2023-2024 System Assessment

Local Planning Report

Beacon Station, Spokane, Washington

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Redacted Version

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.

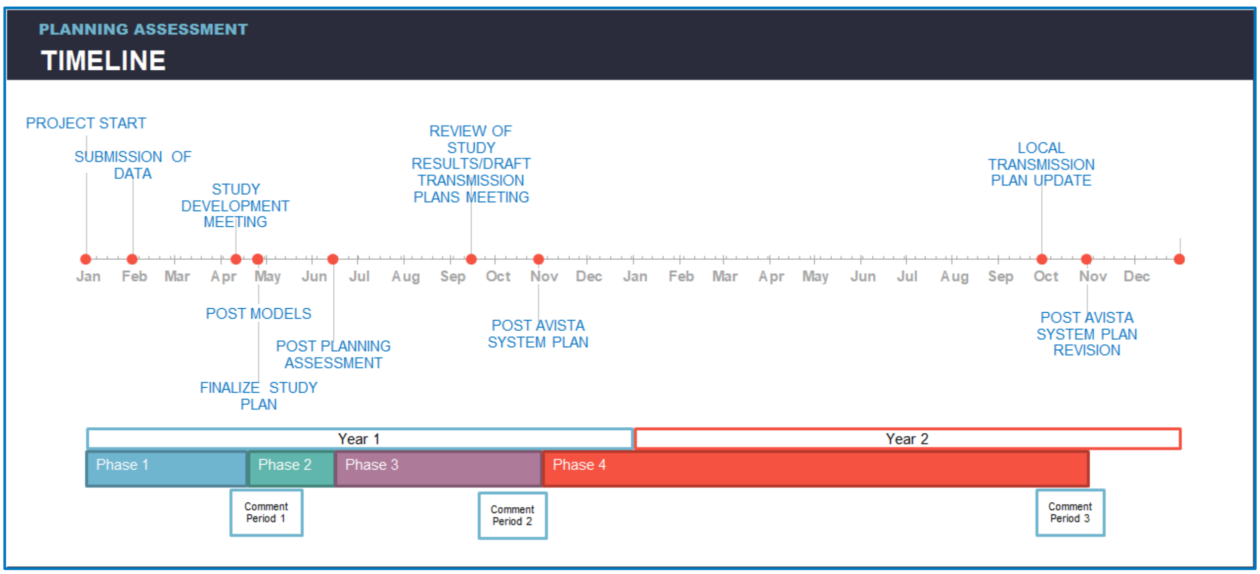

Figure 1: Planning Assessment Timeline

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
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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.

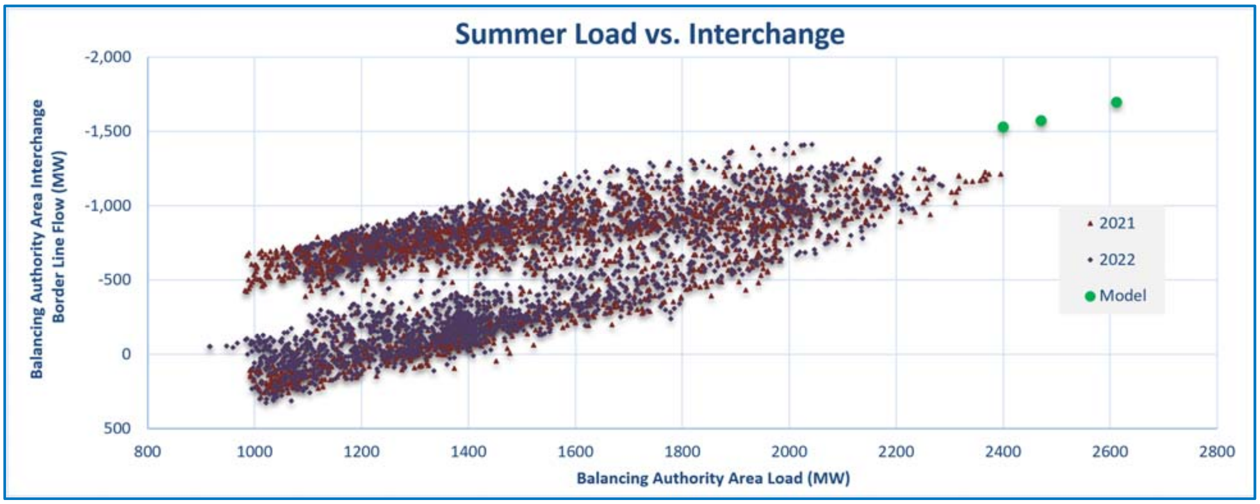

Figure 2: Historical Avista BAA Load Versus Interchange During Summer Months

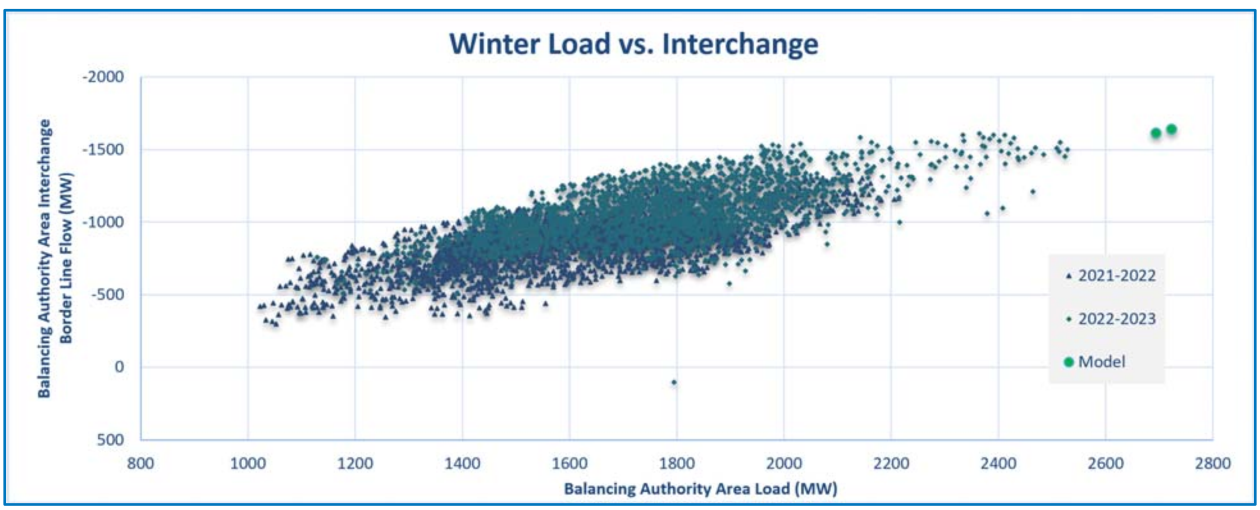

Figure 3: Historical Avista BAA Load Versus Interchange During Winter Months

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.

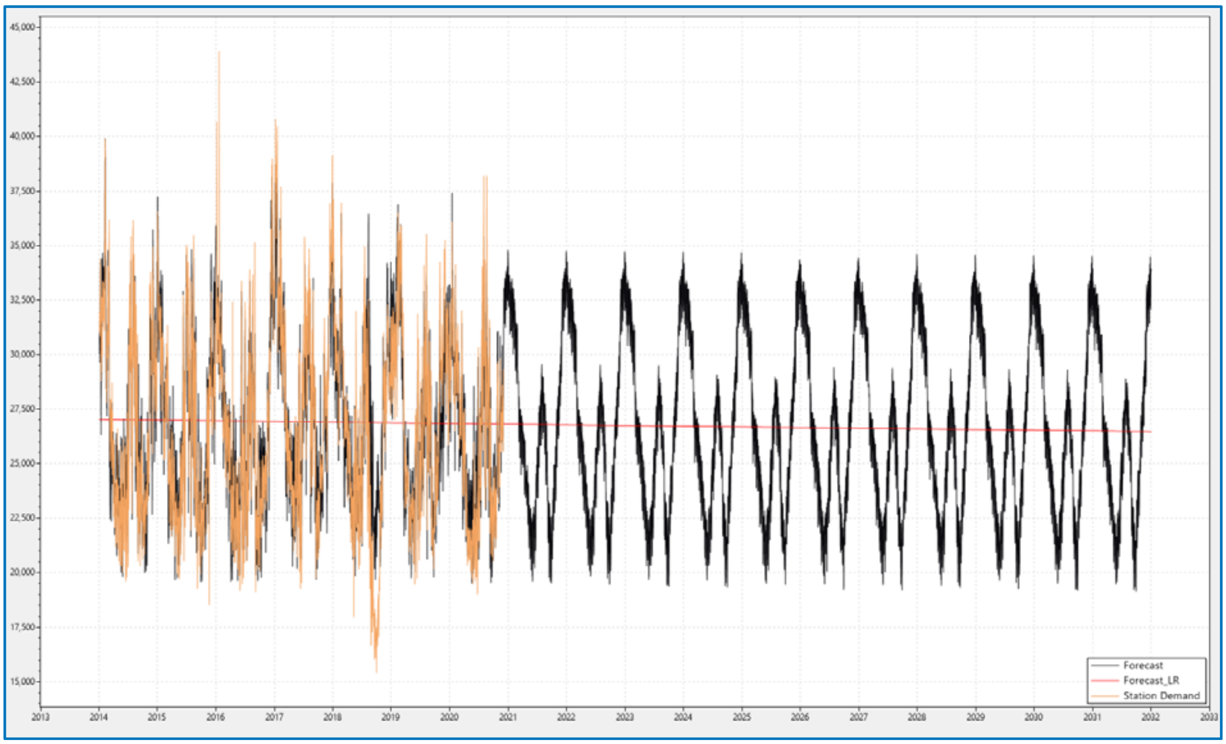

Figure 4: College & Walnut-Example Load Regression Analysis Forecast

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.

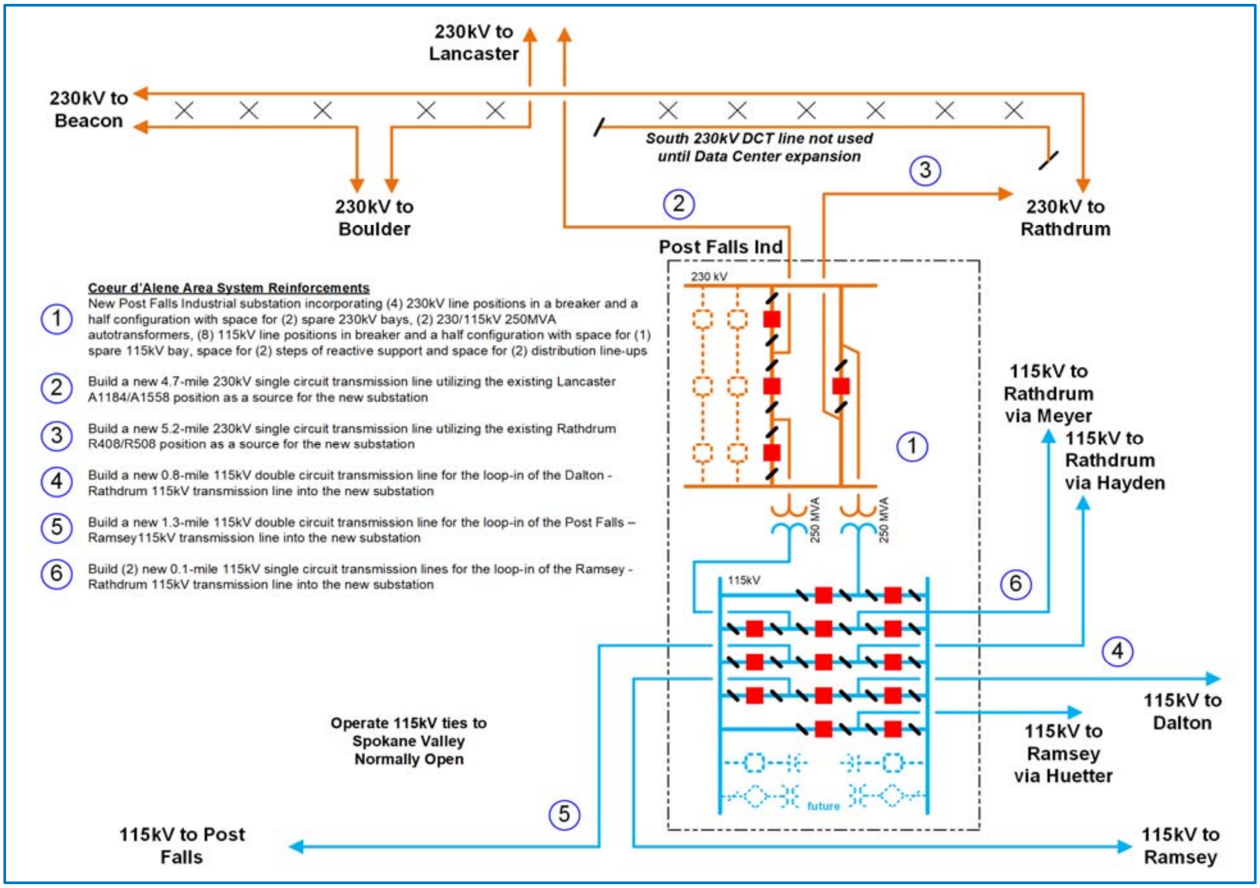

Figure 5: Coeur d’Alene Transmission Reinforcement

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.

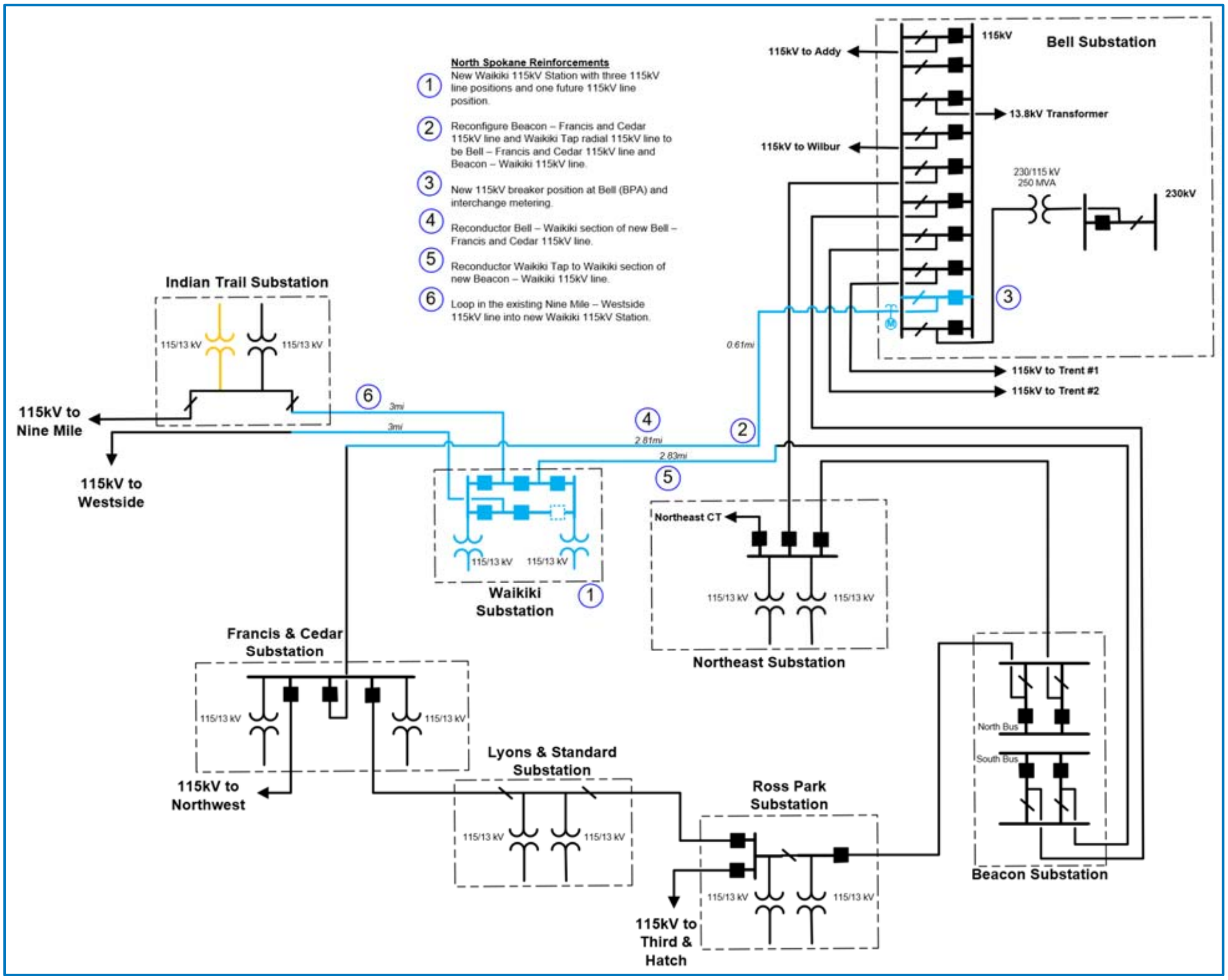

Figure 6: Beacon – Francis & Cedar 115kV Reinforcement

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

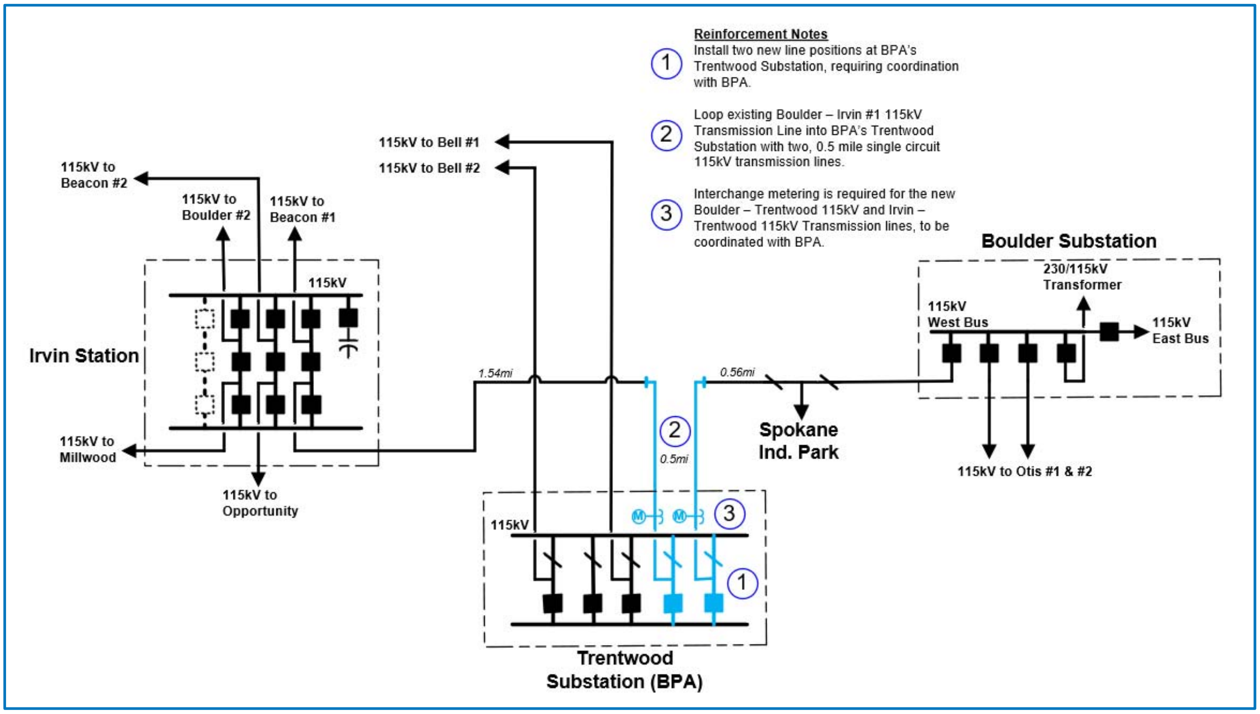

Figure 7: Boulder – Irvin #1 115kV Loop into Trentwood

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.

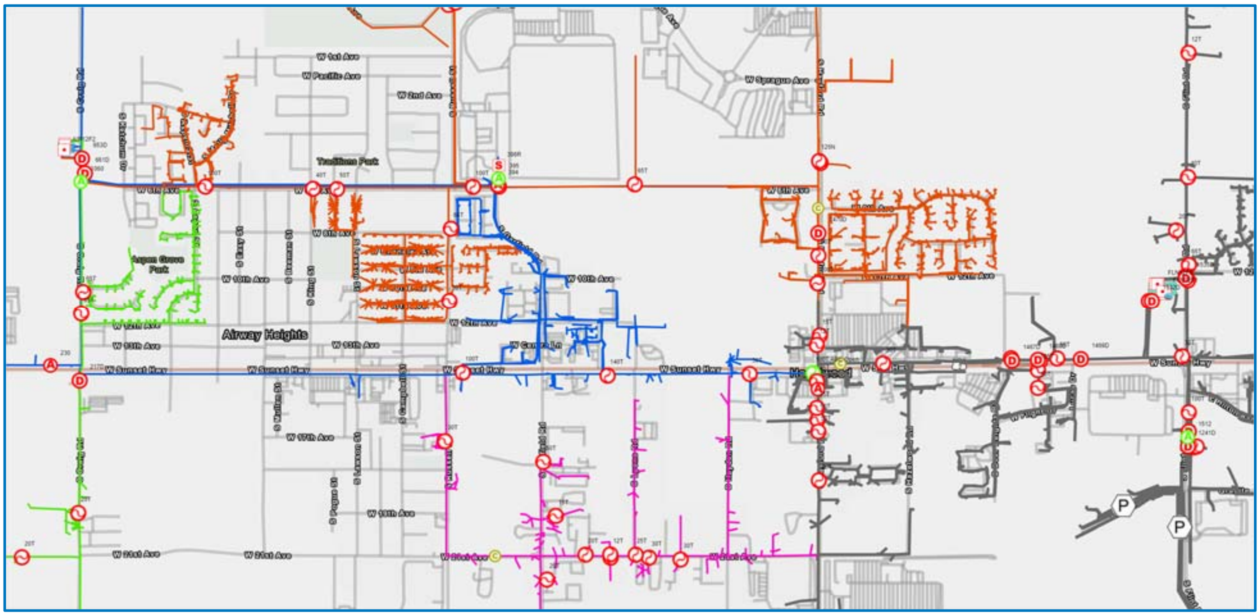

Figure 8: Airway Heights Capacity Considerations

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.

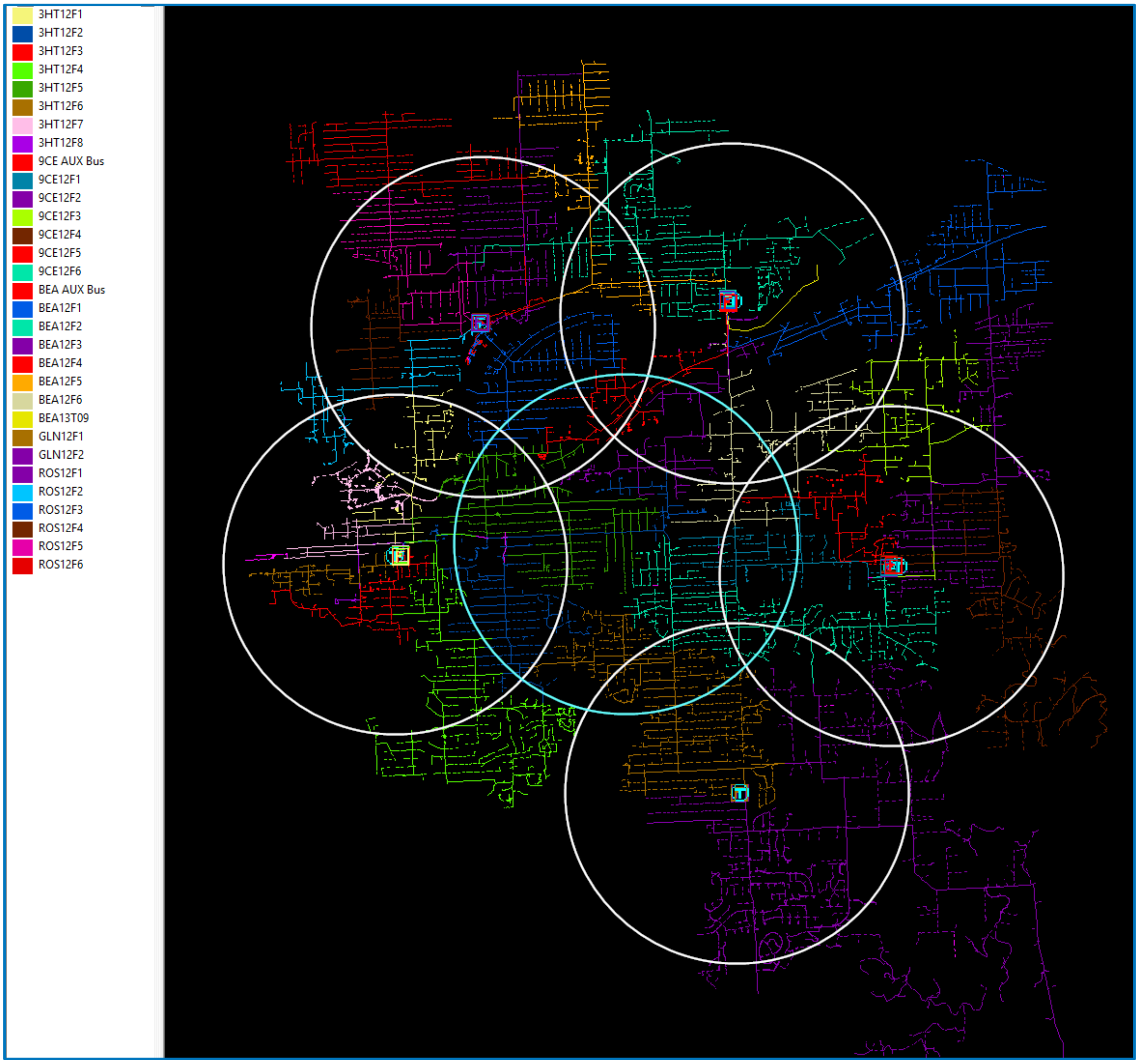

Figure 9: Spokane Area Station Coverage

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.

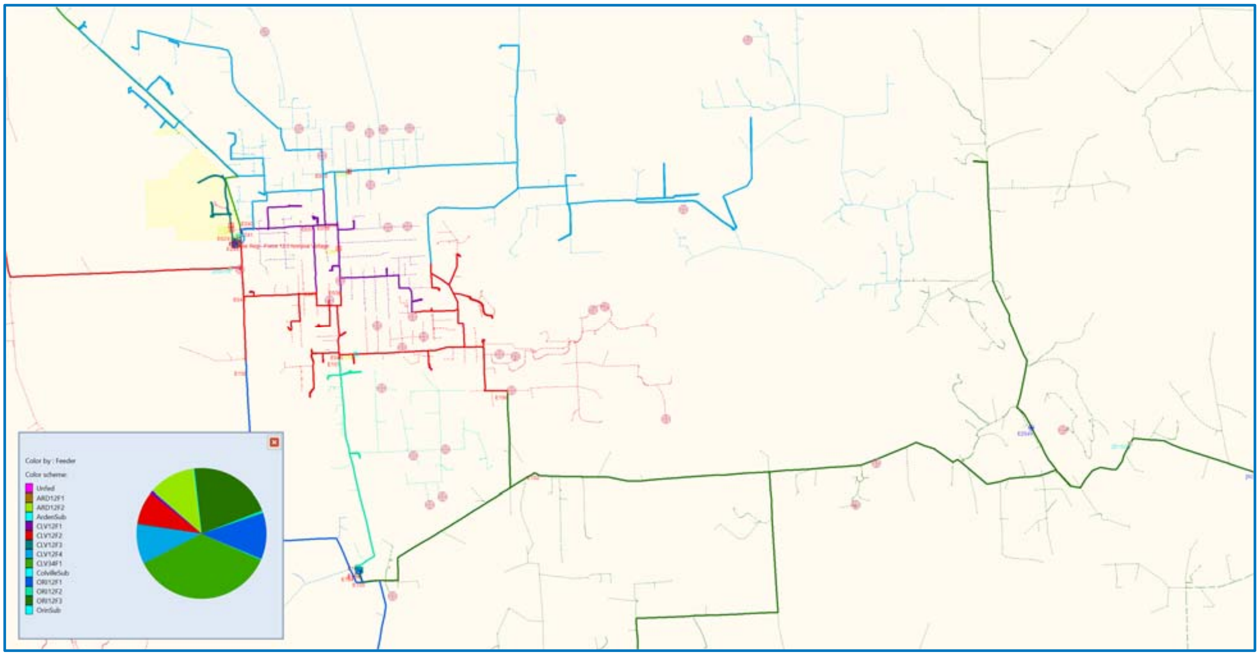

Figure 10: Colville Area Orin Feeder Mitigation

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)

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

5.3. Transmission Short Circuit Analysis (R2.3)

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

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

5.6. Transmission Single Point of Failure

5.7. Distribution Multi-Year Load-Flow Analysis

5.8. Distribution Contingency Analysis

5.9. Distribution Auto-Transfer Analysis

5.10. Distribution Short Circuit Analysis

5.11. NERC Compliance Summary

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.

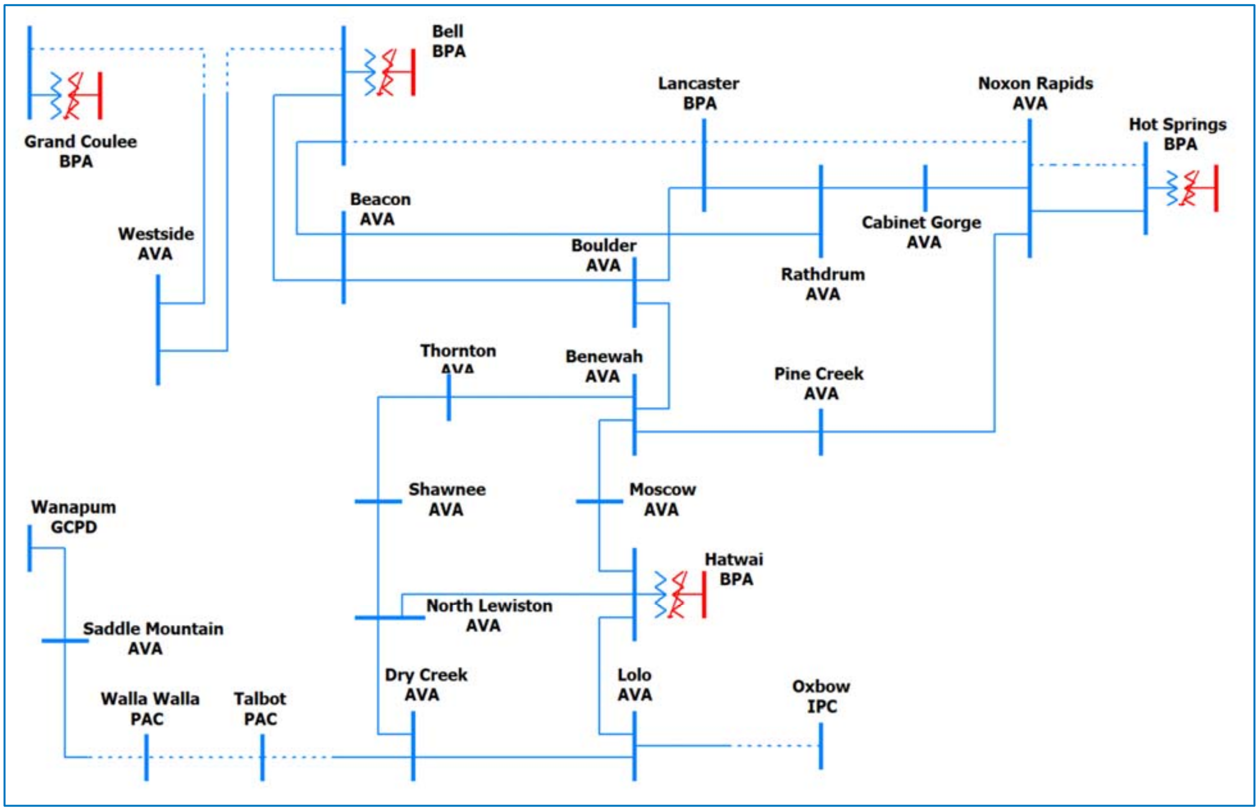

Figure 43: Avista 230kV Transmission System

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.

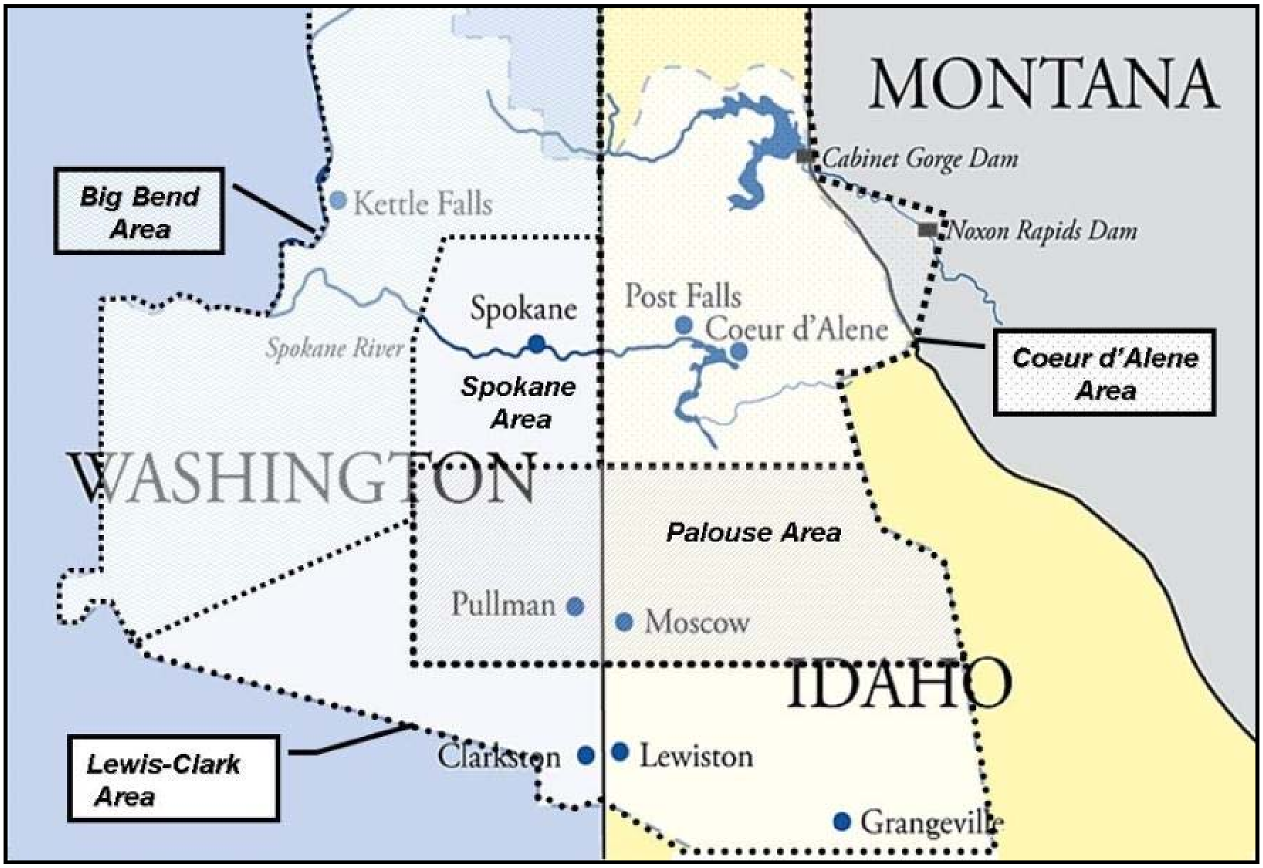

Figure 44: Avista Transmission System Regions

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.

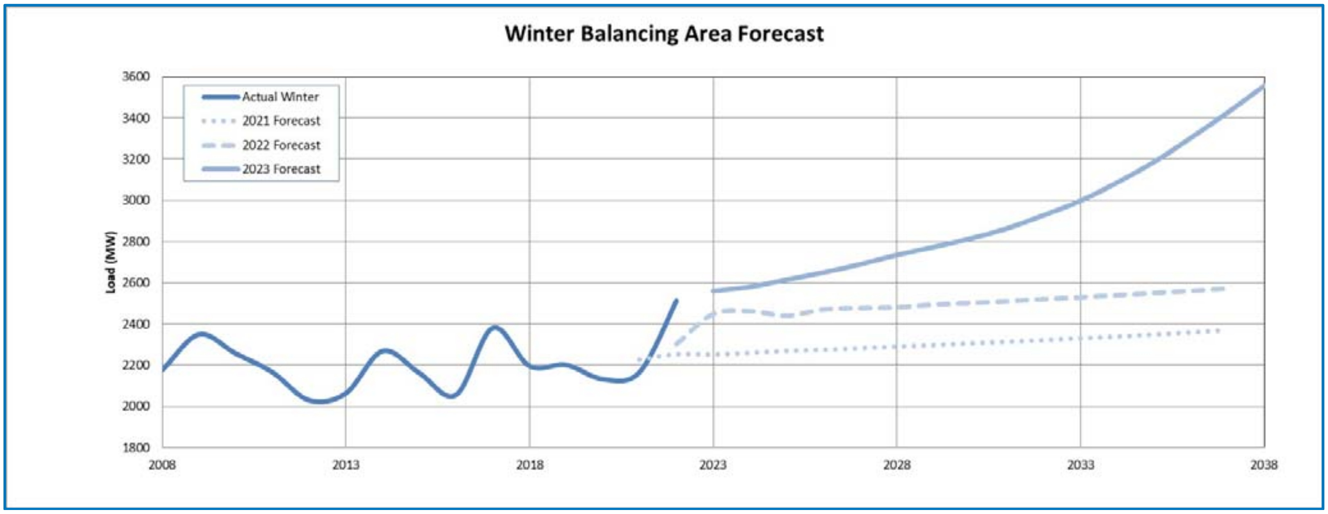

Figure 45: Winter Balancing Authority Area load forecast

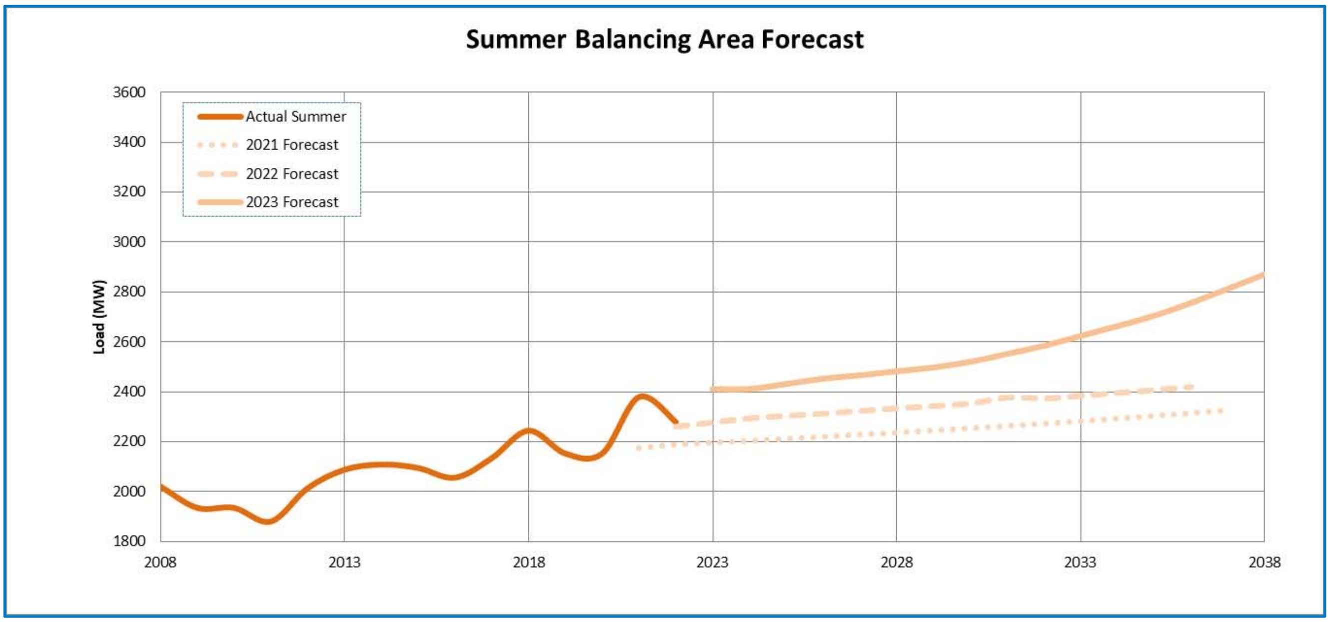

Figure 46: Summer Balancing Authority Area load forecast

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)