2025 Electric Integrated Resource Plan

Appendix D – 10-Year Transmission/ Distribution Plan

2023 Avista System Plan

Sunset Station, Spokane, Washington

Transmission System Planning
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Prepared by: System Planning

Version	Date	Description	Author	Review
V0	2/7/2024	Released	David Thompson	John Gross

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1. System Planning Overview

Avista's System Planning department's core responsibilities include the development of a system plan for system reinforcements to meet transmission system needs for load growth, adequate transfer capability, requests for generation interconnections, line and load interconnections, and long-term firm transmission service.

The development of the system plan follows a two-year process with four phases. Stakeholders have opportunities to participate in the development of the system plan by collaborating with System Planning and providing comments.

- Phase 1 includes establishing the assumptions and models for use in the technical studies, developing and finalizing a Study Plan, and specifying the public policy mandates planners will adopt as objectives in the current study cycle.
- Phase 2 includes performing necessary technical studies and development of the Planning Assessment. The results of the technical studies are documented in the Planning Assessment, including conceptual solutions to mitigate performance issues.
- Phase 3 includes providing the Avista System Plan report to stakeholders. The Avista System Plan will include documentation of the electrical infrastructure plan with preferred solution options. The resulting project list will include additional information regarding projects and system modifications developed through means other than the technical studies.[1]
- Phase 4 comprises most of the year two in the two-year process and includes refining the preferred plan of service. Conceptual projects identified in Phase 2 which have not been fully developed in Phase 3 will be addressed in Phase 4.

Figure 1 provides a visual representation of the four phases through the two-year process.

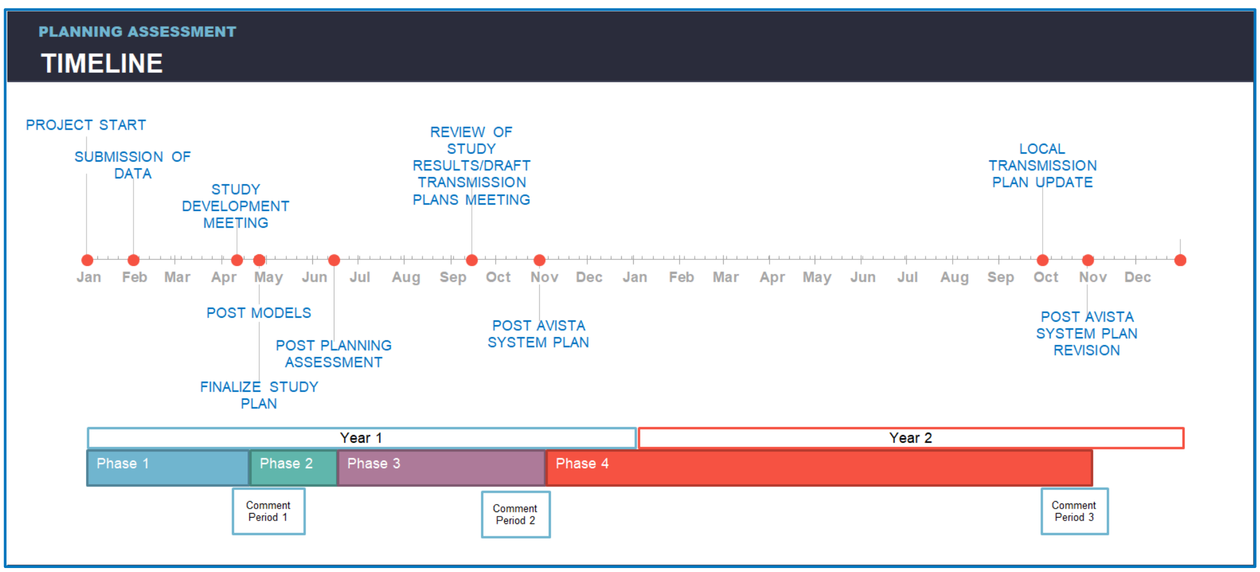

Figure 1: Avista Planning Assessment Timeline

[1] Such other means may include, for example, generation interconnection or transmission service request study processes under the OATT, or joint study team processes within the region.

2. System Project List

The System Project List in Table 1 is compiled by Avista's Engineering Roundtable (ERT). The list includes projects identified in the 2023-2024 System Assessment with additional projects evaluated and prioritized by the ERT. New projects identified in the 2023-2024 System Assessment which have not been vetted by the ERT are not included in the System Project List. TPL CAP refers to Corrective Action Plans (CAPs) to be implemented in accordance with TPL-001-5.

ERT #	Project Name	Driver	Scope	Status	TPL CAP
12	Carlin Bay Station	Performance and Capacity	Construct new distribution station to include single 20MVA transformer and two feeders. Transmission integration to include constructing a new radial transmission line from O'Gara Station to Carlin Bay. The second phase of the project includes rebuilding the existing O'Gara Station to a switching station. New microwave communication paths will be established to O'Gara Station.	Budgeted	
32	Davenport Station Rebuild	Asset Condition	Rebuild existing distribution station at nearby greenfield site. Initial construction will include single 20MVA transformer with three feeders.	Complete	
38	Metro Station Rebuild	Asset Condition	Rebuild existing substation at new location. 115kV bus to be a 6-position ring: 2 – 30MVA transformers, 2 – 115kV UG lines from PST, 2 – 115kV OH lines; switchgear on the 13kV side, both Network and Distribution feeders	Construction	
40	Northwest Station Rebuild	Asset Condition	Scope not complete. Rebuild existing Northwest Station.	Budgeted	
43	Valley Station Rebuild	Asset Condition	Scope not complete. Rebuild existing Valley Station.	Budgeted	
46	Poleline (Prairie) Station Rebuild	Performance and Capacity	Scope not complete. Construct new distribution station to replace Avista facilities at existing Prairie Station. New station to include two 30MVA transformers, four feeders, and looped-through transmission without circuit breakers.	Budgeted	
56	Bronx Station Rebuild	Performance and Capacity	Scope not complete. Reconstruct existing Bronx Station to include distribution facilities.	Budgeted	
58	Westside Station Rebuild	Performance and Capacity	Replace the existing Westside 230/115kV Transformer 2 and construct necessary bus work and breaker positions. Reconstruct 230 and 115kV buses to double bus double breaker 3000/2000 Amp standard. Phase 4: Complete bus work to double bus, double breaker on both the 230kV and 115kV buses	Construction	Yes
60	Ninth and Central - Sunset 115kV Transmission Line Upgrade	Performance and Capacity	Replace the 795 AAC and ACSR conductor on the Ninth and Central – Sunset 115kV Transmission Line with 795 ACSS with E3X coating to match the rest of the line.	Complete	

ERT #	Project Name	Driver	Scope	Status	TPL CAP
61	Post Falls Station Rebuild	Customer Requested	Rebuild existing Post Falls Station in green field location adjacent to existing station. New station will be a ring bus configuration with three transmission line positions, a metered GSU position, and two 115/13kV distribution transformers. The distribution transformers will have four feeders connected.	Budgeted	
62	Lolo Transformer Replacement	Performance and Capacity	Replace Lolo #1 230/115kV transformer with 250MVA rated transformer. Replace Lolo #2 230/115kV transformer with 250MVA rated transformer. 115kV circuit breakers, bus work and other capacity-limiting elements will be replaced. Circuit switchers at Clearwater, Lolo, and Sweetwater stations will be replaced.	Construction	
80	Huetter Station Expansion	Performance and Capacity	Add new 30MVA transformer and two distribution feeders to the existing Huetter Station. Scope includes a new panel house and rerouting the transmission line to the east side of the station. 13kV bus tie switch and a 115kV bus tie switch located on transmission structures outside the substation will be added.	Construction	
95	Clearwater Station Upgrades	Customer Requested	Scope not complete. New 115kV relay panels installed on all line positions. Existing circuit switchers will be replaced as part of the Lolo Transformer Replacement project.	Budgeted	
96	Kettle Falls Protection System Upgrades	Mandatory and Compliance	Upgrade existing protection schemes on the Addy – Kettle Falls and Colville – Kettle Falls 115kV Transmission Lines. New relays at Kettle Falls Station and a new communication path from Kettle Falls to Mount Monumental are required.	Construction	Yes
100	Melville Station	Performance and Capacity	Scope not complete. New switching station near existing tap to Four Lakes Station off the South Fairchild Tap 115kV Transmission Line. Construct new transmission line from Airway Heights to Melville including passing through Russel Road and Craig Road distribution stations. Requires new transmission line terminal at existing Airway Heights Station.	Budgeted	
111	Lyons and Standard Station Expansion	Customer Requested	Add new feeder to existing Lyons and Standard Station.	Construction	
124	Pine Street - Rathdrum 115kV Transmission Line Upgrade	Asset Condition	Rebuild transmission line.	Construction	

ERT #	Project Name	Driver	Scope	Status	TPL CAP
131	Garden Springs Station	Performance and Capacity	Construct new 115kV portion of Garden Springs Station at the existing Garden Springs switching location. New station will terminate Airway Heights – Sunset and Sunset – Westside 115kV Transmission Lines including the South Fairchild Tap. Construct new 230kV portion of Garden Springs Station including two 250MVA nominal 230/115kV transformers. Construct new 230kV transmission line from Garden Springs to a new switching station, Bluebird, at an interconnection point on the BPA Bell – Coulee #5 230kV Transmission Line.	Budgeted	Yes
134	Craig Road Interconnection	Customer Requested	Customer will construct new distribution station. Avista will provide new radial 115kV transmission line from Airway Heights Station as part of the Melville Station project.	Budgeted	
136	IEP Transformer Replacement	Asset Condition	Replace existing transformer located at IEP.	Budgeted	
140	Bunker Hill Customer Capacity	Customer Requested	Install new 20MVA transformer to replace existing transformer and construct new dedicated customer distribution feeder.	Budgeted	
143	Waikiki Capacity Mitigation	Performance and Capacity	Add new 20MVA transformer and two feeders to existing Indian Trail substation.	Budgeted	
148	Barker Capacity Mitigation	Performance and Capacity	Add new 30MVA transformer and three feeders to existing Greenacres substation.	Budgeted	
151	Pleasant View Capacity Mitigation	Performance and Capacity	Scope not complete. Add new 30MVA transformer and two feeders to existing station.	Budgeted	
156	Safely Interrupting Faults	Performance and Capacity	Replace South Othello A57 circuit switcher with 1220kA or greater rated equipment. Replace Barker Road A316 circuit switcher with 40kA or greater rated equipment. Replace Francis and Cedar A676 and A677 circuit switchers with 40kA or greater rated. equipment. Replace Lakeview R330 circuit switcher with 20kA or greater rated equipment. Replace Garfield EG-1 transformer fuse with 10kA or greater rated fuse. Replace Leon Junction SMD-2B transformer fuse with 15kA or greater rated fuse. Replace Long Lake SMD-2B transformer fuse with 15kA or greater rated fuse. Replace North Moscow SMD-2B transformer fuse with 15kA or greater rated fuse.	Budgeted	

ERT #	Project Name	Driver	Scope	Status	TPL CAP
157	Colbert Feeder Extension	Performance and Capacity	Rebuild the existing Colbert Tap 115kV Transmission Line to accommodate new distribution underbuild. New underbuild to be an extension of COB12F2 which will offload COB12F1. Load from COB12F2 will be transferred to MEA12F3.	Construction	

Table 1: Avista System Plan project list[2]

The Generation Interconnection process evaluates Interconnection Customer requests to connect to Avista's transmission or distribution system at a specified Point of Interconnection (POI) through an annual Cluster Study. Table 2 lists the senior-queued projects represented in the electrical system models used for the Cluster Study analysis.

Queue Number	MW Output	Type	Scope	Status
Q59	60MW	Solar/Storage	Construct new 115kV station adjacent to existing Roxboro Station for the POI	Drafted LGIA
Q60	150MW	Solar/Storage	230kV POI at Dry Creek Station	Suspended
Q63	26MW	Hydro	Rebuild of station, distribution, and transmission infrastructure	LGIA
Q66	71MW	Wood Waste	Efficiency improvements and GSU upgrade at Kettle Falls Generation Station	LGIA
Q80	19MW	Solar/Storage	115kV POI on South Fairchild Tap at customer collection station	PURPA
Q84	5MW	Solar/Storage	13.8kV POI adjacent to Chewelah Station	PURPA
Q97	100MW	Solar/Storage	230kV POI at Lolo Station	Suspended
TCS-03	80MW	Solar/Storage	115kV POI at Warden Station	Suspended
TCS-14	375MW	Wind/Storage	230kV POI at Dry Creek Station	Construction

Table 2: Interconnection Generation Projects

3. Major System Projects

The following list is a subset of the project list provided in Section 2. These projects were selected based on their relative impact to the system performance and the project scope has been substantially determined. A general problem statement and summary of project scope is provided. Detailed project reports may be available, containing additional scope and technical information.

3.1. ERT #12: Carlin Bay Station

The population and load demand growth on the east side of Lake Coeur D'Alene has resulted in rising concerns for Avista to reliably support new customers at the far-reaching end of two distribution feeders. These feeders cannot support additional growth in the area considering the increased distances are currently pushing limitations of the 13.8kV distribution system. Issues have emerged, including voltage drop,

[2] Accessed from the Engineering Roundtable SharePoint site December 18, 2023.

reduced fault current, and cold load pickup, all contributing to system protection challenges.

The complete scope of the Carlin Bay Project will be executed in a phased approach so immediate concerns are mitigated and operational while the remainder of the scope can be completed. The complete scope includes the following:

- Phase 1 includes construction of the Carlin Bay Station and a 115kV transmission line tap from the Benewah – Pine Creek 115kV Transmission Line near O'Gara to the Carlin Bay Station. The expected in-service date is 2028.

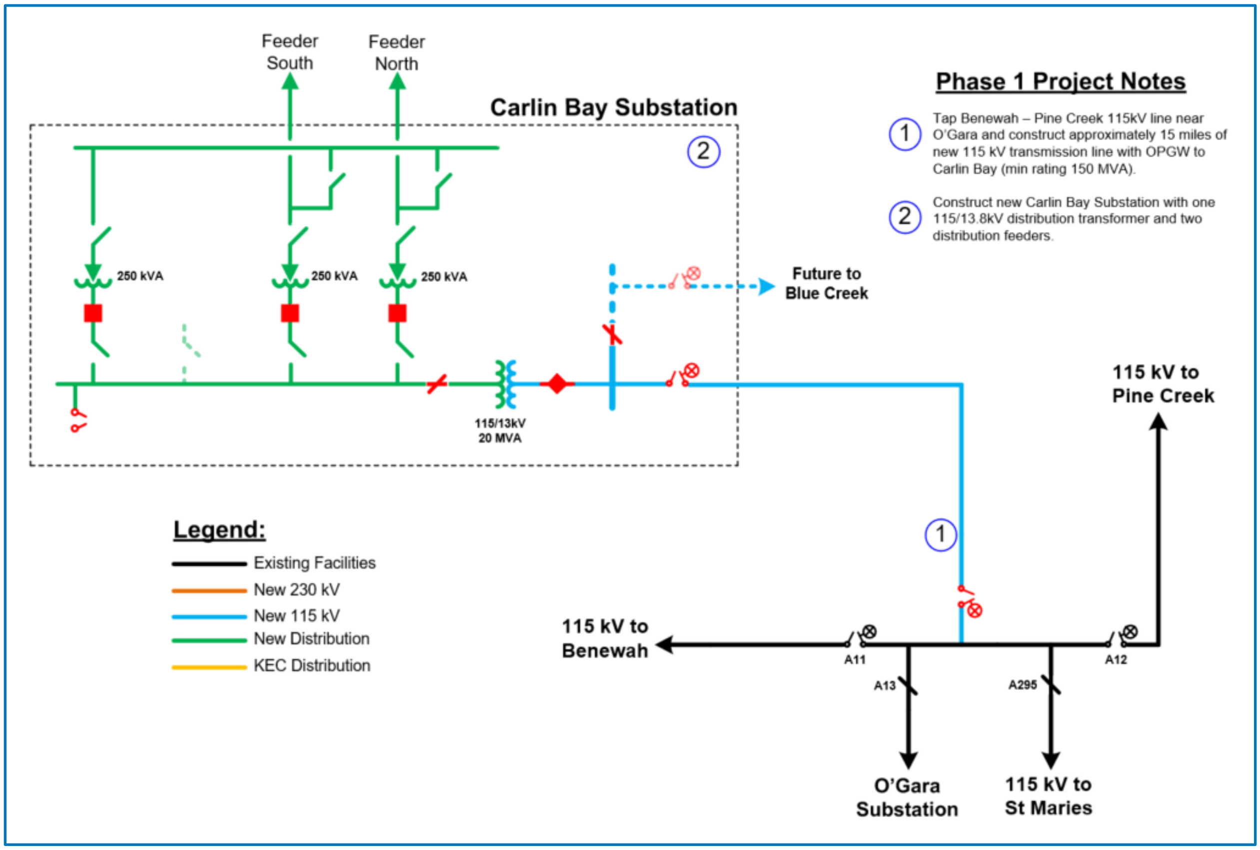

Figure 2: Carlin Bay Station Phase One Diagram

- Phase 2 includes a rebuild of the O'Gara Station to a breaker and a half configuration with space for a future line position and future capacitor bank. The expected in-service date for this work is 2029.

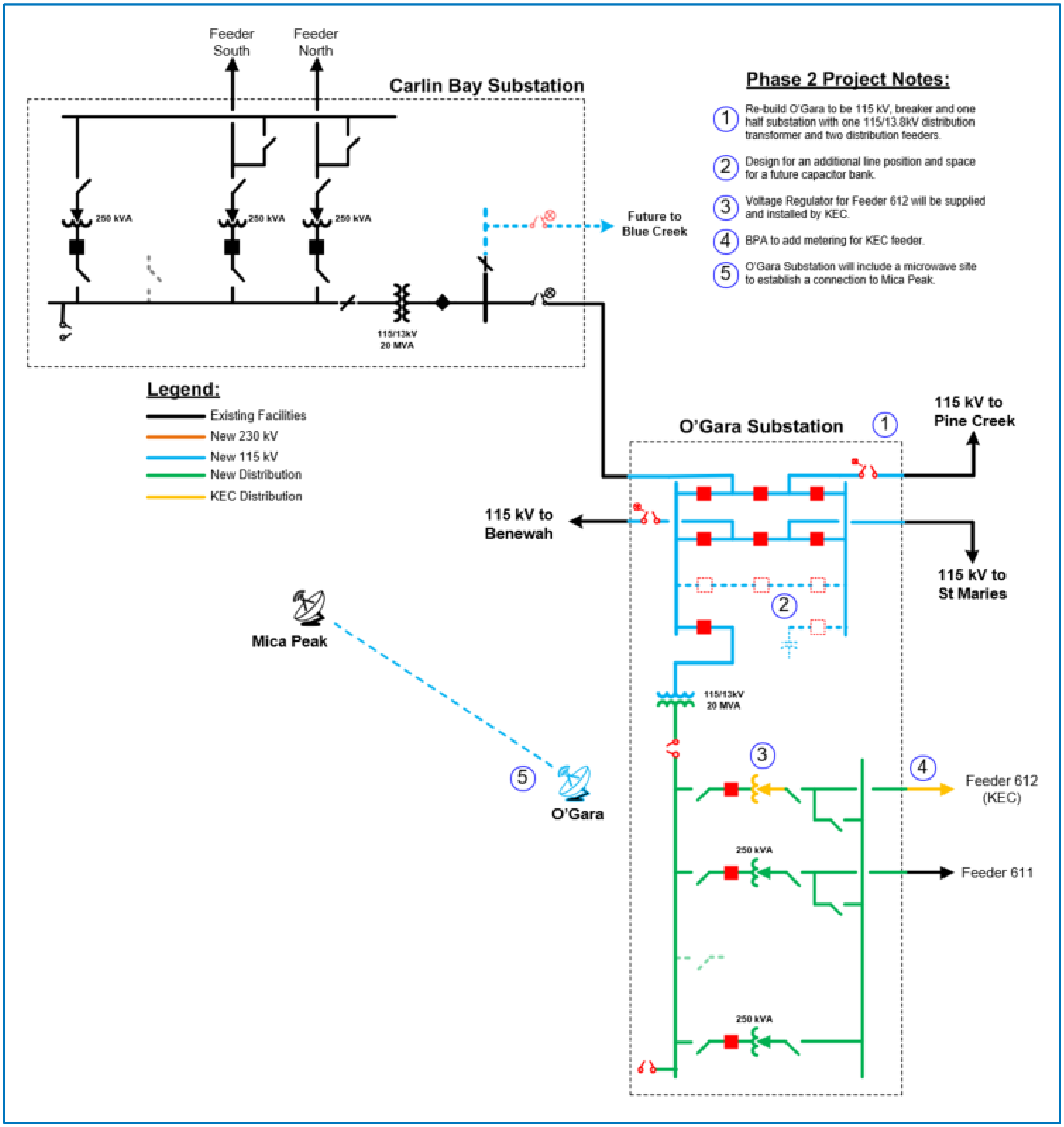

Figure 3: Carlin Bay Station Phase Two Diagram

3.2. ERT #58: Westside Station Rebuild

Outages causing loss of 230/115kV transformers at the BPA Bell or Avista Beacon Station, or outages causing increased impedance from the Bell and/or Beacon Stations to the area's distribution stations cause the Westside #1 and #2 230/115kV transformers to exceed their applicable facility ratings. The Westside Station Rebuild project is a complete station rebuild which includes the replacement of the existing Westside #1 and #2 230/115kV transformers with 250MVA nominal capacity transformers. Both the 230kV and 115kV configurations will be double bus, double breaker.

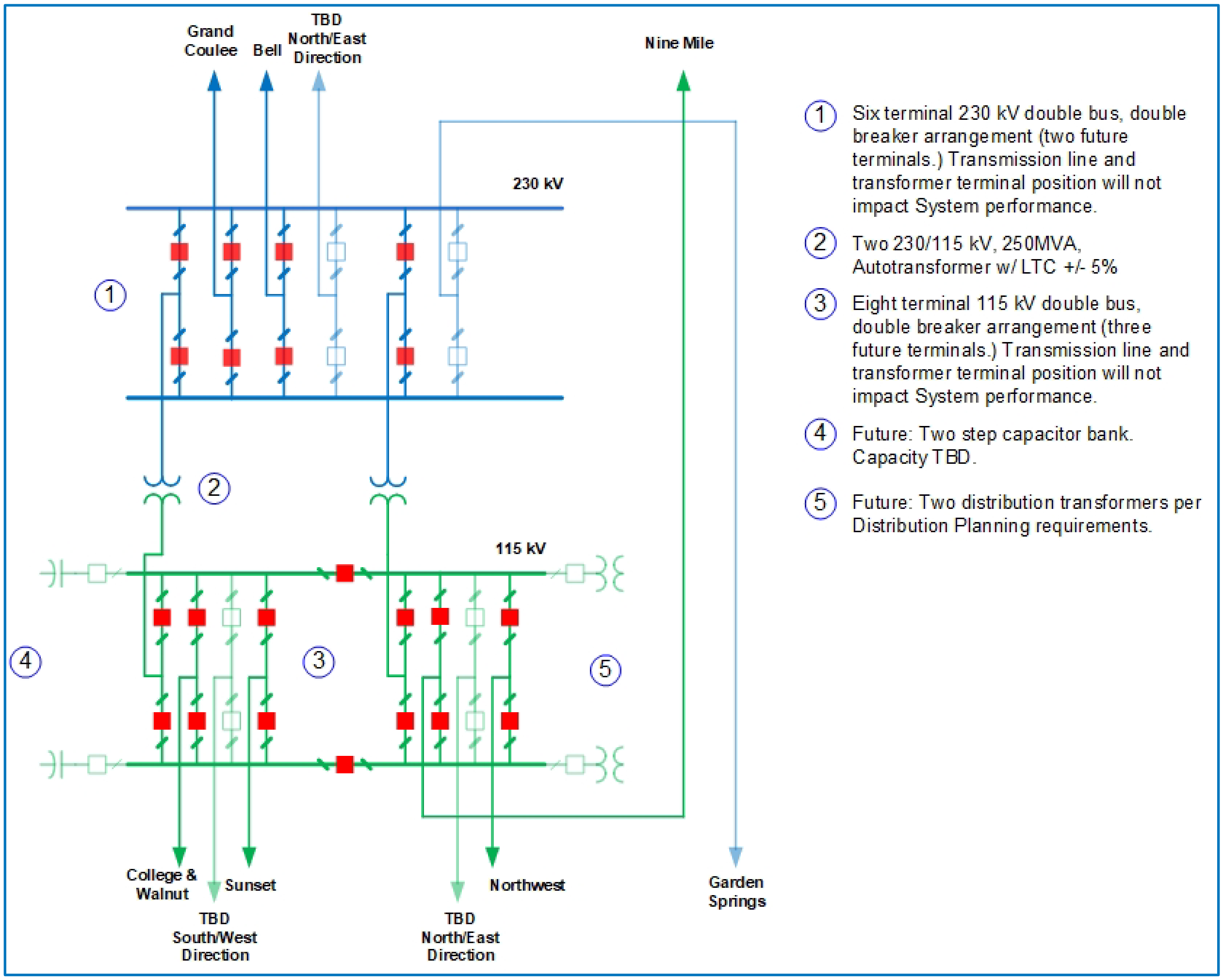

Figure 4: Westside Station Rebuild Project Diagram

3.3. ERT #62: Lolo Transformer Replacement

The two 230/115kV, 125MVA transformers at Lolo Substation were identified for possible overload per TPL-001-5 R2.1.5, which pertains to outages for equipment with long lead times relative to available spares. When the project was under development, Avista did not maintain a spare transformer of this size.

The Lolo Transformer Replacement project is the replacement of the existing 125MVA transformers with 250MVA units as well as replacement of their respective 115kV circuit breakers to accommodate the increased transformer capacity. The circuit switchers on the Lolo distribution transformer and the nearby Sweetwater Substation distribution transformer will also be replaced to meet the additional fault duty associated with the transformer upgrade.

Additionally, the 115kV bus will be replaced due to inadequacy for existing fault duty levels. The remaining 115kV breakers will be replaced as part of the bus rebuild.

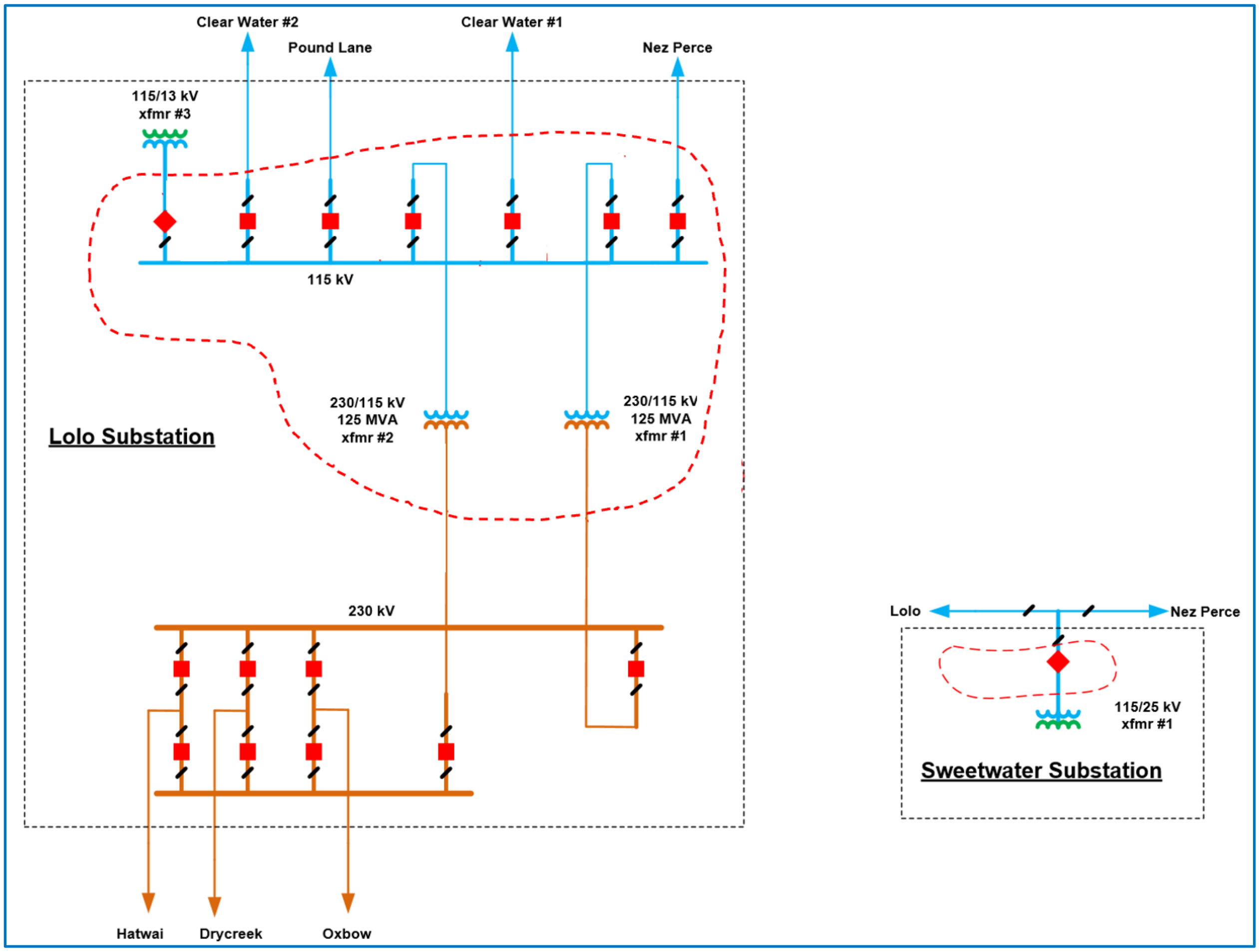

Figure 5: Lolo Transformer Replacement Project Diagram

3.4. ERT #131: Garden Springs Station

The West Plains and Sunset area (up to 245MW) is served by four 115kV transmission lines, which may overload for multiple contingency events during summer loading. Existing mitigation projects (Garden Springs – Sunset 115kV Transmission Line rebuild and the Ninth and Central – Sunset 115kV Transmission Line rebuild) help reduce the amount of overloading, but do not correct known contingency issues.

The West Plains System Reinforcement initiative includes the construction of a new 230kV transmission source into the area to mitigate reliability and operability constraints. A new transmission line is proposed to connect the Bell – Coulee corridor to a new Garden Springs Station. The Garden Springs Station will include two 250MVA nominal 230/115kV transformers and intersect the Sunset – Westside and Airway Heights – Sunset 115kV Transmission Lines.

Additional reinforcements in the area to support distribution system expansion and interconnect new distribution stations includes a new 115kV transmission line from Airway Heights Station to a new Melville Station which intersects the South Fairchild 115kV transmission line Tap near Hallett and White Station. New distribution stations at Flint Road and Russel Road will increase transformation capacity and provide additional feeders to serve the increased distribution system demands. These additional reinforcements will be included in subsequent projects with the intent of providing a comprehensive approach to meet increased customer demand in the West Plains area.

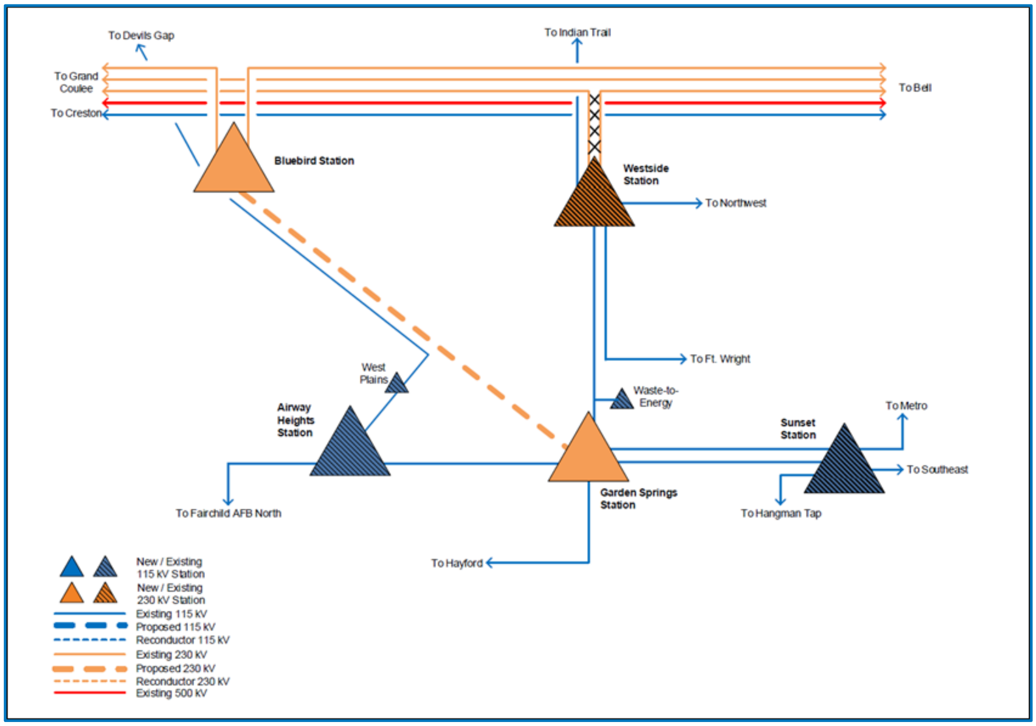

Figure 6: Garden Springs Station Project Diagram

3.5. ERT #143: Waikiki Capacity Mitigation

The Waikiki Capacity Mitigation project addresses issues in the North Spokane by installation of a new 20MVA transformer at the Indian Trail Station. This location can accommodate the additional lineup as it was originally designed for future expansion as shown in Figure 7. This project also proposes an upgrade to the INT12F1 voltage regulator. Distribution buildout and load transfers are needed to distribute the additional transformation capacity.

The project diagram provided in Figure 7 summarizes the project scope, including the necessary modifications to the distribution system to integrate the new Indian Trail feeders and mitigate the identified performance issues. Principal projects elements include the construction of a 1.5-mile feeder tie between INT12F3 and WAK12F4, a 1.2-mile feeder tie between WAK12F4 and WAK12F1, load transfers, additional feeder tie switches, and default configuration changes.

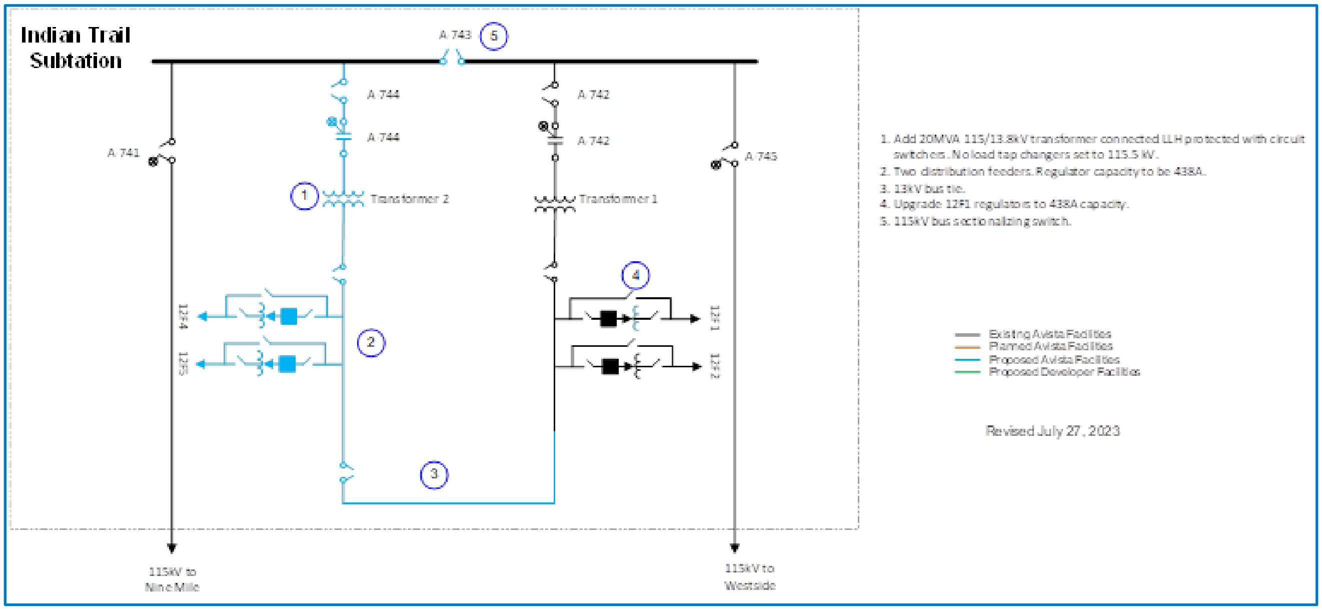

Figure 7: Waikiki Capacity Mitigation at Indian Trail Station

3.6. ERT #148: Barker Capacity Mitigation

This project expands the distribution capacity at Greenacres Station, including the installation of a new 30MVA 115/13kV transformer, 13kV bus tie, three 13.2kV distribution feeders, and associated controls, communication, and facilities equipment. No new transmission work will be required for this project.

Figure 8 provides a preliminary scoping drawing based on the original Greenacres design and the expansion. The existing distribution lineup, 30MVA transformer, and grounding will remain in place. The new lineup includes the second 30MVA transformer and three additional feeders. The regulator capacity will be 438A.

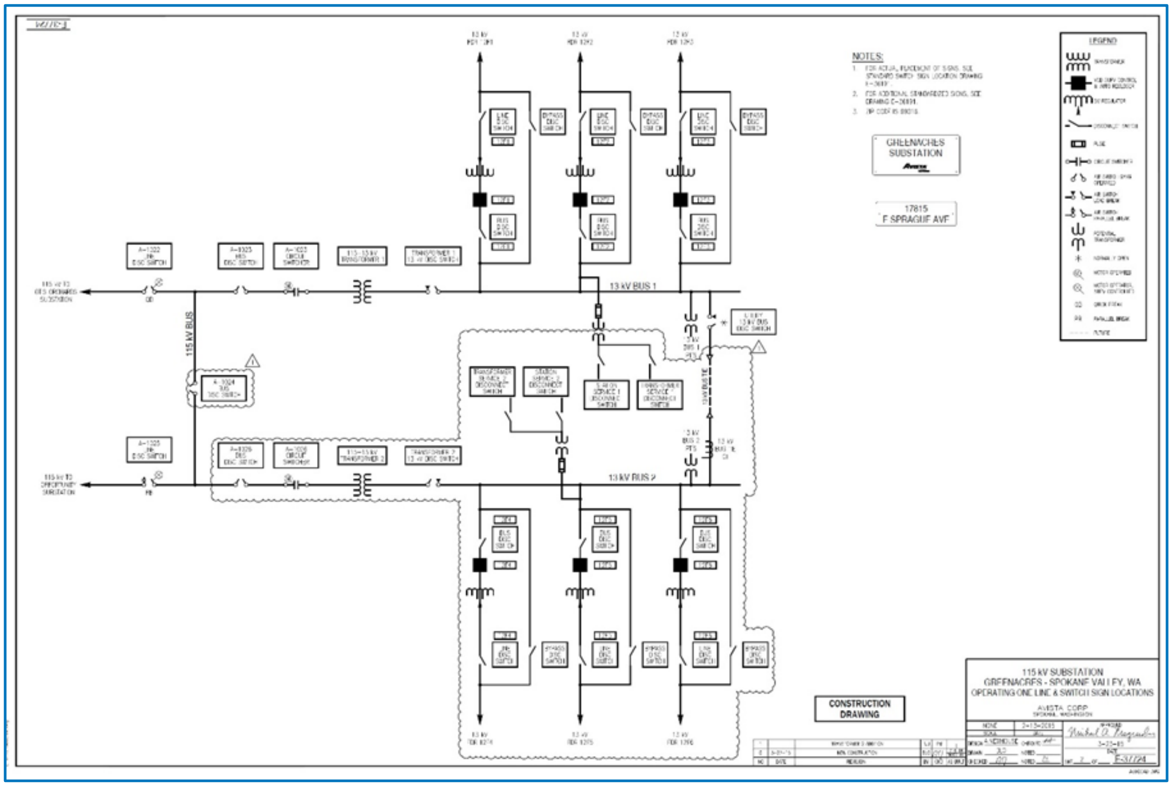

Figure 8: Barker Capacity Mitigation at Greenacres Station

4. Project Prioritization

Avista's ERT serves to evaluate proposed solutions for recognized system deficiencies or necessary expansion while considering alternatives, collaborative approaches, and project prioritization. The ERT considers any transmission, distribution, or substation project requiring a capital investment greater than $1,000,000, providing validation of scope and concept.

Projects deemed to be prudent are prioritized and submitted to the Project Delivery functions to guide the development of work plans, schedules, and budgets. Project priorities are expected to remain consistent relative to the dynamic needs of the business.

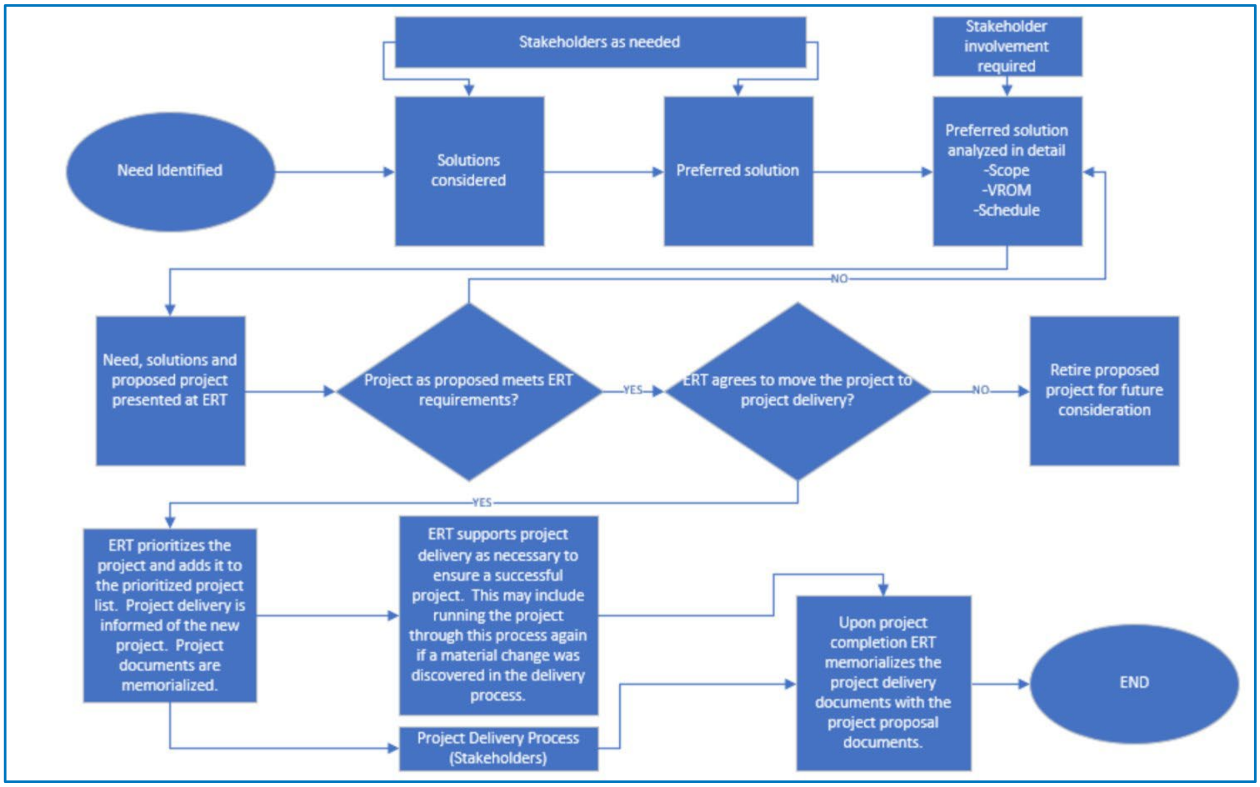

Figure 9: Engineering Roundtable Process

The ERT project prioritization process evaluates a combination of Technical Importance and Initiation Urgency perspectives. Scoring metrics consider the opportunities and potential impact to the system within a 10-year horizon. The project portfolio as presently prioritized and scored is summarized in Figure 10.

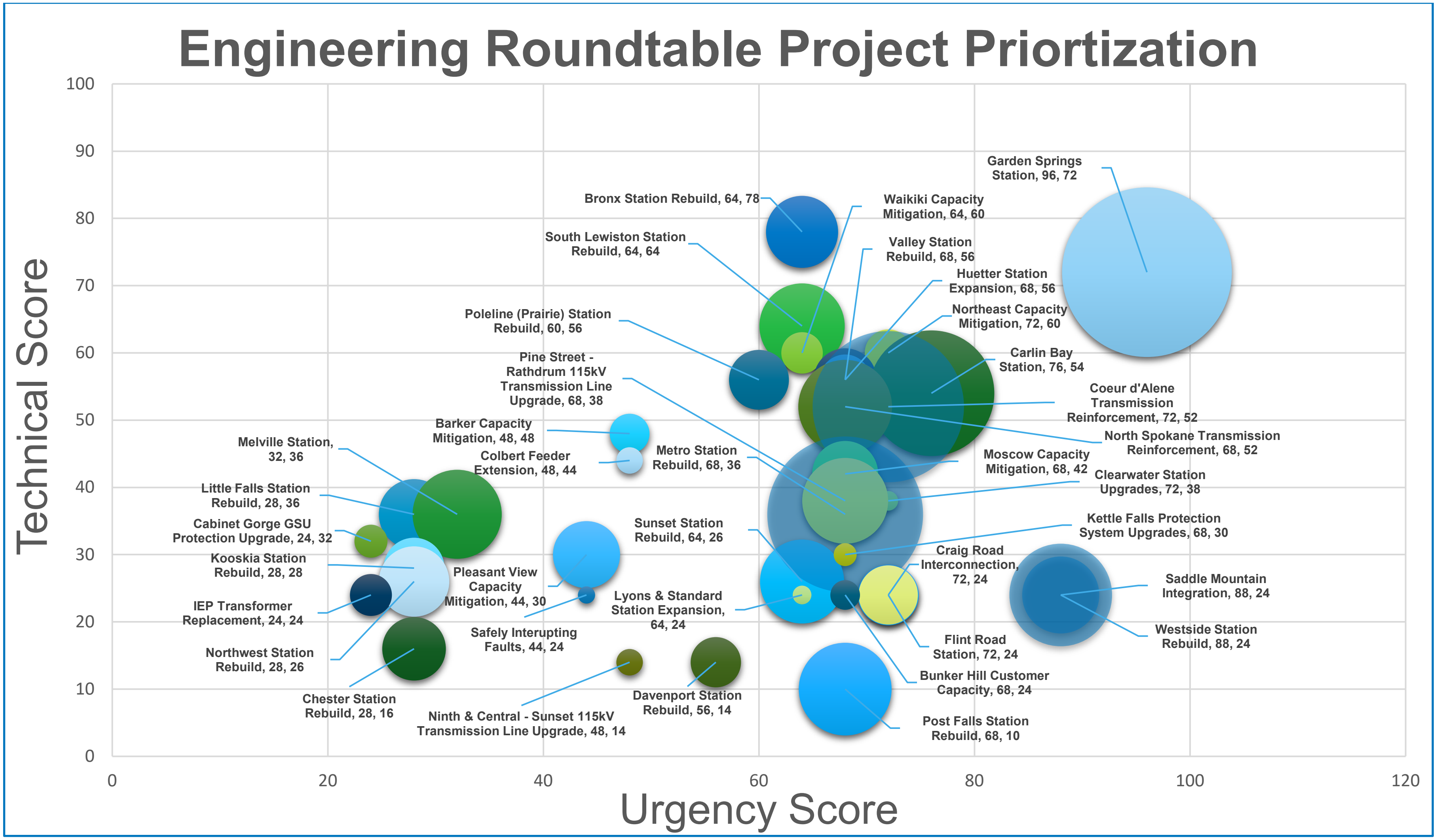

Figure 10: Engineering Roundtable Project Prioritization and Scoring

5. Project Schedule

The Project Delivery Roundtable (PDRT) reviews the substation, distribution, and transmission projects as prioritized by the ERT and aligns internal resources and coordinates project scheduling within the five-year capital plan and construction resources. The PDRT construction schedule is shown in Table 3.

Project	ERT Reference	Start	Finish
2024			
Lyons & Standard Capacity Increase	#111 Lyons & Standard Station Expansion	May 2023	April 2024
Westside Substation Rebuild - Phase 3	#56 Westside Station Rebuild	October 2020	October 2024
2025			
Huetter 115kV Substation – Expansion	#80 Huetter Station Expansion	August 2022	February 2025
Indian Trail 115kV Substation	#143 Waikiki Capacity Mitigation	December 2022	March 2025
Greenacres 115kV Substation	#148 Barker Capacity Mitigation	September 2022	April 2025
Poleline 115kV Substation	#46 Poleline (Prairie) Station Rebuild	February 2023	September 2025
Cloudwalker/Dry Creek Interconnect	TCS-14	May 2024	November 2025
2026			
Valley Substation	#43 Valley Station Rebuild	April 2024	February 2026
Airway Heights to Craig Road	#134 Craig Road Interconnection	March 2025	April 2026
Metro 115-13kV Substation Rebuild	#38 Metro Station Rebuild	June 2022	August 2026
2027			
Bunker Hill Substation	#140 Bunker Hill Customer Capacity	December 2024	January 2027
Bluebird Substation	#131 Garden Springs Station	June 2024	January 2027
Bronx Substation	#56 Bronx Station Rebuild	September 2025	November 2027
Post Falls Substation (New)	#61 Post Falls Station Rebuild	January 2024	December 2027
2028			
Garden Springs Substation	#131 Garden Springs Station	July 2023	April 2028
Metro 115-13kV Substation Rebuild	#38 Metro Station Rebuild	July 2020	May 2028
Pleasant View Substation	#151 Pleasant View Capacity Mitigation	October 2025	June 2028
Carlin Bay Substation	#12 Carlin Bay Station	July 2023	September 2028
2029			
Melville Switching Station	#100 Melville Station	August 2026	April 2029
O'Gara Substation	#12 Carlin Bay Station	September 2022	August 2029
2030			
Northwest Substation	#40 Northwest Station Rebuild	February 2026	March 2030

Table 3: PDRT schedule

2023-2024 System Assessment

Local Planning Report

Beacon Station, Spokane, Washington

Electric System Planning
Avista Utilities
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Spokane, WA 99220
TransmissionPlanning@avistacorp.com
DistributionPlanning@avistacorp.com

Prepared by: System Planning

Version	Date	Description	Author	Review
A	6/29/2023	2023 initial draft with TPL-001-5 additions	Planning Team	J Gross
B	9/15/2023	2023 draft released for stakeholder review	Planning Team	J Gross
0	11/17/2023	Released	Planning Team	J Gross

Beacon Station, located in East Spokane at the base of Beacon Hill and north of the Spokane River, was originally constructed in 1950 and rebuilt in 1987. The station contains two 230/115kV autotransformers rated at 250MVA and two 30MVA distribution transformers. Beacon serves as a principal hub of Avista's Spokane Area 230kV and 115kV transmission systems with 230kV connections to Bell (BPA), Boulder, and Rathdrum and 115kV connections to Bell (BPA), Francis & Cedar, Irvin, Ninth & Central, Northeast, and Ross Park Stations. Its six distribution feeders serve approximately 8,000 residential, commercial, and industrial customers in the area.

Several transmission reinforcement projects in the Beacon Station area are included as planned projects in the 2023-2024 System Assessment.

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1. Executive Summary

The Avista System Assessment provides two specific deliverables relating to the electric transmission and distribution system's performance during normal operating conditions and when impacted by defined outage conditions and contingencies:

- Documentation of technical analysis results demonstrating system performance
- Conceptual solutions to mitigate operational issues to maintain expected performance

The 2023-2024 System Assessment results are based on models reflecting current conditions and predictive forecasts. Assumptions in the assessment reflect changes in customer loads and system configurations representing recently constructed and expected energized system assets. Customer loads are forecasted to increase an average of 1.16% in winter and 1.24% in summer across the Avista service territory. These growth rates are inclusive of anticipated future load modeling changes including forecasted electrification and localized area load growth. Forecasted load used for the transmission system analysis includes a probable scenario of high building and transportation electrification. Methods to implement electrification forecasts for the distribution system are under development and were not included in the distribution system analysis. Localized load growth in the Coeur d'Alene, Post Falls, North Spokane, West Plains, and Lewiston areas contribute to new performance issues and amplifies existing system constraints identified in prior assessments. Generation assumptions have also changed regarding how Avista dispatches existing generation, partially driven by Avista's integration into the Energy Imbalance Market in 2022. The Energy Imbalance Market economically dispatches participating resources to balance supply and demand. Generation dispatch impacts the expected performance of the electric system by altering the use of existing infrastructure.

Projects not presently approved by the Avista Capital Planning Group (CPG) or new projects to address performance issues have been identified through analysis results, internal collaboration and outside stakeholder input using the Attachment K process. Conceptual mitigation alternatives for new performance issues are provided and will be refined in partnership with stakeholders. New requests to the CPG will include the following principal recommendations:

- Transmission reinforcements in Beacon, Coeur d'Alene, Lewiston-Clarkston, North Spokane, Palouse, and Sandpoint areas
- Rebuild the Beacon Station to address fault duty and performance issues
- Address fault interruption devices presently underrated and posing potential safety concerns
- Increase distribution capacity in the Coeur d'Alene, Moscow, North Spokane, Post Falls, and Spokane Valley areas

The 2023-2024 System Assessment provides the foundation for additional perspectives and conversations regarding the future of Avista's electric system. The System Planning Team is appreciative of feedback and additional insights regarding the content of this report and will incorporate that feedback into comprehensive project solutions for a robust future electric system.

2. Introduction

The System Assessment document includes distribution and transmission contributions. For each, assumptions, corrective action plans, and technical analyses are created and produce current and forecasted system needs. Combined system needs for both distribution and transmission produce a holistic system view and provide transparency of contributions and effects of one focus area to another. The System Assessment document also provides a single point of reference for outside groups requiring system existing and forecasted information.

The *2023-2024 System Assessment* (Local Planning Report) is a deliverable from Phase 2 of a two-year process as defined in Avista's *Open Access Transmission Tariff (OATT) Attachment K*. The System Assessment identifies the Transmission System facility additions required to reliably interconnect forecasted generation resources, serve the forecasted loads of Avista's Network Customers and Native Load Customers, and meet all other Transmission Service and non-OATT transmission service requirements, including rollover rights, over a 10-year planning horizon. The Planning Assessment process is open to all Interested Stakeholders, including, but not limited to, Transmission Customers, Interconnection Customers, and state authorities. The Western Electric Coordinating Council (WECC) facilitates interconnection wide planning and development of wide-area planning proposals.

The two-year planning process desired timeline is illustrated in Figure 1. The completion of Phase 2 includes providing the documented results of performing necessary technical studies. The state of the existing and future system is provided. Where the technical studies identified performance issues, conceptual projects have been proposed.

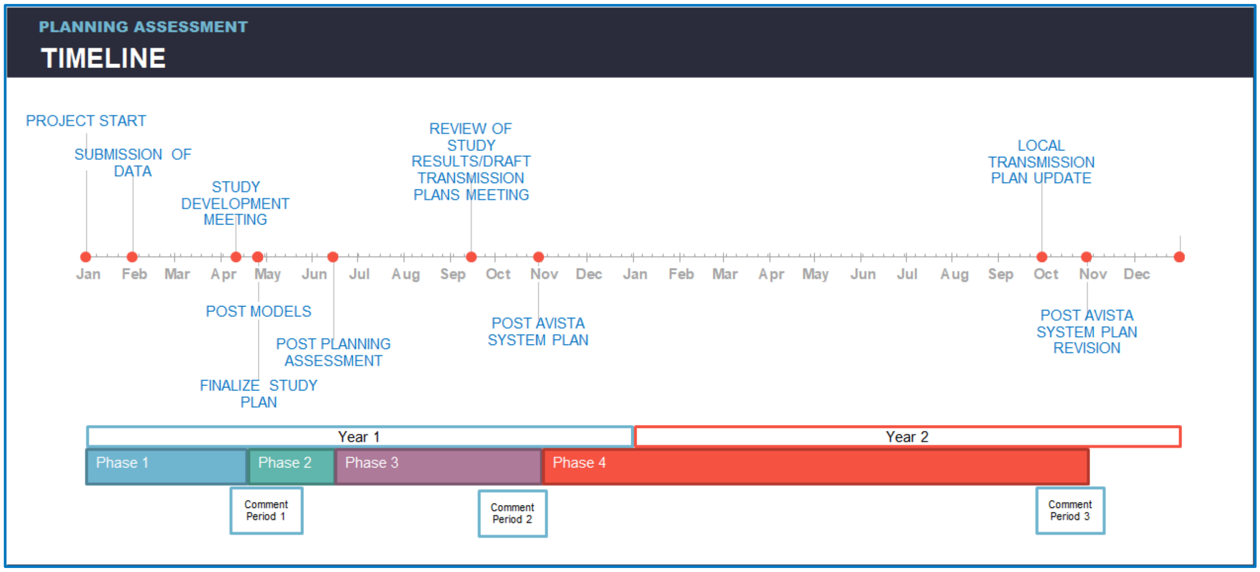

Figure 1: Planning Assessment Timeline

Phase 3 of the process will follow the completion of the System Assessment. Phase 3 includes providing the Avista System Plan report to stakeholders. The Avista System Plan will include documentation of the electrical infrastructure plan with preferred solution options. The resulting project list will include additional information regarding projects and system modifications developed through means other than the technical studies[1].

[1] Such other means may include, for example, generation interconnection or transmission service request study processes under the OATT, or joint study team processes under NorthernGrid.

2.1. Point of Contact

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

Electric System Planning
Avista Utilities
PO Box 3727, MSC-16
Spokane, WA 99220
TransmissionPlanning@avistacorp.com
DistributionPlanning@avistacorp.com

3. Study Assumptions

The technical studies performed as part of this System Assessment were conducted according to the *2023-2024 Avista System Assessment Study Plan*. The following sections provide a summary of key assumptions regarding the representation of the electrical system and methodologies of analysis.

3.1. Transmission System

3.1.1. System Conditions

A set of transmission system models were developed to represent specific operating scenarios. The scenarios were selected to capture reasonably expected conditions which may stress the performance of the transmission system. Figure 2 and Figure 3 provide a comparison of the Summer and Winter models to historical Balancing Authority Area (BAA) load and BAA interchange excluding dynamic imports. The model scenarios represented by green markers represent a 1 in 10 probability of occurrence.

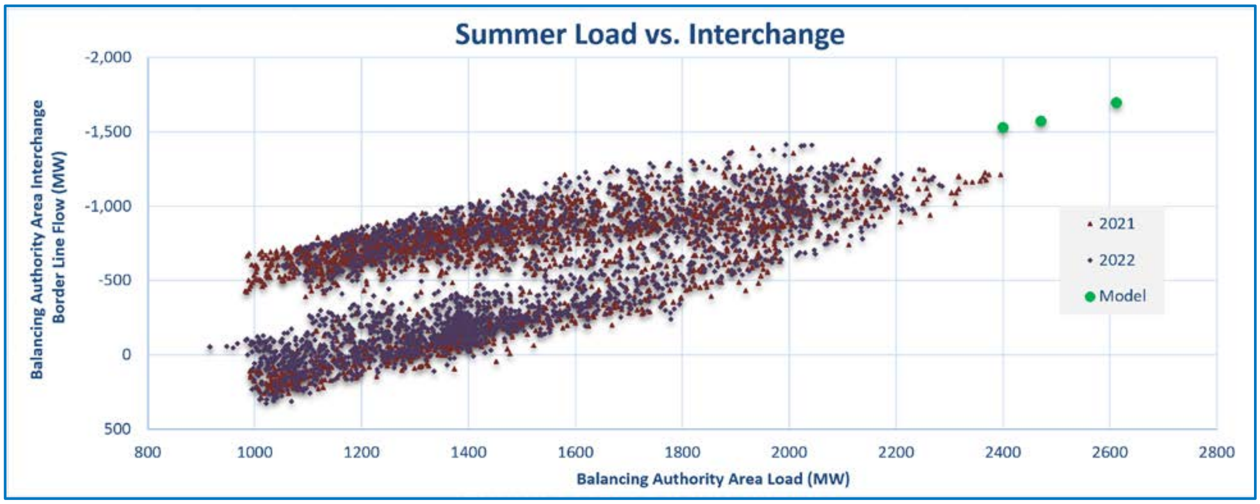

Figure 2: Historical Avista BAA Load Versus Interchange During Summer Months

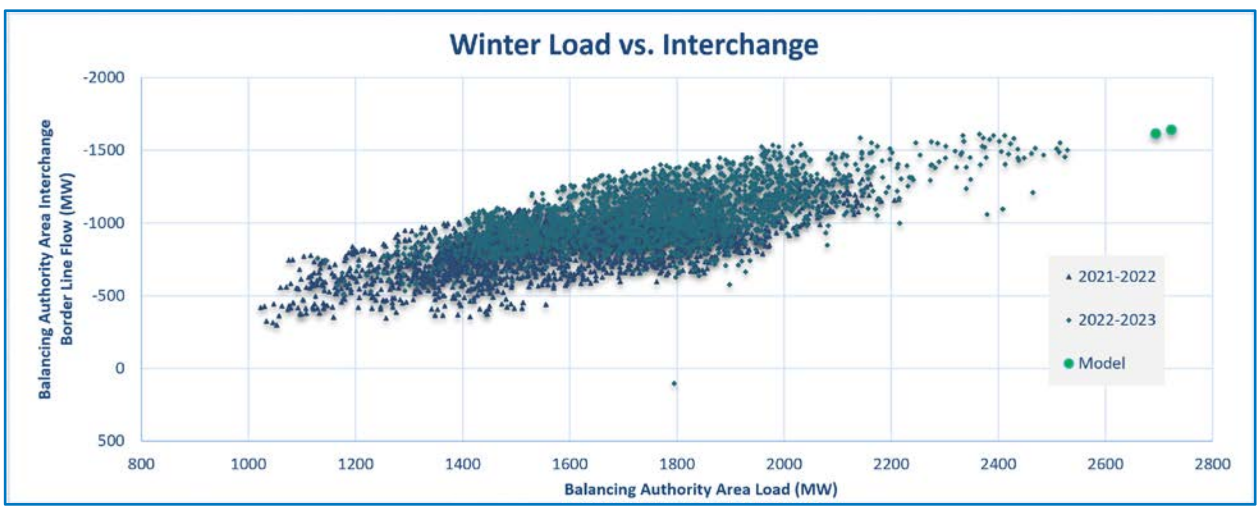

Figure 3: Historical Avista BAA Load Versus Interchange During Winter Months

A detailed summary of specific flows and loading levels for the Planning Cases used in the *2023-2024 System Planning Assessment* is provided in Appendix 7.2 Case Summary.

3.1.2. Projects Modeled

The transmission system models include representation of projects expected to be constructed within the applicable planning horizon. The models are analyzed with and without these projects to demonstrate the impact of the projects on the performance of the system. Table 1 provides the list of projects included in the models.

Included in Table 1 are designations for projects that are included in the base, the five-year, and the 10-year planning models. The Five-Year Planned Projects are significant because they represent the expected system configuration and performance in the planning horizon. It should be noted the entire scope of each project is considered complete and operational when included in the designated planning model.

ERT #	Project Name	Driver[2]	Scope	Status	Included in Model		
					1-year	5-year	10-year
12	Carlin Bay Station	Performance and Capacity	Construct new distribution station to include single 20MVA transformer and two feeders. Transmission integration to include constructing a new radial transmission line from O'Gara Station to Carlin Bay. The second phase of the project includes rebuilding the existing O'Gara Station to a switching station. New microwave communication paths will be established to O'Gara Station.	Budgeted		X	X
26	Sunset Station Rebuild	Mandatory and Compliance	Rebuild the existing Sunset Station as breaker and a half configuration.	Complete	X	X	X
38	Metro Station Rebuild	Asset Condition	Rebuild existing station at new location. 115kV bus to be a 6-position ring: 2 – 30MVA xfer's, 2 – 115kV UG lines from PST, 2 – 115kV OH lines; switchgear on the 13kV side, both Network and Distribution feeders	Construction		X	X
53	Flint Road Station	Performance and Capacity	New distribution station located west of Spokane along the Airway Heights - Sunset 115kV Transmission Line. Two new 30MVA transformers with four distribution feeders will be the initial configuration.	Complete	X	X	X
58	Westside Station Rebuild	Performance and Capacity	Replace the existing Westside 230/115kV Transformer 2 and construct necessary bus work and breaker positions. Reconstruct 230 and 115kV buses to double bus double breaker 3000/2000 Amp standard. Phase 4: Complete bus work to double bus, double breaker on both the 230kV and 115kV buses	Construction	X	X	X
60	Ninth & Central - Sunset 115kV Transmission Line Upgrade	Performance and Capacity	Replace the 795 AAC and ACSR conductor on the Ninth & Central – Sunset 115kV Transmission Line with 795 ACSS with E3X coating to match the rest of the line.	Construction		X	X
62	Lolo Transformer Replacement	Performance and Capacity	Replace Lolo 230/115kV Transformer 1 with 250MVA rated transformer. Replace Lolo 230/115kV Transformer 2 with 250MVA rated transformer. 115kV circuit breakers, bus work and other capacity-limiting elements will be replaced. Circuit switchers at Clearwater, Lolo, and Sweetwater stations will be replaced.	Construction		X	X

[2] Driver refers to the classification for investment as defined by Avista and referenced in Appendix C – Investment Driver Definitions.

ERT #	Project Name	Driver[2]	Scope	Status	Included in Model 1-year	5-year	10-year
75	Saddle Mountain Integration	Performance and Capacity	Construct a 3-position 230kV DBDB arrangement with space for two future positions at the line crossing of the Walla Walla – Wanapum 230kV and Benton – Othello 115kV Lines Construct a 4-position 115kV breaker and a half arrangement with space for four future positions Install 1-230/115kV transformer rated at 250MVA. Reconstruct Othello SS – Warden #1 115kV Transmission Line to minimum 205MVA including upgrades to terminal equipment at both stations. Reconstruct Othello SS – Warden #2 115kV Transmission Line to minimum 205MVA including upgrades to terminal equipment at all stations. Construct 11 miles of 115kV line with a minimum summer rating of 205MVA from Saddle Mountain Station to the new Othello City station with a N/O tap to existing S. Othello Station. Reconstruct Othello Station to a 3-position breaker and a half with 2 – 30MVA transformers at new property.	Complete	X	X	X
96	Kettle Falls Protection System Upgrades	Mandatory and Compliance	Upgrade existing protection schemes on the Addy – Kettle Falls and Colville – Kettle Falls 115kV Transmission Lines. New relays at Kettle Falls Station and a new communication path from Kettle Falls to Mount Monumental are required.	Construction	X	X	X
100	Melville Station	Performance and Capacity	Scope not complete. New switching station near existing tap to Four Lakes Station off the South Fairchild Tap 115kV Transmission Line. Construct new transmission line from Airway Heights to Melville including passing through Russel Road and Craig Road distribution stations. Requires new transmission line terminal at existing Airway Heights Station.	Budgeted			X
131	Garden Springs Station	Performance and Capacity	Construct new 115kV portion of Garden Springs Station at the existing Garden Springs switching location. New station will terminate Airway Heights – Sunset and Sunset – Westside 115kV Transmission Lines including the South Fairchild Tap. Construct new 230kV portion of Garden Springs Station including two 250MVA nominal 230/115kV transformers. Construct new 230kV Transmission Line from Garden Springs to a new switching station, Bluebird, at an interconnection point on the BPA Bell – Coulee #5 230kV Transmission Line.	Budgeted			X
N/A	Boulder-Irvin #1 115kV Transmission Line Upgrade	Performance and Capacity	Project updates the existing Boulder-Ivin #1 115kV Transmission Line from Boulder to SIP. Remaining replacements are existing 556AAC on Barker Road and approximately a ¼ mile section just east of SIP, currently delayed by easement dispute. Replacements will be made with 795 ACSS.	Construction	X	X	X

Table 1: Projects Represented in Transmission System Models

3.1.3. Performance Criteria

Avista's transmission system performance criteria are defined in *TP-SPP-01 – Transmission System Performance*. Specific criteria are provided for acceptable steady state voltage limits, post-contingency voltage deviations, transient voltage response, thermal performance, load loss limits and allowable operating plans for the system. Criteria for identifying system instability, weak systems, and acceptable short circuit equipment loading is also provided.

3.1.4. Studies Performed

Technical studies are performed as part of the System Assessment. The methodologies for each study are documented in *TP-SPP-01 – Transmission System Performance*. The defined set of technical studies include:

- Steady State Contingency Analysis
- Spare Equipment Analysis
- Short Circuit Analysis
- Stability Contingency Analysis
- Voltage Stability Analysis
- Protection System Failure Analysis

3.2. Distribution System

3.2.1. System Conditions and Modeling Assumptions

The power system model used to analyze the distribution system was based on a snapshot of the system as it existed in April 2023, with all lines and equipment in service. The loads characterized in the model used the peak load and load curve SCADA data from 2020, 2021, 2022, and 2023. Collected data for August 15, 2023, was used directly in the model to represent the Heavy Summer scenario. The Heavy Winter scenario was mostly represented by data from December 22, 2022. A load forecast was developed using a multivariate regression analysis with each feeder assumed to have a linearized growth rate over the 10-year planning horizon. The highest growth rates were observed in the Coeur d'Alene, Rathdrum, and Post Falls areas.

Figure 4 shows an example of the multiple regression used to project a station's rate of load growth. The plot represents College & Walnut Transformers 1 and 2 in the orange data, the 10-year forecast in black, and the associated trend in red. Forecasted load is primarily based on 40-year average heating and cooling degree day data.

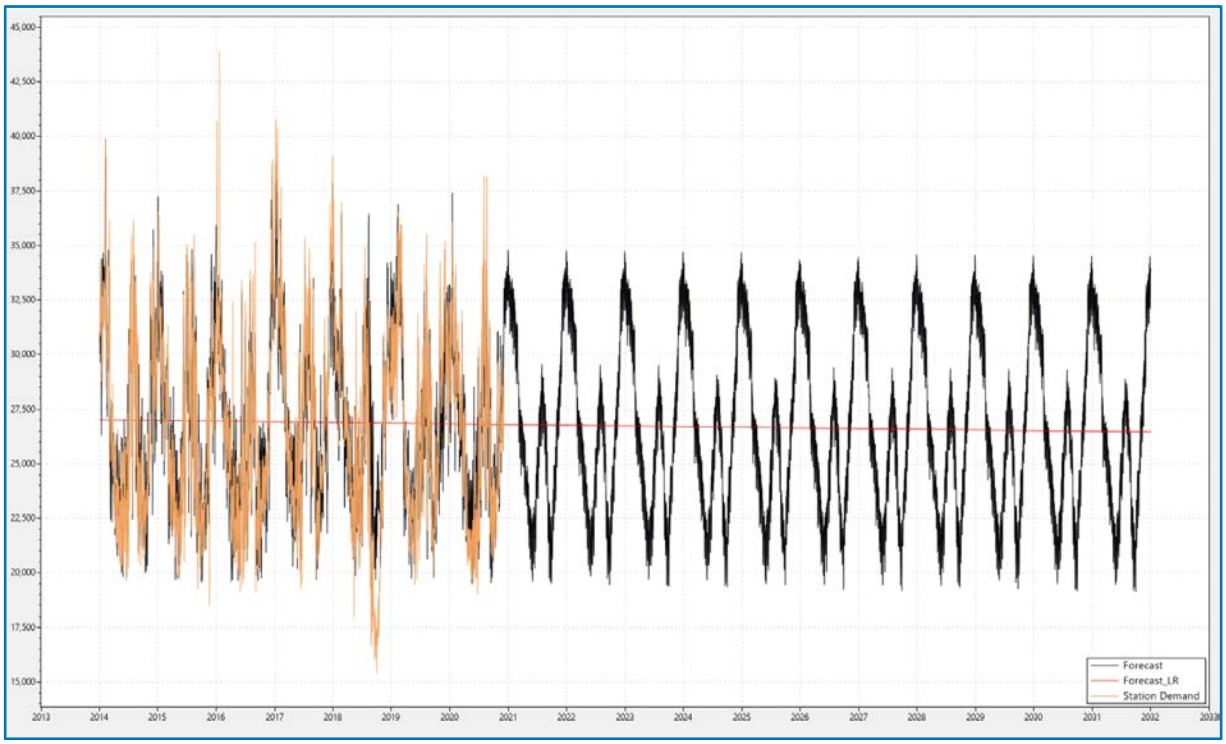

Figure 4: College & Walnut-Example Load Regression Analysis Forecast

Specific seasonal and loading scenarios are represented within the models and are used to evaluate if the system will meet the performance criteria defined in *DP-SPP-02 – Distribution System Performance V5*. When analysis indicates an inability of the system to meet the performance criteria for the scenarios listed in Table 2, projects will be developed addressing how the performance criteria will be met. Additional sensitivity scenarios may be studied in addition to those listed in Table 2.

Scenario	Description	Ambient Temperature Represented
Heavy Summer	Day-time peak load occurring between June and August with loads representing a 1 in 10 probability	40°C (104°F)
Heavy Winter	Day-time peak load occurring between December and March with loads representing a 1 in 10 probability	-28.9°C (-20°F)
Heavy Summer Sensitivity	Same scenario as Heavy Summer with loads representing the highest summer temperature on record	42.8°C (109°F)

Table 2: Distribution System Scenarios

Historical weather data was reviewed to select the scenarios listed in Table 2. *DP-SPP-02 – Distribution System Performance V5* outlines the methodology and data for Table 2.

3.2.2. Projects Modeled

The distribution system models include representation of projects expected to be constructed within the applicable planning horizon. The models are analyzed with and without these projects to demonstrate the impact of the projects on the performance of the system. Table 3 provides the list of projects which will be included in the models when individual project analysis is performed.

ERT #	Project Name	Driver	Scope	Status
12	Carlin Bay Station	Performance and Capacity	Construct new distribution station to include single 20MVA transformer and two feeders. Transmission integration to include constructing a new radial transmission line from O'Gara Station to Carlin Bay. The second phase of the project includes rebuilding the existing O'Gara Station to a switching station. New microwave communication paths will be established to O'Gara Station.	Budgeted
26	Sunset Station Rebuild	Mandatory and Compliance	Rebuild the existing Sunset Station as breaker and a half configuration.	Complete
32	Davenport Station Rebuild	Asset Condition	Rebuild existing distribution station at nearby greenfield site. Initial construction will include single 20MVA transformer with three feeders.	Construction
38	Metro Station Rebuild	Asset Condition	Rebuild existing station at new location. 115kV bus to be a 6-position ring: 2 – 30MVA xfers', 2 – 115kV UG lines from PST, 2 – 115kV OH lines; switchgear on the 13kV side, both Network and Distribution feeders	Construction
46	Poleline (Prairie) Station Rebuild	Performance and Capacity	Scope not complete. Construct new distribution station to replace Avista facilities at existing Prairie Station. New station to include two 30MVA transformers, four feeders, and looped-through transmission without circuit breakers.	Budgeted
53	Flint Road Station	Performance and Capacity	New distribution station located west of Spokane along the Airway Heights - Sunset 115kV Transmission Line. Two new 30MVA transformers with four distribution feeders will be the initial configuration.	Complete
75	Saddle Mountain Integration	Performance and Capacity	Construct a 3-position 230kV DBDB arrangement with space for two future positions at the line crossing of the Walla Walla – Wanapum 230kV and Benton – Othello 115kV Lines Construct a 4-position 115kV breaker and a half arrangement with space for four future positions Install 1-230/115kV transformer rated at 250MVA. Reconstruct Othello SS – Warden #1 115kV Transmission Line to minimum 205MVA including upgrades to terminal equipment at both stations. Reconstruct Othello SS – Warden #2 115kV	Complete

ERT #	Project Name	Driver	Scope	Status
			Transmission Line to minimum 205MVA including upgrades to terminal equipment at all stations. Construct 11 miles of 115kV line with a minimum summer rating of 205MVA from Saddle Mountain Station to the new Othello City station with a N/O tap to existing S. Othello Station. Reconstruct Othello Station to a 3-position breaker and a half with 2 – 30MVA transformers at new property.	
80	Huetter Station Expansion	Performance and Capacity	Add new 30MVA transformer and two distribution feeders to the existing Huetter Station. Scope includes a new panel house and rerouting the transmission line to the east side of the station. 13kV bus tie switch and a 115kV bus tie switch located on transmission structures outside the station will be added.	Construction
111	Lyons & Standard Station Expansion	Customer Requested	Add new feeder to existing Lyons & Standard Station.	Construction
140	Bunker Hill Customer Capacity	Customer Requested	Install new 20MVA transformer to replace existing transformer and construct new dedicated customer distribution feeder.	Budgeted
143	Waikiki Capacity Mitigation	Performance and Capacity	Add new 20MVA transformer and two feeders to existing Indian Trail Station.	Budgeted
148	Barker Capacity Mitigation	Performance and Capacity	Add new 30MVA transformer and three feeders to existing Greenacres Station.	Budgeted

Table 3: Projects Represented in Distribution System Models

3.2.3. Performance Criteria

The performance criteria used in evaluating the performance of the distribution system is outlined in *DP-SPP-02 – Distribution System Performance V5* Table 1.

3.2.4. Studies Performed

Technical studies are performed as part of the System Assessment. The methodologies for each study are documented in *DP-SPP-02 – Distribution System Performance*. The defined set of technical studies include:

- Load Forecast Development
- Multi-Year Load-Flow Analysis
- Contingency Analysis (under development)
- Auto-Transfer Analysis
- Short Circuit Analysis (under development)

4. Corrective Action Plans

When technical studies demonstrate the system's inability to meet performance requirements, Corrective Action Plans are developed to address how the performance requirements will be satisfied. Revisions to Corrective Action Plans are allowed in subsequent System Assessments but the planned system must continue to meet performance requirements. Corrective Action Plans can be developed to meet the performance requirements for one or more sensitivity cases analyzed.

Corrective Action Plans developed to address performance issues identified on the transmission system must be implemented in accordance with TPL-001-5[3] R2.7. If situations arise outside Avista's control that prevent the implementation of a Corrective Action Plan within the required timeframe, Avista is then permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation while providing documentation of the actions and resolution. Avista shall document the problematic performance issue, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. (TPL-001-5, R2.7.3)

In some instances, performance requirements can be met using Operating Procedures making Corrective Action Plans unnecessary. Operating Procedures may also introduce undesired risks to the system. Projects are developed and recommended to address the instances where expected system performance using Operating Procedures is not considered acceptable.

Corrective Action Plans for the transmission and distribution system are provided in the following sections.

4.1. Existing Projects

Included in Table 4 below are projects identified in prior years' technical studies that have been incorporated into Avista's Engineer Roundtable prioritized project list.

ERT #	Project Name	Driver	Scope	Status	TPL CAP
12	Carlin Bay Station	Performance and Capacity	Construct new distribution station to include single 20MVA transformer and two feeders. Transmission integration to include constructing a new radial transmission line from O'Gara Station to Carlin Bay. The second phase of the project includes rebuilding the existing O'Gara Station to a switching station. New microwave communication paths will be established to O'Gara Station.	Budgeted	
46	Poleline (Prairie) Station Rebuild	Performance and Capacity	Scope not complete. Construct new distribution station to replace Avista facilities at existing Prairie Station. New station to include two 30MVA transformers, four feeders, and looped-through transmission without circuit breakers.	Budgeted	
47	Stateline Station	Performance and Capacity	Scope not complete. New distribution station located between Pullman and Moscow.	Budgeted	
56	Bronx Station Rebuild	Performance and Capacity	Scope not complete. Reconstruct existing Bronx Station to include distribution facilities.	Budgeted	

[3] NERC Transmission Planning standard TPL-001-5, https://nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

ERT #	Project Name	Driver	Scope	Status	TPL CAP
58	Westside Station Rebuild	Performance and Capacity	Replace the existing Westside 230/115kV Transformer 2 and construct necessary bus work and breaker positions. Reconstruct 230 and 115kV buses to double bus double breaker 3000/2000 Amp standard. Phase 4: Complete bus work to double bus, double breaker on both the 230kV and 115kV buses	Construction	Yes
60	Ninth & Central - Sunset 115kV Transmission Line Upgrade	Performance and Capacity	Replace the 795 AAC and ACSR conductor on the Ninth & Central – Sunset 115kV Transmission Line with 795 ACSS with E3X coating to match the rest of the line.	Construction	
62	Lolo Transformer Replacement	Performance and Capacity	Replace Lolo 230/115kV Transformer 1 with 250MVA rated transformer. Replace Lolo 230/115kV Transformer 2 with 250MVA rated transformer. 115kV circuit breakers, bus work and other capacity-limiting elements will be replaced. Circuit switchers at Clearwater, Lolo, and Sweetwater stations will be replaced.	Construction	
80	Huetter Station Expansion	Performance and Capacity	Add new 30MVA transformer and two distribution feeders to the existing Huetter Station. Scope includes a new panel house and rerouting the transmission line to the east side of the station. 13kV bus tie switch and a 115kV bus tie switch located on transmission structures outside the station will be added.	Construction	
82	Cabinet Gorge GSU Protection Upgrade	Performance and Capacity	Install circuit breakers on high side of GSU.	Budgeted	
96	Kettle Falls Protection System Upgrades	Mandatory and Compliance	Upgrade existing protection schemes on the Addy – Kettle Falls and Colville – Kettle Falls 115kV Transmission Lines. New relays at Kettle Falls Station and a new communication path from Kettle Falls to Mount Monumental are required.	Construction	Yes
100	Melville Station	Performance and Capacity	Scope not complete. New switching station near existing tap to Four Lakes Station off the South Fairchild Tap 115kV Transmission Line. Construct new transmission line from Airway Heights to Melville including passing through Russel Road and Craig Road distribution stations. Requires new transmission line terminal at existing Airway Heights Station.	Budgeted	
131	Garden Springs Station	Performance and Capacity	Construct new 115kV portion of Garden Springs Station at the existing Garden Springs switching location. New station will terminate Airway Heights – Sunset and Sunset – Westside 115kV Transmission Lines including the South Fairchild Tap. Construct new 230kV portion of Garden Springs Station including two 250MVA nominal 230/115kV transformers. Construct new 230kV transmission line from Garden Springs to a new switching station, Bluebird, at an interconnection point on the BPA Bell – Coulee #5 230kV Transmission Line.	Budgeted	Yes
143	Waikiki Capacity Mitigation	Performance and Capacity	Add new 20MVA transformer and two feeders to existing Indian Trail Station.	Budgeted	

ERT #	Project Name	Driver	Scope	Status	TPL CAP
148	Barker Capacity Mitigation	Performance and Capacity	Add new 30MVA transformer and three feeders to existing Greenacres Station.	Budgeted	
151	Pleasant View Capacity Mitigation	Performance and Capacity	Scope not complete. Add new 30MVA transformer and two feeders to existing station.	Budgeted	
156	Safely Interrupting Faults	Performance and Capacity	Replace South Othello A57 circuit switcher with 1220kA or greater rated equipment. Replace Barker Road A316 circuit switcher with 40kA or greater rated equipment. Replace Francis & Cedar A676 and A677 circuit switchers with 40kA or greater rated. equipment. Replace Lakeview R330 circuit switcher with 20kA or greater rated equipment. Replace Garfield EG-1 transformer fuse with 10kA or greater rated fuse. Replace Leon Junction SMD-2B transformer fuse with 15kA or greater rated fuse. Replace Long Lake SMD-2B transformer fuse with 15kA or greater rated fuse. Replace North Moscow SMD-2B transformer fuse with 15kA or greater rated fuse.	Budgeted	

Table 4: Existing Projects Included in Avista's Five-Year Capital Budget Plan

4.2. New Projects

Corrective Action Plans identified by technical analysis completed as part of the *2023-2024 System Assessment* are provided in this section. The Corrective Action Plans provided were not identified during previous years' technical analyses or they were not included in Avista's prioritized project list. The project scope outlined for each Corrective Action Plan is preliminary and will require further study including the evaluation of alternatives (traditional and non-traditional) and coordination with stakeholders to confirm the appropriate scope is executed. Each Corrective Action Plan will be reviewed in subsequent System Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. (TPL-001-5, R2.7.4)

The new required projects and associated performance issues, in addition to the planned projects included in the study assumptions, are summarized in Table 5 below.

	Corrective Action Plan			System Impact			
Issue	Project Name	Planning Scope	Desired In-service Timeline	Worst Performance Criteria Issue	Impacted Facilities	Impact Timeline	TPL?
1	**Coeur d'Alene Transmission Reinforcement**	New 230kV source station between Boulder and Rathdrum	5-10 years	P2: A-624 breaker failure at Rathdrum	OTI-PF and PF-RAM overload	Existing	Yes
2	**Lewiston-Clarkston Transmission Reinforcement**	New 230kV transmission line between Hatwai and Lolo stations	5-10 years	P6: HTWA-LOL + DCR-PDL	NLW-CLW overload	Existing	Yes, possible Ops Plan

	Corrective Action Plan			System Impact			
Issue	Project Name	Planning Scope	Desired In-service Timeline	Worst Performance Criteria Issue	Impacted Facilities	Impact Timeline	TPL?
3	**North Spokane Transmission Reinforcement**	Upgrade 3/0 copper section of Beacon – Francis & Cedar, reconfigure existing lines between Bell and Waikiki including new interconnection at Bell, Waikiki Station modifications, two new lines between Indian Trail and Waikiki, and loop Boulder – Irvin line into Trentwood	4-7 years	P6: F&C-ROS + NW-WES and P6 Bell #6 Outages	BEA-F&C overload and BEA-BELL issues	Existing	Yes
4	**Sandpoint Transmission Reinforcement**	New 115kV transmission into the Sandpoint area or upgrades of existing facilities	5-10 years	P6: LIBY transformer + CAB transformer	ALFL-SDCK overload	Existing	Yes
5	**Beacon Transmission Reinforcement**	Rebuild Beacon with higher capacity equipment and redundant bus design	5-10 years	Close in fault on BEA 115/13kV transformer and Beacon breaker failures	BEA 115kV circuit breakers and Spokane 115kV system	5+ years	Yes
6	**Palouse Transmission Reinforcement**	Under development	5-10 years	SHN transformer outage with M23-TVW outage	M23-M15	Existing	Yes, possible Ops Plan
7	**Safely Interrupting Faults**	Existing project scope needs to be expanded to include replacement of Airway Heights and Post Street circuit switchers	2-5 years	Faults on distribution transformers	AIR, PST	Existing	No
8	**West of Lancaster**	Expand RAS for specific scenarios	2-5 years	P7 West of Lancaster	BLD-RAT, OTI-PF, PF-RAM	Existing	No
9	**Airway Heights Capacity**	Transfer load to FLN12F1	1 year	Peak summer capacity	AIR12F1, Xfmr 2	2026	No
10	**Glenrose Capacity**	New East Central Station	5 years	Peak summer capacity	GLN12F1, GLN12F2, Xfmr 1	Existing	No
11	**Lewiston Capacity**	Rebuild SLW, expand TEN, and new LOID and WHT Stations	5-10 years	Peak summer capacity	TEN, LOL, NLW, SLW	Existing	No

Issue	Corrective Action Plan: Project Name	Planning Scope	Desired In-service Timeline	System Impact: Worst Performance Criteria Issue	Impacted Facilities	Impact Timeline	TPL?
12	**Liberty Lake Capacity**	TBD	5 years	Peak summer capacity	LIB12F1, LIB12F3, Xfmr 2	Existing	No
13	**Moscow Capacity**	Load transfers, new SEL Station, rebuild M15	5-10 years	Peak summer capacity	M15512, M15514, Xfmr 1	Existing	No
14	**North Spokane Distribution Reinforcement**	INT expansion, NE expansion, feeder re-configuration, MEA expansion	5-10 years	Peak summer capacity	BEA, COB, F&C, INT, L&S, MEA, NE, WAK	Existing	No
15	**Rathdrum Capacity Mitigation**	Add one additional feeder to off load RAT231 and RAT233	5-10 years	Peak summer capacity	RAT231	2027	No
16	**Orin Capacity**	TBD	TBD	Peak winter capacity	ORI12F3, Xfmr 1	Existing	No
17	**Wilbur Capacity**	Upgrade WIL transformer	2-3 years	Peak winter capacity	Xfmr 1	Existing	No
18	**Valley Capacity**	Upgrade VAL transformer	TBD	Peak winter capacity	Xfmr 1	Existing	No

Table 5: Corrective Action Plans Identified in *2023-2024 System Assessment*

4.2.1. Transmission

4.2.1.1. Coeur d'Alene Transmission Reinforcement

Consistent load growth in the Coeur d'Alene region continues to outpace transmission system reinforcements. The area summer peak load has increased from 158MW in 2010 to 223MW in 2020, an annual rate of 3.5%. This growing load results in ongoing near-term thermal issues for the loss of the Rathdrum East 115kV bus (P2.2 and P2.3) and the loss of the 115kV source with a Rathdrum 115kV bus tie breaker failure (P2.4), both of which require Corrective Action Plans for mitigation. Additionally, numerous N-1-1 outage issues (P6, A6, and A7) continue to limit planned outages in the Coeur d'Alene region to shoulder months. Forced outage combinations may result in load shedding during heavy load periods.

The area load is served by two 230/115kV transformers at Rathdrum Station and four 115kV transmission lines from neighboring areas. Some of the identified contingency issues were temporarily corrected in 2014 with a 115kV line reconfiguration at the "Magic Corner", but at the expense of additional load loss exposure resulting from autotransformer outages at Rathdrum. The 115kV system was put back into normal configuration after the completion of the Coeur d'Alene – Pine Creek 115kV Transmission Line Rebuild Project in 2020, which added a new 115kV source from Pine Creek Station.

Study results show that adding a station in Coeur d'Alene area is the most cost effective and flexible system reinforcement, minimizing the need for multiple 115kV line reconductors and adds resiliency to the transmission system. Preliminary scope of the Coeur d'Alene Area Transmission Reinforcement project is shown in Figure 5.

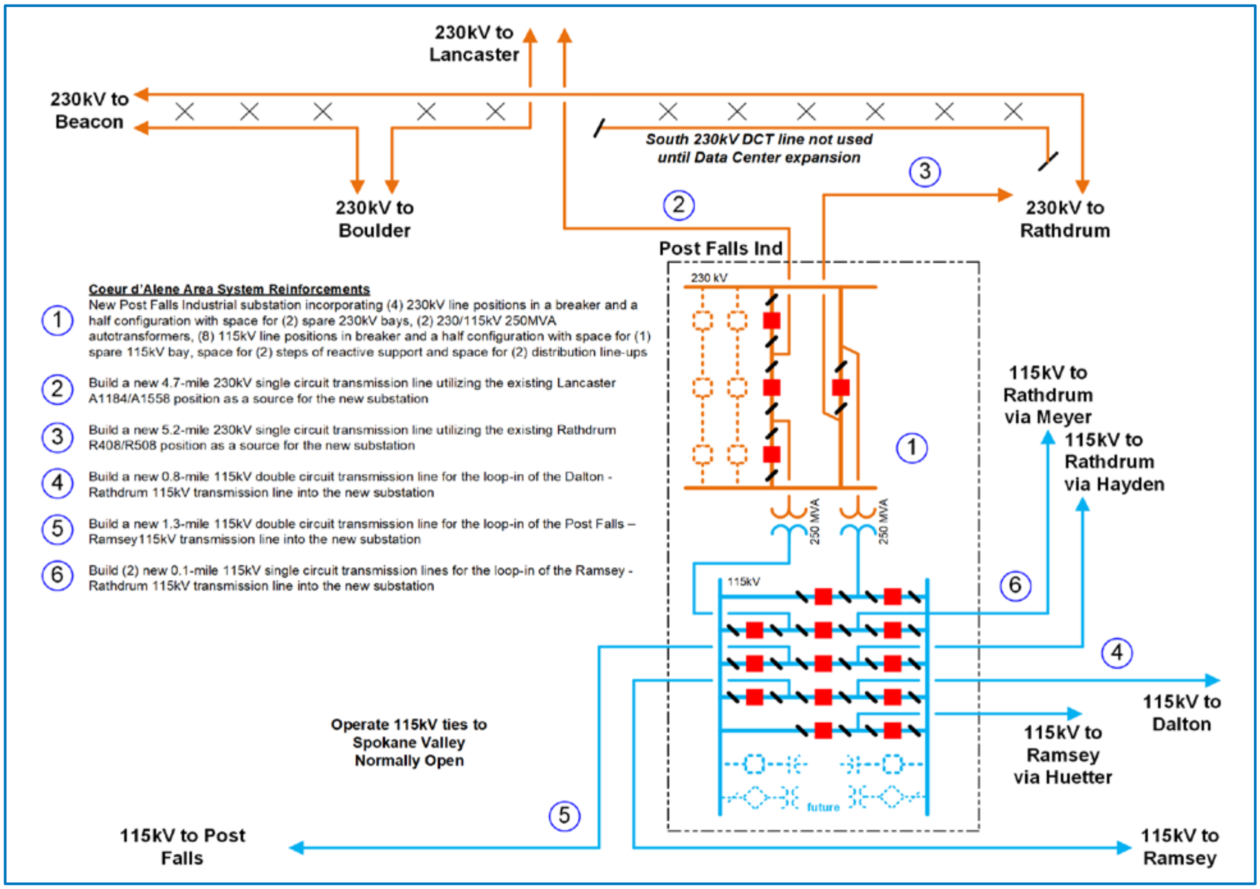

Figure 5: Coeur d'Alene Transmission Reinforcement

The requirement for the Coeur d'Alene Transmission Area Reinforcement project was identified through the transmission steady state near-term and long-term contingency analysis. This specific project and 230kV transmission expansion scope will be provided in the subsequent Corrective Action Plan and study documents.

4.2.1.2. Lewiston-Clarkston Transmission Reinforcement

Issues in the Lewiston-Clarkston Area have been understood since the West of Hatwai projects were completed in 2005. To manage planned outages, the following automatic actions have been incorporated into current Operational Procedures:

- The Lolo – Oxbow Back Tripping Remedial Action Scheme (RAS) is in place for planned 115kV and 230kV line outages. The contingency issues are more pronounced during late spring and summer seasons due to heavy system loading and high ID-NW transfers south into Idaho Power's system.
- A Thermal Trip Scheme has been established to trip the Clearwater – North Lewiston 115kV Transmission Line when overloaded based on existing transmission line load and ambient temperature data within a prescribed time limit.

This area has several N-1-1 issues that require the above automatic actions in addition to schedule reductions and requisite sectionalizing of the 115kV system for more problematic outages.

The Clearwater – North Lewiston 115kV Transmission Line, which currently loads above 90% under N-1 conditions, is the weak link in this area. This condition limits planned outages in the area to shoulder months. The most extreme contingency is an outage of the Hatwai – Lolo 230kV Transmission Line for which the RAS is implemented, and multiple 115kV transmission lines must be sectionalized to avoid overloads for the next contingency.

Evaluation results show a preliminary concept of a second Hatwai – Lolo 230kV Transmission Line will resolve the Clearwater - North Lewiston adverse results shown in the steady state results described in Section 5 Technical Analysis below.

4.2.1.3. North Spokane Transmission Reinforcement

Load growth in the North Spokane area has contributed to inadequate transmission system performance. Near-term P6 contingencies result in thermal issues for both Beacon – Francis & Cedar 115kV Transmission Line and Beacon – Bell 115kV interconnections.

The Francis & Cedar Station is served by three 115kV transmission lines. A category P6 outage involving the Francis & Cedar – Ross Park and Northwest – Westside 115kV Transmission Lines leave only the Beacon – Francis & Cedar 115kV Transmission Line serving the Northwest and Francis & Cedar Stations. The Beacon – Francis & Cedar 115kV Transmission Line is constrained by a section of seven strand 3/0 copper conductor between the Bell and Waikiki Taps. Upgrading the conductor to present construction standards will mitigate the observed performance issue. This outage combination under forced conditions may result in load shedding during Heavy Summer scenarios.

There are four 115kV facilities between the Beacon and Bell stations that result in near-term thermal issues under P6 contingencies and long-term single contingency thermal issue with loss of the Bell 230/115kV Transformer 6. Near-term thermal issues result when two of the following facilities are out of service.

- Bell 230/115kV Transformer 6
- Beacon – Bell #1 115kV Transmission Line
- Beacon – Northeast 115kV Transmission Line
- Bell – Northeast 115kV Transmission Line

A transformer outage followed by an outage of one of three interconnecting 115kV transmission lines (Beacon – Bell, Beacon – Northeast, or Bell – Northeast) results in system overloads on the remaining 115kV transmission line between Beacon and Bell stations.

Preliminary scope to address the Beacon – Francis & Cedar thermal concern and some of the Beacon – Bell interconnection concerns are shown in Figure 6.

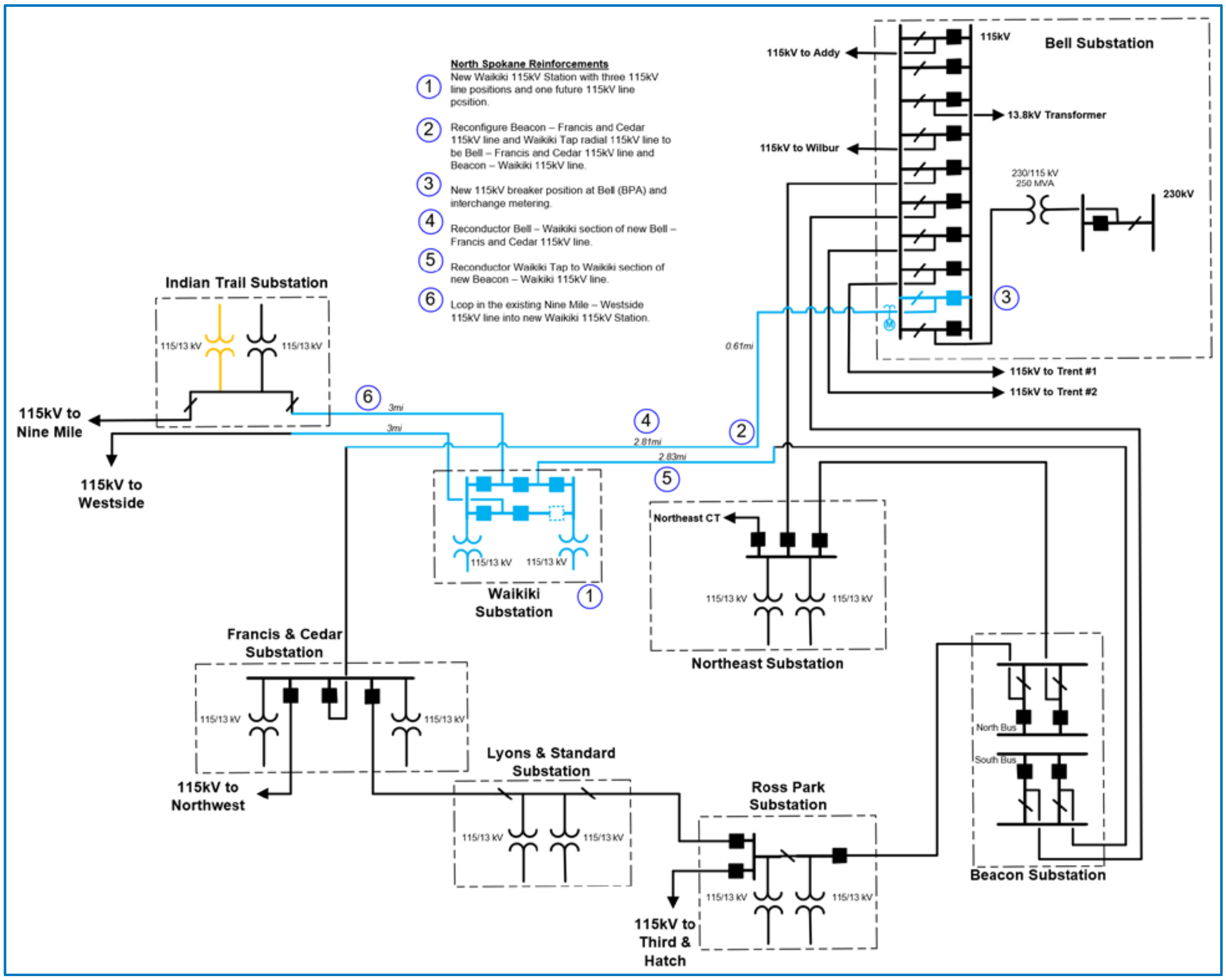

Figure 6: Beacon – Francis & Cedar 115kV Reinforcement

Preliminary scope to mitigate the remaining thermal issues for Beacon – Bell interconnections is shown in Figure 7.

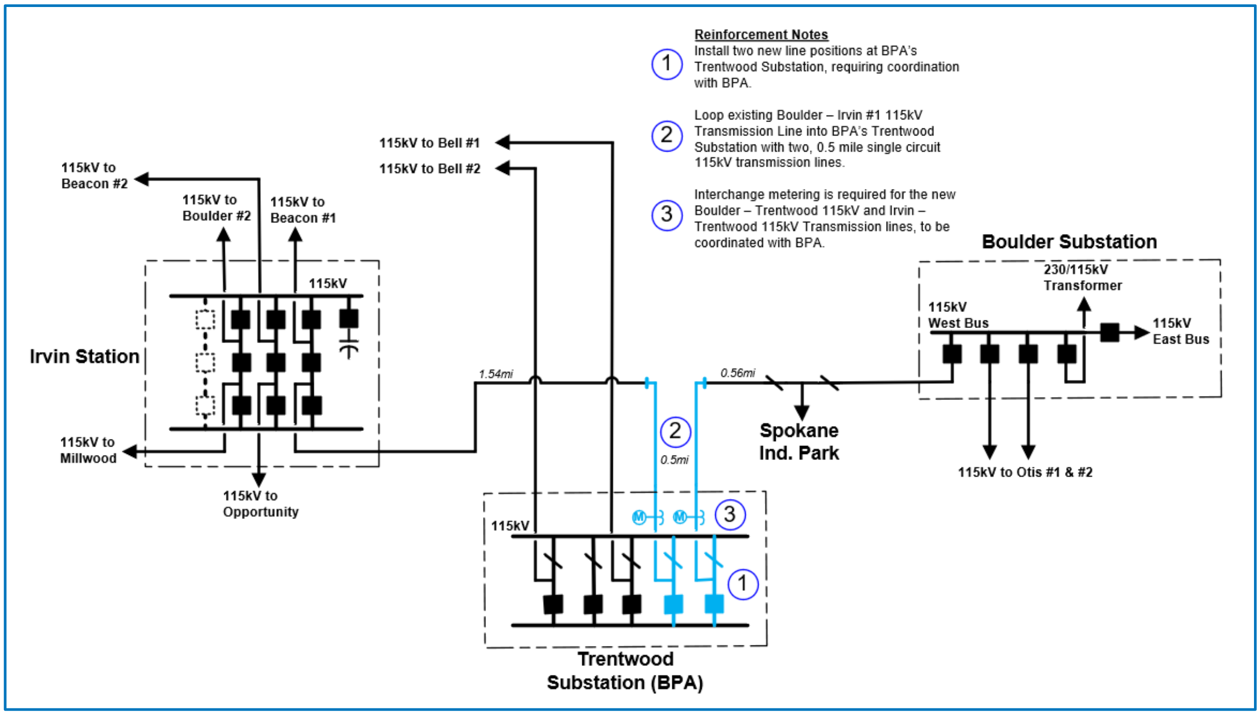

Figure 7: Boulder – Irvin #1 115kV Loop into Trentwood

The requirement for the North Spokane Transmission Reinforcement project was identified through the transmission steady state near-term and long-term contingency analysis. Specific project scope will be provided in subsequent study documents.

4.2.1.4. Sandpoint Transmission Reinforcement

The Sandpoint area is served by three transmission lines. An N-1-1 (P6 long lead) outage involving the Libby 230/115kV Transformer 1 and Cabinet 230/115kV Transformer 1 leaves only the Albeni Falls – Sand Creek 115kV Transmission Line serving load in the area. This outage combination under forced conditions may result in load shedding during Heavy Winter scenarios.

A reinforcement project needs to be developed to mitigate the observed transmission line overloads and low voltages under outage conditions. Several alternatives exist and vary in scope. The project may include the construction of a new 115kV transmission line to the Sandpoint area from Rathdrum or Albeni Falls Stations, providing a fourth transmission line into the area. Coordination of a project with Bonneville Power Administration (BPA) could include upgrades to the Albeni Falls – Sand Creek 115kV Transmission Line and the construction of additional capacitor banks in the area. The optimum long-term mitigation alternative has not been determined. Further analysis of the project is necessary and will be evaluated in subsequent system assessments.

The need for the Sandpoint Transmission Reinforcement project was identified through the transmission steady state near-term contingency analysis.

4.2.1.5. Beacon Transmission Reinforcement

Performance of Beacon Station is a critical part of reliably serving load in Spokane. Short circuit and contingency analysis indicate improvements are necessary to meet reliability requirements.

The available fault duties for high voltage circuit breakers at the Beacon Station presently exceed 95% of their interrupting ratings. The A-608 and A-614 positions, protecting Beacon 115/13kV Transformer 1 and 2 respectively, have an available fault current above 38kA. Several other 115kV transmission line positions have fault duties greater than 90% of their equipment rating or exceeding the equipment rating after planned projects are constructed in the area. Initial review of the mechanical capability of the bus indicated adequacy to the 40kA level. Further evaluation of the existing station's mechanical design for fault withstand is also necessary.

In addition to the underrated interrupting capabilities, a breaker failure of either the 115kV or 230kV tie breakers causes performance issues in the area. Outages including either Beacon 230/115kV transformer and the Bell 230/115V Transformer 6 also cause performance issues. Long term outages of either Beacon transformers, even with an available spare, will cause possible load serving constraints during heavy loading times. Bell Transformer 6 capacity also needs to be addressed with BPA.

Protection system single point of failure analysis identified contingencies at Beacon as problematic. Evaluation of design alternatives is required.

A rebuild of the Beacon Station is proposed. Evaluation of a feasible construction plan for the rebuild needs to be developed. The resulting rebuilt station will require circuit breakers rated at industry standard 50kA or greater, and bus configuration either as double bus double breaker or breaker and a half. Additional consideration on whether a third 230/115kV transformer is necessary or prudent is warranted.

The need for the Beacon Transmission Reinforcement project was identified through the transmission short circuit analysis, steady-state contingency analysis, spare equipment analysis, and single point of failure analysis. Further development of the scope for the Beacon Transmission Reinforcement project is necessary and will be reviewed in subsequent system assessments.

4.2.1.6. Palouse Transmission Reinforcement

Two primary deficiencies in the Palouse area revolve around outages of the two 230/115kV transformers or the two 115kV transmission lines connecting Moscow 230 Station to Shawnee Station.

First, the combined N-1-1 (P6) outage of the Moscow 230 and Shawnee 230/115kV transformers cause voltage collapse in the Palouse area if there are no mitigating actions taken following the outage of the first transformer. System deficiencies are observed in all scenarios studied but the worst performance occurs in the Heavy Winter scenario.

The current Operating Procedure to correct the voltage collapse, results in this load center being served by only two 230/115kV transformers. Given a forced or planned outage of the first transformer, followed by a second transformer outage (N-1-1, P6 long lead) a system blackout (up to 200MW of load loss) is localized to the Palouse area. Some of the dropped load can be restored by transferring to neighboring 115kV sources, but up to 60MW of load would be permanently off-line during heavy load conditions until a 230/115kV transformer was restored. The Operating Procedure permits the deferral of a Corrective Action Plan to meet the TPL-001-5 requirements.

Secondly, the two 115kV transmission lines connecting Moscow Station to Shawnee Station are nearing their load serving capacity. The primary issue is low voltage being observed for an

N-1-1 (P6) outage of the Shawnee 230/115kV Transformer followed by either an outage of the Moscow – South Pullman or Moscow 230 – Terra View 115kV Transmission Lines. A maintenance issue is the N-1-1 (A6.1) combination of either of these lines open at Moscow and the loss of the Shawnee 230/115kV transformer resulting in thermal overloads on the remaining 115kV transmission line serving the loop.

These line issues occur during the heavy summer scenarios and can be addressed with an Operating Procedure to transfer Moscow City Station south to the North Lewiston Station.

A preliminary concept to resolve these issues was explored. The first issue could be corrected with a third 230/115kV transformer in the area and the 115kV line issues could be corrected by extending the Moscow City – Leon Junction– North Lewiston 115kV Transmission Line into a new 115kV line position at Moscow 230 Station, leaving Moscow City station on the new networked line.

The requirement for the Palouse Transmission Reinforcement project was identified through the transmission steady state near-term and long-term contingency analysis. Specific project scope will be provided in subsequent study documents.

4.2.1.7. Safely Interrupting Faults

The A-187 and A-511 circuit switchers at Airway Heights and the A-435 and A-436 circuit switchers at Post Street are part of fault reduction schemes; none of which were evaluated in detail in the previous system assessment.

The Airway Heights circuit switchers reach 90% of interrupting rating in the 2028 Heavy Summer scenario and are overdutied in the 2033 Heavy Summer scenario utilizing the existing fault reduction scheme. Replacement with appropriately rated circuit switchers or another design alternative is required.

The Post Street circuit switchers are presently overdutied. Replacement with appropriately rated circuit switchers and elimination of the fault reduction scheme is recommended.

The existing Safely Interrupting Faults project needs to expand scope to include the circuit switcher replacements at Airway Heights and Post Street. The additional project scope was identified through the transmission short circuit analysis. The distribution short circuit analysis also identified two midline reclosers which are underrated. The C909R located on CDA121 and E170 located on SPI12F2 need to be replaced with recloser capable of interrupting 3500A.

4.2.1.8. West of Lancaster

The transmission system located west of the Lancaster Station is constrained during period of high generation. The outage of 230kV transmission lines, including the P7 outage of the Beacon – Rathdrum and Lancaster – Rathdrum 230kV double circuit, will overload the parallel 115kV transmission lines.

Mitigation of the overloads can be achieved through modifications to Avista’s Clark Fork RAS. Further evaluation of proposed arming levels, triggering events, and generation tripping is necessary.

4.2.2. Distribution

4.2.2.1. Airway Heights Capacity Mitigation

The AIR12F1 feeder and Airway Height 115/13kV Transformer 2 do not meet the performance criteria as identified in the distribution multi-year load-flow analysis. A proposed project scope to mitigate the identified issue is to transfer a portion of AIR12F1 along Highway 2 to FLN12F1. The completion of the Flint Road Station in 2023 provides for sufficient new capacity to transfer the load.

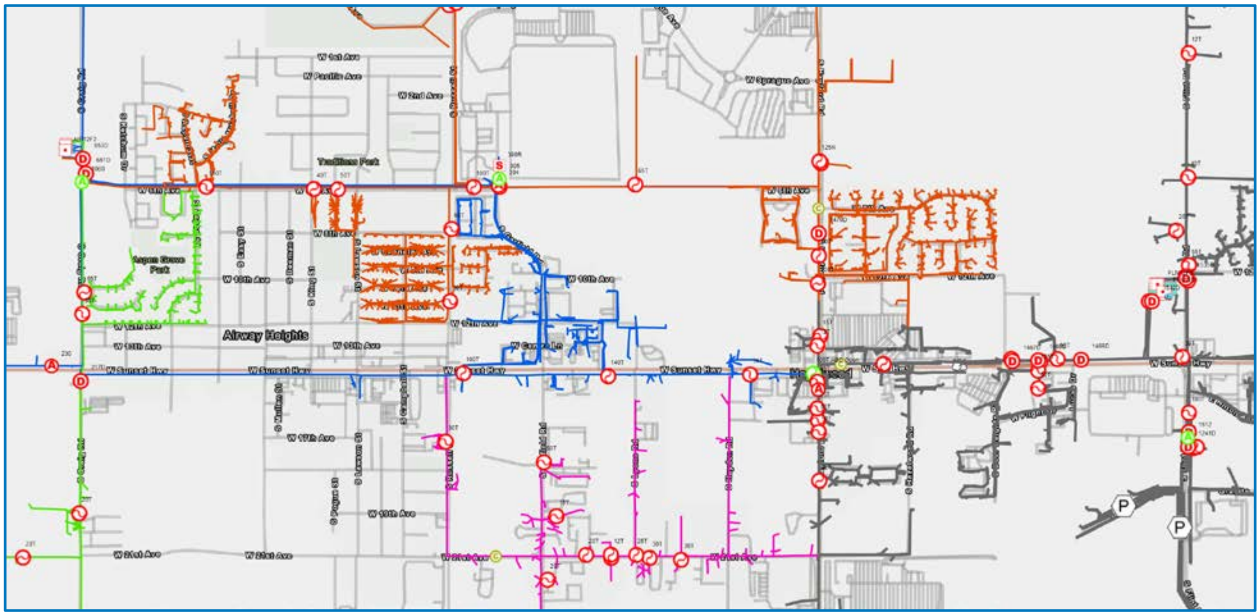

Figure 8: Airway Heights Capacity Considerations

4.2.2.2. Glenrose Capacity Mitigation

A new station referred to as East Central Station is proposed to mitigate the Glenrose feeders and transformers not meeting the performance criteria as identified in the distribution multi-year load-flow analysis. Feasibility of constructing a new station within the timeframe required to meet performance requirements may require additional mitigation measures. Upgrading the existing feeder regulators to 438A regulators and replacing the transformer with a 30MVA nominal transformer is a potential near-term mitigation project. The increased transformer size would not include adding a third feeder to the station.

The following figure illustrates the proximity of the proposed East Central Station to existing stations. In addition to offloading Glenrose Station, the new station will provide capacity to reduce loading on Third & Hatch, Beacon, Ross Park, and Ninth & Central Stations.

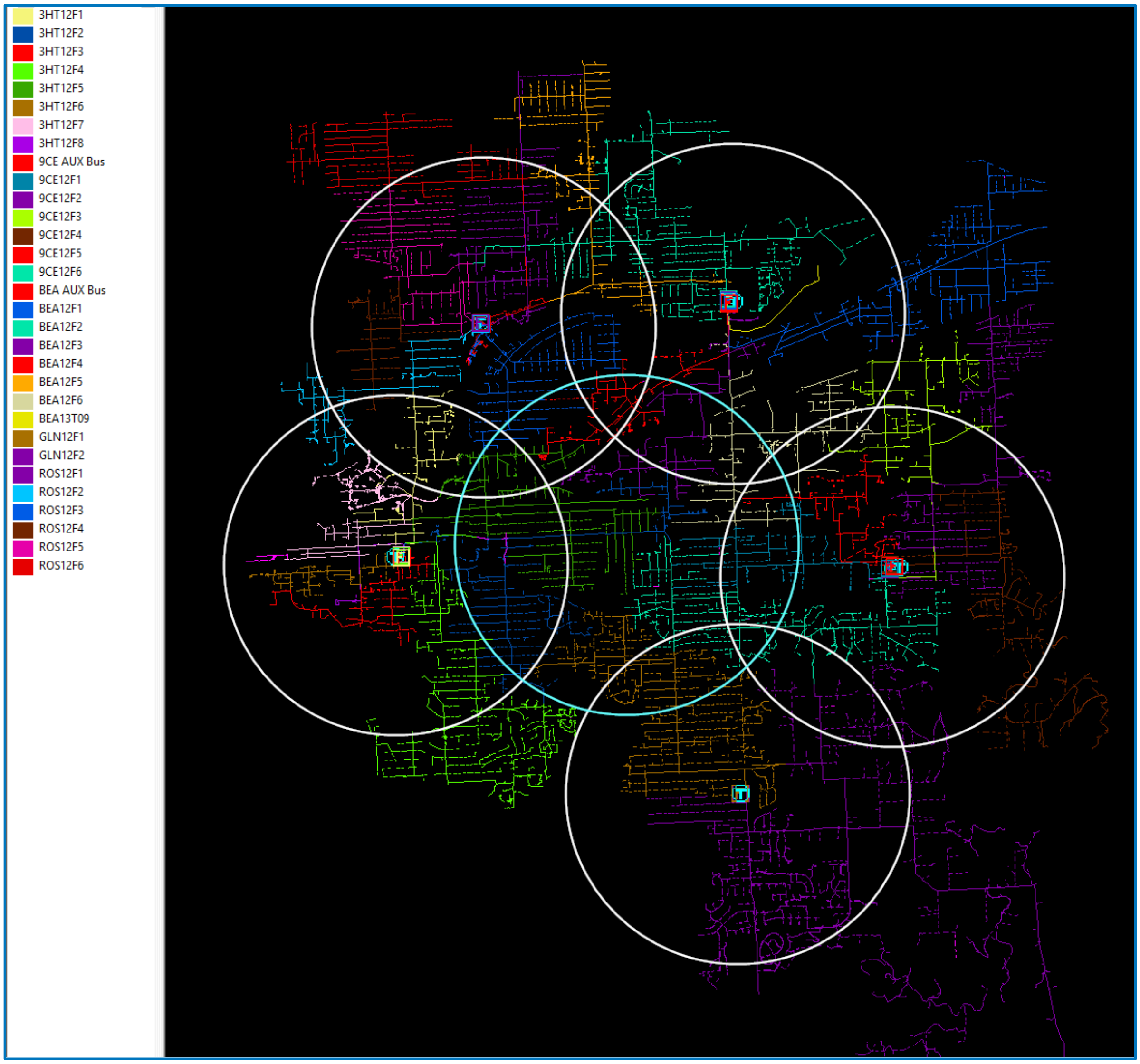

Figure 9: Spokane Area Station Coverage

4.2.2.3. Lewiston Capacity Mitigation

The equipment at the stations located in the Lewiston area are shown to not meet the performance criteria as identified in the distribution multi-year load-flow analysis. A proposed mitigation project will require several individual projects which collectively will provide the required system performance. The individual projects conceptually include:

- Rebuild existing South Lewiston Station with increased capacity
- Expand existing Tenth & Stewart Station to have six feeders
- Construct a new distribution station in the Lewiston Orchards neighborhood
- Construct a new distribution station previously referenced as Wheatland Station.

4.2.2.4. Liberty Lake Capacity Mitigation

A project is under development to mitigate equipment at the Liberty Lake Station not meeting the performance criteria as identified in the distribution multi-year load-flow analysis. Traditional mitigation alternatives are viewed to be challenging due to specific geographic constraints surround the Liberty Lake area. Further evaluation of the identified performance issues and possible non-traditional project alternatives is warranted.

4.2.2.5. Moscow Capacity Mitigation

A combination of projects is proposed in the Moscow area are proposed to address the M15512 and M15514 feeders and Moscow 115/13kV Transformer 1 not meeting the performance criteria as identified in the distribution multi-year load-flow analysis. Some transfer of load between existing feeders will provide near-term capacity improvements until more substantial capacity projects can be implemented. A new distribution station referred to as Selkirk Station is proposed to be located south of Moscow. With the additional capacity provided by the new station the existing Moscow Station can be rebuilt or upgraded to have standardized equipment sizing of six 600A feeders and two 30MVA transformers.

4.2.2.6. North Spokane Distribution Reinforcement

Several projects are proposed when a reinforcement plan to address the performance issues identified in the North Spokane area. There has been some infrastructure investment in the area including new feeder ties, regulator upgrades, phase balancing, and load transfers. One of the projects is the expansion of the existing Indian Trail Station with the addition of a 20MVA transformer and two feeders. The project is already included in the five-year budget and construction plan. New projects identified as part of the reinforcement plan include the following:

- Add an additional 20MVA transformer to the Indian Trail Station and add two new feeders.
- Replace the existing 20MVA transformers at the Northeast Station with 30MVA transformers and add a sixth feeder.
- Reconfigure the feeder system to best utilize the added transformation capacity by building new lines, adding switches and reconductoring where needed.
- Add an additional 30MVA transformer to the Mead Station and add two new feeders.

4.2.2.7. Rathdrum Capacity Mitigation

Installing a second feeder connected to the Rathdrum 115/13kV Transformer 2 is proposed to mitigate the RAT231 not meeting the performance criteria as identified in the distribution multi-year load-flow analysis. The existing Rathdrum 115/13kV Transformer 2 is a nominal 20MVA transformer with sufficient capacity for a second feeder. The new feeder will be able to directly offload RAT231 from either the south or west out of Rathdrum Station.

4.2.2.8. Orin Capacity Mitigation

A project is under development in the Colville area to mitigate the ORI12F3 feeder and Orin 115/13kV Transformer 1 not meeting the performance criteria as identified in the distribution multi-year load-flow analysis. Station equipment upgrades combined with upgrades on the ORI12F3 feeder could provide some additional capacity. Additional project concepts include constructing a new distribution station near BPA’s Colville Station or Avista’s Colville Service Center. Feeder integration work would include new main trunk construction to connect portions of CLV12F4 and ORI12F3.

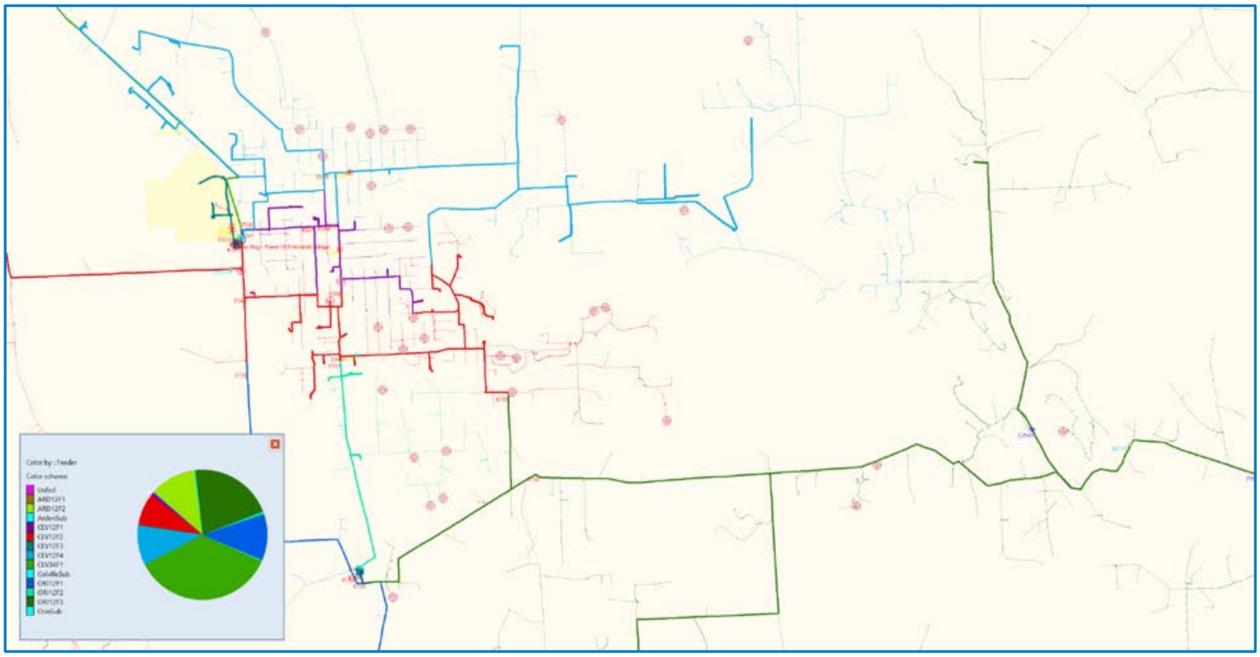

Figure 10: Colville Area Orin Feeder Mitigation

4.2.2.9. Wilbur Capacity Mitigation

A project is under development mitigate the Wilbur 115/13kV Transformer 1 not meeting the performance criteria as identified in the distribution multi-year load-flow analysis. Upgrading the existing transformer will provide sufficient capacity to meet the performance criteria. The feasibility of upgrading equipment at Wilbur Station needs to be evaluated. Additional alternatives include the implementation of non-traditional projects such as demand response, targeted energy efficiency, and distribution connected generation.

4.2.2.10. Valley Capacity Mitigation

Valley 115/13kV Transformer 1 does not meet the performance criteria for summer and winter as identified in the distribution multi-year load-flow analysis. Additionally, there are known voltage issues that need to be addressed. Upgrading the existing transformer combined with feeder protection upgrades will provide sufficient capacity to meet the performance criteria. A project is under development to assess the feasibility of upgrading equipment at Valley Station.

5. Technical Analysis

5.1. Transmission Steady State Near-Term Analysis (R2.1)

Steady state analysis was performed on the transmission system models representing the near-term planning horizon that represented peak, off peak, and sensitivity scenarios. If the analysis indicates an inability of the system to meet the performance requirements, the System Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. (TPL-001-5, R2.7)

5.1.1. Planning Events (R3.1)

The steady-state analysis of system normal conditions, described by the P0 event, demonstrated all Bulk Electric System (BES) facilities in the Avista system are within the continuous thermal ratings and all transmission facility voltages are within the specified limits.

The following sections describe the study results from the steady state contingency analysis for contingencies categorized as P1 through P7. The contingency analysis of P3 and P6 events considered Operating Procedures executed as part of system adjustments following the initial outage condition. Some Operating Procedures associated with P2 and P6 events consider corrective actions to utilize nonconsequential load loss.

5.1.1.1. Heavy Summer Scenario (R2.1.1)

Beacon Station Breaker Failure and Bus Outages

A breaker failure condition on the R-427 breaker at Beacon Station results in system overloads even with Five-Year Planned Projects implemented. These overload conditions occur on three 115kV transmission lines including Bell – Northeast, Francis & Cedar – Northwest, and Northwest – Westside, and the Bell 230/115kV Transformer 6. Overloads range from 102% to 112% within the five-year horizon, assuming the planned projects are implemented within that same timeframe.

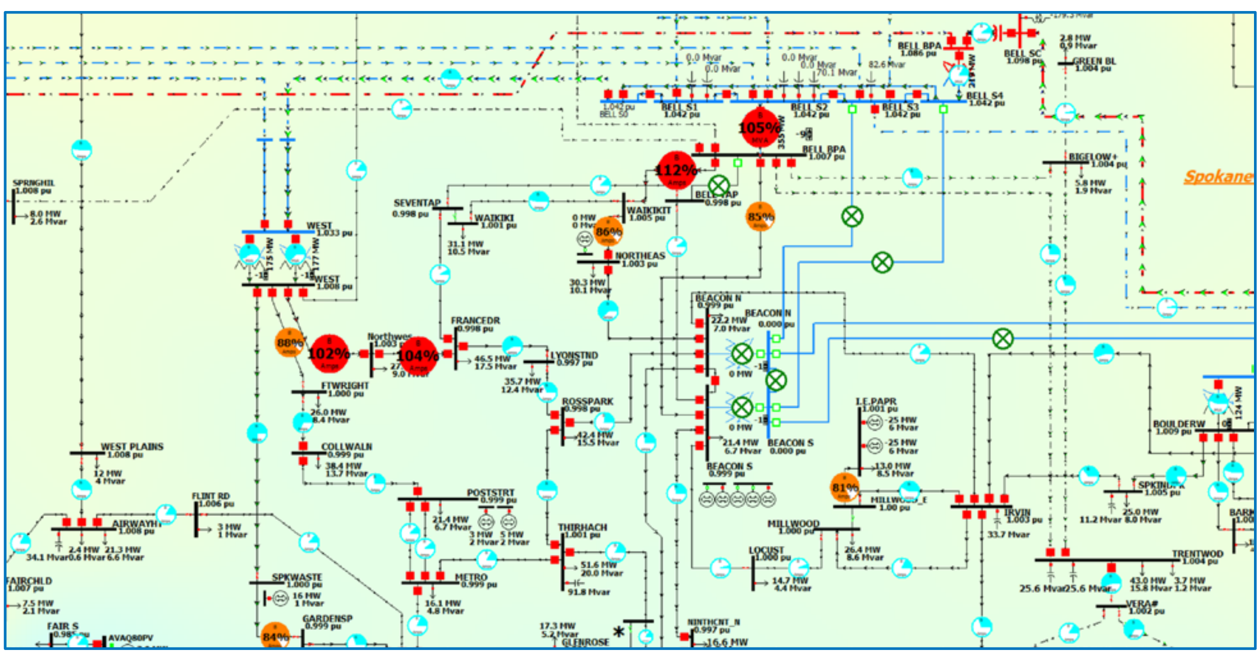

Figure 11: R-427 Breaker Failure at Beacon In 2028 Heavy Summer with Projects Scenario

An Operating Procedure to drop nonconsequential load can be used following the P2 contingency events at Beacon Station. The thermal overload violations are below emergency ratings, allowing time for the System Operator to take a single action to reduce loading of the equipment. The Operating Procedure permits the deferral of a Corrective Action Plan to meet the TPL-001-5 requirements. The Beacon Transmission Reinforcement Planning Initiative will be developed to address the performance concerns.

Bell 230/115kV Transformer 6 Outage

A contingency consisting of an outage of the Bell 230/115kV Transformer 6 followed by an outage of the Beacon – Bell, Beacon – Northeast, or Bell – Northeast 115kV Transmission Lines results in system overloads on the remaining 115kV transmission line between Beacon and Bell stations. Overload magnitudes of 184% in the current year and 188% within the five-year horizon are projected assuming all Five-Year Planned Projects are implemented.

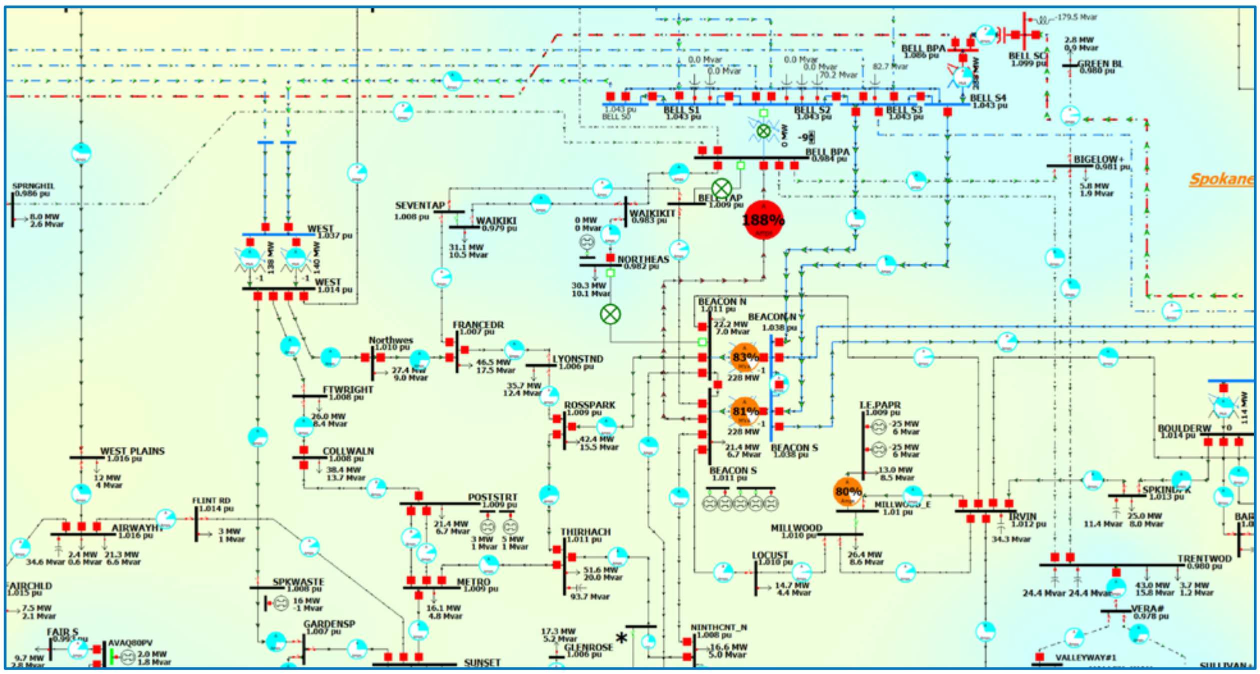

Figure 12: Bell 230/115kV Transformer 6 and Beacon – Northeast 115kV Line Outage In 2028 Heavy Summer with Projects Scenario

An operating plan is required to mitigate this condition. The operating plan states that following the initial outage, close Bell switch B-839 and open the line section between Waikiki and Bell on the Beacon – Francis & Cedar 115kV Transmission Line.

The Operating Procedure permits the deferral of a Corrective Action Plan to meet the TPL-001-5 requirements. The North Spokane System Reinforcement Planning Initiative and Beacon Transmission Reinforcement Projects will be developed and proposed to address the performance concerns.

Ninth and Central Station Bus Tie Breaker Failure

A breaker failure condition on the A-688 breaker at Ninth and Central Station results in system overloads even with Five-Year Planned Projects implemented. The overload condition occurs on the Ross Park – Third and Hatch 115kV Transmission Line. Overloads range from 104% to 115% within the five-year horizon, assuming the planned projects are implemented within that same timeframe.

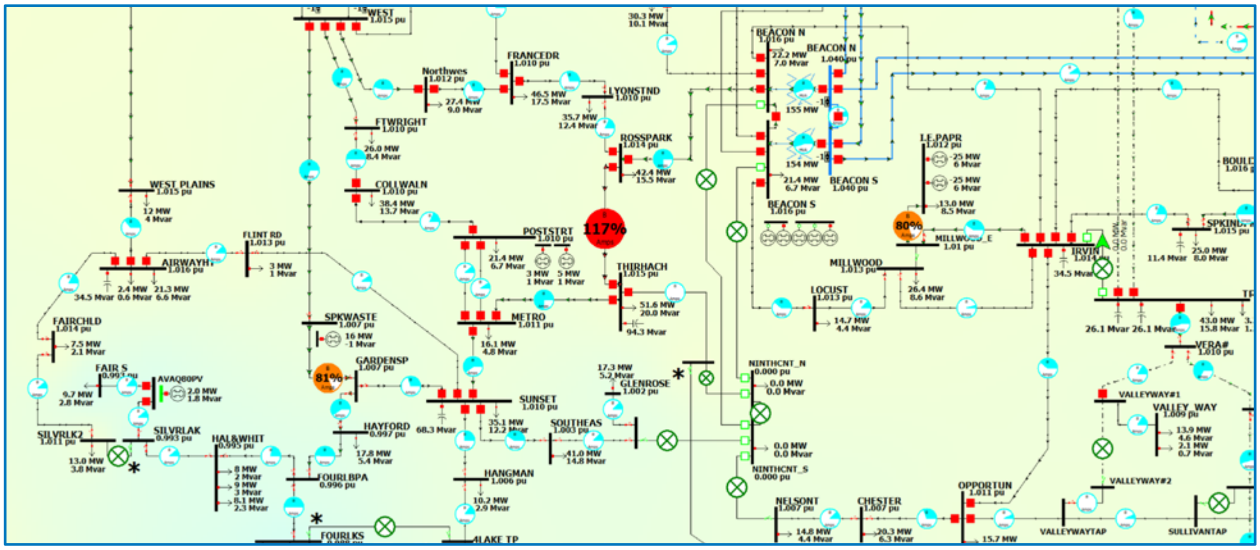

Figure 13: A-688 Breaker Failure at Ninth & Central In 2028 Heavy Summer with Projects Scenario

An Operating Procedure to drop nonconsequential load can be used following the P2 contingency events at Ninth and Central Station. The thermal overload violations are below emergency ratings, allowing time for the System Operator to take a single action to reduce loading of the equipment. The Operating Procedure permits the deferral of a Corrective Action Plan to meet the TPL-001-5 requirements. The Garden Springs Station project addresses the performance concerns.

Rathdrum Station Breaker Failure and Bus Outages

A breaker failure condition on the A-624 breaker at Rathdrum Station results in system overloads, even with Five-Year Planned Projects implemented. These overloads occur on the Otis Orchards – Post Falls and Post Falls – Ramsey 115kV Transmission Lines. Overloads range from 127% to 143% within the five-year horizon assuming all Five-Year Planned Projects are implemented.

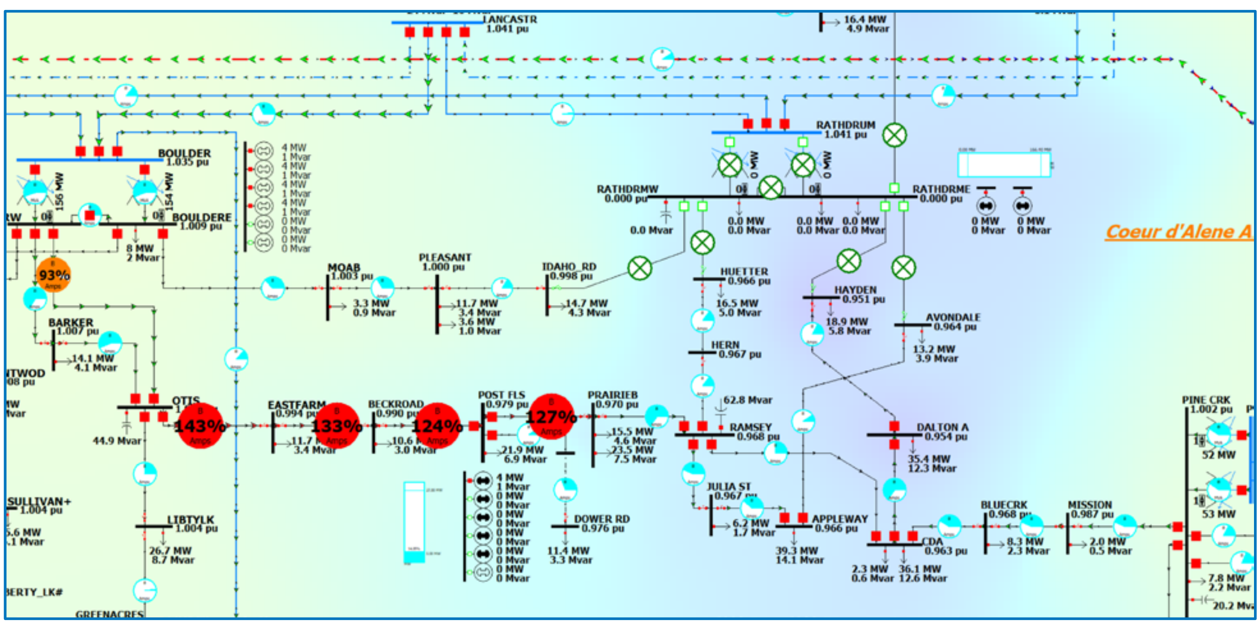

Figure 14: A-624 Breaker Failure at Rathdrum in 2026 Heavy Summer with Projects Scenario

A Corrective Action Plan is necessary to mitigate the performance issues identified for an A-624 breaker failure at Rathdrum Station. An effective Corrective Action Plan, the Coeur d'Alene Transmission Reinforcement, will include projects to mitigate the observed overloaded transmission lines and provide improved system resiliency for serving new customer growth in the area.

Clearwater – North Lewiston Line Overload

A contingency consisting of an outage on the Dry Creek – Pound Lane 115kV Transmission Line and a simultaneous outage on the Hatwai – Lolo 230kV Transmission Line results in system overloads on the Clearwater – North Lewiston 115kV Transmission Line. An overload of 116.3% exists within the five-year horizon assuming all Five-Year Planned Projects are implemented. Other outages in the area, combined with an outage of the Hatwai – Lolo 230kV Transmission Line, will also cause the Clearwater – North Lewiston 115kV Transmission Line to exceed applicable facility ratings.

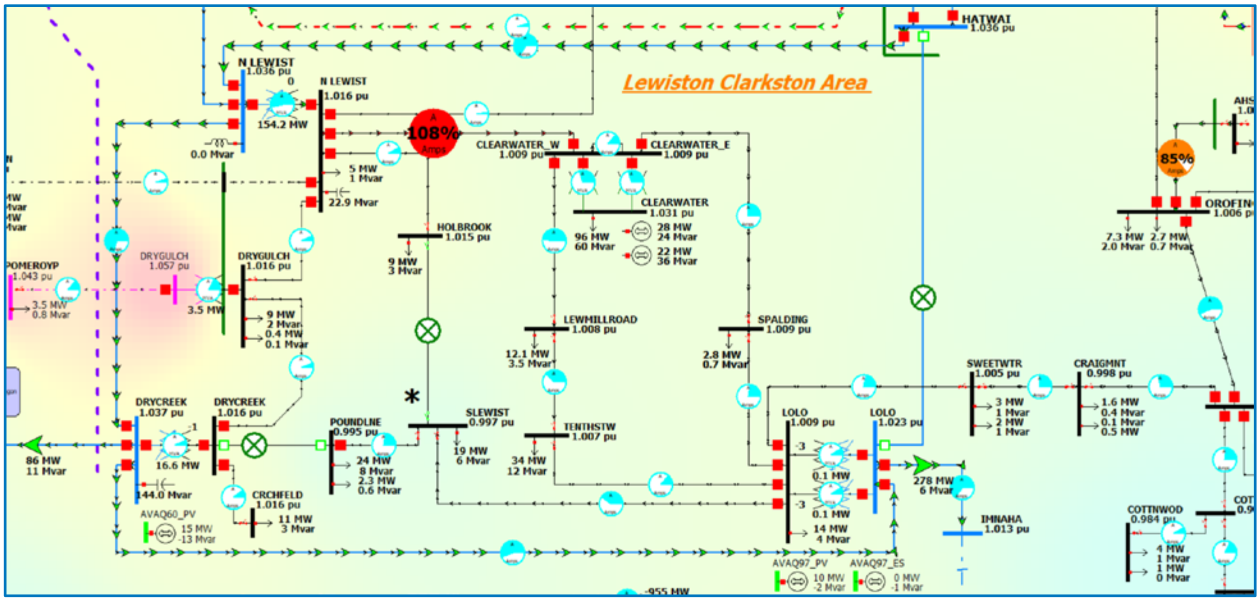

Figure 15: Hatwai – Lolo 230kV Line and Dry Creek – Pound Lane 115kV Line Outage In 2028 Heavy Summer with Projects Scenario

A Corrective Action Plan is necessary to mitigate the performance issues identified for the Clearwater – North Lewiston 115kV Transmission Line exceeding applicable facility ratings. An effective Corrective Action Plan, the Lewiston-Clarkston Transmission Reinforcement, will include projects to mitigate the observed overloaded transmission line as well as provide improved system resiliency for serving new customer growth in the area.

Francis & Cedar Transmission Line Outages

An outage of both the Francis & Cedar – Ross Park and Northwest – Westside 115kV Transmission Lines leaves the Beacon – Francis & Cedar 115kV Transmission Line serving the Northwest and Francis & Cedar stations.

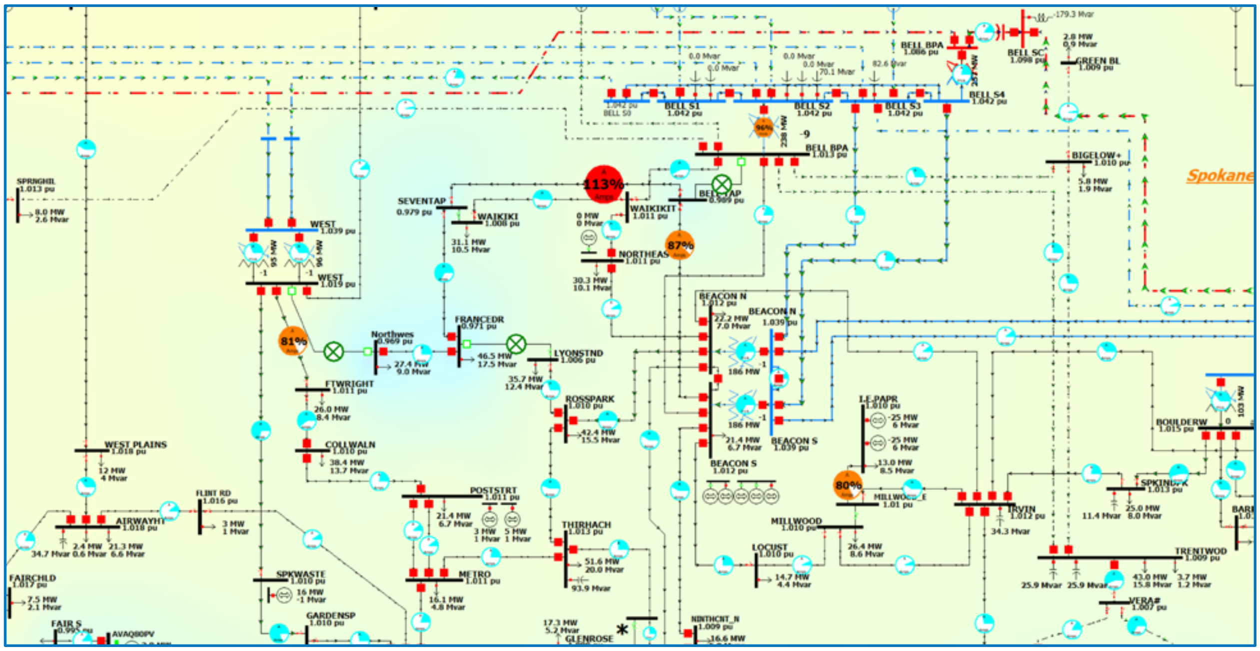

Figure 16: Francis & Cedar – Ross Park and Northwest - Westside 115kV Line Outage In 2026 Heavy Summer with Projects Scenario

A Corrective Action Plan is necessary to mitigate the performance issues identified. A North Spokane Transmission Reinforcement project will be developed and proposed to address the performance concerns.

West Plains Transmission Line Outages

A contingency consisting of an outage on the College & Walnut – Westside 115kV Transmission Line and a simultaneous outage on the Garden Springs – Westside 115kV Transmission Line open at Westside results in system overloads. These overloads occur on four 115kV transmission lines, Francis & Cedar – Northwest, Metro – Third & Hatch, Northwest – Westside, and Ross Park – Third & Hatch. Overloads range from 103% to 116% within the five-year horizon assuming all Five-Year Planned Projects are implemented.

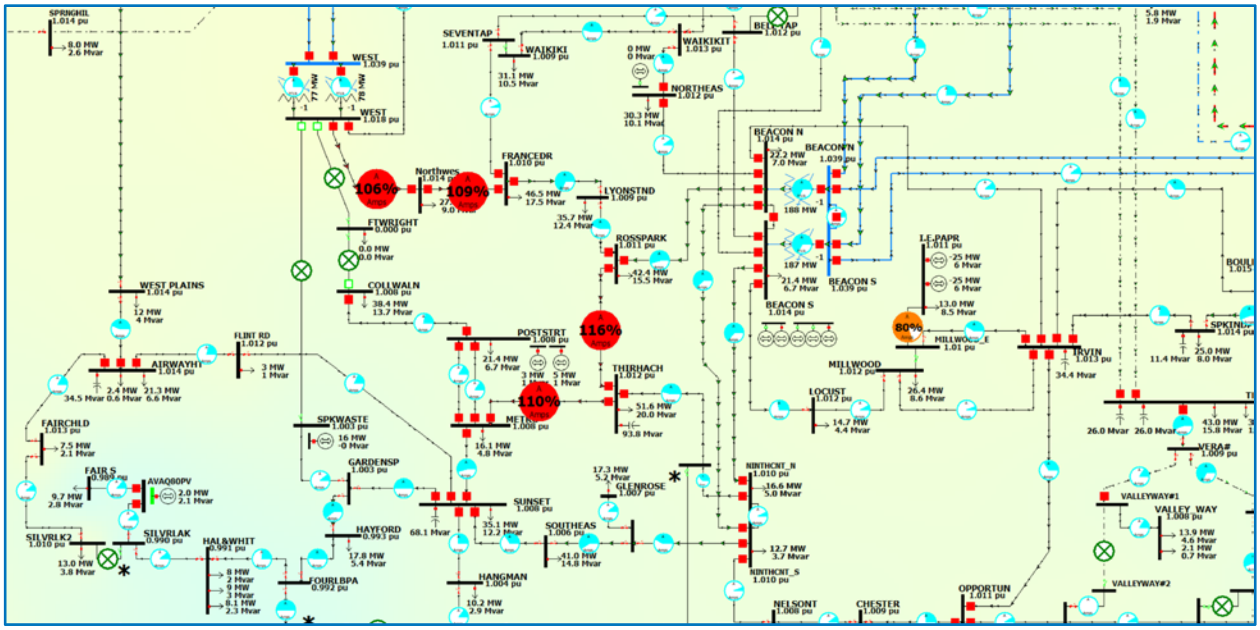

Figure 17: College & Walnut – Westside and Garden Springs – Westside 115kV Transmission Line Open at Westside Outage In 2026 Heavy Summer with Projects Scenario

A Corrective Action Plan is necessary to mitigate the performance issues. An effective Corrective Action Plan will include projects to mitigate the observed overloaded transmission lines and provide improved system resiliency for serving new customer growth in the area. Completion of the Garden Springs Station project, which includes scope to provide a 230kV source into the area, will sufficiently address the identified performance issues. The Garden Springs Station project is planned but will not be completed within the near-term planning horizon.

5.1.1.2. Heavy Winter Scenario (R2.1.1)

Palouse Transformers

The combined outages of the Moscow 230 and Shawnee 230/115kV Transformers cause potential voltage collapse in the Palouse area if there are no mitigating actions taken following the outage of the first transformer. System deficiencies are observed in all scenarios studied but the worst performance occurs in the Heavy Winter scenario. Low voltage issues are also observed for an outage on the Shawnee 230/115kV Transformer 1 and subsequent outage on the Moscow 230 – Terra View 115kV Transmission Line.

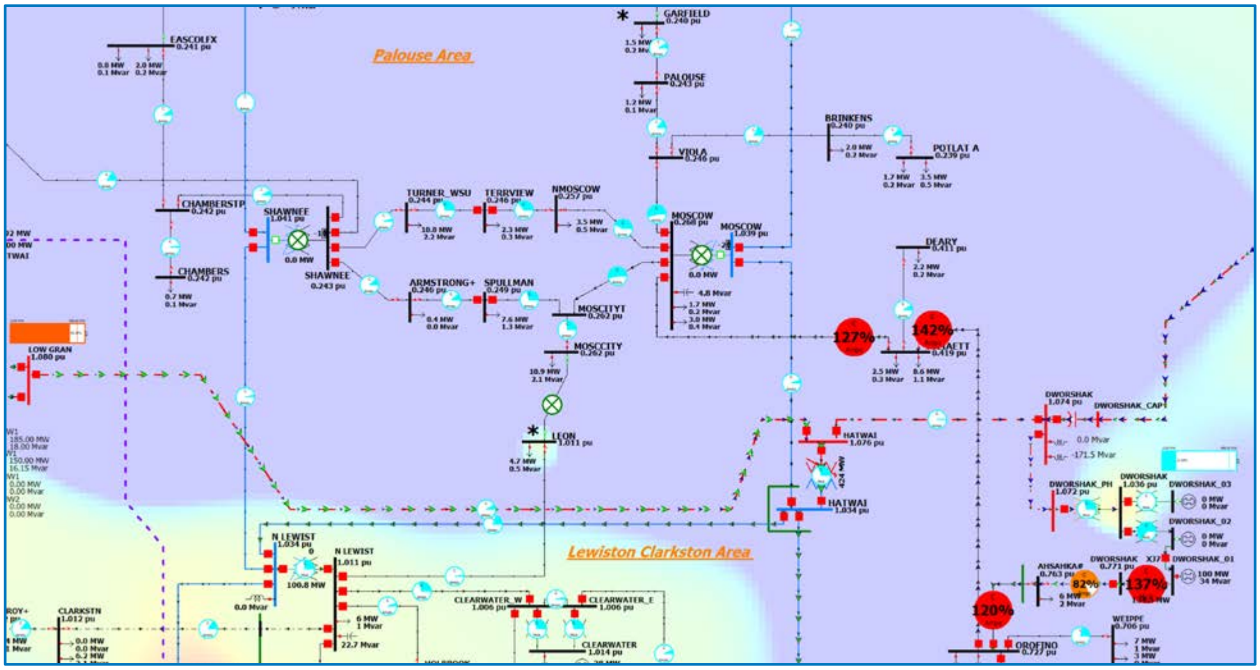

Figure 18: Moscow 230 230/115kV Transformer and Shawnee 230/115kV Transformer Outage In 2028 Heavy Winter with Projects Scenario

An Operating Procedure to reconfigure the system can be used following the first outage of either Moscow 230 230/115kV Transformer 1 or Shawnee 230/115kV Transformer 1. The results of the second transformer outage with the system reconfigured is a system blackout localized to the Palouse area. The Operating Procedure permits the deferral of a Corrective Action Plan to meet the TPL-001-5 requirements. A Palouse Transmission Reinforcement project will be developed to address the performance concerns.

Sandpoint Area Outages

The outage of both the Libby 230/115kV Transformer 1 and Cabinet 230/115kV Transformer 1 will cause the Albeni Falls – Sand Creek 115kV Transmission Line to exceed applicable facility ratings along with low voltage violations in the heavy loading scenarios. The remaining source to the local area is the Albeni Falls – Sand Creek 115kV Transmission Line which is incapable of providing sufficient reactive power support even if shunt capacitors are added at Sand Creek, Bonners Ferry, and Sandpoint Stations.

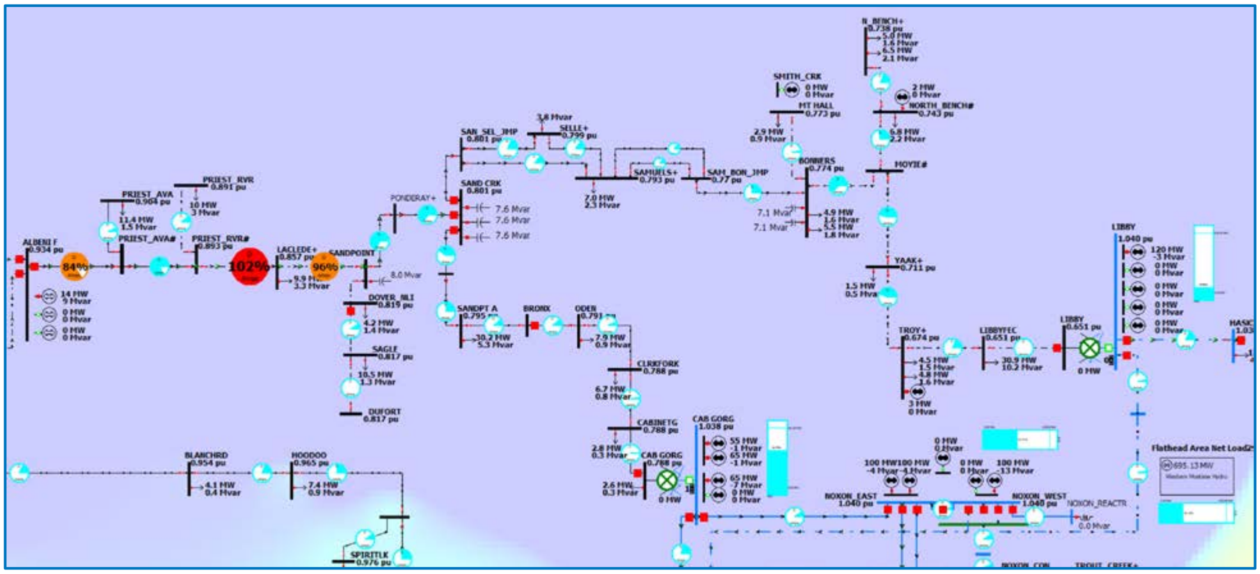

Figure 19: Cabinet 230/115kV Transformer 1 and Libby 230/115kV Transformer 1 Outage In 2028 Heavy Winter with Projects Scenario

A Corrective Action Plan is necessary to mitigate the performance issues as there is not a feasible Operating Procedure to address the performance issues. An effective Corrective Action Plan will include projects to mitigate the observed overloaded transmission lines as well as provide improved system resiliency for serving new customer growth in the area. The Sandpoint Transmission Reinforcement project will be developed to address the performance concerns.

5.1.1.3. Light Spring Scenario (R2.1.2)

Devil's Gap Area Overgeneration

The Addy – Devil's Gap 115kV Transmission Line overloads for the P6 outage of Airway Heights – Devil's Gap and Nine Mile – Westside 115kV Transmission Lines. The Ford – Long Lake – Devil's Gap sections of the Addy – Devil's Gap 115kV Transmission Line was recently rebuilt, but the Devil's Gap A521 CTs continue to be a limiting element. Under P6 conditions, a reduction in local generation is acceptable, therefore an existing Operating Procedure can be used to meet performance requirements.

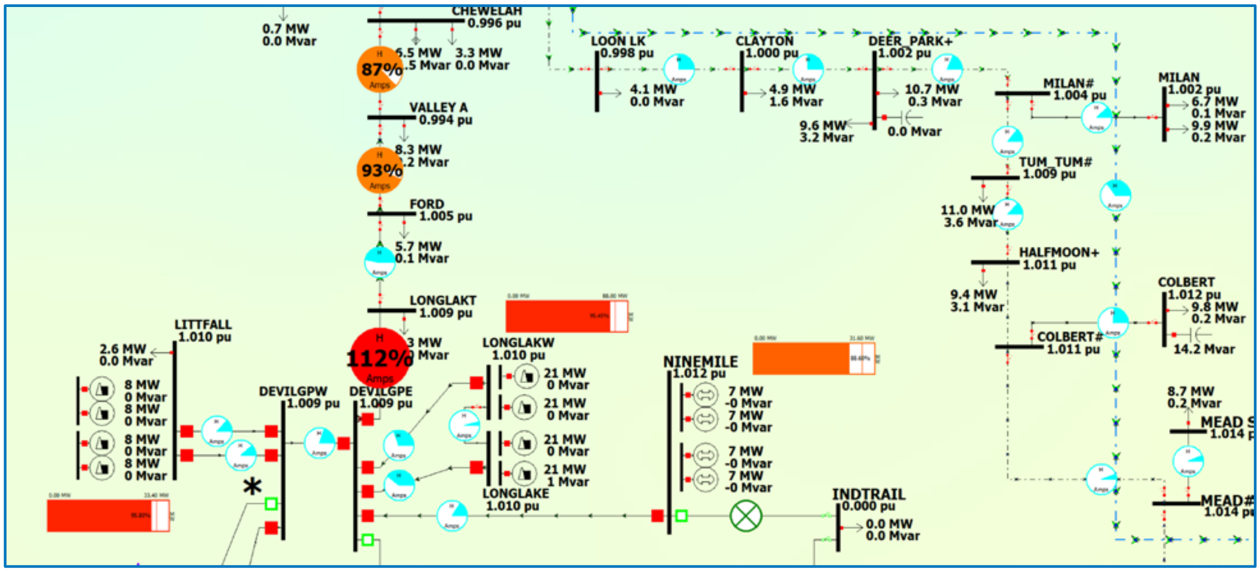

Figure 20: Airway Heights – Devil's Gap and Nine Mile - Westside 115kV Transmission Line Outage In 2024 Light Spring Scenario

Stratford Area Overgeneration

The Chelan – Stratford 115kV Transmission Line overloads based on outage combinations from the Stratford Station. The 49.4 miles long transmission line is composed of 19-#8 CU, 250 CU, and 556.5 ACSR conductor segments resulting in a capacity limitation of 92.4MVA at 40°C. Under P6 conditions, a reduction in local generation is acceptable, therefore an existing Operating Procedure can be used to meet performance requirements until the Chelan – Stratford 115kV Transmission Line is rebuilt based on age and condition.

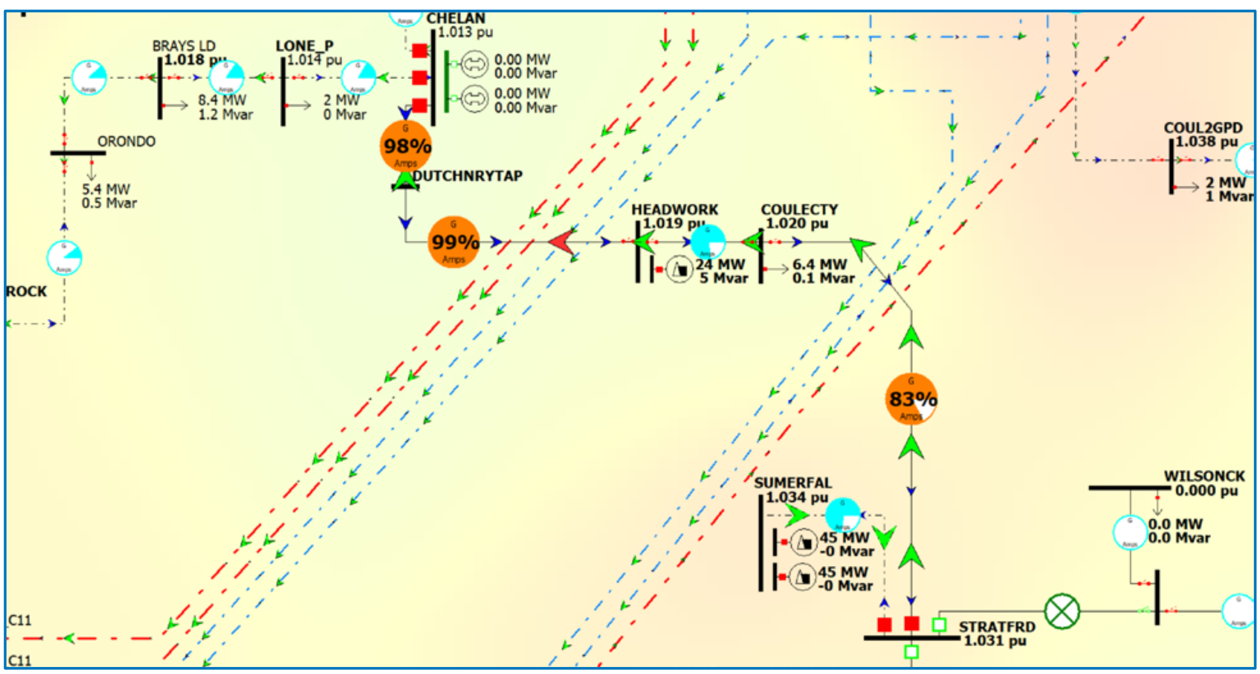

Figure 21: Devil's Gap – Stratford and Larson - Stratford 115kV Transmission Line Outage In 2024 Light Spring Scenario

5.1.1.4. Light Summer High Transfer Sensitivity (R2.1.4)

West of Lancaster Overloads

The Boulder – Rathdrum, Otis Orchards – Post Falls and Post Falls – Ramsey 115kV Transmission Lines overload for the P7 outage of the Beacon – Rathdrum and Lancaster – Rathdrum 230kV double circuit. Similar overloads occur for the P7 outage of Beacon – Rathdrum and Boulder – Lancaster 230kV double circuit outage. There are also multiple N-1-1 (P6) 230kV outage combinations that result in overloading the underlying 115kV system during this condition.

In the past the underlying 115kV system was protected via thermal relays which opened both 115kV lines in the event of an overload. The protection scheme was removed with the loop-in of Lancaster given the action now resulted in an overload of BPA's Bell – Lancaster 230kV Transmission Line.

This has become more of an issue since Avista entered the Energy Imbalance Market (EIM). Prior to entering the EIM, the Rathdrum CTs were rarely on-line during spring runoff (high transfer season). The N-1-1 (P6) issue has shown up in real-time recently during planned outages and the 230kV double circuit (P7) outage issue is now common.

Local generation can be reduced to mitigate N-1-1 contingency issues. A Remedial Action Scheme (RAS) to drop local generation to mitigate the 230kV double circuit (P7) outage issues will be required if future generation is incorporated in the Rathdrum area. This new RAS would be armed based on West of Lancaster flows and would have to be coordinated with BPA and generation at Rathdrum and Lancaster. The Operating Procedure permits the deferral of a Corrective Action Plan to meet the TPL-001-5 requirements.

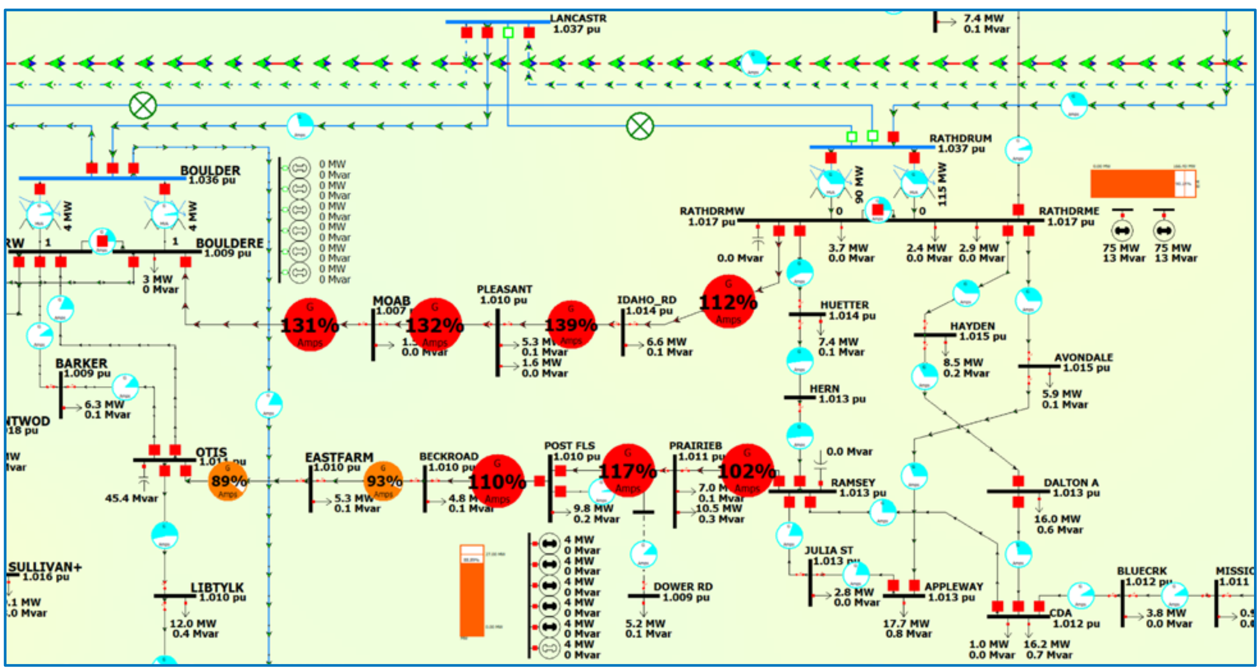

Figure 22: Beacon - Rathdrum and Boulder - Rathdrum 230kV Transmission Line Outage In 2028 Light Summer West of Hatwai (WOH) Scenario

5.1.1.5. Voltage Ride-Through (R3.3.1.1)

Voltage ride-through analysis includes evaluating the tripping of generators where simulations indicate generator bus voltages or high side of the generation step up voltages are less than known or assumed minimum generator steady state or ride-through voltage limits. Voltage ride-through limits are monitored according to PRC-024 – Attachment 2 (TPL-001-5, R3.3.1.1). Analysis shows no instances where generator bus voltages and generation step up voltages exceed PRC-024 limits in the near-term planning horizon.

5.1.1.6. Cascading

Relay Loadability Tripping (R3.3.1.2)

The tripping of transmission elements when relay loadability limits are exceeded was studied for P1 - P7 contingency events. Transmission elements are monitored at 115% of their maximum ratings. Avista's PRC-023 R6 study methodology includes monitoring circuit loading at 130% of the facility rating for double contingency combinations. If transmission elements exceed 130% of the facility rating in the PRC-023 R6 study, then their protection settings are set to not operate at or below 115% of the highest seasonal facility rating. When applicable for P3 and P6 contingency events, mitigation alternatives were evaluated following the first outage to prevent elements from exceeding 115% of their maximum rating following the second outage.

In all scenarios studied, the Beacon – Northeast 115kV Transmission Line and Bell 230/115kV Transformer 6 (P6) outage causes the Beacon – Bell 115kV Transmission Line to exceed 115% of its maximum rating. The subsequent tripping of the Beacon – Bell 115kV Transmission Line separates Avista's system from BPA at Bell and results in voltage collapse in BPA's 115kV system. The observed voltage collapse is contained to the local area and is a known issue on BPA's system. Figure 23 shows the results of the voltage collapse condition. There is a temporary Operating Procedure to reconfigure the system to make a third Beacon – Bell 115kV Transmission Line as an interim measure until a more permanent solution is developed. The Operating Procedure permits the deferral of a Corrective Action Plan to meet the TPL-001-5 requirements. A North Spokane System Reinforcement Planning Initiative will be developed and proposed to address the performance concerns.

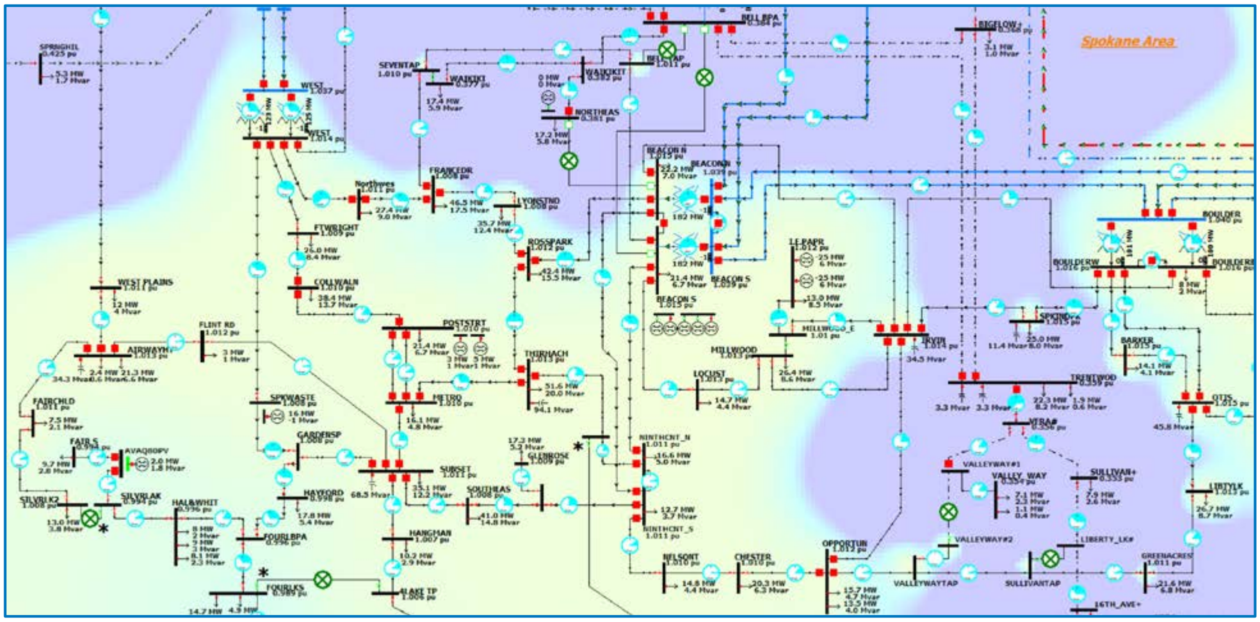

Figure 23: Northwest – Westside 115kV and Bell Bank #6 Followed by Opening Beacon – Bell 115kV in 2028 Heavy Summer with Projects Scenario

The loading of transmission elements exceeding 115% of their maximum facility ratings is provided in Table 6. With mitigation alternatives included between outages of the listed P6 contingency events there was no further tripping of transmission elements to simulate.

Contingency	24LSp	24HS	28HSp	28HS	28HS Projects	28HW
P2						
BF: A624 Rathdrum East & West 115kV						
Otis Orchard - Post Falls 115kV (Beck Road Tap - Post Falls)		745.2				
P6						
N-1: Beacon - Northeast 115kV + T-1: Bell #6 230/115kV						
Beacon - Bell #1 115kV	873.7	879.3	791.1	896.5	895.6	987.5

Table 6: Loading of Transmission Elements Exceeding 115% of Highest Rating in Near-Term Planning Horizon (Amps)

System Instability (WR4[4])

Cascading is identified when a post contingency analysis of category P0 - P7 events result in steady-state facility loading that is either more than a known BES facility trip setting or exceeds 125% of the highest seasonal facility rating for the BES facility studied and when subsequently tripped causes additional facilities to exceed 125% of the highest seasonal facility rating. Table 7 provides the filtered results of the steady state near-term contingency analysis to show only elements exceeding 125% of the monitored seasonal rating.

Contingency	24LSp	24HS	28HSp	28HS	28HS Projects	28LS WOH	28HW
P2							
BF: A624 Rathdrum East & West 115kV							
Otis Orchard - Post Falls 115kV (East Farms Tap - Beck Road Tap)		132.7		129.6	132.8		
Otis Orchard - Post Falls 115kV (East Farms Tap - Otis Orchard)		142.7		139.7	143.0		
Post Falls - Ramsey 115kV (Post Falls - Prairie)		128.6		122.9	127.1		106.1
P6							

[4] WR4 represents the WECC definition of cascading as defined in TPL-001-5. (TPL-001-WECC-CRT-3.2)

Contingency	24LSp	24HS	28HSp	28HS	28HS Projects	28LS WOH	28HW
N-1: Beacon - Bell #1 115kV + T-1: Bell #6 230/115kV							
Beacon - Northeast 115kV	128.8	147.5	116.9	149.6	149.4		112.4
N-1: Beacon - Northeast 115kV + T-1: Bell #6 230/115kV							
Beacon - Bell #1 115kV	165.7	189.5	150.1	192.2	192.0	122.7	145.7
N-1: Beacon - Rathdrum 230kV + N-1: Lancaster - Rathdrum 230kV							
Boulder - Rathdrum 115kV (Boulder - Moab)						131.1	
Boulder - Rathdrum 115kV (Moab - Pleasant)						132.5	
Boulder - Rathdrum 115kV (Pleasant - Idaho Rd)						138.9	
N-1: Bell - Northeast 115kV + T-1: Bell #6 230/115kV							
Beacon - Bell #1 115kV	142.9	130.0	119.4	130.0	129.9	101.9	109.2
N-1: Cabinet - Rathdrum 230kV + N-1: Noxon - Pine Creek 230kV							
NOXON_WEST (40787) -> LANCASTR (40624) CKT 1 at NOXON_WEST			132.7			124.0	
P7							
N-2: Beacon - Rathdrum 230kV & Boulder - Lancaster 230kV							
Boulder - Rathdrum 115kV (Pleasant - Idaho Rd)						130.2	
N-2: Beacon - Rathdrum 230kV & Lancaster - Rathdrum 230kV							
Boulder - Rathdrum 115kV (Boulder - Moab)						131.1	
Boulder - Rathdrum 115kV (Moab - Pleasant)						132.5	
Boulder - Rathdrum 115kV (Pleasant - Idaho Rd)						138.9	

Table 7: Facility Loading Exceeding 125% Of Seasonal Rating in Near-Term Planning Horizon (%)

The Rathdrum A-624 breaker failure contingency causes the Otis Orchards – Post Falls and Post Falls – Ramsey 115kV Transmission Lines to exceed 125% of their seasonal rating. Load in the Coeur d'Alene area directly impacts the loading of the remaining transmission lines following the outage. Subsequent tripping of the Otis Orchards – Post Falls 115kV Transmission Line causes the CdA 15th St. – Pine Creek 115kV Transmission Line to exceed 125% of its seasonal rating with a localized voltage collapse in the Coeur d'Alene area. Figure 24 shows the results of the cascading condition. A Corrective Action Plan is necessary to address the performance issues.

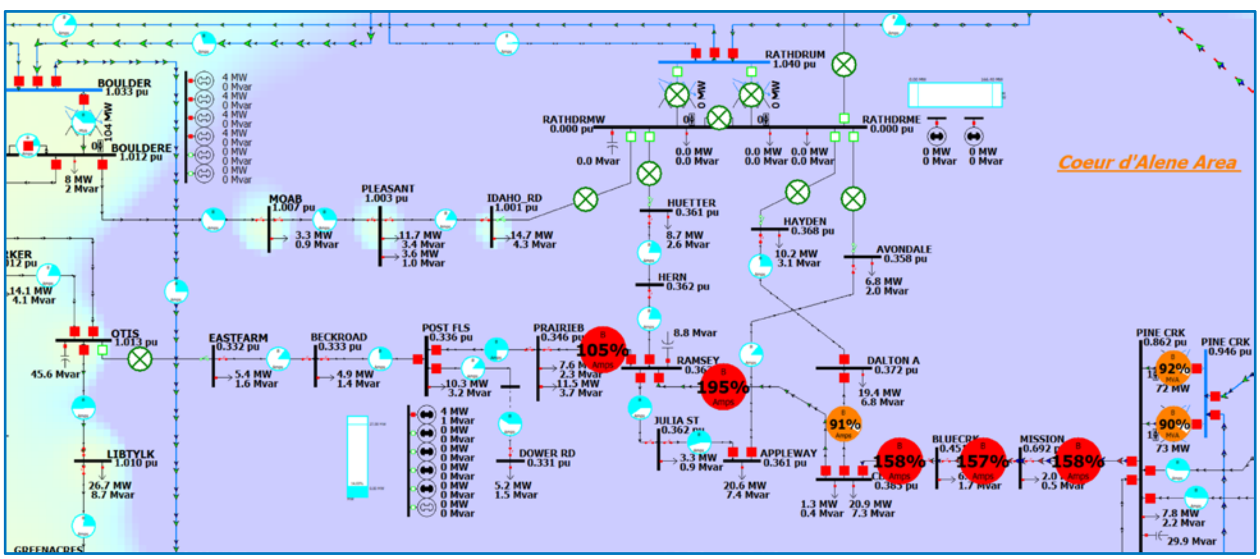

Figure 24: Rathdrum A-624 Breaker Failure Followed by Opening Otis Orchards – Post Falls in 2028 Heavy Summer with Projects Scenario

The N-1-1 (P6) Bell 230/115kV Transformer 6 outage paired with various local 115kV transmission lines causes the remaining 115kV lines between Beacon and Bell to exceed 125% of their seasonal rating. The subsequent tripping of the remaining 115kV transmission lines separates Avista's system from BPA at Bell and results in voltage collapse in BPA's

115kV system but does not result in the remaining transmission lines to exceed 125% of their seasonal ratings. Figure 25 shows the results of the cascading condition. A Corrective Action Plan is not necessary to address the performance issues as an Operating Procedure can be used, though the system issues mentioned above, will warrant a solution to this deficiency.

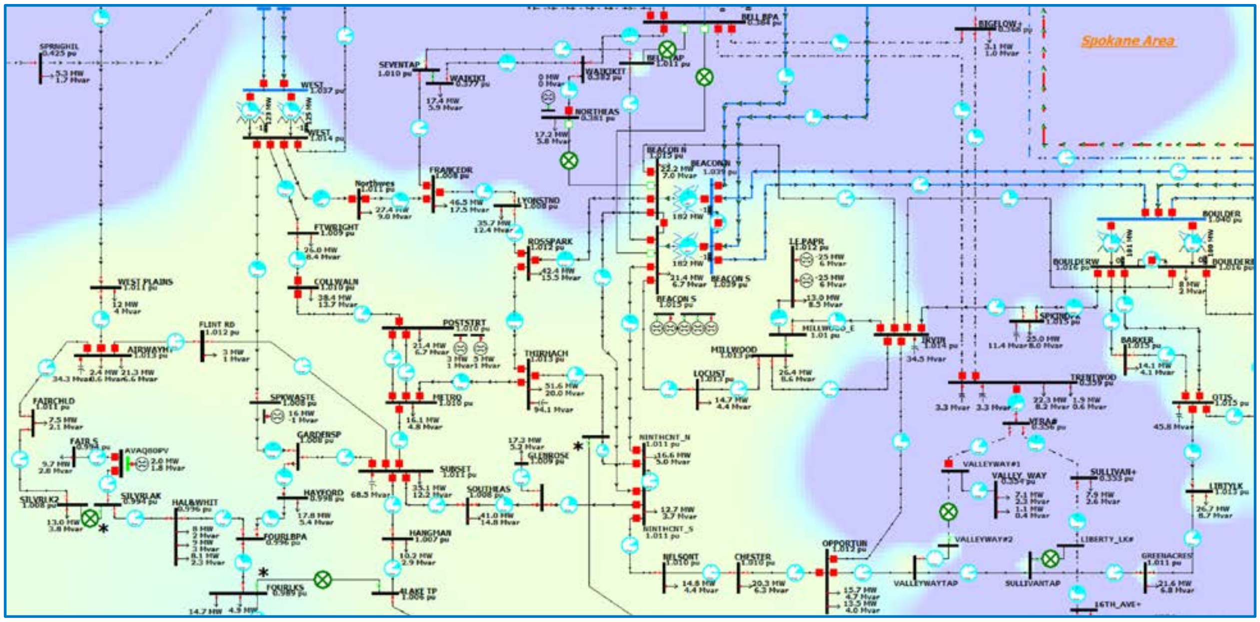

Figure 25: Bell #6 and a Second 115kV Local Outage Followed by Opening the Remaining Beacon to Bell 115kV Transmission Line in 2028 Heavy Summer with Projects Scenario

The remaining N-1-1 (P6) and N-2 (P7) issues associated with the 2028 Light Summer High Transfer scenario are addressed in Section 5.1.1.4 above.

With mitigation alternatives included between outages of the listed P6 contingency events in Table 7, there was no further tripping of transmission elements to simulate.

5.1.1.7. Unsolved

The P1 – P7 contingency events in the near-term planning horizon were monitored for unsolved power flow solutions. The results are provided in Table 8.

Contingency	24LSp	24HS	28HSp	28HS	28HS Projects	28LS WOH	28HW
A6							
N-1: Albeni Falls - Sand Creek 115kV Open @ ALB + N-1: Bronx - Cabinet 115kV		unsolved		unsolved	unsolved		116.3
N-1: Albeni Falls - Sand Creek 115kV Open @ ALB + N-1: Bronx - Sand Creek 115kV							unsolved
N-1: Albeni Falls - Sand Creek 115kV Open @ ALB + T-1: Cabinet Gorge 230/115kV		148.4		149.8	149.8		unsolved
A7							
N-1: Albeni Falls - Sand Creek 115kV Open @ ALB + N-2: Flathead - Libby 230kV & Libby - Noxon 230kV							unsolved
N-1: Brownlee - Hells Canyon 230kV + N-2: Flathead - Libby 230kV & Libby - Noxon 230kV			unsolved	unsolved	unsolved	unsolved	
N-1: Columbia Falls - Flathead 230kV + N-2: Conkelley - Libby 230kV & Libby - Noxon 230kV	unsolved	154.6					
N-1: Flathead - Hot Springs 230kV + N-2: Flathead - Libby 230kV & Libby - Noxon 230kV			217.1				unsolved
N-2: Albeni Falls - Sand Creek 115kV & Bronx - Sand Creek 115kV + N-1: Flathead - Libby 230kV							unsolved

Contingency	24LSp	24HS	28HSp	28HS	28HS Projects	28LS WOH	28HW
N-2: Albeni Falls - Sand Creek 115kV & Bronx - Sand Creek 115kV + T-1: Hungry Horse #1 230/13.8kV							unsolved
N-2: Brownlee - Hells Canyon 230kV & Lolo - Oxbow 230kV + N-2: Flathead - Libby 230kV & Libby - Noxon 230kV			unsolved	unsolved	unsolved	unsolved	

Table 8: Steady State Near-Term Unsolved Contingency Results in Near-Term Planning Horizon

There were no P1 – P7 contingency events in the near-term planning horizon that resulted in an unsolved power flow solution. The restoration contingencies are shown above for reference.

For reference, the A6 contingency of the Albeni Falls – Sand Creek 115kV Transmission Line open at Albeni Falls and Cabinet Gorge 230/115kV Transformer 1 led to an unsolved condition applicable to Avista. The resulting power flow condition is shown in Figure 26. A localized voltage collapse occurs in the Sandpoint area with the load being served only from Libby Station, located roughly 90 miles away.

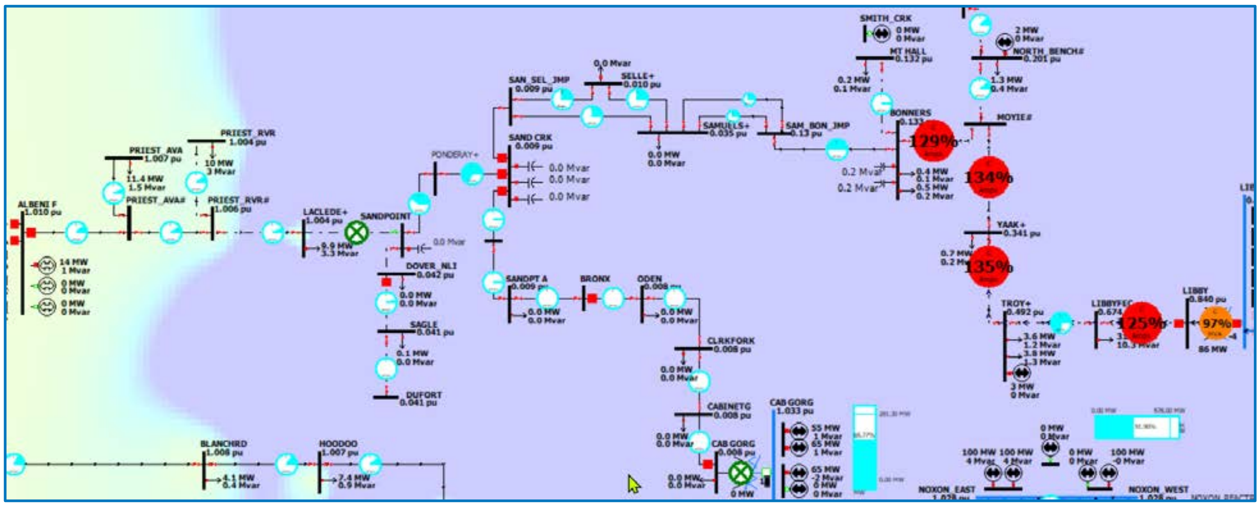

Figure 26: Unsolved Condition for N-1: Albeni Falls - Sand Creek 115kV + T-1: Cabinet Gorge 230/115kV in 2026 Heavy Winter Scenario

5.1.2. Extreme Events (R3.2)

The following sections describe the study results from the steady state contingency analysis for contingencies categorized as extreme events in the near-term planning horizon.

5.1.2.1. Right-of-Way Outages

The transmission line right-of-way south of Westside Station contains the College & Walnut – Westside and Sunset – Westside 115kV Transmission Lines. The Sunset – Westside 115kV Transmission Line will become the Garden Springs – Westside 115kV Transmission Line following completion of the Garden Springs Station Project. An outage of both transmission lines in the right-of-way causes facilities to exceed their applicable facility ratings. Figure 27 shows the simulation result for the 2028 Heavy Summer scenario. Cascading was not observed.

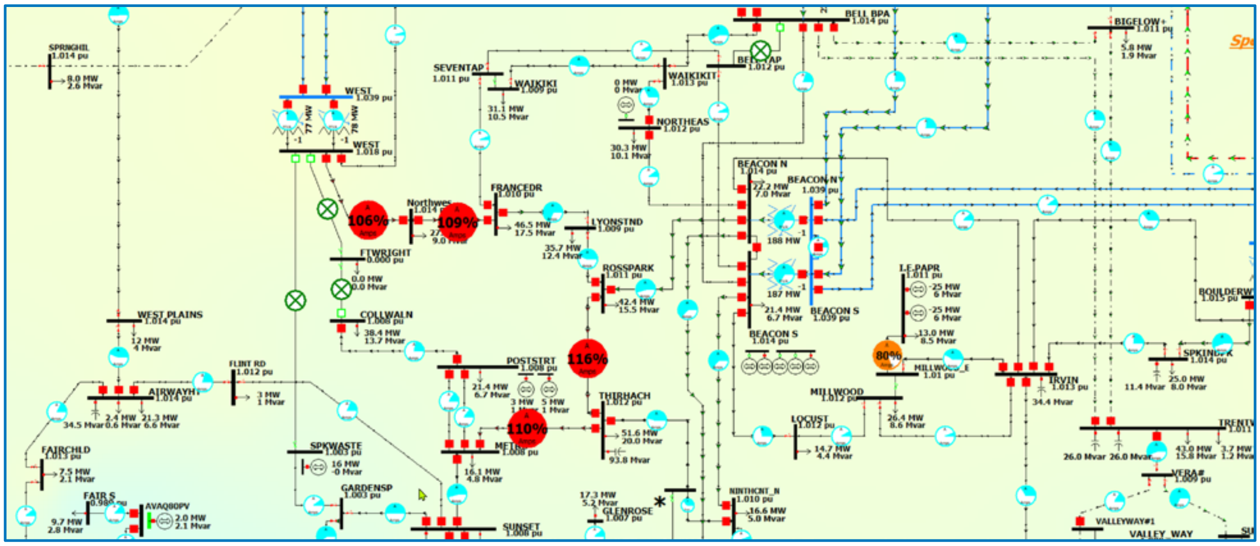

Figure 27: College & Walnut - Westside 115kV and Garden Springs - Westside 115kV Right-Of-Way Extreme Event In 2028 Heavy Summer with Projects Scenario

In the Heavy Spring, Heavy Summer, and High Transfer scenarios, the right-of-way outage west of Lancaster Station causes the underlying 115kV transmission system to exceed applicable facility ratings. Generation located east of the area contributes to the overload condition. Figure 28 shows the simulation result for the 2028 Heavy Spring scenario. Cascading was not observed.

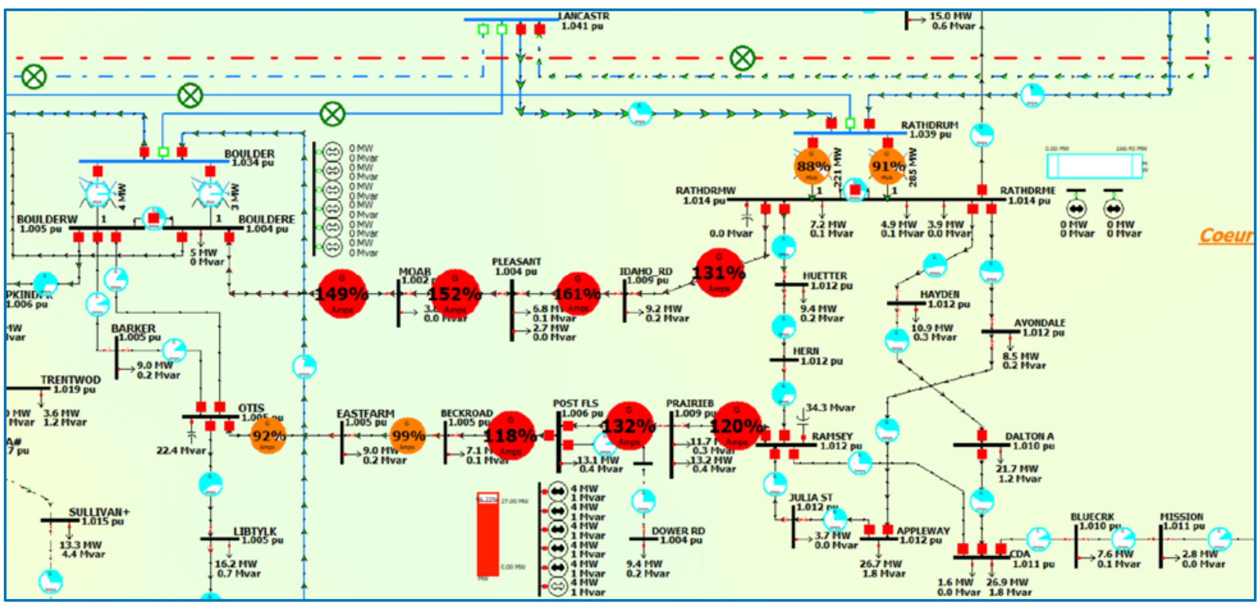

Figure 28: Bell - Taft 500kV And Bell - Lancaster 230kV And Beacon - Rathdrum 230kV And Boulder - Lancaster 230kV Right-of-Way Extreme Event in 2028 Heavy Spring with Project Scenario

5.1.2.2. Station Outages

The entire loss of either the Bell or Beacon Station was the most severe extreme contingency and the only extreme event whose impact was not completely mitigated by applying available measures. Either event is considered to have an extremely low probability of occurrence. If either event were to occur, it is likely to progress with intermediate steps allowing Operating Procedures to minimize the impact to the transmission system.

5.1.3. Voltage Stability

5.1.3.1. Maximum Power Transfer Analysis

A load ramp maximum power transfer analysis was conducted for five geographic areas in Avista's electric system. The load in each area was increased until voltage collapse occurred. All additional generation necessary to supply the increase in load came from a distribution of all generation in WECC. The following sections provide the analysis results including identification of critical buses to be further analyzed for adequate reactive power margin.

The limiting contingency in the Big Bend Area is a breaker failure on the Larson – Sand Dunes – Warden 115kV Transmission Line at Grant County PUD's Larson Station with total area load of 807MW. The critical bus for the area is the Odessa Station. Recently completed projects, including projects associated with Saddle Mountain and Rattlesnake Flats, have improved the system performance in the area.

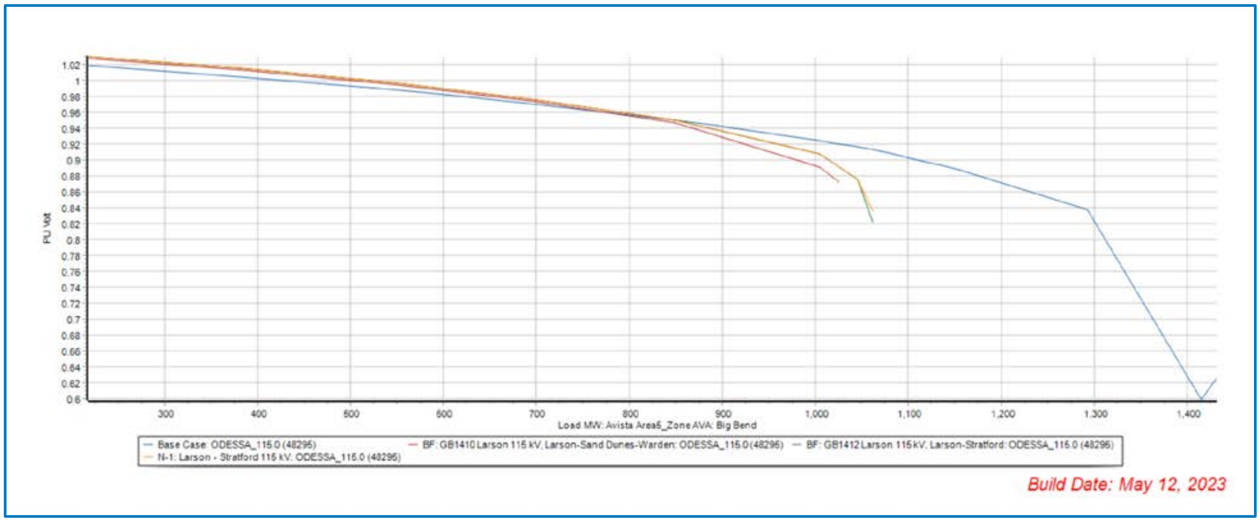

Figure 29: Big Bend Area Maximum Power Transfer Analysis Results

The limiting contingency in the Coeur d'Alene Area is a tie breaker failure on the Rathdrum Station 115kV buses with total area load of 619MW. The critical bus for the area is the Hayden Station. Recently completed projects, including the Magic Corner and Coeur d'Alene 15th St. – Pine Creek 115kV Transmission Line Rebuild projects, have improved the system performance in the area.

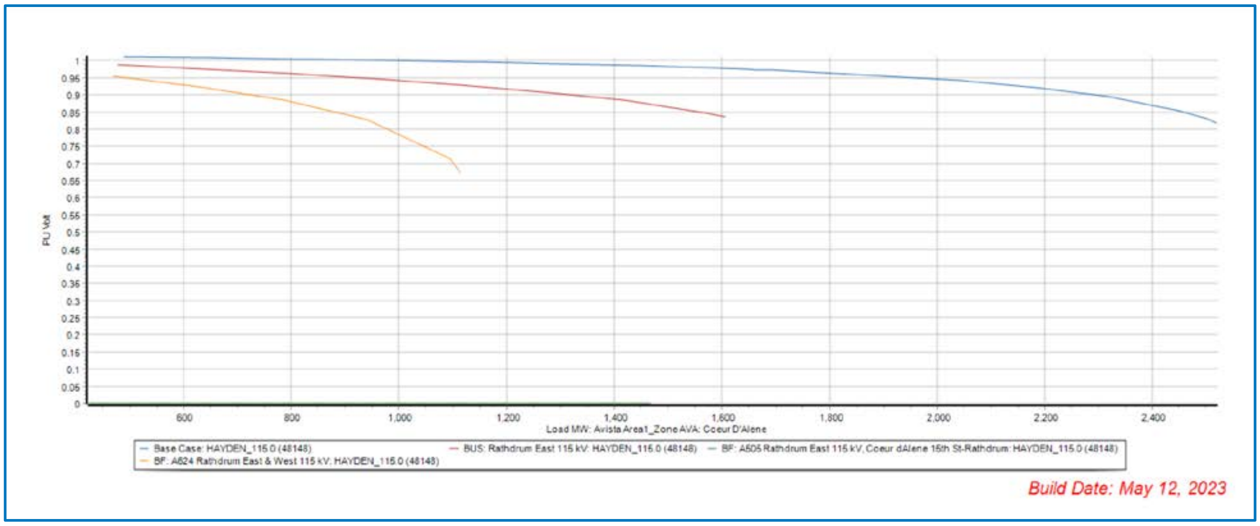

Figure 30: Coeur d'Alene Area Maximum Power Transfer Analysis Results

The limiting contingency in the Lewis-Clark Area is a breaker failure on the Clearwater – Lolo 115kV Transmission Line at Lolo Station with total area load of 319MW. The critical bus for the area is the East Grangeville Station.

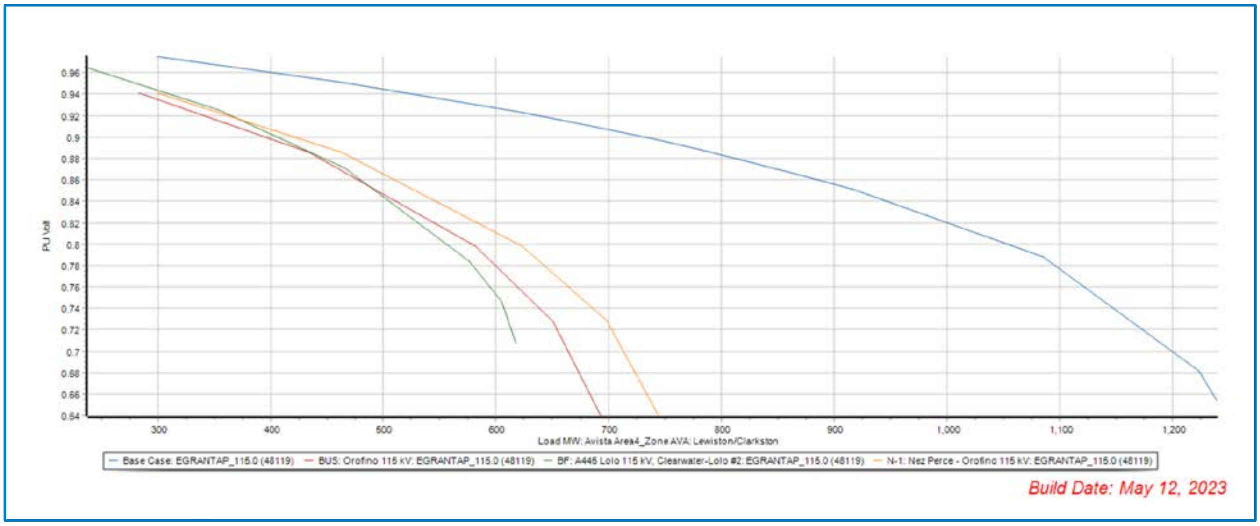

Figure 31: Lewis-Clark Area Maximum Power Transfer Analysis Results

The limiting contingency in the Palouse Area is the loss of the Moscow 230 230/115kV Transformer 1 with total area load of 458MW. The critical bus for the area is the Garfield Station.

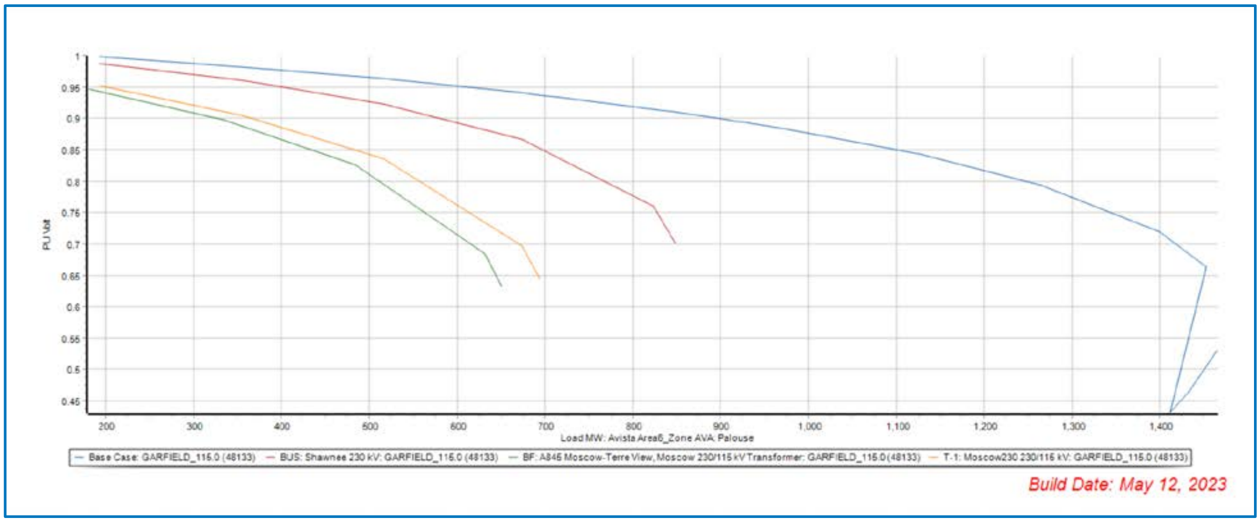

Figure 32: Palouse Area Maximum Power Transfer Analysis Results

The limiting contingency in the Spokane Area is the is the tie breaker failure on the Beacon Station 115kV buses with total area load of 1,135MW. The critical bus for the area is the Cheney Station.

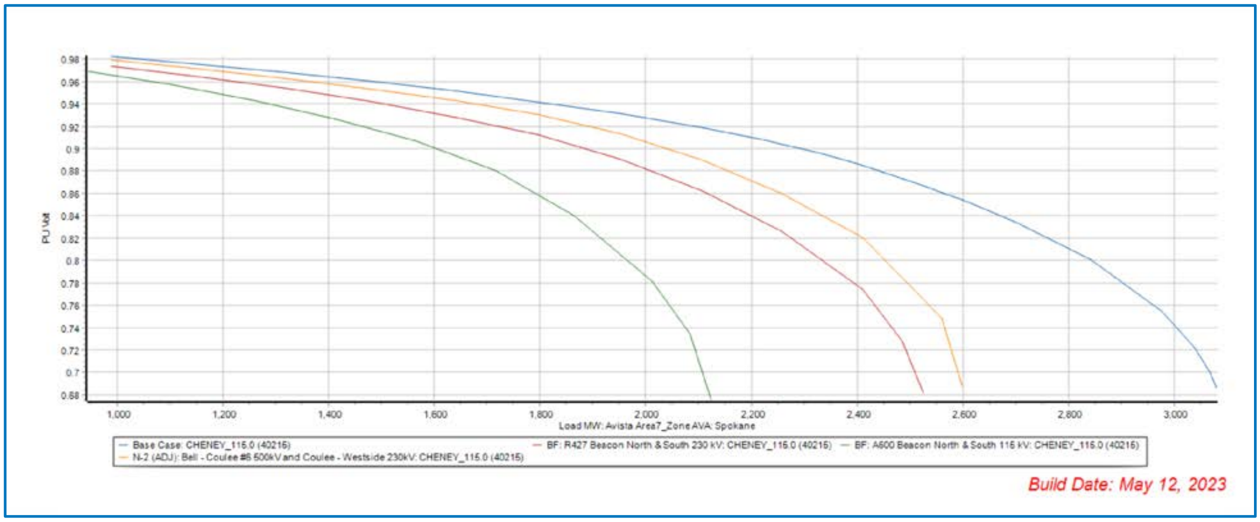

Figure 33: Spokane Area Maximum Power Transfer Analysis Results

5.1.3.2. Reactive Power Injection (QV) Analysis

The reactive power and voltage relationship show the sensitivity and variation of bus voltages with respect to reactive power injections or absorptions. A system is considered stable, with respect to voltage, if QV sensitivity is positive for every bus. Positive reactive margin is an indication of the transmission system's ability to maintain voltage stability. Low reactive margin (below 200Mvar at any 230kV bus or any 230/115kV source on the low side) is considered marginal and is indicative of potential system concerns with voltage instability.

The critical buses identified in the maximum power transfer analysis and 115kV buses of 230/115kV transformers were studied in a QV analysis. The QV analysis showed there is adequate reactive margin for the 115kV source buses and critical buses for each of the areas studied. All buses studied showed a positive reactive margin. The East Grangeville Station was shown to have the lowest reactive margin in Avista transmission system with all lines in service and under a contingency event. The 115kV bus at Shawnee Station was shown to have 113Mvar of reactive margin under the P6 event of both the Shawnee 230/115kV Transformer 1 and Moscow 230 230/115kV Transformer 1. The reactive margin is adequate but should continue to be monitored in subsequent study efforts.

Table 9 through Table 13 provide tabulated results of the QV analysis. Buses highlighted in orange indicate they were the critical buses identified from the maximum power transfer analysis. Reactive margin results less than 200Mvar are highlighted in red.

	Base Case	BF: GB-1410 Larson 115kV, Larson-Sand Dunes-Warden	BF: GB1412 Larson 115kV, Larson-Stratford	N-1: Larson - Stratford 115kV
Odessa 115kV	-99	-53	-54	-54
Saddle Mountain 115kV	-841	-812	-816	-837

Table 9: Big Bend Area QV Analysis Results (Mvar)

	Base Case	BF: A505 Rathdrum East 115kV, Coeur d'Alene 15th St-Rathdrum	BF: A624 Rathdrum East and West 115kV	BUS: Rathdrum East 115kV
Cabinet Gorge 115kV	-390	-387	-381	-385
Hayden 115kV	-686	NA	-152	-234
Pine Creek	-628	-611	-538	-601
Rathdrum	-1080	NA	NA	NA

Table 10: Coeur d'Alene Area QV Analysis Results (Mvar)

	Base Case	BF: A445 Lolo 115kV, Clearwater-Lolo #2	BUS: Orofino 115kV	N-1: Nez Perce - Orofino 115kV
Dry Creek 115kV	-833	-717	-812	-817
East Grangeville 115kV	-84	-62	-48	-84
Lolo 115kV	-1047	NA	-957	-965
North Lewiston 115kV	-860	-702	-835	-841

Table 11: Lewis-Clark Area QV Analysis Results (Mvar)

	Base Case	BF: A845 Moscow-Terre View, Moscow 230/115kV Transformer	T-1: Moscow230 230/115kV	BUS: Shawnee 230kV
Benewah 115kV	-384	-384	-383	-370
Moscow 115kV	-652	-163	-219	-476
Garfield 115kV	-114	-70	-80	-106
Shawnee 115kV	-554	-388	-384	-200

Table 12: Palouse Area QV Analysis Results (Mvar)

	Base Case	BF: A600 Beacon North and South 115kV	N-2: Bell - Westside 230kV and Coulee - Westside 230kV	BF: R427 Beacon North and South 230kV
Beacon 115kV	-1417	NA	-1118	-948
Boulder 115kV	-1234	-1000	-1105	-987
Cheney 115kV	-208	-181	-185	-196
Westside 115kV	-1131	-771	-575	-977

Table 13: Spokane Area QV Analysis Results (Mvar)

5.1.4. Known Outages (R2.1.4, R2.4.4)

Avista incorporates a three-step process to identify known outages of generation or Transmission Facilities that are planned in the Near-Term Planning Horizon that may result in system issues and then assesses the impact of selected known outages on System performance.

- Generate a current list of planned outages of generation and Transmission Facilities in the Near-Term Planning Horizon from the RC West webSmartOMS identifying all system outages beginning January 1, 2024, through December 31, 2028.
    - This is consistent with the documented outage coordination procedure RC0630 detailing the Outage Coordination Process.
- Identify planned outages from the RC West outage list that may result in system issues based on existing near-term planning contingency results.
    - If a planned outage results in potential system issues, verify that the planned outage is scheduled during shoulder month loading.
- Perform assessment for the P0 and P1 categories identified with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned.

Planned outages of generation or Transmission Facilities are listed in Table 14.

Coordinated Planned Outage	Season and Duration	Known System Issues	Assessment Results
DWORSHAK PH: PCB XJ-7	WIN: 1 hour	None	Not required
MIDWAY-BENTON NO 1 115KV LINE	WIN: 20 days	None	Not required
TUCANNON RIVER: 115KV CAP GROUP 1 and 2	SPR: 11 days	None	Not required
TAFT-BELL NO 1 500KV LINE	SPR: 1 day	None	Not required
HUNGRY HORSE-CONKELLEY NO 1 230KV LINE	SUM: 4 days	None	Not required
GARRISON: 500_230KV TRANSFORMER 1	SUM: 10 days	None	Not required
HUNGRY HORSE-COLUMBIA FALLS NO 1 230KV LINE	SUM: 4 days	None	Not required
LITTLE GOOSE PH-LITTLE GOOSE NO 1 500KV LINE	SUM: 4 days	None	Not required
DWORSHAK PH-DWORSHAK NO 1 500KV LINE	FAL: 3 days	None	Not required
MIDWAY-BENTON NO 2 230KV LINE	FAL: 5 days	None	Not required

Table 14: Near-Term Planned Outage System Issues and Results

Studies determined that no known outages of Generation or Transmission Facilities, planned in the Near-Term Planning Horizon, resulted in system issues that requires those outages to be included in this System Assessment.

5.1.5. Spare Equipment (R2.1.5)

Avista's spare equipment strategy for transmission facilities provides for spares of the following equipment: 230/115kV transformers, GSU transformers, transmission UG cable, HV circuit breakers, HV air switches, shunt reactors and shunt capacitors.

Steady state analysis was performed on the transmission system models representing the near-term planning horizon to study the impact of possible unavailability of Avista's 230/115kV transformers and select other transformers. Category P0, P1 and P2 planning events were evaluated with the pre-existing condition of a transformer outage for the following:

- Beacon 1 and 2
- Bell 6 (BPA)
- Benewah
- Boulder 1 and 2
- Cabinet Gorge
- Dry Creek
- Dworshak (USACE)
- Hatwai (BPA)
- Libby (BPA)
- Lolo 1 and 2
- Moscow 230
- North Lewiston
- Pine Creek 1 and 2
- Rathdrum 1 and 2
- Saddle Mountain
- Shawnee
- Westside 1 and 2

The following sections describe the study results not previously addressed in the near-term planning analysis.

5.1.5.1. Big Bend Area

A Saddle Mountain 230/115kV Transformer outage resulted in no system performance issues. However, generation from Rattlesnake Flats and Lind Solar could be curtailed per SOP-21.

5.1.5.2. Coeur d'Alene Area

In addition to Cabinet and Libby 230/115kV outages already identified, outages for either transformer and subsequent outages involving Albeni Falls – Priest River or Albeni Falls – Sand Creek 115kV Transmission Lines result in area voltage collapse. These issues also will be addressed as part of the Sandpoint Reinforcement Project Corrective Action Plan.

5.1.5.3. Spokane Area

Outages of either Beacon 230/115kV transformer and subsequent outage involving Bell 6 results in overload of the remaining Beacon unit. Outages of both Beacon units results in overload of the Bell 6 unit as well as Francis and Cedar – Northwest and Northwest – Westside 115kV Transmission Lines.

Outages of either Beacon 230/115kV transformer and subsequent outage of the Bell – Westside 230kV Transmission Line results in overload of the remaining Beacon unit. These overloads are mitigated with the completion of the Garden Springs Station Project.

Outages of either Beacon 230/115kV transformer and subsequent outages of a Bell 230kV bus tie breaker results in overload of the remaining Beacon unit. The performance issues associated with both Beacon and Bell stations will be addressed as part of the North Spokane and Beacon Transmission Reinforcement Projects.

Outages of either Boulder 230/115kV transformer and a subsequent outage involving for the Beacon 115kV bus tie breaker results in overloads of the College and Walnut – Westside 115kV and Francis and Cedar – Northwest 115kV Transmission Lines. Additionally, outages of either transformer in addition to a subsequent outage involving the Beacon 230kV bus tie breaker results in overloads on the Bell – Northeast 115kV Transmission Line. These overloads are mitigated with the completion of the Garden Springs Station Project.

Outages of either Westside 230/115kV transformer and subsequent outages involving Beacon 230 or 115kV buses or Ninth & Central 115kV buses results in overloads of Ross Park – Third & Hatch and Metro – Third & Hatch 115kV Transmission Lines. These overloads are mitigated with the completion of the Garden Springs Station Project.

Outages of either Westside 230/115kV transformer and subsequent outage for the Beacon 230kV bus tie breaker results in overload of the Bell 230/115kV Transformer 6.

Outages of both Westside 230/115kV transformers results in overload of the Metro – Third & Hatch 115kV Transmission Line and Bell 230/115kV Transformer 6. The Metro – Third & Hatch 115kV Transmission Line overload is mitigated with the completion of Garden Springs Station Project.

5.2. Transmission Steady State Long-Term Analysis (R2.2)

Steady state analysis was performed on the transmission system models representing the long-term planning horizon which represented the Heavy Summer scenario. If the analysis indicates an inability of the System to meet the performance requirements, the System Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. (TPL-001-5, R2.7)

5.2.1. Planning Events (R3.1)

The steady-state analysis of system normal conditions, described as the P0 event, demonstrated all BES facilities in the Avista system are within the continuous thermal ratings and all transmission facility voltages are within the specified limits. The following sections describe the study results from the steady state contingency analysis for contingencies categorized as P1 – P7. Many of the performance issues identified in the near-term planning horizon still existing in the long-term planning horizon even with expected projects represented in the models.

5.2.1.1. Bell 230/115kV Transformer 6 Outage

A contingency consisting of an outage of the Bell 230/115kV Transformer 6 results in system overloads on the remaining 115kV transmission line between Beacon and Bell stations. This overload is a result of the stronger source with the West Plains reinforcement at Garden Springs.

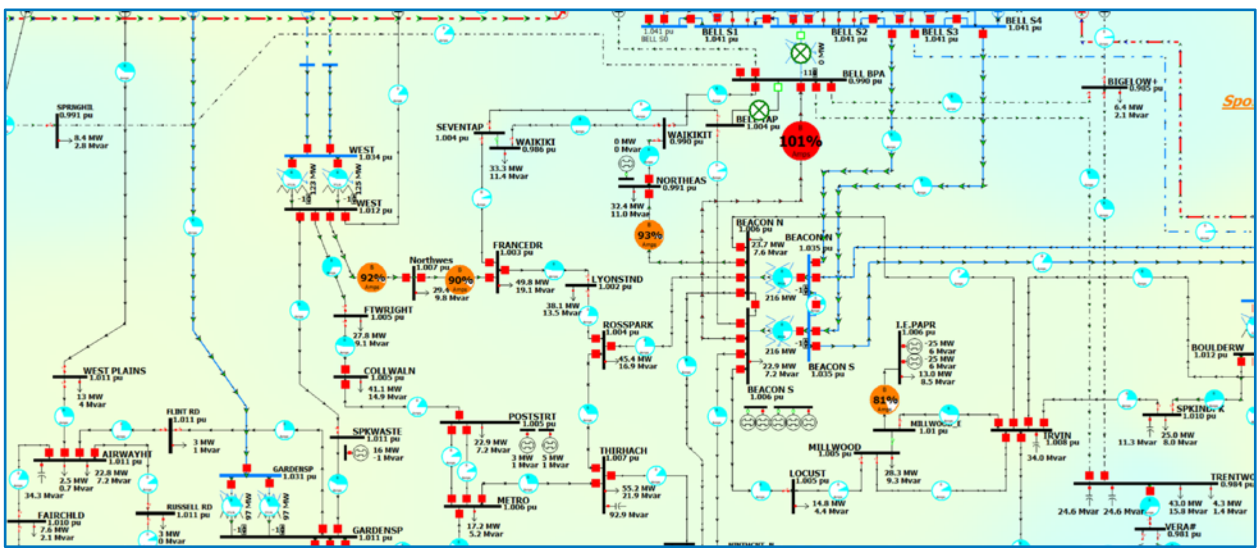

Figure 34: Bell 230/115kV Transformer 6 in 2033 Heavy Summer

Additionally, there are multiple N-1-1 (P6) 115kV outage combinations in the north Spokane area that result in line overloads.

As discussed in the near-term planning section, a North Spokane System Reinforcement Planning Initiative will be developed and proposed to address the performance concerns.

5.2.1.2. Voltage Ride-Through (R3.3.1.1)

Voltage ride-through analysis includes evaluating the tripping of generators where simulations show generator bus voltages or high side of the generation step up voltages are less than known or assumed minimum generator steady state or ride-through voltage limitations. Voltage ride-through limits are monitored according to PRC-024 – Attachment 2 (TPL-001-5, R3.3.1.1). Analysis shows no instances where generator bus voltages and generation step up voltages exceed PRC-024 limits in the long-term planning horizon.

5.2.1.3. Cascading

Relay Loadability Tripping (R3.3.1.2)

The tripping of transmission elements where relay loadability limits are exceeded was studied for P1 – P7 contingency events. No performance issues were identified beyond those observed in the near-term planning horizon. The loading of transmission elements exceeding 115% of their maximum facility ratings is provided in Table 15. With mitigation alternatives included between outages of the listed P6 contingency events there was no further tripping of transmission elements to simulate.

Contingency	33HS
P2	
BF: A624 Rathdrum East & West 115kV	
Otis Orchard - Post Falls 115kV (Beck Road Tap - Post Falls)	771.2
Post Falls - Ramsey 115kV (Post Falls - Prairie)	711.8
P6	
N-1: Beacon - Northeast 115kV + T-1: Bell #6 230/115kV	
Beacon - Bell #1 115kV	984.0

Table 15: Loading of Transmission Elements Exceeding 115% of Highest Rating in Long-Term Planning Horizon (Amps)

System Instability (WR4)

Cascading is identified when a post contingency analysis of category P0 - P7 events result in steady-state facility loading that is either more than a known BES facility trip setting or exceeds 125% of the highest seasonal facility rating for the BES facility studied and when subsequently tripped causes additional facilities to exceed 125% of the highest seasonal facility rating. Table 16 provides the filtered results of the steady state long-term contingency analysis to show only elements exceeding 125% of the monitored seasonal rating.

Contingency	33HS
P2	
BF: A506 Rathdrum 115kV, Pine Street-Rathdrum	
Ramsey - Rathdrum #1 115kV (Huetter - Rathdrum)	**126.1**
BF: A624 Rathdrum East & West 115kV	
Otis Orchard - Post Falls 115kV (Beck Road Tap - Post Falls)	**145.3**
Otis Orchard - Post Falls 115kV (East Farms Tap - Beck Road Tap)	**155.0**
Otis Orchard - Post Falls 115kV (East Farms Tap - Otis Orchard)	**166.0**
Post Falls - Ramsey 115kV (Post Falls - Prairie)	**149.9**
BUS: Rathdrum East 115kV	
Ramsey - Rathdrum #1 115kV (Huetter - Rathdrum)	**125.9**
P6	
N-1: Appleway - Rathdrum 115kV + N-1: Dalton - Rathdrum 115kV	
Ramsey - Rathdrum #1 115kV (Huetter - Rathdrum)	**125.9**
N-1: Beacon - Bell #1 115kV + T-1: Bell #6 230/115kV	
Beacon - Northeast 115kV	**164.1**
Bell - Northeast 115kV (Waikiki Tap - Northeast)	**132.0**

Table 16: Facility Loading Exceeding 125% of Seasonal Rating in Long-Term Planning Horizon (%)

Additional contingencies related to the Rathdrum Station in the long-term planning horizon show facility loading exceeding 125% of the highest seasonal facility rating. The tripping of the identified facilities has the same results as the Rathdrum A-624 breaker failure discussed in the near-term planning horizon section.

With mitigation alternatives included between outages of the listed P6 contingency events in Table 16, there was no further tripping of transmission elements to simulate.

5.2.1.4. Unsolved

The P1 – P7 contingency events in the long-term planning horizon were monitored for unsolved power flow solutions. The results are provided in Table 17.

Contingency	33HS
P6	
N-1: Hurricane- Walla Walla 230kV + N-1: North Lewiston - Tucannon River 115kV	unsolved
N-1: North Lewiston - Tucannon River 115kV + T-1: Hatwai 500/230kV	unsolved
A6	
N-1: Albeni Falls - Sand Creek 115kV Open @ SCR + T-1: Cabinet Gorge 230/115kV	unsolved
A7	
N-1: Brownlee - Hells Canyon 230kV + N-2: Flathead - Libby 230kV & Libby - Noxon 230kV	unsolved
N-1: North Lewiston - Tucannon River 115kV Open @ NLW + N-2: Brownlee - Hells Canyon 230kV & Lolo - Oxbow 230kV	unsolved
N-2: Brownlee - Hells Canyon 230kV & Lolo - Oxbow 230kV + N-2: Flathead - Libby 230kV & Libby - Noxon 230kV	unsolved
A3	
N-1: North Lewiston - Tucannon River 115kV Open @ NLW + G-1: Ice Harbor - One of Units 1-6	unsolved

Table 17: Steady State Near-Term Unsolved Contingency Results in Long-Term Planning Horizon

No performance issues within Avista's Planning Coordinator area were identified in addition to those observed in the near-term planning horizon. The unsolved contingencies in adjacent Planning Coordinator areas are caused by power flow solution methods and the application of remedial action schemes between outages of a multiple facility contingency.

5.2.2. Extreme Events (R3.2)

The following sections describe the study results from the steady state contingency analysis for contingencies categorized as extreme events in the long-term planning horizon.

No performance issues were identified in addition to those observed in the near-term planning horizon.

5.3. Transmission Short Circuit Analysis (R2.3)

A short circuit analysis study was conducted using the transmission system models and the Fault Analysis tool in PowerWorld Simulator. The short circuit analysis is used to determine whether fault interrupting devices on the Avista system have interrupting capability for expected faults. The short circuit analysis is conducted on 1-, 5-, and 10-year scenarios assuming projects have been completed. The duties provided are for three phase faults. High voltage circuit breakers, circuit switchers, and high voltage fuses are evaluated.

The tables below are a filtered list of interrupting devices with adjusted fault currents exceeding 90% of their interrupt ratings. Equipment with fault currents exceeding 95% of the interrupt rating require Corrective Action Plans. If the analysis indicates an inability of the system to meet the performance requirement, the System Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. (TPL-001-5, R2.8)

5.3.1. High Voltage Circuit Breakers

There are no breakers identified with potential fault duties exceeding their rating. Breakers with fault duties approaching their rating are shown in Table 18. The Beacon 115kV fault duty is approaching the 40kA rating of the breakers. Evaluation of a 50kA or higher rating or design alternative is recommended.

Station	Device	kV	kA	Description	2024 Case (A)	%Duty	2028 Case (A)	%Duty	2033 Case (A)	%Duty
Beacon	A-608 OCB	121	40	BEA - Transformer 1 115-13.8kV	37,897	95	38,636	97	39,438	99
Beacon	A-614 OCB	121	40	BEA - Transformer 2 115-13.8kV	37,897	95	38,636	97	39,438	99
Beacon	A-609 OCB	121	40	BEA – F&C 115kV	36,614	92	37,364	93	38,063	95
Beacon	A-604 OCB	121	40	BEA - BLD 1 115kV	35,622	89	36,267	91	37,071	93
Beacon	A-606 OCB	121	40	BEA – 9CE 1 115kV	35,293	88	36,297	91	36,452	91
Beacon	A-611 OCB	121	40	BEA – 9CE 2 115kV	35,286	88	36,292	91	36,447	91
Beacon	A-610 OCB	121	40	BEA - Bell 1 115kV	--	<90	--	<90	36,126	90
Beacon	A-612 OCB	121	40	BEA - BLD 2 115kV	--	<90	--	<90	36,378	91

Table 18: High Voltage Circuit Breakers Exceeding 90% Of Rating

5.3.2. Circuit Switchers

South Othello, Barker Road, Francis & Cedar, Lakeview, Sweetwater, and Lolo Stations presently have circuit switcher devices with potential fault duties greater than their ratings. These devices are not elements of fault blocking or protection schemes that would provide an exemption.

South Othello, Barker Road, Francis & Cedar, and Lakeview require circuit switcher replacements with higher capacity devices or other design alternatives.

Sweetwater and Lolo were identified as part of the Lolo Transformer Replacement project and are scheduled to be replaced in 2024.

Clearwater, Post Street and Airway Heights Stations have circuit switcher devices with potential fault duties greater than their ratings even utilizing protection schemes reducing the fault duty. All will require circuit switcher replacements with higher capacity devices or other design alternatives.

The list of circuit switchers is shown in Table 19. Items noted with an asterisk (*) are based on the utilization of the protection scheme.

Station	kV	kA	Description	2024 Case (A)	%Duty	2028 Case (A)	%Duty	2033 Case (A)	%Duty
South Othello	121	6	SOT - Transformer 1	10,194	170	10,826	180	10,247	171
Barker Road	121	20	BKR - Transformer 1	23,413	117	24,024	120	24,142	121
Francis & Cedar	121	20	F&C - Transformer 1	20,905	105	21,057	105	21,641	108
Francis & Cedar	121	20	F&C - Transformer 2	20,905	105	21,057	105	21,641	108
Lakeview	242	8	LKV - Transformer 1	8,048	101	8,097	101	8,109	102
Sweetwater	121	7	SWT - Transformer 1	6,855	98	7,191	103	7,215	103
Lolo	121	20	LOL - Transformer 3	18,237	91	22,061	110	21,769	109
*Clearwater	121	7	CLW – Transformer 1	7,788	111	8,370	120	8,390	120
*Clearwater	121	7	CLW – Transformer 2	7,788	111	8,370	120	8,390	120
*Post Street	121	7	PST – Transformer 1	7,867	112	7,915	113	8,005	114
*Post Street	121	7	PST – Transformer 2	7,867	112	7,915	113	8,005	114
*Airway Heights	121	7	AIR – Transformer 1	--	<90	6,304	90	9,361	134
*Airway Heights	121	7	AIR – Transformer 2	--	<90	6,304	90	9,361	134
East Colfax	121	7	ECL - Transformer 1	6,618	95	6,614	95	6,687	96
Glenrose	121	20	GLN - Transformer 1	--	<90	--	<90	18,441	92
Spokane Industrial Park	121	25	SIP - Transformer 3	23,255	93	23,707	95	23,858	95
Greenwood	121	6	GRN - Transformer 1	5,570	93	5,507	93	5,517	93
Colville	121	6	CLV – Transformer 1	5,680	95	5,640	94	5,650	94

Table 19: High Voltage Circuit Switchers Exceeding 90% Of Rating

5.3.3. High Voltage Fuses

The fuses listed in Table 20 presently have fault duties exceeding their rating, except for North Moscow, which is at its limit. All provide transformer protection. Replacement with higher capacity fuses or other design alternatives is required.

Station	kV	kA	Description	2024 Case (A)	%Duty	2028 Case (A)	%Duty	2033 Case (A)	%Duty
Garfield	121	1.2	GAR - Transformer 1	4,033	336	4,045	336	4,043	336
Prairie	121	10	PRA - Transformer 2	12,652	127	13,414	134	13,438	134
Leon Junction	121	10	LEO - Transformer 1	10,826	108	11,004	110	10,947	109
Long Lake 13kV	121	10	L13 - Transformer 1	10,615	106	10,687	107	10,658	107
North Moscow	121	10	NMO - Transformer 1	10,009	100	10,036	100	10079	100

Table 20: High Voltage Fuses Exceeding 90% of Rating

5.4. Transmission Stability Near-Term Analysis (R2.4)

Stability analysis was performed on the transmission system models representing the near-term planning horizon which represented peak, off-peak, and sensitivity scenarios. If the analysis indicated an inability of the system to meet the performance requirements, the System Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. (TPL-001-5, R2.7)

5.4.1. Planning Events (R4.1)

The following sections describe the study results from the stability contingency analysis for contingencies categorized as P1 – P7.

5.4.1.1. Heavy Summer Scenario (R2.4.1)

Devil's Gap Islanding Conditions

During faults causing the clearing of the Devil's Gap East bus, an island is created with the Little Falls generation units and load radially connected to the Devil's Gap West bus. The ability for Little Falls generation to maintain acceptable voltage and frequency within the island depends on the load present and generation levels. Further analysis is necessary to determine existing generation protection schemes deployed and the capabilities of the existing and proposed controls systems installed on the Little Falls generation.

The present configuration of Devil's Gap Station has both Little Falls 115kV Transmission Lines connected to the West bus and both Long Lake 115kV Transmission Lines connected to the East bus, as shown in Figure 35. The configuration was initially developed to meet historical operational concepts associated with the West of Hatwai path.

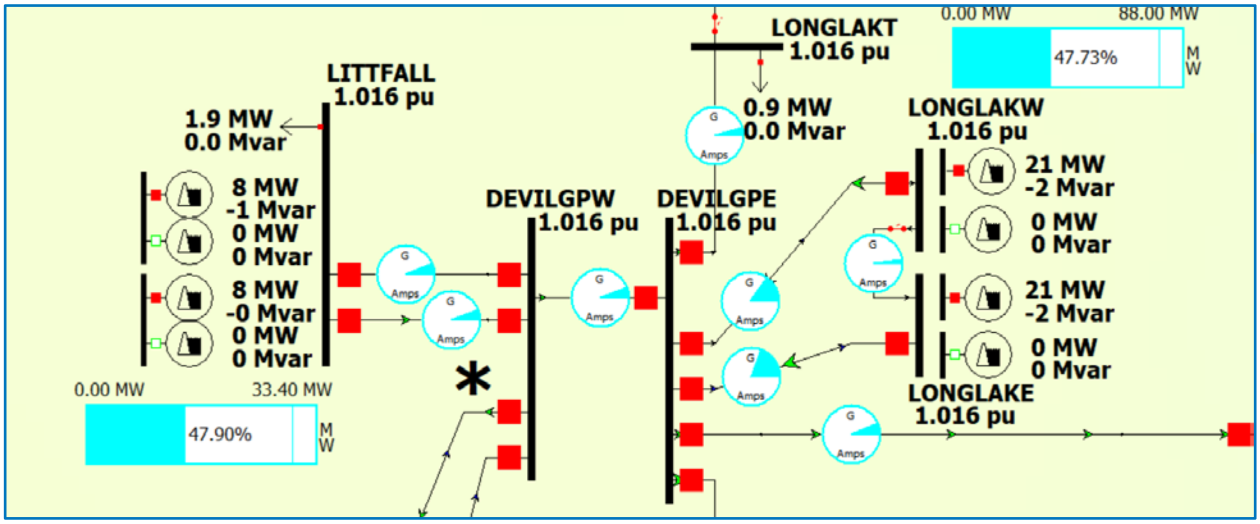

Figure 35: Devil's Gap Station Configuration

Following the redevelopment of the local area operation, a re-evaluation of the Devil's Gap configuration did not occur. Conceptually, terminating the Little Falls and Long Lake dual transmission lines to non-contiguous points in the Devil's Gap bus structure will increase the reliability of the plants and eliminate the potential islanding condition for loss of the East bus. The islanding condition occurs in all cases studied.

5.4.1.2. Light Spring Scenario (R2.4.2)

Summer Falls Out of Step

The Summer Falls generators are marginally stable if a three-phase fault occurs on the Larson – Stratford 115kV Transmission Line near Larson. This outage leaves the Stratford area radially fed by a 75-mile 115kV system originating out of Wenatchee as shown in Figure 36. The resulting weak system is least stable during light load conditions, which transfers the most generation out of the area.

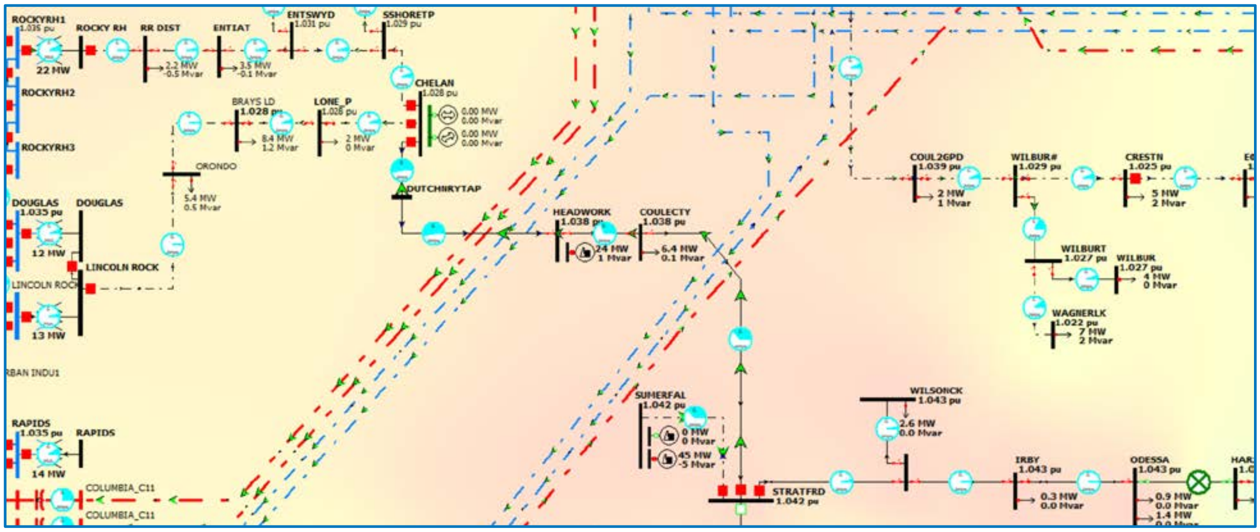

Figure 36: 115kV System After Larson – Stratford 115kV Trip

The protection scheme on the transmission line does not presently utilize a communication aided tripping methodology. The time delay for a Zone 2 fault has been reduced to nine cycles relative to the typical setting of 20 cycles. The study results are shown in Figure 37.

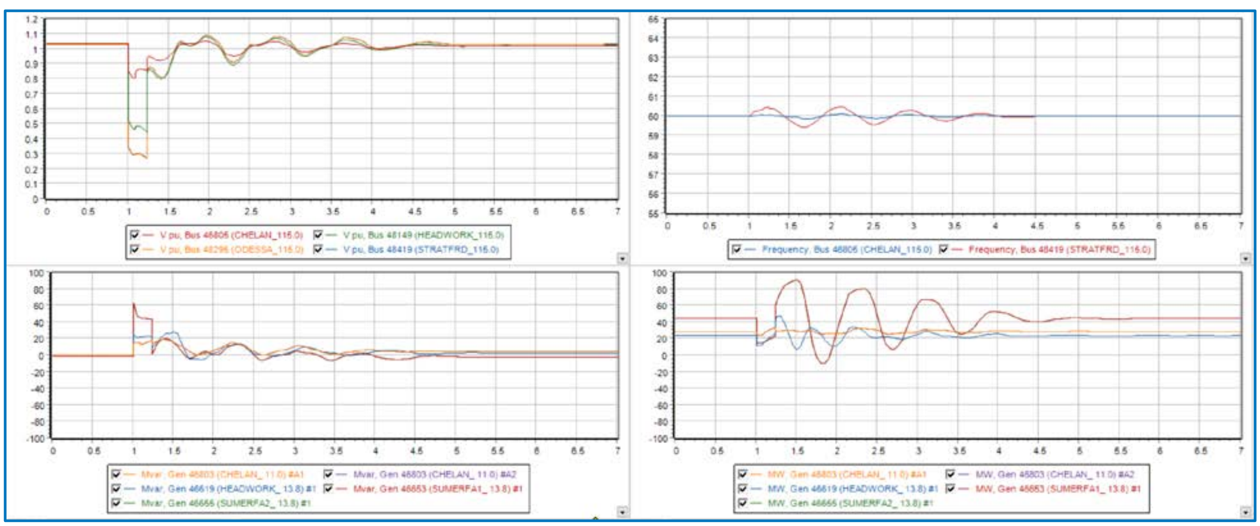

Figure 37: Summer Falls Generation Response: N-1 Larson-Stratford 115kV 3P at LAR

5.4.1.3. Light Summer High Transfer Sensitivity (R2.4.3)

The Light Summer High Transfer sensitivity scenario brings both the West of Hatwai (Path 6) and Montana to Northwest (Path 8) near their transfer limit and simulations identified no non-extreme event violations. The three-phase fault on the Bell – Taft 500kV line near Bell remains the most impactful contingency with tripped load of 254MW and tripped generation of 840MW. Results are shown in Figure 38.

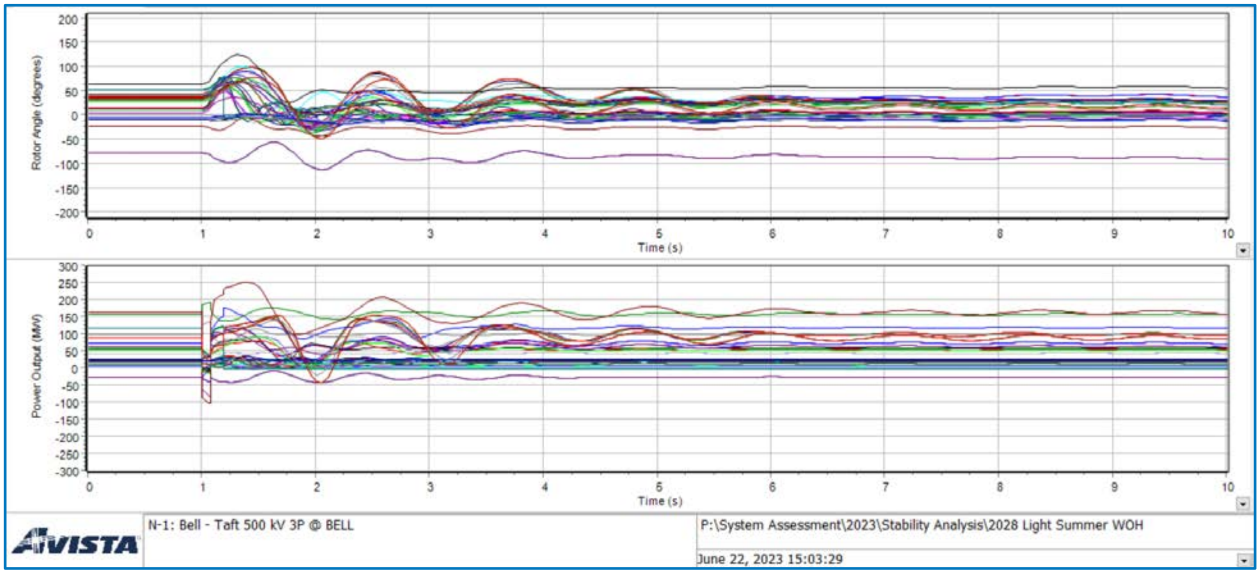

Figure 38: System Response to N-1: Bell - Taft 500kV 3P at Bell

5.4.2. Extreme Events (R4.2)

Contingencies simulating three phase faults on transmission lines with breaker failures were the most severe contingencies and the only extreme event whose impact was not mitigated. These events are considered to have an extremely low probability of occurrence. If the event were to occur, it could cause local generation to lose synchronism with the system. Generation protection schemes were not included in the simulation but are an existing component that would aid to minimize the impact to the transmission system. The stations where breaker failures may cause generators to lose synchronism include Beacon, Bell, Boulder, Lancaster, Rathdrum, Noxon, and Westside. Figure 39 is an example of extreme results for a breaker failure on Beacon R-427 during Heavy Spring conditions. Cascading was not identified for any of the simulated contingencies, though the high transfer case did not solve for this contingency.

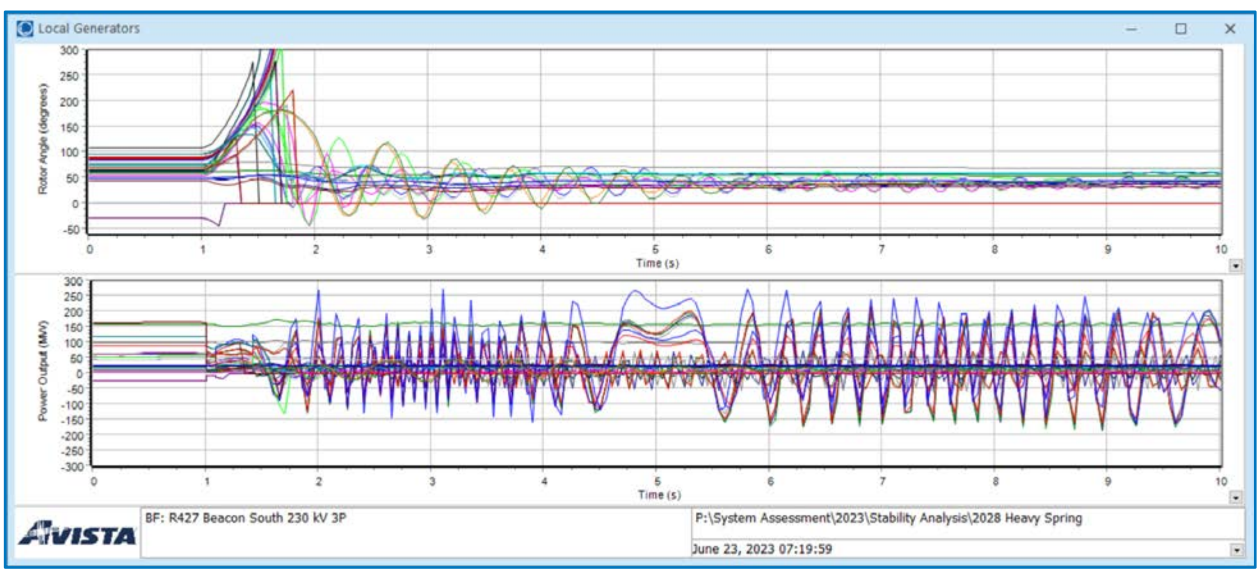

Figure 39: Breaker Failure R-427 Beacon South 230kV

5.4.3. Spare Equipment (R2.4.5)

Avista's spare equipment strategy for transmission facilities provides for spares for the following equipment: 230/115kV transformers, GSU transformers, transmission UG cable, HV circuit breakers, HV air switches, shunt reactors and shunt capacitors.

Stability analysis was performed on the transmission system models representing the near-term planning horizon to study the impact of possible unavailability of Avista's 230/115kV transformers and select other transformers. Category P1 and P2 planning events were evaluated with the pre-existing condition of a transformer outage for the following:

- Beacon 1 and 2
- Bell 6 (BPA)
- Benewah
- Boulder 1 and 2
- Cabinet Gorge
- Dry Creek
- Dworshak (USACE)
- Hatwai (BPA)
- Libby (BPA)
- Lolo 1 and 2
- Moscow 230
- North Lewiston
- Pine Creek 1 and 2
- Rathdrum 1 and 2
- Saddle Mountain
- Shawnee
- Westside 1 and 2

There were no other stability issues beyond those previously identified.

5.5. Transmission Stability Long-Term (R2.5)

The Long-Term Transmission Planning Horizon stability analysis assesses the impact of proposed additions and changes of the system model within the specified timeframe. Stability analysis was performed on the transmission system case models representing the long-term planning horizon. The case models used were reflective of the near-term system model with the addition of the Garden Springs Station. The long-term analysis results mirrored those of the near-term stability results and support the Corrective Action Plans identified in the above near-term section. The addition of Garden Springs Station contributed no adverse impacts to system stability.

5.6. Transmission Single Point of Failure

Single point of failure analysis for Avista's protection systems was performed in accordance with TPL-001-5 Transmission System Performance Requirements. This analysis incorporates both steady state and stability studies to ensure system performance meets TPL-001-5 criteria requirements. If the analysis indicates an inability of the System to meet the performance requirements, the System Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. The study methodology and performance criteria used in the analysis is provided in *TP-SPP-01 – Transmission System Performance*.

5.6.1. Initial Analysis

Initial Analysis is the first step of the single point of failure analysis process. This step is performed by System Planning using conservative assumptions for system analysis. Analysis includes Steady State and Stability Analysis. Results which do not meet performance criteria are identified during Initial Analysis and are packaged for further, more detailed individual evaluation by Avista's Relay and Protection Design Department during Final Review.

5.6.1.1. Steady State Analysis

The protection system single point of failure steady state analysis was conducted using the transmission system models with the Contingency Analysis tool in PowerWorld Simulator. The steady state analysis was used to determine whether performance criteria can be met in the event of a single point of failure within Avista's protection and associated control and instrumentation systems. The steady state analysis is conducted on 1-, 5-, and 10-year scenarios assuming planned projects have been completed.

Table 21 provides the results of the steady state contingency analysis. Overload magnitudes on each line affected are indicated in relation to the instigating contingency condition. Contingencies at Beacon Station and at Rathdrum Station demonstrated overloads on remaining 115kV transmission lines in their respective areas. A protection system failure at Westside Station causes the Bell 230/115kV Transformer 6to exceed its normal facility rating. The single point of failure contingency issues observed are less severe than the issues already identified in the Transmission Steady State Near-Term Analysis for Heavy Summer scenario with P2 contingencies. For the three P5 contingencies listed, mitigation of single points of failure in the protection systems would not address the more severe issues identified for P2 contingencies.

	22HS	26HS	26HS Proj	26HS Sen	31HS	31HS Proj	31HS Sen
P5							
PSF: Beacon 230/115kV							
College and Walnut - Westside 115kV (Fort Wright - Westside)	100.6	104.7	103.5	112.8	107.2		
Francis and Cedar - Northwest 115kV	122.3	126.8	125.8	136.5	129.7	110.6	118.6
Northwest - Westside 115kV	115.7	119.7	118.8	128.8	122.3	107.0	114.7
PSF: Rathdrum 230/115kV							
Otis Orchard - Post Falls 115kV (Beck Road Tap - Post Falls)							103.5
Otis Orchard - Post Falls 115kV (East Farms Tap - Beck Road Tap)				101.9			107.2
Otis Orchard - Post Falls 115kV (East Farms Tap - Otis Orchard)	103.9	103.9	103.8	112.0	108.1	109.2	117.6
Post Falls - Ramsey 115kV (Post Falls - Prairie)				100.5			106.7
PSF: Westside 230/115kV							
BELL S2 (40088) -> BELL BPA (40087) CKT 6 at BELL BPA			103.3	103.7	100.3		

Table 21: Protection System Failure Initial Steady State Results

5.6.1.2. Stability Analysis

The protection system single point of failure stability analysis was conducted using the transmission system models with the Transient Stability tool in PowerWorld Simulator. The stability analysis is used to determine whether performance criteria can be met in the event of a single point of failure within Avista's protection systems and associated control and instrumentation systems. The stability analysis is conducted on 1-, 5-, and 10-year scenarios assuming planned projects have been completed. The contingencies studied included both single line-ground (P5) and three phase (Extreme Events) faults on each 115kV and 230kV bus in Avista's Planning Coordinator area.

The stability analysis produced no criteria violations for P5 contingencies. Twelve contingency events cause generator out-of-step instances because of generators being disconnected from the system. Out-of-step generators, with the corresponding instigating contingency, are listed below. Generation loss is an acceptable consequence of any event excluding P0.

	22LSp		26HS		26HSProj		26HSSen		26LSpProj		31HW	
	Criteria Violation	Duration or Time	Criteria Violation	Duration or Time	Criteria Violation	Duration or Time	Criteria Violation	Duration or Time	Criteria Violation	Duration or Time	Criteria Violation	Duration or Time
P5												
PSF: Cabinet 115kV SLG												
Out of Step Generator												
CABGOR12 13.8kV	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4
CABGOR34 13.8kV	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4
PSF: Cabinet 230kV SLG												
Out of Step Generator												
CABGOR12 13.8kV			OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4
PSF: Clearwater 115kV SLG												
Out of Step Generator												
CWGEN4 12kV	OOS	3.3							OOS	3.3	OOS	3.2
PSF: Devil's Gap 115kV SLG												
Out of Step Generator												
LITFAL12 4kV	OOS	3.3	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.3	OOS	3.4
LITFAL34 4kV	OOS	3.3	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.3	OOS	3.3
LONGLKG1 4kV	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3
LONGLKG2 4kV	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3
LONGLKG3 4kV	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3
LONGLKG4 4kV	OOS	3.3							OOS	3.3		
PSF: Irvin 115kV SLG												
Out of Step Generator												
IEP-A 13.8kV			OOS	3.4	OOS	3.4	OOS	3.4			OOS	3.4
IEP-B 13.8kV			OOS	3.4	OOS	3.4	OOS	3.4			OOS	3.4
WR1. 1.4. Part 1												
I.E. PAPR 115kV							52.4	999				
PSF: Kettle Falls 115kV SLG												
Out of Step Generator												
KETTLEAV 13.8kV			OOS	3.4	OOS	3.4	OOS	3.4			OOS	3.4
PSF: Little Falls 115kV SLG												
Out of Step Generator												
LITFAL12 4kV	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3
LITFAL34 4kV	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3
PSF: Long Lake 115kV SLG												
Out of Step Generator												
LONGLKG1 4kV	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3
LONGLKG2 4kV	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3
LONGLKG3 4kV	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.3
LONGLKG4 4kV	OOS	3.3							OOS	3.3		
PSF: Nine Mile 115kV SLG												
Out of Step Generator												
NINEMI12 13.8kV	OOS	3.2	OOS	3.2	OOS	3.2	OOS	3.2	OOS	3.2	OOS	3.2
NINEMI34 13.8kV	OOS	3.3							OOS	3.3	OOS	3.2
PSF: Noxon 230kV SLG												
Out of Step Generator												
CABGOR12 13.8kV	OOS	3.1							OOS	3.1		
CABGOR34 13.8kV	OOS	3.1							OOS	3.1		
NOXON12 14.4kV	OOS	3.1	OOS	3.1	OOS	3.1	OOS	3.1	OOS	3.1	OOS	3.1
NOXON34 14.4kV	OOS	3.1	OOS	3.1	OOS	3.1	OOS	3.1	OOS	3.1	OOS	3.3
PSF: Post St 115kV SLG												
Out of Step Generator												
MONROEA 13.8kV	OOS	3.2	OOS	3.3	OOS	3.3	OOS	3.3	OOS	3.2	OOS	3.2
PSF: Stratford 115kV SLG												
Out of Step Generator												
SUMERFA1 13.8kV	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4		
SUMERFA2 13.8kV	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4	OOS	3.4		

Table 22: Protection System Failure Initial Stability Results

Extreme events were analyzed and evaluated for cascading. If Cascading is observed for single point failure extreme events, an assessment of possible mitigations is conducted. Cascading criteria used for evaluation is defined as unrestrained load or generation loss or inadequate voltage recovery defined trigger points in *TP-SPP-01 – Transmission System*

Performance Section 2.2. The table below identifies extreme events which resulted in cascading conditions due to unrestrained generation loss. Each bus listed is required to have a Final Review by the Relay and Protection Design Department to determine the actual expected clearing times.

	22LSp	26HS	26HSProj	26HSSen	26LSpProj	31HW
EES-2						
PSF: Beacon 115kV 3PH	3440.0	960.8	960.8	910.8	3440.5	2588.5
PSF: Beacon 230kV 3PH	4780.5	3158.9	3158.8	3158.9	4781.0	3822.5
PSF: Boulder 230kV 3PH	3438.0	1316.4	1316.4	1323.4	3430.5	2618.5
PSF: Rathdrum 230kV 3PH	3294.0	1205.8	1205.8	1177.8	3294.5	1691.5
PSF: Westside 230kV 3PH	3440.0	855.8	855.8	855.8	3412.5	761.8

Table 23: Protection System Failure Initial Extreme Event Unrestrained Generation loss

5.6.2. Final Review

Relay and Protection Design evaluated Initial Analysis results provided by System Planning. Actual expected clearing times were defined by Relay and Protection Design and used in Final Review by System Planning to determine adequate system performance. Final Review results are documented below.

5.6.2.1. Single Point of Failure TPL-001-5 Results

Relay and Protection Design provided actual expected clearing times for contingencies with unrestrained generation loss, highlighted in the table below. Provided clearing times were added to PowerWorld stability analysis Extreme Events and the updated results identified aborted contingencies. Aborted contingencies are provided below with the associated seconds into the simulation was aborted.

	22LSp Abort Time	26LSpProj Abort Time
EES-2		
PSF: Beacon 115kV 3PH	14.367	16.175
PSF: Beacon 230kV 3PH	18.910	14.517
PSF: Boulder 230kV 3PH	15.125	14.258
PSF: Rathdrum 230kV 3PH	14.310	

Table 24: Protection System Failure Extreme Event Aborted Contingencies

The stability analysis methodology used does not emulate specific generator relaying settings. A generic out-of-step generator protection relay can be used in the simulations to represent typical rotating machine protection schemes. A trip setting for a deviation of 120 degrees from a generator's initial angle has been identified as a reasonable assumption in-line with actual generator protection settings at local generation facilities. Using the generic relay settings in the transient analysis resulted in the tripping of generators for out-of-step conditions during the contingencies listed in Table 25. The contingencies that cleared out-of-step generators prior to the point of system instability, represented by PowerWorld abort time, depicted stable contingencies. All contingencies proved solved and stable.

	22LSp Gen Relay Clear Time	22LSp Contingency Solution	26LSpProj Gen Relay Clear Time	26LSpProj Contingency Solution
EES-2				
PSF: Beacon 115kV 3PH	Under 2.0s	Solved/Stable	Under 2.0s	Solved/Stable
PSF: Beacon 230kV 3PH	Under 2.0s	Solved/Stable	Under 2.0s	Solved/Stable
PSF: Boulder 230kV 3PH	Under 2.0s	Solved/Stable	Under 2.0s	Solved/Stable
PSF: Rathdrum 230kV 3PH	Under 2.0s	Solved/Stable		

Table 25: Protection System Failure Extreme Event Incorporating Generator Relaying

Stable contingencies that do not result in cascading conditions due to unrestrained generation loss (TP-SPP-01 2.2 trigger point 2850MW) meet the performance criteria. The table below has been updated with generation losses resulting after updated relay clearing times provided by Relay and Protection Design were applied.

	22LSp	26HS	26HSProj	26HSSen	26LSpProj	31HW
EES-2						
PSF: Beacon 115kV 3PH	3411.0				3411.5	
PSF: Beacon 230kV 3PH	3387.0	2072.3	2072.3	170.8	3387.5	1829.9
PSF: Boulder 230kV 3PH	2999.1				2999.6	
PSF: Rathdrum 230kV 3PH	2999.1				2505.9	
PSF: Westside 230kV 3PH	1648.1				1648.6	

Table 26 Protection System Failure Extreme Event Unrestrained Generator Loss

Stability analysis of Avista's system show seven instances of Cascading caused by the occurrence of extreme events. An evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the events will be conducted.

Further evaluation of performance issues related to the Beacon Station identified in the steady-state contingency analysis and short circuit analysis will also consider the elimination of single points of failure at Beacon Station along with improved protection schemes with faster clearing times.

5.7. Distribution Multi-Year Load-Flow Analysis

Distribution system capacity was evaluated based on recent performance and projected load growth over the next 10 years. The stations discussed below have utilization rates forecasted to be greater than 80% within the study period. The list excludes stations that have existing designated projects.

The load forecasting method used was a multivariate regression. The regression used heating degree days, cooling degree days, day of the week, holidays, month, season, and daily peak five-minute demand at the feeder as independent variables. Where consistent data was available, three to four years of history was used to forecast a future trend. The forecast does not include any future block-load additions.

The map shown in Figure 40 provides a geographic view of feeders exceeding performance criteria within the 10-year planning horizon. Load growth in the North Spokane, Spokane Valley, Coeur d’Alene, Post Falls. Moscow, and Lewiston areas will cause additional equipment loading issues if mitigation measures are not completed.

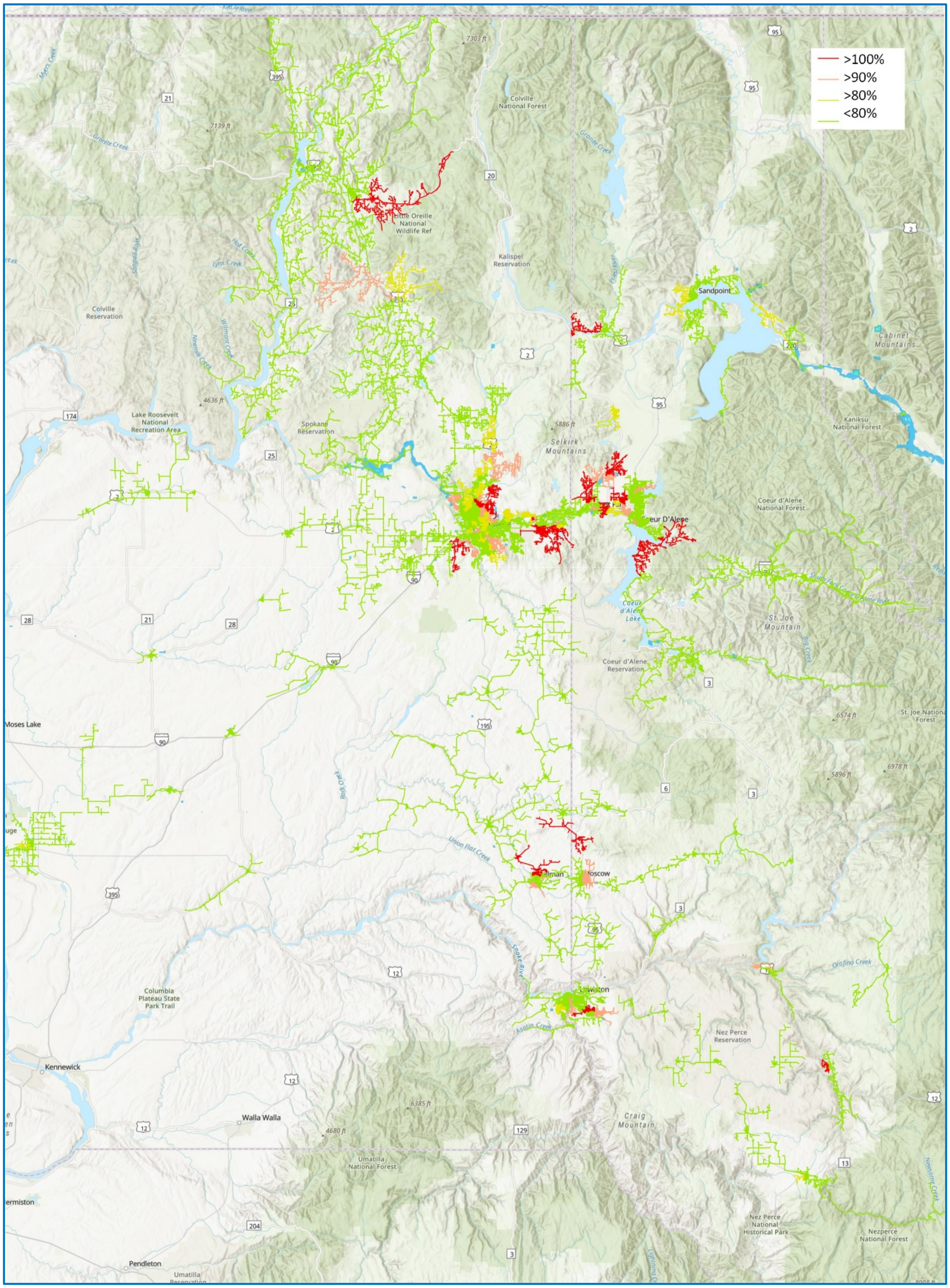

Figure 40: Ten-year Feeder Loading Projection Map

5.7.1. Summer Scenario

5.7.1.1. Airway Heights Capacity

The AIR12F1 feeder exceeds the performance criteria starting in 2026 and approaches 100% of its facility rating in the 10-year planning horizon based on the calculated growth rate. The Airway Heights 115/13kV Transformer 2, which serves AIR12F1, also becomes heavily loaded.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
AIRWYHGT.CB.12F1	74.9	77.1	79.3	81.5	83.9	86.3	88.7	91.3	93.9	96.6	99.3
AIRWYHGT.XFMR.2	66.4	68.1	69.9	71.6	73.4	75.3	77.2	79.2	81.2	83.3	85.4

Table 27: Airway Heights Summer Loading Beyond Performance Expectations

An Airway Heights Capacity Mitigation project will be developed and proposed to address the performance concerns.

5.7.1.2. Glenrose Capacity

The GLN12F1 and GLN12F2 feeders have exceeded the performance criteria in operational conditions. Some feeder transfer capacity is available and is utilized as necessary during peak summer conditions. It is expected GLN12F2 will approach 100% of its facility rating within the five-year planning horizon based on the calculated growth rate. The Glenrose 115/13kV Transformer 1 is also observed to be heavily loaded.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
GLENROSE.CB.12F1	86.5	87.6	88.8	89.9	91.1	92.3	93.5	94.7	96.0	97.2	98.5
GLENROSE.CB.12F2	86.4	90.2	94.2	98.3	102.6	107.1	111.8	116.7	121.9	127.2	132.8
GLENROSE.XFMR.1	85.5	86.3	87.1	87.9	88.8	89.6	90.4	91.3	92.2	93.0	93.9

Table 28: Glenrose Summer Loading Beyond Performance Expectations

A Glenrose Capacity Mitigation project will be developed and proposed to address the performance concerns.

5.7.1.3. Sandpoint Capacity

The Sandpoint 115/20kV Transformers 1 and 2 are shown to exceed the performance criteria within the five-year planning horizon based on the calculated growth rate. The two transformers are operated in parallel with each other therefore their loading should reasonably be equivalent.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
SANDPNT.XFMR.1	81.8	83.1	84.3	85.6	86.9	88.3	89.6	91.0	92.4	93.8	95.2
SANDPNT.XFMR.2	76.8	77.7	78.6	79.5	80.4	81.3	82.3	83.2	84.2	85.2	86.2

Table 29: Sandpoint Summer Loading Beyond Performance Expectations

The Bronx Station Rebuild project in the Sandpoint area has been budgeted to be completed within the five-year horizon.

5.7.1.4. Lewiston Capacity

Several feeders and transformers in the Lewiston, Idaho area are shown to exceed the performance criteria within the five-year planning horizon based on the calculated growth rate. Some equipment has exceeded the performance criteria in operational conditions. The projected growth rate is driven by new housing developments in the area

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
10TH_STW.CB.1254	86.6	90.6	94.7	99.0	103.5	108.2	113.1	118.3	123.7	129.3	135.2
10TH_STW.CB.1257	76.0	78.2	80.5	82.8	85.1	87.6	90.1	92.7	95.3	98.1	100.9

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
10TH_STW.XFMR.1	66.5	68.6	70.8	73.1	75.4	77.8	80.3	82.9	85.5	88.3	91.1
10TH_STW.XFMR.2	83.9	86.0	88.2	90.4	92.6	95.0	97.3	99.8	102.3	104.8	107.4
LOLO.CB.1359	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
LOLO.XFMR.3	82.8	84.2	85.5	86.9	88.3	89.7	91.2	92.6	94.1	95.7	97.2
NLEWISTN.XFMR.115_13_1	64.2	65.6	67.1	68.6	70.1	71.7	73.3	74.9	76.6	78.3	80.0
SLEWISTN.CB.1358	59.5	61.7	63.9	66.1	68.5	71.0	73.5	76.1	78.8	81.6	84.6
SLEWISTN.XFMR.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1	84.1

Table 30: Lewiston Area Summer Loading Beyond Performance Expectations

A Lewiston Capacity Mitigation project will be developed and proposed to address the performance concerns.

5.7.1.5. Liberty Lake Capacity

The LIB12F1 feeder exceeds the performance criteria starting in 2028 and approaches 100% of its facility rating in the 10-year planning horizon based on the calculated growth rate. The LIB12F3 and Liberty Lake 115/13kV Transformer 2, which serves LIB12F3 and LIB12F4, also exceed the performance criteria. Little to no growth is expected on LIB12F3.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
LIBRTYLK.CB.12F1	63.7	67.0	70.5	74.1	77.9	81.9	86.1	90.6	95.2	100.2	105.3
LIBRTYLK.CB.12F3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3
LIBRTYLK.XFMR.2	66.0	68.4	70.9	73.5	76.2	79.0	81.9	85.0	88.1	91.3	94.7

Table 31: Liberty Lake Summer Loading Beyond Performance Expectations

A Liberty Lake Capacity Mitigation project will be developed and proposed to address the performance concerns.

5.7.1.6. Moscow Capacity

Moscow City Station is a 115kV to 13.8kV distribution station located in the south part of Moscow, ID. Moscow City 115/13kV Transformer 1 is a 20MVA transformer with three feeders, serving approximately 6900 service points. Moscow City 115/13kV Transformer 2 is a 20MVA transformer with two feeders, serving approximately 4000 service points. The station is radially fed by the Moscow City – South Pullman 115kV Transmission Line with an alternate feed from the North Lewiston – Moscow City 115kV Transmission Line.

The Moscow area is projected to experience load growth over the next 10 years mostly with new housing developments and new local manufacturing facilities. The Moscow City 115/13kV Transformer 1 has exceeded the performance criteria in operational conditions. M15512 and M15514 feeders are shown to exceed the performance criteria within the 10-year planning horizon based on the calculated growth rate.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MOSCOW.CB.512	78.0	79.2	80.5	81.7	83.0	84.3	85.7	87.0	88.4	89.8	91.2
MOSCOW.CB.514	67.2	68.7	70.2	71.8	73.4	75.1	76.7	78.4	80.2	82.0	83.8
MOSCOW.XFMR.1	86.8	87.3	87.8	88.2	88.7	89.2	89.7	90.2	90.7	91.2	91.8

Table 32: Moscow City Summer Loading Beyond Performance Expectations

A Moscow Capacity Mitigation project will be developed and proposed to address the performance concerns.

5.7.1.7. North Spokane Capacity

Several feeders and transformers in the North Spokane area are shown to exceed the performance criteria within the five-year planning horizon based on the calculated growth rate.

Some equipment has exceeded the performance criteria in operational conditions. The projected growth rate is driven by new housing developments, apartment complexes, general commercial, and light industrial expansion in the area.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
BEACON.CB.12F2	77.2	78.7	80.1	81.6	83.1	84.6	86.2	87.8	89.4	91.1	92.8
COLBERT.CB.12F1	68.6	70.2	71.9	73.6	75.4	77.2	79.1	81.0	83.0	85.0	87.0
COLBERT.XFMR.BPAT_ COLBERT	84.8	85.8	86.9	88.0	89.1	90.2	91.4	92.5	93.6	94.8	96.0
FRAN_CDR.CB.12F2	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9
FRAN_CDR.CB.12F4	75.3	76.2	77.2	78.1	79.1	80.1	81.1	82.1	83.1	84.2	85.2
FRAN_CDR.XFMR.2	79.1	80.0	81.0	82.1	83.1	84.1	85.2	86.2	87.3	88.4	89.5
INDIANTR.CB.12F1	78.6	79.5	80.3	81.2	82.0	82.9	83.8	84.7	85.6	86.5	87.4
INDIANTR.XFMR.1	73.8	74.9	75.9	77.0	78.0	79.1	80.2	81.3	82.5	83.6	84.8
LYON_STD.CB.12F2	73.2	74.9	76.6	78.3	80.0	81.8	83.7	85.6	87.5	89.5	91.5
LYON_STD.CB.12F3	68.5	70.0	71.6	73.2	74.9	76.6	78.3	80.0	81.8	83.7	85.6
LYON_STD.CB.12F4	67.7	70.4	73.1	76.0	79.0	82.1	85.4	88.7	92.2	95.8	99.6
LYON_STD.XFMR.1	74.5	76.1	77.9	79.6	81.4	83.2	85.1	87.0	89.0	91.0	93.0
MEAD.CB.12F1	64.9	66.6	68.3	70.1	71.9	73.7	75.6	77.6	79.6	81.7	83.8
NRTHEAST.CB.12F1	67.1	69.6	72.1	74.7	77.5	80.3	83.2	86.3	89.4	92.7	96.0
NRTHEAST.CB.12F2	71.5	73.0	74.6	76.2	77.8	79.5	81.2	82.9	84.7	86.5	88.3
NRTHEAST.CB.12F3	49.7	53.0	56.6	60.4	64.4	68.8	73.4	78.3	83.5	89.1	95.1
NRTHEAST.CB.12F4	69.1	73.0	77.0	81.2	85.7	90.4	95.4	100.7	106.2	112.1	118.2
WAIKIKI.CB.12F3	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6
WAIKIKI.CB.12F4	75.4	76.5	77.7	78.9	80.1	81.3	82.5	83.8	85.0	86.3	87.6
WAIKIKI.XFMR.115_13_1	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3
WAIKIKI.XFMR.115_13_2	84.5	84.5	84.5	84.5	84.5	84.5	84.5	84.5	84.5	84.5	84.5

Table 33: North Spokane Area Summer Loading Beyond Performance Expectations

A North Spokane Capacity Mitigation project has been developed to address the performance concerns. The project includes several sub-projects, some of which have already been budgeted, with the remainder to be proposed for prioritization.

5.7.1.8. Rathdrum Capacity

Rathdrum Station is a 115kV to 13.8kV distribution station located southeast of Rathdrum at the intersection of North Meyer and Boekel Roads. It has two 20MVA transformers with two Avista feeders and one Kootenai Electric feeder. The station serves approximately 4800 Avista service points and is fed from the Rathdrum Station's 115kV East and West buses. The station includes a 230kV source and five 115kV transmission lines with feeder ties to Huetter and Idaho Road Stations.

The Rathdrum Prairie is projected to experience load growth over the next 10 to 20 years, with the City of Post Falls anticipating a doubling of its population in that timeframe. The undeveloped areas are often considered for commercial and industrial growth.

Present feeder loading is reasonable, but the loading is expected to increase significantly through the next 10 years, with the expectation the RAT231 and RAT233 feeder will exceed the performance criteria in 2027 and 2026 and reaches 100% of their facility ratings in the 10-year planning horizon based on the calculated growth rate.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
RATHDRUM.CB.231	69.0	71.8	74.6	77.6	80.6	83.8	87.2	90.6	94.2	98.0	101.9
RATHDRUM.CB.233	73.2	76.1	79.1	82.3	85.5	88.9	92.4	96.1	99.9	103.9	108.0

Table 34: Rathdrum Summer Loading Beyond Performance Expectations

A Rathdrum Capacity Mitigation project will be developed and proposed to address the performance concerns.

5.7.2. Winter Scenario

5.7.2.1. Orin Capacity

Orin Station is a 115kV to 13.8kV distribution station located a couple miles south of Colville on Hwy 395. It has a single 10MVA transformers feeding three Avista feeders. The station serves approximately 2200 Avista service points and is radially fed by a tap off the Addy-Kettle Falls 115kV Transmission Line.

The Orin area is projected to experience moderate load growth over the next 10 years. The ORI 115/13kV Transformer 1 and ORI12F3 have exceeded the performance criteria in operational conditions.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
ORIN.XFMR.1	107.9	111.0	114.7	118.4	122.3	126.5	130.7	134.6	139.6	143.6	149.0
ORIN.CB.12F3	107.8	110.7	114.4	118.3	122.2	126.3	130.6	134.2	139.4	143.1	148.6

Table 35: Orin Winter Loading Beyond Performance Expectations

An Orin Capacity Mitigation project will need to be developed to address the performance concerns.

5.7.2.2. Moscow Capacity

Summer capacity concerns and project proposals were discussed above in Section 5.7.1.7 Moscow Capacity. This project will also address winter performance concerns.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MOSCOW.XFMR.1	92.6	93.4	94.6	95.6	96.4	97.2	98.5	99.5	100.4	101.5	102.4
MOSCOW.CB.512	74.3	75.5	77.2	78.5	79.8	81.1	82.8	84.2	85.6	87.0	88.4
MOSCOW.CB.514	74.5	76.3	78.1	80.4	82.3	84.2	86.7	88.7	90.9	93.5	95.7

Table 36: Moscow City Winter Loading Beyond Performance Expectations

5.7.2.3. Wilbur Capacity

Wilbur Station is a 115kV to 13.8kV distribution station located north of the city of Wilbur, Washington. Wilbur 115/13kV Transformer 1 is a 7.5MVA transformer with two feeders, serving approximately 1300 service points. This station serves the cities of Wilbur, Creston, and Almira. The station is radially fed by a tap off the BPA Bell-Creston 1 115kV Transmission Line.

The Wilbur area is projected to experience load growth over the next 10 years, consisting mostly of new housing developments and local manufacturing facilities. The Wilbur 115/13kV Transformer 1 has exceeded the performance criteria in operational conditions and approaches 100% of its facility rating in the 10-year planning horizon based on the calculated growth rate.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
WILBUR.XFMR.1	91.1	92.3	93.6	95.0	96.5	97.9	99.2	100.7	102.2	103.8	105.4

Table 37: Wilbur Winter Loading Beyond Performance Expectations

A Wilbur Capacity Mitigation project will need to be developed to address the performance concerns.

5.7.2.4. Sandpoint Capacity

Sandpoint Station is a 115kV to 20kV distribution station located on the west side of Sandpoint, ID at the intersection of Pine Street and Lincoln Avenue. It has three 12.5MVA transformers with four Avista feeders. Sandpoint Transformer 1 and Transformer 2 are paralleled and feed three of the four feeders. The station serves approximately 8000 service points. The station is fed by the Bronx-Sand Creek 115kV Transmission Line.

The Sandpoint area is projected to experience load growth over the next 10 years mostly with new housing developments. Sandpoint 115/13kV Transformer 1 and Transformer 2 have exceeded the performance criteria in operational conditions and approach 100% of its facility rating in the 10-year planning horizon based on the calculated growth rate. SPT4S21, which serves the rural area west of Sandpoint is expected to have the most growth in the area and exceeds performance criteria in operational conditions in the 10-year planning horizon.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
SANDPNT.XFMR.1	90.0	92.3	94.6	97.2	99.7	102.0	104.8	107.7	110.7	113.7	117.1
SANDPNT.XFMR.2	90.0	92.3	94.6	97.2	99.7	101.9	104.7	107.6	110.6	113.7	117.1
SANDPNT.CB.4S21	47.5	50.3	53.0	56.1	59.3	62.2	65.6	69.4	73.4	77.5	81.9

Table 38: Sandpoint Winter Loading Beyond Performance Expectations

A Sandpoint Capacity Mitigation project is being developed to address the performance concerns. The project tentatively includes the addition of a new station (Bronx Station) and two feeders.

5.7.2.5. Valley Capacity

Valley Station is a 115kV to 13.8kV distribution station located south of Valley, Washington. Valley 115/13kV Transformer 1 is a 7.5MVA transformer with three feeders, serving approximately 2400 service points. The station is fed by the Addy-Devil's Gap 115kV Transmission Line.

Valley 115/13kV Transformer and VAL12F1 feeder have exceeded the performance criteria in operational conditions.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Valley XFMR	100.32	100.32	100.32	100.32	100.32	100.32	100.32	100.32	100.32	100.32	100.32
VAL12F1	85.91	85.91	85.91	85.91	85.91	85.91	85.91	85.91	85.91	85.91	85.91

Table 39: Valley Winter Loading Beyond Performance Expectations

5.8. Distribution Contingency Analysis

The methodology to study distribution system performance during contingency events is under development. Contingency events intended to be studied include outages of feeders and station transformers.

5.9. Distribution Auto-Transfer Analysis

Analysis of feeder capacity during auto-transfer switching was performed based on peak summer loading. AT switches were modeled to toggle to their alternate source for evaluation of sufficient capacity on the adjacent feeder to pick up the load. Analysis results show 'Normal' and 'Switched' configuration loading values per feeder and ATS in Table 40.

Feeder ID - N/C Switch Feeder	Switch ID - N/C Switch Feeder	Case	N/C Switch Feeder (kVA)	N/C Switch Feeder (Amps)	Loading - N/C Switch Feeder (%)	Feeder ID - N/O Switch Feeder	Switch ID - N/O Switch Feeder	N/O Switch Feeder (kVA)	N/O Switch Feeder (Amps)	Loading - N/O Switch Feeder (%)
CDA124	ZC912AT-1	Normal	9,405	412.3	65.1	APW113	ZC912AT-2	6,507	333.6	65.1
CDA124	ZC912AT-1	Switched	8,708	381.4	60.6	APW113	ZC912AT-2	7,185	362.9	70.9
TEN1253	ZL1410E-2	Normal	8,608	407.7	70.7	TEN1255	ZL1410E-1	8,254	405.5	67.5
TEN1253	ZL1410E-2	Switched	6,796	324.4	53.2	TEN1255	ZL1410E-1	10,099	488.3	81.2
FWT12F3	Z554AT-1	Normal	5,767	265.0	43.2	NW12F2	Z554AT-2	6,115	275.0	53.7
FWT12F3	Z554AT-1	Switched	2,396	111.3	27.1	NW12F2	Z554AT-2	10,265	483.8	94.5
HOL1205	ZL1421E-1	Normal	3,292	157.5	36.5	SLW1316	ZL1421E-2	5,965	282.2	55.1
HOL1205	ZL1421E-1	Switched	2,567	121.7	28.2	SLW1316	ZL1421E-2	6,730	321.5	62.8
3HT12F7	Z614AT-1	Normal	9,521	429.4	64.6	3HT12F1	Z614AT-2	4,665	208.1	40.6
3HT12F7	Z614AT-1	Switched	4,684	221.7	62.7	3HT12F1	Z614AT-2	9,483	422.0	82.4
3HT12F1	Z1311AT-1	Normal	4,665	208.1	33.7	3HT12F7	Z1311AT-2	9,521	429.4	77.2
3HT12F1	Z1311AT-1	Switched	3,771	167.3	31.0	3HT12F7	Z1311AT-2	10,440	472.8	85.0
C&W12F4	Z365AT-1	Normal	6,279	314.4	63.7	3HT12F6	Z365AT-2	6,941	319.7	62.4
C&W12F4	Z365AT-1	Switched	3,408	180.7	35.0	3HT12F6	Z365AT-2	9,959	458.7	89.6
3HT12F5	688AT-3	Normal	8,363	376.1	59.1	3HT12F1	688AT-2	4,665	208.1	40.6
3HT12F5	688AT-3	Switched	8,111	365.5	58.4	3HT12F1	688AT-2	4,907	218.2	42.6
AIR12F3	Z669AT-1	Normal	4,206	224.8	41.5	FLN12F4	Z669AT-2	1,745	79.6	13.2
AIR12F3	Z669AT-1	Switched	2,086	120.0	19.8	FLN12F4	Z669AT-2	4,206	184.0	31.8

Table 40: Feeder Loading Under Normal and Switched ATS States

Analysis results show no feeders exceeding the 95% continuous loading performance criteria defined in *DP-SPP-02 – Distribution System Performance V5*. Evaluation of Pullman area ATS's is under development.

5.10. Distribution Short Circuit Analysis

Evaluation of fault interrupting device's ability to detect and isolate faults was performed using a short circuit analysis as described in *DP-SPP-02 – Distribution System Performance V5*. Five specific performance criteria were evaluated:

- Fault current shall be less than 95% of the interrupting equipment capability.
- Fault current shall be less than 7100A.
- Fault current shall be greater than two times the fuse rating.
- Fault current shall be greater than four times the maximum load.
- Fuse rating shall be greater than two times the maximum load.

5.10.1.Interrupting Rating

Fault current was found to exceed the performance criteria for four distribution devices as shown in Table 41. Each device listed has calculated expected fault current more than their designed ratings. Faults downstream of the devices cannot be expected to be interrupted.

Feeder	Equipment Type	Equipment Location	Interrupting Ability (Amps)	3PH-G Fault	1PH-G Fault	%Duty
CDA121	Recloser	C909R Midline	2000	3086	2296	154%
SPI12F2	Recloser	E170 Midline	2000	3259	3281	164%
SLW1358	Breaker	Station	2000	6425	6560	328%
SLW1348	Breaker	Station	2000	6425	6560	328%

Table 41: Distribution Interrupting Devices Exceeding 95% of Rating

The existing *Safely Interrupting Faults* project, previously developed to address transmission system performance deficiencies, will be evaluated to expand scope such that the listed distribution devices in Table 41 will be appropriately mitigated.

5.10.2.Maximum Available Fault Current

The feeders listed in Table 42 have maximum available fault current exceeding 7100A.

Feeder	Max of 3PH-G (A)	Max of L-G (A)
9CE12F4	7212	7291
9CE12F5	7213	7292
9CE12F6	7212	7291
F&C12F4	7005	7104
FLN12F4	7225	7307
LMR1530	7511	7631
LMR1531	7511	7632
LMR1532	7510	7629
PST12F2	5849	7678
SPU124	7092	8402
SUN12F4	7167	7244
SUN12F5	7168	7244
SUN12F6	7165	7239

Table 42: Feeder Maximum Available Fault Current

Corrective Action Plans will not be developed to mitigate the feeders listed in Table 42 from exceeding the criteria. Further evaluation of the criteria and its intended application will be performed. Establishing a maximum available fault current is typically done as a proxy for evaluated protective device coordination. It is not anticipated to have protective device coordination issues on the identified feeders.

5.10.3.Fuse to Fault Ratio

Calculated fault current was compared to fuse ratings for evaluation of correctly sized fuses to adequately see downstream faults. Across all Avista's distribution system, 288 fuses were identified to be sized too large. The typical location of the identified fuses is on feeders serving rural areas where the fault current becomes relatively low.

The complete list of fuses not meeting the 2:1 ratio performance criterion will be provided to Distribution Engineering for further evaluation. Evaluation may include confirming the actual installed fuse sizes are correctly listed in Avista's databases and, if appropriate, determine if the fuses can be replaced with smaller rated fuses.

5.10.4. Fuse to Load Ratio

Fuse ratings were compared to the maximum load for evaluation if a fuse could interrupt service to customers during peak loading scenarios. Across Avista's distribution system, 418 fuses were identified to be sized too small for the load connected downstream.

The complete list of fuses not meeting the performance criterion will be provided to Distribution Engineering for further evaluation. Evaluation may include confirming the actual installed fuse sizes are correctly listed in Avista's databases, reviewing load allocation assumptions, and if appropriate, determine if the fuses can be replaced with larger rated fuses.

5.10.5. Fault Current to Load Ratio

Calculated fault current was compared to the maximum load for evaluation if a fuse could be properly selected to meet both the fault to fuse rating and the fuse to load ratio performance criteria. The line segments with fuses listed in Table 43 are those with a fault to load ratio of less than four. The listed fuses are therefore assumed to not have the ability to be properly sized as either the fault current is too low, or the load is too high.

	Summer			Winter			
	Min Fault	Max Load	Fault to Load Ratio	Min Fault	Max Load	Fault to Load Ratio	Existing Fuse Size
BLU321							
389:1539652:0	380	126.4	3.0	380	185.9	2.0	S&C Positrol T Speed 80
389:4280629:0	237	76.4	3.1	237	113.4	2.1	S&C Positrol T Speed 65
389:3265172:2	163	50.7	3.2	163	74.0	2.2	S&C Positrol T Speed 50
394:3563517:1	212	64.1	3.3	212	94.2	2.2	S&C Positrol T Speed 50
389:4770838:0	150	44.0	3.4	150	64.2	2.3	S&C Positrol T Speed 30
389:839578:0	179	51.2	3.5	179	74.7	2.4	S&C Positrol T Speed 40
389:4280630:0				164	52.4	3.1	S&C Positrol T Speed 40
394:2670165:0				151	44.8	3.4	S&C Positrol T Speed 30
401:68835:1				132	36.7	3.6	S&C Positrol T Speed 40
CHW12F2							
389:1692631:12	265	77.9	3.4	265	124.4	2.1	S&C Positrol T Speed 50
389:4415813:0				359	137.7	2.6	S&C Positrol T Speed 65
389:3411553:1				449	142.6	3.2	S&C Positrol T Speed 80
CHW12F3							
389:3447682:1	109	81.1	1.3	109	159.8	0.7	S&C Positrol T Speed 65
389:741889:1	67	40.1	1.7	67	87.4	0.8	S&C Positrol T Speed 50
389:2154437:15	57	30.2	1.9	57	67.5	0.8	S&C Positrol T Speed 40
389:1613574:5	212	89.0	2.4	212	211.1	1.0	S&C Positrol T Speed 80
389:2170054:0	67	37.3	1.8	67	57.3	1.2	S&C Positrol T Speed 50
389:955447:5	62	34.0	1.8	62	52.4	1.2	S&C Positrol T Speed 30
394:437664:1	297	135.1	2.2	297	249.6	1.2	S&C Positrol T Speed 100
394:445022:0	50	16.2	3.1	50	36.3	1.4	S&C Positrol T Speed 10
394:435536:1	51	15.9	3.2	51	36.3	1.4	S&C Positrol T Speed 15
389:742632:1	61	26.3	2.3	61	40.5	1.5	S&C Positrol T Speed 25
389:742901:0	63	22.3	2.8	63	34.7	1.8	S&C Positrol T Speed 20
389:742970:2				117	45.3	2.6	S&C Positrol T Speed 15
389:767601:29				169	61.9	2.7	S&C Positrol T Speed 20
394:582970:1				158	56.8	2.8	S&C Positrol T Speed 25
389:741916:0				56	18.3	3.0	S&C Positrol T Speed 15
389:955251:28				53	18.0	3.0	S&C Positrol T Speed 15
389:3083707:6				49	15.9	3.1	S&C Positrol T Speed 6
389:1257273:0				57	17.4	3.3	S&C Positrol T Speed 15
389:2993690:0				55	16.0	3.5	S&C Positrol T Speed 10
389:742016:4				61	16.7	3.6	S&C Positrol T Speed 12

	Summer			Winter			
	Min Fault	Max Load	Fault to Load Ratio	Min Fault	Max Load	Fault to Load Ratio	Existing Fuse Size
389:742549:1				239	65.2	3.7	S&C Positrol T Speed 40
389:955204:5				106	28.0	3.8	S&C Positrol T Speed 40
CHW12F4							
389:742768:4				178	69.3	2.6	S&C Positrol T Speed 40
394:439931:0				136	50.6	2.7	S&C Positrol T Speed 25
394:438966:2				138	52.0	2.7	
394:3570429:1				184	57.9	3.2	S&C Positrol T Speed 40
394:783424:1				159	43.1	3.7	S&C Positrol T Speed 30
394:2269238:0				311	80.5	3.9	S&C Positrol T Speed 50
389:742956:2				91	23.5	3.9	S&C Positrol T Speed 15
389:3390773:0				586	145.9	4.0	S&C Positrol T Speed 80
CKF711							
389:2669074:2				308	93.6	3.3	S&C Positrol T Speed 100
389:2633810:0				269	77.1	3.5	S&C Positrol T Speed 50
389:3097044:0				284	79.5	3.6	S&C Positrol T Speed 65
FOR12F1							
389:4547122:0	255	67.5	3.8	255	119.3	2.1	S&C Positrol T Speed 100
389:2905939:2				84	27.9	3.0	S&C Positrol T Speed 25
389:3591044:0				158	47.4	3.3	S&C Positrol T Speed 50
FOR12F2							
389:4774089:0				148	49.9	3.0	S&C Positrol T Speed 50
GAR461							
389:533043:0	126	34.6	3.6	126	34.6	3.6	S&C Positrol T Speed 65
GIF12F1							
389:889011:2	65	35.6	1.8	65	66.1	1.0	S&C Positrol T Speed 30
389:1038656:1	60	29.7	2.0	60	55.2	1.1	S&C Positrol T Speed 25
389:2932987:0	57	26.2	2.2	57	48.8	1.2	S&C Positrol T Speed 20
401:71712:0	108	32.5	3.3	108	62	1.7	S&C Positrol T Speed 30
394:2778985:1	328	89.6	3.7	328	170	1.9	S&C Positrol T Speed 100
389:888266:2				52	22.4	2.3	S&C Positrol T Speed 15
394:529990:1				76	33	2.3	S&C Positrol T Speed 25
394:530667:1				73	28.7	2.6	S&C Positrol T Speed 20
389:2932985:0				57	19.6	2.9	S&C Positrol T Speed 20
389:888409:2				52	14	3.7	S&C Positrol T Speed 10
GIF34F1							
394:632567:18	53	45.8	1.2	53	76.4	0.7	S&C Positrol T Speed 20
389:2147347:2	95	56.2	1.7	95	93.7	1.0	S&C Positrol T Speed 30
389:1020420:2	175	62.1	2.8	175	103.5	1.7	S&C Positrol T Speed 40
389:888592:1	272	85.5	3.2	272	142.5	1.9	S&C Positrol T Speed 50
389:1043441:0				200	64.2	3.1	S&C Positrol T Speed 80
389:3881567:0				252	69.3	3.6	S&C Positrol T Speed 40
389:1010495:5				167	42	4.0	S&C Positrol T Speed 40
GIF34F2							
389:3215051:0				153	72.3	2.1	S&C Positrol T Speed 40
394:2884848:1				172	72.1	2.4	S&C Positrol T Speed 50
389:3130310:10				314	79.6	3.9	S&C Positrol T Speed 65
GRA12F2							
389:1416365:0	313	88.1	3.6	313	93.2	3.4	S&C Positrol T Speed 50
KET12F2							
389:1356506:0	146	40.8	3.6	146	46.6	3.1	S&C Positrol T Speed 65
LAT421							
389:595357:3				448	178.8	2.5	S&C Positrol T Speed 100
389:3872787:1				310	79.5	3.9	S&C Positrol T Speed 80
MLN12F2							
389:71182:0				625	164.9	3.8	S&C Positrol T Speed 100
OGA611							
389:4044018:2	133	37.7	3.5	133	37.3	3.6	S&C Positrol T Speed 50
SAG741							
389:2422312:32	336	103.0	3.3	336	119	2.8	S&C Positrol T Speed 65
389:1175353:0	257	80.4	3.2	257	92.7	2.8	S&C Positrol T Speed 50
389:869242:1	159	45.1	3.5	159	52.6	3.0	S&C Positrol T Speed 30

	Summer			Winter			
	Min Fault	Max Load	Fault to Load Ratio	Min Fault	Max Load	Fault to Load Ratio	Existing Fuse Size
394:3076647:0	153	38.0	4.0	153	44.4	3.5	S&C Positrol T Speed 25
SLK12F2							
394:3413044:1	473	127.1	3.7	473	132.7	3.6	S&C Positrol T Speed 80
394:3413037:1	490	127.1	3.9	490	132.7	3.7	S&C Positrol T Speed 100
SPI12F1							
389:3729587:2				178	59.8	3.0	S&C Positrol T Speed 65
SPI12F2							
389:945847:1	115	33.6	3.4	115	75.9	1.5	S&C Positrol T Speed 30
389:696602:5	72	19.8	3.6	72	45.1	1.6	S&C Positrol T Speed 25
389:1188115:0				193	79.5	2.4	S&C Positrol T Speed 40
394:2857330:1				298	101.9	2.9	S&C Positrol T Speed 50
STM633							
394:2430344:1	90	22.4	4.0	90	23	3.9	S&C Positrol T Speed 25
SUN12F4							
401:25646:0	433	119.7	3.6	433	126.3	3.4	S&C Positrol T Speed 140
SUN12F5							
389:292836:5				630	184.3	3.4	S&C Positrol T Speed 100
WAL543							
389:1072307:2	180	60.3	3.0	180	60.3	3.0	S&C Positrol T Speed 65
389:797745:21	127	38.1	3.3	127	38.1	3.3	S&C Positrol T Speed 50
389:4735971:6	54	13.3	4.0	54	13.3	4.0	S&C Positrol T Speed 20
COB12F1							
389:2416481:2	487	175.6	2.8				S&C Positrol T Speed 140

Table 43: Fault Current to Load Ratio

Corrective Action Plans will not be developed to mitigate each fuse listed in Table 43. In some instances, the results can be used to provide additional justification of existing projects such as the Carlin Bay project. Further evaluation of the study methodology and assumptions will be performed to determine the validity of the results.

5.11. NERC Compliance Summary

5.11.1. Instability Corrective Action Plans (FAC-014-3, R7)

The following Corrective Action Plans have been developed to address system instability identified through technical analysis in the Near-Term Planning Horizon.

CAP	Type of Instability	Criteria	Contingency	System Condition	Facilities
Coeur d'Alene Transmission Reinforcement	Steady state cascading	125% of the highest seasonal facility rating	BF: A624 Rathdrum East and West 115kV	Heavy Summer Heavy Winter	Otis Orchard - Post Falls 115kV Post Falls - Ramsey 115kV

Table 44: Corrective Action Plans Mitigating Instability

5.11.2. Facilities Contributing to Cascading, Instability, and Uncontrolled Separation (FAC-014-3, R8)

The following list of facilities comprise of a planning event contingency that would cause instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the BES as identified through technical analysis in the Near-Term Planning Horizon.

Planning Event	Facility	Reference
A624 Rathdrum East and West 115kV	Rathdrum bus tie breaker A624 Rathdrum East 115kV bus Rathdrum West 115kV bus	Section 5.1.1.6

Table 45: Facilities Contributing to Instability, Cascading, or Uncontrolled Separation

5.11.3. WECC Path Elements

The following list of Avista owned facilities are elements within a WECC rated path.

Avista Facility	Location	WECC Path
Coulee (BPA) to Westside	230kV transmission tine	6 – West of Hatwai
Dry Creek to Talbot (PacifiCorp)	230kV transmission line	6 – West of Hatwai
Lolo to Oxbow (IPC)	230kV transmission line	14 – Idaho-Northwest
Burke to Thompson Falls #1 (NWECO)	115kV transmission line	8 – Montana-Northwest
Burke to Thompson Falls #2 (NWECO)	115kV transmission line	8 – Montana-Northwest
Devil's Gap to Stratford	115kV transmission line	6 – West of Hatwai
Lind to Warden	115kV transmission line	6 – West of Hatwai
North Lewiston to Tucannon River (BPA)	115kV transmission line	6 – West of Hatwai
A437 Circuit Breaker	Burke Station	8 – Montana-Northwest
A438 Circuit Breaker	Burke Station	8 – Montana-Northwest
A520 Circuit Breaker	Devil's Gap Station	6 – West of Hatwai
R617 Circuit Breaker	Dry Creek Station	6 – West of Hatwai
R517 Circuit Breaker	Dry Creek Station	6 – West of Hatwai
A36 Circuit Breaker	Lind Station	6 – West of Hatwai
R487 Circuit Breaker	Lolo Station	14 – Idaho-Northwest
R387 Circuit Breaker	Lolo Station	14 – Idaho-Northwest
A586 Circuit Breaker	North Lewiston Station	6 – West of Hatwai
A1014 Circuit Breaker	Stratford Station	6 – West of Hatwai
A253 Circuit Breaker	Warden Station	6 – West of Hatwai
R634 Circuit Breaker	Westside Station	6 – West of Hatwai
R534 Circuit Breaker	Westside Station	6 – West of Hatwai

Table 46: Avista Facility Elements within WECC Paths

6. Appendix A – System and Company Description

6.1. Overview

Avista is a publicly held energy company primarily involved in the production, transmission, and distribution of energy (natural gas and electricity). Avista, formerly known as The Washington Water Power Company, was founded on March 13, 1889, in Spokane, Washington, by 10 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 396,082 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 41 geographically displays the Avista service territory.

Figure 41: Avista Service Territory

6.2. Transmission System

6.2.1. Transmission Infrastructure

Avista owns and operates a system of over 2,300 miles of electric transmission facilities which include approximately 700 miles of 230kV and 1,600 miles of 115kV transmission lines. Figure 42 illustrates Avista's Transmission System on a regional map.

Figure 42: Avista Transmission Line Map

The Avista 230kV transmission lines are the backbone of Avista's Transmission System and consist of two "rings" centered near the Spokane and Coeur d'Alene areas. The northern ring connects generation in northwestern Montana to the larger load centers while the southern ring serves the Moscow-Pullman and Lewiston-Clarkston areas. Figure 43 shows a station-level drawing of Avista's 230kV transmission system including interconnections to neighboring utilities. Avista's 230kV transmission system is interconnected to the BPA 500kV transmission system at BPA's Bell, Hot Springs, and Hatwai Stations.

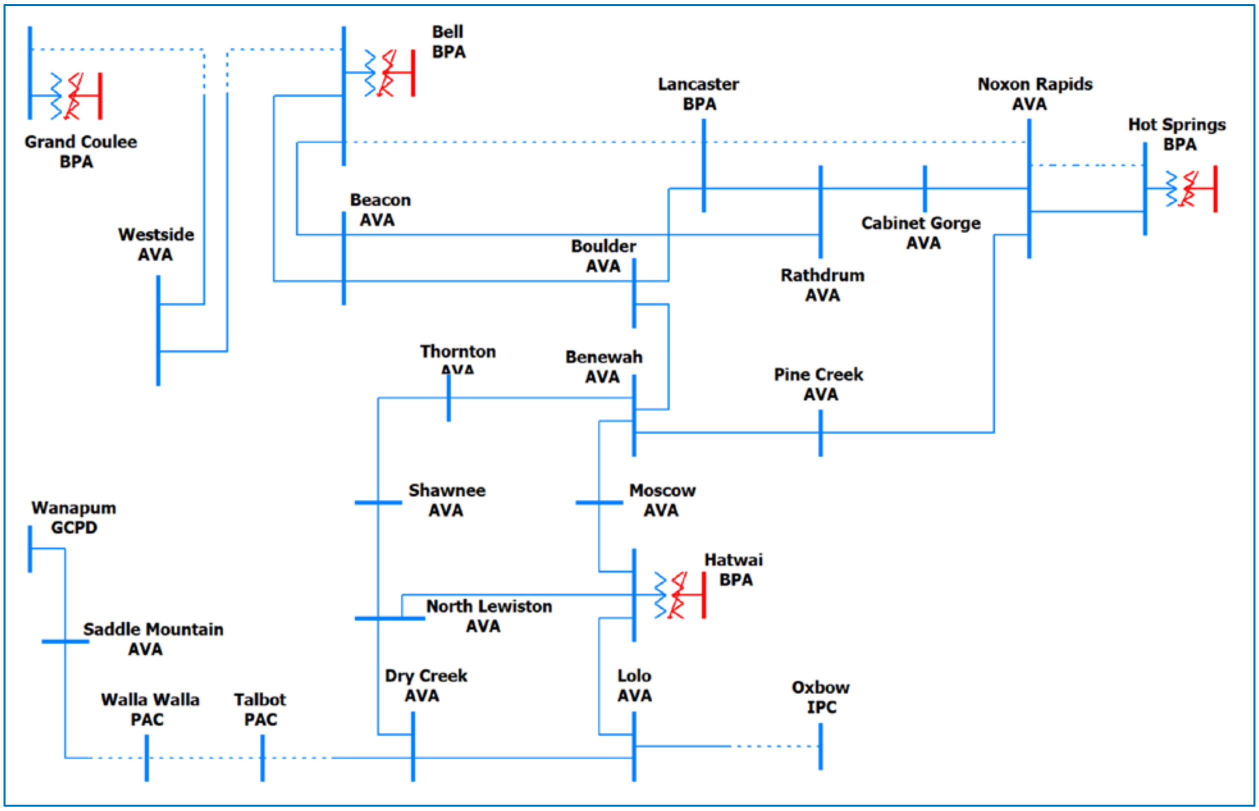

Figure 43: Avista 230kV Transmission System

6.2.2. Transmission System Areas

Avista has separated its transmission system into the five geographical areas, namely Spokane, Coeur d'Alene, Big Bend, Palouse, and Lewis-Clark. The areas are shown with their approximate boundaries in Figure 44.

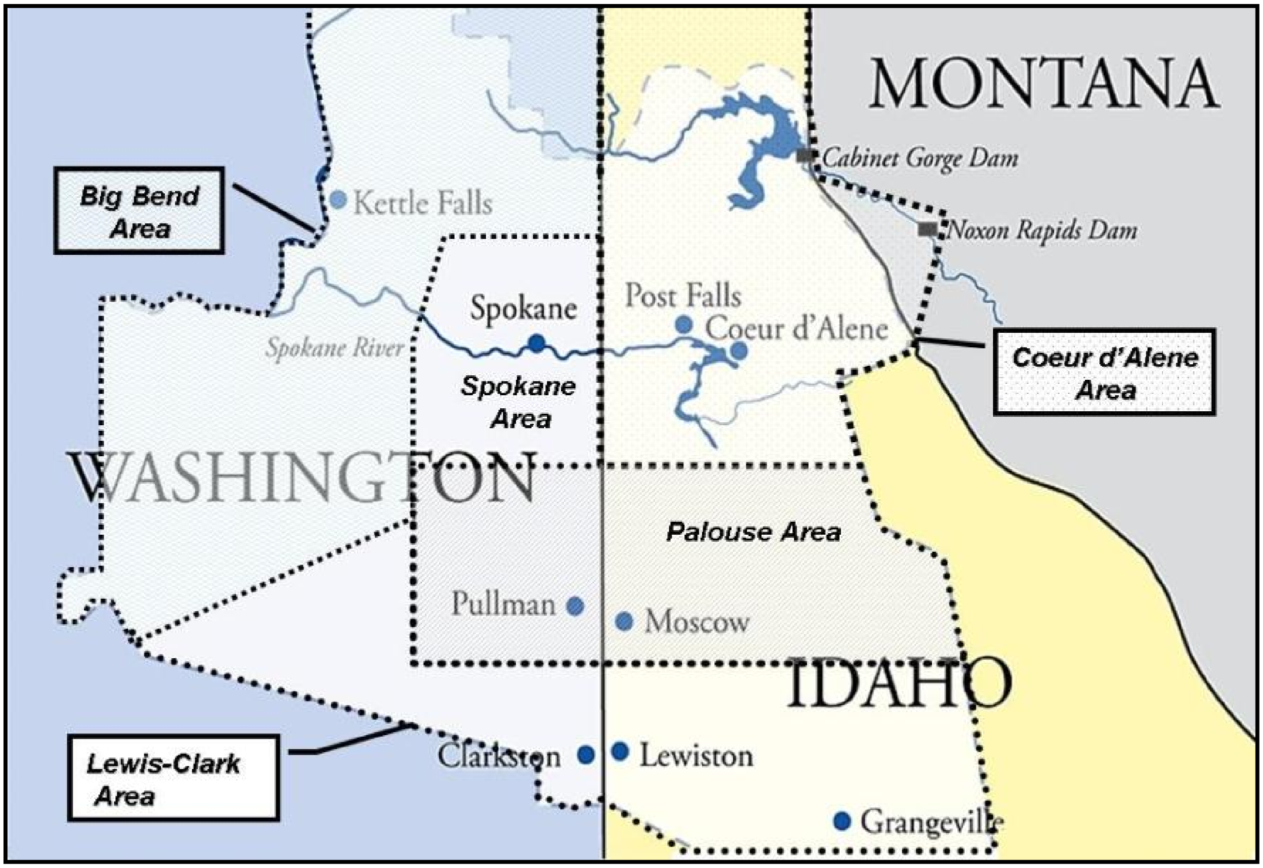

Figure 44: Avista Transmission System Regions

6.2.3. WECC Rated Paths

Avista owns transmission assets in the following WECC transfer paths:

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

6.2.4. Points of Interconnection

Avista's BAA is directly interconnected to the BAAs operated by BPA, Public Utility District No. 2 of Grant County, Public Utility District No. 1 of Chelan County, Idaho Power Company, PacifiCorp, NorthWestern Energy, and Seattle City Light.

Significant points of interconnection are associated with the BPA 500/230kV transformers located at G.H. Bell Substation in Spokane, Washington, Hatwai Substation in Lewiston, Idaho, and Hot Springs Substation in Hot Springs, Montana.

Within Avista's BAA, Avista's transmission and distribution system is interconnected with Pend Oreille PUD's transmission system and several Load Serving Entities including Asotin County PUD, Big Bend Electric Cooperative, City of Cheney, City of Chewelah, Clearwater Power Company, Fairchild Air Force Base, Idaho County Light & Power Cooperative, Inland Power & Light Company, Kootenai Electric Cooperative, Modern Electric Water Company, Northern Lights, and City of Plummer. Avista-owned generation and distribution stations not connected directly to Avista's transmission system are typically telemetered into Avista's BAA.

6.3. Generation Resources

Avista has a diverse mix of generation with most of its generation being hydropower with various projects located on the Spokane and Clark Fork Rivers. Avista owns eight hydroelectric 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 utilizes power supply purchase and sale arrangements of varying lengths to meet a portion of its load requirements.

For more information on Avista’s generation, please refer to Avista’s latest Integrated Resource Plan (IRP).

6.4. Distribution System

Avista’s distribution system consists of over 19,200 miles of distribution lines operated at voltages ranging from 12.5kV to 34.5kV. Most of the distribution system is configured as radial feeders with ties to adjacent feeders and stations for redundancy. The distribution system serving the downtown Spokane area is an exception and is operated in a networked configuration.

6.5. Customer Demand

Avista develops a biannual Electric IRP which is a thoroughly researched and data-driven document to guide responsible resource planning for the company.

6.5.1. Native Load

Avista historically experiences peak load in the winter months, between November and early February. Air conditioning loads have created some pockets where summer peak load can exceed the winter peak load. This phenomenon has transformed Avista into a dual peaking utility.

As documented in the IRP, Avista’s 20-year native peak load growth rate was 0.35 percent in the winter and 0.42 percent in the summer.

6.5.2. Balancing Authority Area Load

The BAA load growth rate is expected to be consistent with the native load growth rate. The forecast data for the loads which are not Avista’s native loads are provided by BPA on behalf of the Load Serving Entity of each load.

Avista’s BAA load peaked at 2,514MW in the winter of 2022 and 2,380MW in the summer of 2021. Figure 45 and Figure 46 shows the BAA load historical winter and summer peaks from 2008-2020 and the forecasted monthly peaks for 2021-2030.

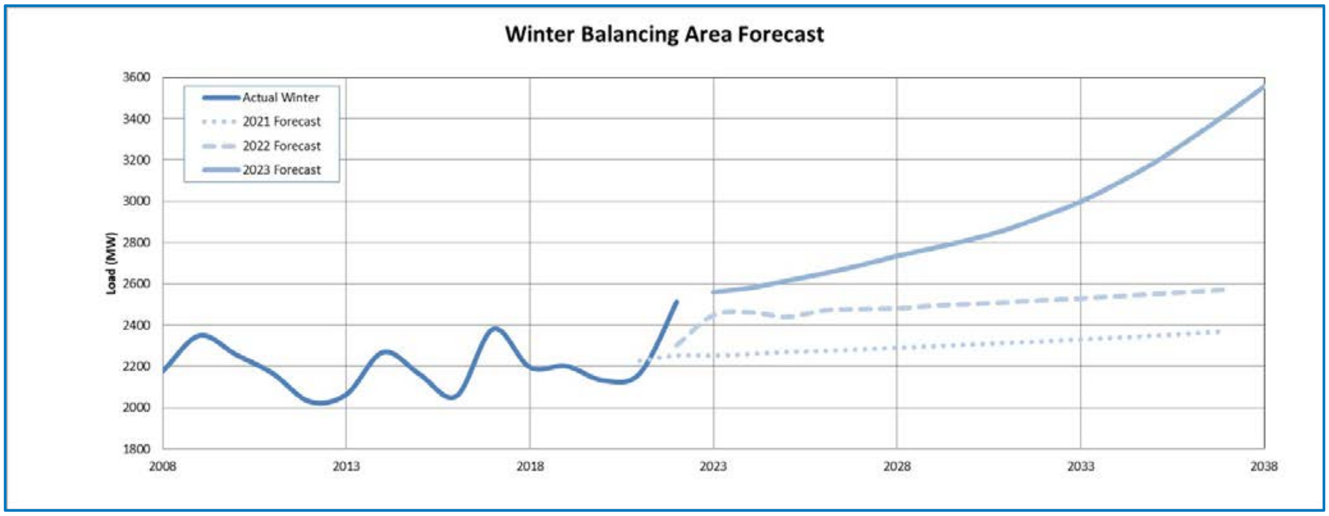

Figure 45: Winter Balancing Authority Area load forecast

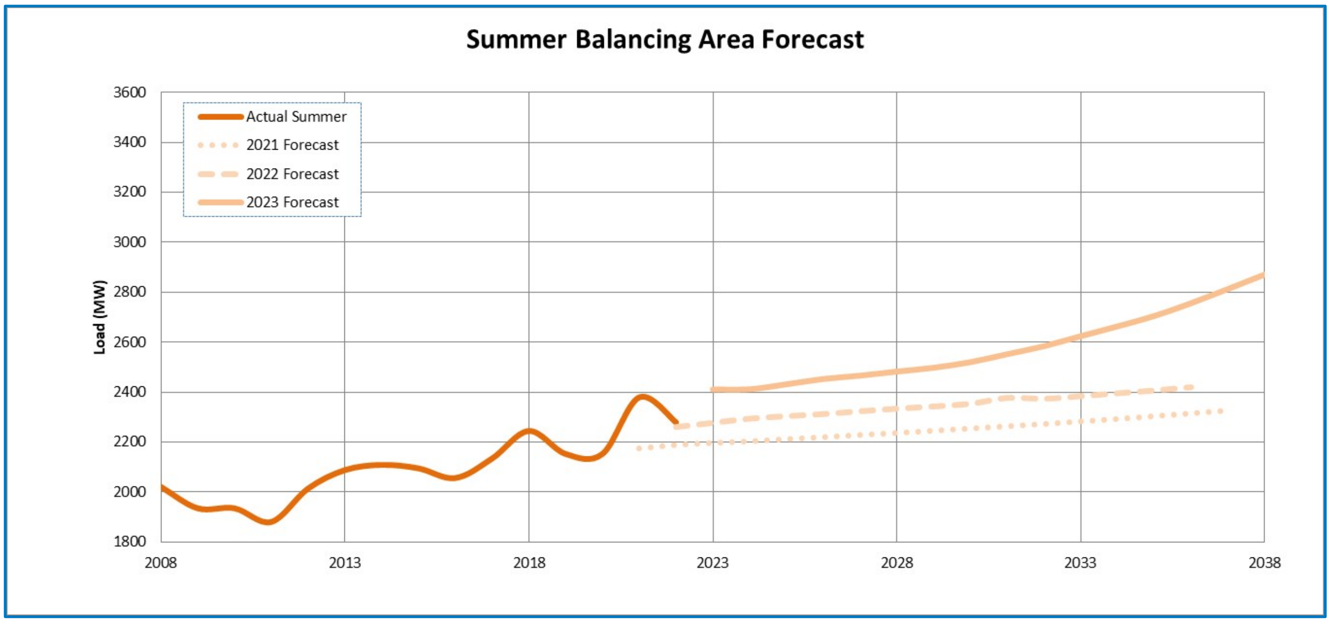

Figure 46: Summer Balancing Authority Area load forecast

7. Appendix B – Transmission Models

7.1. Planning Case Development

A set of transmission system models (Planning Cases) are developed biannually to model Avista's 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* outlines the use of WECC-approved base cases and applying steady state and dynamic data modifications as required representing desired scenarios. Additional details are provided in *TP-SPP-01 – Transmission System Performance* and the *Avista System Planning Assessment - 2023 Study Plan*.

The following scenarios are developed to represent various seasonal conditions over the near-term and long-term transmission planning horizons (TPL-001-5, R2, R2.2):

- The Heavy Summer cases represent a typical summer peak scenario where the Avista BAA is near peak load with local hydro generation at mid to late summer output. These scenarios model moderate transfers on Path 8 and Path 14 across Avista's BAA and heavy Path 8 transfers south into Idaho's BAA. These scenarios are limited by the summer thermal limits on various elements of the Transmission System, which helps to define where the system is near capacity.
  - The first year is the latest Operations case projected out to the following year.
  - The fifth and tenth year are based on the latest WECC approved cases.
- The Heavy Winter cases represent a typical winter peak scenario where the Avista BAA is near peak load and the local hydro generation is at moderate levels. These scenarios model significant transfers across Avista's BAA from regional thermal resources. The lower ambient temperature increases the operating limits of the various elements of the Transmission System and the reactive load is near unity power factor.
  - The first year is the latest Operations case projected out to the following year.
  - The fifth and tenth year are based on the latest WECC approved cases.
- The Light Spring cases represent typical April and May loading during early morning minimum load conditions.
- Spring peak scenario with High West of Hatwai Flows (High Transfer case): during light summer (nighttime 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 establish some of the arming levels for Remedial Action Schemes. 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.

7.2. Case Summary

Scenario	Description (likelihood or "return time")	1 Year (2024)	5 Year (2028)	10 Year (2033)	TPL
Heavy Summer	Loads 1 in 20*****, Generation per Generation Dispatch******	X	X	X	R2.1.1, R2.2.1, R2.4.1, and R2.5
Heavy Winter	Loads 1 in 20*****, Generation per Generation Dispatch******		X		R2.1.1, R2.2.1, R2.4.1 and R2.5
Heavy Spring	Sensitivity to high load during the spring		X		R2.1.3 and R2.4.3 sensitivity for R2.1.2 and R2.4.2
Light Spring	Loads 1 in 2*****, Generation per Generation Dispatch******		X		R2.1.2 and R2.4.2
HS 5-Year Projects	Sensitivity to Proposed five-year Projects during Heavy Summer***		X		R2.1.3 and R2.4.3 sensitivity for R2.1.1 and R2.4.1
High E-W Transfer	Sensitivity to light load, high generation, and high system transfers		X		R2.1.3 and R2.4.3 sensitivity for R2.1.2 and R2.4.2

*****	All monthly historical peaks during indicated season used to calculate median monthly peak value. For loading 1 in 20, during any given year, 5% of the time the seasonal peak will be above indicated loads, and 95% of the time the seasonal peak will be below.
******	Generation units are placed on or off using the Generation Dispatch sheet according to the season indicated.
*******	Scenario will assume planned projects are not constructed therefore representing the existing transmission system facilities.

Table 47: System Assessment Evaluation Case Descriptions

8. Appendix C – Investment Driver Definitions

8.1. Customer Requested

Includes customer requests for new gas or electric service connections, line extensions, or system reinforcements to serve a single large customer. We have often referred to new service connections as “growth.” Prompt and efficient response to customer requests for service is a Commission requirement.

Example Projects and Programs:

1. Installing electric and natural gas distribution facilities in a new housing or commercial development.
2. Adding street or area lights per request from the City/County or private individual, respectively.
3. The costs associated with the first installation of electric and gas meters.

8.2. Customer Service Quality and Reliability

Investments required to maintain or improve service quality, to introduce new types of services and options to meet customer needs and expectations, to meet customer service quality requirements, and to achieve our electric system reliability objectives.

Example Projects and Programs:

1. Advanced Metering Infrastructure
2. Specific projects that are predominantly built to improve system reliability such as distribution automation, worst feeder program, or outage management system
3. Adding new customer products and services such as community solar, building energy management systems
4. Redeveloping our customer website – www.avistautilities.com

8.3. Mandatory and Compliance

Investments driven by compliance with laws, rules, and contractual obligations that are external to the Company such as State and Federal statutes, settlement agreements, FERC, NERC, and FCC rules, Commission Orders, among others.

Example Projects and Programs:

1. Investments to meet FERC hydro license conditions such as the mitigation of gas super-saturation, or environmental permit requirements including clean air and water.
2. Spending required to meet contract requirements, such as the owner/operator agreement for Colstrip, or tribal settlement agreements.
3. Transmission additions to meet NERC/WECC planning requirements.
4. To comply with regulatory requirements such as identifying and remediating gas overbuilds, natural gas cathodic protection, or hydro safety requirements.
5. Costs for relocating natural gas or electric facilities associated with road development projects,
6. To comply with franchise agreements or right-of-way permits including state, county, city franchise and tribal permits.
7. Investments required under regulatory settlements such as isolated steel pipe removal.

8.4. Performance and Capacity

Includes a range of system reinforcement projects to meet defined performance standards, typically developed by the Company, or to enhance the performance level of assets based on a demonstrated need or financial analysis.

Example Projects and Programs:

1. Upgrades to transmission, station, and distribution assets to relieve grid congestion or to mitigate thermal overloads.
2. Gas pipeline capacity needed to meet the Company's "design day" standard of -25F°.
3. Investments in hydro and thermal generation to maintain a level of unit availability or to achieve efficiency output objectives.
4. New employee training facilities to accommodate greater numbers of craft apprentices entering the workforce.
5. Ergonomic office equipment to reduce the incidence of employee health issues.
6. New engineering building at the Clark Fork River projects.
7. Purchase or expand office facilities to accommodate additional employees or special projects, including Project Atlas and Project Everest as examples.
8. New computer software and hardware to achieve work process and business continuity objectives.

8.5. Asset Condition

Investments to replace assets based on industry accepted, asset management principles and strategies. Asset management strategies are designed to optimize the overall lifecycle value for customers. Examples of common asset strategies include:

1. Run to failure (streetlights)
2. Inspection-based replacement (gas leak survey, pole test and treat)
3. Monitor-based replacement (power transformer gas monitoring)
4. Calendar-based replacement (PC refresh, cell phones)
5. Condition-based replacement (fleet replacement based on age, vehicle mileage, and operating expense)

Example Projects and Programs:

1. Personal computer (3-year) and cell phone (2-year) refresh cycles
2. Wood pole inspection and replacement (20-year)
3. HVAC replacement (condition based)
4. Aldyl-A pipe program
5. New replacement office furniture
6. Project Compass
7. New roof for office building
8. New microwave communications system (driven by FCC)
9. Replacement of fleet vehicles and equipment
10. Natural gas meter ERTs
11. Gantry crane replacement program
12. Spokane hydro redevelopment
13. Thermal plant "run-time" capital maintenance program
14. Distribution transformer change-out program (TCOP)

15. Station inspection and equipment replacement program (circuit breakers, voltage regulators, insulators, cables, and control systems)

8.6. Failed Plant and Operations

Requirements to replace failed equipment such as failed transformers, switches, poles, wires, cables, gas pipes, and meter sets. Also includes inspection-based replacements of natural gas and electric infrastructure identified by Operations.

Example Projects and Programs:

1. Cable, equipment, vaults, and manholes located in Avista's electric secondary district (Spokane business district)
2. Electric distribution minor blanket (capital maintenance and repairs of existing overhead and underground systems)
3. Electric and gas meter blanket (replacement of failed units)
4. Transmission blanket (storm response)
5. Electric distribution storm damage
6. Natural gas minor blanket (capital maintenance and repairs of existing gas plant)

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