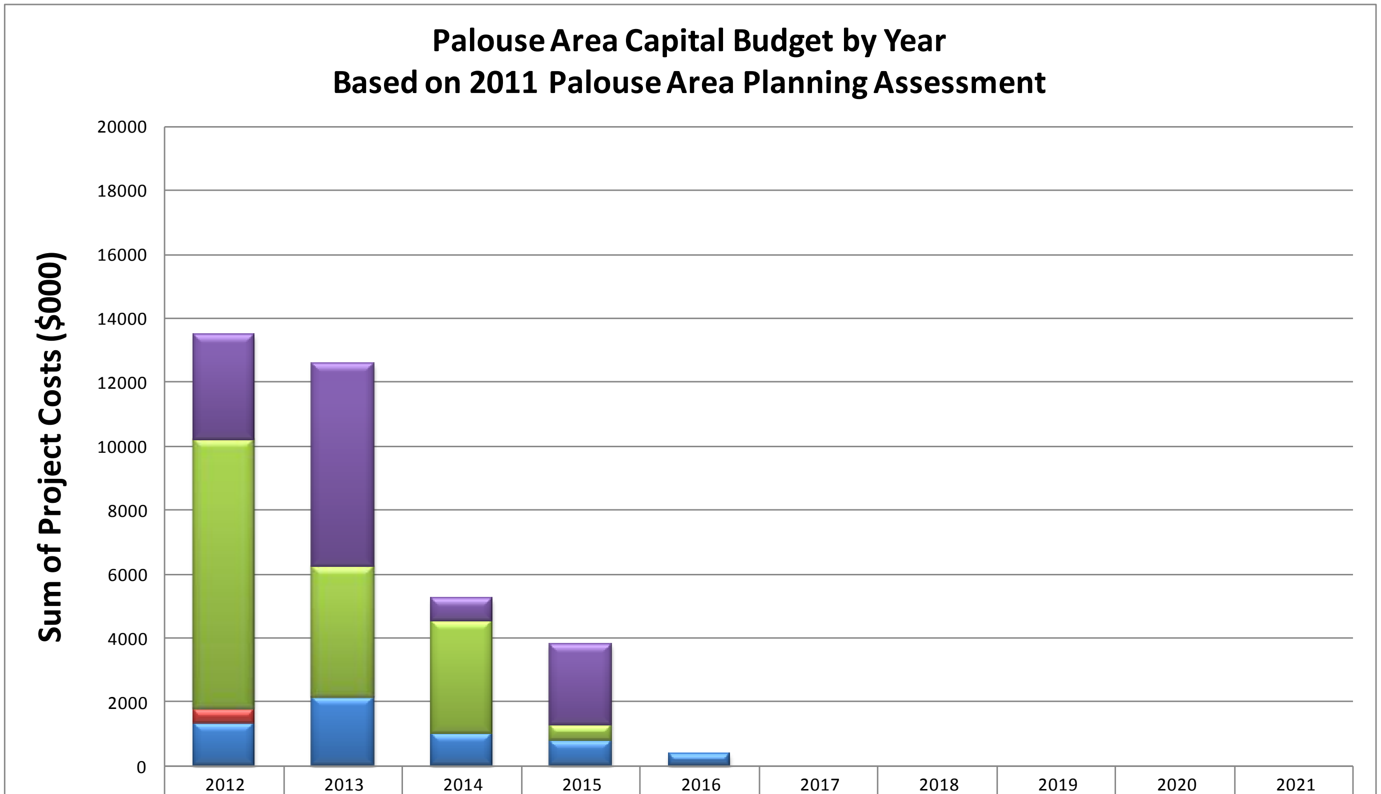
8 RECOMMENDED PROJECT PRIORITIZATION AND SCHEDULE

The projects identified in Section 4 are scheduled and budgeted in Table 8-1 below. Some projects have required in service dates earlier than those identified in this Planning Assessment but due to budget, construction and/or operational schedule it is understood that some issues cannot be mitigated in the desired timeframe. This report suggests obtainable project schedules to represent a realistic planning approach.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
System Planning Projects	**$7,550,000**	**$2,900,000**	**$2,500,000**	**$500,000**							**$13,450,000**
TPL-002, N-1	**$2,900,000**	**$2,900,000**	**$2,500,000**	**$500,000**							**$8,800,000**
Latah-Moscow Voltage Support Project				**$500,000**							**$500,000**
ER: 2481 - System - Replace/Install Capacitor Banks				$500,000							$500,000
Moscow 230 Rebuild Project	**$2,900,000**	**$2,900,000**	**$2,500,000**								**$8,300,000**
ER: 2000 - Power Transformers-Transmission & GSU (incl sales tax)											
ER: 2484 - Moscow 230 kV Sub-Rebuild 230 kV Yard	$2,900,000	$2,900,000	$2,500,000								$8,300,000
(blank)	**$4,650,000**										**$4,650,000**
Customer Interconnection	**$4,650,000**										**$4,650,000**
ER: 2545 - Thorton 230kV Interconnection Switching Station	$3,250,000										$3,250,000
ER: 2070 - Thorton 230kV Interconnection Switching Station	$1,400,000										$1,400,000
Other Projects	**$5,914,500**	**$9,700,000**	**$2,750,000**	**$3,300,000**	**$400,000**						**$22,064,500**
(blank)	**$5,914,500**	**$9,700,000**	**$2,750,000**	**$3,300,000**	**$400,000**						**$22,064,500**
Customer Interconnection	**$850,000**	**$5,450,000**									**$6,300,000**
ER: 25xx - Bovill 115kV Substation - Construct	$850,000	$5,450,000									$6,300,000
Driven by Distribution Eng.	**$800,000**	**$1,750,000**	**$2,750,000**	**$800,000**	**$400,000**						**$6,500,000**
ER: 1006 - Power Transformers-Distribution (incl sales tax)											
ER: 2274 - Tamarack 115 kV Sub - New Const.		$250,000									$250,000
ER: 2414 - System - Dist Reliability - Improve Worst Feeders	$500,000	$1,000,000	$1,000,000	$800,000	$400,000						$3,700,000
ER: 2502 - N Moscow Sub - Increase Capacity		$425,000	$1,750,000								$2,175,000
ER: 2516 - Distribution - Pullman & Lewis Clark	$300,000	$75,000									$375,000
Driven by Substation Eng.	**$1,330,000**										**$1,330,000**
ER: 2204 - System - Wood Substation Rebuilds											
ER: 2533 - Pullman Substation - Rebuild	$1,330,000										$1,330,000
Driven by Transmission Eng.	**$2,500,000**	**$2,500,000**		**$2,500,000**							**$7,500,000**
ER: 2549 - Moscow City-N. Lewiston 115kV Transmission Line Rebuild	$2,500,000	$2,500,000		$2,500,000							$7,500,000
Smart Grid Project	**$434,500**										**$434,500**
ER: 2530 - SGDP-Pullman Smart Grid Demonstration Project	$434,500										$434,500
Grand Total	**$13,464,500**	**$12,600,000**	**$5,250,000**	**$3,800,000**	**$400,000**						**$35,514,500**

TABLE 8-1: RECOMMENDED PROJECT PRIORITIZATION AND SCHEDULE.

Figure 8-1 provides a graphical view of the capital budget for the Palouse Area as presented in Table 8-1. The budgeted amounts are categorized in columns by the group or entity responsible for executing the projects.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Grand Total	13465	12600	5250	3800	400	0	0	0	0	0
Transmission	3250	6375	750	2500	0	0	0	0	0	0
Substation	8450	4100	3500	500	0	0	0	0	0	0
Smart Grid	435	0	0	0	0	0	0	0	0	0
Distribution	1330	2125	1000	800	400	0	0	0	0	0

FIGURE 8-1: PALOUSE AREA CAPITAL BUDGET BY YEAR.

9 POINT OF CONTACT

A Point of Contact for questions regarding the Planning Assessment and the projects described within it has been designated. Please contact the party named below for any questions:

Kenneth Dillon
Contracts Engineer, Transmission Services
PO Box 3727
Spokane, WA 99220
kenny.dillon@avistacorp.com
(509) 495-4436

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Appendix A - Transmission Map

Redacted per CEII requirements

Appendix B - System One Line Drawing

Redacted per CEII requirements

Appendix C - System Power Flow Plots

2016 Heavy Winter

2016 Heavy Summer, Low Hydro

2021 Heavy Winter

2021 Heavy Summer, Low Hydro

Redacted per CEII requirements

Appendix D - Power Flow Violation Summary

Redacted per CEII requirements

Appendix E - Transient Stability Results

The following tables provide the results from a user written program which analyzes the transient stability simulations performed. Due to the number of simulation performed, plots of the results or detailed analysis results are not included in this Planning Assessment but can be provided upon request.

Redacted per CEII requirements

Appendix E - 2010 Spokane Planning Assessment

Spokane Area

2010 REGIONAL ASSESSMENT

TRANSMISSION PLANNING

Prepared by John Gross

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Spokane Area

2010 REGIONAL ASSESSMENT

Date Completed: August 12, 2010

Prepared By: John Gross

The signature below indicates approval by the Chief System Planning Engineer. This regional assessment has been conducted with due diligence and has been reviewed and accepted by the necessary stakeholders. This approval certifies that this regional assessment as an adequate planning approach for the region of interest.

Scott Waples Chief System Planning Engineer

Aug 12, 2010
Date

Version History

Version	Version Date	Action	Change Tracking	Reviewed By
A	11 May 2010	Preliminary Draft	New Document	J. Gross
B	21 June 2010	Issue for Planning Meeting	Comments from Planning	J. Gross
C	22 June 2010	Result of Planning Meeting	Included comments	J. Gross
0	12 Aug 2010	Final Report	Eng & Ops Input	J. Gross

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TABLE OF CONTENTS

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Spokane Area

2010 REGIONAL ASSESSMENT

1 Executive Summary

The Avista Spokane Area is located primarily in Spokane and Stevens Counties in Washington State. The majority of the load served in the area can be categorized as urban, high density load with the exception of the outlying areas including the edge of the West Plains and the Deer Park/Chewelah Valley. The transmission system consists of several major elements: a 500 kV source at the Bonneville Power Administration's (BPA) Glenn H. Bell (Bell) Substation, a 230 kV backbone system which provides sources to the area from generation resources from the East and West as well as capacity for energy transfers across Avista's System, and the underlying 115 kV transmission lines which serve the local loads.

Load growth in the Spokane Area is projected to be 2.2% for summer and 2.3% for winter based on historic load growth data. Total anticipated load not including transmission system losses for peak summer 2011 is 1035 MW and 1175 MW for peak winter 2011. Total installed Avista owned distribution (i.e. 115/13.8 kV) transformation nameplate capacity in the Spokane Area is 1246 MVA based on transformer nameplate ratings.

This study examines the Spokane Area 230 kV and 115 kV transmission system. The studies performed include steady state power flow contingency analysis and voltage stability analysis utilizing both steady state and time domain methodologies.

Projects identified as required to prevent either thermal, voltage, or stability violations are included in the following list. Some projects have required in service dates earlier than those identified in this report but due to budget, construction and/or operational schedule it is understood that some issues cannot be mitigated in the desired timeframe. This report suggests obtainable project schedules to represent a realistic planning approach with the appropriate budgetary support. **All projects listed here (or superior alternatives) must be completed within the ten year planning horizon to meet applicable NERC Reliability Standards. Separate detailed project studies will be conducted as necessary to determine the best project(s) to be carried forward into the Avista capital budgeting process.**

- Replace the existing 125 MVA Westside #1 & #2 230/115 kV Transformers with 250 MVA transformers and reconstruct Westside Substation with the 230 kV bus arrangement as a double bus double breaker configuration and the 115 kV bus configuration to eliminate tie breaker failure and bus outage as credible contingencies ,

- Construct a new Garden Springs Substation with a 250 MVA 230/115 kV transformer, a radial 230 kV transmission line to Westside Substation, and 115 kV reconductor/integration work,
- Interconnect the Avista Boulder – Rathdrum 230 kV Transmission Line into the BPA Lancaster Substation,
- Complete the Irvin Project per *SP-2009-03 – Summary – Irvin (Spokane Valley Transmission Reinforcement) Project* including new 115 kV Irvin Substation, 115 kV reconductor work, rebuild of Millwood Substation, and addition of circuit breakers to Opportunity Substation,
- Install capacitor banks at Airway Heights and Hallett & White Substations,
- Reconductor segments of the Airway Heights – Silver Lake, South Fairchild Tap, and Sunset – Westside 115 kV Transmission Lines,
- Reconductor the Ninth & Central – Sunset 115 kV Transmission Line,
- Reconstruct the Beacon Substation 230 kV bus to a double bus double breaker configuration and the 115 kV bus configuration to eliminate tie breaker failure and bus outage as credible contingencies,
- Construct a new 230 kV transmission line from the Bell – Coulee Corridor to the Westside Substation to separate existing double circuit,
- Upgrade 115 kV line relaying in the Spokane area to communication aided schemes,
- Install redundant out of step protection at Nine Mile HED, and Boulder Park Generation Facilities,
- Construct new North/South Freeway, Downtown West, Hawthorne, Otis Orchards, and Greenacres Distribution Substations required for load service. Locations for theses substations are further defined in Section 5.3.

The total cost of projects required based on System Planning’s analysis of the Transmission System is expected to be about $79 million in the ten year planning horizon. Other projects identified in the Spokane Area are expected to be about $82 million for a total of $161 million. See Section 8 for a breakdown of these costs and the priorities of projects.

2 General System Description

The Avista Spokane Area is located primarily in Spokane and Stevens Counties in Washington State. The majority of the load served in the area can be categorized as urban, high density load with the exception of the outlying areas including the edge of the West Plains and the Deer Park/Chewelah Valley. The transmission system consists of several major elements: a 500 kV source at the Bonneville Power Administration's (BPA) Glenn H. Bell (Bell) Substation, a 230 kV backbone system which provides sources to the area from generation resources from the East and West as well as capacity for energy transfers across Avista's System, and the underlying 115 kV transmission lines which serve the local loads.

The major sources to the Spokane Area include hydro generation resources located in Northern Idaho and Western Montana, natural gas fired turbines just to the East in Northern Idaho, the 500/230 kV transformer at Bell Substation in Northern Spokane, the hydro generation resources located to the North and West from the Pend Oreille and Columbia Rivers, and local hydro generation resources on the Spokane River. Avista owns two 230 kV transmission lines, the Beacon – Rathdrum and Boulder Rathdrum 230 kV Transmission Lines, which connect the Rathdrum Substation located in Northern Idaho to 230 kV hubs in the Spokane Area. Avista owns two additional 230 kV transmission lines, the Beacon – Bell 4 & 5 230 kV Transmission Lines, which connect the 500 kV Bell Substation source to the Avista Beacon Substation. In general the remaining sources are connected to the Spokane Area through the BPA Transmission System.

Local load service is provided by the Beacon, Bell, Boulder and Westside Substations. Each of these stations has 230/115 kV transformation. The Westside Substation is located on the northwest edge of the Spokane Area and has two 125 MVA 230/115 kV transformers sourced by two 230 kV lines, one from Grand Coulee Dam and the other from Bell Substation. Because the transmission line into the Westside Station is a double circuit 230 kV transmission line, these sources to the Station are not completely independent. Beacon Substation is somewhat centralized in the North part of the Spokane Area and has two 250 MVA 230/115 kV transformers sourced from the north by the Bell Substation and the East by the Beacon – Boulder and Beacon – Rathdrum 230 kV Transmission Lines. Boulder Substation is located in the northern portion of Spokane Valley and has two 250 MVA 230/115 kV transformers sourced from the West by the Beacon – Boulder 230 kV Transmission Line, the East by the Boulder – Rathdrum 230 kV Transmission Line and from the south by the Benewah – Boulder 230 kV Transmission Line. The underlying 115 kV transmission system connects these hubs as well as interconnects local generation resources.

The Western Electricity Coordinating Council rated path West of Hatwai (Path 6) includes transmission lines connecting the Spokane Area to the West. These lines are the Bell – Coulee 6 500 kV, Bell – Coulee 3 & 5 230 kV, Bell – Creston 115 kV and Coulee – Westside 230 kV Transmission Lines. Note that this list of facilities contains only the facilities in the Spokane Area and does not constitute the entire West of Hatwai path as defined by WECC. The BPA owns all of these lines but Avista owns the last two miles and terminating position at Westside on the Coulee – Westside 230 kV Transmission Line. Presently one of the limiting contingencies for this path, during high West of Hatwai flows caused by light load and high Western Montana Hydro conditions, is the double line outage of the Bell – Coulee 6 500 kV and Bell – Westside 230 kV Transmission Lines as the underlying 115 kV system and 230/115 kV transformers at Westside Substation become overloaded.

Local generation facilities within the Spokane Area include the following:

Boulder Park	Unit 1 - 6 @ 4.1 MW each	Avista
Monroe Street HED	Unit 1 @ 15.6 MW	Avista
Nine Mile HED	Unit 1 Off Line, Unit 2 @ 4.5 MW, Unit 3 @ 8.2 MW & Unit 4 @ 7.1 MW	Avista
Northeast CT	Unit 1 @ 68 MW	Avista
Upper Falls HED	Unit1 @ 10.2 MW	Avista
Upriver HED	Units 1& 2 @ 5.8 MW & Unit 3-5 @ 2 MW	City of Spokane
Waste to Energy	Unit 1 @ 22.4 MW[1]	City of Spokane

There are presently no generation interconnection requests within the Spokane Area. Reardan I 50 MW (LGIR #11) and Reardan II 40 MW (LGIR #22) which are located in the Big Bend Area, were in the interconnection queue, but has subsequently been withdrawn. If in the future, these projects decide to move forward they will have an impact to the West Plains subarea. These projects were not included in the study work conducted for this regional assessment.

The 115 kV transmission system in the Spokane Area is primarily operated in a networked configuration. Other areas of Avista's Transmission System operate with normally open points referred to as "star points". A star point is used to minimize power flow to mitigate overloads on the 115 kV system in the event of an outage on the overlying 230 kV transmission system, as well as reducing overall system losses in the area. Operating in a "star" configuration also reduces exposure to loads served by long transmission lines. In the Spokane Area, star points switches can be operated open or closed based on outages, specific flow conditions, or due to operational constraints.

Avista's communication system in the Spokane Area includes a wide variety of technologies including: fiber optic cable, analog and digital microwave, radio, and power line carrier. Local protection schemes, such as the permissive overreaching transfer trip (POTT) schemes used on 115 kV transmission lines, utilize the local area fiber network established by the former Avista Corporation affiliate Avista Communications. Microwave and direct (station to station) fiber are used for the 230 kV transmission line protection schemes.

[1] Energy telemetered into the Puget Sound Energy Balancing Area and sold to Puget Sound Energy.

The Spokane Area is divided into sub-regions based on their geographical nature and transmission configuration. These sub-regions include the following:

Northwest Spokane: This sub-region is sourced primarily by Westside, Beacon and the BPA Bell Substations. Avista is the only load serving entity providing retail service in the urban areas of this sub-region (Inland Power and Light provides load service to the more rural areas to the north and northeast). Avista's substations providing load service to this sub-region include Indian Trail, Waikiki, Northwest, Francis & Cedar, Lyons & Standard, Northeast, Ross Park, Beacon and Fort Wright. The 115 kV transmission line configurations connect the 230 kV sources together; specifically there are transmission lines between Beacon and Westside Substations and also Beacon and Bell Substations.

South Spokane: This sub-region is sourced primarily by Beacon and Westside Substations. The relative distance of these sources to the load is greater than desired and several transmission issues are becoming evident due to the amount of load served as well as the distances to the various sources. Avista is the only load serving entity providing retail service in this sub-region. Avista's substations providing load service to this sub-region include Beacon, Ross Park, Third & Hatch, Metro, Post Street, College & Walnut, Sunset, Southeast, Glenrose and Ninth & Central. Included in this sub-region is the Downtown Network which provides service to the downtown Spokane customers. The Downtown Network is a combination of 13.8 kV underground feeders connected in a network configuration (as opposed to the radial feeder configuration for the remainder of the Avista distribution system) between the Metro and Post Street Substations. The Monroe Street and Upper Falls HED Projects are located in South Spokane sub-region and are interconnected to the Post Street Substation. The 115 kV transmission line configurations connect Beacon and Westside Substations.

Spokane Valley, Otis Orchards and Liberty Lake: This sub-region is sourced primarily by Boulder and Beacon Substations. Several non-Avista load serving entities provide retail service in this sub-region including Inland Power and Light, Modern Electric Water Company and Vera Water and Power. The substations for Inland Power and Light, Modern Electric Water Company and Vera Water and Power served in this sub-region are primarily served from the BPA via radial 115 kV transmission lines from Bell and Trentwood Substations. Avista provides transmission service to Modern Electric Water Company at three separate substations: Opportunity, Locust, and Nelson Substations. There are three 115 kV transmission lines providing local load service to Avista loads: Beacon – Boulder 1 & 2 and Ninth & Central – Otis Orchards 115 kV Transmission Lines. Presently the Beacon – Boulder 2 115 kV Transmission Line provides service to Inland Paper Company, Avista's second largest industrial customer. The Boulder – Otis Orchards 1 & 2 and Otis Orchards – Post Falls 115 kV Transmission Lines provide load service to the eastern portion of the sub-region including Otis Orchards. The Boulder Park Generation Project is located in this sub-region and is interconnected to the Boulder Substation.

West Plains: This sub-region is sourced primarily by the Beacon, Devils Gap, and Westside Substations. The relative distance of these sources to the load is greater than desired and several transmission issues are becoming evident due to the amount of load served as well as the distances to the various sources.

Inland Power and Light, the City of Cheney, and Fairchild Air Force Base also provide retail service in this sub-region. Avista's substations providing load service to this sub-region include the Airway Heights, Hallett & White, Silver Lake, and Sunset Substations. There are primarily two transmission lines providing local load service to Avista loads: Airway Heights – Silver Lake and Sunset – Westside (including the South Fairchild Tap) 115 kV Transmission Lines. The Spokane International Airport and the Fairchild Air Force Base are located within this sub-region. The Waste to Energy Generation Project is located in this sub-region and is interconnected on the Sunset – Westside 115 kV Transmission Line.

Deer Park/Chewelah Valley: This sub-region is sourced primarily by the BPA Bell and Addy Substations. BPA provides transmission service to Avista loads by means of the Addy – Bell 115 kV Transmission Line. Avista's only transmission in the area is radial taps off of the Addy – Bell 115 kV Transmission Line. Avista provides retail load service from Colbert, Deer Park, Loon Lake, Mead, and Milan Substations. Inland Power and Light also provides retail load service in this sub-region.

Load growth in the Spokane Area is projected to be 2.2% for summer and 2.3% for winter based on ten years of historic load growth data. Total anticipated load not including transmission system losses for peak summer 2011 is 1035 MW and 1175 MW for peak winter 2011. Total installed Avista owned distribution (i.e. 115/13.8 kV) transformation nameplate capacity in the Spokane Area is 1246 MVA based on transformer nameplate ratings.

This study examines the Spokane Area 230 kV and 115 kV transmission system composed of the five sub-regions described.

3 Transmission Map

Redacted per CEII requirements

4 System One Line Drawing

Redacted per CEII requirements

5 System Analysis and Future Requirements

5.1 Study Procedure

The System Planning Group develops base cases annually according to the internal guideline document “Case Building Checklist” (located on SharePoint). Four seasonal scenarios are developed from standard WECC seasonal cases which represent bookends that have been historically established through previous studies. The scenarios developed include the following:

1. Heavy Summer with High Local Hydro Generation (Heavy Summer, High Hydro Case)

   This is the typical summer peak study where the Avista Balancing Area load is near peak and the local hydro generation is at a typical mid-summer output. This case scenario represents Avista’s heavy summer loading with moderate transfers into Avista’s Balancing Area. This case is limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the system is near capacity.

2. Heavy Summer with Low Local Hydro Generation (Heavy Summer, Low Hydro Case)

   This is the typical summer peak study where the Avista Balancing Area load is near peak and the local hydro generation has a low output. This case plays a dual role, in that it represents both Avista’s heavy summer loading scenario along with significant transfers into Avista Balancing Area to supplement the low hydro generation. This case is limited by the summer thermal limits on various elements of the transmission system, which helps to define where the system is near capacity.

3. Heavy Winter Case

   This is the typical winter peak study where the Avista Balancing Area load is heavy but the lower ambient temperature increases the operating limits of the various elements of the Transmission System. Local hydro generation is at a moderate level and there are significant transfers into Avista’s Balancing Area from regional thermal resources.

4. Light Summer with High West of Hatwai Flows (Light Summer Case)

   During light summer (night time loading) with high Western Montana Hydro and high Montana thermal generation, the WECC rated path “West of Hatwai” (WECC Path #6) reaches its heaviest loading. During this scenario, portions of the Transmission System are nearing their stability limits. These limits define some of the operating constraints for the region and also establish some of the arming levels for Remedial Action Schemes (RAS). This case is also limited by the summer thermal limits on various elements of the transmission system, which helps to define where the system is near capacity.

These base cases are developed to represent both the five and ten year Avista planning horizon. A detailed summary of specific flows and loading levels for the 2010 planning cases can be viewed in the interoffice memorandum SP-2010-03 – 2010 Planning Cases Summary Data.

Sections 5.2 through 5.6 describe thermal overload and/or voltage problems that were observed under normal operating and contingency conditions for the base cases described above. The contingencies evaluated are a standard contingency set, used by System Planning, reviewed and updated annually. Documentation on the contingency set is provided by the Avista Contingency Modeling Guide. Each problem identified includes a list of projects capable of mitigating the violation. **A separate detailed project study will be conducted as necessary to determine the best project(s) to be carried forward into the Avista capital budgeting process.**

The reliability criteria used in evaluating the performance of the transmission system is the present North American Electric Reliability Corporation or WECC reliability criteria including the following:

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

5.2 Planned System Modifications

The following sections describe either projects to enhance the existing Spokane Area system or mitigate deficiencies discovered during the course of the regional assessment. These items should be addressed as construction schedules and annual budgets permit:

SMART GRID

Avista proposes to deploy smart grid technology that will directly benefit over 110,000 residents of the City of Spokane, Washington while creating a national model for other utilities across the country. It does so by upgrading the electric distribution system that moves power from Avista's substations to its retail customers in Spokane. These improvements will complement other, future smart grid improvements made to the high-voltage transmission system and at customers' homes and businesses. Avista's Smart Grid goals are to reduce system losses, minimize impacts of outages to our customers and to monitor the system to utilize equipment more effectively. Washington State University's engineering school is partnering with Avista in order to help analyze and report the benefits from the implementation of the smart grid technology. The project will begin in November 2009 and will be completed by October 2012. The total project costs are estimated to be $40 million, and the cost share from the DOE is proposed to be $20 million.

Avista's Smart Grid Project will implement a distribution management system, intelligent devices and a communication network allowing for a portion of the distribution system to respond to dynamic loading and outage conditions. The installation of smart grid enabling technology will take place on 55 distribution circuits and 17 substations.

SPOKANE 115 KV LINE RELAYING UPGRADES

System studies have revealed sensitivity to Western Montana Hydro (WMH) generation output and slow clearing 115 kV transmission faults in the Spokane and Coeur d'Alene Areas. WMH generation consists of Avista's Noxon Rapids and Cabinet Gorge hydroelectric dams, the U.S. Army Corps of Engineers' Libby hydroelectric dam, and the U.S. Bureau of Reclamation's Hungry Horse hydroelectric dam. The WMH output typically peaks in late spring and early summer due to water runoff conditions. Installation of protection systems which support high speed fault clearing on the Spokane / Coeur d'Alene 115 kV transmission system significantly reduces the WMH sensitivity to 115 kV faults. This allows operation of the 115 kV transmission system in a manner which supports high reliability to customers and offers flexibility during outage conditions.

The required communication infrastructure upgrades to implement communication aided tripping has been completed. The replacement of protection relays is still required at a number of substations before the communication aided tripping schemes can be utilized.

BEACON – FRANCIS & CEDAR AND WAIKIKI TAP 115 KV LINE REROUTE

Avista is relocating approximately 0.8 miles of the Beacon – Francis & Cedar 115 kV Transmission Line and Waikiki Tap of the Bell – Northeast 115 kV Transmission Line located between Waikiki Road and Whitworth Drive at Whitworth University. There is also a main 13kV feeder (Waikiki 12F3) that is under built on the Beacon – Francis & Cedar 115 kV Transmission Line that will be relocated. The lines will be relocated approximately 250 feet to the north and will adjoin an existing BPA power line corridor. All of the relocated facilities will remain on Whitworth University property.

MILLWOOD SUBSTATION REBUILD

Millwood Substation is over 50 years old and is in need of a complete rebuild. This station serves IEP (Avista's second largest customer) with 115 kV and 60 kV service, the Millwood community, and part of the neighboring Spokane Valley area. The present transmission bus through the substation is strain (wire) bus on wood structures, which does not meet present substation design and construction standards (rigid pipe bus) for a station of this size. All the 115 kV air switches are reaching the end of their useful lives. The station transformers are 52 and 35 years old and at least one will need a capacity upgrade with the rebuild. With IEP's new 115 kV station in service, Avista's 115-60 kV transformer is sufficient for service for the foreseeable future. The distribution switchgear is over 50 years old with two of the feeder breakers installed in 1958 and the other two in 1974. The three 115 kV circuit switchers are 38, 36, and 29 years old, respectively, and also need to be upgraded. Overall, this substation is top priority for the next Avista distribution substation rebuild. The plan is to begin design in late 2010 with construction to occur in 2011-12.

NINTH & CENTRAL SUBSTATION CONFIGURATION

The plan at Ninth & Central has been to build a new distribution station within the existing 115 kV Switchyard. This station would ultimately be configured with 2-30 MVA transformers and 6 feeders. Each transformer would be connected to separate 115 kV buses in the switchyard and a distribution bus tie would be installed. The existing distribution station would be removed entirely. In addition, the 8th & Fancher 115 kV line to Latah Jct. would be moved into Ninth & Central with its own 115 kV breakered bay. This eliminates the problematic long rural tap off of the Ninth & Central-Third & Hatch 115 kV Transmission Line to Latah Jct. Design has not started. Prioritization with other projects will set the start date.

SUNSET SUBSTATION REBUILD

A complete rebuild of Sunset is required. This major substation serving the south Spokane area is reaching the end of its useful life. The oldest 115 kV circuit breaker on the system resides at Sunset. We have AC and DC service power and control circuit problems in this sub which make adding or replacing equipment very difficult and expensive. Increased capacity for transformer 2 and a new feeder will be required in the near future per Distribution Planning. It is not prudent to rebuild this operating substation in place. The plan is to build a new substation to current design and construction standards adjacent to the existing substation on property Avista already owns. Design has not started. Prioritization with other projects will set the start date.

OTIS ORCHARDS SUBSTATION BREAKER REPLACEMENT

Otis Orchards Switching Station presently has four 115 kV breakers approaching 50 years old. These oil circuit breakers are reaching the end of their useful lives and will be replaced with gas circuit breakers. In addition, the 115 kV line relaying needs to be replaced with new microprocessor based relays in order to provide high speed communication aided tripping for system events to avoid transmission system stability issues (reference "Boulder Park Generation Transient Stability" report by Rich Hydzik 11/13/2009). These two projects will be completed together over 2010-11. Design for these projects is well underway as of June 2010.

DISTRIBUTION UPGRADES

Several distribution feeders have been identified as needed to be upgraded or replaced due to their existing condition and recent historical performance. The scheduling, budgeting, design and construction required for this work is done by the Distribution Engineering Group and therefore are only mentioned here for completeness.

Additional distribution upgrades include the addition of feeder ties which will aid in the operational flexibility of the distribution system. The regional operation engineers largely drive these types of projects and are therefore only mentioned here for completeness.

5.3 Normal System Conditions (N-0): NERC Category A

NORTH-SOUTH FREEWAY SUBSTATION (A.K.A. HILLYARD SUBSTATION)

A new substation located in Hillyard (NE portion of Spokane) has been identified by the Distribution Engineering Group to provide relief to the distribution facilities of Beacon and Ross Park Substations. This substation will also support future development along the Spokane North-South Freeway corridor. The new substation has been temporarily named North/South Freeway Substation and is proposed to be interconnected to the transmission system by tapping and eventually looping in the Beacon – Bell #1 115 kV Transmission Line. This project has been initiated in the capital budget process and is scheduled to be completed in 2013.

DOWNTOWN WEST SUBSTATION

To relieve distribution capacity constraints in the South Spokane sub-region, it has been proposed by the Distribution Engineering Group to construct a new substation located on the western edge of downtown. The new substation has temporarily been named Downtown West Substation and would potentially be interconnected to the Metro – Sunset 115 kV Transmission Line. The addition of this substation will offload existing facilities at the College & Walnut Substation and provide necessary backup capacity to the Sunset Substation. This project has been initiated in the capital budget process and is scheduled to be completed in 2014.

HAWTHORNE SUBSTATION

The Northwest Spokane sub-region has been identified by the Distribution Engineering Group to be in need of a new distribution substation near the existing Bell Substation. This area has a large potential for load growth and the existing distribution facilities in the area will be inadequate to continue to feed the load. The new substation is proposed to be located adjacent to the old Kaiser facility which would allow for the ability to supply sufficient and reliable power to potential industrial customers as well as pick up additional load growth and off load existing facilities. The new substation has been named the Hawthorne Substation. The desired interconnection to the transmission system has not been finalized at this time as there is potential to use this substation as a means of reinforcing the transmission system to the north of Spokane. An adequate interconnection option which would allow the Hawthorne Substation to become energized is tapping the existing Beacon – Bell #1 115 kV Transmission Line. This project has been initiated in the capital budget process and is scheduled to be completed in 2013.

GREENACRES / OTIS ORCHARDS SUBSTATIONS

A new substation located in the southeast region of the Spokane Valley Area has been identified by the Distribution Engineering Group to offload existing distribution facilities at Liberty Lake and Barker Substations. The construction of this substation, presently called Greenacres Substation, has been selected as a means of deferring the addition of distribution facilities at Otis Orchards Switching Station. This project has been initiated in the capital budget process and is scheduled to be completed in 2013.

The existing Otis Orchards Switching Station has also been identified as the preferred location for adding distribution 115/13.8 kV transformation to support Otis Orchards. Discussion and study results are provided in *Otis Orchards 115/13kV Project* written by Jill Ham in 2009.

WESTSIDE 230/115 KV TRANSFORMERS

The existing Westside #1 & #2 230/115 kV Transformers show thermal overloads during an all lines in service condition within the ten year planning horizon. Both transformers have a nameplate rating of 125 MVA. The continuous ratings determined by the rating methodology provided in IEEE C57.91 are 108 MVA and 124 MVA respectively for Transformer #1 and #2. During a heavy summer, low hydro scenario Transformer #1 loads to 108.5% (CY 2015) and 141.56% (CY 2020) in the five and ten year planning horizon respectively. For the same scenario Transformer #2 loads to 96.48% in the ten year planning horizon. The primary cause of these overloads is the lack of necessary 230/115 kV transformation to serve the North and South Spokane sub-regions. The following are possible alternatives to mitigate this issue:

1. Do nothing – The Westside #1 & #2 230/115 kV Transformers will exceed 100% of their ratings within 5 years. The Heavy Summer, Low Hydro scenario represents a worse case for this issue as local hydro generation on the Spokane River interconnected to the 115 kV Transmission System helps offset the transformation requirements at Westside Substation. Continued load growth will cause more severe overloading. This is not an acceptable option.

2. Interconnect the Lancaster Substation into Avista's Transmission System. Looping the Boulder – Rathdrum 230 kV Transmission Line into the Lancaster Substation, the energy from the Western Montana Hydro complex and thermal units in Northern Idaho will tend to flow more to the Beacon and Boulder Substations. This tends to reduce flows on the Westside #1 & #2 230/115 kV Transformers but not enough to prevent potential overloads.

3. Replace existing Westside #1 & #2 230/115 kV Transformers with 250 MVA nameplate rated transformers. Replacing the transformers will mitigate the overload issue but will also worsen other underlying 115 kV transmission issues due to reduced impedances of the transformers.

4. Construct a 230/115 kV transformation substation in the South Spokane sub-region. Garden Springs is a possible site which allows for ease of integration into the existing transmission system in the area. With this new station installed, the Westside #1 230/115 kV Transformer will load to under 80% and 108.5% capacity in the 5 and 10 year planning horizons. The single contingency of a transformation outage at Garden Springs Substation will cause the existing Westside Substation Transformers to overload.

A combination of Alternatives 2, 3 and 4 are the preferred mitigation approach at this time. Appropriate scheduling and coordination with other 230 kV substation construction must be considered. Presently, internal discussions within Avista have led to the decision to reconstruct Westside Substation with new transformers prior to constructing a new substation at Garden Springs. Operationally, the Westside

Substation cannot be taken out of service for reconstruction. Completing the interconnection at Lancaster Substation and constructing the Garden Springs Substation will allow for more operational flexibility to take Westside Substation out of service. Constructability and the operational flexibility of these projects will be analyzed during the detailed project report process.

BELL 230/115 KV TRANSFORMER

The Bell #6 230/115 kV Transformer is owned and maintained by the BPA and has a name plate rating of 250 MVA. This transformer becomes loaded to 96.8% of the continuous rating of 250 MVA during a Heavy Summer, Low Hydro condition in the five year planning horizon with all lines in service. In the ten year planning horizon under the same scenario, the transformer is loaded to 108.36%. Because this is BPA's equipment, the responsibility to mitigate the issue should primarily be borne by BPA. The local growth within the BPA Balancing Area and by the growth within Avista's Balancing Area contributes to the overload; therefore it is reasonable, from a Regional Planning perspective, to develop a joint mitigation approach which proves beneficial to both parties. The following are possible alternatives to mitigate this issue:

1. Do nothing – The Bell #6 230/115 kV Transformer will exceed 100% of its continuous rating within 5 to 10 years. This is not an acceptable option.
2. Increase 230/115 kV transformation capacity at Bell Substation. Replacing the BPA's only existing transformer in the Spokane Area with a higher rated transformer or adding a second 230/115 kV transformer would mitigate the overload.
3. Add additional 230/115 kV transformation to the Spokane Area. Garden Springs is a possible site which allows for ease of integration into the existing transmission system in the area. This project will bring the Bell #6 230/115 kV Transformer to 101.3% loading in the ten year planning horizon for N-0 conditions.
4. Interconnect the Lancaster Substation into Avista's Transmission System. Looping the Boulder – Rathdrum 230 kV Transmission Line into the Lancaster Substation, the energy from the Western Montana Hydro complex and thermal units in Northern Idaho will tend to flow more to the Beacon and Boulder Substations. This reduces flows on the Bell #6 230/115 kV Transformer to just under 100% of its continuous rating in the ten year planning horizon.

A combination of Alternatives 2, 3 and 4 are the preferred mitigation approach at this time. A detailed study analysis in cooperation with BPA is required to determine the best mitigation approach going forward. The options provided here have only gone through a cursory review. Appropriate scheduling and coordination with other 230 kV substation construction must be considered. Presently, internal discussions within Avista have led to the decision to reconstruct Westside Substation with new transformers prior to constructing a new substation at Garden Springs.

5.4 Single Contingency Issues (N-1): NERC Category B

Several single contingencies issues have been identified in the Spokane Area. The mitigation for these issues typically cannot be a single project but rather several projects which collectively provide adequate performance and required compliance with the applicable Standards. The following projects will provide the required mitigation of single contingency issues. Optimization and further refinement will be performed in project reports if not already completed.

1. Westside #1 & #2 230/115 kV Transformer replacement with 250 MVA transformers,
2. Construction of Garden Springs Substation with a 250 MVA 230/115 kV transformer. Transmission integration will include termination of five 115 kV transmission lines adjacent to the existing Garden Springs Switching Station. The following construction will also be required:
    a. A radial 230 kV transmission line from Westside Substation,
    b. Reconductor of the two 115 kV transmission lines from Garden Springs to Sunset with 795 kcmil conductor.
3. Interconnection Lancaster Substation into the Boulder – Rathdrum 230 kV Transmission Line,
4. Completion of the Irvin Project including the following:
    a. Reconductor the Beacon – Boulder #2 115 kV Transmission Line with 795 kcmil conductor,
    b. Rebuild Millwood Substation,
    c. Construct new Irvin Substation in breaker and a half bus configuration and addition of distribution facilities and a 33.5 MVAr capacitor bank,
    d. Rebuild Irvin – Opportunity 115 kV Transmission Line with 795 kcmil conductor,
    e. Add 115 kV breakers to Opportunity Substation as required,
    f. Construct new 2.19 miles of single circuit 115 kV transmission lined with 556 kcmil conductor from Irvin Substation to Inland Empire Paper facilities.
5. Install 115 kV capacitor banks at Airway Heights and Hallett & White and reconductor the following transmission lines in the West Plains Area:
    a. Airway Heights – Fairchild AFB North segment of the Airway Heights – Silver Lake 115 kV Transmission Line with 556 kcmil conductor,
    b. Garden Springs – Four Lakes Tap segment of the South Fairchild Tap with 795 kcmil conductor,

c. Garden Springs – Sunset segment of the Sunset – Westside 115 kV Transmission Line with 795 kcmil conductor.

Though these five projects provide adequate performance according to the applicable standards, they do not provide the desired operational performance. The outage of the Bell – Westside 230 kV Transmission Line leaves the western portion of the Spokane Area to be supplied directly from Grand Coulee on the Coulee – Westside 230 kV Transmission Line. It would be preferred in the near term and will become necessary in the long term to have an additional means of sourcing Westside and Garden Springs Substations. This additional sourcing will also provide relief from the dependence on Bell Substation. A Line and Load Interconnection Request (LLIR) should be submitted to BPA to begin the study process and determine a project scope that will satisfy both Avista's and BPA's requirements.

WESTSIDE 230/115 KV TRANSFORMERS

The Westside #1 & #2 230/115 kV Transformers can become thermally overloaded for several single contingency outages in the five and ten year planning horizon. The *2010 Summer Operating Studies Report* indicates that an overload condition could occur in a late summer 2010 scenario. The underlying N-0 thermal overload as described in Section 5.3 is of primary concern. The single contingency outage that causes the most severe overload is the outage of the parallel Westside Transformer. Westside #1 230/115 kV Transformer will overload to 157.37% and 197.21% for the outage of the Westside #2 230/115 kV Transformer in the five and ten year planning horizon respectively for a Heavy Summer, Low Hydro scenario. In general, the other outages causing an overload of these transformers are ones which increase the impedance to the 230/115 kV transformers at Bell and Beacon Substations, which includes outages of other transformers in the area. Refer to Section 5.3 for the preferred mitigation approach. Replacing the existing transformers with 250 MVA transformers mitigates this individual issue but alone does not provide a holistic solution to other issues in the Spokane Area.

BEACON 230/115 KV TRANSFORMERS

Under a single contingency configuration, the Beacon #1 & #2 230/115 kV Transformers show thermal overloads of 103.28% and 113.77% in the five and ten year planning horizon respectively for a Heavy Summer, Low Hydro scenario. The most severe single contingency outages are the loss of the adjacent Beacon Transformer. Loss of the Bell #6 230/115 kV Transformer causes the Beacon #1 & and #2 230/115 kV Transformers to approach their thermal limits in the five year planning horizon and exceed them in the ten year planning horizon. Also, in the ten year planning horizon the single contingency outages of Beacon – Boulder or Bell – Westside 230 kV Transmission Lines show loadings of over 90%. The following are possible alternatives to mitigate this issue:

1. Do nothing – thermal overloads will persist and become more severe over time.
2. Complete the five proposed projects stated at the beginning of Section 5.4. If completed, no single contingency outage will cause the transformers to exceed their thermal limits. The outage of a Beacon Transformer will still cause the adjacent transformer to be loaded to near 95%.

Alternative 2 is the preferred mitigation approach at this time. This issue will be revisited in future Spokane Area Regional Assessments.

SPOKANE VALLEY THERMAL OVERLOADS AND LOW VOLTAGE

Several single contingency outages cause thermal overloads and low voltages in the Spokane Valley Area. The more severe outages tend to be line-end-open scenarios on the Beacon – Boulder #1 & #2 and Ninth & Central – Otis Orchards 115 kV Transmission Lines. Increased load growth and increased demand requirements of Inland Empire Paper have pushed the existing transmission system to its limits. Details of the issues and description of potential mitigation approaches are provided in the System Planning Study The Irvin Project – Final dated May 6, 2009 written by Jim Farby. The preferred projects and summary of work required is provided in the System Planning interoffice memorandum SP-2009-03 – Summary – Irvin (Spokane Valley Transmission Reinforcement) Project. The project is also identified as item number four at the beginning of Section 5.4. The cost for these projects totals $15.2 million.

WEST PLAINS THERMAL OVERLOADS AND LOW VOLTAGES

The transmission system in the West Plains Area has several constraints due to lack of the necessary transmission infrastructure to serve the existing load. Presently, there is some operational flexibility due to strategic placement of air switches on the South Fairchild Tap and Airway Heights – Silver Lake 115 kV Transmission Lines but thermal limitations and low voltage issues prevent the full ability to utilize this flexibility. The System Operating Procedure SOP-12 West Plains Operations outlines the switching requirements for specific outages. Previous studies including West Plains Transmission – LM2500 Installation and West Plains Internal Discussion written by Mike Magruder and Mark Lippincott have pointed out the need to reconductor certain segments of existing transmission lines as well as constructing a new 115 kV transmission line from Fairchild AFB North to Silver Lake Substation. The construction of the new line was completed in 2008. Specific transmission facilities which continue to experience thermal overloads are the Airway Heights – Fairchild AFB North segment of the Airway Heights – Silver Lake 115 kV Transmission Line, Garden Springs – Four Lakes Tap segment of the South Fairchild Tap, and the Garden Springs – Sunset segment of the Sunset – Westside 115 kV Transmission Line. Low voltages issues also exist for the same scenarios causing thermal overloads as well as several additional contingencies. The operational study 2008 West Plains Reactive Study written by Rich Hydzik outlines the specific issues and demonstrates a potential mitigation approach of adding 115 kV capacitor banks at Airway Heights and Hallett & White Substations. The following are possible alternatives to mitigate the West Plains issues:

1. Do nothing – thermal and voltage violations will continue to worsen.
2. Reconductor existing transmission lines which show overloading. This will aid in the low voltage issues in addition to mitigating thermal overloads by reducing the voltage drop from the existing transmission lines with higher resistance. The transmission lines required to be reconductored include the following:

a. Airway Heights – Fairchild AFB North segment of the Airway Heights – Silver Lake 115 kV Transmission Line with 556 kcmil conductor,

b. Garden Springs – Four Lakes Tap segment of the South Fairchild Tap with 795 kcmil conductor,

c. Garden Springs – Sunset segment of the Sunset – Westside 115 kV Transmission Line with 795 kcmil conductor.

3. Install 115 kV capacitor banks at Airway Heights and Hallett & White Substations. This will provide mitigation to the low voltage issues but does not fully address the underlying issue of a lack of necessary transmission facilities in the area. Capacitor banks will provide sufficient relief of low voltages until a more comprehensive plan can be executed (i.e. new 230/115 kV transformation in the area).

A combination of Alternatives 2 and 3 are the preferred mitigation approach at this time.

NINTH & CENTRAL – SUNSET 115 KV TRANSMISSION LINE

Segments of the Ninth & Central – Sunset 115 kV Transmission Line exhibit thermal overloads for various contingencies in the area. The primary cause of these overloads is the loss of a line which supplies the South Spokane and West Plains Areas. The existing Ninth & Central – Sunset 115 kV Transmission Line is primarily constructed of 795 kcmil conductor but is limited by some segments of 250 CU conductor. The segment from Ninth & Central to the Glenrose Tap experiences the worst thermal overloads of 101.83% and 115.4% in the five and ten year planning horizon for line end open condition at Westside on the Sunset – Westside 115 kV Transmission Line. The following are possible alternatives to mitigate this issue:

1. Do nothing – this overload is unacceptable.

2. Complete the five proposed projects stated at the beginning of Section 5.4. Once completed, no single contingency outage will cause this transmission line to exceed its thermal limits.

3. Reconductor approximately1.97 miles of 250 CU conductor with 795 kcmil conductor on the Ninth & Central – Glenrose Tap line segment. This will prevent the overload from occurring but does not address the underlying issues of providing a source in the South Spokane and West Plains Areas.

It is recommended that Alternative 3 be carried forward to mitigate the issue within the five year planning horizon. Execution of Alternative 2 is ultimately desired but may not be completed in time to prevent this issue.

BEACON – NINTH & CENTRAL #1 & #2 115 KV THERMAL OVERLOADS

Each Beacon – Ninth & Central 115 kV Transmission Line will overload for loss of the adjacent Beacon – Ninth & Central 115 kV Transmission Line. Beacon – Ninth & Central #1 115 kV Transmission Line has a slightly lower rating then line #2 and will load to 93.58% and 107.5% in the five and ten year planning horizon respectively for a Heavy Summer, Low Hydro scenario. The #1 line utilizes 795 kcmil conductor and the #2 line utilizes 397 ACSS conductor. The following are possible alternatives to mitigate this issue:

1. Do nothing – thermal overloads will persist and become more severe over time.
2. Complete the five proposed projects stated at the beginning of Section 5.4. Once completed, no single contingency outages will cause these lines to exhibit overloads.
3. Reconductor both transmission lines with 1272 kcmil conductor or other higher capacity conductor. This would be an exception to Avista's standard 115 kV transmission line construction and does not address the underlying issues.

Alternative 2 is the preferred mitigation approach at this time.

NORTHWEST SPOKANE THERMAL OVERLOADS

Several lines in the Northwest Spokane sub-region will overload for loss of adjacent 115kV transmission lines connecting the Area sources. The specific lines that experience overloads include: Francis & Cedar – Northwest, College & Walnut – Westside, Northwest – Westside, Beacon – Bell #1 and Bell – Northeast 115 kV Transmission Lines. This is a complex issue but a high-level explanation of the cause is the lack of a source in the South Spokane and West Plains Areas as well as insufficient capacity on the 115 kV transmission system to provide power transfer capability between 230/115 kV sources. The most severe overloads occur on the Fort Wright – Westside segment of the College & Walnut – Westside 115 kV Transmission Line for loss of the Northwest – Westside 115 kV Transmission Line. The line exhibits loadings of 90.18% and 104.23% respectively in the five and ten year planning horizon. Also the Bell – Waikiki Tap segment of the Bell – Northeast 115 kV Transmission line for loss of the Beacon – Bell #5 230 kV Transmission Line loads to 93.89% and 109.02% in the five and ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – thermal overloads will persist and become more severe over time.
2. Complete the five proposed projects stated at the beginning of Section 5.4. Once completed, no single contingency outages will cause these lines to exhibit overloads.
3. Employ the existing Seven Mile Tap 115 kV transmission line presently being utilized as a 13.2 kV distribution feeder to connect Indian Trail and Waikiki Substations at 115 kV. Also installing three line positions at the Indian Trail Substation would allow for the creation of the following transmission lines: Indian Trail – Westside, Nine Mile – Indian Trail, Francis & Cedar – Indian Trail 115 kV Transmission Lines. This construction would allow Waikiki Substation to be supplied from the new Francis & Cedar – Indian Trail 115 kV Transmission Line and frees

the Beacon – Francis & Cedar 115 kV Transmission Line to be utilized for connecting other distribution substations. While several of the thermal overloads are mitigated by this construction, the underlying issues still need to be addressed.

Alternative 2 is the preferred mitigation approach at this time. Alternative 3 should be further analyzed to determine what additional operating capacity is gained if Alternative 2 has been completed.

SUNSET – WESTSIDE 115 KV TRANSMISSION LINE

In addition to the issues described by subsection West Plains Thermal Overloads and Low Voltages, the Sunset – Westside 115 kV Transmission Line overloads between the Waste to Energy Tap and Garden Springs. This occurs for several contingencies, the worst being the loss of the Northwest – Westside 115 kV Transmission Line which cause loadings of 91.97% and 104.85% in the five and ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – thermal overloads will persist and become more severe over time.
2. Complete the five proposed projects stated at the beginning of Section 5.4. Once completed, no single contingency outages will cause this line to exhibit overloads.
3. Reconductor approximately 0.72 miles of the transmission line with 795 kcmil conductor. This will provide a higher thermal rating but not address the underlying transmission system issues.

Alternative 2 is the preferred mitigation approach at this time.

ROSS PARK – THIRD & HATCH AND POST STREET – THIRD & HATCH

The Ross Park – Third & Hatch and Post Street – Third & Hatch 115 kV Transmission Lines exhibit thermal overloads for several local area contingencies. These lines provide a means of connecting the Beacon Substation source to the downtown load center. The most severe contingency is the loss of the Fort Wright – Westside segment of the College & Walnut – Westside 115 kV Transmission Line. The Ross Park – Third & Hatch 115 kV Transmission Line will load to 102.47% in the ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – thermal overloads will persist and become more severe over time.
2. Complete the five proposed projects stated at the beginning of Section 5.4. Once completed, no single contingency outages will cause these lines to exhibit overloads.
3. Reconductor approximately 4 miles of the Ross Park – Third & Hatch and Post Street – Third & Hatch Transmission Lines with 795 kcmil conductor. This will provide a higher thermal rating but will not address the underlying transmission system issues.

Alternative 2 is the preferred mitigation approach at this time.

ADDY – BELL 115

Stations along the Addy – Bell 115 kV Transmission Line exhibit low voltage conditions during outage conditions which cause a line end open condition. The most severe outage is the Bell – Mead segment causing voltages to decline to 100.1 kV (0.87 pu) and 97.8 kV (0.85 pu) in the five and ten year planning horizon respectively during a Heavy Winter scenario. This transmission line is owned and operated by BPA, however Avista has native load being served out of five of the eight distribution substations supplied by the transmission line. The mitigation approach should be developed by the BPA. Avista may develop its own plans to support the North Spokane Area which will better serve its customers in the future. A joint approach will be taken and results published in future Spokane Area Regional Assessments.

5.5 Multiple Contingency Issues: NERC Category C and D

Several multiple contingency issues have been identified in the Spokane Area. Similar to the issues described in Subsection 5.4, the mitigation approach for these issues typically cannot be a single project but rather several projects which collectively provide adequate performance and necessary compliance with the applicable Standards. If the single contingency issues are addressed by completing the projects described at the beginning of Subsection 5.4, then the multiple contingency issues become far less severe and are more manageable. The remaining contingencies causing thermal overloads include bus outages and/or bus tie failures at Beacon, Bell, Boulder, and Otis Orchards Substations. Also, the rights of way outage of the Sunset – Westside and College & Walnut – Westside 115 kV Transmission Lines will cause overloads of the Northwest – Westside and Francis & Cedar – Northwest 115 kV Transmission Lines. The following projects will provide the required mitigation of these multiple contingency issues. Optimization and further refinement will be performed in project reports if not already completed.

1. Reconstruct Beacon Substation utilizing bus configurations which eliminate a bus outage as a credible event.
2. Construct new 230 kV transmission line from the Bell – Coulee transmission line corridor to Westside Substation. This allows for the elimination of the common mode double circuit outage of the existing Bell – Westside and Coulee – Westside 230 kV Transmission Lines.
3. Construct an additional 230/115 kV source in the Coeur d'Alene Area to mitigate a 115 kV bus outage at Otis Orchards Switching Station. This will be further addressed in the Coeur d'Alene Area Regional Assessment.
4. Continue to implement *System Operating Procedure 23* which allows for controlled load shedding. Note that over the long term, this is not an acceptable option.

Following are descriptions of multiple contingency issues if no projects are completed in the Spokane Area.

BEACON BUS TIE FAILURE AND 230 KV OR 115 KV BUS OUTAGES

Single bus outages of either the 115 kV or 230 kV buses at Beacon Substation cause thermal overloads to the remaining 115 kV transmission lines. Both voltage levels have bus tie breakers and their failure to open during a fault condition causes more severe thermal overloads then a single bus outage. A 115 kV bus tie failure causes the Otis Orchards – Ninth & Central 115 kV Transmission Line to overload at 149.95% and 171.45% in the five and ten year planning horizon neglecting the more substantial overload of the Westside 230/115 kV Transformers. A 230 kV bus tie failure exhibits the worst thermal overload on the Bell – Northeast 115 kV Transmission Line with 199.75% and 232.35% in the five and ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – the consequences are severe and will continue to worsen with time. System Operating Procedure 23 allows for the controlled shedding of load which will mitigate the thermal overloads though most of the Spokane Area will be required to be dropped to do so.

2. Add series tie breakers to the 115 kV and 230 kV buses to eliminate a bus tie failure as a credible outage. Single bus outages will still be credible and will continue to cause thermal overload issues.

3. Construct bus configurations on the 115 kV and 230 kV buses allowing for bus outages to no longer be credible outages. This could potentially be double bus, double breaker for the 230 kV buses and double bus double breaker or breaker and a half for the 115 kV buses.

4. Add additional 230/115 kV sources in the South Spokane sub-region to offset the reliance on Beacon Substation.

A combination of options is desired including Alternatives 3 and 4. Additional relief from this issue is gained by completing the projects listed at the beginning of Subsection 5.4.

BELL BUS TIE FAILURE AND 230 KV OR 115 KV BUS OUTAGES

The Bell Substation is owned and operated by the BPA therefore bus outages or tie breaker failures must be addressed by the BPA. If the projects listed at the beginning of Subsection 5.4 are completed, a single 230 kV bus outages at Bell Substation will cause marginal thermal loading levels between 90 – 100%. Though this is acceptable performance, the conditions will worsen with time and a mitigation approach must be addressed to develop a strategic plan. 230 kV bus tie failures will continue to cause overloads on Avista facilities. If no projects are completed, the most severe bus tie failure is between Bell 230 kV bus sections 1 and 2 causing the Beacon 230/115 kV Transformers to overload at 120% in the ten year horizon. Completion of the projects listed in Subsection 5.4 will only reduce this overload to 112%. A joint plan with the BPA and Avista must be developed to address this issue. Until such a plan is determined, the use of *System Operating Procedure 23* will be used for controlled load shedding.

WESTSIDE 230 KV AND 115 KV BUS OUTAGE

With the present transmission system configuration a 115 kV bus outage at Westside Substation exhibits thermal overloads more severe than a 230 kV bus outage. The highest overload occurs on the Third & Hatch – Post Street 115 kV Transmission Line at 124.64% and 148.16% in the five and ten year planning horizon. Several other transmission lines as well as the Beacon and Bell 230/115 kV Transformers exhibit overloads. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.

2. Construct a new 230/115 kV source at Garden Springs. This will mitigate issues caused by the 115 kV bus outage at Westside Substation with the existing 115 kV transmission line

configuration. A 230 kV bus outage will cause the same level of overloads prior to construction of Garden Springs Substation unless additional 230 kV transmission lines are constructed.

3. Construct bus configurations on the 115 kV and 230 kV buses allowing for bus outages to no longer be credible outages. This could potentially be double bus, double breaker for the 230 kV buses and double breaker double bus or breaker and a half for the 115 kV buses. As new 230/115 kV transformers have been identified to be installed at Westside Substation and the desire to construct a green field substation to accommodate the transformers, a coordinated project to re-construct Westside Substation in a more reliable configuration is assumed to be more feasible.

Though Alternative 2 provides some relief, Alternative 3 is the desired mitigation approach at this time.

BELL – WESTSIDE AND COULEE – WESTSIDE 230 KV OUTAGE

The common mode double circuit outage of the Bell – Westside and Coulee – Westside 230 kV Transmission Lines causes similar issues to a 230 kV bus outage at Westside Substation. This double circuit transmission line is the primary source to Westside Substation. If the Garden Springs project is executed and includes a new 230 kV transmission line to supply Garden Springs from Westside Substation, it is unacceptable to have two 230/115 kV substations rely on a single mode failure. With the existing transmission system configuration this outage will cause the Third & Hatch – Post Street 115 kV Transmission Line to overload to 138.19% and 166.87% in the five and ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.

2. Construct a second 230 kV transmission line from the Bell – Coulee transmission line corridor to the Westside Substation. This will allow for the elimination of the common mode double circuit outage of the existing Bell – Westside and Coulee – Westside 230 kV Transmission Lines.

Alternative 2 is the preferred mitigation approach at this time.

BOULDER 115 KV BUS TIE FAILURE AND 115 KV BUS OUTAGES

Bus outages at Boulder Substation are not as severe as at other 230/115 kV substations but thermal overloads are still observed. The loss of the west 115 kV bus has similar results to the 115 kV tie breaker failure. The highest overload occurs on the Ninth & Central – Otis Orchards 115 kV Transmission Line with 111.46% and 135% in the five and ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.

2. Complete the Irvin Project. All thermal overloads exhibited in the Spokane Valley Area will be mitigated. Though less severe, high thermal loadings in the Coeur d'Alene Area are not mitigated but will be addressed in the Coeur d'Alene Regional Assessment.

3. Construct 115 kV bus configuration to eliminate bus outages and tie breaker failures as credible events.

Alternative 2 is the preferred mitigation approach at this time.

NINTH & CENTRAL 115 KV BUS TIE FAILURE AND 115 KV BUS OUTAGES

A bus outage or bus tie failure causing both buses to be out of service at Ninth & Central Substation will cause thermal overloads on several remaining 115 kV transmission lines. The bus tie failure is more severe than a single bus outage causing the worst overload to occur on the Ross Park – Third & Hatch 115 kV Transmission Line at 119.77% and 132.91% in the five and ten year planning horizon neglecting overloads of the Westside 230/115 kV Transformers. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.

2. Reconstruct the Ninth & Central Substation allowing for bus outages to no longer be credible outages. There is a desire to move the existing distribution transformers to be directly supplied by the Ninth & Central 115 kV bus rather than in line with the Ninth & Central – Sunset 115 kV Transmission Line. The mitigation approach could therefore be a coordinated effort to address more than one issue.

3. Complete the Garden Springs and Irvin Projects. All thermal overloads will be mitigated and these projects are required to mitigate single contingency issues.

Alternative 3 is the preferred mitigation approach at this time. Execution of Alternative 2 may be done solely to address concerns regarding the Ninth & Central Substation distribution load.

OTIS ORCHARDS 115 KV BUS OUTAGE

A bus outage at Otis Orchards Substation causes thermal overloads on the Ninth & Central – Otis Orchards 115 kV Transmission Line and on transmission lines in the Coeur d'Alene Area. The Ninth & Central – Otis Orchards 115 kV Transmission Line will overload to 98.64% and 117.15% in the five and ten year planning horizon. Overloads in the Coeur d'Alene Area are caused by the loss of the Otis Orchards – Post Falls 115 kV Transmission Line therefore requiring all of the Coeur d'Alene Area to be primarily sourced by Rathdrum Substation. The following are possible alternatives to mitigate this issue:

1. Do nothing - overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.

2. Complete the Irvin Project. All thermal overloads in the Spokane Valley Area will be mitigated and this project is required to mitigate single contingency issues. Thermal overload issues in the Coeur d'Alene Area will be addressed in the Coeur d'Alene Area Regional Assessment.

Alternative 2 is the preferred mitigation approach at this time.

NORTHWEST 115 KV BUS OUTAGE

A bus outage at Northwest Substation causes thermal overloads on the Sunset – Westside and College & Walnut – Westside 115 kV Transmission Lines. The Waste to Energy Tap to Garden Springs segment of the Sunset – Westside 115 kV Transmission Line will overload to 90.17% and 102.74% in the five and ten year planning horizon. The College & Walnut – Westside 115 kV Transmission Line does not exhibit an overload in the five year planning horizon but will load to 101% in the ten year horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.

2. Completion of the Garden Springs Project will mitigate the thermal overload and this project is required to mitigate single contingency issues.

Alternative 2 is the preferred mitigation approach at this time.

POST STREET BUS OUTAGE

A bus outage at Post Street Substation causes thermal overloads on the Sunset – Westside and Ninth & Central – Sunset 115 kV Transmission Lines. The Waste to Energy Tap to Garden Springs segment of the Sunset – Westside 115 kV Transmission Line does not exhibit an overload in the five year planning horizon but will load to 97.39% in the ten year horizon. The Ninth & Central – Sunset 115 kV Transmission Line will overload to 101.58% and 114.28% in the five and ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.

2. Completion of the Garden Springs Project will mitigate the thermal overload and this project is required to mitigate single contingency issues.

Alternative 2 is the preferred mitigation approach at this time.

THIRD & HATCH BUS OUTAGE

A bus outage at Third & Hatch Substation causes thermal overloads on the Ninth & Central – Sunset 115 kV Transmission Line. This transmission line will overload to 102.77% and 114.59% in the five and ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.
2. Completion of the Garden Springs Project will mitigate the thermal overload and this project is required to mitigate single contingency issues.

Alternative 2 is the preferred mitigation approach at this time.

BEACON – RATHDRUM AND BEACON – BOULDER 230 KV OUTAGE

The common mode double circuit outage of the Beacon – Rathdrum and Beacon - Boulder 230 kV Transmission Lines causes several thermal overloads. The most severely overloaded transmission line is the Beacon – Boulder #2 115 kV Transmission Line loading to 123.02% and 137.59% in the five and ten year planning horizon. The Beacon 230/115 kV Transformers also exhibit overload at 95.74% and 108.38% in the five and ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.
2. Complete the Lancaster Interconnection Project. All thermal overload violations will be mitigated and this project aids in the improvement of several other single contingency issues.

Alternative 2 is the preferred mitigation approach at this time.

BOULDER – OTIS #1 & #2 115 KV OUTAGE

The common mode double circuit outage of the Boulder – Otis Orchards#1 & #2 115 kV Transmission Lines cause thermal overloads on the Ninth & Central – Otis Orchards 115 kV Transmission Line and transmission lines in the Coeur d'Alene Area. The Ninth & Central – Otis Orchards 115 kV Transmission Line loads to 112.37% and 135.43% in the five and ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.
2. Complete the Irvin Project. All thermal overloads in the Spokane Valley Area will be mitigated and this project is required to mitigate single contingency issues. Thermal overload issues in the Coeur d'Alene Area will be addressed in the Coeur d'Alene Area Regional Assessment.

Alternative 2 is the preferred mitigation approach at this time.

WESTSIDE 230/115 KV TRANSFORMERS

The Westside #1 & #2 230/15 kV Transformers exhibit thermal overloads for many multiple contingencies in the Spokane Area. Several multiple contingencies cause increased flows on the transformers exacerbating all lines in service overloads described in Subsection 5.3. The worst contingency is a 115 kV tie breaker failure at Beacon Substation causing the Westside #1 230/115 kV Transformer to overload to 259.29% in the ten year planning horizon. The following are possible alternatives to mitigate this issue:

1. Do nothing – overloads will become more severe with time. *System Operating Procedure 23* allows for the controlled shedding of load which will mitigate the thermal overloads.
2. Replace existing Westside #1 & #2 230/115 kV Transformers with 250 MVA nameplate rated transformers. This project is necessary to mitigate all lines in service and single contingency issues.

Alternative 2 is the preferred mitigation approach at this time.

5.6 Resulting Issues

If all of the options identified in Section 5 are completed within the ten year planning horizon to mitigate the discussed issues, there are CY 2020 emergent issues that will be addressed in future Spokane Area Regional Assessments. These issues include the following:

1. Boulder – Otis Orchards #2 115 kV Transmission Line overloads to 92% for line end open condition of Boulder – Otis Orchards #1 115 kV Transmission Line open at Boulder Substation,
2. Beacon #1 & #2 230/115 kV Transformers overload to 95% for loss of the adjacent Beacon Transformer,
3. Northwest – Westside and Francis & Cedar – Northwest 115 kV Transmission Lines load to 91% for the line end open condition on the College & Walnut – Westside 115 kV Transmission Line open at Westside Substation.
4. 230 kV bus tie failures and bus outages at Bell Substation cause the underlying 115 kV system to overload to as much as 118%.
5. Boulder Substation 115 kV bus tie failure causes the Ninth & Central – Otis Orchards 115 kV Transmission Line to overload to 100.3% and transmission lines from Rathdrum Substation to load to 98%.
6. Otis Orchards 115 kV bus outage causes the Coeur d'Alene 15th St – Rathdrum 115 kV Transmission Line to load to 94.3% and Ramsey – Rathdrum #1 115 kV Transmission Line to load to 102.2%.

6 Voltage Stability Analysis (PV & QV)

Steady state analysis techniques were used to evaluate the voltage stability performance in the Spokane Area. Further investigation of voltage stability using dynamic (time-domain) simulation is presented in Section 7. PV and QV analysis were used to assess the area's conformity with the relevant planning criteria. PV analysis of a particular area or of a particular transfer path reveals the static stability margin of that area or of that path while QV analysis yields the reactive power margin at a particular bus in the power system under consideration.

A key element of voltage stability studies is the determination of a critical bus or a cluster of critical busses. According to the WECC publication "*Voltage Stability Criteria, Undervoltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology*" (1998), the critical bus exhibits one or more of the following characteristics under the worst single or multiple contingency:

- Has the highest voltage collapse point on the QV curve,
- Has the lowest reactive power margin,
- Has the greatest reactive power deficiency,
- Has the highest percentage change in voltage.

The following sections provide methodology and results for the PV and QV analysis conducted.

6.1 PV Analysis

METHODOLOGY

A PV curve is obtained in power-flow simulation by monitoring a voltage at a bus of interest and varying (increasing) the power (load or transfer) in small increments until power-flow divergence is encountered. Each equilibrium point represents a steady-state operating condition. No defined paths are present in the Spokane Area therefore only a Load Ramp PV Curve analysis was performed. The PV analysis conducted monitored all busses in the Spokane Area. All loads within the Spokane Area were increased until voltage collapse occurred (i.e. the case became numerically unstable). It was assumed that all additional generation necessary to supply the increase in load came from Grand Coulee Dam. This is a reasonable assumption to represent off system purchases from the Mid Columbia market. LTC and switched shunts were disabled to provide a post-transient response prior to operator intervention. A set of contingencies depicting one or more transmission outages was used to produce a series of PV curves. The operating limit can be established as the lowest of the following as obtained from the PV analysis results:

1. 5% below the area load magnitude at the 'nose-point' for Category A performance,

2. 5% below the area load magnitude corresponding to the ‘nose-point’ on the PV curve representing the worst Category B contingency,

3. 2.5% below the area load magnitude corresponding to the ‘nose-point’ on the PV curve representing the worst Category C contingency (controlled load shedding is allowed to achieve this operating limit).

RESULTS

As load increases in the Spokane Area, the worst Category B contingency is the Bell #1 500/230 kV Transformer outage. The nose point occurs near 1685 MW therefore the theoretical operating limit could be a total Spokane Area load of 1600 MW (it should be noted that the 2010 FERC Market Power Study indicates that the Avista system Simultaneous Import Limit is 679 MW for the summer season). The worst Category C contingency becomes the bus tie failure at Bell Substation between 230 kV bus sections 1 and 4. The critical bus for this outage is the Cheney 115 kV bus. Controlled load shedding is allowed therefore the criticality of this contingency is not easily determined. Figure 6-1 shows the PV curves for two critical buses and the worst performing contingencies. From observation, the post transient voltage deviation at Cheney Substation exceeds 5% for the Bell S1 & S4 230 kV bus outage. This issue is also address in Subsection 5.5.

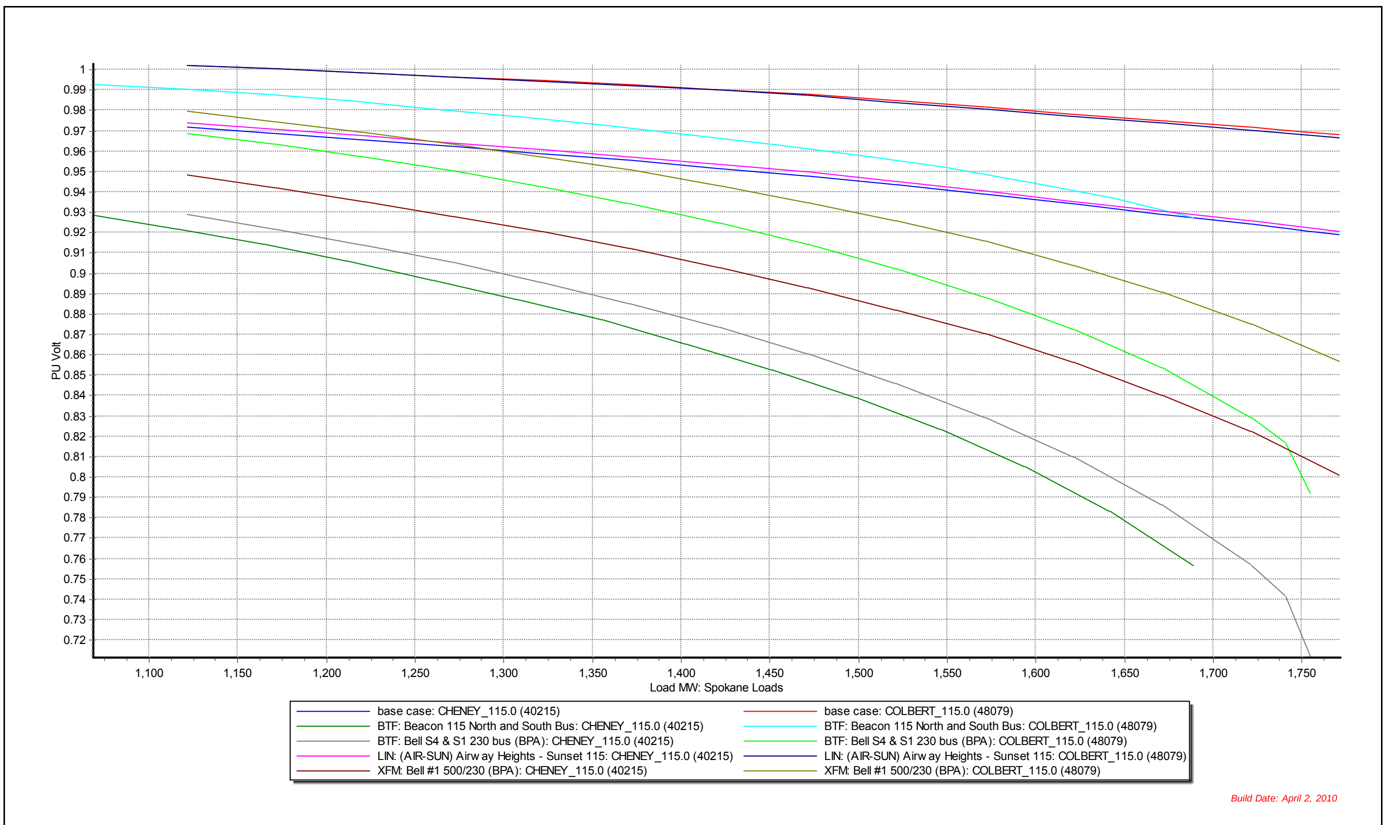


FIGURE 6-1: LOAD RAMP PV CURVE RESULTS FOR CRITICAL BUSSES.

6.2 QV Analysis

METHODOLOGY

Using results of the PV Analysis, a set of critical busses can be determined. All critical busses and 115 kV busses of 230/115 kV transformers will be studied in the QV analysis. All bus voltages in the Spokane Area are monitored as the reactive demand at the bus under study is varied. This process is repeated for a set of contingencies depicting one or more transmission outages and for the remaining busses to be studied. LTC and switched shunts were disabled to provide a post-transient response prior to operator intervention. The reactive power margin (RPM) can be assessed from the results of the QV analysis. RPM is defined as the negative of the value of the reactive demand at the minimum point of the QV curve.

RESULTS

The QV Analysis showed there is adequate reactive margin for the 115 kV source busses and critical busses in the Spokane Area. Table 6-1 and Table 6-2 show the results of the worst performing contingency for each bus analyzed. The Westside 115 kV bus had the least reactive margin at 462 MVAr for the outage of the Bell #1 500/230 kV Transformer and 387 MVAr for the tie breaker failure between Bell Substation 230 kV bus sections 1 & 4. These outage scenarios are also addressed in Subsections 5.4 and 5.5.

The smallest reactive margin at the critical busses analyzed occurred at the Colbert 115 kV bus with a value of 52 MVAr for the Colbert Tap to Mead Tap outage on the Addy – Bell 115 kV Transmission Line. This issue is also addressed in Subsection 5.4.

Number	Name	Nom kV	Case Name	V at Q0	Q0	Qinj_0	Qinj_min	V at Qmin	Qmin
40215	CHENEY	115	XFM: BELL #1 500/230 (BPA)	0.95	0	0	-147.32	0.4985	-147.32
48079	COLBERT	115	LIN: (ADD-BEL) COLBERT TAP - MEAD TAP 115 (BPA)	0.98	0	13.41	-48.29	0.5621	-52.68
48023	BEACON N	115	XFM: BELL #1 500/230 (BPA)	0.99	0	0	-517.4	0.6862	-517.40
48029	BEACON S	115	XFM: BELL #1 500/230 (BPA)	0.99	0	0	-517.44	0.6863	-517.44
40087	BELL BPA	115	XFM: BELL #1 500/230 (BPA)	0.98	0	0	-494.59	0.6535	-494.59
48522	BOULDERE	115	XFM: BELL #1 500/230 (BPA)	0.99	0	0	-514.98	0.6604	-514.98
48520	BOULDERW	115	XFM: BELL #1 500/230 (BPA)	0.99	0	0	-514.9	0.6604	-514.90
48461	WEST	115	XFM: BELL #1 500/230 (BPA)	0.99	0	0	-462.25	0.656	-462.25

TABLE 6-1: CATEGORY B QV ANALYSIS RESULTS FOR 5 YEAR HORIZON.

Number	Name	Nom kV	Case Name	V at Q0	Q0	Qinj_0	Qinj_min	V at Qmin	Qmin
40215	CHENEY	115	BTF: BEACON 115 NORTH AND SOUTH BUS	0.93	0	0	-128.15	0.5085	-128.15
48079	COLBERT	115	BTF: BELL S2 & S3 230 BUS (BPA)	0.97	0	13.16	-221.61	0.5228	-225.41
48023	BEACON N	115	BTF: BELL S4 & S1 230 BUS (BPA)	0.97	0	0	-457.17	0.7025	-457.17
48029	BEACON S	115	BTF: BELL S4 & S1 230 BUS (BPA)	0.97	0	0	-457.21	0.7025	-457.21
40087	BELL BPA	115	BTF: BELL S4 & S1 230 BUS (BPA)	0.97	0	0	-446.24	0.6735	-446.24
48522	BOULDERE	115	BTF: BELL S4 & S1 230 BUS (BPA)	0.98	0	0	-458.16	0.6779	-458.16
48520	BOULDERW	115	BTF: BELL S4 & S1 230 BUS (BPA)	0.98	0	0	-458.09	0.6779	-458.09
48461	WEST	115	BTF: BELL S4 & S1 230 BUS (BPA)	0.97	0	0	-387.63	0.6353	-387.63

TABLE 6-2: CATEGORY C QV ANALYSIS RESULTS FOR 5 YEAR HORIZON.

7 Transient Stability Analysis

7.1 Study Methodology

Transient stability analysis is commonly employed in the study of power system stability to reveal the total "system trajectory" following a disturbance.

Standard WECC, NERC and Avista requirements for disturbance performance were used to evaluate the results of dynamic stability analysis simulations. These requirements are as follows:

- Maximum allowable transient voltage dip of 25 percent at load buses or 30 percent at non-load buses.
- Maximum allowable transient voltage dip not to exceed 20 percent for more than 20 cycles at load buses.
- Minimum allowable frequency of 59.6 Hz for 6 cycles or more at load buses.
- Maximum allowable post-transient voltage deviation of 5 percent from pre-disturbance voltage.

The WECC/NERC voltage performance criteria are illustrated in Figure 7-1. A more detailed explanation and further information can be referenced in "*TPL – (001 thru 004) – WECC – 1 – CR – System Performance Criteria*" at www.wecc.biz.

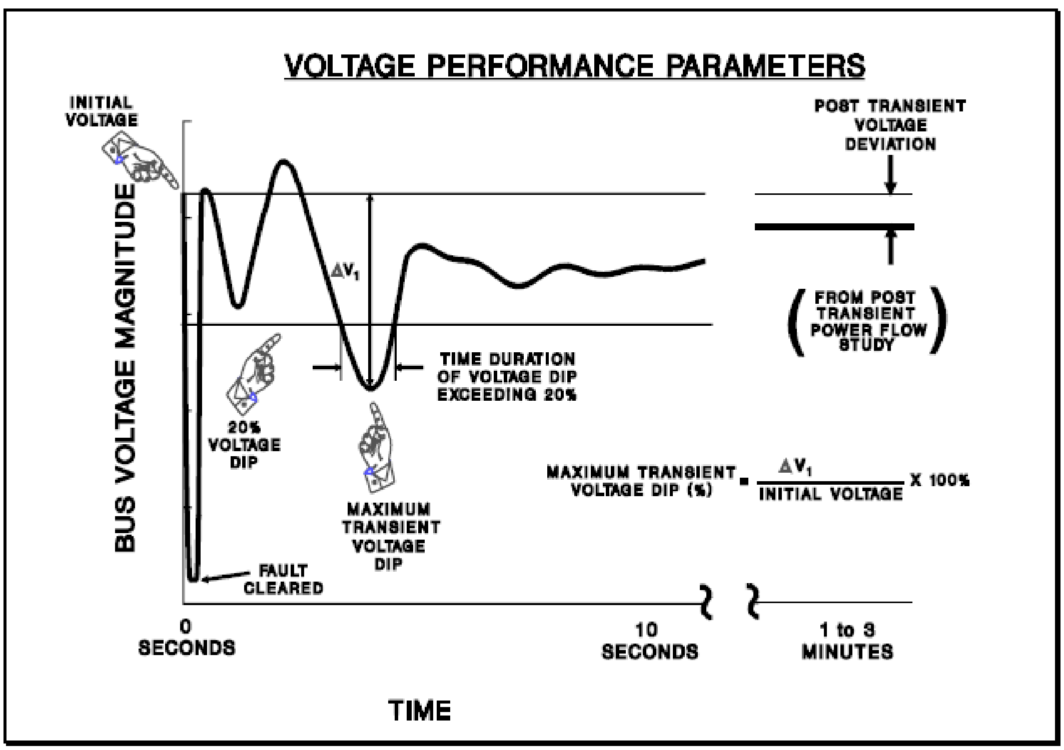


FIGURE 7-1: WECC/NERC VOLTAGE PERFORMANCE CRITERIA AND PARAMETERS, HTTP://WWW.WECC.BIZ/STANDARDS/WECC CRITERIA/TPL - (001 THRU 004) - WECC - 1 - CR - SYSTEM PERFORMANCE CRITERIA.PDF.

Avista's System Planning Group uses GE PSDS software to perform transient stability simulations. The dynamic stability simulation module DYTOOLS is utilized to batch process multiple contingency scenarios in an efficient manner. Analysis of the results is conducted using a user written program to screen for criteria violations. A summary of violations is produced as well as individual plot files for each simulation performed.

Past studies have shown that transient stability on Avista's system is influenced by Western Montana Hydro, West of Hatwai flows, Northwest to Idaho flows, and Montana to the Northwest flows. As these three transfer paths can be heavily loaded during light load hours, the light load case is the most stressed. Avista's System Planning Group presently analyzes the four seasonal cases described in Subsection 5.1. The following are issues observed that should be addressed.

7.2 Single Contingency Issues (N-1): NERC Category B

NINE MILE

The Nine Mile Generator Units 3 and 4 were observed going out of step for a three phase fault on the Nine Mile – Westside 115 kV Transmission Line with time delayed clearing by the Nine Mile terminal. The Zone 2 time delay on the Nine Mile terminal is set to sixteen cycles to coordinate with other transmission line protection schemes in the area. This is a shorter time delay than Avista's typical Zone 2 time delay setting. The out of step condition was observed in the Light Summer and Heavy Winter Cases. This issue was likely not observed in the Heavy Summer cases due to the dispatch scenario of generation on the Spokane River. The following are possible alternatives to mitigate this issue:

1. Do nothing – out of step condition will cause damage to the generating facility.
2. Install redundant out of step protection scheme.
3. Improve the Zone 2 time delay clearing time on the Nine Mile terminal. This could be implemented by utilizing communication aided tripping schemes. Providing a communication path for protection schemes can be costly. Also, modification of the Transmission System in the surrounding area as required by Section 5 will potentially allow for improved performance.
4. Implement local generation dropping scheme with other Spokane River hydro plants.
5. Construct a third 115 kV transmission line to tie Nine Mile back to the Spokane load center.

Alternative 2 is the preferred mitigation approach at this time.

BOULDER PARK

Boulder Park Generators Units 1 through 6 will go out of step for Zone 2 time delayed three phase faults on either of the Boulder – Otis #1 and #2 115 kV Transmission Lines with time delayed clearing by either terminal. This issue has been identified and mitigation addressed in "Boulder Park Generation

Transient Stability" report by Rich Hydzik 11/13/2009. As stated in the report, the following are possible solutions to mitigate this issue:

1. Upgrade the protection schemes on the Boulder – Otis #1 and #2 115 kV lines.
2. Apply out of step relaying to trip Boulder Park generation as it begins to go out of step.
3. Shorten the Zone 2 timers on the Boulder – Otis #1 and #2 115 kV lines from 15 cycles to 5 cycles.

The planned relay upgrades on the Boulder – Otis #1 and #2 115 kV lines should proceed with all due haste. In addition to addressing performance at Boulder Park, these upgrades significantly improve performance in the WMH area. With the relay upgrades in place, the Post Falls – Otis 115 kV Transmission Line and the Rathdrum – Boulder 115 kV Transmission Line can be operated closed during periods of high WMH, significantly increasing reliability in the Coeur d'Alene area.

Until the relay upgrades are completed, out of step relaying should be applied or Zone 2 timers should be shortened.

7.3 Multiple Contingency Issues: NERC Category C

Three phase bus faults were simulated with normal clearing for all 115 kV and 230 kV buses in the Spokane Area. No criteria violations were observed in these simulations.

8 Recommended Project Prioritization and Schedule

The projects identified in Section 5 are prioritized, scheduled, and budgeted in Table 8-1 below. The projects and related expenditures enumerated in this assessment do not include any transmission, substation, or distribution blankets. The total cost estimate for each project is lumped into the construction year the project is required to be energized. Therefore the subtotal for each year may not be the budgeted amount as each project may take multiple years to complete. Some projects have required in service dates earlier than those identified in this report but due to budget, construction and/or operational schedule it is understood that some issues cannot be mitigated in the desired timeframe. This report suggests obtainable project schedules to represent a realistic planning approach. The budgeted amounts are categorized in columns by the group or entity responsible for executing the project. Items highlighted indicate a modification from the present "*T and D Capital Budget – 5 year plan*."

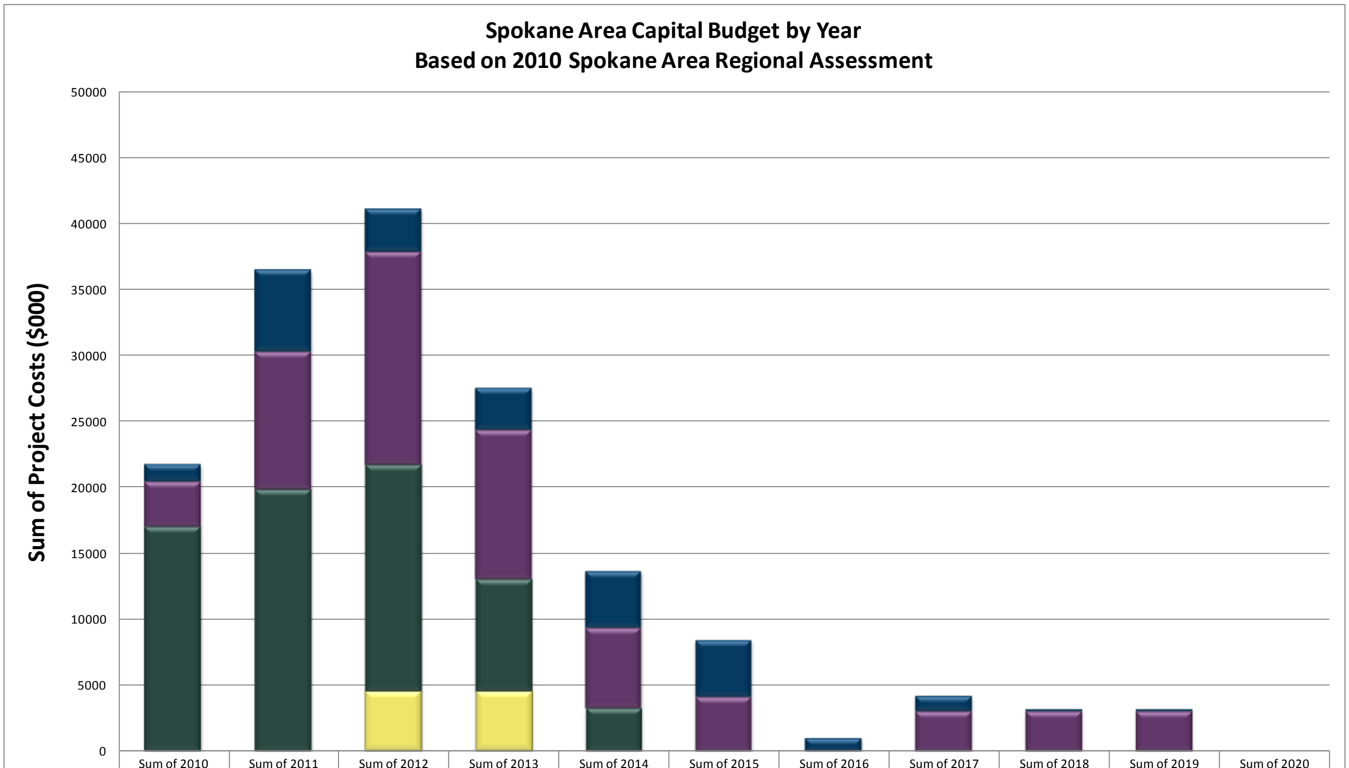
Total ($000)	BPA	Distribution	Substation	Transmission	Grand Total
2010			**$ 450.00**	**$ 975.00**	**$ 1,425.00**
West Plains Transmission Reinforcement			**450**	**975**	**1425**
ER: 2481 - Airway Hts. - Install 30 MVAR Cap Bank			450		450
ER: 2310 - Recond. AIR-SLK (Complete)				975	975
2011		**$ 3,206.70**	**$ 5,280.00**	**$ 5,650.00**	**$ 14,136.70**
Driven by Distribution Eng.		**3206.7**			**3206.7**
ER: 2296 - Northeast 115 Sub - Inc Capacity		450			450
ER: 2303 - Metro 115 Sub - Install Fdr 13639 Position		721.7			721.7
ER: 2394 - Post Street Bridge Conduit work		125			125
ER: 2438 - Bridge the Valley Project (Beacon 12F6)		200			200
ER: 2443 - Otis Orchards 115-13, 20 MVA Sub		1200			1200
ER: 2517 - EFM 12F2 feeder tie		110			110
ER: NEW081 - MEA 12F3 Add New Feeder		400			400
Driven by Operations				**3000**	**3000**
ER: NEWXXX - BEA - 9CE 1 &2 Rebuild				3000	3000
Driven by Substation Eng.			**4280**		**4280**
ER: 2280 - Northwest - Install Circuit Switchers			120		120
ER: 2283 - Millwood 115 Sub Rebuild			3660		3660
ER: 2390 - Otis Orchards 115 Sub-Replace Breakers & Relays			500		500
Driven by Transmission Eng.				**650**	**650**
ER: 2473 - Beacon-F&C 115: Reroute @ Whitworth				650	650
Garden Springs Integration			**500**		**500**
ER: 2422 - Garden Springs Substation Property			500		500
West Plains Transmission Reinforcement			**500**	**2000**	**2500**
ER: 2423 - Recond. GDN-H&W				2000	2000
ER: 2481 - Hallet & White - Install 30 MVAR Cap Bank			500		500
2012		**$ 47,260**	**$ 18,250**	**$ 2,840**	**$ 68,350**
Driven by Distribution Eng.		**47260**			**47260**
ER: 2317 - Lyons & Standard 115 Sub-Inc Capacity		335			335
ER: 2395 - SE 115 Sub - Upgrade XFMR #1 & Add 13F6		1075			1075
ER: 2414 - System - Dist Reliability - Improve Worst Feeders		850			850
ER: NEWXXX - Smart Grid		45000			45000

Total ($000)	BPA	Distribution	Substation	Transmission	Grand Total
Driven by Operations			**500**		**500**
ER: 2481 - Francis & Cedar - Install 50 MVAR Cap Bank			500		500
Driven by Substation Eng.			**9000**		**9000**
ER: 2251 - Post St 115 Sub-Improvements & Upgrades			480		480
ER: 2341 - Ninth & Central Sub - Increase Capacity & Rebuild			3520		3520
ER: NEWXXX - Sunset Substation Rebuild			5000		5000
Irvin Project				**1840**	**1840**
ER: 2474 - Beacon-Boulder 115 #2: Upgrade to 140 MVA				1840	1840
Spokane/CDA Relay Project			**3750**		**3750**
ER: 2217 - Spokane - CDA 115 kV Line Relaying Upgrades			3750		3750
West Plains Transmission Reinforcement				**1000**	**1000**
ER: 2310 - Recond. GDN-SUN				1000	1000
Westside Rebuild			**5000**		**5000**
ER: 2000 - Westside 230-115 kV, 250 MVA Autos			5000		5000
2013	**$ 9,000**	**$ 10,438**	**$ 16,560**	**$ 4,550**	**$ 40,548**
9CE-SUN Reconductor				**900**	**900**
ER: NEWXXX - Recond. 9CE - SUN				900	900
Driven by Distribution Eng.		**10038**	**2485**		**12523**
ER: 2237 - Metro 115 Sub - Install Fdr 13631		950			950
ER: 2285 - Sunset 115 Sub - Upgrade XFMR #2		1000			1000
ER: 2320 - Barker Road 115 Sub - Add 2nd XFMR		875			875
ER: 2413 - SIP 12F6 - Construct		450			450
ER: 2417 - Hawthorne 115 Sub - Construct			2485		2485
ER: 2479 - North/South Freeway Substation		2500			2500
ER: 2514 - Recond.		4263			4263
Hawthorne Integration				**1000**	**1000**
ER: 2417 - Hawthorne Transmission Integration				1000	1000
Irvin Project		**400**	**7325**	**1950**	**9675**
ER: 2446 - Irvin - IEP 115 kV line				1000	1000
ER: 2446 - Irvin 115 kV Switching Station			6675		6675
ER: 2446 - Irvin Transmission Integration				150	150
ER: 2481 - IRV-OPT 115 kV rebuild				800	800
ER: 2481 - OPT/Irvin 115kV VAR Support (Cap Bank)			650		650
ER: NEW113 - OPT12F2 Build New Feeder, Abandon Xmission		400			400
Lancaster Interconnection	**9000**			**500**	**9500**
ER: NEW120 - Lancaster	9000				9000
ER: NEW120 - Lancaster Transmission Integration				500	500
Westside Rebuild			**6750**	**200**	**6950**
ER: NEW052 - Westside 230 Sub - Rebuild			6750		6750
ER: NEW052 - Westside Rebuild Integration				200	200
2014		**$ 4,808**	**$ 2,000**		**$ 6,808**
Driven by Distribution Eng.		**4807.6**			**4807.6**
ER: 2322 - Spokane Downtown West Sub, 115-13, 20 MVA		2257.6			2257.6
ER: NEW111 - Greenacres 115 Sub Integration		2550			2550
Irvin Project			**2000**		**2000**
ER: NEWXXX - Oppurtunity Breakers			2000		2000
2015			**$ 9,100**	**$ 7,000**	**$ 16,100**
Garden Springs Integration			**9100**	**7000**	**16100**

Total ($000)	BPA	Distribution	Substation	Transmission	Grand Total
ER: 2422 - Garden Springs - Westside 230				5500	5500
ER: 2422 - Garden Springs Substation			9100		9100
ER: 2422 - Garden Springs Transmission Integration				500	500
ER: 2422 - Recond GDN-SUN #1				1000	1000
2016				**$ 1,600**	**$ 1,600**
Westside Rebuild				**1600**	**1600**
ER: NEWXXX - Split Westside 230 Double Circuit				1600	1600
2017				**$ 2,000**	**$ 2,000**
Bell Transformer Mitigation (Place Keeper)				**2000**	**2000**
ER: NEWXXX - Bell Transformation Mitigation				2000	2000
2019			**$ 9,000**	**$ 600**	**$ 9,600**
Beacon Rebuild			**9000**	**600**	**9600**
ER: 2112 - Beacon 230 - 2 x 2			9000		9000
ER: 2112 - Beacon Rebuild Transmission Integration				600	600
Grand Total	**$ 9,000**	**$ 65,712**	**$ 60,640**	**$ 25,215**	**$ 160,567**

TABLE 8-1: RECOMMENDED PROJECT PRIORITIZATION AND SCHEDULE.

Figure 8-1 provides a graphical view of the capital budget for the Spokane Area as presented in Table 8-1. The budgeted amounts are categorized in columns by the group or entity responsible for executing the projects.



	Sum of 2010	Sum of 2011	Sum of 2012	Sum of 2013	Sum of 2014	Sum of 2015	Sum of 2016	Sum of 2017	Sum of 2018	Sum of 2019	Sum of 2020
Grand Total	21750	36481.7	41120	27533	13657.6	8425	1000	4200	3200	3200	0
Transmission	1300	6245	3270	3200	4300	4300	1000	1200	200	200	0
Substation	3470	10420	16190	11310	6125	4125	0	3000	3000	3000	0
Distribution	16980	19816.7	17160	8523	3232.6	0	0	0	0	0	0
BPA	0	0	4500	4500	0	0	0	0	0	0	0

FIGURE 8-1: SPOKANE AREA CAPITAL BUDGET BY YEAR.

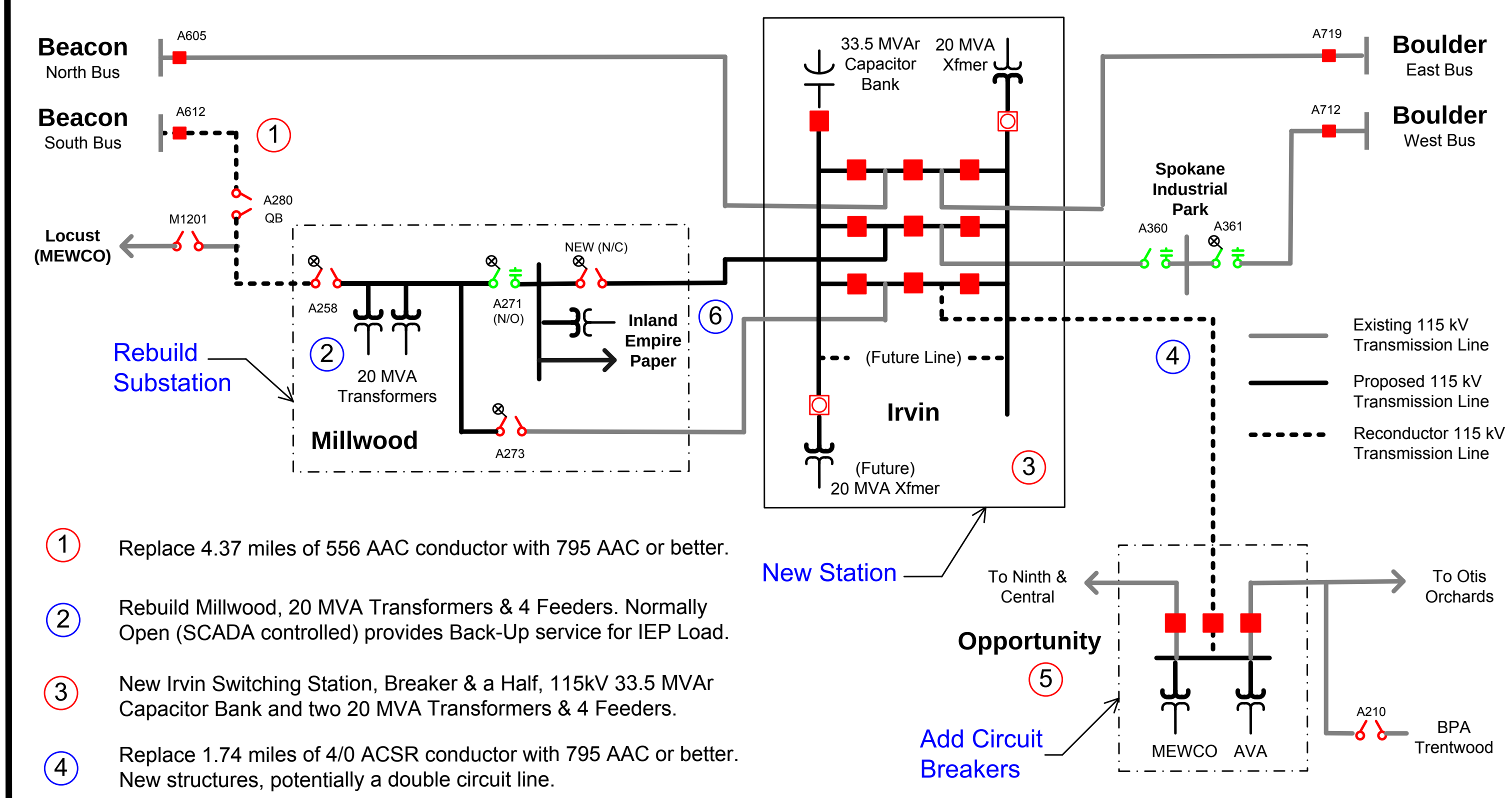
A summary of the present "*T and D Capital Budget – 5 year plan*" related to the Spokane Area is provided in Table 8-2. The total budgeted cost has been lumped into the construction year the project is required to be energized. Therefore the subtotal for each year may not be the budgeted amount as each project may take multiple years to complete.

Total ($000)	Distribution	Substation	Transmission	Grand Total
2010		**$ 750**	**$ 975**	**$ 1,725**
West Plains Transmission Reinforcement		**750**	**975**	**1725**
ER: 2310 - West Plains Transmission Reinforcement			975	975
ER: 2481 - Airway Hts. - Install 30 MVAR Cap Bank		450		450
ER: 2481 - Hallet & White - Install 30 MVAR Cap Bank		300		300
2011	**$ 3,207**	**$ 4,280**	**$ 650**	**$ 8,137**
Driven by Distribution Eng.	**3206.7**			**3206.7**
ER: 2296 - Northeast 115 Sub - Inc Capacity	450			450
ER: 2303 - Metro 115 Sub - Install Fdr 13639 Position	721.7			721.7
ER: 2394 - Post Street Bridge Conduit work	125			125
ER: 2438 - Bridge the Valley Project (Beacon 12F6)	200			200
ER: 2443 - Otis Orchards 115-13, 20 MVA Sub	1200			1200
ER: 2517 - EFM 12F2 feeder tie	110			110
ER: NEW081 - MEA 12F3 Add New Feeder	400			400
Driven by Substation Eng.		**4280**		**4280**
ER: 2280 - Northwest - Install Circuit Switchers		120		120
ER: 2283 - Millwood 115 Sub Rebuild		3660		3660
ER: 2390 - Otis Orchards 115 Sub-Replace Breakers & Relays		500		500
Driven by Transmission Eng.			**650**	**650**
ER: 2473 - Beacon-F&C 115: Reroute @ Whitworth			650	650
2012	**$ 2,260**	**$ 12,750**	**$ 1,840**	**$ 16,850**
Driven by Distribution Eng.	**2260**			**2260**
ER: 2317 - Lyons & Standard 115 Sub-Inc Capacity	335			335
ER: 2395 - SE 115 Sub - Upgrade XFMR #1 & Add 13F6	1075			1075
ER: 2414 - System - Dist Reliability - Improve Worst Feeders	850			850
Driven by Substation Eng.		**4000**		**4000**
ER: 2251 - Post St 115 Sub-Improvements & Upgrades		480		480
ER: 2341 - Ninth & Central Sub - Increase Capacity & Rebuild		3520		3520
Irvin Project			**1840**	**1840**
ER: 2474 - Beacon-Boulder 115 #2: Upgrade to 140 MVA			1840	1840
Spokane/CDA Relay Project		**3750**		**3750**
ER: 2217 - Spokane - CDA 115 kV Line Relaying Upgrades		3750		3750
Westside Rebuild		**5000**		**5000**
ER: 2000 - Westside 230-115 kV, 250 MVA Autos		5000		5000
2013	**$ 10,438**	**$ 16,810**	**$ 1,450**	**$ 28,698**
Beacon Rebuild		**250**		**250**
ER: 2112 - Beacon 230 - 2 x 2		250		250
Driven by Distribution Eng.	**10038**	**2535**		**12573**
ER: 2237 - Metro 115 Sub - Install Fdr 13631	950			950
ER: 2285 - Sunset 115 Sub - Upgrade XFMR #2	1000			1000
ER: 2320 - Barker Road 115 Sub - Add 2nd XFMR	875			875
ER: 2413 - SIP 12F6 - Construct	450			450
ER: 2417 - Hawthorne 115 Sub - Construct		2485		2485
ER: 2479 - North/South Freeway Substation	2500			2500

Total ($000)	Distribution	Substation	Transmission	Grand Total
ER: 2514 - Recond.	4263			4263
ER: NEW111 - Greenacres 115 Sub Integration		50		50
Irvin Project	**400**	**7825**	**1450**	**9675**
ER: 2446 - Irvin 115 kV Switching Station		7825		7825
ER: NEW113 - OPT12F2 Build New Feeder, Abandon Xmission	400			400
ER: NEW119 - OPT/Irvin 115kV VAR Support			1450	1450
Westside Rebuild		**6200**		**6200**
ER: NEW052 - Westside 230 Sub - Rebuild		6200		6200
2014		**$ 2,258**	**$ 2,100**	**$ 4,358**
Driven by Distribution Eng.		**2257.6**		**2257.6**
ER: 2322 - Spokane Downtown West Sub, 115-13, 20 MVA		2257.6		2257.6
Garden Springs Integration			**2100**	**2100**
ER: 2422 - South Spokane 230 kV Reinforcement			2100	2100
(blank)		**$ -**		**$ -**
Driven by Operations		**0**		**0**
ER: 2481 - Francis & Cedar - Install 50 MVAR Cap Bank		0		0
Grand Total	**$ 15,905**	**$ 36,848**	**$ 7,015**	**$ 59,767**

TABLE 8-2: BUDGETED PROJECTS AND PRIORITIZATION

9 Project Diagrams



1 Replace 4.37 miles of 556 AAC conductor with 795 AAC or better.

2 Rebuild Millwood, 20 MVA Transformers & 4 Feeders. Normally Open (SCADA controlled) provides Back-Up service for IEP Load.

3 New Irvin Switching Station, Breaker & a Half, 115kV 33.5 MVAr Capacitor Bank and two 20 MVA Transformers & 4 Feeders.

4 Replace 1.74 miles of 4/0 ACSR conductor with 795 AAC or better. New structures, potentially a double circuit line.

5 Convert Opportunity to a Switching Station (Single Bus). Two AVA Feeders and four MEWCO Feeders.

6 New 2.19 miles Single Circuit 556 AAC (IEP Tap). Possible double circuit Irvin to Millwood/IEP line.

Project Completion, all facilities in service by year end 2013.

Irvin Project

Project Diagram: SP-0220

AVISTA Corp.

SPOKANE, WASHINGTON

ORIGINAL DATE	APPROVAL
DESIGN: SYSTEM PLANNING	

NO.	Date	REVISION NOTES	BY	CKD

10 Adjacent Utility One Line Drawings

Redacted per CEII requirements

11 System Power Flow Plots

11.1 2015 Heavy Winter

11.2 2015 Heavy Summer, Low Hydro

11.3 2020 Heavy Winter

11.4 2020 Heavy Summer, Low Hydro

11.5 2020 Heavy Summer, Low Hydro – Bell #6 Transformer

11.6 2020 Heavy Summer, Low Hydro – Beacon 115 kV Tie Breaker Failure

Redacted per CEII requirements

12 Area Contacts as of June, 2010

	Title	Work Phone	Cell Phone	Email
Avista				
Spokane Headquarters				
John Gross	System Planning Engineer	509-495-4591		john.gross@avistacorp.com
Scott Waples	Chief Transmission Planning Eng	509-495-4462		scott.waples@avistacorp.com
Tracy Rolstad	Sr Power System Consultant	509-495-4538		tracy.rolstad@avistacorp.com
Dean Spratt	System Planning Engineer	509-495-8119		dean.spratt@avistacorp.com
Reuben Arts	System Planning Engineer	509-495-2787		reuben.arts@avistacorp.com
John Gibson	Sr Efficiencies Engineer II	509-495-4115		john.gibson@avistacorp.com
Will Stone	Distribution Planner	509-495-2539		william.stone@avistacorp.com
Mike Magruder	Substation Engineering Manager	509-495-4187		mike.magruder@avistacorp.com
Ken Sweigart	Transmission Engineering Manager	509-495-4417		ken.sweigart@avistacorp.com
Randy Spacek	System Protection Manager	509-495-8991		randy.spacek@avistacorp.com
Dave James	Distribution Engineering Manager	509-495-4185		dave.james@avistacorp.com
Rich Hydzik	Transmission Operations Eng	509-495-4005		rich.hydzik@avistacorp.com
Jacob Reidt	Manager Network Engineer	509-495-2012		jacob.reidt@avistacorp.com
John McClain	Regional Operations Engineer	509-495-4458		john.mcclain@avistacorp.com

Neighboring Utilities				
Bonneville Power Administration				
Brian Markham – Bell Region	Customer Service Engineer	509-358-7426		bsmarkham@bpa.gov
Inland Power & Light				
Richard Damiano	Chief Engineer	509-747-7151		richd@inlandpower.com
Modern Electric Water Company		509-928-4540		modern@mewco.com
Vera Water & Power		509-924-3800		
City of Cheney		509-498-9230		

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14 Appendix A – Power Flow Violation Summary

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15 Appendix B – Transient Stability Results

The following tables provide the results from a user written program which analyzes the transient stability simulations performed. Due to the number of simulation performed, plots of the results or detailed analysis results are not included in this document but can be provided upon request.

Redacted per CEII requirements

Appendix F - TP-SPP-04 – Data Preparation for Steady State and Dynamic Studies

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Appendix G - TP-SPP-06 – Contingency Analysis

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Appendix H - TP-SPP-07 – Loads and Resources

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